Chapter-II

2. Performance review relating to Government Company

Assam Power Generation Corporation Limited

Review on the working of Assam Power Generation Corporation Limited

Executive summary

Power is an essential requirement for all facets of life and has been recognized as a basic human need. In Assam, the generation of power is managed by the Assam Power Generation Corporation Limited (APGCL) which was incorporated in 23 October 2003 under the Companies Act, 1956. As on 31 March 2010, APGCL had two Thermal Power Stations (TPS) and one Hydel Power Station with installed capacity of 254 MW and 100 MW respectively. The turnover of APGCL was ₹ 331.32 crore in 2009-10 which was equal to 9.41 *per cent* and 0.38 *per cent* of the of State PSU's turnover and State Gross Domestic Product respectively. It employed 1,386 employees as on 31 March 2010.

Capacity addition and project management

Against 1,855 MW being capacity addition envisaged by the Government of Assam (GOA) to meet the energy generation requirement in the State during 2005-10, the actual addition was 100 MW leaving a deficit of 1,755 MW. The State was not in a position to meet the demand as the power generated as well as purchased together fell short by 2,697.98 MU and 3,541.36 MU in 2005-06 and 2009-10 respectively due to shortfall in capacity addition.

One, out of four projects taken up for implementation during the period of review, scheduled to be completed by June 2008, remained incomplete even after a lapse of 28 months from the schedule. Progress of three other projects was also tardy. These projects have already incurred cost overrun of ₹ 377 crore.

Contract management

During 2005-10, contracts valuing ₹ 911.44 crore were awarded for execution. APGCL extended undue favour to Bharat Heavy Electricals Limited (BHEL) by reducing liquidated damage (LD) by ₹ 9.75 crore. The Company also incurred avoidable liability of ₹ 51 crore for not claiming excise duty benefit admissible under deemed export benefit of Foreign Trade Policy 2004-09.

Operational performance

Performance of the existing generating stations depends on efficient use of material, manpower and capacity of the plant so as to generate maximum energy possible without affecting the long term operation of the plant.

Audit scrutiny of operational performance revealed the following:

Procurement of gas

The Company failed to arrange adequate gas required for generation of power by its two TPS. This resulted in loss of generation of 606.82 MU valuing ₹ 47.61 crore.

Consumption of gas

The heat consumption per unit of electricity generated ranged from 3,581Kcal/unit to 4,022 Kcal/unit during the period 2005-10 as against 3,266 to 3,658 Kcal/ unit being norms prescribed

by the Assam Electricity Regulatory Commission (AERC) which resulted in excess consumption of gas valuing ₹ 51.58 crore.

Deployment of manpower

APGCL had 1,386 employees as on 31 March 2010. The actual manpower did not conform to the norms recommended in National Electricity Plan (NEP). The excess manpower entailed extra expenditure of ₹ 165.06 crore.

Plant Load Factor (PLF)

The average PLF of all the TPS though increased from 36.17 *per cent* in 2005-06 to 61.02 *per cent* in 2009-10, it still remained below the national average of 77.22 *per cent*. The shortfall in generation with reference to national PLF worked out to 3,110.58 MU.

Outages

Total hours lost due to planned outages though decreased from six *per cent* in 2005-06 to 0.96 *per cent* in 2006-07, it again increased to 6.36 *per cent* in 2009-10. The forced outages though decreased over the five years from 46.46 to 19.77 *per cent* of the total available hours, it remained above the norm of 10 *per cent* fixed by Central Electricity Authority (CEA).

Auxiliary consumption

The actual auxiliary consumption of the two TPS exceeded the norm fixed by AERC which resulted in excess consumption of 105.49 MU of energy which could have otherwise been despatched to the grid.

Financial management

Despite having sufficient fund in the fixed deposits, the Company resorted to bank overdraft to meet the cash deficit from operating activities. This resulted in avoidable interest liability of ₹ 68.86 lakh. Further, the Company suffered loss of interest of ₹ 4.31 crore on blocked funds due to holding of inventory in excess of norms of Central Electricity Regulatory Commission (CERC).

Environmental Issues

The Company did not address the environmental issues in proper perspective as it was not equipped with the facilities for monitoring and control of environmental pollution. Although, all the four ongoing projects were eligible for carbon credit benefit, APGCL failed to initiate action for registration of the project as Clean Development Mechanism project at the DPR stage due to lack of awareness. The company lost potential revenue of ₹ 69.32 crore in the form of carbon credit in Lakwa Waste Heat Recovery Project. Benefit that would have been available in respect of three other projects have also not been worked out by the Company.

Conclusion and Recommendations

The deficiencies in the Company's functioning are controllable and there is scope to improve the performance through better management of its operations. The review contains eight recommendations which include proper project management, ensuring adequate receipt of gas to run the power stations, and developing a proper system of MIS so that the operations of the company can be properly monitored by the top management.

Introduction

2.1 Power is an essential requirement for all facets of life and has been recognized as a basic human need. The availability of reliable and quality power at competitive rates is crucial to sustain growth of all sectors of the economy. The Electricity Act, 2003 provides a framework conducive to development of the Power Sector; promotes transparency and competition and protects the interest of the consumers. Pursuant to Section 3 of the *ibid* Act,

the Government of India (GOI) prepared the National Electricity Policy (NEP) in February 2005 in consultation with the State Governments and Central Electricity Authority (CEA) for development of the Power Sector.

During 2005-06, the electricity requirement in Assam, as approved by Assam Electricity Regulatory Commission (AERC), was 3449 Million Units (MU). Of that, only 751.02 MU were available in 2005-06, leaving a shortfall of 2697.98 MU (78 *per cent*). The comparative figures of required and available generation for the year 2009-10 were 5253.36 MU and 1712 MU respectively, leaving a deficit of 3541.36 MU. Thus, there was a growth in demand of 1804.36 MU over the period of 5 years against which the availability increased only by 960.98 MU.

The State had installed capacity of 844.5 MW, at the beginning of 2005-06, which increased to 944.5 MW at the end of 2009-10.

During 2005-10, actual capacity addition was only 100 MW against 254 MW planned by the State, leaving a shortfall of 154 MW. The State was not in a position to meet the demand as the power generated as well as power purchased fell short by 127 to 267 MW during 2005-10.

2.2 Power generation in Assam is carried out by Assam Power Generation Corporation Limited (APGCL) which was incorporated on 23 October 2003 under the Companies Act, 1956. It functions under the administrative control of the Power Department of the Government of Assam. The Management of the Company is vested with a Board of Directors comprising of not more than nine and not less than six Directors and it is headed by a Chairman appointed by the State Government. As on March 2010, the Board comprised of eight members including the Chairman. The day-to-day operations are carried out by the Managing Director, who is the Chief Executive of the Company, with the assistance of four Chief General Managers and three General Managers, who head each power station. The Company had two thermal generation stations and one hydro generation station with the installed capacity of 254 MW and 100 MW respectively. The turnover of the Company was ₹ 331.32 crore in 2009-10, which was equal to 9.41 *per cent*[*] and 0.38 *per cent*[*] of the State PSUs turnover and State Gross Domestic Product respectively. It had 1386 employees as on 31 March 2010.

Scope and Methodology of Audit

2.3 The present review, conducted during February 2010 to May 2010, covers the performance of the Company during 2005-10. The review mainly deals with Planning, Project Management, Financial Management, Operational Performance, Environmental Issues and Monitoring by top management. The

* Total Turnover of all the State PSUs ₹ 3522.26 crore and the State GDP ₹ 88023 crore.

audit examination involved scrutiny of records at the Head Office and all the three generating stations. The methodology adopted for attaining the audit objectives with reference to audit criteria consisted of explaining audit objectives to top management, scrutiny of records at Head Office and selected units, interaction with the auditee personnel, analysis of data with reference to audit criteria, raising of audit queries, discussion of audit findings with the Management and issue of draft review to the Management for comments.

Audit Objectives

The objectives of the performance audit were:

2.4.1 Planning and Project Management

- To assess whether capacity addition programme taken up/ to be taken up to meet the shortage of power in the State is in line with the National Policy of 'Power for All by 2012';
- To assess whether a plan of action is in place for optimization of generation from the existing capacity; and
- To ascertain whether the execution of projects were managed economically, effectively and efficiently.

2.4.2 Financial Management

- To ascertain whether the projections for funding the new projects and up-gradation of existing generating units were realistic including the identification and optimal utilization for intended purpose; and
- To assess the soundness of financial health of the generating undertakings.

2.4.3 Operational Performance

- To assess whether the power plants were operated efficiently and preventive maintenance as prescribed was carried out minimising the forced outages;
- To assess whether requirements of each category of fuel worked out realistically, procured economically and utilised efficiently;
- To assess whether the manpower requirement was realistic and its utilisation optimal; and
- To assess whether the Life Extension (LE), Renovation and Modernization (R&M) programmes were ascertained and carried out in an economic, effective and efficient manner.

2.4.4 Environmental Issues

To assess whether the various types of pollutants (air, water, noise, hazardous waste) in power stations were within the prescribed norms and complied with the statutory requirements.

2.4.5 Monitoring and Evaluation

To ascertain whether adequate MIS existed in the entity to monitor and assess the impact and utilize the feedback for preparation of future schemes.

Audit Criteria

2.5 The audit criteria adopted for assessing the achievement of the audit objectives were:

- National Electricity Plan, guidelines of Central Electricity Authority;
- Standard procedures adopted by the Company for award of contract;
- Targets fixed for generation of power and parameters fixed for plant availability, Plant Load Factor (PLF) etc;
- Performance of best operating units/ all India Averages; and
- Prescribed norms for planned outages and Acts relating to Environmental laws.

Financial Position and Working Results

2.6 The company has finalised its accounts only up to 2008-09 and prepared provisional accounts for 2009-10 based on which the financial position of the company for the five years ending 2009-10 are given below:

Financial Position of APGCL for the period 2005-10

Particulars	2005-06	2006-07	2007-08	2008-09	2009-10 (Provisional)
(₹ in crore)					
A. Liabilities					
Paid up Capital	455.86	455.86	455.86	455.86	455.86
Reserve & Surplus (including Capital Grants but excluding Depreciation Reserve)	61.21	141.67	161.87	158.66	232.35
Borrowings (Loan Funds)					
Secured	NIL	271.87	361.06	348.86	301.18
Unsecured	281.80	125.48	134.57	152.53	151.23
Current Liabilities & Provisions	110.24	124.98	106.95	225.83	261.09
Total	**909.11**	**1119.86**	**1220.31**	**1341.74**	**1401.71**
B. Assets					
Gross Block	715.76	1177.11	1022.11	1070.08	978.20
Less: Depreciation	542.66	576.95	466.42	509.87	463.62
Net Fixed Assets	173.10	600.16	555.69	560.21	514.58
Capital works-in-progress	467.33	197.82	282.01	384.81	445.53
Investments	51.62	91.92	29.87	9.46	12.56
Current Assets, Loans and Advances	176.12	186.21	303.85	323.56	389.49
Miscellaneous Expenditure	0.03	0.02	0.02	0.01	NIL
Accumulated losses	40.91	43.73	48.87	63.69	39.55
Total	**909.11**	**1119.86**	**1220.31**	**1341.74**	**1401.71**

The table indicates that accumulated losses of the Company though increased from ₹ 40.91crore in 2005-06 to ₹ 63.69 crore in 2008-09,it came down to ₹ 39.55 crore in 2009-10. The Debt Equity ratio of the Company ranged from 0.54:1 to 0.82:1 during the five years period indicating that the Company has been unable to take advantage of financial leverage.

The details of working results like cost of generation of electricity, revenue realisation, net surplus/loss and earnings and cost per unit of operations are given below:

Working Results of APGCL for the period 2005-10

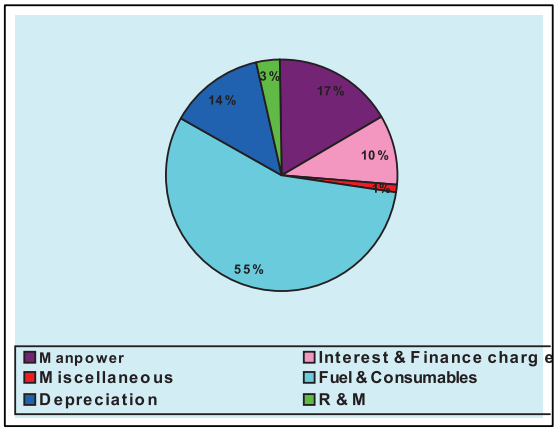
Sl. No.	Description	2005-06	2006-07	2007-08	2008-09	2009-10 (Provisional)
			(₹ in crore)			
1	Income					
	Generation Revenue	133.73	152.91	247.65	351.16	331.32
	Other income including interest/subsidy	1.78	9.91	17.58	9.29	35.95
	Total Income	**135.51**	**162.82**	**265.23**	**360.45**	**367.27**
2	Generation					
	Total generation (In MUs)	808.05	867.54	1541.32	1682.82	1712.21
	Less: Auxiliary consumption (In MUs)	57.03	62.19	67.53	84.14	57.03
	Total generation available for Transmission and Distribution (In MUs)	**751.02**	**805.35**	**1473.79**	**1598.68**	**1655.18**
3	**Expenditure**					
(a)	**Fixed cost**					
(i)	Employees cost	34.35	31.95	35.07	73.87	57.44
(ii)	Administrative and General expenses	1.79	2.12	2.55	4.71	2.60
(iii)	Depreciation	30.56	32.19	51.14	43.45	46.24
(iv)	Interest and finance charges	23.41	7.36	33.83	80.02	32.37
	Total fixed cost	**90.11**	**73.62**	**122.59**	**202.05**	**138.65**
(b)	**Variable cost**					
(i)	Fuel consumption Gas	82.72	103.46	120.50	159.12	187.08
(ii)	Lubricants and consumables	0.19	0.29	0.94	0.56	0.63
(iv)	Maintenance	3.30	3.45	3.15	5.74	10.96
	Total variable cost	**86.21**	**107.20**	**124.59**	**165.42**	**198.67**
C.	Total cost 3(a) + (b)	176.32	180.82	247.18	367.47	337.32

Sl. No.	Description	2005-06	2006-07	2007-08	2008-09	2009-10 (Provisional)
			(₹ in crore)			
4	Realisation (per unit)	1.78	1.89	1.67	2.20	2.00
5	Fixed cost (per unit)	1.20	0.91	0.83	1.26	0.84
6	Variable cost (per unit)	1.15	1.33	0.84	1.03	1.20
7	**Total cost per unit (5+6)**	**2.35**	**2.24**	**1.67**	**2.29**	**2.04**
8	**Contribution per unit (4-6)**	**0.63**	**0.56**	**0.83**	**1.17**	**0.80**
9	**Profit (+)/Loss(-) (4-7)**	**-0.57**	**-0.35**	**0.00**	**-0.09**	**-0.04**

2.6.1 Elements of Cost

Diagram I

Components of various elements of cost

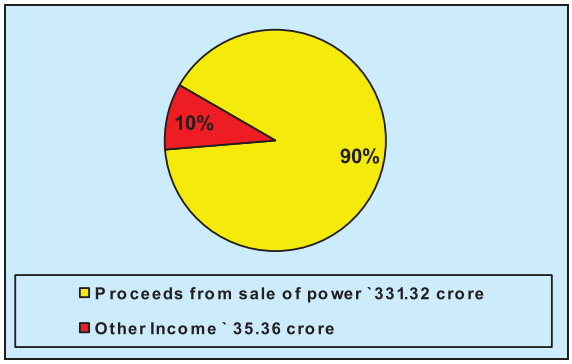


Employees cost, interest & finanicial charges and fuel & consumables constitute the major elements of costs. The percentage break-up of costs for 2009-10 is given in pie chart-I.

2.6.2 Elements of revenue

Diagram II

Components of various elements of revenue

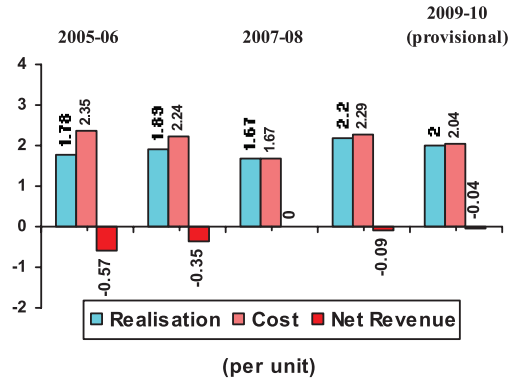


Proceeds from sale of power constitutes the major element of revenue. The percentage break-up of revenue for 2009-10 is given in pie chart-II.

2.6.3 Recovery of cost of operations

Diagram-III

Recovery of Cost of Operations



APGCL was not able to recover its cost of operations. During the last five years ending 2009-10, the net revenue has been negative except in the year 2007-08 as shown in bar chart-III.

Barring 2007-08, APGCL failed to recover its cost of operation during 2005-10.

Had the total revenue earned by APGCL been sufficient to cover the cost, additional resources of ₹ 92.34 crore could have been made available for capacity addition/life extension programmes. The main reasons for high cost of generation have been poor capacity utilization, high auxiliary consumption, high man power cost, high interest cost etc.

Audit Findings

2.7 Audit explained the audit objectives to the Company during an 'entry conference' held on 02 February 2010. Subsequently, audit findings were reported to the Company and the State Government and discussed in an 'exit conference' held on 22 July 2010, which was attended by the Principal Secretary, Power and Transport Department and the Managing Director of the Company. The Company replied to audit findings on 12 August 2010. Replies from the Government are still awaited (November 2010). The views expressed by the Company have been considered while finalising this review. The audit findings are discussed below:

Operational Performance

2.8 The operational performance of APGCL for the five years ending 2009-10, given in ***Annexure –7*** was evaluated on various operational parameters. It was also examined whether APGCL was able to maintain pace of capacity addition with the growing demand for power in the State. Audit findings, discussed in the subsequent paragraphs, disclose that the losses were controllable and there was ample scope for improvement.

Planning

2.9 National Electricity Policy (NEP) aims at making available over 1000 units of electricity per capita by 2012. To achieve that the Government of India (GOI) emphasised full exploitation of hydro potential being cheaper source of energy compared to thermal. Besides, environmental concerns are also to be suitably addressed through appropriate advance actions.

During the period from 2005-10, actual generation was substantially less than the peak demand as shown below:

Peak Demand and Corresponding Own Generation

Year	Own Generation at peak demand (MW)	Peak Demand(MW)	Percentage of actual generation to Peak Demand
2005-06	90.00	716.00	12.56
2006-07	67.50	797.10	8.47
2007-08	235.40	868.90	27.09
2008-09	232.80	892.60	26.08
2009-10	225.20	984.10	22.88

Actual generation was 8 to 27 *per cent* of peak demand.

The actual generation was 8 to 27 *per cent* of the peak demand. The total supply even after import was not sufficient to meet the peak demand as shown below:

Peak Demand and Sources of Meeting Peak Demand

Year	Peak Demand (MW)	Peak Demand met (MW)	Sources of meeting peak demand		Peak Deficit (Percentage of Peak Demand)
			Own (MW)	Import (MW)	
2005-06	716.00	576.00	90.00	486.00	20
2006-07	797.10	626.10	67.50	558.60	21
2007-08	868.90	741.90	235.40	506.50	15
2008-09	892.60	625.60	232.80	392.80	30
2009-10	984.10	750.10	225.20	524.90	24

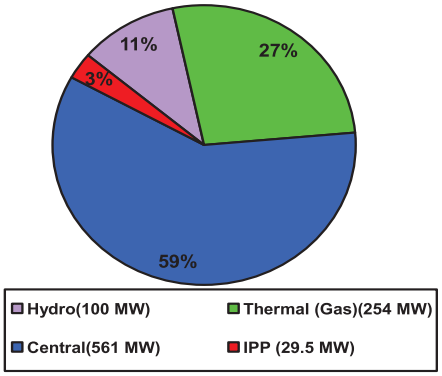
The shortfall in generation led to import of energy at higher cost.

The shortfall of 127 to 267 MW (about 15 to 30 *per cent* of the peak demand) was noticed even after import of 279.25 MU of energy at higher cost incurring additional expenditure of ₹ 107.97 crore during the period from 2006-07 to 2009-10. This shortfall resulted in rotational load shedding forced on the populace.

2.9.1 Capacity Additions

Diagram IV

Installed capacity



The State had total installed capacity of 844.5 MW, at the beginning of 2005-06, increased to 944.5 MW at the end of 2009-10. The break-up of generating capacities, as on 31 March 2010 under thermal (Gas), hydro, Central and Independent Power Producers (IPP) is shown in pie chart –IV.

To meet the energy generation requirement of 8126 MUs in 2010 as assessed by the State Government, capacity addition of about 1855 MW was required during 2005-10. 'Projects under Construction' (PUC) earmarked for capacity addition in the State during 2005-10 according to NEP are detailed below:

Projects under Construction and Committed Projects.

Sector	Thermal	Hydro	Non-conventional Energy	Total
	(In MW)			
Project(s) Under Construction	38	-	-	38
Total	**38**	**-**	**-**	**38**

Installed capacity, capacity additions envisaged, actual additions and peak demand vis-à-vis energy supplied during 2005-10 were as below:

Capacity, additions planned and achieved and demand vis-à-vis supply.

Sl. No.	Description	2005-06	2006-07	2007-08	2008-09	2009-10
1.	Capacity at the beginning of the year (MW)	254	254	254	354	354
2.	Additions Planned for the year as per National Electricity Plan (MW)	-	38	-	-	-
3.	Additions planned by the Company/State (MW)	-	-	100	54	100
4.	Actual Additions (MW)	-	-	100	-	-
5.	Capacity at the end of the year (MW) (1 + 4)	254	254	354	354	354

Sl. No.	Description	2005-06	2006-07	2007-08	2008-09	2009-10
6.	Shortfall in capacity addition (MW) State(4 – 3)	-	-	0	54	100
	Shortfall in capacity addition (MW) NEP(4 – 2)	-	38	-	-	-
7.	Demand (MU)	4218	4442	4858	5166	5466
8.	Demand met (MU)					
	a) Own Generation (MU)	751.02	805.35	1473.79	1598.68	1617.25
	b) Power Purchased by State (MU)	2761.36	2910.30	2530.61	2640.32	3010.12
9.	Shortfall (MU) (7-8)	705.62	726.35	853.60	927.00	838.63

Actual capacity addition was 100 MW against 254 planned by the State.

It shows that during 2005-10, actual capacity addition was only 100 MW against 254 MW planned by the State, leaving a shortfall of 154 MW. The State was not in a position to meet the demand as the power generated as well as power purchased fell short by 706 to 927 MU during 2005-10.

2.9.2 Optimum Utilisation of existing facilities

A plan was needed to be in place for optimal utilisation of existing facilities by undertaking life extension programmes, and timely repair and maintenance. As per the norms of CEA, Residual Life Assessment (RLA) studies are to be carried out in respect of the generating units which have completed twenty years or 1,60,000 hours of operation. The details of the power generating units, which were due for RLA studies during five years ending 2009-10 *vis-à-vis* actually taken, were as follows:

Due dates and dates of taking up RLA studies.

Sl. No.	Name of the Plant	Unit No.	Installed Capacity	Due Date (as per CEA norms)	Whether completed 1,60,000 hours of operation	Date when actually taken up
1	**Namrup TPS**	1	23	April 1985	Yes	Not yet done
		2	23	April 1985	Yes	Not yet done
		3	23	April 1985	Yes	Not yet done
		5	30	April 1996	Yes	December 2004

Renovation and modernisation of power generating units were undertaken without Residual Life assessment study.

It may be seen that one (Unit 5 of Namrup TPS) out of 4 thermal units due for RLA studies was taken up for RLA study, that too was delayed by over eight years. Further, APGCL took up R&M/LE programmes on *adhoc* and piecemeal basis as brought out in ***para 2.17***.

The management stated that RLA study was conducted on Unit 5 only because the existing Units at Namrup would be phased out gradually once the Namrup RPP is commissioned.

Management's contention that the Units at Namrup are going to be phased out after the commissioning of Namrup RPP does not appear justified because the project is not going to be commissioned before 2012, whereas these units had completed 1,60,000 hours of operation in 2002 and were due for RLA study.

Project Management

2.10 Project management includes timely acquisition of land, effective actions to resolve bottlenecks, obtain necessary clearances from Ministry of Environment and Forest and other authorities, rehabilitation of displaced families, proper scheduling of various activities using scientific techniques, adequate budget provisions, transparent and appropriate contract management etc.

We noticed time and cost over runs due to absence of co-ordination and control mechanisms in the implementation of the projects during 2005-10.

2.10.1 Ongoing Projects-physical and financial progress.

The following table indicate the physical and financial progress of the four power projects taken up for implementation during 2005-10 and the time and cost overrun there against:

Sl. No.	Name of the Project (Capacity)	Project cost as per DPR (Revised cost and date)	Date of Approval by PIB	Date of NIT	Date of work Order /Letter of Intent (LOI)	Value of work order	Stipulated date of completion (Expected date of completion)	Physical Progress as in April 2010	Expenditure incurred up to April 2010
		(₹ in crore)							
1	Lakwa WHRP (37.5 MW)	161 (236.40* March 2006)	December 2000	January 2005	March 2006	223.27	June 2008 (October 2010)	Civil Works- 45 to 90 *per cent* Mechanical Works 0 to 70 *per cent*	198. 38
2	Namrup RPP (100 MW)	410.97 (693.92 January 2009)	March 2007	September 2007	December 2008	564.60	August 2012 (NA)	Only piling work started	4.71
3	Myntriang SHEP (9MW)	67.92 (81.01†)	December 2006	June 2007	April 2008	76.48	February 2011 (NA)	Work in progress for Approach road and other infrastructures	12.29
4	Lungnit SHEP (6 MW)	50.81 (56.37*)	December 2006	December 2006	December 2008	47.09	August 2011 (December 2011)	19.60 *per cent* completed as per Master Schedule Network	6.50

There was inordinate delay in every stage of project implementation.

It can be seen from the above table that abnormal time was taken in implementation of four projects at every stage of project implementation *i.e*, NIT, evaluation of bids, award of work and execution.

* The value includes the contract awarded to another contractor for construction of the intake water plant.
† Contracted cost *plus* departmental cost.

Delay in taking up the projects led to cost overrun of ₹ 377 crore.

Lakwa WHRP has already been delayed by 28 months (October 2010) over the scheduled date of completion. The physical progress of other three projects being implemented was also not satisfactory. The delay in taking up the projects have already led to cost overrun of ₹ 377 crore‡.

The inordinate delay did not reflect well on the commitment of the State Government to meet the increasing demands of electricity. Further, the delay causes not only increase in the cost of projects to be borne by the Government but also the cost at which the electricity would be supplied, to be borne by the people of the State. The irregularities noticed in execution of the projects are discussed in succeeding paragraphs:

2.10.2 1 × 37.2 MW Lakwa Waste Heat Recovery Project (Lakwa WHRP)

Lakwa WHRP – 1 × 37.2 MW was to enhance APGCL's generating capacity and enhance cycle efficiency of Lakwa TPS located in Sibsagar. Its DPR for ₹ 161 crore was prepared in May 1999 and approved by CEA and PIB in December 1999 and 2000 respectively at debt equity ratio of 70:30. As funds could not be arranged, the State Government decided to finance the project out of State Plan funds and invited (February 2005) global tenders. Two bids were received from Bharat Heavy Electricals Limited (BHEL) and URAL ENERGO MONTAZH, RUSSIA. The bid of the Russian firm was rejected as it did not submit the bid guarantee of ₹ 2.50 crore. The contract was awarded (February 2006) to BHEL after negotiation at ₹ 206.07 crore. The examination of records relating to award of work to BHEL and subsequent execution of works by it disclosed irregularities as brought out in the succeeding paragraph:

Pace of progress of Lakwa Waste Heat Recovery Project has been poor since beginning.

BHEL failed to keep pace in execution of works with the scheduled completion date of 30 June 2008 since beginning. For instance, as on September 2008 against 85 *per cent* of equipments supplied, civil & erection work was complete to the extent of only 35 *per cent*. The project had already suffered cost overrun of ₹ 22.17 crore due to increased Interest During Construction (IDC) period from ₹ 7.44 crore to ₹ 29.61 crore because of delay in commissioning.

The project has already been delayed by 28 months.

Considering the tardy progress of work, CEA on request from BHEL allowed BHEL to complete the project by October 2010. The Project had already been delayed by 28 months has not been completed by the revised schedule of October 2010.

Delay in completion led to loss of potential generation of 390 MU.

The inordinate delay in completion of the project led to loss of generation of 390 MU (realisable value ₹ 81.90 crore) for the period from July 2008 to March 2010.

‡ Lakwa WHRP ₹ 75.40 crore, Namrup RRP ₹ 282.95 crore, Myntriang SHEP ₹ 13.09 crore, Lungnit SHEP ₹ 5.56 crore

2.10.3 9 MW Myntriang Small Hydro Electric Project (Myntriang SHEP)

DPR for the project was prepared after 12 years of collection of Hydrological data.

The Myntriang SHEP envisages utilization of 432 Sq. Km of catchments area of Myntriang river in two stages for generation of 9 MW of power. The project though was conceived in 1984, hydrological data recorded from 1984 to June 1993, final DPR was prepared twelve years thereafter in June 2005.

The DPR estimated the cost of the project at ₹ 67.92 crore which was approved by the PIB in December 2006. After invitation of open tender (June 2007), the LOI for the work was awarded to the lowest bidder *viz.,* Sarda Eco Power in April 2008.

In the above context, we observed the following anomalies:

- DPR was approved by PIB considering 16 *per cent* IRR. However, based on AERC (Terms and Conditi on of Tariff) Regulation, 2006 IRR for the project works out to 13.81 *per cent* for Stage I and 11.16 *per cent* for stage II leading to deferment of payback period.

Economic viability based on projected PLF is unmatched within the State.

- Economic viability was determined on the basis of 84.11 *per cent* PLF for stage I and 76.14 *per cent* PLF for stage II which is unmatched within the State; PLF achieved by Karbi Langpi HEP (Commissioned in April 2007) has never exceeded 58 *per cent* PLF till March 2010.
- Although, the project was scheduled to be completed by February 2011, the work of mobilisation and development of infrastructure as on June 2010 was completed to the extent of only 10 and 50 *per cent* respectively.

In reply, the Management stated (August 2010) that the progress of work at Myntriang SHEP was slow because of bad, inclement weather experienced during execution, delay in obtaining blasting licence, adverse law and order situation, bundhs, *etc*.

The Management's contention is an after thought. In fact, the Management did not analyse the reasons for delay and its impact on the project.

2.10.4 6 MW Lungnit Small Hydro Electric Project (Lungnit SHEP)

Lungnit SHEP envisaged utilisation of catchments area of the Lungnit River in two stages for generation of 6 MW power.

Project cost escalated by ₹ 10.67 crore due to delay in taking up execution of the project.

The work of execution of the project with an estimated (September 1999) cost of ₹ 40.14 crore was taken up in December 2006 *i.e.* after 78 months from the date of DPR leading to revision (March 2005) in cost estimate to ₹ 50.81 crore. In the tender invited for execution of the project though none of the two participating bidders *viz*, a consortium of P.Das & Company (PDC) *and* IC-

SHP (a Chinese firm) and Nortech Power Limited was technically qualified for the execution of hydel projects, yet the Consortium was selected being the lowest bidder.

Though LOI for the work was issued in July 2007, PDC, the lead partner demanded (June 2008) increase in contract price from ₹ 39.50 crore to ₹ 47.08 crore under the pretext that IC-SHP had left the Consortium due to delay in issue (January 2008) of work order and the new member *viz*., Jyoti Limited to be inducted in the Consortium was unwilling to accept the prevailing contract price as the validity of price bid had already expired (August 2007). The offer of PDC was accepted by the Company.

Additional liability of ₹ 7.58 crore incurred due to delay in settlement of contract.

Thus, due to delay in settlement of the contract and unjustified acceptance of the lead partner's revised offer, the Company incurred an additional financial liability of ₹ 7.58 crore.

The progress of work has been slow since beginning. We noticed that work of mobilisation and infrastructure scheduled to be completed by February 2010 as per Master Control Network, was actually completed to the extent of 60 and 50 *per cent* respectively up to the scheduled date.

Our scrutiny further revealed the following anomalies:

- Economic feasibility in the DPR of the project was judged basing 76.26 *per cent* PLF for stage I and 77 *per cent* for stage II whereas declared PLF as per DPR was only 50 *per cent*.
- PIB cleared (December 2006) the project considering 14.40 *per cent* Internal Rate of Return (IRR) whereas IRR as per DPR works out to 12.05 *per cent* for Stage I and 11.47 *per cent* for Stage II.

In reply, the management stated that the project could not be undertaken in time due to financial constraint. As regards selection of technically unqualified contractor, the Management stated that the consultant had completely evaluated the technical bid after obtaining various clarifications on certain points before opening the financial bid. Further, management attributed slow progress of work to the stalemate arising due to the contractor's undue insistence for price increase on the plea that the quantity of work to be executed was much more than that initially assessed by the contractor before submitting the tender bid.

We noticed that:

- The Ministry of New and Renewable Energy had already sanctioned ₹ 18 crore and released ₹ 1.8 crore as the first instalment for the project in April 2000.
- The consultant had clearly mentioned (April 2007) in the Technical Evaluation Report that none of the participating bidders met the

technical qualification as required in the tender document. The consultant maintained the same stand even after evaluating (June 2007) the financial bid.

APGCL was, thus, exposed to the risk of non performance or under performance by the consortium.

Contract Management

2.11 Contract management is the process of efficiently managing contract (including inviting bids and award of work) and execution of work in an effective and economic manner. The works were awarded on turnkey (composite) basis to a single party involving civil constructions, supplies of machines and ancilliary works. During review period contracts valuing ₹ 911.44 crore were awarded. The agreements related to civil works, supply of equipments and miscellaneous works.

Instances of irregularities in the award and execution of contracts are discussed below:

2.11.1 1 × 37.2 MW Lakwa Waste He at Recovery Project (Lakwa WHRP)

Liquidated damage of ₹ 7.58 crore was not recovered from BHEL's bills.

Bid document for the project stipulated that in the event of delay in completion of work, Liquidated Damages (LD) at the rate of maximum 10 *per cent* of the contract price would be recovered from the contractor. However, while executing the contract, LD was reduced to five *per cent* resulting in undue benefit of ₹ 9.75 crore to BHEL. Further, even LD at the rate of five *per cent* was not recovered from BHEL's pending bill of ₹ 30.50 crore. It recovered only ₹ 2.17 crore and therefore, the opportunity of recovery of balance LD of ₹ 7.58 crore was remote.

APGCL did not avail exemption from excise duty under Deemed Export Benefit Scheme.

Foreign Trade Policy, 2004-09 stipulates that power projects routed through International Competitive Bidding process are eligible for duty drawback of both customs and central excise under Deemed Export Benefit Scheme. However, BHEL's quoted price included Central Excise Duty @ 16 *per cent*. This resulted in an avoidable liability of ₹ 18.68 crore to APGCL of which ₹ 7.53 crore was paid to BHEL till May 2010.

Compensation payable by BHEL for excess shut down of units was not recovered from BHEL's bills.

Although, it was mutually agreed in the meeting dated 30 September 2008 that BHEL would take 390 days' shutdown of three units (units 5, 6 and 7) for construction of stacks, BHEL took 905 days for the same. The excess shut down of 515 days (905- 390 days) beyond the agreed period entailed potential loss of generation of 233 MU (realisable value ₹ 51.26 crore). As per agreement APGCL, though, claimed compensation for loss of generation, BHEL declined to pay for the same under the pretext that the original agreement (September 2006) did not provide for any such compensation. We observed that APGCL failed to prevail upon BHEL the fact that the original

agreement had no bearing on the agreement subsequently made in September 2008.

Management, in reply, stated that:

- LD was reduced from 10 *per cent* to 5 *per cent* as BHEL reduced the contract price by 15.4 *per cent*.
- Deemed Export Benefit is admissible only in case of supplies to mega power projects (500 MW and above).
- Profit oriented business organisation can never compensate for consequential loss as the same is unquantifiable.

Reply of the management is not acceptable because:

- The contract did not contain any other provision except LD to adequately safeguard the financial interest of the Company in the event of delay by BHEL.
- The same is not supported by any Excise Rules.
- Loss of generation is quantifiable *i.e* 233 MU.

2.11.2 1X 100 MW Namrup Replacement Power Project (Namrup RPP)

As mentioned in the case of Lakwa WHRP in ***Para 2.11.1*** here also while finalizing the contract, BHEL considered only the customs duty drawback and included the excise duty of ₹ 32.32 crore in the offered price. This unduly enhanced the contract price and created an avoidable liability of ₹ 32.32 crore.



NAMRUP REPLACEMENT POWER PROJECT

Operational Performance

2.12 Operations of APGCL is dependent on input efficiency consisting of material and manpower and, output efficiency in connection with Plant Load Factor, plant availability, capacity utilization, outages and auxiliary consumption. These aspects have been discussed below:

Input efficiency

2.13 Procedure for procurement of gas

Assam Electricity Regulatory Commission (AERC) fixes power generation targets for thermal power stations (TPS) considering capacity of plant, average plant load factor, and past performance. The position of gas linkages fixed by the APGCL for its two TPSs, gas required as per norms fixed by AERC, gas received and potential loss of generation due to shortfall in receipt during the period 2005-08[§] is given below:

Sl. No.	Particulars	2005-06	2006-07	2007-08	Total
1	Gas Linkage Fixed (MMSCM[**)]	569.4	569.4	569.4	1708.20
2	Gas required (MMSCM)	455.57	452.37	452.68	1360.62
3	Gas received(MMSCM)	331.59	357.92	430.82	1120.33
4	Short fall in gas received (MMSCM)	123.98	94.45	21.86	240.29
5	Short fall in generation(MU)	301.48	236.47	68.87	606.82
6	Loss of potential net Revenue (₹ in crore)	23.09	19.81	4.71	47.61

*There was no shortfall in 2008-09 and 2009-10.

It would be seen from the above that gas actually received by APGCL was below gas linkage fixed as well as gas required for generation of power at PLF, fixed by AERC. Potential loss of generation in the two TPSs due to short receipt of gas worked out to 606.82 MU, valuing ₹ 47.61[††] crore during the period from 2005-06 to 2007-08.

That the management lacked initiative in arranging adequate gas for the two TPSs at correct price and adequate pressure during the period from 2005-06 to 2007-08 as would be evident from the following:

2.13.1 Inadequate supply of gas

APGCL failed to obtain firm commitment for supply of gas.

- Oil India Limited (OIL) has been supplying 0.66 Million Standard Cubic Meter Per Day (MMSCMD) of gas to the Namrup TPS on fall

§ There was no shortage in supply of gas against gas required as per plant load factor specified by AERC in the year 2008-09 and 2009-10.
**MMSCM=Million Standard Cubic Meter
†† Total realisable ₹109.85 crore less cost of gas ₹ 62.24 crore.

back‡‡ basis since 1965. APGCL entered into a written agreement (September 2005) with OIL for committed supply of the above quantity with effect from November 2007.

- Similarly, Gas Authority of India Limited (GAIL) which was a major supplier of gas for the Lakwa TPS has been supplying 0.4 MMSCMD of gas on fall back basis only.

2.13.2 Delay in drawal of gas

GOI allotted 0.5 MMSCMD of gas for Lakwa TPS in August 2001.

Government of India (GOI) though allotted 0.5 MMSCMD of gas for its Lakwa TPS in August 2001 with instruction to the Board to enter into agreement with OIL by November 2001 the Company drew up the agreement in September 2005 i.e. five years after the date of allocation.

As per policy of GOI pricing of gas was made under two categories *viz,* Administered Price Mechanism (APM) and non-Administered Price Mechanism (non-APM). Gas allotted under APM was required to be supplied to the Power and Fertilizer sectors on priority basis at a subsidized rate.

Accordingly, price of APM gas for North-East Region was fixed at ₹ 1920 per 1000 SCM linked to net calorific value (NCV) of 10000 kilo calories (Kcal) per SCM.

However, before the finalisation of agreement in September 2005, a new pricing order was issued (June 2005) by the GOI whereby any additional gas to be supplied henceforth from newly explored well was to be priced at ₹ 3200 per 1000 SCM.

In the agreement between the APGCL and OIL price of gas was fixed at ₹ 3200 per 1000 SCM linked to NCV between 8000 and 8500 Kcal. The reasons for reduction of NCV from 10000 to 8000 and 8500 Kcal per SCM were not on record.

Belated execution of agreement with supplier resulted in avoidable excess expenditure on fuel charges of ₹ 52.24 crore.

It can be concluded from the facts of the case that due to belated execution of agreement and drawal of gas from OIL, the APGCL had to incur avoidable expenditure on fuel charges to the tune of ₹ 52.24 crore for drawal of 177.46 MMSCM of gas for the period from December 2008 to March 2010 as detailed in ***Annexure-8***.

In reply, the management stated that delay in entering into agreement with OIL was due to OIL's insistence for liquidation of its long outstanding dues before resumption of fresh supplies .Moreover, OIL informed APGCL that the gas supply to LTPS would be made from newly discovered oil fields outside the purview of APM price. Hence, the price was fixed at ₹ 3200/1000 SCM.

‡‡ Without any firm daily quantitative commitment

Management's reply is not acceptable as the GOA took over all the outstanding dues of ASEB to OIL up to September 2001 as per the tripartite agreement (March 2003) among the GOI, the GOA and Reserve Bank of India. Therefore, had APGCL entered into the agreement before June 2005 it could have availed gas at APM rate *i.e* ₹ 1920 per 1000 SCM.

2.13.3 Incorrect gas price allowed

Gas supplied to two units of APGCL were priced differently in violation of GOI orders.

As mentioned in ***para 2.13.2***, price of gas for North-East Region was fixed at ₹ 1920 per 1000 SCM. It was, however, noticed that OIL charged ₹ 3200 per 1000 SCM for 188.48 MMSCM of unused gas from Namrup TPS supplied to Lakwa TPS from June 2005 to November 2008. This resulted in excess payment of ₹ 24.12 crore {(₹ 3200 – ₹ 1920) x 188.48 MMSCM} excluding royalty and other taxes. We observed that before entering into any arrangement with OIL, APGCL did not ensure the prevailing pricing pattern of gas with reference to GOI orders from time to time.

The management, in reply, stated that OIL refused to divert the unused gas of Namrup TPS to Lakwa TPS at the APM price on the plea that the unused gas had already been allocated to North Eastern Electric Power Corporation Limited (NEEPCO).

The reply is unacceptable as the allocation of unused gas of Namrup TPS to NEEPCO was made without obtaining any consent from APGCL, the gas supplied to Lakwa TPS during June 2005 to November 2008 was from the APGCL's own allocation of 0.66 MMSCMD of gas per day for Namrup TPS and therefore should have been priced at the same rate at which it was supplied to Namrup TPS.

2.13.4 Uncontrolled drawal of gas from a private source.

The agreement (September 2005) with OIL *inter alia* stipulated transportation of gas by APGCL or its authorised agent. APGCL was to pay for actual gas drawn or Minimum Guaranteed Quantity (MGQ) of 0.4 MMSCMD (80 *per cent* of the committed quantity of 0.5 MMSCMD) whichever is higher.

Accordingly, APGCL entered into (December 2008) an agreement with AGCL for transportation of gas. The agreement also provided that AGCL might supply gas from sources other than OIL on fall back basis with the prior permission of APGCL.

Uncontrolled drawal of gas from a private source resulted in short drawal of gas from OIL and consequent avoidable expenditure of ₹ 5.18 crore on account of Minimum Guaranteed Quantity charges.

We noticed that:

AGCL injected gas from a private source namely Canaro Resources Limited (CRL) into the same pipeline carrying gas from OIL without providing for verification by APGCL of the quality and quantity of the CRL gas. The uncontrolled injection of CRL gas as such, resulted in short drawal of gas from

OIL which prompted OIL to raise claim amounting to ₹ 5.18 crore on account of MGQ charges from December 2008 onwards which was avoidable.

In reply, the management stated that there was no mechanism to ascertain whether short drawal of gas from OIL was due to the fault of OIL or AGCL and the claims by way of debit notes raised by OIL for MGQ during the period December 2008 to March 2010 was not entertained by APGCL as the matter is disputed.

We noticed that as per technical report (November 2009) accepted by APGCL, AGCL and OIL, OIL was capable of supplying 0.5 MMSCMD of gas to Lakwa TPS but it was unable to draw the same. Management had also stated (November 2009) that injection of CRL gas into the pipeline led to short drawal of gas from OIL.

Further, Management's contention that the claims of OIL were not entertained was not based on fact because APGCL had already confirmed (8 May 2010) the claims of OIL.

2.13.5 Loss of generation due to supply of gas at low pressure.

The power stations faced problems of low gas pressure.

The APGCL did not ensure supply of gas to the two TPSs at the required pressure for which the power stations faced problems of low pressure of gas from time to time. Test check of records relating to outages of plants revealed that the Lakwa TPS fell under forced shutdown for 37463.74 hours during the period of review due to low pressure of gas with consequential loss of generation aggregating to 632.08 MU valued at ₹ 114.44 crore as given in ***Annexure- 9***.



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To draw gas at required pressure, existing infrastructure was revamped and higher transportation charges allowed to the transporters.

It was also noticed that in order to draw 0.5 MMSCMD of gas for Lakwa TPS the existing infrastructure was revamped and a revised agreement was drawn up with AGCL in December 2008. The revised agreement stipulated that AGCL would receive gas from OIL's off-take point, boost its pressure and transport the compressed gas through its High Pressure and Low Pressure pipelines and deliver the same at Lakwa at a minimum pressure of 5 kg/cm^{2}g for which the transportation charge was also revised from the existing ₹ 185 per 1000 SCM to ₹ 565.70 per 1000 SCM. The transportation charge included the cost of compressor as well as the cost of high pressure pipeline from Duliajan to Namrup.

However, on scrutiny it was observed that the gas received from OIL for Lakwa TPS was not boosted at the compressor station of AGCL (Duliajan) and the low pressure gas was injected into a low pressure pipeline from Duliajan to Lakwa, for which intake pressure at Lakwa TPS has been lower than the contracted intake pressure.

The transporters though did not comply with the requirement, higher TC was paid to it.

Since transportation of gas to Lakwa TPS was not done according to the revised agreement allowing the higher rate as per the revised agreement led to over-payment and consequential loss to the company to the extent of ₹ 6.65 crore {(₹ 565.70 – ₹ 185) x 174.64 MMSCM} of gas transmitted.

In reply, the management stated that they have already taken up the matter with AGCL in May 2010. However, the fact remains that the Company is yet (August 2010) to obtain any assurance from AGCL regarding refund of excess payment *etc*.

2.13.6 Consumption in excess of standard due to high heat rate.

Non-achievement of heat rate fixed by AERC resulted in excess consumption of gas worth ₹ 51.58 crore.

Tariff for electricity fixed by the AERC from the years 2005-06 to 2009-10 was based on heat rate[§§] ranging from 3266 to 3658 K.cal per unit of electricity generated from gas. Consumption of gas was, thus, to be regulated according to the above norms fixed by the AERC. The year-wise details of the heat rate achieved by the TPSs during 2005-10 and consequential excess consumption of gas is depicted in ***Annexure-10***.

We observed that heat consumption per unit of electricity generated ranged from 3581 K.cal/ Unit to 4022 K.cal/ Unit during the period 2005-10 as against the 3266 to 3658 K.cal/unit being the norms prescribed by the AERC resulting in excess consumption of gas worth ₹ 51.58 crore.

Management, in reply, stated that the excess heat consumption was due to running of the machines at partial load or no load because of erratic gas supply and less demand in the grid.

§§ Heat Rate= The heat required to generate one unit of energy

We observed that the target of heat rate was fixed at 50 *per cent* Plant Load Factor (PLF) for both NTPS and LTPS and these factors were considered by AERC before fixing the target for heat rate to be achieved. The average PLF in both the stations have gone up recently but the consumption of excess gas has not decreased.

Manpower

2.14 NEP recommended manpower per megawatt of installed capacity of power stations. Position of sanctioned strength & actual manpower *vis-a-vis* the manpower recommended under NEP are given below:

Actual Manpower vis-a-vis sanctioned strength and NEP norms

Sl. No.	Particulars	2005-06	2006-07	2007-08	2008-09	2009-10
1	Sanctioned strength	1731	1645	1554	1557	1557
2	Manpower as per the NEP recommendation	135	135	314	314	314
3	Actual manpower	1640	1541	1575	1510	1386
4	Expenditure on salaries (₹` in crore)	28.57	26.64	28.90	66.36	50.20
5	Extra expenditure with reference to sanctioned strength (`₹ in lakh)	-	-	-	-	-
6	Extra expenditure with reference to NEP norms (`₹ in crore) [(4/3) x (3–2)]	26.22	24.31	23.14	52.56	38.83

The Company's manpower per MW exceeded the norms recommended under National Electricity Plan.

The table above shows that actual manpower during the period 2005-10 exceeded the norms recommended under NEP. The Company, thus, incurred extra expenditure of ₹ 165.06 crore on excess manpower with reference to NEP norms. The excess manpower included 112 personnel stationed at Chandrapur Thermal Power Station (CTPS) and 105 personnel at Bongaigaon Thermal Power Station (BTPS) which remained closed since 1999.

Despite having excessive manpower, the generating stations were regularly employing temporary/contract staff for regular jobs. During 2005-10, generating stations deployed temporary staff for such jobs and incurred an expenditure of ₹ 57.72 lakh.

Further, the overtime wages paid by generating stations during the same period worked out to ₹ 1.09 crore. However, no action was taken to rationalise its staff strength or explore ways to utilise them optimally.

In reply, the management stated that the excess staff at CTPS and BTPS have been brought down to 88 and 93 respectively and the position would be further reviewed for transfer and re-deployment to the extent feasible.

Output Efficiency

2.15.1 Shortfall in generation

The targets for generation of power for each year are fixed by the AERC. It was observed in Audit that the APGCL was able to generate a total of 6610.97 MU of power during 2005-06 to 2009-10 against a target of 6789.47 MU fixed. This resulted in a net shortfall of 178.50 MU as shown below:

Targeted and Actual Generation

Year	Target (MU)	Actual (MU)	Shortfall (MU)	Percentage of Shortfall to the target
2005-06	940.15	808.07	132.08	14.05
2006-07	1112.52	867.54	244.98	22.02
2007-08	1379.97	1540.33	(160.36)	-
2008-09	1600.63	1682.82	(82.19)	-
2009-10	1756.20	1712.21	43.99	2.50

The Company's generation of energy fell short of norms fixed by AERC.

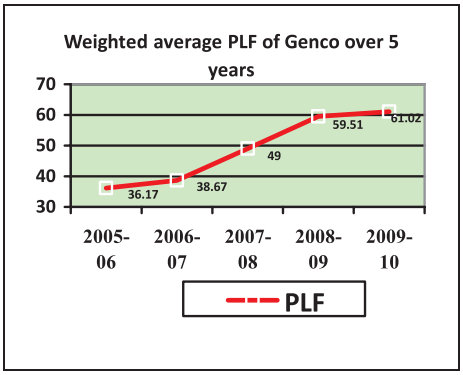
In reply, the management stated that shortfall in generation during 2005-06 and 2006-07 was due to short supply of gas to the thermal power stations and shortfall in hydel generation during 2009-10 was due to low availability of water during monsoon.

The reply of the management is not based on fact since, during 2009-10, the lone hydro electric project Karbi Langpi had actually surpassed the target and it was gas based Namrup TPS which failed to achieve the target set by AERC.

2.15.2 Low Plant Load Factor (PLF)

Diagram-V

Average Plant Load Factor for 2005-10



PLF refers to the ratio between the actual generation and the maximum possible generation at installed capacity. According to norms fixed by Central Electricity Regulatory Commission (CERC), the PLF for thermal power generating stations should be 80 *per cent*, against which the national average was 77.22 *per cent.*

Average Plant Load Factor of the Power Station was below the national average.

Against these weighted average PLF of APGCL during 2005-10 is shown in diagram-V. It can be seen in the diagram that though the average PLF of the TPSs increased from 36.17 *per cent* in 2005-06 to 61.02 *per cent* in 2009-10 it still remained less than the National Average of 77.22 *per cent.*

The details of average realization *vis-a-vis* average cost per unit, PLF achieved, average realization at national PLF, PLF at which average cost would be recovered and the difference of PLF in *per cent* are given in the following table:

PLF attained vis-a-vis National PLF

Sl. No.	Description	2005-06	2006-07	2007-08	2008-09	2009-10
1.	Average Realisation (₹ per Unit)	1.78	1.89	1.67	2.20	2.00
2.	Average Cost (₹ per Unit)	2.35	2.24	1.67	2.29	2.04
3.	Actual PLF (*Per cent*)	36.17	38.67	49.00	59.51	61.02
4.	Average Realisation at National PLF♣ (₹ per Unit)	3.80	3.77	2.63	2.85	2.53
5.	PLF at which average cost stands recovered (*Per cent*) (2/1 X 3)	47.75	45.83	49.00	61.94	62.24
6.	Difference (*Per cent*) (5 – 3)	11.58	7.16	0	2.43	1.22
7.	Shortfall in generation	913.48	857.77	627.91	371.52	339.90

The table above shows that had APGCL attained the National Average PLF it could have recovered its average cost of generation. The estimated shortfall in generation works out to 3110.58 MU (with respect to National Average PLF of 77.22 *per cent*) during 2005-06 to 2009-10.

The details of maximum possible generation at installed capacity, actual generation and corresponding PLF achieved in respect of each generating unit for the five years up to 2009-10 are given in ***Annexure -11***. The main reasons for the low PLF, as observed by us were low plant availability, low capacity utilisation, major shut downs and delays in repairs and maintenance discussed in succeeding paragraphs:

2.15.3 Low plant availability

Plant availability means the ratio of actual hours operated to maximum possible hours available during certain period. As against the CERC norm of 80 *per cent* plant availability during 2004-09 and 85 *per cent* during 2010–14, the average plant availability of power stations was 60.31 *per cent* during the five years up to 2009-10.

The details of total hours available, total hours operated, planned outages, forced outages*** and overall plant availability in respect of the State as a whole are shown in next page:

♣National Average PLF of 2008-09 was 77.22 *per cent*, which has been taken comparison purpose during the period under review.

*** Forced outages include shutdown of units due to machine breakdown, low gas pressure and grid disturbance.

Plant Outages and Plant Availability

Sl. No.	Particulars	2005-06	2006-07	2007-08	2008-09	2009-10
1	Total hours available	113880	113880	131400	131400	131400
2	Operated hours	53812.16	58818.16	78264	90932.46	97059.92
3	Planned outages (in hours)	7159.07	1101.34	7955.17	11992.47	8363.20
4	Forced Outages (In hours)	52908.77	53960.50	45180.83	28475.07	25976.88
5	Plant availability (2/1 x 100) (*per cent*)	47.25	51.65	59.56	69.20	73.87
6	Targeted Plant availability	58.91	76.70	78.10	78.10	78.10

The low availability of Power plants was due to longer duration of forced outages caused by inordinate delays in repair and maintenance and non-availability of required quantity of gas at adequate pressure along with disturbance in the grid. Some specific cases of longer period of shut down of the machines are given below:

- Unit 5 of LTPS was shut down for seven months due to delay in construction of Lakwa WHRP.
- Unit 5 of NTPS was shut down for seven months due to Stator winding failure.
- Unit 4 of NTPS was shut down for sixteen months from August 2005 to January 2007 for failure of starter diesel engine as discussed in para ***2.15.5***.

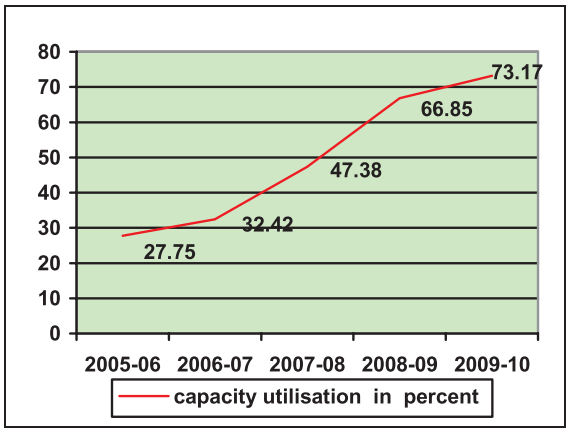
2.15.4 Low Capacity Utilisation

50.49 *per cent* of the installed capacity remained unutilised due to short supply of gas, ageing of units and constraints on transmission capacity.

Capacity utilisation means the ratio of actual generation to possible generation during actual hours of operation. Based on national average PLF of 77.22 *per cent* and plant availability at 80 *per cent*, the standard capacity utilisation factor works out to be 62 *per cent* for thermal power plants. Our analysis revealed that on the average 50.49 *per cent* of the installed capacity remained unutilized. The capacity utilisation is shown in the graph given in the next page:

Diagram-VI

Diagram Showing Capacity Utilisation



The main reasons for the low utilisation of available capacity during 2005-06 to 2007-08, as analysed in audit were: - Running of units with partial load or without load for short supply of gas; reduced capacity of old generating unit; and constraints on transmission capacity due to grid disturbance.

It would be seen that the capacity utilisation of the thermal units has improved during the review period from 27.75 *per cent* in 2005-06 to 73.17 *per cent* in 2009-10. As examined in audit, capacity utilisation of the thermal units has improved due to improvement in the supply of gas.

2.15.5 Outages

Outages refer to the period for which the generating unit is not available for power generation. Audit observed following deficiencies in planned and forced outages. The total number of hours lost due to planned outages decreased from 6 *per cent* in 2005-06 to 0.96 *per cent* in 2006-07 but again increased to 6.36 *per cent* in 2009-10. The forced outages in power stations though decreased from 52908.77 hours in 2005-06 to 25976.88 hours in 2009-10 *i.e.* from 46.46 to 19.77 *per cent* of the total available hours in the respective years, it remained more than the norm of 10 *per cent* fixed by CEA in all the five years ending 31 March 2010. Compliance of the CEA norms would have entailed availability of plant for additional operational hours with consequent generation of 920.91 MU.

Forced outages though decreased over the five years period still remained more than norms fixed by CEA.

Unit No. 4 of Namrup TPS was put under shutdown since August 2005 due to failure of the starter diesel engine. In January 2007, the engine was repaired and made operational. The engine failed again in February 2007. The tender was called for purchase of new engine but it could not be finalised as yet (August 2010). However, in July 2009, the company had decided to operationalise the unit with the help of a repaired diesel engine brought from Lakwa TPS which was lying idle since 2005. Since then, the unit was generating on an average 7 MU per month.

Unit No. 4 of Namrup TPS remained shut down for four years for want of a starter diesel engine.

Thus, due to indecision on the part of the management, the unit remained under shut down for 45 months resulting in loss of potential generation of 315 MU (realisable value ₹: 60.33 crore).

Indecision/delayed decision to operationalise Unit No. 4 resulted in loss of generation.

Management, in reply, stated that tender for procurement of starter diesel engine could not be finalised as yet (August 2010) for want of a suitable vendor.

2.15.6 Auxiliary consumption of power

Energy consumed by power stations themselves for running their equipments and common services is called Auxiliary Consumption. The norms prescribed by CEA in the National Electricity Plan for Combined Cycle gas based power plant was 3 *per cent.*

AERC laid down norms for auxiliary consumption in respect of the three power stations. Year-wise and station-wise auxiliary consumption (in percentage of gross generation) allowed by AERC *vis-a-vis* actual consumption recorded by the power stations during the period of review is shown below:

Actual Auxiliary consumption vis-a vis approved by AERC

Year	Auxiliary consumption approved by AERC (in *per cent*)			Actual Auxiliary consumption (in *per cent*)		
	Namrup TPS	Lakwa TPS	Karbi Langpi HEP	Namrup TPS	Lakwa TPS	Karbi Langpi HEP
2005-06	4.50	5.50	NA*	5.24	9.42	NA
2006-07	4.50	5.50	NA	5.64	8.64	NA
2007-08	4.30	5.59	0.50	5.47	7.17	0.50
2008-09	4.00	5.59	0.50	5.42	7.52	0.50
2009-10	3.00	5.59	0.50	4.76	8.77	0.50

* NA: Not applicable—Plant commissioned in 2007-08

Auxiliary consumption of thermal power stations exceeded the norms allowed by AERC.

It showed that barring Karbi Langpi HEP, actual auxiliary consumption of the remaining power stations exceeded the norms allowed by AERC. As worked out in Audit, due to excess consumption in auxiliaries, 105.49 MU of energy could not be despatched to the grid.

Management, in its reply (May 2010) to audit observation attributed excess auxiliary consumption to:

- Part loading of gas turbines due to non-availability of adequate gas supply and grid conditions at Lakwa TPS.
- Low capacity utilization of the de-rated machinery vis-à-vis static auxiliary consumption, erratic gas supply and inadequate power evacuation system at Namrup TPS.

However, the fact remains that these aspects might have been considered by AERC before determining different benchmarks of performance of the power stations.

Repairs & Maintenance

2.16 To ensure long term sustainable levels of performance, it is important to adhere to periodic maintenance schedules. The efficiency and availability of equipment is dependent on the strict adherence to annual maintenance and equipment overhauling schedules. Non-adherence to schedule carry a risk of the equipment consuming more gas, fuel oil and a higher risk of forced outages which necessitate undertaking R&M works. These factors lead to increase in the cost of power generation due to reduced availability of equipments which affect the total power generated.

In the above context, we observed that:

- Periodic maintenance of the units was not carried out as per schedule of the original manufacturers (OEM).
- Maintenance works were carried out only in the event of break down of machinery.
- Time to be taken for various maintenance works were not specified by the management.

The following instances would illustrate the point:

Actual Preventive Maintenance carried out vis-a-vis recommended

Preventive maintenance of units was not carried out as recommended by the original equipment manufacturers.

Sl. No.	Types of preventive maintenance	Recommended Hours of operation before maintenance	Actual hours of operation before maintenance	Delay in maintenance (Hours)	Year in which servicing has been carried out
1	Washing of Air filter net ,Unit-I (WCL make)	3000-4000	8999	4999	2008-09
2	Compressor Cleaning and combustion operation	7000	11537	4537	2009-10
3	Major overhauling of Unit-2 (WCL make)	28000	40052	12052	2007-08
4	Major Overhauling of Unit-6 (BHEL make)	48000	72886	24886	2008-09

In reply, management stated that periodic maintenance of some units could not be carried out as per schedule of OEM due to non availability of spares in time, power demand of the state and further denied that maintenance works were carried out only in the event of break down of the machines.

Renovation and Modernisation

2.17 Renovation & Modernisation (R&M) and refurbishment activities involve identification of the problems of generating units of TPSs, preparation of techno economic viability reports, preparation of detailed project reports (DPR) to lay down benefits to be achieved from these works.

R&M activities are aimed at overcoming problems in operating units caused due to generic defects, design deficiency and ageing by re-equipping, modifying, augmenting them with latest technology/systems. R&M activities are undertaken in TPS operating at Plant Load Factor (PLF) of 40 *per cent* and above after assessing the performance and requirement of the units.

Refurbishment activities are aimed at extending economic life of the units by 15 to 20 years which have served for more than 20 years or operating at PLF below 40 *per cent*. Necessary permission and clearance for R&M and Refurbishment activities from AERC/CEA/State Government are obtained. For Refurbishment and R&M activities, Power Finance Corporation (PFC) sanctions loan equal to 70 *per cent* of the estimated cost of the activity against guarantee furnished by the State Government and rest of the fund is met through internal sources or loan from State Government.

2.17.1 10th Plan R & M Scheme

10th Plan R & M Scheme primarily envisaged restoration of the Unit No.2 of Namrup TPS which was under shutdown since August 2001 and raising generation from 350 MU in 2005-06 to 600 MU in 2007-08 and 740 MU in 2008-09 in respect of Lakwa TPS.

Scheduled date of completion, actual date of completion of the programme at the two TPSs are shown in the following statement:

10th Plan R & M Scheme

Name of Power Station	Scheduled Date of completion (Revised date)	Actual Date of completion
Lakwa TPS	31 March 2007 (September 2007)	In progress
NTPS	31 March 2007	December 2007

We observed that:

- The programme at Lakwa TPS remained incomplete even after a lapse of 33 months from the targeted (revised) date of completion.
- The programme at Namrup TPS was completed after a lapse of 8 months from the targeted date.

R&M programme at Lakwa TPS was delayed due to delay in awarding work and at Namrup TPS due to delay in arranging funds.

- At Lakwa TPS, out of 40 items of work to be executed as per DPR, 23 items were fully completed as on April 2010. The programme at Lakwa TPS was delayed due to delay in awarding work orders. Barring four orders (value: ₹ 13.52 crore), remaining 22 orders of ₹ 13.83 crore were issued after the targeted date of completion.
- For restoration of the Unit-2 of Namrup TPS, a provision of ₹ 12 crore was made in the DPR prepared in December 2002. As per the provision of the DPR, the restoration of the unit would be completed in March 2004 and on restoration, the unit would be able to generate 120 MU per annum at 60 *per cent* PLF. The Company, however, took 59 months as against 14 months envisaged in the DPR for restoration of the unit due to delay in arranging fund from PFCL because of delay in execution of Asset Hypothecation Deed (AHD) resulting in loss of generation of 326.25 MU (realisable value: ₹ 54.48 crore).
- Works of ₹ 10.90 crore of O & M nature were included in R & M activities and expenditure on them were incurred out of R & M funds. This also resulted in deferment of O & M expenses over a long period which was otherwise realizable through tariff of the year in which the expenditure was actually incurred.

There was shortfall in achievement of generation target at the end of 2008-09.

- Although, R&M schemes envisaged increase in generation to 1402 MU, APGCL achieved 1248 MU leaving a shortfall of 154 MU at the end of 2008-09.

The management, in reply, stated that the delay in completion of R&M programme at Lakwa TPS was due to poor response from OEM, technical short comings in finalisation of NITs, remote location*, etc.*

However, the fact remains that while the R&M programme at Lakwa TPS was scheduled to be completed by September 2007, NITs for many components of the work were floated only in the years 2008-09 and 2009-10.

As regards delay in restoration of Unit-2, management stated that the execution of AHD was delayed as assets of Namrup TPS was mortgaged to Life Insurance Corporation of India which was reluctant to issue 'No Objection Certificate' and finally, the company considered mortgaging assets of Lakwa TPS (unit-4) to PFCL for disbursement of loans. The fact, however, remains that the company could have considered mortgaging the assets of Lakwa TPS instead of creating second charge on the assets of Namrup TPS to avoid delay and loss of generation.

2.17.2 Operation & Maintenance

The operation and maintenance (O&M) cost includes expenditure on the employees, repair & maintenance including stores and consumables, consumption of capital spares not part of capital cost, security expenses,

administrative expenses *etc*., of the generating stations besides corporate expenses apportioned to each generating stations *etc*., but exclude the expenditure on fuel.

CERC has fixed norms for O&M cost. It was noticed that the Company had achieved the CERC norms in all the five years as shown below:

Actual O & M cost incurred vis-a-vis norms

Year	Installed Capacity (MW)	O & M cost approved by CERC	O & M cost per MW approved by CERC	Actual cost incurred	Actual cost per MW	Excess of actual cost above approval	Excess O&M Cost incurred per MW
			(₹ in crore)				
2005-06	254	46.23	0.18	39.44	0.16	-	-
2006-07	254	46.23	0.18	37.52	0.15	-	-
2007-08	354***	84.68	0.24	40.77	0.12	-	-
2008-09	354	84.68	0.24	84.32	0.24	-	-
2009-10	354	84.68	0.24	71.00	0.20	-	-

It was noticed that Company had achieved the CERC norms in respect of O&M cost in all the five years.

Financial Management

2.18 Efficient fund management is the need of the hour in any organisation. This also serves as a tool for decision making, for optimum utilisation of available resources and borrowings at favourable terms at appropriate time.

The power sector companies should, therefore, streamline their systems and procedures to ensure that funds in idle inventory are not invested, outstanding advances are adjusted/recovered promptly and funds are not borrowed in advance of actual need.

The main sources of funds were realisations from sale of power, funds from State/Central Governments, loans from State Government/Financial Institutions (FI) *etc*. These funds were mainly utilised to meet payment of fuel purchase bills, debt servicing, employee and administrative costs and system improvement works of capital and revenue nature.

Details of sources and utilisation of resources on actual basis for all the power sector companies for the years 2005-06 to 2009-10 are given in the following table:

*** Includes Karbi Langpi Hydro Electric project of 100 MW.

Sources and utilisation of resources

Sl. No.	Particulars	2005-06	2006-07	2007-08	2008-09	2009-10
			(₹ in crore)			
Cash inflow						
1.	Net Profit/(loss)	(40.83)	(18.00)	1.18	(7.03)	29.93
2.	Add: adjustments	53.41	50.66	83.09	114.73	77.80
	Operating profit before working capital changes.	12.58	32.66	84.27	107.70	107.73
3.	Operating activities	110.17	56.45	-	118.54	34.98
4.	Investing activities	0.56	275.77	93.35	29.16	25.45
5.	Financing activities	798.82	154.29	118.49	5.75	73.68
	Total	**922.13**	**519.17**	**296.11**	**261.15**	**241.84**
Cash outflow						
6.	Operating activities	169.89	2.65	41.44	31.32	39.73
7.	Investing activities	722.61	501.65	126.36	158.27	89.30
8.	Financing activities	23.41	7.36	33.83	83.23	81.34
	Total	**915.91**	**511.66**	**201.63**	**272.82**	**210.37**
	Net increase in cash and cash equivalents	6.22	7.51	94.48	(11.67)	31.47

The cash deficit from operating activities in the years 2005-06, 2007-08 and 2009-10 was overcome mainly by increased grants and borrowings from the State Government. However, in the year 2008-09, APGCL earned net cash from operating activities to the extent of ₹ 87.22 crore. Main reasons for cash deficit in the financing and investing activities in the years 2008-09 and 2009-10 were heavy interest commitment on loans, locking up of funds in inventory and spare parts not required immediately and heavy capital expenditure without adequate returns. Therefore, there is an urgent need to optimise internal resource generation by enhancing the PLF to national level. This would have enabled increased availability of funds to the extent of ₹ 579.30 crore (realisable value of shortfall in generation with reference to national PLF).

However, we also noticed that the Company could not utilise the available funds for the intended purposes and kept the funds in short term deposits from time to time. Some instances, as noticed in audit, are given below by way of illustration.

Despite having sufficient fixed deposits, the APGCL resorted to Bank overdraft.

- While, the Company had fixed deposits ranging from ₹ 76.62 crore (March 2008) to ₹ 86.59 crore (March 2010), it resorted to overdraft ranging from ₹ 3 crore to ₹ 2.46 crore during the period of three years ended 31 March 2010, which resulted in avoidable payment of interest of ₹ 68.86 lakh.

For availing loan long before actual execution of work resulted in loss of interest of ₹ 0.16 crore.

- Inspite of receiving (April 2000) ₹ 1.8 crore as the first instalment of subsidy from the Ministry of New and Renewable Energy for

implementation of Lungnit SHEP, APGCL obtained State Government loan of ₹ one crore on March 2006 at the rate of 10.50 *per cent* interest, 39 months before the contract was signed (July2009). Thus, availing of loan before the actual execution of work resulted in net loss of interest of ₹ 15.75 lakh.

Holding of spares in excess of norms resulted in loss of interest of ₹ 4.31 crore.

- As per the guidelines of Central Electricity Regulatory Commission (CERC), the Thermal Power Stations (TPS) have to maintain spares of ₹ four lakh for each MW of installed capacity. As worked out by us, the value of spares to be maintained by the TPSs on the basis of CERC guidelines should be ₹ 10.16 crore. However, during the year 2008-09, the TPSs held a stock of spares valued at ₹ 51.19 crore resulting in holding of spares in excess of norm by ₹ 41.03 crore.

This resulted in blocking up of funds and corresponding loss of interest of ₹ 4.31 crore (calculated at 10.50 *per cent* rate of interest on ₹ 41.03 crore) for one year alone.

Management, in reply, stated that the company held excess inventory since lead time for procurement of imported spares was very high**.** The facts, however, remain that the Company was holding stocks in excess of the CERC norms.

Claims and Dues

2.19 The APGCL sells energy to DISCOMS at the rates specified by AERC from time to time. AERC fixed the tariff rates after considering various economic and other factors. Generally, sale price does not cover the total input costs. The table below gives the details of subsidy claims raised, subsidy realised, energy bills on DISCOMS and recoveries there against and gas bills received *vis-a-vis* payments made for the review period.

Claims and dues

Sl. No.	Details	2005-06	2006-07	2007-08	2008-09	2009-10	Total
		(₹ in crore)					
1	Energy Bills on ASEB	133.73	152.90	247.65	351.16	334.00	1219.44
2	Amounts Received	113.14	211.51	254.64	317.76	286.22	1183.27
3	Gas Bills Received	80.25	97.44	119.32	157.61	183.77	638.39
4	Payments Made	80.25	97.44	119.32	157.61	183.77	638.39

It can be seen from the above table that the company's dues & claims on account of the above have not been received in time except in 2006-07 and 2007-08.

In order to secure its financial interest, a commercial enterprise needs to have a well organised system of internal check and control especially with regard to its claims and dues.

Tariff Fixation

2.20 The APGCL is required to file the application for approval of Generation Tariff for each year 120 days before the commencement of the respective year or such other date as may be directed by the Commission. The Commission accepts the application filed by APGCL with such modifications /conditions as may be deemed just and appropriate and after considering all suggestions and objections from public and other stakeholders, issue an order containing targets for controllable items and the generation tariffs for the year within 120 days of the receipt of the application.

The Commission sets performance targets for each year of the Control Period for the items or parameters that are deemed to be "controllable".

Any financial loss on account of underperformance on targets is not recoverable through tariffs.

Audit noticed that the Commission did not allow expenditure of ₹ 3.32 crore and ₹ 6.43 crore during two years *viz.,* 2005-06 and 2006-07 respectively on account of cost of fuel (₹ 2.58 crore), interest on term loan (₹ 6.87 crore) and return on equity (₹ 30.36 lakh), considering those costs as controllable which resulted in adding to the loss of APGCL for the respective years.

Environment Issues

2.21 In order to minimize the adverse impact on the environment, the GOI had enacted various Acts and Statutes. At the State level, Assam State Pollution Control Board (SPCB) is the regulating agency to ensure compliance with the provisions of these Acts and Statutes. Ministry of Environment and Forests (MoE&F), GOI and Central Pollution Control Board (CPCB) are also vested with powers under various Statutes.

Audit scrutiny relating to compliance with the provisions of various Acts in this regard revealed the following:

2.21.1 Operation of plant without consent

Lakwa TPS was operating without statutory consent required from the State Pollution Control Board (SPCB).

Since its commissioning in 1981, Lakwa TPS was operating without obtaining any consent required under Air and Water Prevention and Control of Pollution Acts, 1974 and 1981 respectively. In May 2000, CPCB directed the Company to take immediate measures to obtain consent to operate from SPCB. SPCB, though accorded (August 2009) consent to operate for the year 2008-09, it did not give similar consent for the years 2009-10 and 2010 – 11 as the company was yet to liquidate the outstanding consent fees of ₹ 38.70 lakh payable for the period of 18 years since the date of commissioning. Thus, the plant has been operating without any consent from SPCB.

2.21.2 Absence of monitoring facilities and equipments

As per the provisions of the Environment (Protection) Act, 1986, TPSs should provide on-line monitoring systems to record Small particulate matter (SPM) levels. However, the Company did not comply with the same. Moreover, the following additional irregularities were also observed at Lakwa TPS.

Power Stations were not equipped with pollutant gas monitoring facilities.

- Out of seven stacks of seven gas turbine units of Lakwa TPS, provision for setting up pollutant gas monitoring facilities exists only in three stacks.
- Although, the three out of seven stacks had provision for installation of equipments to measure actual emission of pollutants, the same were yet to be installed.

2.21.3 Stack height not conforming to SPCB standards

Stack height did not conform to the norms set by SPCB.

The SPCB while according consent to operate for the year 2008-09 *inter-alia* stated that stack height should be minimum 30 meters. It was noticed that Lakwa TPS has four stacks of only 16 meters which was in violation of the stack height norms of the SPCB, leading to discharge of smoke and other pollutants at a lower/undesired level of the atmosphere.

Noise Pollution

2.22 Noise Pollution (Regulation and Control) Rules, 2000 aim to regulate and control noise producing and generating sources with the objective of maintaining ambient air quality. To achieve the above, noise emission from equipment be controlled at source, adequate silencing equipment should be provided at various noise sources and a green belt should be developed around the plant area to diffuse noise dispersion. The TPSs are required to record sound levels in all the areas stipulated in the rules referred to above.

There was no provision for recording/monitoring noise level at the Power Stations.

Audit scrutiny revealed that none of the thermal power station of the Company recorded noise levels at all nor there was any equipment installed to record the noise levels of the power stations.

Water pollution

The Company does not have any system for monitoring pollutant in the waste water discharge from the Power Stations.

2.23 APGCL does not have any system of monitoring pollutants in the waste water discharge from the two thermal power stations.

2.23.1 Non-registration of projects under Clean Development Mechanism (CDM)

We noticed that although, all the four ongoing projects are eligible for carbon credit benefit, APGCL did not initiate action for registration of the project as

Failure to get the projects registered as CDM projects entailed potential loss of revenue in the form of carbon credit.

CDM project at the initial stage due to lack of awareness. Belatedly, the company engaged (November 2009) a consultant to explore the possibility of availing the benefit in respect of Lakwa WHRP. The firm projected that Lakwa WHRP is capable of generating in 9 years an estimated 930109 CER[†††] by selling which the company could have earned net revenue of ₹ 69.32 crore[‡‡‡] (CER 930109 X 12 Euro x ₹ 69.86 = ₹ 77.97 crore discounted at 12 *per cent* for 1st Five years and 10 *per cent* for next four years = ₹ 69.32 crore).

The projects though eligible, were not registered as CDM project.

Thus, the company may lose potential revenue of ₹ 69.32 crore in the form of carbon credit due to its ignorance and failure to get CDM registration. Benefit that would have been available in respect of three other projects have not been worked out by the Company.

Monitoring by top management

MIS data and monitoring of service parameters

2.24 The APGCL plays an important role in the State economy. For such a giant organisation to succeed in operating economically, efficiently and effectively, there should be documented management systems of operations, service standards and targets. Further, there has to be a Management Information System (MIS) to report on achievement of targets and norms. The achievements need to be reviewed to address deficiencies and also to set targets for subsequent years. The targ ets should generally be such that the achievement of which would make an organisation self-reliant. Audit review of the system existing in this regard revealed the following:

- Although, there exists an MIS in respect of the thermal power stations, regular monthly or yearly analysis and reporting to the top management was not being done.
- The detailed MIS in respect of the Karbi Langpi Hydro-Electric Project was yet to be in place (June 2010).

Conclusion

- **The company could not meet the power demand of the State due to inadequate capacity additions. Peak demand of the State could not be met even by import of power.**
- **There has been cost overrun due to delay in taking up of the projects.**

††† One CER = 12 Euros, 1 Euro = ₹ 69.86.
‡‡‡ As worked out by the consultant appointed by APGCL.

- **The company failed to exercise necessary controls over fuel linkage and consumption.**
- **There has been low capacity utilisation of the plants .**
- **R&M programmes of the Company were taken up without carrying out the Residual Life Assessment Study of the Units. The executed R&M programmes also failed to achieve the desired objective.**
- **Management did not address the issues of environmental pollution.**
- **The performance data collected through MIS was not placed before the Board for review.**

Recommendations

The following recommendations are made

The Company/State government must

- **Plan capacity addition commensurate with the state's energy requirement.**
- **Ensure proper project management for completion of the projects within scheduled date.**
- **Undertake Residual Life Assessment Study, Techno Economic Feasibility Study before undertaking Renovation and Modernisation programme.**
- **Plan and procure fuel (gas) commensurate with its requirement.**
- **Maintain vigil so as to ensure fulfilment of contractual obligations by the transporters of gas.**
- **Ensure that receipt of gas is commensurate with generation target fixed by the Company/AERC.**
- **Ensure management control over achievement of station heat rate as per AERC norms.**
- **Evolve an adequate MIS for evaluating the performance of all the generating stations and ensuring periodical analysis and review by top management for corrective action *etc.***