CHAPTER II

Performance reviews relating to Government companies

2.1 Working of Karnataka Power Corporation Limited

Executive Summary

Power is an essential requirement for all facets of life and has been recognised as a basic human need. In compliance with the Electricity Act, 2003, Government of India prepared (February 2005) National Electricity Policy (NEP) in consultation with State Governments and Central Electricity Authority (CEA) with a view to achieve 'Power for All' by 2012.

Karnataka Power Corporation Limited was incorporated on 20 July 1970 under the Companies' Act, 1956, as a wholly-owned Company under the administrative control of Energy Department of the Government of Karnataka (GoK). As on 31 March 2010, the Company had two thermal power stations (1,970 MW), eighteen hydro generation stations (3,637.35 MW), two renewable energy stations (10.56 MW) and one Diesel Generating (DG) plant (127.92 MW) with a total installed capacity of 5,745.83 MW. The turnover of the Company was ₹4,397.25 crore in 2009-10, which was equal to 12.09 per cent and 1.47 per cent of the turnover of State PSUs and State Gross Domestic Product respectively. As on 31 March 2010, the Company had employee strength of 6,281.

Capacity addition

Though the installed capacity in the State increased from 7,084.80 MW at the beginning of 2005-06 to 10,387.81 MW at the end of 2009-10, yet the State was not in a position to meet the peak demand. The peak demand, which was 5,949 MW in 2005-06 increased to 8,094 MW in 2009-10 and the deficit which was 6.57 per cent in 2005-06 increased to 12.91 per cent in 2009-10. Even the purchase of power from private producers could not suffice the required demand forcing the State to impose load shedding. The shortfall as compared to required demand increased from 1,326 MU in 2005-06 to 5,059 MU in 2009-10.

Against the required capacity addition of 8,050 MW during 2005-10, the actual capacity addition was 3,183.11 MW, leaving a shortfall of 4,866.89 MW. Though 1,644 MW of capacity was planned to be added by the Company (KPCL) during 2005-10, the actual addition was only 861 MW, leaving a deficit of 783 MW.

Achievement of Power for All by 2012

Karnataka Electricity Regulatory Commission (KERC) had forecast (December 2008) peak requirement of 10,120 MW by the end of 2012. In order to meet this demand, the installed capacity required worked out to 14,913 MW. Considering the installed capacity of 10,387.81 MW at the end of 2009-10, the capacity addition required to be commissioned between 2010-11 and 2011-12 worked out to 4,525 MW. The projects on hand, however, would add capacity to the extent of 2,053 MW, still leaving a gap of 2,472 MW. Thus, the primary objective of power for all by 2012 may not be achieved.

Project management

Of the ten projects planned by the Company during 2005-10, only seven were taken up, of which only four were completed and three were under implementation. Of the balance three projects, one project was shelved and the two were yet to be taken up for want of environmental clearance and assured gas supplies. The implementation period of the completed projects was beyond the scheduled period and the time overrun ranged from 1.5 months to 36 months due to delay in supply of materials and commissioning of critical equipments.

Contract management

The Company failed to levy liquidated damages of ₹ 82.85 crore on contractors for delayed completion / supply and also failed to recover excess payment towards duties and taxes. Undue benefit was extended to the supplier of coal due to incorrect interpretation of the term 'pro-rata' while adjusting for coal with excess moisture content.

Operational performance

Life extension works of RTPS Units 1 and 2 were not taken up as per CEA norms though due for replacement or refurbishment. Failure to undertake R&M works of Diesel Generating plant resulted in higher maintenance costs. Delay in execution of uprating works in Nagjhari Power House resulted in loss of generation of 2,671 MU.

The norm for operation and maintenance (O&M) expenditure was exceeded in thermal power stations whereas it was within the norm in hydro stations. Against the average O&M cost of ₹18.20 lakh per MW up to 2007-08 and ₹16.88 lakh per MW thereafter, the actual O&M cost per MW was ₹33.34 lakh, ₹33.78 lakh, ₹34.75 lakh, ₹39.90 lakh and ₹38.52 lakh during 2005-10.

Procurement of fuel

Shortages in lifting of allotted quantity of coal were observed leading to loss of generation valued ₹78.46 crore. Though the thermal power stations had sufficient capacity to unload the rakes within the time allowed by Railways, delay was noticed in clearing the rakes resulting in payment of demurrage of ₹ 31.30 crore.

Consumption of fuel

Coal valued ₹ 905.36 crore was consumed in excess of norms specified by the equipment supplier.

Deployment of manpower

The Company had not assessed the required manpower. Excess non-technical staff was observed in hydro stations while there was shortage of technical and non-technical staff in thermal power stations as compared to norms. The salaries and wages paid to excess non-technical staff in hydro stations was to the tune of ₹185.15 crore

Auxiliary consumption

Auxiliary consumption of hydro stations exceeded the norm fixed by CEA and such excess consumption was 528.49 MU valued at ₹ 29.21 crore. As regards thermal power stations, it was within the norms fixed by KERC / Central Electricity Regulatory Commission (CERC).

Plant Load Factor

The generation and Plant Load Factor (PLF) achieved were far below the designed generation and PLF in thermal power stations. The Company was not able to achieve the norm prescribed by CERC in 2008-09 and 2009-10 due to longer duration of forced shutdown. Though the PLF achieved by RTPS during 2006-10 was above the norm fixed by CERC and national average, it showed a declining trend i.e. from 89.18 per cent in 2006-07 to 80.78 per cent in 2009-10. This was due to ageing of Units, quality of coal, frequent breakdown of Units, running on partial load, back-down instructions from Load Despatch Centre (LDC) and non-achievement of rated parameters.

Bellary Thermal Power Station (BTPS) had not achieved the norm for PLF specified by CERC.

The targets for generation as approved by CEA were achieved by hydro stations.

Outages

The number of hours lost due to planned outages in thermal power stations increased from 2,283.82 hours in 2006-07 to 3,757.25 hours in 2009-10 i.e., from 3.72 per cent to 5.36 per cent of the available hours. The forced outage hours were within the norm of 10 per cent of the available hours fixed by CEA in all the years except 2008-09. In RTPS, 1.65 per cent to 7.45 per cent of the operated capacity remained unutilised resulting in loss of generation of 2,388 MU due to running of Units on partial load and reduced capacity due to their ageing. Loss of generation at BTPS due to operation below the rated capacity was 1,147 MU.

Financial management

The dues receivable from ESCOMs increased from ₹2,525.02 crore at the end of March 2006 to ₹4,032.16 crore at the end of March 2010 due to poor realisation resulting in increased dependence on short term loans for meeting operational requirements. The borrowings increased from ₹ 4,552.40 crore at the end of March 2006 to ₹ 7,381.97 crore at the end of March 2010 leading to additional interest burden of ₹284.79 crore. As at the end of March 2010, RTPS held spares valued ₹136.43 crore which was in excess of the prescribed guidelines by ₹77.63 crore resulting in locking up of funds and loss of interest of ₹4.77 crore for one year alone.

Although the Power Purchase Agreements empowered the Company to appropriate payments received from ESCOMs first towards outstanding interest and thereafter towards principal dues, the Company failed to do so resulting in accumulation of interest to the extent of ₹1,170.83 crore.

Environmental issues

The Company had exceeded the parameters prescribed by Central Pollution Control Board / Environmental Acts in respect of air, water and noise pollution. As RTPS failed to comply with the directions of State Pollution Control Board, it could not avail of concessional rates on water cess leading to extra expenditure of ₹1.16 crore.

Conclusion and Recommendations

The State is not in a position to achieve 'Power for All by 2012' due to lack of concerted efforts for augmentation of capacity. The project management was ineffective as instances of time

overrun were noticed. New hydro projects proposed to be taken up by the Company were either awaiting clearance from MoEF or held up due to local agitation. Renewable Energy Sources in the State also remained underutilised. The operational performance of thermal power stations was sub-optimal due to fixation of generation targets below the available hours, low plant load factor, inefficient fuel management, failure to undertake timely renovation and modernisation and life extension schemes. The consumption of coal was in excess as compared to designed parameters. The poor realisation of dues and consequent accumulation of outstandings from ESCOMs forced the Company to resort to borrowings entailing payment of interest. This had also affected its ability to take up new projects.

The review contains eight recommendations:

The Company needs to streamline procedures for procurement, acceptance and consumption of coal and strive to improve efficiency;

The thermal power stations should strive to improve performance to the level of norms of CERC / KERC and CEA and achieve the specifications prescribed by equipment suppliers;

The Company should also analyse / investigate reasons for excess consumption of fuel, higher outage hours, higher auxiliary consumption and other higher operating parameters;

The Company needs to take up renovation and modernisation and life extension programmes as per schedule. This would result in optimum utilisation of existing facilities;

The Government needs to evolve a long-term strategy for capacity augmentation through its own agencies and by private sector participation;

From a long-term perspective there is a need to diversify energy sources and provide clean energy. Development of hydro and renewable energy sources needs to be accorded top priority for energy security;

The Government also needs to encourage, adopt and implement Demand Side Management and Energy Efficiency measures in addition to capacity addition; and

The Government should consider setting up a task force on priority so that the objective of providing power for all by the end of 2012 is achieve.

Introduction

Power is an essential requirement for all facets of life and has been recognised as a basic human need. The availability of reliable and quality power at competitive rates is very crucial to sustain growth of all sectors of the economy. The Electricity Act, 2003 provides a framework conducive to the development of Power Sector, promote transparency and competition and protect the interest of the consumers. In compliance with Section 3 of the 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 based on optimal utilisation of resources like coal, gas, nuclear material, hydro and renewable sources of energy. The Policy aims at, *inter alia*, laying guidelines for accelerated development of the Power Sector. It also requires CEA to frame the National Electricity Plan once in five years. The Plan would be a short term framework of five years and give a 15 year perspective.

2.1.2 The electricity requirement[14] in the State of Karnataka during the year 2004-05 was 35,237 Million Units (MU) (ex-bus) of which only 33,644 MU (ex-bus) were available leaving a shortfall of 1,593 MU, which works out to 4.52 *per cent* of the requirement. The total installed generation capacity in Karnataka at the end of 2004-05 was 5,934.80 Mega Watt (MW) (excluding firm allocation of 1,150 MW from Central Generating Stations - CGS) and the effective available capacity was 5,612 MW (ex-bus) against the peak demand of 5,971 MW (ex-bus) leaving a deficit of 359 MW. As on 31 March 2010, the comparative figures of requirement and available capacity were 45,550 MU (ex-bus) and 9,117.91 MW (excluding firm allocation of 1,269.90 MW from CGS). Thus, there was growth in demand of 10,313 MU during the review period, whereas the capacity addition was 3,183.11 MW (excluding the share available from CGS).

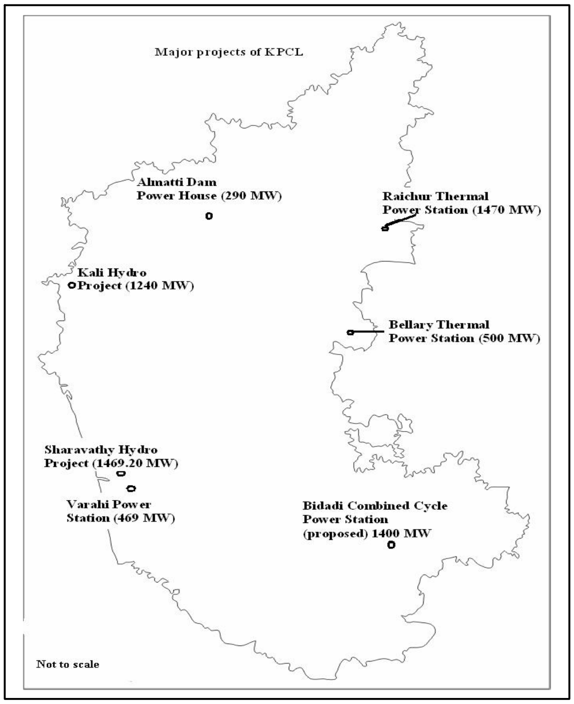
2.1.3 In Karnataka[15], the public sector utility engaged in generation of power is Karnataka Power Corporation Limited (Company), which was incorporated on 20 July 1970 under the Companies' Act, 1956, as a wholly-owned Company under the administrative control of Energy Department of the Government of Karnataka (GoK). The Management of the Company is vested with Board of Directors (BoD) comprising not less than three and not more than seventeen

[14] **information compiled from the annual reports of Southern Regional Power Committee, Central Electricity Authority.**

[15] **the main utilities in Karnataka's power sector are the Karnataka Power Corporation Limited - the Public Sector generation utility, the Karnataka Power Transmission Corporation Limited (KPTCL) - the Public Sector transmission utility and five Public Sector regional distribution utilities or electricity supply companies (ESCOMs) viz., Bangalore Electricity Supply Company Limited, Mangalore Electricity Supply Company Limited, Gulbarga Electricity Supply Company Limited, Hubli Electricity Supply Company Limited and Chamundeshwari Electricity Supply Corporation Limited. A special purpose vehicle *viz.,* Power Company of Karnataka Limited was formed (August 2007) by Government of Karnataka to supplement the efforts of the Company in capacity addition and to carry out tariff-based bidding process on behalf of ESCOMs to bridge the gap between availability and demand.**

directors, appointed by the State Government. As at the end of March 2010, there were fourteen directors on the Board including the Chief Minister who was the Chairman. The day-to-day operations of the Company are carried out by the Managing Director (MD) who is the Chief Executive of the Company. The MD is assisted by the Executive Directors and the Chief Engineers who are responsible for the operation and maintenance of thermal and hydro stations respectively.

The Company had two thermal power stations (1,970 MW[16]), eighteen hydro generation stations (3,637.35 MW), two renewable energy stations (10.56 MW[17]) and one Diesel Generating (DG) plant[18] (127.92 MW) with a total installed capacity of 5,745.83 MW as at 31 March 2010.



Of hydro stations, 11 *per cent* (399.95 MW) were irrigation-based projects, 12 *per cent* (438.40 MW[19]) were run-of-the-river[20] schemes, 30 *per cent* (1,090 MW[21]) were storage-based schemes (dependent on the level of water in the reservoirs) and 47 *per cent* (1,709 MW) were peaking stations[22].

The turnover of the Company was ₹ 4,397.25 crore in 2009-10, which was equal to 12.09 *per cent* and 1.47 *per cent* of the turnover of State PSUs and State Gross Domestic Product (advance estimates at current prices) for the year 2009-10 respectively. As on 31 March 2010, the Company had employee strength of 6,052 excluding 229 of erstwhile Visvesvaraya Vidyuth Nigama

---

[16] Raichur Thermal Power Station (seven Units of 210 MW each) and Bellary Thermal Power Station (single unit of 500 MW).

[17] Kappadagudda Wind Farm (4.56 MW) and Solar Photo-voltaic Plant (6 MW).

[18] during the year 2009-10, the installed capacity of DG plant was considered as 108 MW by the Company.

[19] Almatti (290 MW), Bhadra (39.2 MW), Ghataprabha (32 MW), Munirabad (28 MW) and four mini hydro projects aggregating 10.75 MW *viz.,* Kalmala, Sirwar, Ganekal and Mallapur.

[20] run-of-the-river hydro station has no reservoir to store water inflow from the catchment area. The natural flow and elevation drop of a river are used to generate electricity. Shivanasamudram (42 MW), Shimshapura (17.2 MW), Mahatma Gandhi Hydro Electric (139.2 MW) and Gerusoppa (240 MW) projects are such stations operated by the Company.

[21] Sharavathy (1,035 MW) and Linganamakki (55 MW).

[22] power stations providing power to electrical grids for meeting peak demand (highest point of consumer consumption of electricity) are called peaking stations. In the State, Kali Stage 1 (970 MW), Kali Stage 2 (270 MW), Varahi (460 MW) and Mani (9 MW) are considered as peaking stations.

Limited (VVNL), which was merged with the Company with effect from 1 April 2006.

2.1.4 The reviews relating to the Company included in the earlier[23] Audit Reports and their present status is given below:

Review	Reference	Present status
Raichur Thermal Power Station – Units 1 and 2	Audit Report (Commercial), 1987	Deemed to be discussed by Committee on Public Undertakings (COPU)
Varahi Hydroelectric Project	Audit Report (Commercial), 1990	Discussed by COPU during 1992-93. Recommendations made in April 1993.
Implementation of Hydel projects	Audit Report (Commercial), 1994	Discussed by COPU in September 1996. Recommendations were made in March 1997, July 1999 and March 2001.
Raichur Thermal Power Station – Units 3 to 6	Audit Report (Commercial), 2000	Deemed to be discussed by COPU.
Sharavathy Tailrace Project, Gerusoppa	Audit Report (Commercial), 2003	Discussed by COPU in November 2005 / January 2006. No recommendations were made.
Fuel management in power sector companies	Audit Report (Commercial), 2004	Discussed by COPU in August 2009. No recommendations were made.
Renovation and modernisation works of hydro generating stations in Visvesvaraya Vidyuth Nigama Limited	Audit Report (Commercial), 2006	Review is yet to be discussed by COPU.
Raichur Thermal Power Station – Unit 7	Audit Report (Commercial), 2007	Review is yet to be discussed by COPU.

Scope and Methodology of Audit

2.1.5 The present review, conducted during March to June 2010, covers the performance of the Company during the period from 2005-06 to 2009-10. The review mainly deals with Planning, Project Management, Financial Management, Operational Performance (with particular reference to thermal stations and a general review of the ongoing projects relating to hydro stations), Environmental Issues and Monitoring by top Management. Audit examination involved scrutiny of records at Head Office and three (out of eleven) generating projects planned for commissioning during X and XI plan periods (2002-12).

The source-wise details of projects envisaged for commissioning during X and XI plans and projects actually commissioned up to March 2010 were as follows:

Particulars	Hydro		Thermal		Gas		Renewable Energy		Total	
	No.	Capacity (MW)	No.	Capacity (MW)	No.	Capacity (MW)	No.	Capacity (MW)	No.	Capacity (MW)
Planned for commissioning during X and XI plans	5	1,030	4	1,460	1	350[24]	2	11.50♣	12	2,851.50
Actually commissioned up to March 2010	3	535*	2	710	-	-	2	8.50	7	1,253.50

♣includes 9 MW Solar Photo-voltaic plant which is complete to the extent of 6 MW.
***includes uprating of Nagjhari Power House by 45 MW, which is partly completed (15 MW).**

[23] from 1987 onwards.
[24] capacity has been revised to 1,400 MW.

Of the twelve projects (2,851.50 MW) planned for commissioning during X and XI plans (2002-12), only seven (1,253.50 MW) were commissioned up to March 2010. Of this, we took up for analysis three projects completed during 2005-10 - one thermal and two hydro projects (including uprating of partly completed hydro station) with a combined capacity of 745 MW. The details of projects taken up by the Company during 2002-10 and selected for review (59 *per cent* of new capacity additions made during 2002-10) are indicated in **Annexure 8.**

2.1.6 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, issue of audit queries, discussion of audit findings with the Management and issue of draft review to the Management and Government for comments.

Audit Objectives

2.1.7 The objectives of the performance audit were:

2.1.8 Planning and Project Management

- To assess whether capacity addition programme taken up / to be taken up to meet 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 optimisation of generation from the existing capacity;
- To ascertain whether the contracts were awarded with due regard to economy and in transparent manner;
- To ascertain whether the execution of projects were managed economically, effectively and efficiently;
- To ascertain whether hydro projects were planned and formulated after taking into consideration the optimum design to get the maximum power, dam design and safety aspects; and
- To ascertain whether the Company had taken up the projects under non-conventional sources such as wind, solar, biomass *etc.,* and tap generation from captive power sources.

2.1.9 Financial Management

- To ascertain whether the projections for funding the new projects and upgradation of existing generating units were realistic including the identification and optimal utilisation for intended purpose;
- To assess whether all claims including energy bills and liquidated damages were properly raised and recovered in an efficient manner; and
- To assess the soundness of financial health of the generating undertaking.

2.1.10 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 were worked out realistically, procured economically and utilised efficiently;
- To assess whether the manpower requirement was realistic and its utilisation optimal;
- To assess whether the Life Extension (LE) / Renovation and Modernisation (R&M) programmes were ascertained and carried out in an economic, effective and efficient manner; and
- To assess the impact of LE / R&M activity on the operational performance of the Unit.

2.1.11 Environmental Issues

- To assess whether various types of pollutants (air, water, noise, hazardous waste) in the power stations were within the prescribed norms and the stations complied with the required statutory requirements; and
- To assess the adequacy of waste management system and its implementation.

2.1.12 Monitoring and Evaluation

- To ascertain whether adequate Management Information System (MIS) existed in the entity to monitor and assess the impact and utilise the feedback for preparation of future schemes.

Audit Criteria

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

- National Electricity Plan, norms / guidelines of CEA and Ministry of Power (MoP) regarding planning and implementation of projects;
- norms and statistical reports of Central Electricity Regulatory Commission (CERC), Karnataka Electricity Regulatory Commission (KERC), Southern Regional Power Committee (SRPC) and State Planning Commission;
- standard procedures for award of contract with reference to principles of economy, efficiency and effectiveness;
- targets fixed for generation of power;
- parameters fixed for plant availability, Plant Load Factor (PLF), *etc.*;
- comparison with best performers in the regions / all India averages;
- prescribed norms for planned outages; and
- Acts relating to environmental laws.

Financial Position and Working Results

2.1.14. The financial position of the Company for the five years ending 2009-10 is given below:

(Rupees in crore)

Table 1

Particulars	2005-06	2006-07	2007-08	2008-09	2009-10
Liabilities					
Paid-up Capital	662.98	743.26	743.26	1,243.26	1,743.26
Reserve and Surplus (including Capital Grants but excluding Depreciation Reserve)	1,836.27	2,182.09	2,370.70	2,630.60	3,037.76
Borrowings (Loan Funds)					
Secured	2,584.34	2,894.85	2,632.30	2,665.83	3,552.01
Unsecured	1,968.06	1,971.81	2,350.91	3,966.86	3,829.96
Current Liabilities & Provisions (including Deferred Tax Liability)	629.02	1,098.07	1,023.56	1,301.03	1,272.87
Total	**7,680.67**	**8,890.08**	**9,120.73**	**11,807.58**	**13,435.86**
Assets					
Gross Block	6,053.61	6,507.56	8,529.57	8,893.19	9,142.44
Less: Depreciation	2,668.92	3,169.07	3,531.68	3,904.29	4,313.90
Net Fixed Assets	3,384.69	3,338.49	4,997.89	4,988.90	4,828.54
Capital works-in-progress	1,098.88	2,151.51	563.60	1,346.96	2,071.45
Investments	1.35	1.35	1.35	1.35	6.35
Current Assets, Loans and Advances	3,164.28	3,381.91	3,550.78	5,467.21	6,526.50
Miscellaneous Expenditure to the extent not written off	31.47	16.82	7.11	3.16	3.02
Total	**7,680.67**	**8,890.08**	**9,120.73**	**11,807.58**	**13,435.86**

Against the ideal debt-equity[25] ratio of 4:1, it was 4.41:1 in 2005-06, decreased to 2.24:1 in 2009-10. This was due to higher infusion in equity capital (₹ 1,080.28 crore) as compared to increase in long term borrowings (₹ 975.16 crore) during 2005-10.

Current Assets, Loans and Advances as at the end of March 2010 included principal dues (₹ 4,032.16 crore) and interest on these dues (₹ 1,170.83 crore) receivable from Electricity Supply Companies (ESCOMs) towards sale of energy. The extent of dues receivable from ESCOMs varied between 74.76 *per cent* (2008-09) and 82.14 *per cent* (2007-08) of the current assets, loans and advances of the Company.

The Company sells energy to ESCOMs at the rates specified by KERC from time to time. KERC fixes the tariff after considering various economic and other factors. Generally sale price does not cover the total input costs. The differential amount is absorbed by the Company. We observed that dues from ESCOMs were not regularly realised. Correspondingly, defaults in payment of bills of coal companies for supply of coal were also observed.

[25] **for the purposes of debt-equity ratio, long-term loans are only considered.**

The table below gives the details of energy bills raised on ESCOMs and recoveries there against and coal bills received *vis-à-vis* payments made for the review period.

(Rupees in crore)

Table 2

Sl. No.	Details	2005-06	2006-07	2007-08	2008-09	2009-10
1	Opening balance of energy charges receivable from ESCOMs	2,082.82	2,568.37[26]	2,307.33	2,361.96	3,280.49
2	Sales during the year	2,438.01	3,433.80	3,344.89	4,147.90	4,397.25
3	Total amount due (1+2)	4,520.83	6,002.17	5,652.22	6,509.86	7,677.74
4	Energy charges realised from ESCOMs (including book adjustments and write offs)	1,995.81	3,694.84	3,290.26	3,229.37	3,645.58
5	Closing balance of energy charges receivable from ESCOMs (3-4)	2,525.02	2,307.33	2,361.96	3,280.49	4,032.16
6	Percentage of realisation to dues outstanding (4/3 x 100)	44.15	61.56	58.21	49.61	47.48
7	Coal bills received	1,415.07	1,633.52	1,598.75	2,323.13	2,097.74
8	Payments made	1,309.22	1,490.51	1,373.67	1,890.78	1,769.36
9	Difference (7-8)	105.85	143.01	225.08	432.35	323.38

Note: The above table does not include power sold to other states / agencies under open access and interest on belated payments receivable from ESCOMs.

The Company was forced to borrow short term loans to meet operational requirements due to poor realisation of dues from ESCOMs.

The poor realisation of receivables and consequent accumulation of huge outstandings from ESCOMs forced the Company to raise short term loans for meeting its operational requirements. The short term borrowings which was ₹ 1,629.46 crore at the end of 2005-06 increased to ₹ 3,483.87 crore at the end of 2009-10, representing an increase of 113.81 *per cent*.

In accordance with the terms and conditions concluded in the Power Purchase Agreements (PPAs) with ESCOMs, the Company levied interest on the progressive outstanding receivables but we observed that ESCOMs had not paid the interest of ₹ 1,170.83 crore. Although the PPAs empowered the Company to appropriate the payments received from ESCOMs first towards outstanding interest and thereafter towards the principal dues, the Company had not appropriated the receipts from ESCOMs towards outstanding interest. Instead, the amounts received were appropriated towards principal dues thus allowing the interest to accumulate over the years.

We also observed that the Company had paid interest of ₹ 17.85 crore during 2005-10 to washeries / collieries / contractors for its failure to ensure timely settlement of their bills.

[26] **revised due to merger of VVNL with effect from 1 April 2006.**

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

(Rupees in crore)

Table 3

Sl. No.	Description		2005-06	2006-07	2007-08	2008-09	2009-10
1	**Income**						
	Generation revenue		2,520.67	3,433.82	3,344.85	4,147.90	4,397.25
	Other income including interest / subsidy		148.89	316.56	306.50	283.38	409.29
	Total Income		**2,669.56**	**3,750.38**	**3,651.35**	**4,431.28**	**4,806.54**
2	**Generation**						
	Total generation (in MU)		19,888.94	26,635.44	25,613.16	25,080.30	26,020.19
	Less: Auxiliary consumption (in MU)		919.61	1,163.84	1,149.75	1,235.20	1,282.96
	Total generation available for transmission and distribution (in MU)		**18,969.33**	**25,471.60**	**24,463.41**	**23,845.10**	**24,737.23**
3	**Expenditure**						
(a)	**Fixed cost**						
(i)	Employees cost		213.85	363.62	419.13	349.52	313.88
(ii)	Administrative and general expenses		27.78	69.13	71.08	89.06	88.42
(iii)	Write off of receivables		19.17	420.77	256.17	0.00	1.13
(iv)	Depreciation		265.55	244.66	363.83	378.55	390.54
(v)	Consumables		75.25	52.34	42.85	42.15	50.05
(vi)	Interest and finance charges		349.65	383.28	412.72	572.61	504.79
	Total fixed cost		**951.25**	**1,533.8**	**1,565.78**	**1,431.89**	**1,348.81**
(b)	**Variable cost**						
(i)	Fuel consumption						
	(a)	Coal	1,320.35	1,702.97	1,626.57	2,141.48	2,227.95
	(b)	Oil	10.81	83.56	151.24	415.29	437.58
	(c)	Chemicals	2.81	2.86	2.83	2.31	2.34
(ii)	Cost of water (hydro)		39.78	56.13	54.01	48.72	57.54
	Total variable cost		**1,373.75**	**1,845.52**	**1,834.65**	**2,607.80**	**2,725.41**
(c)	**Total cost 3(a) + (b)**		**2,325.00**	**3,379.32**	**3,400.43**	**4,039.69**	**4,074.22**
4	Realisation (*per* unit) (₹)		1.33	1.35	1.37	1.74	1.78
5	Fixed cost (*per* unit) (₹)		0.50	0.60	0.64	0.60	0.55
6	Variable cost (*per* unit) (₹)		0.73	0.73	0.75	1.09	1.10
7	Total cost (5+6) (*per* unit) (₹)		1.23	1.33	1.39	1.69	1.65
8	Contribution (4-6) (*per* unit) (₹)		0.60	0.62	0.62	0.65	0.68
9	**Profit (+) / Loss (-) (4-7) (*per* unit) (₹)**		**0.10**	**0.02**	**-0.02**	**0.05**	**0.13**

2.1.16 The graphical representation and details of realisation, fixed cost, variable cost, total cost, contribution and profit / loss per unit of different sources of energy are indicated in **Annexure 9**.

2.1.17 The operation of the Company resulted in profit in all the years except in the year 2007-08. The generation revenue substantially increased during 2006-07 mainly due to increase in generation capacity by 354.32 MW as erstwhile VVNL was amalgamated with the Company. The generation revenue increased substantially (by ₹ 803.05 crore) during 2008-09 due to increased thermal generation as compared to 2007-08. The higher margin in thermal power in comparison to hydro power contributed to substantial increase in profit during 2008-09.

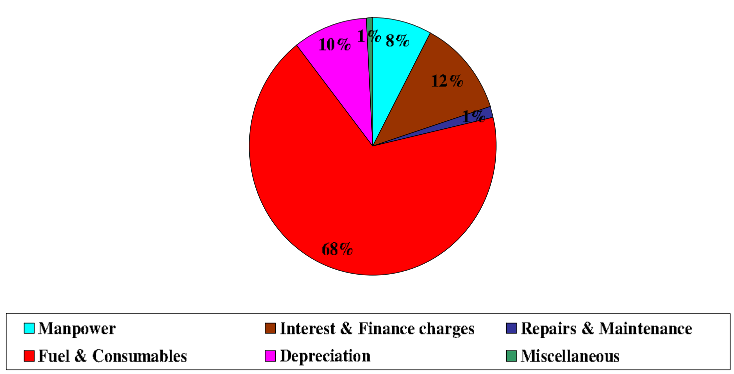
2.1.18 The total fixed cost increased during 2006-07, due to absorption of employee costs relating to employees of erstwhile VVNL and pay revision effected during that year. Besides, during 2006-07 and 2007-08, the Company wrote off receivables due from KPTCL and ESCOMs amounting to ₹ 420 crore and ₹ 250 crore respectively, resulting in increased fixed cost *per* unit during these years.

2.1.19 The variable cost *per* unit of energy generated by thermal power stations increased from ₹ 1.59 in 2005-06 to ₹ 1.87 in 2009-10. Similarly, the variable cost *per* unit generated by DG plant increased from ₹ 5.43 in 2006-07 to ₹ 8.19 in 2009-10, the reason for such increase being the steep rise in cost of fuel.

Elements of Cost

2.1.20 Fuel and Consumables and Interest and Finance charges constituted the major elements of costs. The percentage break-up of costs for 2009-10 is given below in the pie-chart:

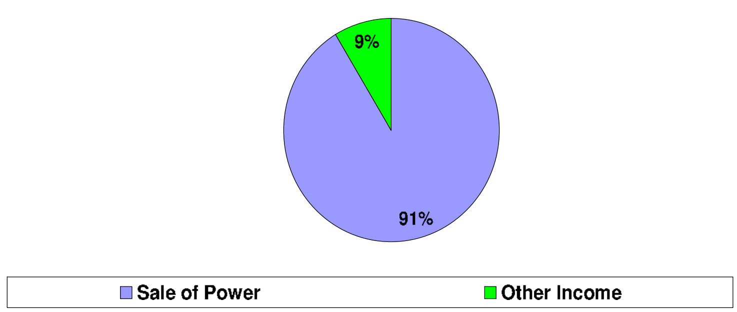
Components of various elements of cost



Elements of revenue

2.1.21 Sale of power constituted the major element of revenue. The percentage break-up of revenue for 2009-10 is given below in the pie-chart:

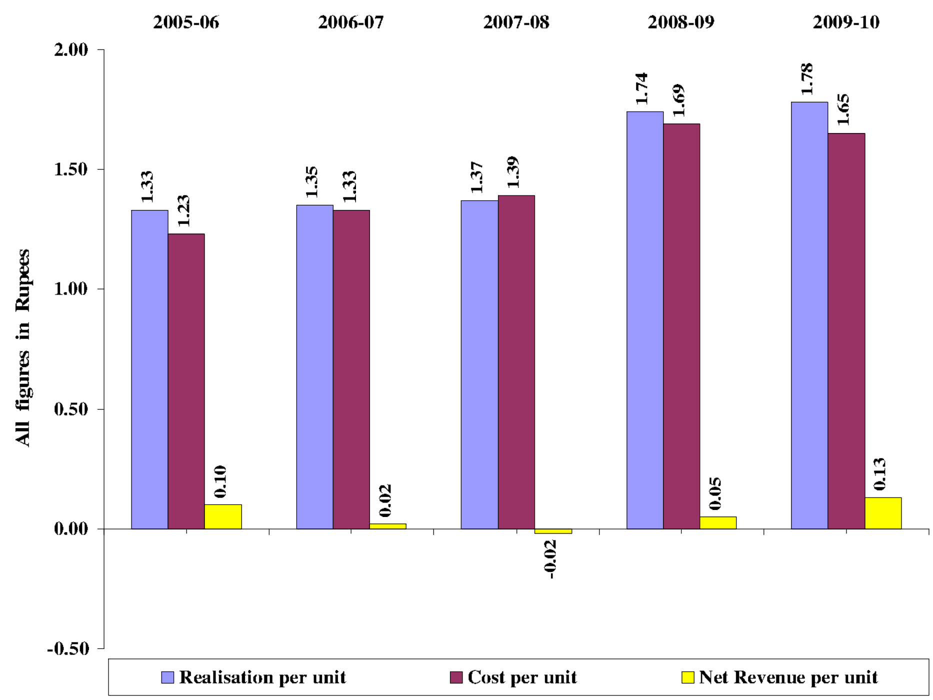
Components of various elements of revenue



Other income mainly included interest on delayed realisation of sale proceeds, other interest and miscellaneous receipts.

Recovery of cost of operations

2.1.22 The Company was able to recover its cost of operations in all the years in respect of all sources as indicated in **Annexure 9**. The graphical representation of overall *per* unit realisation, cost and margin is indicated below:



Though the net revenue *per* unit was positive from different sources of energy in the year 2007-08, yet the overall net revenue *per* unit was negative due to write off of receivables (₹ 250 crore) and increased administrative expenditure / finance charges of corporate office.

The main reasons for increase in cost of generation from ₹ 1.23 *per* unit in 2005-06 to ₹ 1.65 *per* unit in 2009-10 were increased administration and general expenses, interest cost and expenses on fuel.

Audit Findings

2.1.23 We explained the objectives of the performance review to the Company during an 'Entry Conference' held in April 2010. Audit findings were reported to the Company and the State Government in July 2010 and discussed in the 'Exit Conference' held in August 2010, which was attended by the Principal Secretary, Energy Department, GoK and the Managing Director of the Company.

The Company replied to audit findings in August 2010, while the reply of the Government is awaited (September 2010). The views expressed by the Company have been considered while finalising the review. The audit findings are discussed below.

Operational Performance

2.1.24 The operational performance of the Company for the five years ending 2009-10 is given in **Annexure 10**. The operational performance of the Company was evaluated on various operational parameters such as plant load factor, plant availability, capacity utilisation, outages and auxiliary consumption. It was also seen whether the Company was able to maintain pace in terms of capacity addition with the growing demand for power in the State. Audit findings in this regard are also discussed in the subsequent paragraphs. These audit findings show that there was scope for improvement in performance.

Planning

2.1.25 National Electricity Policy aims to provide availability of over 1,000 units of *per* capita electricity by 2012, for which it was estimated that need based capacity addition of more than 1,00,000 MW would be required during 2002-2012 in the country. The Central Government has laid emphasis on the full development of hydro potential, being the cheaper source of energy as compared to thermal. The Central Government was to support the State Government for expeditious development of hydro power projects by offering the services of Central Public Sector Undertakings like National Hydro Power Corporation, National Thermal Power Corporation and North Eastern Electric Power Corporation. The requirement of generation as per NEP was 1,038 Billion Units requiring generation growth of 9.5 and 7.5 *per cent per annum* during X plan (2002-2007) and XI plan (2007-2012) respectively. In order to fully meet both energy and peak demand by 2012, there is need to create adequate reserve capacity margin. In addition to enhancing the overall availability of installed capacity to 85 *per cent*, a spinning reserve[27] of at least five *per cent* needs to be created. Besides, environmental concerns have to be suitably addressed through appropriate advance actions.

2.1.26 During the period from 2005-06 to 2009-10, the actual generation in the State was substantially less than the peak as well as the average demand as shown below:

Table 4

At the end of the year	Installed capacity of the State (MW)	Average gross demand (MW)	Gross peak demand (MW)	Total gross demand (MU)	Actual gross generation (MU)	Percentage of actual generation to average demand[28]	Percentage of actual generation to peak demand[29]
1	2	3	4	5	6	7	8
2005-06	6,513.99	5,078	5,949	34,515	34,266	77.03	65.75
2006-07	6,529.24	5,717	6,401	41,161	40,314	80.50	71.90
2007-08	7,613.35	5,848	6,732	41,102	40,012	78.10	67.85
2008-09	8,083.16	6,277	7,051	44,226	41,640	75.73	67.41
2009-10	9,117.91	6,843	8,094	47,027	43,517	72.60	61.38

27 part loaded generating capacity with some reserve margin that is synchronised to the system and is ready to provide increased generation at short notice pursuant to despatch instruction or instantaneously in response to a frequency drop (Indian Electricity Grid Code, March 2002).

28 Sl. No.7 = (Sl. No.6 / ((Sl. No.3*24*365)/1,000)) x 100.

29 Sl. No.8 = (Sl. No.6 / ((Sl. No.4*24*365)/1,000)) x 100.

As may be seen from the above, the percentage of actual generation to peak demand which was 71.90 *per cent* in 2006-07 reduced to 61.38 *per cent* in 2009-10. The reason for such ever-increasing gap was the absence of concerted efforts to augment capacity. This had resulted in the total supply for the State being insufficient to meet the peak demand, as shown below:

The shortfall in meeting peak demand during 2009-10 was 12.91 *per cent.*

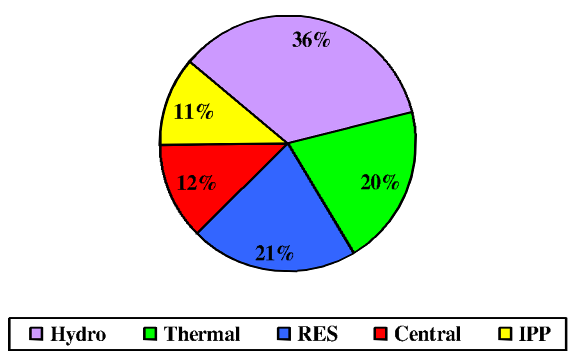
Table 5

Year	Gross peak demand (MW)	Peak demand met (MW)	Peak deficit	
			MW	Percentage of peak demand
2005-06	5,949	5,558	391	6.57
2006-07	6,401	5,959	442	6.91
2007-08	6,732	5,715	1,017	15.11
2008-09	7,051	6,707	344	4.88
2009-10	8,094	7,049	1,045	12.91

Thus, there remained a shortfall of 344 to 1,045 MW (4.88 *per cent* to 15.11 *per cent* of the peak demand) which was bridged by rotational load shedding.

Capacity Additions

2.1.27 The State had a total installed capacity of 7,084.80 MW (including firm allocation of 1,150 MW from Central Generating Stations) at the beginning of 2005-06 which increased to 10,387.81 MW (including firm allocation of 1,269.90 MW from CGS) at the end of 2009-10. The break up of generating capacities, as on 31 March 2010 under Thermal[30], Hydro[31], Renewable Energy Sources (RES), Central[32] and Independent Power Producers[33] (IPP) is shown in the pie chart below:



2.1.28 As per the Long term Demand Forecast[34] for the years from 2006 to 2017 prepared (December 2006) by KPTCL and approved by KERC, the maximum energy requirement of the State for the year 2009-10 was estimated

[30] contribution from State sector alone *i.e.*, the share of the Company, which includes 127.92 MW from DG Plant.

[31] contribution from State sector alone *i.e.*, share of the Company.

[32] consists of 1,074.54 MW of thermal and 195.36 MW of nuclear power (firm allocation from CGS).

[33] consists of 860 MW of thermal, 220 MW of gas and 106.5 MW of diesel power.

[34] as part of planned development of generation, transmission and distribution facilities and in line with the Government policy, KPTCL has been entrusted with the task of determining the long term, year-wise energy and demand forecast for the State.

at 50,794 MU. Similarly the maximum peak demand (at 65 *per cent* load factor) for the State was projected at 8,921 MW.

Thus, to meet the peak demand of 8,921 MW and energy requirement of 50,794 MU as estimated by KPTCL[35] for the year 2009-10, a capacity addition of about 8,050 MW[36] was required during the period from 2005-06 to 2009-10. Against this, the earmarked capacity addition according to NEP, categorised as Projects Under Construction (PUC[37]) at State level, was only to the extent of 1,808 MW, as detailed below.

(in MW)

Table 6

Category	Thermal	Hydro	Gas	Nuclear	Non-conventional Energy	Total
PUC	1,350[38]	340[39]	0	118	0	1,808

2.1.29 Of the 1,808 MW of projects categorised under PUC, 558.96 MW[40], which were originally proposed to be completed during X plan, spilled over to XI plan due to delay in supplies / placement of order for Balance of Plants[41] / erection by suppliers / contractors.

[35] estimate of KPTCL is considered, as the report is of 2006, the year closest to the year of Audit review.

[36] worked out considering a forecast error of 5 *per cent* (as per KERC norm), spinning reserve of 5 *per cent* (as per Para 5.2.3 of National Electricity Plan), load factor of 65 *per cent* on KPTCL forecast of 8,921 MW and availability of 7,084.80 MW at the end of 2004-05.

[37] projects under construction are projects whose capacity addition is proposed during XI plan (2007-12). This includes projects under implementation slipping from earlier plans.

[38] contribution of the Company was 750 MW. The balance 600 MW relates to Torangallu Extension Project, implemented by JSW Energy (Vijayanagar) Ltd., Bellary.

[39] entire hydro capacity addition was by the Company.

[40] Bellary Thermal Power Station Unit 1 of 500 MW and Kaiga Unit 3 share of 58.96 MW.

[41] the plant systems and equipments of a thermal station consist of a Main Plant and a Balance of Plant. The main plant comprises of boiler, turbine and generator. The balance of plant includes all plants and equipment other than those included in main plant system *viz.,* coal handling plant, ash handling plant, water treatment system *etc.,* (Source: CEA's draft standard design criteria).

2.1.30 The particulars of capacity additions envisaged, actual additions by the Company and peak demand *vis-à-vis* energy supplied by the State during the review period are given below.

Table 7

Sl. No.	Description	2005-06	2006-07	2007-08	2008-09	2009-10
1	Capacity of the Company at the beginning of the year (MW)	4,530.51	4,640.51	4,994.83	5,509.83	5,739.83
2	Additions planned by the Company (MW) (including spill over of previous year, shown in brackets)	125	515 (15)	515 (515)	510	774 (265)[42]
3	Actual additions by the Company (MW)	110	0	515	230	6
4	Capacity of the Company at the end of the year (MW) (1+3)	4,640.51	4,994.83[43]	5,509.83	5,739.83	5,745.83
5	Shortfall in capacity addition by the Company (MW) (2-3)	15	515	0	280	768
6	Gross Peak demand (MW)	5,949	6,401	6,732	7,051	8,094
7	Energy Requirement of State (MU)	34,515	41,161	41,102	44,226	47,027
8	Energy supplied:					
	a) by the Company (MU)	18,969	25,472	24,463	23,845	24,737
	b) Energy purchased (MU)	14,220	13,802	13,996	16,488	17,231
9	Shortfall (MU) (7-(8(a)+8(b))	1,326	1,887	2,643	3,893	5,059

2.1.31 We observed that the actual capacity addition in the State during the review period (2005-10) was 3,183.11 MW, leaving a shortfall of 4,866.89 MW with reference to the required capacity addition. In this context, it is to be noted that during 2008-09, BESCOM purchased high cost energy from private sources at rates ranging from ₹ 6.81 to ₹ 7.93 *per* unit in order to meet the deficit. Against this, the average cost of energy purchased by ESCOMs from the Company was only ₹ 1.65 *per* unit. Evidently, purchase of power at high rates to tide over the deficit burdens the exchequer.

The achievements of the Company with reference to targeted capacity additions during the review period (2005-10) are given below:

- Against 1,644 MW of firm[44] capacity addition planned during 2005-10, the actual addition was only 861 MW (52 *per cent*).
- The works relating to two projects *viz.,* Raichur Thermal Power Station (RTPS) Unit 8 (250 MW) and Bellary Thermal Power Station (BTPS) Unit 2 (500 MW) are still under progress although these were envisaged to be completed by 2008-09 and 2009-10 respectively. While the delay in commissioning of RTPS Unit 8 was attributed (April 2010) to delay in supply of materials and in completion of Boiler-Turbine-Generator package works by M/s Bharat Heavy Electricals Limited (BHEL), the delay in commissioning of BTPS Unit 2 was due to delay in receipt of

[42] 15 MW (Nagjhari Power House Unit 6) was excluded from annual plan of 2009-10.
[43] the increase in installed capacity by 354.32 MW was due to merger of VVNL.
[44] firm capacity refers to projects which were approved by CEA and taken up by the Company for implementation.

environmental clearance from Ministry of Environment and Forests (MoEF), GoI.

- The residual works of the partly completed Nagjhari Power House were not completed even by the end of March 2010 although these were planned to be commissioned during 2008-09. The uprating of Unit 5 was in progress whereas Unit 6 was yet (September 2010) to be taken up for renovation.
- Apart from the above firm capacity addition, the Company had also planned implementation of projects of 415 MW capacity *viz.,* Bidadi Combined Cycle Plant Project (350 MW) and second phase uprating of Sharavathy Generating Station (65 MW). The former did not take off due to absence of Government of India policy regarding allocation of natural gas. The uprating of Sharavathy Generating Station was not taken up.

Power for all by 2012

The primary objective of *power for all by 2012* is not achievable as capacity addition planned was not commensurate with the projected demand.

2.1.32 KERC had forecast[45] (December 2008) peak requirement of 10,120 MW by the end of XI plan period (2011-12) with energy requirement of 58,388 MU. The peak demand for the State in 2009-10 was 8,094 MW against the installed capacity of 10,387.81 MW. The peak demand was met only to the extent of 7,049 MW (*i.e.,* 67.86 *per cent* of installed capacity) due to capacity constraints.

To meet the peak demand of 10,120 MW forecast by KERC for 2011-12, the required installed capacity worked out to 14,913 MW (at the peak rate of 67.86 *per cent* met during 2009-10). Hence, the shortfall of 4,525 MW is required to be commissioned between 2010-11 and 2011-12 so as to achieve the objective of providing power for all by 2012. We, however, observed that only six[46] projects with capacity addition of 2,053 MW were projected for completion by the end of 2012, still leaving a gap of 2,472 MW. Government informed (September 2010) that besides the above planned additions, capacity of 1,000 MW from renewable energy sources and 500 MW from Bellary Thermal Power Station (Unit 3) would be added by 2012.

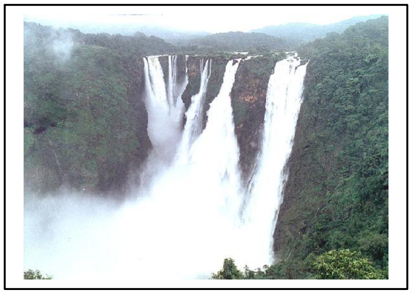
We observed that the Company was yet (September 2010) to finalise the contractor for execution of Bellary Thermal Power Station (Unit 3) and as per the Detailed Project Report, the completion period was projected as three years from date of placement of order (beyond the year 2012). The details of projects proposed to be taken up under renewable energy sources (1,000MW) were not available. We also observed that even after considering the Government's contention, there existed a shortage of 972 MW. In view of the above, the objective of providing power for all by 2012 may not be achieved.

[45] the latest available forecast prepared by KERC is considered.

[46] BTPS Unit 2 (500 MW), RTPS Unit 8 (250 MW), Udupi Power Corporation Limited (1,200 MW), Jurala Hydro Electric Project (70 MW), uprating of Nagjhari Power House Unit 5 and 6 by 30 MW (2 x 15 MW) and Solar Photo Voltaic project (3 MW).

Hydro Energy sources

2.1.33 CEA had assessed (2001) potential of 4,347 MW of hydro power in the State at 60 *per cent* load factor. The Government of India launched a programme in May 2003 for preparation of Preliminary Feasibility Reports (PFRs) of hydro electric schemes (more than 25 MW) under '*50,000 MW initiative*'. CEA reported (July 2010) the potential as 6,459 MW in Karnataka for '*above 25 MW*' category. Of this 3,585.4 MW had already been developed by the Company.



The Company had submitted (September 2004) PFRs in respect of five hydro electric projects aggregating 1,900 MW *viz.,* Kalinadi Stage III (300 MW), Tamankal (300 MW), Gundia (300 MW), Gangavali (400 MW) and Agnashini (600 MW), proposed to be implemented by the Company. Gundia project, which was cleared by CEA only in April 2008 (at an estimated cost of ₹ 1,119.56 crore) was yet to be implemented (September 2010) due to non-receipt of environmental clearance from MoEF.

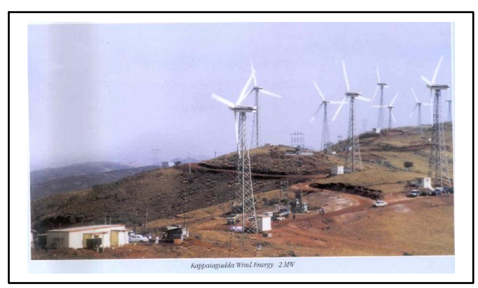
The survey and investigation works in respect of Kalinadi Stage III, Gangavali and Agnashini were not taken up due to agitation by local population. In respect of Tamankal project, clearance for usage of water was pending from Krishna Water Dispute Tribunal. The Company was yet to prepare DPRs in respect of these four projects (September 2010).

Besides the above projects, five more projects *viz.,* Shivanasamudram (345 MW), Mekedatu Stage II (360 MW), Gundia II (200 MW), Sharavathy pumped storage scheme (900 MW) and Kali pumped storage scheme (600 MW), aggregating 2,405 MW, had also been identified[47] for survey and investigation. The DPRs relating to these schemes had not been prepared till date (September 2010).

Renewable Energy sources

Renewable energy sources were only partially harnessed.

2.1.34 In the State, Karnataka Renewable Energy Development Limited (KREDL) acts as the nodal agency for facilitating implementation of renewable energy sources. Against assessed potential of 17,685 MW of renewable energy, only 2,755 MW (15.58 *per cent*) was harnessed as at the end of March 2010.



Optimum utilisation of existing facilities

2.1.35 In order to cope with the rising demand for power, not only additional capacity needs to be created as discussed above, a plan needs to be in place for optimum utilisation of existing facilities and also undertaking life extension programme / replacement of the existing facilities which are near completion of

[47] **as per CEA report.**

their age besides timely repair / maintenance. Renovation and Modernisation (R&M) and Life Extension (LE) of existing / old power stations have been recognised as an effective option to achieve additional generation from existing units at low cost and short gestation period. Besides generation improvement and life extension, other benefits from R&M include improvement in environmental emissions and improvement in availability, safety and reliability.

2.1.36 We observed that though all the six Units (21.32 MW each) of DG plant at Bangalore were due for R&M / Life Extension (LE) programmes between April 2008 and January 2009 as per CEA norms (completion of 15 years or 1,50,000 hours of operation), yet none of the Units were taken up. Government stated (September 2010) that the regular maintenance, medium maintenance and major overhauling were carried out and with these the plant could be run for 2-3 years after its life period. Government further stated that it is proposed to convert DG plant to gas-based plant based on the availability of domestic gas / Liquefied Natural Gas.

Deferment of R&M / LE works indefinitely on the ground of conversion to green fuel was not justified in the absence of GoI policy on allocation of natural gas and uncertainty regarding laying of pipeline for gas supplies. Failure to undertake R&M as per CEA norms had resulted in higher maintenance costs of plant and machinery. The expenditure on repairs of plant and machinery increased from ₹ 2.94 crore (₹ 2.3 lakh *per* MW) in 2005-06 to ₹ 6.47 crore in 2008-09 (₹ 5.06 lakh *per* MW).

We also observed that against the installed capacity of 127.92 MW (21.32 MW x 6 Units), the Company was utilising 108 MW (18 MW x 6 Units) only[48] as the original equipment manufacturer (OEM), had recommended utilisation to the extent of 80 *per cent* capacity for better performance of machines and fuel economy. We, however, observed that the Company followed the OEMs suggestion only to overcome severe vibration experienced during the operation of the Units at their full capacity as its efforts to get the defects rectified by the OEM were not successful. Operation of plant at 80 *per cent* capacity had resulted in consumption of excess heat of 292 Kcal/Kwh (as against turbine heat rate of 1,920 Kcal/Kwh guaranteed by the OEM, the heat rate was 2,212 Kcal/Kwh) resulting in excess consumption of fuel (Low Sulphur Heavy Stock) valued at ₹ 83.28 crore during 2005-10. The Company could have taken up the R&M works in time to improve the capacity of plant to its installed capacity.

2.1.37 Residual Life Assessment (RLA) study involving non-destructive and destructive tests is conducted after 20 years of life or 1.6 lakh hours of operation to reveal the remaining life of various critical components of plants so as to take timely steps to extend the life of the plant by appropriate repairs and replacements. RLA study can be carried out earlier, after 15 years or 1 lakh hours of operation, if the plant condition so necessitates.

No plan of action was envisaged for R & M works.

We observed that no plan of action was envisaged for RTPS Units 1 and 2, which are aged more than 20 years and had operated for more than 1.6 lakh hours. The Units are due for replacement or refurbishment during 2010 and

[48] **as reported by the Company to KERC in 2008-09 and Audit in June 2009. Date of OEMs recommendation not available.**

2011 as per CEA guidelines. The Company has planned to take up life extension works of these two Units in XII plan (2012-17).

Government replied (September 2010) that BHEL had conducted RLA studies of Boiler, Turbine and Generator in respect of Unit 2 in 2003 and in respect of Unit 1 in 2005. As a follow-up requirement, BHEL had been entrusted with task of conducting comprehensive RLA studies of Unit 2 from July 2010 and Unit 1 from September 2010.

Project Management

2.1.38 Preparation of an accurate and realistic DPR after considering feasibility study, considering factors like creation of infrastructure facility and addressing bottlenecks likely to be encountered in various stages of project planning are critical activities in the planning stage of the project.

2.1.39 Project management includes timely acquisition of land, effective actions to resolve bottlenecks, obtain necessary clearance from Ministry of Environment and Forests and other authorities, rehabilitation of displaced families, proper scheduling of various activities, adequate budget provisions, *etc*. The monitoring mechanism of the projects at pre-implementation stage is generally not as vigorous as it is in respect of 'ongoing projects'. The Ministry of Power (MoP) has devised control mechanism which would enable monitoring and follow up from feasibility to ordering stage. Notwithstanding this, time and cost over runs were noticed due to absence of coordinating mechanism throughout the implementation of the projects during the review period as discussed in succeeding paragraphs.

2.1.40 The following table indicates the scheduled and actual dates of completion of the power stations, date of start of transmission, date of commissioning of power stations and the time overrun.

Time overrun

Table 8

Sl. No.	Name of the Unit	Details	As per DPR	As per Contract	Actual	Time overrun (in months)
1	**2**	**3**	**4**	**5**	**6**	**7 (6-5)**
1	Almatti Dam Power House a) Unit 5 (55 MW)	Date of completion of unit	15.04.2005	02.05.2005	06.07.2005	02
		Date of start of transmission	15.04.2005	02.05.2005	06.07.2005	02
		Date of commercial operation / commissioning of unit[49]	15.04.2005	02.05.2005	06.07.2005	02
	b) Unit 6 (55 MW)	Date of completion of unit	15.07.2005	20.06.2005	10.08.2005	02
		Date of start of transmission	15.07.2005	20.06.2005	10.08.2005	02
		Date of commercial operation / commissioning of unit	15.07.2005	20.06.2005	10.08.2005	02
2	Nagjhari Power House Unit 4 (15MW)	Date of completion of unit	06.06.2004	30.04.2005	28.02.2008	34
		Date of start of transmission	06.06.2004	30.04.2005	28.02.2008	34
		Date of commercial operation / commissioning of unit	06.06.2004	30.04.2005	18.04.2008	36
3	BTPS Unit 1 (500 MW)	Date of completion of unit	28.12.2006	29.12.2006	25.03.2008	15
		Date of start of transmission	28.12.2006	28.12.2006	25.03.2008	15

[49] **As per CEA, a hydro unit is considered as commissioned when the trial run operation is started**.

Sl. No.	Name of the Unit	Details	As per DPR	As per Contract	Actual	Time overrun (in months)
		Date of commercial operation / commissioning of unit[50]	28.03.2007	28.03.2007	28.07.2008	16
4	Varahi Underground Power House Stage 2 a) Unit 3 (115 MW)	Date of completion of unit	26.07.2008	22.10.2008	03.01.2009	02
		Date of start of transmission	26.07.2008	22.10.2008	03.01.2009	02
		Date of commercial operation / commissioning of unit	26.07.2008	22.10.2008	03.01.2009	02
	b) Unit 4 (115 MW)	Date of completion of unit	26.07.2008	24.11.2008	14.01.2009	1.5
		Date of start of transmission	26.07.2008	24.11.2008	14.01.2009	1.5
		Date of commercial operation / commissioning of unit	26.07.2008	24.11.2008	14.01.2009	1.5

Out of four projects completed during 2005-10 none were completed on schedule.

2.1.41 It could be seen from above that out of four projects implemented during the review period, none was completed in time. The time overrun varied between 1.5 months and 36 months.

2.1.42 An analysis of reasons for major delay revealed that the slippages in time schedule were avoidable at various stages of implementation of BTPS Unit 1 as they were occasioned by delay in supply of materials by BHEL and delay in commissioning of ash handling plant, coal handling plant and switchyard. In respect of Nagjhari Power House Unit 4, the delay in deciding the modification to the existing rotor spider resulted in delay in completion as discussed in paragraph 2.1.83.

2.1.43 The estimated cost of projects completed during the review period, actual expenditure, cost escalation and percentage increase in the cost are tabulated below:

<u>Cost overrun</u>

Table 9 **(Rupees in crore)**

Sl. No.	Name of the Unit	Estimated cost as per DPR[51]	Awarded Cost[52]	Actual expenditure as on 31 March 2010[51]	Expenditure over and above estimate (6) = (5-3)	Percentage increase as compared to cost as per DPR (6/3)
1	**2**	**3**	**4**	**5**	**6**	**7**
1	Almatti Dam Power House[53]	714.93	455.73	520.54	Nil	Nil
2	Nagjhari Power House Unit 4 (15 MW)	15.66	13.83	15.98	0.32	2.04
3	BTPS Unit 1 (500 MW)	2,230.75	1,772.08	2,100.18	Nil	Nil
4	Varahi Underground Power House Stage 2[54] a) Unit 3 (115 MW) b) Unit 4 (115 MW)	286.05	243.99	264.74	Nil	Nil

[50] as per CEA, a thermal unit is considered as commissioned when the unit achieves full rated load. As BTPS Unit 1 did not achieve full rated load even during 2008-09, CEA had not considered the commissioning date of 25 March 2008 declared by the Company.
[51] including interest during construction, overheads and other contingencies.
[52] excluding interest during construction, overheads and other contingencies.
[53] Units 1 to 6, of which Units 5 and 6 (55 MW x 2) were completed during 2005-06.
[54] the DPR cost and actual cost includes ₹ 9.30 crore, being the expenditure incurred during execution of earlier stage (Stage 1).

It could be seen from the above that out of four projects implemented during review period, there was marginal increase in cost in respect of only one project (Nagjhari Power House Unit 4) as compared to the cost estimated in the DPR.

Contract Management

2.1.44 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 are generally awarded on turnkey (composite) basis to a single party involving civil construction, supplies of machines and ancillary works.

2.1.45 During the review period contracts valued at ₹ 4,861.69 crore (completed ₹ 2,901.44 crore and ongoing ₹ 1,960.25 crore) were executed. The agreements related to civil works, supply of equipment and other miscellaneous works.

2.1.46 We observed:

- The Engineering, Procurement and Construction (EPC) contract concluded (December 2003) with M/s BHEL for BTPS Unit 1 provided for recovery of liquidated damages (LD) up to 15 *per cent* of the contract price. The contract price of ₹ 1,618.56 crore increased to ₹ 1,673.57 crore due to increase in the rates of duties, variation in foreign exchange rates and other additional works. As per the terms and conditions of the contract, the price *inter alia* included all taxes and duties existing on the date of contract as well as future variations during the contract period. We observed that the Company considered only the initial contract price while enforcing recovery of LD for belated completion of works instead of the final contract price, which resulted in short recovery of ₹ 8.25 crore[55]. Against the loss of revenue of ₹ 1,112.46 crore suffered by the Company due to delay in completion of the Unit 1, it was able to recover LD to the extent of ₹ 242.78 crore. Government stated (September 2010) that the corrected LD would be recovered from the dues payable to M/s BHEL. Further developments are awaited (September 2010).

- The Company entered into an agreement in December 2004 with M/s Modern Construction Company Private Limited (MCCPL) for the work of laying pipeline from Maralihalla stream to Bellary Thermal Power Station (BTPS) at a cost of ₹ 17.70 crore. Clause 3(c) of the agreement provided for taking over and completion of balance works at the risk and cost of the contractor in the event of the contractor failing to adhere to the

[55] **(₹ 1,673.57 crore - ₹ 1,618.56 crore) x 15 *per cent*.**

milestones. The contractor failed to execute the work and the Company rescinded the contract in January 2006 on the ground that the progress achieved by the contractor was slow and performance below par. The balance works were then got executed through M/s Gammon India Limited and the actual cost worked out to ₹ 22.30 crore. The additional cost as compared to earlier cost was ₹ 13.06 crore. The Company adjusted ₹ 4.92 crore from the bank guarantee of MCCPL and the balance cost of ₹ 10.74 crore which was recoverable from MCCPL, in terms of clause 3(c) of the agreement, was not recovered till date (September 2010). MCCPL had submitted a claim and filed a case in the Hon'ble High Court of Karnataka, which is pending adjudication (September 2010).

- The Company had entered into an agreement with M/s VA Tech Hydro Consortium in July 2006 for setting up two new Units (3 and 4) at Varahi Underground Power House. The agreement also included renovation and modernisation of existing Units 1 and 2. As per the agreement, in the event of non-completion of work as per terms, liquidated damages at the rate of 15 *per cent* of contract price subject to a maximum of ₹ 30.86 crore was leviable. Against the scheduled date of November 2008 for handing over the Units 3 and 4, the Units were handed over only in December 2009 by the contractor. Similarly, renovation works of Units 1 and 2, which were to be completed by January 2009, are yet to be taken up (September 2010).

  As the completion of works of all the Units (1 to 4) were delayed, maximum liquidated damages of ₹ 30.86 crore had to be levied. We observed that Company had not levied the same till date (September 2010), although it held bank guarantee from the contractor amounting to ₹ 20.40.crore[56].

  Government stated (September 2010) that LD would be levied and recovered from the dues payable to the agency after take over of the Units.

- The agreement with VA Tech Hydro Consortium also stipulated that any statutory variation in percentage of applicable taxes, duties, levies, *etc.,* was to be reimbursed by the Company to the contractor or by the contractor to the Company, as the case may be. The rates of excise duty (ED) and central sales tax (CST) prevailing at the time of entering into agreement was 16.32 *per cent* and 4 *per cent* respectively which progressively decreased to 10.30 *per cent* and 2 *per cent* respectively during the execution of the contract. The Company, however, released payments based on old ED and CST rates, which resulted in excess payment of ₹ 4.16 crore. On being pointed out, the Company recovered (March 2010) the excess payments made towards ED and CST. We observed that though the countervailing duty (equal to ED) on the imported items had also decreased consequent to reduction in ED, the excess payment made towards Countervailing Duty remained

[56] **₹ 17.53 crore *plus* Euro 4.95 lakh at ₹ 58 *per* Euro.**

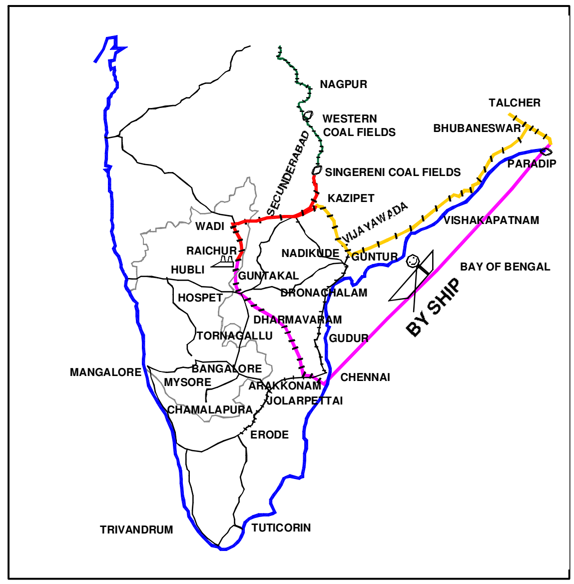
unaddressed as VA Tech Hydro Consortium was paid merely on the basis of draw down schedule[57] instead of at reduced rates.

Operational Performance

2.1.47 Operation of generation companies are dependent on input efficiency consisting of material and manpower and output efficiency in terms of plant load factor, plant availability, capacity utilisation, outages and auxiliary consumption. These aspects have been discussed below.

Input Efficiency

Procedure for procurement of coal



2.1.48 The Central Electricity Authority (CEA) fixes power generation targets for thermal power stations considering capacity of plant, average plant load factor and past performance. The Company works out coal requirement on the basis of targets so fixed and past coal consumption trends. The coal requirement so assessed is conveyed to the Standing Linkage Committee (SLC) of the Ministry of Coal, GoI, which decides the source and quantity of coal supply to TPSs on quarterly basis. On the basis of linkage source approved by SLC, the Company enters into Coal Supply Agreements (CSA) with collieries.

2.1 49 Supply of coal for RTPS is from (i) M/s Singareni Collieries Company Limited (SCCL), Andhra Pradesh, (ii) M/s Western Coalfields Limited (WCL), Maharashtra, (iii) M/s Mahanadi Coalfields Limited (MCL), Talcher, Orissa and (iv) imported coal. The Company entered into fuel supply agreements with WCL and SCCL in March 2000 and September 2001 respectively which were renewed from time to time. The fuel supply agreement with MCL was concluded only in June 2008. At present, new coal supply agreements concluded in 2009, in line with the New Coal Distribution Policy of Ministry of Coal, GoI, are in force.

With a view to improve Gross Calorific Value of Coal and also to meet the statutory requirement of MoEF to use coal with ash content of less than 34 *per cent*, the Company entered into agreements with washery agencies for supply of washed coal. As per the agreement, the washery agencies were required to lift raw coal directly from collieries based on the instructions of the Company and supply washed coal equivalent to 80 *per cent* of raw coal lifted. As the

[57] a schedule of estimated expenditure to be incurred on a project. In the instant case, draw down schedule was prepared considering ED and CST at the rate of 16.32 *per cent* and 4 *per cent* respectively.

envisaged benefits (improvement in station heat rate and boiler efficiency and reduction in coal consumption) were not achieved, the Company discontinued washing operations from May 2009.

2.1.50 The position of coal linkages fixed, coal lifted, generation targets prescribed and actual generation achieved during the period from 2005-06 to 2009-10 by RTPS was as under:

Table 10

Sl. No.	Particulars	2005-06	2006-07	2007-08	2008-09	2009-10	Total
1	Coal Linkage fixed (lakh MT)	84.90	89.55	96.60	92.37	71.20	434.62
2	Quantity of coal lifted (lakh MT)	73.09	81.62	80.45	76.69	56.59	368.44
3	Generation targets (MU)	10,330	10,330	10,329	10,302	10,302	51,593
4	Actual generation achieved (MU)	9,165	11,483	10,875	10,519	10,402	52,444
5	Shortfall in generation targets (MU) (3-4)	1,165	-	-	-	-	-

It would be seen from the above that the total linkage of coal during the five years fixed by SLC for the Company was 434.62 lakh MT. Against this, only 368.44 lakh MT was lifted by the Company from collieries, resulting in short receipt of 66.18 lakh MT (15.23 *per cent*). This resulted in shortfall in achievement of the prescribed generation targets in 2005-06 by 1,165 MU in RTPS valued at ₹ 78.46 crore[58].

Government attributed (September 2010) the short receipt of coal to non-availability / non-allotment of sufficient rakes, operational constraints by Railways and to production constraints at collieries.

Fuel Supply Arrangement

2.1.51 Coal is classified into different grades. The price of the coal depends on the grade of coal. Supply of indigenous coal for RTPS is regulated through Coal Supply Agreement (CSA) with the collieries.

In respect of BTPS, Government of India has allotted (November 2003) dedicated coal mines in Wardha Valley of Maharashtra. A Joint Venture named Karnataka Emta Coal Mines Limited (KECML) was floated by the Company with Eastern Minerals and Trading Agency, Kolkata, for development of this mine and supply of washed coal.

A review of CSA revealed the following:

Non-levy of penalty of ₹ 33 crore from KECML for non-supply of coal

2.1.52 A Fuel Supply Agreement (FSA) was entered into in May 2007 between the Company and the KECML for supply of coal. In accordance with the agreement, the delivery of coal was to commence one month prior to the scheduled date of synchronisation of BTPS. In the event of failure to supply coal from captive mines, KECML was to arrange supplies from any other source at no extra cost to the Company and failure to execute the supplies were to attract levy of penalty at the rate of half *per cent* of initial contract value (₹ 330 crore) for every week's delay subject to a maximum of 10 *per cent* of contract value.

---

[58] **though the shortfall in achievement of prescribed targets worked out to ₹ 272.61 crore, it is limited to ₹ 78.46 crore as it was only to this extent there was loss of generation for want of coal during 2005-06.**

The synchronisation of BTPS Unit 1 was decided to be conducted on 25 March 2008 and accordingly KECML was to supply coal to facilitate synchronisation. As KECML failed to supply even by March 2008, the Company transported 905.72 MT of coal from RTPS, situated nearby BTPS, and synchronised the Unit. We observed that though the maximum penalty (₹ 33.00 crore) could be levied considering the actual date of supply of coal, the Company did not levy penalty on KECML as per contractual terms for delay in supply of coal.

Government stated (September 2010) that the Company had informed KECML about the recovery of penalty towards non-supply of coal and the same was under review. Further developments are awaited (September 2010).

Undue benefit to KECML

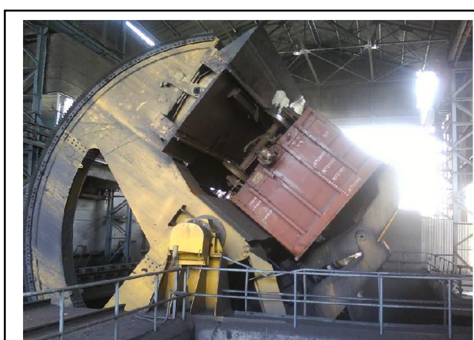
2.1.53 KECML was required to supply washed coal having total moisture content not exceeding 15 *per cent*. In case it exceeded 15 *per cent*, pro-rata adjustment was to be made in the weight of coal. Further, the Company had the right to reject and consume (without any payment) the washed coal containing total moisture in excess of 17 *per cent* as per unloading point analysis.

We observed that whenever the total moisture content ranged between 15 *per cent* and 17 *per cent*, the Company did not adopt pro-rata adjustment method for the quantities received. Instead, the deductible quantity was arrived at by applying the percentage of moisture content in excess of 15 *per cent* on the quantities received, resulting in excess payment to KECML.

Government stated (September 2010) that the Company had informed KECML of the method of pro-rata calculation and that further action would be initiated based on their comments.

Payment of demurrage charges to Railways

2.1.54 Coal and secondary fuel (HFO and LDO) supplies to thermal power stations are received through railway wagons. Railways allowed free time of seven hours *per* rake at RTPS and five hours *per* rake at BTPS for unloading and retaining and if the rakes were detained beyond this time, demurrage was payable to railways. We observed that though the Coal Handling Plants at RTPS and BTPS had sufficient capacity to unload and release the rakes within the time allowed by Railways, there was delay in clearing the rakes after unloading. This resulted in payment of demurrage amounting to ₹ 31.30 crore during 2005-10.



The Company preferred a claim for ₹ 13.61 crore on M/s BHEL towards demurrages paid on account of delay in unloading of coal from wagons which was occasioned by belated completion of wagon tipplers at BTPS. We observed that the claim was not contractually enforceable as the Company had recovered the maximum liquidated damages (₹ 242.78 crore) from BHEL for belated completion of Unit 1 as commented upon in paragraph 2.1.46

Quality of coal

2.1.55 Each thermal station is designed for usage of a particular grade of coal. Usage of envisaged grade of coal ensures optimising generation of power and economising cost of generation. The grade of coal to be received from collieries was classified into six categories based on their corresponding Useful Heat Value (UHV). The price coal decreased on a graduated scale as the grade of coal slipped from B to G. As per agreements with coal companies, the sampling of coal was to be carried out jointly by the seller and the Company or its representative at the loading end. In case, no sample was collected at the loading end, the sampling and analysis done at the unloading end was to be the basis for determining the grade for that particular rake and payment regulated accordingly.

We, however, observed that 2,786 rakes, (89 *per cent*) of the 3,121 rakes of raw coal received at RTPS end from various coal companies during the period 2005-10 did not conform to the grade declared at loading point. This had not only resulted in the Company paying higher rates for lower grade coal but also resulted in inferior coal being fed to the Units. The Company had also not assessed the extra expenditure on coal due to these grade slippages.

While confirming grade slippages at RTPS (unloading end), Government stated (September 2010) that the Company was regularly requesting the coal companies to execute the supplies as per the billed grade. Government further stated that the analysis reports at RTPS end were never considered by the coal companies.

Loss of generation due to inadequate fuel stock in bunkers

2.1.56 The minimum fuel stock was not maintained in the bunkers at thermal power stations and the Company faced problems of shortage of fuel from time to time. Test check of records relating to outages of plants showed that the different Units of RTPS were under forced shutdown during 2005-10 due to shortage of coal in bunkers resulting in loss of generation aggregating 645 MU valued at ₹ 165.73 crore (based on realisation *per* unit of RTPS).

Consumption of fuel

Excess consumption of coal

2.1.57 Consumption of coal depends upon its calorific value. The norms fixed in the project report of RTPS and BTPS for generation of one unit of power *vis-à-vis* maximum and minimum consumption of coal *per* unit of power during the review period is indicated in the table below:

(Kg/Kwh)

Table 11

Name of the Unit	Norms fixed in the project report	Average min consumption during the reviewed years	Average max consumption during the reviewed years
RTPS Units 1 and 2	0.4854	0.6477[59] (2008-09)	0.6887[59] (2009-10)
RTPS Unit 3	0.6328		
RTPS Unit 4	0.6486		
RTPS Units 5 and 6	0.6562		
RTPS Unit 7	0.6519		
BTPS Unit 1	0.4850	0.5590 (July 2008)	0.8701 (September 2008)

From the above it may be seen that consumption remained higher than the norms in all the years under review in RTPS Units 1, 2 and 3 and in 2008-09 and 2009-10 in BTPS Unit 1. Audit analysis showed that consumption above the norms resulted in excess consumption of coal to the tune of 37.98 lakh MT during 2005-10 as detailed in **Annexure 11**.

Government stated (September 2010) that the norms fixed in the project report were only tentative and attributed the higher consumption of coal to absence of homogeneity of coal received from different sources, grade slippages, presence of huge lumps, stones, boulders and extraneous materials in the supplies.

2.1.58 The value of excess consumption of coal in two thermal power stations of the Company amounted to ₹ 905.36 crore as detailed below:

Table 12

Sl. No.	Particulars		2005-06	2006-07	2007-08	2008-09	2009-10
1	Unit generated (MU)	RTPS	9,164.73	11,483.43	10,874.86	10,518.59	10,402.10
		BTPS	-	-	-	1,198.86	2,860.83
2	Coal required as *per* norms (lakh MT)	RTPS	55.36	69.20	65.71	64.05	63.19
		BTPS	-	-	-	5.81	13.88
3	Coal consumed (lakh MT)	RTPS	60.90	76.25	72.30	68.13	71.64
		BTPS	-	-	-	8.10	17.86
4	Excess consumption (lakh MT) (3 – 2)	RTPS	5.53	7.06	6.59	4.08	8.45
		BTPS	-	-	-	2.29	3.98
5	Rate *per* MT (₹)	RTPS	2,168	2,233	2,250	2,869	2,488
		BTPS	-	-	-	2,305	2,499
6	Coal consumed *per* unit (Kg.) [Sl. No.3 x 100) / Sl. No.1]	RTPS	0.6645	0.6640	0.6648	0.6477	0.6884
		BTPS	-	-	-	0.6756	0.6243
7	Value of excess coal (₹ in crore) (Sl. No.4 x Sl. No.5)/100		120.11	157.43	148.28	169.84	309.70

[59] **the Company does not compute coal consumption for each Unit. The coal consumption for Station is computed, which is then apportioned to each Unit on the basis of gross generation.**

Manpower Management

2.1.59 The manpower requirement *per* MW for operation and maintenance of a generating station as per National Electricity Plan (April 2007) for X and XI plan periods is given below:

(No. of persons *per* MW)

Table 13

Nature of function	X Plan (2002-07)			XI Plan (2007-12)		
	Thermal plant of capacity		Hydro	Thermal plant of capacity		Hydro
	500 MW	<500 MW		500 MW	<500 MW	
Technical	0.82	1.15	1.53	0.74	1.03	1.38
Non-Technical	0.30	0.61	0.26	0.27	0.55	0.23

2.1.60 The following table summarises the normative manpower requirement as per CEA *vis-à-vis* the actual manpower deployed by the Company during the review period.

Table 14

Sl. No.	Particulars		2005-06	2006-07	2007-08	2008-09	2009-10
1	**Normative Manpower requirement as per CEA**						
	Technical	Thermal	1,691	1,838	1,646	2,016	2,016
		Hydro	4,851	5,197	4,688	4,708	5,034
		Total	**6,542**	**7,035**	**6,334**	**6,724**	**7,050**
	Non-Technical	Thermal	897	975	879	1,014	1,014
		Hydro	824	883	781	785	839
		Total	**1,721**	**1,858**	**1,660**	**1,799**	**1,853**
2	**Actual manpower**[60]						
	Technical	Thermal	1,613	1,593	1,589	1,916	1,960
		Hydro	1,572	1,765	1,624	1,587	1,568
		Total	**3,185**	**3,358**	**3,213**	**3,503**	**3,528**[61]
	Non-Technical	Thermal	667	718	688	734	666
		Hydro	1,488	1,617	1,571	1,512	1,511
		Total	**2,155**	**2,335**	**2,259**	**2,246**	**2,177**[61]
3	**Excess(+) / deficit (-)**						
	Technical	Thermal	-78	-245	-57	-100	- 56
		Hydro	-3,279	-3,432	-3,064	-3,121	-3,466
	Non-technical	Thermal	-230	-257	-191	-280	-348
		Hydro	664	734	790	727	672
4	Expenditure on salaries [62] (₹ in crore)		213.85	363.62	419.13	349.52	313.88
5	Extra expenditure with reference to excess non-technical staff in hydro[63] (₹ in crore)		**22.03**	**40.52**	**49.91**	**39.37**	**33.32**

[60] Manpower requirement is considered only in the year subsequent to year of completion of project (*i.e.,* if a project is completed in March 2008, the man power requirement is taken for 2008-09).

[61] The employee strength of the Company as on 31 March 2010 was 6,281, of which 5,705 employees were working in power stations. The balance 576 employees were working in corporate / administrative offices.

[62] total expenditure on salaries for the Company.

[63] average per employee expenditure for the Company is worked out and then extra expenditure due to excess manpower is computed.

No action was taken to rationalise manpower as per norms.

2.1.61 We observed that the Company has not assessed either the required manpower or idle manpower. Consequently, the strength of technical staff in hydro stations was much less whereas the strength of non-technical staff in these stations was more than the normative requirement. The salaries and wages paid to such excess non-technical staff amounted to ₹ 185.15 crore during the period from 2005-06 to 2009-10.

In respect of thermal stations, the strength of technical and non-technical staff was lesser than the normative requirements.

Government stated (September 2010) that the Company had appointed a consultant to review and assess the staff strength. Further developments are awaited (September 2010).

Output Efficiency

Shortfall in generation

2.1.62 The targets for generation of thermal power by the Company for each year are fixed by the BoD considering maintenance schedules, past performance and grid requirements. The targets are reviewed and approved by CEA. We observed that the Company was able to achieve targeted generation in thermal power stations only during 2006-07 and 2007-08. The shortfall in generation during other years (2005-06, 2008-09 and 2009-10) aggregated to 3,613 MU (9.57 *per cent*) as shown in the following table:

(in MU)

Table 15

Year	Target	Actual	Shortfall
	(in million Units)		
2005-06	10,330	9,165	-1,165
2006-07	10,330	11,483	-
2007-08	10,329	10,875	-
2008-09	13,212	11,717	-1,495
2009-10	14,216	13,263	-953

RTPS was able to meet targeted generation in all the years except 2005-06 and 2009-10. While the shortfall in 2005-06 was due to good monsoon and back-down instructions from Load Despatch Centre (LDC), it was due to non-commissioning of RTPS Unit 8 (scheduled for completion in September 2009) during 2009-10.

The shortfall in BTPS Unit 1, during 2008-09 was mainly due to mechanical and technical problems which continued even during 2009-10.

The year-wise details of energy to be generated and plant load factor (PLF) achievable as per design *vis-à-vis* actual generation and plant load factor achieved respectively by thermal generating stations during 2005-10 are indicated in **Annexure 12**.

2.1.63 It is seen from the annexure that:

- The actual generation and actual PLF achieved were far below the energy to be generated and PLF as per design during the five years up to 2009-10.
- Against the possible generation of 73,181 MU of energy at designed capacity during the five years ended 2009-10, the actual generation was 56,503 MU leading to shortfall of 16,678 MU.
- As the PLF had been designed considering the availability of inputs, the loss of generation (16,678 MU) during 2005-10 indicated that resources and capacity were not being utilised to the optimum level due to design deficiencies, quality of fuel, frequent breakdown of Units, running Units on partial load and back down instructions from LDC.

2.1.64 Generation targets for hydro projects are fixed considering the average inflow and generation of ten years, maintenance schedule and grid requirements. The target as approved by CEA *vis-à-vis* actual generation during 2005-10 are detailed in **Annexure 13.** The Company had achieved the targeted generation in all hydro stations except mini hydro stations as their operation was dependent on the release of water for irrigation.

We analysed the achievement of generation based on the designed capacities and inflow of water in respect of three major hydro stations *viz.,* Sharavathy Generating Station, Varahi Underground Power House and Nagjhari Power House. We observed that there was shortfall in generation by 713 MU in respect of Nagjhari Power House as compared to the designed capacity (based on the achieved live water storage) resulting in loss of possible revenue of ₹ 25.39 crore[64] during 2005-10. Similarly, there was shortfall in generation of 3,982 MU in respect of Sharavathy Generating Station as compared to the generation possible based on inflow of water, resulting in loss of possible revenue of ₹ 50.17[65] crore during 2005-10.

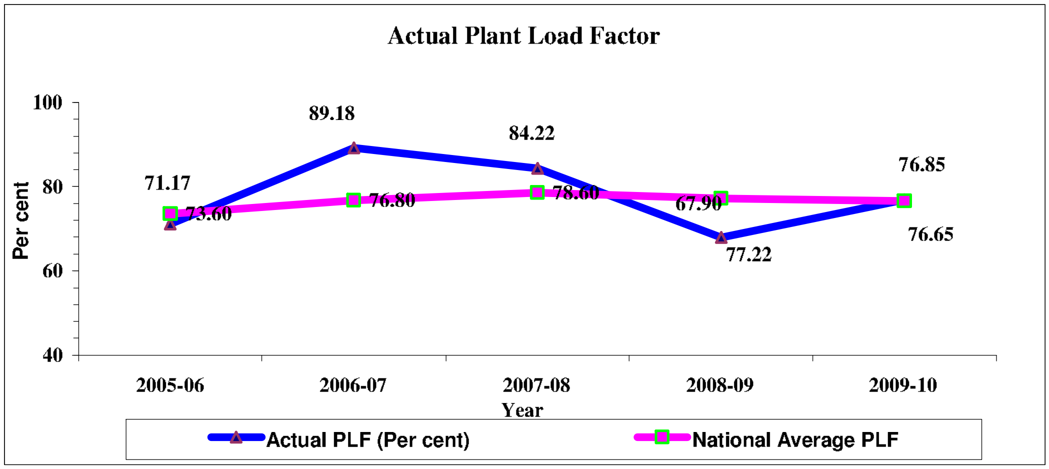
Low Plant Load Factor (PLF)

2.1.65 Plant load factor (PLF) refers to the ratio between actual generation and maximum possible generation at installed capacity. The PLF norms fixed by CERC for thermal power generating stations was 80 *per cent*, while the national average between 2005-06 and 2009-10 was 76.57 *per cent*[66].

PLF of 77.22 *per cent* at National level was achieved during 2008-09. The highest ever PLF of 95.99 *per cent* was achieved in GHTPS at Lehra Mohabbat, among all State sector thermal power stations.
(Source: Performance review of thermal power stations 2008-09 by CEA).

[64] considering selling price of 35.6 paise per unit as per State Government order of June 1993.
[65] considering selling price of 12.6 paise per unit as per State Government order of June 1993.
[66] Source : MoP, Annual report 2009-10 (Chapter 3), PLF up to January 2010.

The graph depicting the actual plant load factor *vis-à-vis* national average PLF for the last five years ended 2010 is given below:



Note: The trend line up to 2007-08 depicts PLF of RTPS alone and that of 2008-09 and 2009-10 depicts both RTPS and BTPS.

The Company was not able to achieve the norm prescribed by CERC in 2005-06, 2008-09 and 2009-10. The decline in overall PLF achieved by thermal power stations in 2008-09 and 2009-10 was due to longer duration of forced shutdown of BTPS Unit 1.

Though the PLF achieved by RTPS during 2006-10 was above the norm fixed by CERC and national average, the PLF registered by the station showed a declining trend *i.e.,* from 89.18 *per cent* in 2006-07 to 80.78 *per cent* in 2009-10. This was due to ageing of Units, quality of coal, frequent breakdown of Units, running on partial load, back-down instructions from LDC and non-achievement of rated parameters.

2.1.66 The details of average realisation *vis-à-vis* average cost *per* unit, PLF achieved, average national PLF, actual PLF and the loss of margin relating to RTPS and BTPS are tabulated below:

Table 16

Sl. No.	Description		2005-06	2006-07	2007-08	2008-09	2009-10
1	Average Realisation (₹ *per* unit)	RTPS	2.34	2.37	2.42	2.82	2.63
		BTPS				3.21	2.90
2	Average Cost (₹ *per* unit)	RTPS	2.21	2.13	2.20	2.57	2.39
		BTPS				5.15	3.03
3	Average Contribution (₹ *per* unit)	RTPS	0.75	0.74	0.77	0.78	0.72
		BTPS				1.02	1.17
4	Average Margin (Sl. No.1 - Sl. No.2)	RTPS	0.13	0.24	0.22	0.25	0.24
		BTPS				-1.94	-0.13
5	Actual PLF (*per cent*)	RTPS	71.17	89.18	84.22	81.68	80.78
		BTPS				27.37	65.32
6	National Average PLF[67]		73.60	76.80	78.60	77.22	76.65
7	Units Generated (MU)	RTPS	9,164.73	11,483.43	10,874.86	10,518.59	10,402.10
		BTPS				1,198.86	2,860.83

[67] **national average PLF of combined sectors (State, Centre and Private) was considered for comparison.**

Sl. No.	Description		2005-06	2006-07	2007-08	2008-09	2009-10
8	Units to be generated by station as per National average PLF (MU) (Sl. No.7 / Sl. No.5 x Sl. No.6)	RTPS	9,477.65	9,889.30	10,149.18	9,944.24	9,870.28
		BTPS	-	-	-	3,382.39	3,357.05
9	Shortfall in Units as compared to National average PLF (MU) (Sl. No. 8 – Sl. No. 7)		312.92	-	-	2,183.53	496.22
10	Loss of contribution (₹ in crore) (Sl. No.9 x Sl. No.3) / 10		23.47	-	-	222.72	58.06

2.1.67 It is seen from the above table that while RTPS recorded positive margins during all the years, BTPS recorded negative margin during 2008-09 and 2009-10. The estimated shortfall in generation by RTPS and BTPS in comparison to national average PLF worked out to 2,992.67 MU resulting in loss of possible contribution amounting to ₹ 304.25 crore.

2.1.68 The details of maximum possible generation at installed capacity, actual generation and corresponding PLF achieved by RTPS and BTPS for the five years up to 2009-10 are given in **Annexure 12**. The main reason for low PLF in BTPS was longer duration of forced shutdown, low capacity utilisation due to technical problems and delay in regular operations by four months (April 2008 to July 2008) after synchronisation.

Low plant availability

2.1.69 Plant availability is the ratio of actual hours operated to maximum possible hours available during certain periods. The details of total hours available, total hours operated, planned outages, forced outages and overall plant availability in respect of the Company are shown below:

Overall Operating Availability of 85.05 *per cent* was achieved during 2008-09 among all sectors (Central, State and Private).
(Source: Performance review of thermal power stations 2008-09 by CEA).

Table 17

Sl. No.	Particulars		2005-06	2006-07	2007-08	2008-09	2009-10
1	Total hours available		61,320	61,320	61,488	70,080	70,080
2	Operated hours		45,680.05	55,622.63	52,654.77	57,775.97	59,786.27
3	Planned outages (in hours)		4,891.03	2,283.82	4,204.63	3,567.93	3,757.25
4	Forced outages (in hours)		1,803.32	1,277.20	2,089.68	8,256.45	5,759.70
5	Idle hours[68]		8,945.60	2,136.35	2,538.92	479.65	776.78
6	Percentage of	Planned outages to total available hours	7.98	3.72	6.84	5.09	5.36
7		Forced outages to total available hours	2.94	2.08	3.40	11.78	8.22
8	Plant availability (*per cent*)	As worked out by the Company	89.08	94.19	89.76	83.13	86.42
		As worked out by Audit (Sl. No.2 / Sl. No.1) x 100	74.49	90.71	85.63	82.44	85.31

Note: The information up to 2007-08 pertains to RTPS alone and that of 2008-09 and 2009-10 relates to both RTPS and BTPS.

[68] period during which the Units were shut down due to grid requirements though the Units were ready with required inputs for operation.

While the percentage of planned outages to available hours decreased from 7.98 in 2005-06 to 5.36 in 2009-10, the percentage of forced outages to available hours increased from 2.94 to 8.22 during this period.

2.1.70 We observed that the Company worked out the plant availability factor after including idle hours caused by No Load Demand (NLD[69]). Against the CERC norm of 80 *per cent* plant availability during 2004-09 and 85 *per cent* thereafter (without considering idle hours), the average plant availability of RTPS was 84.77 *per cent* during 2004-09 and 86.48 *per cent* during 2009-10.

The idle hours due to NLD was occasioned by availability of adequate water in storage reservoirs due to favorable monsoon, reduced demand and cheaper hydro power.

Although the Company approached the Government on several occasions to permit it to generate and sell power to other agencies during the period of NLD, Government did not permit it on the plea that the energy was required for consumption in the State in case of exigencies of increased demand.

2.1.71 BTPS Unit 1 did not conform to the norm fixed by CERC for plant availability during 2008-09 and 2009-10 as the Unit was shutdown for longer periods (7,105.41 hours of 17,520 available hours) due to delay in completion of critical works by BHEL for which LD of ₹ 242.78 crore was levied. However, the loss of revenue suffered by the Company due to forced shutdown of plant amounted to ₹ 886.70 crore (considering PLF of 80 *per cent* fixed by CERC).

2.1.72 The details of plant availability in respect of three[70] major hydro projects are given below

Table 18

Sl. No.	Particulars		2005-06	2006-07	2007-08	2008-09	2009-10
I	**Sharavathy Generating Station**						
1	Total hours available		87,600	87,600	87,840	87,600	87,600
2	Operated hours		75,991.27	82,142.60	83,735.88	80,822.32	78,330.58
3	Planned outages (in hours)		1,677.32	1,425.78	1,827.52	926.32	720.07
4	Forced outages (in hours)		1,095.05	508.80	786.92	1,867.76	1,921.28
5	Idle Hours		8,836.36	3,522.82	1,489.68	3,983.60	6,628.07
6	Plant availability (*per cent*)	As worked out by Audit	86.75	93.77	95.33	92.26	89.42
II	**Nagjhari Power House**						
1	Total hours available		43,800	43,800	43,920	43,800	43,800
2	Operated hours		17,213.63	31,901.15	27,314.27	26,903.58	16,901.18
3	Planned outages (in hours)		1,059.25	1,130.07	3,728.53	3,306.85	1,342.35
4	Forced outages (in hours)		2,706.70	1,096.70	488.12	4,829.00	1,050.65
5	Idle Hours		22,820.42	9,672.08	12389.08	8760.57	24,505.82

[69] complete shut down of Units based on the instructions of Load Despatch Centre due to reduced demand.

[70] the remaining hydro stations are either run-of the river or irrigation based hydro systems.

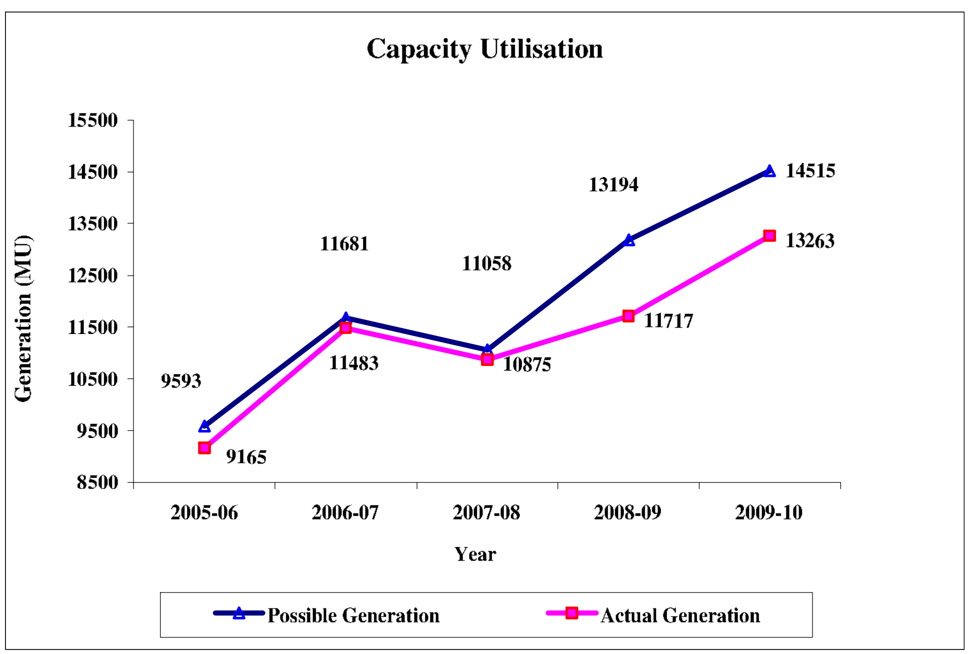
Sl. No.	Particulars		2005-06	2006-07	2007-08	2008-09	2009-10
6	Plant availability (*per cent*)	As worked out by Audit	39.30	72.83	62.19	61.42	38.59
III	**Varahi Underground Power House**						
1	Total hours available		17,520	17,520	17,568	17,520	35,040
2	Operated hours		16,759.88	15,347.92	16,567.80	16,738.63	23,790.60
3	Planned outages (in hours)		56.17	2,101.25	869.63	525.65	2,005.82
4	Forced outages (in hours)		79.7	62.43	40.62	199.73	5,196.00
5	Idle Hours		624.25	8.4	89.95	55.99	4,047.58
6	Plant availability (*per cent*)	As worked out by Audit	95.66	87.60	94.31	95.54	67.90

It could be seen that the plant availability varied from 38.59 *per cent* (Nagjhari Power House in 2009-10) to 95.66 *per cent* (Varahi Underground Power House in the year 2005-06) during 2005-10.

The idle hours in Sharavathy Generating Station was mainly due to low load demand. The low plant availability in Nagjhari Power House was due to operation of station only during peaking hours, taking up of R&M works relating to Units 4 & 5 and restricted operation with a view to preserve water to meet demand in summer. The decline in plant availability of Varahi Underground Power House in 2009-10 was due to rectification works in newly commissioned Units (3 and 4).

Low capacity utilisation

2.1.73 Capacity utilisation is the ratio of actual generation to possible generation during actual hours of operation. The graph depicting the capacity utilisation for the last five years ended 2010 is given below:



Note:The trend line up to 2007-08 depicts capacity utilisation of RTPS alone. For 2008-09 and 2009-10 it includes both RTPS and BTPS.

Audit analysis revealed that during 2005-10, 1.65 *per cent* to 7.45 *per cent* of the operated capacity remained unutilised at RTPS, resulting in loss of generation of 2,388 MU. This was mainly due to running of Units on partial load and reduced capacity due to their ageing. Similarly the loss of generation at BTPS due to operation below the rated capacity was 1,147 MU.

Outages

2.1.74 Outages refer to the period for which the plant remained closed for attending planned / forced maintenance. We observed:

The forced outages in thermal stations are showing an increasing trend though they are within norms prescribed by CEA.

- The total number of hours lost due to planned outages in thermal power stations increased from 2,283.82 hours in 2006-07 to 3,757.25 hours in 2009-10 *i.e.,* from 3.72 *per cent* to 5.36 *per cent* of the total available hours in the respective years.
- The forced outage hours recorded by the thermal power stations were within the norm of 10 *per cent* of the available hours fixed by CEA in all the years except 2008-09 (11.78 *per cent*).
- Though the forced outages in RTPS increased from 1,277.20 hours in 2006-07 to 3,757.02 hours in 2009-10 *i.e.,* from 2.08 *per cent* to 6.13 *per cent* of the total available hours, the forced outages remained within the norm of 10 *per cent* fixed by CEA.

Energy loss on account of forced outages was 9.29 *per cent* in 2008-09 among all sectors (Central, State and Private).
(Source: Performance review of thermal power stations 2008-09 by the CEA).

- In BTPS, though the forced outages decreased from 5,102.73 hours (58.25 *per cent*) in 2008-09 to 2,002.68 hours (22.86 *per cent*) in 2009-10, yet the Unit exceeded the norm fixed by CEA. The overall increased forced outages during 2008-09 and 2009-10 was mainly due to shut down of BTPS Unit 1 for four months (April to July 2008) and for three months (July to September 2009) respectively. This was attributed to delay in completion of critical works by M/s BHEL and mechanical problems encountered while running the Unit.

Auxiliary consumption of power

2.1.75 Auxiliary consumption is the energy consumed by power stations themselves for running their equipment and common services. The CERC norm for auxiliary consumption was 9 *per cent* up to March 2009, which was reduced to 8.5 *per cent* thereafter. The combined auxiliary consumption recorded by thermal power stations during 2005-10 was within the norms.

Auxiliary power consumption at national level was 8.32 *per cent* during 2008-09.
(Source: Performance review of thermal power stations 2008-09 by the CEA).

2.1.76 In respect of hydro power stations, CERC has fixed a norm of 0.2 to 0.7 *per cent* of gross generation for auxiliary energy consumption, depending upon the type of Power House and the excitation system. The normative auxiliary consumption, considering the maximum allowance of 0.7 *per cent*, worked out to 457.54 MU for the period 2005-10. Against this, the actual auxiliary consumption was 986.03 MU, resulting in excess consumption of 528.49 MU valued at ₹ 29.21 crore (considering realisation rate of respective years).

Repairs and Maintenance

2.1.77 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 coal, 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 equipment which affect the total power generated.

2.1.78 We observed (May 2010) that records indicating the dates when the Units had fallen due for periodical maintenance and the dates of maintenance works actually done were not maintained in both hydro and thermal power stations.

Renovation and Modernisation

2.1.79 Renovation and Modernisation (R&M) and refurbishment activities involve identification of the problems of the Units, preparation of techno-economic viability reports and preparation of DPR to lay down benefits to be achieved from these works.

2.1.80 R&M activities are aimed at overcoming problems in operating Units caused by generic defects, design deficiency and ageing by re-equipping, modifying, augmenting them with latest technology / systems. R&M also helps in improving the performance of generating stations in terms of output, reliability and availability in terms of the original design values, reduction in maintenance requirements, ease of maintenance and enhanced efficiency. R&M activities are undertaken in thermal power stations operating at PLF of 40 *per cent* and below after assessing the performance and requirement of the Units.

2.1.81 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 have been operating at PLF below 40 *per cent*. Necessary permission and clearance for R&M and refurbishment activities from State Electricity Regulatory Commission / CEA / State Government are to be obtained. Residual Life Assessment (RLA) studies are also conducted for all refurbishment activities and in major R&M works. 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 the rest of the fund is met through internal sources or loan from State Government.

2.1.82 We observed:

- the Company had not taken up R&M activities of DG plant at Bangalore and RTPS Units 1 and 2 (as detailed in paragraphs 2.1.36 and 2.1.37).
- though the Company was to complete R&M[71] of Nagjhari Power House, Sharavathy, Supa and Linganamakki by 2009-10, action was yet to be initiated (September 2010).
- the Company planned to undertake life extension works in Bhadra generating station only during XII plan although the same was programmed for completion during XI plan[71].

Delay in executing uprating works

2.1.83 The Company awarded (May 2003) works relating to uprating of Units 4 to 6 of Nagjhari Power House (15 MW each) at a cost of ₹ 32.20 crore. While the supply of items was to be completed within 33 months (March 2006), the work relating to erection was to be completed within 8 months from the date of handing over the unit to the contractor. The Units were to be taken up sequentially for uprating works.

Based on the vibration studies conducted, the contractor, M/s VA Tech Hydro India Private Limited, Bhopal proposed (January 2004) modification to the existing rotor spider to reduce the vibration levels. The Company referred (July 2004) the same to expert committee and then (January 2005) to M/s BHEL (original equipment manufacturer), which recommended that these modifications would not have significant effect in bringing down vibration levels. Accordingly, Unit 4 was handed over (February 2005) to the contractor with instructions to carry out the works as per the scope of the contract.

While Unit 4 was synchronised in February 2008 after uprating, the work relating to Unit 5 was in progress as at the end of March 2010. Thus, uprating of Units which was envisaged for completion during X plan not only spilled over to XI plan but also remained partially achieved till date (September 2010). We observed that there was delay (between January 2004 and February 2005) in deciding whether to modify the existing rotor spider or replace it. The delay in completion of Unit 4 led to sequential delay in taking up R&M works relating to remaining two Units. The estimated loss of generation due to belated completion of Unit 4 and consequential pendency in completion of works in Units 5 and 6 was 2,671 MU up to March 2010.

[71] **as per CEA report.**

Operation and Maintenance

2.1.84 The operation and maintenance (O&M) cost includes expenditure on employees, repairs and maintenance including stores and consumables, consumption of capital spares not part of capital cost, security expenses, administrative expenses *etc.,* of generating stations besides corporate expenses apportioned to each generating station *etc.,* but excludes the expenditure on fuel.

2.1.85 CERC in its 2009 Regulations allowed O&M norm for 2009-10 as ₹ 18.20 lakh, ₹ 16 lakh, ₹ 13 lakh and ₹ 11 lakh *per* MW in respect of 200-250 MW, 300-350 MW, 500 MW and 600 MW and above capacity thermal power Units respectively. The overall average cost *per* MW on weighted average method worked out to ₹ 18.20 lakh up to 2007-08 and ₹ 16.88 lakh for 2008-09 and 2009-10. Against the above mentioned norms, the total O&M cost *per* MW incurred by the Company was ₹ 33.34 lakh, ₹ 33.78 lakh, ₹ 34.75 lakh, ₹ 39.90 lakh and ₹ 38.52 lakh during 2005-10. O&M expenses were much higher than the norms fixed by CERC in this regard.

2.1.86 In respect of hydro generating stations, the CERC norm for O&M expenses for 2009-10 was fixed at ₹ 38.45 lakh *per* MW. We observed that during 2005-10, the O&M expenses of hydro generating stations varied from ₹ 13.22 lakh *per* MW to ₹ 18.43 lakh *per* MW.

Financial Management

2.1.87 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 favorable terms at appropriate time.

2.1.88 The power sector companies should, therefore, streamline their systems and procedures to ensure that:

- Funds are not invested in idle inventory,
- Outstanding advances are adjusted / recovered promptly,
- Funds are not borrowed in advance of actual need, and
- Swapping high cost debt with low cost debt is availed expeditiously.

The main sources of funds were realisations from sale of power, loans from State Government / Banks / Financial Institutions (FI), equity contribution from State Government, etc. These funds were mainly utilised to meet expenditure on fuel (coal and oil), debt servicing, employee and administrative costs, system improvement works of capital and revenue nature.

2.1.89 Details of sources and utilisation of resources on actual basis by the Company for the years 2005-06 to 2009-10 are given below:

(Rupees in crore)

Table 19

Sl. No.	Particulars	2005-06	2006-07	2007-08	2008-09	2009-10
Cash Inflow:						
1	Net Profit / (loss)	344.56	371.06	250.93	391.58	732.35
2	Add: Adjustments	602.57	632.49	768.61	949.10	859.96
3	Operating profit before working capital changes (1+2)	947.13	1,003.55	1,019.54	1,340.68	1,592.31
4	Operating activities	48.14	509.85	99.43	208.60	175.97
5	Investing activities	22.04	15.94	16.37	12.90	15.73
6	Financing activities	662.88	310.51	379.11	2,163.78	1,386.18
7	**Total (3+4+5+6)**	**1,680.19**	**1,839.85**	**1,514.45**	**3,725.96**	**3,170.19**
Cash outflow:						
8	Operating activities	618.67	169.36	577.58	1,483.73	1,393.78
9	Investing activities	712.03	1,079.00	427.21	1,155.00	971.09
10	Financing activities	364.76	438.50	692.68	604.31	659.08
11	**Total (8+9+10)**	**1,695.46**	**1,686.86**	**1,697.47**	**3,243.04**	**3,023.95**
12	Net increase / (decrease) in cash and cash equivalent (7-11)	(15.27)	152.99	(183.02)	482.92	146.24
13	Opening balance of cash and cash equivalent	105.40	95.70[72]	248.69	65.67	548.59
14	Closing balance of cash and cash equivalent	90.13	248.69	65.67	548.59	694.83
15	Net increase / (decrease) in cash and cash equivalent (13-14)	(15.27)	152.99	(183.02)	482.92	146.24

It could be observed from the above table that the cash and cash equivalents increased in all the years except during 2005-06 and 2007-08. The cash inflow was mainly through borrowings in the form of cash credit / term loans from commercial banks / financial institutions. The dependence on borrowed funds increased from ₹ 4,552.40 crore at the end of March 2006 to ₹ 7,381.97 crore at the end of March 2010, which was used mainly for meeting capital expenditure and financing activities. This entailed additional interest burden of ₹ 284.79 crore during 2005-10 ultimately increasing the operating cost of the Company. Due to poor realisation, the dues from ESCOMs which was ₹ 2,525.02 crore at the end of March 2006 increased to ₹ 4,032.16 crore at the end of March 2010, which, in turn, forced the Company to rely on borrowed funds. It could also be observed that the Company could meet its working

[72] **opening balance of cash and cash equivalent of 2006-07 does not agree with that of closing balance of 2005-06 due to merger of VVNL with effect from April 2006.**

capital requirements (cash outflow for operating activities) out of the cash generated from operations (sum of operating profit before working capital changes and cash inflow from operating activities) in all the years except during 2008-09.

Spares were held more than CERC norms.

2.1.90 As per the guidelines of CERC, thermal power stations have to maintain spares of ₹ 4 lakh for each MW of installed capacity. The value of spares to be maintained by RTPS on the basis of CERC guidelines worked out to ₹ 58.80 crore. As at the end of March 2010, RTPS held stock of spares valued at ₹ 136.43 crore which was in excess of the prescribed guidelines by ₹ 77.63 crore. This resulted in locking up of funds and consequential loss of interest of ₹ 4.77 crore for one year alone (at 6.15 *per cent* per annum, being the average cost of short term loans for the year 2009-10).

Government stated (September 2010) that the Company had resorted to procurement of spares on need basis and that the matter would be referred to the technical committee for movement of spares to other plants of the Company for utilisation.

Tariff Fixation

2.1.91 The Company is required to file 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 KERC. KERC accepts the application filed by the Company with such modifications / conditions as may be deemed just and appropriate and after considering all suggestions and objections from public and other stakeholders, issues an order containing targets for controllable items and the generation tariffs for the year within 120 days of the receipt of the application.

2.1.92 KERC sets performance targets for each year of the control period for the items or parameters that are deemed to be controllable and which include:

a) Station Heat Rate;
b) Availability;
c) Auxiliary Energy Consumption;
d) Secondary Fuel Oil Consumption;
e) Operation and Maintenance Expenses;
f) Plant Load Factor
g) Financing Cost which includes cost of debt (interest), cost of equity (return); and
h) Depreciation.

We observed:

2.1.93 In respect of sale of energy from RTPS Units 1 to 7, hydro stations and Almatti Dam Power House (ADPH), draft Power Purchase Agreements (PPA) were executed between the Company and KPTCL prior to 2005-06. The rates contained in these draft PPAs were approved by KERC subject to certain operating and commercial parameters. These parameters were contested (2002-03) by the Company and the Appellate Tribunal for Electricity, New Delhi remanded (March 2009) the PPAs back to KERC with a direction to pass a fresh order on PPA between the parties.

The Company continued to claim energy bills during this period, in accordance with

a) the provisional tariffs admitted by Power Company of Karnataka Limited (PCKL[73]) in respect of Kadra, Kodasalli, Gerusoppa and Bhadra stations
b) the rates specified in the PPA executed for RTPS Units 5 and 6
c) the rates indicated in initialed PPA for RTPS Unit 7, BTPS Unit 1, Almatti Dam Power House and Diesel Generating Plant, Yelahanka;
d) the rates specified by GoK in respect of RTPS Units 1 to 4, Kappadagudda stage 1 and all other hydro stations including mini hydro;
e) tariff proposed by PCKL in respect of Kappadagudda stage 2.

KERC approved (August 2009) PPAs of RTPS (single common PPA for Units 1 to 7), ADPH, DG Plant and hydro power projects. Accordingly, the Company concluded (25 May 2010) agreements with ESCOMs giving retrospective effect to it from April 2009. The financial loss during 2005-09, if any, suffered due to non-achievement of technical parameters was not analysed by the Company.

We observed that during 2009-10, the Company did not suffer financial loss on account of underperformance on targets for financial and technical parameters (except on account of station heat rate) as specified by KERC in respect of RTPS.

In respect of BTPS, the PPA is yet to be approved by KERC (September 2010).

Environment Issues

Company has exceeded the prescribed norms of Air, Water and Noise pollution levels.

2.1.94 In order to minimise the adverse impact on environment, the GoI has enacted various Acts and statutes. At the State level, Karnataka State Pollution Control Board (KSPCB) is the regulating agency to ensure compliance with the provisions of these acts and statutes. Ministry of Environment and Forests (MoEF), Government of India and Central Pollution Control Board (CPCB) are also vested with powers under various statutes.

The Company had an environmental wing for obtaining environmental clearances and monitoring compliance with environmental laws. Compliance with the provisions of various environmental Acts are discussed below:

Operation of plant without consent

2.1.95 Application for consent under section 25 and 26 of Water (Prevention and Control of Pollution) Act, 1974 and section 21 of Air (Prevention and Control of Pollution) Act, 1981 is required to be filed 120 days in advance before State Pollution Control Board (*i.e.,* KSPCB). We observed that though RTPS was required to initiate action for renewal of statutory consent of KSPCB for the year 2009-10 in

[73] **verification and scrutiny of energy bills on behalf of ESCOMs is being carried out by PCKL.**

January / February 2009, the application was filed (April 2009) after a delay of two months. We further observed that KSPCB had not communicated its consent for operation of plant for the year 2009-10 as the Company furnished the modified report of water balance only in April 2010. Thus the Station was operated for almost a year without statutory consent.

2.1.96 It was further observed that BTPS had filed application for renewal of consent belatedly. The application for 2009-10 was submitted belatedly by two months and for 2010-11, the Company had not filed for renewal as at the end of May 2010.

Air Pollution

2.1.97 Coal ash, being a fine particulate matter, is a pollutant under certain conditions when it is airborne and its concentration in a given volume of atmosphere is high. Control of Suspended Particulate Matters (SPM) in flue gas is an important responsibility of thermal power stations. Electrostatic Precipitator (ESP) is used to reduce SPM concentration in flue gases. Control of SPM level is dependent on effective and efficient functioning of ESPs.

Non-achievement of specified SPM levels

2.1.98 ESPs installed at RTPS Units were designed to achieve an SPM level of 50 $\mu g/m^3$. As per the National Ambient Air Quality standards issued

(November 2009) by Central Pollution Control Board (CPCB), the concentration of SPM in ambient air in industrial areas should not exceed 60 $\mu g/m^3$. Audit scrutiny revealed that the average annual SPM levels recorded at RTPS was beyond the norms in all the years under review except 2006-07. The Company had not analysed the reasons for not achieving the desired level of SPM in other months for corrective action.

2.1.99 ESP installed at BTPS was designed to achieve an SPM level of 100 $\mu g/m^3$. Audit scrutiny however, showed that the recorded average SPM levels for the year 2008-09 and 2009-10 was 150 $\mu g/m^3$ and 124 $\mu g/m^3$ respectively. Further, in the light of the recent notification (November 2009) issued by CPCB prescribing a norm of 60 $\mu g/m^3$ the existing ESP at BTPS requires modification.

Besides, the level of Respirable Particulate Matter (RPM) also exceeded the permissible level of 40 $\mu g/m^3$ during the years 2008-09 (76 $\mu g/m^3$) and 2009-10 (64 $\mu g/m^3$). The Company had not analysed the reasons for not achieving the desired level of SPM and taken corrective action till date (September 2010).

Non-installation of on-line monitoring equipment

2.1.100 As per the provisions of the Environment (Protection) Act, 1986, thermal power stations should provide on-line monitoring systems to record SPM levels. We noticed that on-line monitoring system was not installed at RTPS and data was collected manually. Non-installation of on-line monitoring equipment was in contravention of the statutory provisions.

Ash disposal

2.1.101 Annual generation of fly ash[74] at RTPS increased from 13.98 lakh MT in 2005-06 to 17.08 lakh MT in 2009-10. MoEF had issued a notification (September 1999) which stipulated that every thermal plant should supply fly ash to Units manufacturing building material free of cost for at least 10 years. Further, it was stipulated that every coal-based thermal power plant was to phase out the dumping and disposal of fly ash on land and achieve 100 *per cent* utilisation of fly ash by the end of ninth year *i.e.,* by September 2008.

Scrutiny of generation and disposal of fly ash for the years under review (2005-10) revealed that against the total fly ash of 81.35 lakh MT generated, only 59.79 lakh MT was issued to small scale / cement industries. The balance quantity of 21.56 lakh MT was dumped on land (ash pond), in contravention of the notification. We also observed that long-term action plan was not drawn up for achievement of 100 *per cent* utilisation of fly ash generated and for phasing out dumping of fly ash on land. Government stated (September 2010) that fly ash utilization increased from 30 *per cent* during 2002-03 to 86 *per cent* in 2010-11.

Clean Development Mechanism

2.1.102 To save earth from green house gases (GHG[75]) a number of countries including India signed the Kyoto Protocol (Protocol), which was adopted (December 1997) in the Third Conference of Parties to the United Nations Framework Convention on Climate Change (UNFCCC). Article 3 of the Protocol targetted reduction of emission of GHG by five *per cent* in the developed countries. UNFCCC had set the standard level of carbon emission allowed for a particular industry or activity. The extent to which an entity is emitting less carbon (as per standard fixed by UNFCCC), it gets credits for the same. Only those power plants that meet the UNFCCC norms and take up new technologies are entitled to sell these credits. The booking of such saving of GHG is called purchase of Certified Emission Reduction (CER), commonly called Carbon Credits. If the developed countries were unable to reduce their own carbon emissions, they could book the savings of GHG in developing

---

[74] **after allowing for bottom ash at 20 *per cent* and loss at 10 *per cent* in economiser, Ash Handling Plant and Electro Static Precipitator hoppers.**

[75] **Carbon di-oxide, Methane, Nitrous Oxide, Hydro Fluorocarbons, Per-Fluorocarbons, Sulphur Hexafluoride.**

countries in their account by paying money to the concerned country. This whole system is named Clean Development Mechanism (CDM). CDM came into force in February 2005.

For sale of CER, registration of power plant is required as a CDM project with UNFCCC. The power plants that commenced operations on or after 1 January 2000 were eligible for registration by submitting the request with Designated National Authority (DNA). In India, MoEF is nominated as DNA.

We observed:

- In respect of projects conceived after January 2000 (BTPS Units 1 and 2 and RTPS Unit 8), the Company had not explored the possibility of availing carbon credits at the time of preparation of DPR itself. Government informed (September 2010) that as per the Company, the thermal plants were not eligible for CDM benefits. We, however, observed that Yermaras Thermal Power Station and Edlapur Thermal Power Station (Joint Venture promoted by the Company and M/s BHEL which are under implementation) had sought CDM status. Besides, the Company appointed (2009-10) M/s Enzen Global Solutions as CDM consultants for availment of carbon credits for existing thermal power plants.
- In respect of Solar Photo Voltaic Plants (SPV) at Yalesandra, Itnal and Yapaladinni, the Company applied (2009 and 2010) to MoEF for carbon credits and appointed (2009) consultants for obtaining necessary approvals and CDM benefits. Emission norms as per UNFCCC are awaited (May 2010).

Noise Pollution

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

Audit scrutiny showed that the noise levels recorded at RTPS during day time in industrial areas for a period of five years up to 2009-10 ranged from 85 decibels (dB) to 90 dB against the prescribed level of 75 dB and from 46 dB to 62 dB in residential areas against the prescribed level of 55 dB. The Company had not analysed the reasons for increased noise levels.

The average noise level recorded at BTPS during day time in industrial area was within the prescribed level of 75 dB for the years 2008-09 and 2009-10.

Water pollution

2.1.104 The waste water of a power plant is a source of water pollution. As per the provisions of the Water (Prevention and Control of Pollution) Act, 1974, the thermal power stations are required to obtain the consent of State Pollution Control Board which *inter alia* contains the conditions and stipulations for water pollution to be complied with by the Station. The Karnataka State Pollution Control Board, at the time of every renewal of consent (renewed annually for a period of twelve months from July to June) had allowed RTPS to discharge sewage effluents from its premises and township on land for irrigation within the premises of RTPS. The station was also directed to recycle and reuse trade effluents (from coal handling plant, oil decanting pump house, De-mineralisation plant) and ash pond overflow for development of greenery and the excess effluents to an extent of 4 cusecs (13,032 kilo litres *per* day) were permitted to be discharged into river Krishna. Audit scrutiny revealed that the discharge into river was within the norms.

2.1.105 The norms prescribed by KSPCB at the time of consent (and subsequent renewals) under Section 25 / 26 of Water (Prevention and Control of Pollution) Act, 1974 and Section 21 of Air (Prevention and Control of Pollution) Act, 1981, stipulated that the Total Suspended Solids (TSS) in effluents from the Station should not exceed 100 milligrams *per* litre (mg/l). We observed that though the average yearly TSS in effluent discharge (trade effluents) at RTPS was within the norm of 100 mg/l in all the years except during 2007-08, the average monthly TSS level exceeded the norm on several occasions, as detailed below:

Table 20

Year	Maximum	Minimum	Average	Number of months in which the norm was exceeded
	(in mg/l)			
2005-06	215	28	97	4
2006-07	137	39	71	2
2007-08	268	20	104	6
2008-09	128	10	47	1
2009-10	84	23	44	0

The main reason for higher level of TSS *vis-à-vis* standards was ineffective functioning of sedimentation tanks and effluent treatment plants. Effective and time bound steps could have avoided the non-repairable damage caused to the water bodies.

2.1.106 As regards BTPS, we observed that the Company had not measured the quantum of TSS in trade effluents on the ground that such effluents were recycled with zero discharge concept. We are of the view that the Company is required to test and evaluate the quantum of TSS in trade effluents irrespective of the fact whether effluents are discharged or entirely recycled as presence of TSS in excess of permissible levels may adversely impact the quality of ground water, even in the case of zero discharge.

Payment of Water Cess at higher rates

2.1.107 As per the provisions of the Water (Prevention and Control of Pollution) Cess Act, 1977, water cess at rates specified is collected for water utilised for the purposes specified in the Act *ibid*. Compliance with the standards laid down by Government of India under Environment (Protection)

Act, 1986 makes the consumer eligible for concessional rate of water cess and also rebate in payment of cess. Audit scrutiny revealed that as RTPS had failed to install meters for measuring each stream of water consumption and to furnish water analysis report and monthly production reports to KSPCB, it could not avail of concessional rates. Compliance with the requirements of KSPCB would have entailed savings of ₹ 1.16 crore during 2005-10.

Non-payment of cess

2.1.108 As per the provisions of Water (Prevention and Control of Pollution) Cess Act, 1977, cess on water utilised for the purposes specified in the Act is required to be remitted to the Pollution Control Board. Audit scrutiny showed that though BTPS had utilised water for the purposes[76] specified in the Act *ibid*, no cess was remitted to KSPCB. The water cess so payable amounted to ₹ 32.92 lakh for the period from April 2008 to March 2010.

Monitoring by top management

MIS data and monitoring of service parameters

The Statutory Auditors are repeatedly commenting on the need to strengthen internal control procedures.

2.1.109 The Company 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 targets should generally be such that the achievement of which would make an organisation self-reliant.

Review of the system revealed that:

- the operational and the financial achievements *vis-à-vis* the targets were discussed by the Management and corrective action were being taken.
- the Statutory Auditors had repeatedly advised strengthening of internal control procedures for purchase of fixed assets, inventory, sale of energy including execution of works contracts and accounting of coal to make them commensurate with the size and nature of business.

Government stated (August 2010) that the Company had appointed internal auditors to further strengthen the internal control procedures.

Acknowledgement

Audit acknowledges the co-operation and assistance extended by the staff and the Management of the Company at various stages of the performance review.

[76] **industrial cooling / spraying in boiler feed and in processes whereby water gets polluted and the pollutants are not easily bio-degradable.**

Conclusion

The peak demand for the State in 2009-10 was 8,094 MW against the installed capacity of 10,387.81 MW. Yet, the peak demand was met only to the extent of 7,049 MW (*i.e.,* 67.86 *per cent* of installed capacity).

The Karnataka Electricity Regulatory Commission (KERC) had forecast (December 2008) peak requirement of 10,120 MW by the end of 2012. To meet the peak demand of 10,120 MW forecast by KERC, the required installed capacity worked out to 14,913 MW. Hence, the shortfall of 4,525 MW is required to be commissioned between 2010-11 and 2011-12 so as to achieve the objective of providing power for all by 2012.

Against this, only six projects with capacity addition of 2,053 MW were projected for completion by the end of 2012, still leaving a gap of 2,472 MW. Hence, the objective of providing power for all by 2012 may not be achieved.

New hydro projects proposed to be taken up by the Company were either awaiting clearance from MoEF or held up due to local agitation. Renewable Energy Sources in the State also remained underutilised.

With regard to operational performance of existing projects of the Company, it was observed that the performance of thermal power stations was sub-optimal due to fixation of generation targets below the available hours, low plant load factor, inefficient fuel management, failure to undertake timely renovation and modernisation and life extension schemes. The consumption of coal was in excess as compared to designed parameters.

The poor realisation of dues and consequent accumulation of outstandings from ESCOMs forced the Company to resort to borrowings entailing payment of interest. This had also affected its ability to take up new projects.

Recommendations

The Company needs to streamline procedures for procurement, acceptance and consumption of coal and strive to improve efficiency. The thermal power stations should strive to improve performance to the level of norms of CERC / KERC and CEA and achieve the specifications prescribed by equipment suppliers. The Company should also analyse / investigate reasons for excess consumption of fuel, higher outage hours, higher auxiliary consumption and other higher operating parameters. The Company needs to take up renovation and modernisation and life extension programmes as per schedule. This would result in optimum utilisation of existing facilities.

The Government needs to evolve a long-term strategy for capacity augmentation through its own agencies and by private sector participation. From a long-term perspective there is a need to diversify energy sources and provide clean energy. Development of hydro and renewable energy sources needs to be accorded top priority for energy

security. The Government also needs to encourage, adopt and implement Demand Side Management and Energy Efficiency measures in addition to capacity addition. The Government should consider setting up a task force on priority so that the objective of providing power for all by the end of 2012 is achieved.

2.2 Electricity Supply Companies

Implementation of *Rural Load Management System* scheme by Electricity Supply Companies

Executive Summary

In Karnataka there is a wide gap between demand and supply of power, which affects both irrigation and domestic consumers. To overcome the gap through better demand side management, a scheme called Rural Load Management Scheme (RLMS) was conceived. The main objective of the RLMS was to provide assured hours of power supply to Irrigation Pump (IP) set consumers and 24 hours power supply a day to non-IP consumers. Other benefits such as reduction in peak load, transmission and distribution losses and improvement in tail end voltage were also envisaged under the scheme.

RLMS scheme

Under the RLMS, a Rural Load Management Unit (RLMU) box is installed on the Low Tension side (output side) of the transformer. The RLMU box comprises of Programmable Logic Controllers (PLC), circuit breaker, modem, electronic meter etc. The main idea behind RLMS is to segregate IP loads on the transformer into two groups. The feeder (11KV) is kept charged for 24 hours in a day. While power supply is given for entire 24 hours to non-IP set consumers, power supply to IP set consumers is regulated by the PLC for specified hours in a staggered manner as per a pre-determined programme. The PLC switches between the two groups alternatively, thereby ensuring assured power supply to IP set consumers.

Audit objectives

A performance audit review was undertaken in three Electricity Supply Companies (BESCOM, HESCOM and MESCOM) to ascertain whether the RLMS scheme was carefully designed with adequate planning; whether the scheme was implemented economically, efficiently and effectively; whether the intended benefits in reduction of distribution losses and improvement in tail end voltage were achieved; and whether the main objective of providing assured hours of power supply to IP set consumers and 24 hours power supply to non-IP set consumers was achieved.

Audit findings

The RLMS scheme was taken up in the ESCOMs without proper planning. The scheme was not scrutinized by Technical Audit. The total cost incurred from December 2004 to March 2010 was ₹589.34 crore. In BESCOM and HESCOM system improvement works were taken up by utilizing higher capacity materials than those specified in the policy of the companies resulting in extra expenditure of ₹4.33 crore in test checked divisions. In HESCOM, qualification requirements of tenderers for supply of RLMU boxes were altered after invitation of tenders.

Tampering was noticed when power supply was not provided to farmers during May 2007 in test checked feeder. The Vigilance Wing of BESCOM noticed tampering of RLMU boxes during April-May 2008 also as power was not provided to farmers for long hours and non-supply hours were not compensated with power supply in other hours. The power supply position (post April 2008) deteriorated. Power cut in RLMS feeders' resulted in non supply of power during the stipulated time to a group of IP set consumers and such periods of non-supply were not compensated with power supply during some other time of the day.

The vicious cycle of power cut in RLMS feeders, non-rotation of timings of power supply and supply during evening hours, led to large scale tampering. The maintenance contractor could not maintain the RLMU boxes being tampered on a large scale. The situation was aggravated by the rising demand-supply gap scenario of power supply. Hence, the scheme, which was modelled to work in a demand-supply gap situation failed in BESCOM and HESCOM. The expenditure made on RLMU boxes in six and five test checked divisions of BESCOM and HESCOM were ₹ 19.73 crore and ₹8.62 crore respectively, served only limited purpose and was largely wasteful.

The incidental benefits of reduction in peak load, reduction in transmission and distribution losses and improvement in tail end voltage were achieved in 20 test checked feeders of three ESCOMs, but the main objective of providing assured hours of power supply to IP set consumers and 24 hours power supply to non-IP set consumers, however, failed in BESCOM and HESCOM. BESCOM stopped implementing RLMS in August 2008, while HESCOM decided in January 2009 not to go ahead with the execution of RLMS in the remaining feeders where work had not commenced.

In MESCOM, however, load shedding was not resorted in RLMS feeders. Under extreme conditions, the feeders were treated at par with Urban feeders (minimum power cut). Instances of tampering noticed were attended to by the maintenance contractor. This led to the success of the scheme only in MESCOM, indicating that the scheme was a workable model if the companies provided power supply to IP set consumers as per Government policy.

To meet the same objective, BESCOM has now embarked upon another scheme called Niranthara Jyothi in which separate lines would be drawn to supply power to IP sets.

Recommendations

All schemes undertaken by the ESCOMs should be scrutinised by Technical Audit so as to assess their viability and sustainability under the then existing conditions.

The objective of the companies should be to provide assured hours of power supply to IP set consumers rather than focusing on preventing tampering. This would entail a win-win situation to the consumers and the companies. Proper maintenance of the assets is also a key to the success of any scheme.

In view of the success of RLMS scheme in MESCOM and as the Expert Committee appointed by the company had also estimated the cost under Niranthara Jyothi to be double the cost under RLMS, BESCOM and HESCOM need to take a re-look at the alternatives to meet the desired objective of providing assured power supply to IP set consumers.

Introduction

With the objective of increasing food production, farmers in Karnataka were encouraged to install Irrigation Pump (IP) Sets to bore-wells and open wells to increase area under cultivation. The consumption of electricity by the IP Set consumers was nearly 40 *per cent* of the total energy sold in Karnataka in 2005-06. The increase in generation did not match the demand and the gap widened resulting in load shedding for consumers.

The Karnataka Power Transmission Corporation Limited, which transmits electricity, proposed (2003), undertaking a scheme called Grama Jyothi Scheme in five Electricity Supply companies[77] (ESCOMs) *viz.,* BESCOM, HESCOM, MESCOM, GESCOM and CESC distribution areas for supply of single phase power supply during the entire day to rural areas and regulate power supply to IP Sets. In the meanwhile (March 2004), Bangalore Electricity Supply Company Limited (BESCOM) experimented with another pilot scheme called *Rural Load Management System* (RLMS) in two feeders at Tavarekere.

Rural Load Management System (RLMS)

2.2.2 In the normal method of power supply, the supply line emanating from the transformer is common to all consumers (IP sets, domestic, commercial *etc*,).

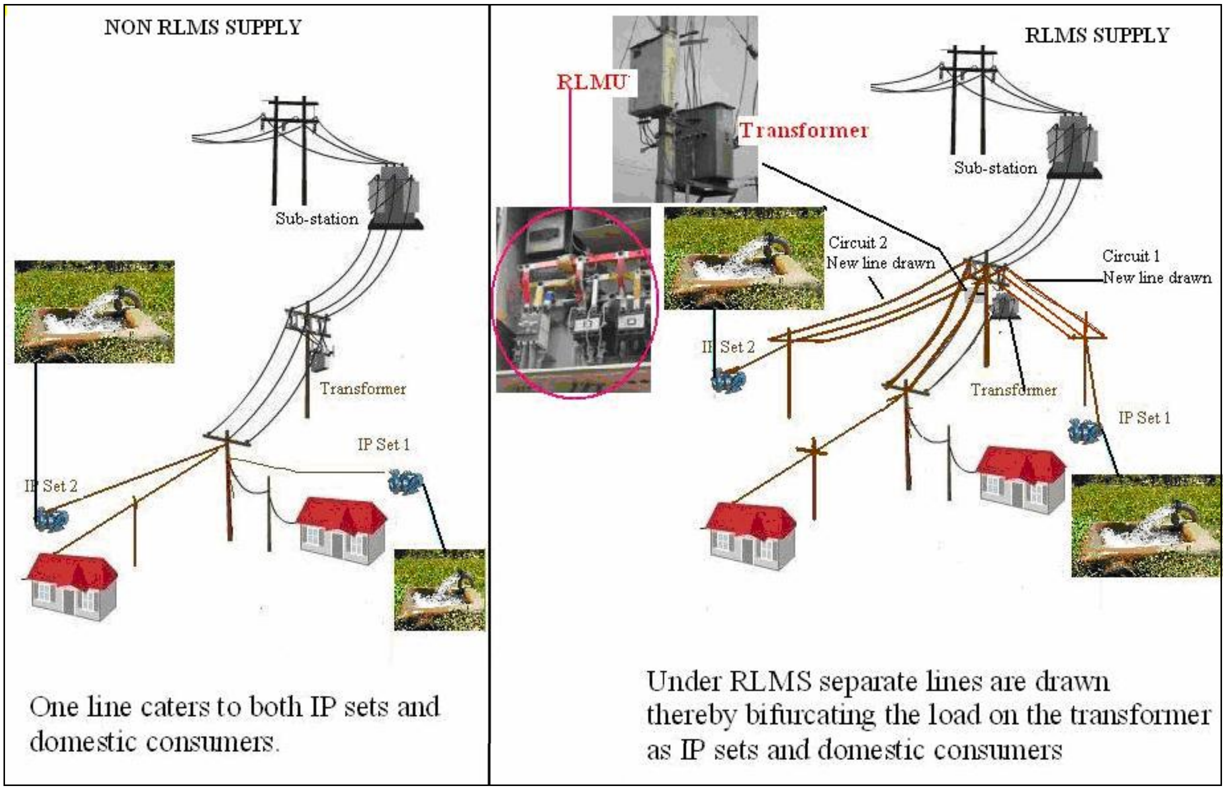
Under the RLMS, a Rural Load Management Unit (RLMU) box is installed on the Low Tension (output) side of the transformer comprising of Programmable Logic Controller (PLC)[78], Circuit breaker, Modem, Electronic meter *etc.* The concept behind RLMS was to segregate the load on each transformer in to IP set consumers and non IP set consumers. The IP set consumers are again bifurcated into two groups. The 11KV feeder (input side) is kept charged for 24 hours. On the output side, power supply is given to non-IP consumers for entire 24 hours, while power supply to IP set consumers is regulated by the PLC for specified hours as per a pre-determined programme. The PLC switches between the two groups of IP sets consumers alternatively. In case of failure of power supply during the programmed hours to IP set consumers, the PLC would automatically provide power supply at another time of the day / night hours.

---

[77] Bangalore Electricity Supply Company Limited (BESCOM), Hubli Electricity Supply Company Limited (HESCOM), Mangalore Electricity Supply Company Limited (MESCOM), Gulbarga Electricity Supply Company Limited (GESCOM), and Chamundeswari Electricity Supply Corporation Limited (CESC).

[78] Programmable Logical Controller (PLC) is an instrument in RLMU box which instructs the system to supply/not to supply power to the circuits as per the programme loaded.

The schematic diagram below shows the then existing method of supply of power and the method of supply of power under RLMS.



The company identified the following merits and demerits for the RLMS scheme.

Merits	Demerits
➢ Assured hours of power supply to IP set consumers. ➢ 24 hours power supply to consumers other than IP set consumers. ➢ Reduction in peak load, reduction in transmission distribution losses and improvement in tail end voltage, thus ensuring quality power. ➢ Additional revenue from other category consumers.	➢ Possibility of bypassing RLMU boxes by IP set consumers.

The Board of BESCOM discussed the results of pilot projects in two feeders at Tavarakere and decided (December 2004) to implement the scheme in 282 feeders (about $1/3^{rd}$ of total feeders in BESCOM) at a total cost of ₹ 195.43 crore. Subsequently, in August 2006 the planned implementation of RLMS was increased to 315 feeders. The company (BESCOM) had emphasized (February 2005) before Karnataka Electricity Regulatory Commission (KERC)[79] that implementation of the RLMS scheme would give an ever lasting

[79] **KERC is responsible for fixing tariff in the State. The company approached KERC as the cost would be considered for tariff purpose.**

solution in bridging the gap between demand and supply. Other ESCOMs (except CESC) also decided (HESCOM : October 2005, MESCOM : December 2006, GESCOM : June/July 2006) to implement the scheme in a phased manner.

The details of RLMS works executed by ESCOMs up to end of March 2010 are as follows.

Company	Total No. of feeders selected for RLMS (Target)	No. of feeders completed	Expenditure incurred (₹ in crore)
BESCOM	315	297	264.86
MESCOM	149	133	67.72
HESCOM	211	126	148.96
GESCOM	81	75	107.80
Total	**756**	**631**	**589.34**

Out of the total 756 feeders selected for RLMS in four ESCOMs, 631 feeders were completed. We observed that 39 feeders in 13 test checked divisions were completed but not commissioned (refer paragraph 2.2.11). BESCOM and MESCOM financed the scheme from its own funds, while HESCOM implemented the scheme with own funds and funds from Rural Electrification Corporation (REC). As at March 2010, out of the sanctioned amount of ₹ 179.39 crore by REC, HESCOM had utilised ₹ 94.52 crore. HESCOM had paid interest of ₹ 19.39 crore and principal amount drawn was still not due for payment (March 2010).

The Board of Directors of BESCOM were informed (January 2008) that the results of RLMS -Phase-I were encouraging and as such specifications were ordered to be drawn to cover the balance 835 rural feeders[80] in Phase II of the scheme. Tenders were invited for Phase II of RLMS and the contractors were given Letters of Award in February 2008. Meanwhile, the officers of BESCOM visited Gujarat State in July 2008 and reported (August 2008) about working of a scheme in which separate[81] power supply lines (11KV) are drawn from substations to feed IP set connections.

The Board of Directors of BESCOM in the meeting held in August 2008 decided to drop the RLMS Scheme Phase-II, treating the results of the RLMS Phase-I as not encouraging. HESCOM had also stopped implementation of the RLMS scheme since January 2009. At present (May 2010) BESCOM is implementing Niranthara Jyothi scheme, whereas MESCOM is continuing to implement the RLMS scheme.

---

[80] **the feeders have increased over the last five years due to addition of new feeders and bifurcation of existing feeders.**

[81] **similar to Niranthara Jyothi Scheme, which was subsequently implemented in Karnataka.**

Scope of audit

2.2.3 Performance Audit was conducted between January 2010 and May 2010 covering planning, evaluation, implementation and achievements of the desired objectives of the RLMS scheme in BESCOM, HESCOM and MESCOM. The execution of the scheme between 2005-06 to 2009-10 in these three ESCOMs, was covered in audit. The audit examination involved scrutiny of records at the Corporate Office of the ESCOMs and 13[♣] out of 31 divisions where the scheme was implemented.

Acknowledgement

We acknowledge the co-operation and assistance extended by the staff and the Management of the companies at various stages of the performance review.

Audit objectives

2.2.4 The Performance Audit was conducted with a view to ascertain whether

- the scheme was goal oriented;
- the scheme was implemented economically, efficiently and effectively;
- to ascertain whether the scheme was effectively monitored at all levels and whether there was adequate maintenance;
- there was reduction in peak load, transmission and distribution losses and improvement in tail end voltage; and
- the main objective of providing assured hours of power supply to IP set consumers and 24 hours power supply to non- IP set consumers was achieved, thus improving consumer satisfaction levels.

Audit criteria

2.2.5 The Audit criteria considered were the following.

- Power supply was to be provided as per Government directions from time to time;
- 24 hour power supply was to be provided to RLMS feeder and instructions for change in timings of PLC were periodically communicated to contractors.
- Schedule of rates of the ESCOMs and Detailed Project Report; and
- Terms of contract with contractors.

[♣] **Probability Proportion to size with replacement (PPSWR) with multiple of number of feeders with estimate cost was adopted as size measure and 13 divisions out of 31 divisions were selected for test check. The 13 divisions are Harihar, Davangere, Nelamangala, Ramnagar, Tumkur and Madhugiri in BESCOM; Hubli, Bagalokot, Dharwad, Haveri and Ranebennur in HESCOM; Sagar and Kadur in MESCOM.**

Audit methodology

2.2.6 The methodology adopted for attaining the audit objectives with reference to the audit criteria were as follows.

- Review of Minutes of the meetings of Board of Directors;
- Review of Detailed Project Reports;
- Scrutiny of records and decision of management relating to award of contracts;
- Review of records relating to implementation of the Scheme; and
- Scrutiny of Management Information System reports.

Audit findings

2.2.7 The objectives of the performance review were explained to Government and the company during an entry conference held in April 2010. The findings emerging out of the test check were reported to the Management in June 2010. The exit conference attended by the Pr.Secretary to the Government and represented by the Managing Directors of the ESCOMs was held in August 2010. The views expressed in the exit conference and replies furnished by the Management have been considered while finalizing the report. The findings are discussed in the succeeding paragraphs.

Planning

2.2.8 Before commencement of a scheme, it is essential that there exists a proper system of planning the activity. Once a decision to implement a scheme involving technical matter is taken up, the scheme should be subjected to Technical audit, so as to ensure that the desired technical parameters are in conformity with the policy of the companies.

The company (BESCOM) experimented (February / March 2004) with a scheme called 'RLMS scheme' in two feeders at Tavarakere. The Board of Directors of BESCOM approved the RLMS Scheme in March 2004 and directed (August 2004) that feeder-wise DPR be prepared. The Board of BESCOM discussed (August 2004) the results of pilot projects (March to July 2004) in two feeders at Tavarakere and decided (December 2004) to implement the scheme in 282 feeders.

Non-conducting of Technical Audit

2.2.9 We observed that in BESCOM, the DPRs were not subjected to technical audit even though the company had a Technical Audit and Quality Control (TAQC) wing. In HESCOM and MESCOM also, the RLMS scheme was not subjected to technical audit.

The company (BESCOM) opined (August 2010) that DPRs were prepared and scrutinised by Planning and Technical departments comprising qualified and experienced engineers and, hence, the need for vetting by TAQC was not felt.

The Planning wing of BESCOM which studied the performance of RLMS in 46 feeders (subsequent to its implementation) had concluded that system improvement works were included on a large scale in the RLMS scheme and hence the scheme had to be audited technically.

System improvement works

2.2.10 'System improvement works' involve works such as extension of Low Tension (LT) lines with conductors, shifting of distribution transformers to load centers, extensive releasing and restringing of existing LT lines and erection of intermediary pole supports to LT lines.

RLMS itself is a Demand Side Management measure and only alteration works required to bifurcate and segregate IP set loads from the existing network needs to be executed. Minimum two circuits need to be formed for sharing the IP set loads and the formation of two circuits is itself sufficient for effective working of RLMS. RLMS scheme is executed in rural areas where the existing transformer capacity was less than 100 KVA and even for 100 KVA with two bifurcated loads the 'weasel' conductors are quite sufficient to take the IP set loads. The policy of the ESCOMs as described in their Schedule of Rates also stipulates that 'weasel' conductors are to be used for rural areas.

We observed that BESCOM and HESCOM planned to execute the RLMS by including system improvements works rather than alteration of works to bifurcate the IP set loads. The materials (conductors and poles) utilised for system improvement works were contrary to its own policy and hence the DPR/planning was deficient to that extent. The scheme was not subjected to Technical audit. The resultant extra expenditure incurred on the higher capacity 'rabbit' conductors and RCC poles (to support the 'rabbit' conductors) in ten test checked divisions of BESCOM and HESCOM was ₹ 4.33 crore. It may be pointed out here that MESCOM, however, executed the RLMS scheme by taking up only alteration works required for bifurcation of IP loads with 'weasel' conductors (supported by PCC poles).

The contention (August 2010) of BESCOM that provision for the required materials depending upon field requirements and future load growth were made in the DPRs runs contrary to the observations made by an Expert Committee constituted by BESCOM, which had opined (May 2008) that such system improvement works could have been reduced. The Managing Director, while offering his remarks to the State Government on the views of the Expert Committee had stated (May 2008) that Expert Committee had put the reduction in cost of estimate at around 40 *per cent* if system improvement works were excluded from RLMS scheme.

Implementation

2.2.11 For the success of any scheme, the scheme has to be implemented economically, efficiently and effectively. Further, for the benefits to be derived the projects need to be implemented and commissioned in time. We observed following deficiencies in the implementation of the scheme in the test checked divisions of ESCOMs.

- BESCOM had awarded (May 2005) to M/s ABB Ltd., the works of RLMS scheme on partial turnkey basis by supplying major materials like distribution transformers, rabbit conductor, poles, disc insulators *etc*. As per the agreements with M/s ABB Limited, the work was to be completed within nine months including monsoon period. In six test checked divisions, however, there was abnormal time overrun in completion of work ranging from 1 to 33 months which was attributed to non-supply of materials by the company.

In HESCOM, qualification requirements of the tenderers were modified after invitation of tenders.

- HESCOM opted to execute the works under RLMS scheme on total turnkey basis and after calling for tenders (January 2006) for execution of works, raised (March 2006) the qualification requirements (QR) of the tenderers. Because of the increased QR, many of the tenderers stood disqualified and were denied opportunity to participate in the tender. This forced the company to accept the single tender of M/s ABB Limited in five divisions[82], while one division *viz.,* Bagalkot was subsequently awarded (July 2007) to M/s PEC Electricals, Hyderabad as per directions of Hon'ble High Court. Hence, the amendment of the QR subsequent to issue of tender notification was not in the best interest of the organization. As per the agreements with the firms (ABB Limited, PEC Electricals and Subhash Projects Marketing Limited), the total turnkey work was to be completed within 12 months from date of Letter of Intent. In six test checked divisions, however, there were delays ranging from 1 month to 13 months and the company, overlooking its interest, did not levy any penalty.

- MESCOM awarded (June 2007) the work of fixing of RLMU boxes to contractors. The other related works of bifurcation of IP load were either executed departmentally or through labour contracts.

- A test check of divisions revealed that the feeders fitted with RLMU boxes were not commissioned even though the work was completed in the following feeders:

Company	Number of divisions test checked	No. of feeders where work was completed	No. of feeders completed but not commissioned	Divisions where feeders were not commissioned with RLMU boxes (no. of feeders not commissioned in brackets)
BESCOM	6	173	9	Nelamangala (9)
HESCOM	5	45	28	Hubli (2), Dharward(11), Bagalkot (5), Rannebennur (10)
MESCOM	2	103	2	Kadur (2)

BESCOM stated (August 2010) that in Nelamangala division, all the RLMS feeders were commissioned soon after the completion of work. The reply is not in line with the details furnished by the Division (April

[82] **of the 13 divisions put to tender in four divisions ABB limited was the lowest; in one division PEC Electricals was the lowest (apart from Bagalkot division) and in two divisions SPM Limited was the lowest tenderer to whom the contract were awarded.**

2010), in which it was stated that though works in nine feeders[83] were completed between October 2008 and June 2009, the same were yet to be commissioned.

- Test check of stores and payments to contractors revealed the following

  - In two divisions (Harihar and Davangere) of BESCOM, materials like conductors, poles, meters *etc.,* to be supplied by the company were drawn from the stores after certification of the completion of work.

  - In Bagalkot division of HESCOM, we observed release of payments even though the Engineer-in-charge had recorded in the bills - "*in view of urgency and it (bill) was only first and partial bill to regularize the advance amount paid. Hence, the bill was signed without taking inventory. The last and final bill will be submitted only after complete inventory*". This bill was passed for payment in November 2008, but it was observed that neither had the inventory been recorded nor final bill settled till March 2010 (date of our scrutiny).

  - In Dharwad division of HESCOM, the Executive Engineer had noted in July 2009 that the PLC units of three feeders (Ibrahimpur, Shanawad and Annigeri) were due for issue to the company though the same had been recorded in measurement book as received. We observed that the payments in respect of these feeders had, however, already been released in November 2008.

Advances given against major materials were pending adjustment for six months to two years.

  - The agreements entered into in October 2005 and April 2007 with the contractors by BESCOM and HESCOM stipulated that payment of 80 *per cent* of the cost of the materials supplied by the contractor would be given as advance and the balance 20 *per cent* would be paid after completion of the work. Test check in four divisions revealed that the advances given on materials amounting to ₹ 5.88 crore and ₹ 1.95 crore were pending adjustment (for two years in HESCOM and six months in BESCOM) respectively as at March 2010.

The deficiencies noticed in the implementation of the scheme points to deficiencies in internal control procedures regarding sourcing of requisite material for works, delay in commissioning and release of payment to contractors. The benefits expected to be extended to the intended beneficiaries from the expenditure incurred were not realised in areas where RLMU boxes were installed but were not commissioned and in other areas the benefits were delayed to the extent there was delay in implementation.

[83] **feeders at Kagimadu, Chakrabavi, Halasabele, Savandurga, Shivagange, Marur, Thaggikuppe, Gudemaranahalli and Managal.**

2.2.12 In ESCOMs, large number of IP sets were not metered. In the absence of meters for IP sets, energy audit could be attempted at the next level *viz.,* transformer centre level. For the purposes of energy audit and analyzing the results of RLMS scheme collection of recordings of energy meters was essential. This energy audit could only be done if modems installed in the RLMU boxes (fixed at transformer centres) could record and transmit the information to the control centre. In the absence of connectivity, a person had to climb each pole to record the meter reading.

We observed that as transformers were situated in remote areas where there was no network connectivity, meter readings could not be remotely recorded. Further, as each feeder had about 50 transformers it was practically not possible to climb each transformer pole for recording reading. Thus, inclusion of modems in RLMUs was not based on ground realities. Considering an average of 50 transformers per feeder, the total unfruitful expenditure on installing modems in RLMU boxes of 631 feeders completed till date, worked out to ₹ 20.01 crore[84]. In this connection, it is to be noted that an Expert Committee set up by the company to study the 'Capital Expenditure' proposals had noted that these meters and modems did not serve any purpose as the IP sets were not metered and, as such, the amount spent on metres and modems could have been avoided.

The opinion (August 2010) of BESCOM that sooner or later all the areas would get network connectivity was not justified, as even if a few transformers were not read, the purpose of energy audit would be defeated and this was known to the company. We noted that the only alternative till then was to obtain the readings on weekly basis from the maintenance contractor in terms of the agreement, which too was not obtained and analysed.

Monitoring and Maintenance

Monitoring of the Scheme

2.2.13 Effective monitoring and follow up is an essential part of the success of any scheme. It was observed that the progress of the RLMS scheme was periodically discussed at circle and zonal levels of all the ESCOMs up to March 2008. From April 2008, the details of data of the RLMS provided by the contractor were not available in the test checked divisions. We note that details of discussions at circle and zonal levels after April 2008 were not on record.

Monitoring of schedule of supply

2.2.14 The main idea behind RLMS scheme is to segregate IP load on each transformer into two groups. While power supply is given to non-IP consumers for entire 24 hours, power supply to IP set consumers is regulated by the Programmable Logic Controllers (PLC) for specified hours in a staggered

[84] ₹ 6,660 per meter x 631 (total feeders in all ESCOMs) x 50 transformers per feeder (approx) = ₹ 20.01 crore. The extra expenditure on meters is not considered as the meters can be used for other connections.

manner. It was not easy to change the timings of PLC unless done remotely and even if one transformer centre was not remotely connected, the change in timings could not be affected. The agreement with the contractor (supplier of RLMU boxes) specified that the PLC was to be capable of storing a pre-determined programme and the schedule was likely to change depending on the season[85] .

In BESCOM and HESCOM, the schedule detailing the timings for power supply to be given to contractors, were not available on record.

Though the condition of providing time schedules and changes were stipulated in the agreement, it was noticed in test checked divisions of BESCOM and HESCOM that there was no record of any intimation given to contractors detailing the timings that the PLC had to provide power to different IP set consumers. MESCOM has reasonably maintained the intimations given to the contractor regarding the schedule of power supply.

The contention (August 2010) of the company (BESCOM) that it had intimated the contractors to maintain timings of power supply had an implication on the company elsewhere stating that providing power to farmers in the evening hours was not well-received and had resulted in tampering. The fact that all the transformers needed to be connected to the control centre to affect the change in timings and that a number of transformers were situated in remote places necessitated the company to ensure that the maintenance contractor was periodically provided with time schedules and changes. In the absence of intimations in the test checked divisions, we could not ascertain that the contractors modified the programme in the PLC units so as to provide power with the stipulated timings (on rotational basis) to different groups of IP set consumers (farmers).

Maintenance by contractors

2.2.15 Proper maintenance of the RLMU boxes is essential for the success of the RLMS scheme.

- BESCOM entered into an agreement in October 2005 with the contractor (ABB Ltd) who supplied RLMU boxes, for the maintenance of the boxes for five years. The details of claims raised by contractor, those admitted and balance pending settlement by the company were not available. During the test check of Ramanagaram division of BESCOM, we observed that in respect of 16 feeders the contractors had claimed payments of ₹ 18.29 lakh[86] towards maintenance charges of feeders, 5 months to 11 months prior to their dates of commissioning.

Maintenance of RLMU boxes was discontinued in BESCOM. HESCOM did not enter into maintenance agreement.

- HESCOM did not enter into maintenance contract, though tenders were called for and evaluated in January 2006.
- MESCOM entered into a maintenance agreement with the supplier of RLMU boxes in June 2007.

---

[85] **Clause 1.02.05 and 1.02.06 of agreement. Clause 1.02.06 referred to a sample schedule as part of the agreement. The sample schedule, that is part of the agreement (referred as Annexure-B), is also not available in the agreements made available to audit.**

[86] **completion dates of feeders as recorded by Accounts Section and Measurement books varied. The payments are yet to be made (August 2010).**

- In BESCOM and MESCOM, the agreements with the maintenance contractors stipulated that the data regarding peak load, energy sent out *etc.,* were to be furnished on weekly basis. This was required to facilitate energy audit[87]. In the test checked divisions of BESCOM, the contractors had furnished these data for intermittent months for certain feeders only up to March 2008. It was during this period (April-May 2008) that Vigilance Wing of BESCOM also reported large scale tampering. The details of data of the RLMS feeders provided by the contractors from April 2008 to till date (August 2010) were not available in the test checked divisions. The company had not decided to restore the maintenance or to terminate the maintenance contracts till date (August 2010). In HESCOM, as no maintenance contract was entered into, no data was available. In MESCOM, such reports were furnished by the contractor in respect of certain feeders intermittently. Energy audit on RLMS feeders were however, not conducted in BESCOM and HESCOM.

The company (BESCOM) stated (August 2010) that it was wrong to say that maintenance was discontinued from March 2008. The maintenance had to be done by the maintenance contractor and could not be done by its own staff as there were 1.18 lakh transformers in its jurisdiction. Tampering and problems of changing the time in PLCs led to strain on the contractors' resources. Vigilance Wing of the company (BESCOM) reported high incidents of tampering in April / May 2008 and the contractor sought police protection.

The reply is factual. The large number of transformers in its jurisdiction and the requirement of maintaining them (by contractors) were known to the company. The factors that led to failure of the scheme were supplying power during evening hours, not instructing the contractor to change the timings of PLC periodically, deteriorating power supply situation resulting in large scale tampering and failure by the contractor to maintain the RLMU boxes.

Realisation of incidental objectives

2.2.16 The data in respect of all the commissioned feeders were not available[88]. We examined the statistics regarding peak load, transmission and distribution losses and tail-end voltages in 20 feeders (randomly selected) from the selected test checked divisions of three ESCOMs. The results are as tabulated below:

Company	Division	Name of the feeder	Reduction in peak load	Reduction in T&D loss	Improvement in tail-end voltage
BESCOM	Nelamangala	Gollahalli	✓	✓	✓
	Nelamangala	Manne	✓	✓	✓
	Tumkur	Virupasandra	✓	✓	✓
	Tumkur	Herur	✓	✓	✓
	Madhugiri	F1 Medigeshi	✓	✗	✓

[87] **Clause 1.02.13, 1.02.12, 1.18.08 and 1.18.09 of the agreement (part III-Section I).**
[88] **refer to paragraph 2.2.15, where non-availability of data in full is stated. The analysis of realisation of incidental objectives is based on data available for the period up to May 2008.**

Company	Division	Name of the feeder	Reduction in peak load	Reduction in T&D loss	Improvement in tail-end voltage
	Madhugiri	F6-DV Halli	✓	✓	✓
	Ramnagar	Bilagumba	✓	✗	✓
	Ramnagar	F7-Kottahalli	✗	✓	✓
	Davangere	Anagod	✓	✓	✓
	Davangere	Asagod	✓	✗	✓
	Harihar	Bennehalli	✓	✓	✓
	Harihar	Yelehole	✓	✓	✓
HESCOM	Hubli	Kamadolli	✗	✓	✓
	Hubli	Saunsi	✗	✓	✓
	Dharwad	Yerikoppa	✗	✓	✓
	Dharwad	Narendra	✓	✓	✓
MESCOM	Sagar	Nandihalli	✗	✓	✓
	Sagar	Apinakatte	✓	✓	✓
	Kadur	Jigenahalli	✓	✓	✓
	Kadur	Kallapura	✓	✓	✓

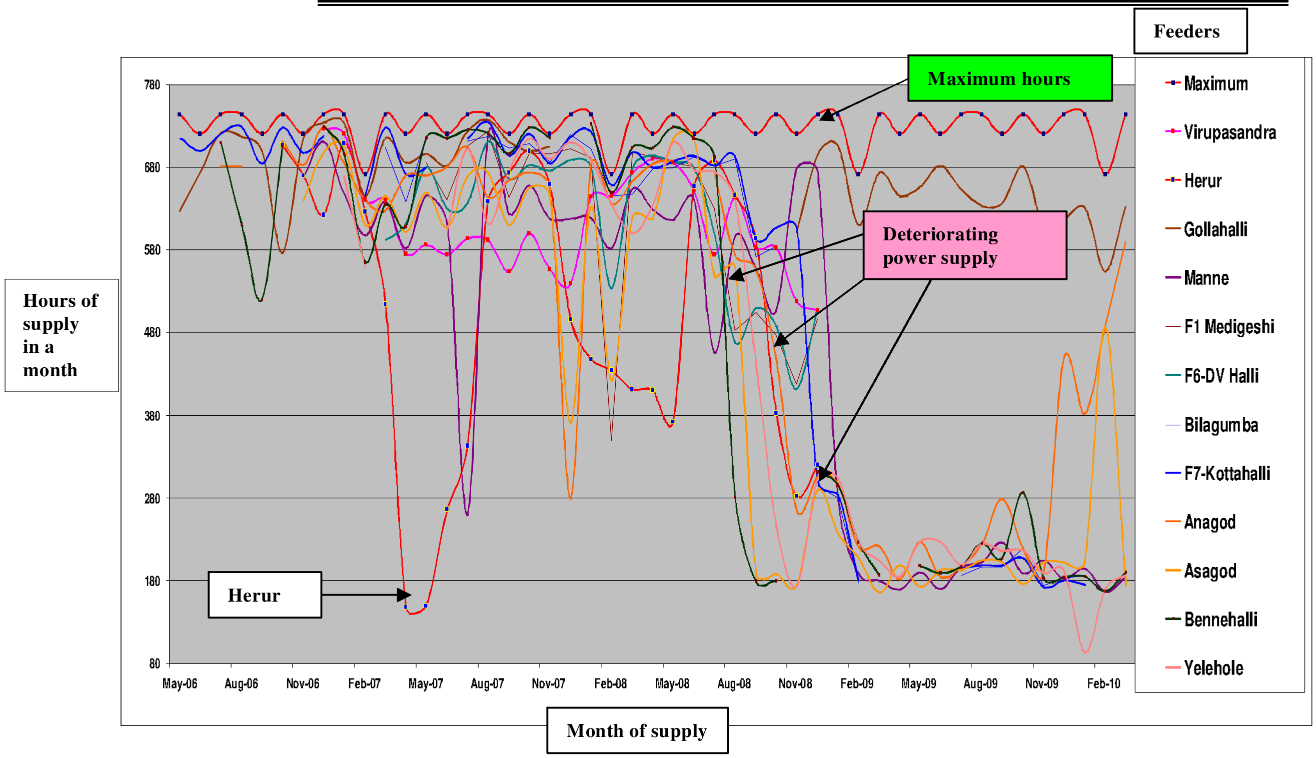
There was reduction in peak load, T&D losses and improvement in tail end voltage after implementation of RLMS.

It is heartening to note that there was reduction in peak load and transmission and distribution losses and improvement in tail-end voltage in most of the feeders.

Realisation of main objective

2.2.17 Possibility of tampering of RLMU boxes was one of the demerits of the scheme expected at the time of conception of the scheme in December 2004. The company (BESCOM) had stated in February 2005 before Karnataka Electricity Regulatory Commission (KERC) that implementation of the RLMS scheme would give an ever-lasting solution in bridging the gap between demand and supply. As per Government order of August 2004, atleast six hours of good quality power supply was to be provided to IP set consumers. Power supply for specified hours was to be provided to each group of IP set consumers in a staggered manner. Thus, load shedding was not to be resorted to and the PLC would control the power supply. The power supplied in respect of 12 feeders (random check) in the selected test checked divisions of BESCOM[89] after commissioning of RLMS is illustrated below:

[89] **test check was limited to BESCOM. In HESCOM, the RLMU units were stated to be by-passed immediately on its commissioning.**



From the above graph, the following was observed:

- The concept behind RLMS scheme was to provide 24 hours power supply to RLMS feeders. This implied that in the RLMS feeders, there should not be any power cut. We, however, observed that none of the feeders received maximum hours of power supply in any of the months indicating power cuts in RLMS feeders.

- Attention is drawn to the power supplies made during April 2007 and May 2007, in Herur feeder of Tumkur Division. As RLMS feeders were to be provided with 24 hours power supply per day, the number of hours of supply in April and May 2007 should have been 720 hours and 744 hours respectively. The feeder at Herur, however, supplied power for only 148 hours and 149 hours in April and May 2007. In the meeting held in May 2007 between the officials of BESCOM and representatives of M/s ABB (contractor), large scale tampering in Tumkur and Kolar circles were discussed and the contractor (M/s ABB Ltd) had reported that there was tampering in some villages at Herur. The quantum of power supplied indicated that farmers had resorted to tampering as the required power was not provided to them.

- The graph above also indicates that power supply in the test checked feeders showed a decreasing trend from June 2008 and reached dismal levels by November / December 2008. The company accepted that tampering was noticed during intensive inspections between April and June 2008. The Vigilance Wing of BESCOM, after checking 55 feeders (714 RLMUs) during April / May 2008 had reported that there was tampering/by-passing in 34 *per cent* of the RLMUs. In most of the cases, the villagers resorted to large scale tampering of RLMU equipment after load shedding / power failure for long duration and as the non-supply hours were not compensated with power supply in other hours. In Many cases, M/s ABB Ltd themselves had by-passed the equipment due to non-availability of spares.

The Company (BESCOM) stated (August 2010) that it was wrong to construe that failure of the scheme was for the reason that the company could not maintain continuous power supply to the RLMS feeders. The company cited that providing power in the evening hours was not being well received by the farmers, who resorted to tampering, alongwith delay in maintenance works by the contractors as the biggest mistakes for the failure of the RLMS scheme. Unauthorized load of IP set connections and inability to compensate for time in PLC programming constrained the company to shed load on RLMS feeders when power scarcity struck during 2008. The Company stated that had the Scheme succeeded during June 2008 to December 2008, there would have been no need for the Company to search for a solution.

The RLMS scheme was a success in MESCOM whereas it failed in HESCOM and BESCOM.

It is to be noted that RLMS scheme was projected to KERC as an everlasting solution to meet the demand-supply gap and as such the RLMS scheme was supposed to work in a power deficit scenario. As could be seen from the graph and analysis, tampering was noticed when power supply was not provided to farmers (*eg.,* noticed in Herur feeder during May 2007). The Vigilance Wing of BESCOM noticed tampering of RLMU boxes during April-May 2008 as power was not provided to farmers for long hours and non-supply hours were not compensated with power supply in other hours. The deteriorating power supply during this period (post April 2008)[90] could also be co-related to power supply position in the test checked feeders (graph). Moreover, by the company's own admission, the supply of power during evening hours was not well received by farmers. Power cut in RLMS feeders results in non supply of power during the stipulated time to a group of IP set consumers and such periods of non-supply had to be compensated with power supply during some other time of the day. Compensating the power supply during the evening hours would not be well received by farmers. The vicious cycle of power cut in RLMS feeders, non-rotation of timings of power supply and supply during evening hours, led to large scale tampering[91]. The maintenance contractor could not maintain the RLMU boxes being tampered on a large scale. The situation was aggravated by the rising demand-supply gap scenario of power supply. Hence, the scheme, which was modelled to work in a demand-supply gap situation, failed in BESCOM and HESCOM. Thus, RLMU boxes served their purpose only for a limited period as the boxes were tampered with subsequently. The expenditure made on RLMU boxes in six test checked divisions of BESCOM and five test checked divisions of HESCOM was

[90] **as per Annual Reports of Southern Regional Power Committee, as a result of load shedding, rural feeders in Karnataka were given power supply (three phase supply required for IP sets) for only 8-9 hours from January 2005 to November 2008 and six hours power supply from November 2008 onwards till end of March 2010.**

[91] **the extent of tampering was not available in BESCOM and HESCOM.**

₹ 19.73 crore and ₹ 8.62 crore[92] respectively, which served only limited purpose and was largely wasteful.

The incidental benefits of reduction in peak load, reduction in transmission and distribution losses and improvement in tail end voltage were achieved in all the ESCOMs. The main objective of providing assured hours of power supply to IP set consumers and 24 hours power supply to non-IP set consumers, however, largely failed in BESCOM and HESCOM. BESCOM stopped implementing RLMS in August 2008, while HESCOM decided in January 2009 not to go ahead with the execution of RLMS in the remaining feeders where work had not commenced.

In MESCOM, however, load shedding was not resorted to in RLMS feeders. Under extreme conditions, the feeders were treated at par with Urban feeders (minimum power cut). Instances of tampering noticed were attended to by the maintenance contractor[93]. This led to the success of the scheme only in MESCOM.

RLMS vis-à-vis Niranthara Jyothi scheme

2.2.18 While the RLMS Phase-I was in progress, the Hono'ble Minister for Public Works Department & Energy and the Managing Director of KPTCL, who was the Chairman of all ESCOMs, directed (August / November 2007) that RLMS work in the balance feeders be taken up in one go. BESCOM floated (November 2007) tenders for Phase-II on partial turnkey basis. No DPR was prepared. The cost of implementing RLMS phase –II for 835 feeders was estimated at ₹ 2,343 crore but the scheme was shelved and works in balance 835 feeders were taken up under another scheme called *Niranthara Jyothi* (where a separate 11 KV line was drawn for supply of power to IP sets) at a cost of ₹ 735 crore.

Comparison of costs

2.2.19 We observed that the cost per feeder under RLMS phase I in BESCOM worked out to ₹ 54 lakh[94], while the cost per feeder in MESCOM worked out to ₹ 51 lakh[95]. BESCOM still had 835 feeders to be taken up under RLMS – Phase II, but, the scheme was abandoned in favour of Niranthara Jyothi scheme conceived after visit of the officials of the Company to the State of Gujarat. To complete works in the balance 835 feeders in RLMS-phase-II, considering the

---

[92] for 14,050 RLMU in six test checked divisions of BESCOM at ₹ 41,298 per RLMU; for 2,338 RLMU in five test check division of HESCOM at ₹ 36,868 per RLMU. The cost per RLMU per unit excludes the cost of meter and modem (refer paragraph 2.2.12). The extra expenditure in these test checked divisions works out to ₹ 28.35 crore.
Note: All RLMUs are considered as bypassed in HESCOM. In the absence of details in BESCOM, 34 *per cent* of RLMU boxes in test checked divisions are considered as 'not functioning', while arriving at the loss, based on the percentage of tampering as arrived in the Vigilance Wing report.

[93] as periodical bills were seen preferred by the contractor up to this period.

[94] total cost incurred for 297 feeders was ₹ 264.86 crore and excluding system improvement works at 40 *per cent* (which were not required as per Expert Committee), the total cost worked out to ₹ 158.92 crore and cost per feeder was ₹ 54 lakh.

[95] total cost incurred for 133 feeders was ₹ 67.72 crore. As there was no system improvement works in MESCOM, the cost per feeder worked out to ₹ 51 lakh.

average cost per feeder of Phase-I, we estimate in BESCOM, the total cost would have been of the order of ₹ 450 crore. Instead, BESCOM took up works under Niranthara Jyothi at a cost of ₹ 735 crore.

The company had constituted (March 2008) two studies. The first, by an Expert Committee under the chairmanship of a former Chairman of erstwhile Karnataka Electricity Board, was to study the benefits that accrued from the RLMS scheme. The Committee was also required to examine the alternative system of dedicated feeders for supply of power to agricultural loads in rural areas, as followed in Gujarat, and compare the cost effectiveness of the two schemes. The second was an in-house study by the Corporate Planning wing of the Company of 46 feeders where RLMS scheme was implemented.

The Expert Committee in their report at Annexure VI (Table-5) detailed the cost[96] of RLMS scheme and the cost of drawing an exclusive 11 KV line for power supply to IP sets (Niranthara Jyothi) and reported that as compared to RLMS, the cost of providing the same facility by constructing exclusive 11 KV feeders to IP sets was much higher and almost double the cost of RLMS.

The company stated (August 2010) that the Expert Committee never looked into the cost of the alternate scheme (Niranthara Jyothi). The company also stated that the Government of Gujarat had sent a team to Karnataka to study and compare the RLMS pilot study before they took up segregation of feeders (Swarna Jyothi scheme), whereas, the ESCOMs in Karnataka continued on the 'hunch' that segregation of feeders (Niranthara Jyothi) would be twice as costly (as RLMS). The Company viewed the Expert Committee's opinion that RLMS was cheaper as a 'myth'.

Comparison of benefits

2.2.20 A comparative statement of the different parameters of RLMS scheme as per the pilot study at Tavarekere, the study of 46 feeders by Planning wing of BESCOM, the results of test check by audit in 12 feeders and results of pilot study under Niranthara Jyothi is given below:

	As per RLMS pilot study at Tavarekere and DPR	**As per study of 46 feeders by Planning wing (Average of 46 feeders)**	**As per test check of 12 feeders by Audit.**	**As per pilot study of Niranthara Jyothi at Malur and DPR**
Peak demand (*per cent*)	50	Reduced in 43 feeders to the extent of 40 *per cent* in peak load current	NA	NA
Peak load (*per cent*)	20	32 (Average)	45 (Average) Decrease in 11 feeders and increase in one feeder	10
Improvement in tail end voltage	NA	318 V to 380 V (Average) (19.5 *per cent*) Improvement in all feeders	326 V to 368 V (Average) Improvement in all	190 V to 220V (single phase)

[96] **excluding system improvement works, which according to the committee, was not required.**

	As per RLMS pilot study at Tavarekere and DPR	As per study of 46 feeders by Planning wing (Average of 46 feeders)	As per test check of 12 feeders by Audit.	As per pilot study of Niranthara Jyothi at Malur and DPR
			feeders	
Reduction in transformer failures	16.66 to 5 *per cent*	Decrease in 40 feeders and increase in 6 feeders	NA	3.8 to 2 *per cent*
Increase in consumption / billing (*per cent*)	46	61 (metered consumption increased in 29 feeders and decreased in 17 feeders)	45 (increase in all feeders)	24.73
Increase in demand	50 *per cent*	NA	NA	
Payback period (years)	2.76 (as per DPR)	-	-	4.65
Reduction in Transmission and Distribution losses (*per cent*)	NA	Average of 28.25 to 27.35 *per cent* (Decrease in 28 feeders and increase in 18 feeders)	Average of 25.66 to 23.66 *per cent* (Decrease in 9 feeders and increase in 3 feeders)	NA

NA= not available.

We observed that the pay back period in the DPR of RLMS phase I was projected at 2 years 10 months. In the Niranthara Jyothi scheme, the payback period was projected at 4 years and 8 months.

We observed that both the Expert Committee and the Report of the Planning Wing had concluded[97] that the RLMS scheme was technically sound and the benefits envisaged under the scheme had been achieved[98], but the high rate of tampering of RLMU boxes had defeated the main objective. The observations of audit about the factors that contributed to the success of RLMS scheme in MESCOM and the reasons for failure of the scheme in BESCOM and HESCOM are brought out in paragraph 2.2.17 *infra*.

Conclusion

The RLMS scheme was taken up in the ESCOMs without proper planning as the scheme was not scrutinised by Technical Audit Wing. Materials of higher capacity than those specified in the policy of the companies were utilised.

The vicious cycle of power cut in RLMS feeders, non-rotation of timings of power supply and supply during evening hours, led to large scale tampering. The maintenance contractors could not maintain the RLMU boxes being tampered on a large scale. This forced the company to go in for further power cuts in RLMS feeders. The situation was aggravated by the rising demand-supply gap scenario of power supply. Hence, the

[97] undated.
[98] benefits included rural households getting 24 hours power supply, benefits to rural small scale industries, benefits to farmers and better demand side management.

scheme, which was modelled to work in a demand-supply gap situation failed in BESCOM and HESCOM. The main objective of providing assured hours of power supply to IP set consumers and 24 hours power supply to non-IP set consumers, however, largely failed in BESCOM and HESCOM.

In MESCOM, however, load shedding was not resorted in RLMS feeders. Under extreme conditions, the feeders were treated at par with Urban feeders (minimum power cut). Instances of tampering noticed were attended to by the maintenance contractors. This led to the success of the scheme in MESCOM.

The incidental benefits of the RLMS scheme *viz.,* reduction in peak load, reduction in transmission and distribution losses and improvement in tail end voltage were, however, achieved in all the ESCOMs.

The success of the RLMS scheme in MESCOM indicated that the scheme is a workable model.

BESCOM and HESCOM stopped implementing RLMS in August 2008 and January 2009. BESCOM has now embarked upon another scheme called Niranthara Jyothi, in which separate lines would be drawn from substations to IP set consumers. The Expert Committee appointed by BESCOM had noted that the cost under Niranthara Jyothi would be double the cost under RLMS.

Recommendations

All schemes undertaken by the Electricity supply companies should be scrutinised by Technical Audit so as to assess its viability and sustainability under the then existing conditions. The companies are aware of the gap in the demand-supply position in the power situation of the State. The company (BESCOM) had projected to the Karnataka Electricity Regulatory Commission that RLMS scheme was an everlasting solution to bridge the gap.

The objective of the companies should be to provide assured hours of power supply to IP set consumers rather than focusing on preventing tampering. This would entail a win-win situation to the consumers and the companies. Proper maintenance of the assets is also a key to the success of any scheme. The Company (BESCOM) has now embarked upon another scheme called Niranthara Jyothi in which separate lines are to be drawn to feed IP set consumers.

In view of the success of RLMS scheme in MESCOM and as the Expert Committee appointed by the company had also estimated the cost under Niranthara Jyothi to be double the cost under RLMS, BESCOM and HESCOM need to take a re-look at the alternatives to meet the desired objective of providing assured power supply to IP set consumers.