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Report of the Comptroller and Auditor General of India on Planning and implementation of transmission projects by Power Grid Corporation of India Limited and Grid management by Power System Operation Corporation Limited For the year ended March 2013

The Report has been laid on the table of the Parliament house on 04-08-2014

Union Government (Commercial)
Ministry of Power
No. 18 of 2014
(Performance Audit)

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Comptroller and Auditor General of India
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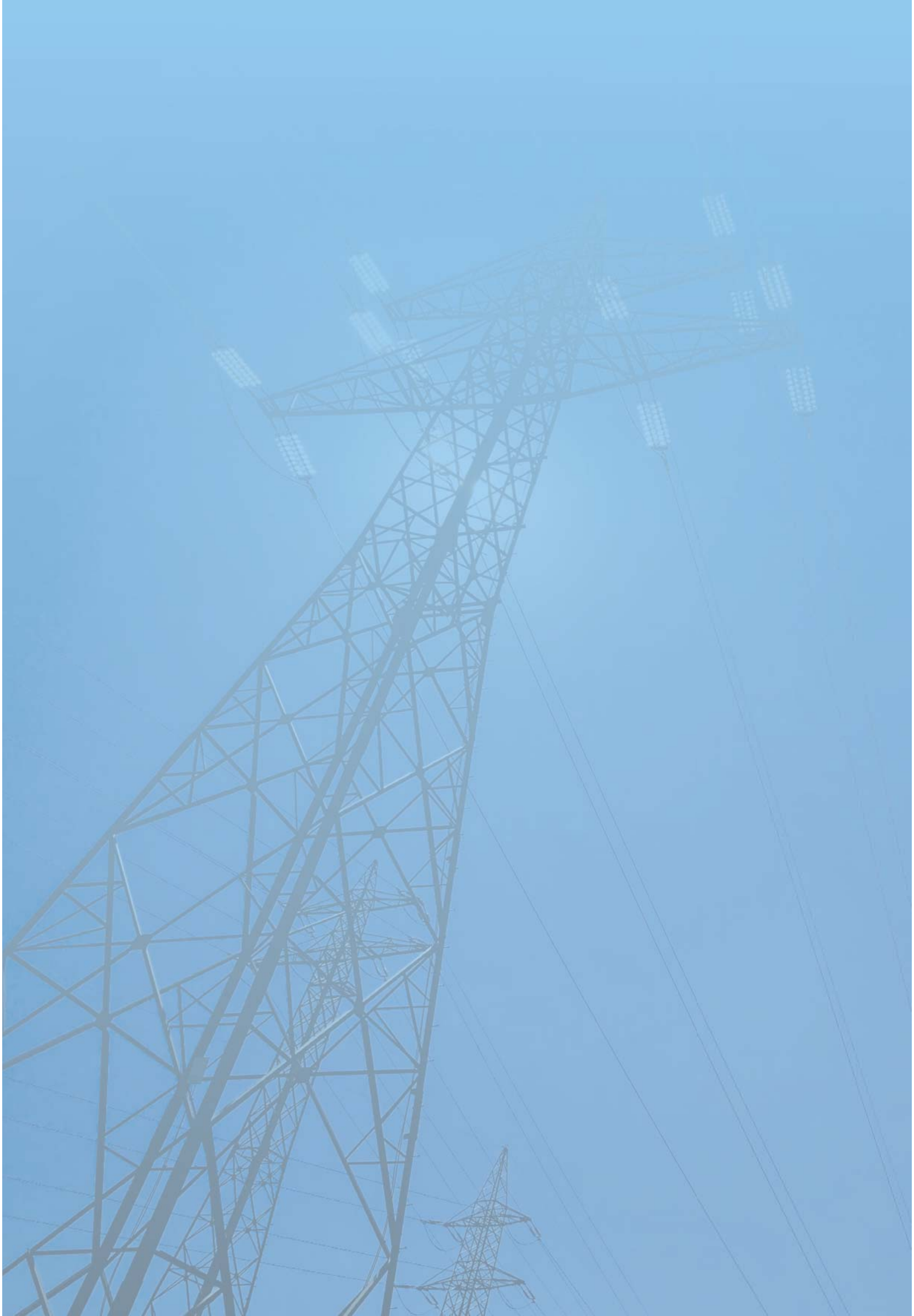


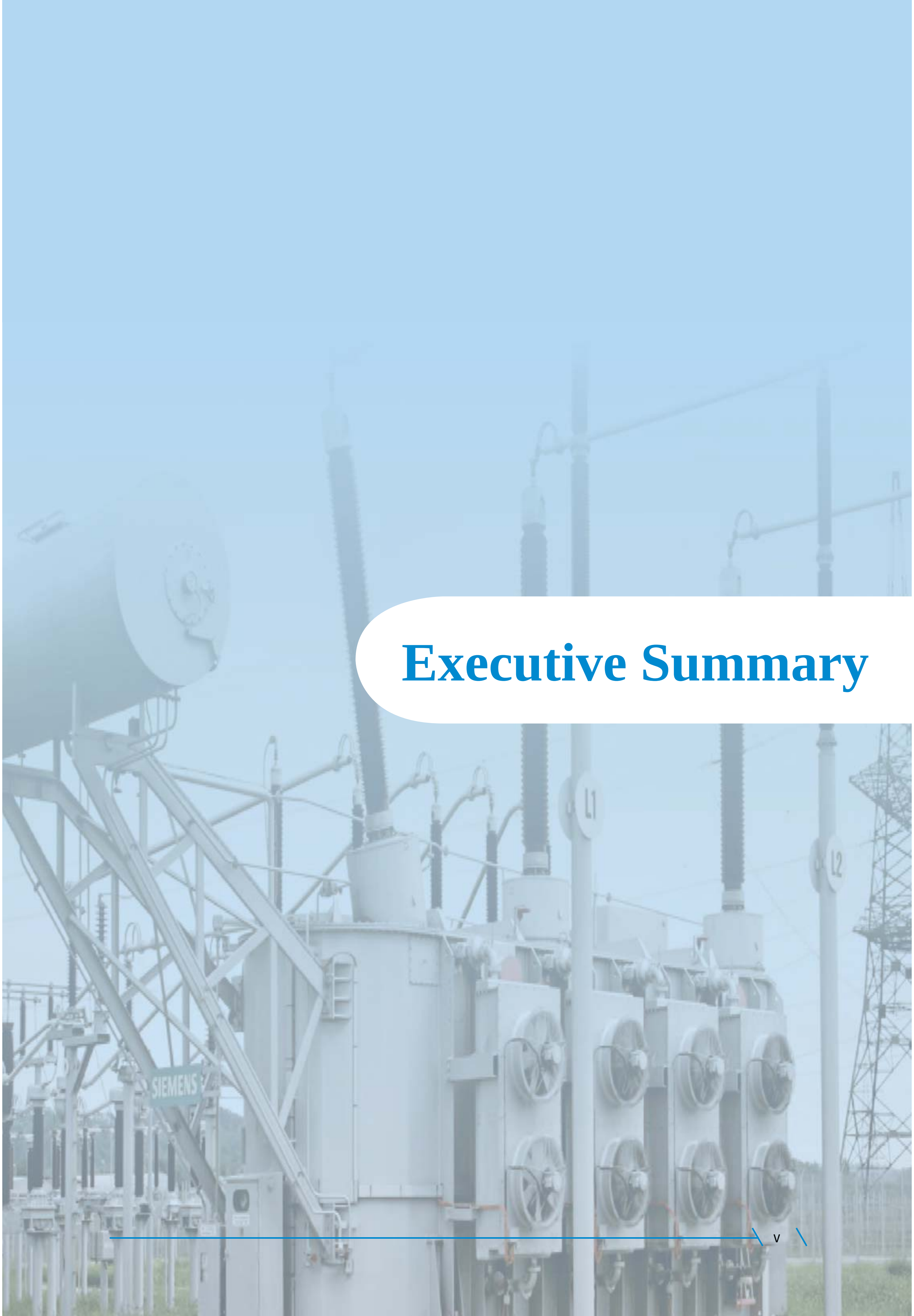
Preface

Power Grid Corporation of India Limited (PGCIL), a Navratna Central Public Sector Enterprise, is mandated under the Electricity Act to ensure development of an efficient, coordinated and economical system of inter state transmission lines for smooth flow of electricity from generating stations to load centres. Power System Operation Corporation Limited (POSOCO), a wholly owned subsidiary of PGCIL, is the apex organisation to ensure integrated operation of power system including scheduling and despatch of electricity through national and regional load despatch centres. Transmission service provider is a key intermediary between generator and distributor of electricity and an efficient and effective transmission network facilitates generation and utilization of power. Inadequacies in transmission network and delay in commissioning of transmission projects may not only result in loss of revenue to PGCIL but may also lead to congestion in evacuation of power. On the other hand creation of lines of higher capacity than required or abnormal redundancies in transmission assets may result in extra financial burden on beneficiaries and public at large.

In the above backdrop, performance audit was taken up to assess the effectiveness of planning and implementation of transmission projects by PGCIL during XI Plan (2007-2012) along with status of augmentation of transmission network up to March 2013. Besides, an attempt has been made to assess shortcomings, if any, in Grid Management by POSOCO in ensuring uninterrupted power supply, including Grid Security and Grid Monitoring, in view of the major Grid disturbances of 30 and 31 July 2012.

The Audit Report has been prepared in accordance with the Performance Audit Guidelines and Regulations on Audit and Accounts, 2007 of the Comptroller and Auditor General of India.

Audit wishes to acknowledge the co-operation received from PGCIL, POSOCO and Ministry of Power, Government of India at each stage of the audit process.



Executive Summary

Executive Summary

Introduction

Inter state and intra state power transmission systems are inter connected and together constitute the grid. In 1984, a working group constituted by Government of India (GOI) for development of 'National Grid' recommended formation of a separate central sector corporation for manning, constructing, operating and maintaining transmission facilities in the country. Accordingly, Power Grid Corporation of India Limited (PGCIL), a Navratna Central Public sector undertaking,[1] was established under the administrative control of Ministry of Power (MOP) in 1989 to implement the decision of GOI to form a 'National Grid'.

Transmission facilitates generation and utilization of power. Inadequacies in transmission network and delay in commissioning of transmission projects may not only result in loss of revenue for PGCIL but may also lead to congestion in evacuation of power. Creating lines of higher capacity than required or abnormal redundancies in transmission assets may result in extra financial burden on beneficiaries[2] and public at large. Accordingly, performance audit was taken up to assess the effectiveness of planning and implementation of transmission projects executed by PGCIL during XI Plan (2007-2012). Besides, an attempt has been made to assess shortcomings, if any, in Grid Management by Power System Operation Corporation Limited (POSOCO) a wholly owned subsidiary of PGCIL, in ensuring uninterrupted power supply, including Grid Security and Grid Monitoring.

Audit scope and sample

The performance audit examined activities from conceptualisation to implementation of selected major transmission projects executed by PGCIL between April 2007 and March 2012 along with the status of augmentation to transmission network made by PGCIL up to March 2013. A sample of 20 transmission projects representing 14 *per cent* in terms of number and 37 *per cent* in terms of value of the projects planned and executed by PGCIL during April 2007 and March 2012 was taken based on materiality and coverage of all Regional Offices of PGCIL. In the wake of the incident of Grid disturbances on 30 and 31 July 2012, the aspect of Grid management by POSOCO, which is mandated with the responsibility to ensure integrated operation of the 'National Grid', was also included in the scope of audit.

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1 ***PGCIL was granted Navratna status in May 2008.***

2 ***State Discoms***

Major Audit Findings

One of the major objectives of formation of PGCIL was to bring about integrated operation of the regional transmission systems by undertaking construction of inter-regional links. This was to facilitate the growth of economic exchange of power (replacing costly energy transactions within a region with cheaper ones from another region to reduce the cost of power) which would ultimately lead to formation of a 'National grid' and ensure better utilisation of available generation resources. The process of integration of five regional grids was progressively taken up from the 1990s and with the synchronisation of Southern Grid with the rest of the grid on 31 December 2013, the entire Indian power transmission grid was being operated at the same frequency completing the technical process of formation of 'National Grid'. However, when viewed in terms of inter-regional power transfer capability and congestion scenario, the objective of formation of 'National Grid' remained to be fully achieved.

In 24 years of its operation up to March 2013, PGCIL built 45 inter-regional transmission lines (220 kV and above), connecting five regions in the country, which works out to 1.2 *per cent*[3] of total such lines in the inter-state transmission grid. Four out of six inter-regional corridors (WR-NR, WR-ER, ER-NER and WR-SR) were capable of carrying only 1.5 *per cent* to 3 *per cent* of installed power generating capacity in the respective power surplus regions. In three out of six inter-regional corridors, there is zero margin (WR-SR) /negligible margins (ER-SR, WR-NR)[4] over and above the capability required to cater to long term customers. Low level of inter-regional transfer capability implied limited scope for transfer of power among regions. Hence the objectives of formation of National Grid *i.e.* meeting deficit from surplus regions and facilitating economic exchanges remained to be fully achieved. Low transfer capability also led to persistent congestion due to transmission constraints. Power exchange data showed that percentage of time congestion occurred above 75 *per cent* increased from two months in 2010-11 to five/six months in 2011-12 and all the 12 months in 2012-13. Similarly, volume of electricity that could not be cleared due to congestion (as a percentage of the actually cleared volume), went above 75 *per cent* for 3 months in 2011-12 and increased to six months in 2012-13. Impact of congestion was visible in large variations in electricity prices. Buyers in S1 and S2 bid areas (Tamil Nadu, Kerala, Andhra Pradesh, Karnataka, south Goa and Union Territory of Pondicherry) consistently incurred higher prices during the last two years (₹ 5.1 to ₹7.3 per unit of electricity as against unconstrained market clearing price of ₹3.5 per unit) to procure power due to transmission constraints. On the other hand, sellers in W3, E1 and E2 bid areas (Chhattisgarh, Orissa, West Bengal, Sikkim, Bihar and Jharkhand) received lower prices (₹2.8 to ₹2.9 per unit) as they could not sell surplus power to deficit areas due to transmission constraints which could have been reduced through strengthening WR-SR and ER-SR links.

(Para 3.1.1)

[3] Total lines – 3743; inter-regional – 45 (765kV, 400 kV and 220 kV).

[4] ER-SR Margin 93 MW in March 2014 (00 to 05 and 10-19 hours) and WR-NR margin 219 MW in March 2014.

XI Plan (2007-2012) noted that planning and operation of the transmission system had shifted from the regional level to the national level necessitating a strong all-India grid. Towards this end, XI Plan stipulated target of inter-regional transfer capacity of 17000 MW. Against the XI Plan target of 17000 MW, PGCIL achieved 13900 MW of inter-regional capacity leaving a shortfall of 3100 MW in achievement. While shortfall to the extent of 1000 MW was due to annulment of one of the projects, the remaining shortfall of 2100 MW was due to controllable factors like delay in submission of proposal for forest clearance and land acquisition issues. MOU targets for inter-regional capacity augmentation by PGCIL for 2007-12 were fixed at 10100 MW which were short of the corresponding XI plan target by 6900 MW (17000 MW minus 10100 MW). In two years (2007-08 and 2010-11) MOU targets were fixed at 'Nil'.

(Para 4.1 and 4.2)

Two parameters *viz*. Transmission Capacity and Transfer Capability are relevant for assessing the capacity of inter-regional corridors. Transmission capacity of a corridor is arrived at by adding the ratings of all transmission lines connecting two regions. Transfer capability on the other hand, is a measure of the ability of a corridor, as a whole, to reliably move power from one region to another. However, PGCIL assesses the need for augmentation of capacity of inter-regional corridors based only on 'Transmission capacity' and does not monitor augmentation of total transfer capability (TTC). Though transmission capacity at the end of XI Plan was 25650 MW, capacity for transfer of power *i.e.* TTC was 11530 MW. PGCIL added (2007-12) transmission capacity of inter-regional transmission corridors of 13900 MW. However, TTC increased from 9400 MW in 2008-09 to only 11530 MW in 2011-12. Thus, for better appreciation of the ability of transmission network to transfer power across regions, it is necessary that TTC is also declared and disclosed alongwith transmission capacity.

(Para 3.1.2)

Bulk of the inter-regional augmentation efforts achieved in XI Plan and planned for XII Plan have been across the ER-NR and ER-WR corridors to wheel power from the pit-head power plants in the coal rich ER to the demand centers in the north and the west. 63 *per cent* of total inter-regional transmission capacity of 25050 MW[5](cumulative at the end of XI Plan) was concentrated along these corridors. Offline simulation studies conducted by an Expert Group constituted by MOP following two major Grid disturbances of 30 and 31 July 2012 have shown that the WR-NR link is the 'short tie' (transmission link shorter in length and tying/connecting two regions) for import of power by NR and in the case of loss of the 'short tie', the 'long tie' of WR-ER-NR could also be lost due to angular separation and power swings[6]. Hence, high level of augmentation of the 'long tie' would not yield desired results for transmission of increased

[5] ***Transmission capacity i.e. summation of ratings of individual lines.***

[6] ***The rotors of generators connected to the grid run at the same electrical speed and in case of small disturbances affecting the speed, restorative forces bring back the rotors to the same speed. However for large disturbances, the restorative forces may be unable to bring all the generators to the same speed. If this happens, the angular difference between the generators goes on increasing (Angular separation) which causes large variations in voltage and power flow in lines.***

power to the NR and there is a need to prioritise implementation of the three new links planned by PGCIL in the WR-NR corridor.

{Para 3.1.3(i)}

Agra-Gwalior double circuit line, a trunk line of the WR-NR corridor, was upgraded from 400 kV voltage level to 765 kV in March 2013. The upgradation created a 765 kV line in parallel with a 220 kV network without any 400 kV system in the WR-NR inter-regional corridor. The impact of such a formation was that in the event of loss of both the circuits of 765 kV line, there would be a 'cascade tripping' of 220 kV network. TTC of WR-NR corridor which was enhanced to 5700 MW from 2000 MW in May 2013 following the upgradation of Agra Gwalior line, was rolled back in October 2013, due to reliability considerations. Thus, the upgradation to 765 kV line in the WR-NR corridor worsened an already delicate nature of WR-NR interconnection.

{Para 3.1.3(ii)}

PGCIL has not put in place a mechanism for assessing utilisation of transmission lines with the result that there were pockets of congestion, as well as areas of redundancy. In Odisha region, there was congestion in the transmission network due to interim 'Loop in Loop out' arrangements made for evacuation of power from Independent power producers without ensuring adequacy of the transmission system. On the other hand, out of 22 high voltage 765 kV lines, six lines remained undercharged at 400 kV for more than 5 years out of which two lines remained undercharged for more than 13 years. During 2011-12, average utilisation of 33 out of 40 inter-regional lines ranged between 0 to 30 *per cent* in all inter-regional corridors except WR-SR and ER-SR. In case of intra-regional lines, 478 (68 *per cent*) out of 706 lines in five regions had average utilisation of less than 30 *per cent*.

(Para 3.1.4 and 3.1.5)

The Country faced a severe Grid disturbance (GD) on 30 and 31 July 2012 which resulted in 757 million units of energy not being served (compared to total generation of 2400 million units per day) to users. The proximate cause for the major GD of 30 July 2012 (involving NR) and 31 July 2012 (involving NR,ER and NER) was the shut down of the trunk line (400 kV Bina - Gwalior-Agra line) between WR and NR for four days (26 to 29 July 2012) in peak season due to construction work. While the shutdown initially planned for four days got extended due to non-completion of work, TTC on WR-NR corridor that was curtailed from 2400 MW to 2000 MW during initially planned shutdown was not restricted to 2000 MW by POSOCO in the extended shutdown though the system had faced a 'near miss' situation on 29 July 2012. TTC was not reviewed on WR-NR corridor on 30 July 2012 which led to scheduling of power by Regional Load Dispatch Centres (RLDCs) beyond the capacity of system. Over scheduling coupled with over-drawals by NR beneficiaries and under-drawals/over-injection by WR beneficiaries/generators overloaded the system beyond control, which ultimately led to 'cascade tripping' of alternate paths. WRLDC did not instruct WR generators to back down power generation and did not convey effective instructions to beneficiaries to reduce under drawal of power, which was a major cause for GD. Beneficiaries/generators in NR and WR did not comply with RLDCs' instructions which contributed to over- loading of lines.

(Para 7.4.1 and 7.4.2)

Systemic issues such as absence of early warning mechanism by way of declaration of emergency status, fragile interconnection of NR with connecting regions due to skewed *inter-se* distribution of power flow among the links, heavy volume of Unscheduled Interchange (UI) flows due to commercial consideration, demand-supply gap and inter-play between UI and congestion mitigation measures also contributed to GDs in July 2012.

(Para 7.4.5)

Works and Procurement Policy of PGCIL (WPPP) limits the exercise of detailed survey of transmission line route to forest stretches only, contrary to advice of Working Group on Power constituted by Planning Commission which suggested that detailed survey should be carried out before start of procurement process. PGCIL, however, as a practice did not conduct detailed surveys of forest stretches also before preparation of Bill of quantity and cost estimates, as stipulated in the WPPP. In test checked 20 projects, actual length of 17 transmission lines in 12 projects had variations as compared to line length considered in the Feasibility Report. The difference in length in two cases was between 10-25 *per cent,* in three cases it was between 25-50 *per cent* and in one case it was more than 50 *per cent*.

(Para 5.1)

Out of 20 transmission projects selected for Audit, only one project was completed within scheduled time and delay was above 20 months in nine projects. Main reasons for delays in execution of the above projects were delay in acquisition of land, delay in handing over site and approved drawings to contractors, delay in release of advance to contractors, delay in forest clearance which were possible to have been controlled by PGCIL with more effective planning and monitoring. PGCIL also lost the opportunity of earning ₹350.28 crore during the project life towards additional return on equity, which could have been earned in terms of CERC Regulations, for commissioning of projects within the prescribed timeline in case of projects approved after 1 April 2009.

(Para 6.3)

Monitoring mechanism for implementation of transmission projects, though in place, needed further strengthening as project review meetings were not held as per the prescribed frequency of once in two months. Against 30 meetings required to be held during 2007-12, meetings ranging between three and twelve were held in various regions. Minutes of the pre award meetings as well as follow up action on the decisions taken in the previous meetings were not recorded.

(Para 8.1 and 8.2)

Between 2004-05 and 2012-13, PGCIL received ₹ 906.49 crore as part of Short Term Open Access (STOA) charges that were required to be used for building new transmission systems as per regulations and orders of CERC. However, PGCIL did not maintain project-wise details of transmission schemes where these STOA charges were utilized, with the result that capital cost of new transmission systems/schemes were not reduced.

(Para 5.2)

Recommendations

Based on the audit findings discussed in the report, the following recommendations are made to facilitate improvement in the planning, implementation of transmission projects and management of Grid:-

(i) CEA and PGCIL may enhance capacity of inter-regional corridors appropriately based on analysis of data regarding power transfer requirements between regions to fully achieve the objective of formation of 'National Grid'.

(ii) PGCIL may disclose and monitor the key parameter of TTC in the long and medium term as per CERC regulations and for better appreciation of the transfer capability of the system.

(iii) MOP may evolve norms for assessing efficiency of transmission network and loss reduction in accordance with the tariff policy.

(iv) POSOCO may study the possibility of developing a system for offering un-requisitioned inter-regional transfer capability to needy users and consider making a proposal in this regard before CERC.

(v) To expedite project execution, PGCIL may initiate advance action to conduct detailed survey of forest stretches and submit forest clearance proposals before investment approval of the project.

(vi) Since long shut down to carry out construction work was the starting point for two major GDs, POSOCO may stipulate tolerance limits for antecedent line loadings and 'no-go' periods for key corridors for allowing long shut downs to prevent GDs. POSOCO may also consider taking up with CERC an appropriate warning system that specifies responsibility centres that would be tasked with informing constituents about state of emergency of the system.

(vii) In order to improve diligence in declaring TTC and scheduling power, POSOCO may critically review the existing practices in this regard to ensure secure grid operation.

MOP was generally in agreement with the audit recommendations.

CHAPTER - 1

Introduction

1.1 Background

Inter-state and intra-state transmission systems are interconnected and together constitute the electricity grid. In 1963, India was divided into five regions[1] with a view to integrating State power systems in each region and promoting the concept of regional power development through integrated power systems transcending State boundaries. In 1984, a working group constituted by Government of India (GOI) for development of a national grid, recommended formation of a separate Central Sector corporation for manning, constructing, operating and maintaining transmission facilities. A major objective of this decision was to reduce operational and commercial problems which had resulted from ownership of transmission facilities by various central generating organisations and joint ventures. Another major objective was to achieve improved integrated operation of regional transmission systems.

1.2 Profile of Power Grid Corporation of India Limited

In the above background, Power Grid Corporation of India Limited (PGCIL) was established in 1989[2] to implement the decision (August 1989) of GOI to form a 'National Grid' with the following main responsibilities:

- to plan, promote and build an integrated and efficient power transmission network in all aspects including investigation, planning, engineering and design;
- to prepare preliminary feasibility and detailed project reports;
- to construct, own, operate and maintain transmission lines, sub-stations, load despatching and communication facilities and appurtenant work;
- wheeling of power generated at various power stations in accordance with the policies and objectives laid down by GOI from time to time; and
- keeping abreast of technology development in transmission, load despatching and communication system.

Accordingly, PGCIL took over (April 1991 to August 1993) transmission assets from seven Central Generating Companies[3] and also took control of existing five[4] Regional Load Despatch Centres (RLDC) in the country between 1994 and 1996. PGCIL was notified (December 1998) as the Central Transmission Utility (CTU) by GOI and is mandated under the Electricity Act, 2003 to, *inter-alia.* ensure development of an efficient, co-ordinated and economical system of inter-state transmission lines for smooth flow of electricity from generating stations to load centers.

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[1] *Northern Region (NR), Western Region (WR), Eastern Region (ER), Southern Region (SR) and North Eastern Region (NER)*

[2] *PGCIL was incorporated as a Government Company on 23 October 1989.*

[3] *NTPC Ltd., NHPC Ltd., North Eastern Power Corporation Ltd., SJVN Ltd. (earlier known as Nathpa-Jhakri Power Corporation Limited), Neyveli Lignite Corporation Limited, Nuclear Power Corporation Limited and THDC India Ltd.*

[4] *Northern Regional Load Despatch Centre, Southern Regional Load Despatch Centre, Western Regional Load Despatch Centre, Eastern Regional Load Despatch Centre and North Eastern Regional Load Despatch Centre.*

PGCIL was conferred Miniratna[5] (Category-I) status by GOI in October 1998 and thereafter Navratna[6] status in May 2008. As on 31 March 2013, PGCIL had paid up capital of ₹4629.73 crore, of which 69.42 *per cent* was held by GOI and balance equity was held by others[7]. After a 'Follow on Public Offer' in December 2013, the paid up capital of PGCIL increased to ₹5231.59 crore, of which 57.90 *per cent* was held by GOI and balance equity was held by others. Equity shares of PGCIL were listed on National Stock Exchange (NSE) and Bombay Stock Exchange (BSE) on 05 October 2007.

1.3 Profile of Power System Operation Corporation Limited

As envisaged in the Electricity Act, 2003, National Load Despatch Centre (NLDC) was established (February 2009) as an apex body to ensure integrated operation of 'National Grid'. Till 30 September 2010, RLDCs and NLDC were being operated by PGCIL and from 01 October 2010, a separate company named Power System Operation Corporation Limited (POSOCO), incorporated on 20 March 2009 as a wholly owned subsidiary of PGCIL, took over the operations of RLDCs and NLDC.

POSOCO was to act as the apex organization to ensure integrated operation of power system including to own, operate and maintain NLDC and RLDCs and ensure optimum scheduling and despatch of electricity in accordance with the Electricity Act 2003, regulations laid down by Central Electricity Regulatory Commission (CERC) and Indian Electricity Grid Code. POSOCO is primarily a knowledge based organization. The assets of RLDCs and NLDC comprise of Supervisory Control and Data Acquisition (SCADA) and IT systems for operation of Regional Grids and the National Grid.

1.4 Physical performance of PGCIL

The physical performance of PGCIL during the period of last six years ended 31 March 2013 are given in Table 1.1.

Table 1.1

Physical performance of PGCIL

Particulars/Years	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13
Length of transmission lines (in ckm) at year end	67,000	71,500	75,290	82,355	92,981	1,00,200
Number of sub-stations at year end	111	120	124	135	150	167
Transformation capacity (in MVA) at year end	73,000	79,500	83,100	93,050	1,24,525	1,64,763
Transmission Network Availability (*per cent*)	99.65	99.55	99.77	99.80	99.94	99.90
Power transmitted on PGCIL Network (MUs)	3,28,709	3,34,013	3,63,723	4,00,596	4,30,992	4,50,027

ckm: circuit kilometre, MVA: Mega Volt Ampere, MUs: Million Units

[5] ***Which provided powers to the Board of the Company to undertake new projects, modernisation, purchase of equipment, etc up to ₹300 crore or equal to their net worth which ever is lower without approval of GOI.***

[6] ***Which provided powers to the Board of the Company to undertake new transmission projects of any amount without approval of GOI***

[7] ***Foreign Institutional Investors: 14.09 per cent, Indian Public: 4.13 per cent, Body Corporates: 4.14 per cent, Mutual Funds: 2.38 per cent, Bank & Financial Institutions: 5.40 per cent and Others: 0.44 per cent.***

1.5 Roles of PGCIL and POSOCO

Transmission system projects are conceived based on requirements assessed by PGCIL in consultation with Central Electricity Authority (CEA), power generators, beneficiaries, regulators and other utilities. PGCIL carries out the work of planning, execution, operation and maintenance of the inter-state transmission system projects for evacuation of Central Sector power generation, within and across regions. POSOCO manages the grid including supervision and control of inter-state transmission systems for grid control and despatch of electricity within regions and country through secure and economic operation of regional grids. It also monitors and regulates operation of grids carrying out all such functions required as an interface with power exchanges as may be related to the business of POSOCO.

1.6 Performance Audit

Transmission facilitates better utilisation of available power generation resources. Inadequacies in transmission network and delay in commissioning of the transmission system may not only result in loss of revenue to PGCIL but may lead to congestion in evacuation of power. Creating lines of higher capacity than required or abnormal redundancies in transmission assets may result in extra financial burden on beneficiaries[8] and public at large.

Keeping in view the above, a performance audit was taken up with defined audit objectives (detailed in Chapter 2) to assess the effectiveness of planning and implementation of transmission projects executed by PGCIL during 2007-2012. Besides, an attempt has been made to assess the efficiency and effectiveness of Grid Management (Chapter 7) by POSOCO/ PGCIL in ensuring uninterrupted power supply, including Grid Security and Grid Monitoring.

[8] *State Discoms*

CHAPTER - 2

Audit Framework

2.1 Scope of Audit

The performance audit covers all activities from conceptualisation to implementation of selected major transmission projects executed by PGCIL between April 2007 and March 2012 along with the status of augmentation to the transmission network made by PGCIL up to March 2013. In the wake of the incident of Grid disturbance on 30 and 31 July 2012, the aspect of Grid management by POSOCO, which is mandated with the responsibility to ensure integrated operation of the national grid, was also included in the scope of audit.

2.2 Audit objectives

Audit objectives of the performance audit were to assess whether: (i) projects were conceptualised and identified properly, expeditiously and in consultation with all related parties; (ii) the system of procurement of goods and services was economic, efficient and effective; (iii) projects were executed economically, efficiently and effectively; and (iv) proper system existed for ensuring effective and efficient Grid management including Grid Security and Grid Monitoring.

2.3 Audit criteria

Audit criteria adopted for the performance audit included: (i) Electricity Act, 2003; (ii) National Electricity Policy, 2005; (iii) Regulations issued by the Central Electricity Regulatory Commission (CERC) relating to transmission and grid management including Indian Electricity Grid Code (IEGC); (iv) CEA's Technical Standards; (v) CEA Transmission planning criteria; (vi) National Electricity Plan; (vii) CEA Reports including Load Generation Balance Review; (viii) XI and XII Plan documents and Mid-term Appraisal of XI Plan; (ix) Report of the Working Group on Power for XI[9] Plan; (x) Memorandum of Understanding signed by PGCIL with Ministry of Power (MOP); (xi) Works & Procurement Policy and Procedure (WPPP) of PGCIL; (xii) Feasibility Reports and Detailed Project Reports of selected transmission projects in the audit sample; (xiii) Minutes of meetings of Standing Committee for power system planning, Regional Power Committees (RPC), Board of Directors (BOD) of PGCIL, Project Sub-Committee and other Board level committees of PGCIL, Project Review Meetings and meetings with contractors, vendors, sub-vendors; (xiv) Bidding Documents and evaluation reports; (xv) Reports of Grid Disturbances (GD) of 30 and 31 July 2012 by PGCIL and POSOCO submitted to CERC, Record of Proceedings before CERC and CERC Order dated 22 February 2014 on GD[10]; (xvi) Report of the Expert Committee constituted by MOP to investigate GDs of July 2012; (xvii) Report of the US-Canada Power System Outage Task

[9] ***Working Group on power was constituted by Planning Commission in April 2006 to formulate power programme for XI Plan with Secretary (Power) as Chairman of the Working Group and Member (Planning) of CEA as Member Secretary.***

[10] ***Accessed from website of CERC***

Force on the blackout of August 2003; (xviii) Manuals and operating procedures formulated by POSOCO; (xix) Operational and other feedback sent by POSOCO to CEA and PGCIL; and (xx) Published papers by power system experts.

2.4 Audit Methodology

An entry conference was held with the Management of PGCIL on 24 July 2012, wherein scope, objectives, audit criteria and audit sample were discussed. A meeting was also held on 9 November 2012 with the Managements of PGCIL and POSOCO apprising them of coverage of the aspect of Grid Management in the performance audit. Relevant records in PGCIL and POSOCO were examined and discussions held with the senior management from time to time during August 2012 to August 2013 for firming up audit conclusions. The draft performance audit report was issued to Managements of PGCIL and POSOCO for their comments on 18 January 2013. The draft report was updated after considering replies of PGCIL and POSOCO and revised (November–December 2013) based on further examination, especially of various aspects of Grid Management. As the draft report covered various technical issues, extensive discussions were held by Audit from time to time with the senior management of PGCIL and POSOCO to firm up audit observations and conclusions. The draft report was issued to MOP on 7 January 2014. A Pre-exit Conference was held with the managements of PGCIL and POSOCO on 12 February 2014 wherein audit findings and conclusions were discussed. After receipt of MOP's reply dated 31 March 2014, to the draft Report, an Exit Conference was held with MOP and managements of PGCIL and POSOCO on 15 April 2014. Representatives from CERC and CEA also attended the Exit conference wherein audit findings and suggestions for improvement proposed in the draft report were discussed. MOP's views on the recommendations contained in the draft report were also obtained during the meeting and duly incorporated in this report.

2.5 Audit Sample

A representative sample of 20 transmission projects representing 14 *per cent* in terms of number and 37 *per cent* in terms of value of the projects planned and executed by PGCIL during April 2007 and March 2012, as detailed in ***Annexure-2.1,*** was taken based on materiality and coverage of all Regional Offices of PGCIL. All 424 contracts pertaining to above selected 20 projects awarded up to March 2012 by the corporate office of PGCIL were examined. Besides, a representative sample of 10 *per cent* of the contracts locally awarded by the concerned Regional Offices in connection with execution of above 20 projects was also selected for examination on the basis of materiality[11]. Further, relevant records pertaining to Grid Management including Grid Security and Grid Monitoring for the period April 2007 to March 2014 were also examined in POSOCO and corporate office of PGCIL.

2.6 Audit findings

Audit findings are discussed in subsequent chapters under the following headings:

Chapter 3: Planning and Project Conceptualisation

Chapter 4: Targets and achievements

[11] ***Top 10 per cent contracts in terms of value (60 contracts)***

Chapter 5: Investment Approval and Project Funding

Chapter-6: Project Implementation and Execution

Chapter-7: Grid Management

Chapter 8: Monitoring system

Chapter 9**:** Conclusion and Recommendations

2.7 Acknowledgment

The cooperation extended by MOP and Managements of PGCIL as well as POSOCO in facilitating smooth conduct of performance audit is appreciated and acknowledged.

CHAPTER 3

Planning and Project Conceptualisation

3.1 Planning of transmission projects by PGCIL

PGCIL is responsible for planning of inter-state transmission projects and these projects fall under the following two categories:

(i) Projects connected with evacuation of power from Central sector generating stations and

(ii) Projects connected with strengthening of power system network.

The proposal for a new transmission project is technically approved by the Standing Committee for Power System Planning (SCPSP)[12] of the concerned regions. Further, each region has a separate committee called Regional Power Committee (RPC)[13] which approves these projects from commercial point of view. Once the project is approved by RPC, it becomes a part of Bulk Power Transmission Agreement (BPTA) and beneficiaries are liable to pay transmission charges to PGCIL. After approval of the project by the concerned Regional SCPSP, PGCIL initiates action for obtaining investment approval, clearances and procurement activities.

Records relating to conceptualisation and planning of 20 selected transmission projects taken up for implementation during April 2007 to March 2012 along with the status of augmentation to the transmission network made by PGCIL up to March 2013 were examined in audit. Results of the examination are given in subsequent paras.

3.1.1 Progress in the formation of National Grid

One of the major objectives of formation of PGCIL was to bring about integrated operation of the regional transmission systems by undertaking construction of inter-regional links. This was to facilitate the growth of economic exchange of power (replacing costly[14] energy transactions within a region with cheaper ones from another region so that cost of power is reduced) which would ultimately lead to the formation of a national grid and ensure better utilisation of available generation resources. Electricity Act, 2003 envisaged 'open access'[15] in transmission to promote competition amongst the generating companies which could sell electricity to different distribution licensees across the country, leading to availability of cheaper

[12] ***SCPSP for each region is constituted by CEA for carrying out its duties of integrated planning under section 73 (a) of the Electricity Act, 2003. These committees are headed by Member CEA and State Transmission Utilities, Central Transmission Utilities, Central Generating Units (CGUs), etc. are members. SCPSP provides technical approval to the projects.***

[13] ***This Committee is chaired by heads of state utilities on rotational basis and CEA, State Transmission Utilities, Central sector generating units, CTU, Load Despatch Centres, traders and Discoms, etc. are its members.***

[14] ***Cost of energy varies according to type of fuel, age of the plant, whether cost plus project or tariff based project, etc.***

[15] ***As per definition given in the Electricity Act, 2003, Open access means non-discriminatory provision for use of transmission lines or distribution system or associated facilities with such lines or system by any licensee or consumer or a person engaged in generation in accordance with the regulations specified by the Appropriate Commission.***

power. National Electricity Policy 2005 envisaged that network expansion should be planned and implemented keeping in view anticipated transmission needs that would be incident on the system in the open access regime.

The process of integration of regional grids through construction of inter-regional links began in the 1990s, initially with High Voltage Direct Current (HVDC) links and later through synchronous interconnections[16]. Southern Region remained interconnected to the rest of the country through 4000 MW of HVDC links till it was synchronously connected through Raichur-Sholapur 765 kV single circuit on 31 December 2013 completing the technical process of formation of 'National Grid'.

Though the technical process of formation of 'National Grid' can be regarded as complete, when viewed in terms of overall inter-regional power transfer capability, the objective of formation of 'National Grid' remains to be achieved (April 2014) as explained below:

(i) Actual power flows exceeded transfer capability of four corridors in 16 months during 2009-13 as detailed in Table 3.1 indicating that the capability of these corridors was inadequate to handle the increasing demands of power exchanges amongst these regions.

Table 3.1

Instances of actual power flows in excess of Total Transfer Capability

Corridor	Month	TTC (in MW)	Actual Flow (in MW)
WR-NR	September 2009	1500	1523
	October 2009	1500	1653
	January 2010	1500	1630
	July 2011	1900	2291
	January 2013	1700	2004
WR-SR	April 2011	800	913
	July 2011	800	901
	October 2011	800	911
	July 2012	800	880
	August 2012	800	909
	September 2012	800	881
	October 2012	800	921
	November 2012	800	896
	December 2012	800	814
ER-SR	March 2011	2330	2431
	April 2011	2330	2382
	December 2011	2120	2186
ER-NER	January 2010	200	233
	March 2013	400	422

[16] *HVDC links are point to point lines through which flow of electricity can be regulated by system operators. Synchronous interconnections on the other hand are Alternating Current (AC) links, through which power flow happens as per the laws of physics. ER and NER were synchronously interconnected first, followed by WR and NR.*

(ii) In 24 years of its operation (till 31.3.2013), PGCIL built 45 inter-regional transmission lines (220 kV and above), connecting five regions, which works out to 1.2 *per cent*[17] of total lines (220 kV and above) in the inter-state transmission grid. Further, four out of six inter-regional corridors (WR-NR, WR-ER, ER-NER and WR-SR) were capable of carrying only 1.5 *per cent* to 3 *per cent* of installed power generating capacity in respective power surplus regions ***(Annexure 3.1)***.

When the issue of adequacy of inter-regional capability was discussed in the Exit Conference (April 2014), it transpired that there were no specific norms to assess adequacy of inter-regional capability with reference to operating requirements. However, MOP had reservations about using installed capacity as a benchmark for assessment of adequacy of transmission capacity of inter-regional corridors. It is, however, pertinent to note in this connection, that the European council as per their Ten year Transmission Network Development Plan 2012, had proposed a criterion for interconnection development, asking Member States a minimum import capacity level equivalent to 10 *per cent* of their installed production. Thus, comparison of adequacy of transmission system with reference to installed generation capacity would appear to be an international good practice. Capital investment made by PGCIL in eleven inter-regional links commissioned during XI plan was ₹ 4287 crore (7.7 *per cent* of the total capital investment of PGCIL in XI Plan) while capital investment in intra regional links was ₹ 51043 crore (92.3 *per cent* of total capital investment of PGCIL in XI plan). Thus, efforts of PGCIL in XI Plan were directed more towards strengthening intra regional network as compared to inter regional linkage.

(iii) POSOCO expected the present achievement of linkage of SR with National Grid to be operated as a weak link in the initial few years, as PGCIL was required to commission twenty elements in WR and SR before import of power by SR could be scheduled across the new Raichur-Sholapur link. Further, synchronous interconnection was achieved by PGCIL through a single circuit while the second circuit of Raichur-Sholapur line which is important for safe and secure operation of interconnected grid was yet (March 2014) to be commissioned by an independent transmission project developer selected through tariff based bidding by REC Transmission projects Limited, a subsidiary of Rural Electrification Corporation Limited (REC).

Low level of inter-regional transfer capability implies limited scope for transfer of power among regions. Hence the objectives for formation of National Grid *i.e.* meeting deficit from surplus region and facilitating economic exchanges remained largely unfulfilled**.**

MOP stated (March 2014) that National Grid was not restricted to links that were crossing regional boundaries but covered up-stream and downstream network as well; total transmission lines under inter-state increased from 22000 ckm in 1992-93 to more than 105000 ckm in January 2014; Inter-regional power exchange takes place on account of supply-demand

[17] ***Total lines – 3743; Inter-regional – 45 (765 kV, 400 kV and 220 kV)***

gap in inter-connected regions and are planned as per projected transfers; at present there is no congestion in long term power exchange but in certain scenario, congestion may occur under medium and short term depending upon quantum, period and duration of requirement; National grid development is a continuous process and shall keep pace with power sector development.

The reply is to be viewed against the following facts:

(i) According to note of MOP (August 1989) to Cabinet for setting up of PGCIL, the role of PGCIL is not limited to serving projected demand-supply gap but also to facilitate economic exchanges across the country and ensure better utilization of available generation resources. This is possible only if regional grids are adequately 'meshed' and integrated which is yet to be achieved as inter-regional links are still weak.

(ii) In the deliberations before the Coordination Forum[18] in August 2009, it transpired that occasional congestion indicates optimum investment in transmission while regular congestion indicates inadequacy. Analysis of power exchange data ***(Annexure 3.2)*** of Indian Energy Exchange and Power Exchange India Limited showed that instances of percentage of time[19] congestion occurred above 75 *per cent* increased from two months in 2010-11 to all 12 months in 2012-13. Similarly, volume of electricity that could not be cleared due to congestion (as a percentage of the actually cleared volume), in Power Exchange India Limited went above 75 *per cent* for 3 months in 2011-12 and increased to five months in 2012-13.

(iii) Impact of congestion and inadequacies of transmission networks is visible in large variations in the electricity prices over regions. Comparison of Market Clearing Price (MCP *i.e.* clearing price for cleared transactions in the whole country, if there is no congestion at all) with the Area Clearing Prices[20] in Indian Energy Exchange ***(Annexure 3.2)*** showed that buyers in S1 and S2 bid areas (States of Tamil Nadu, Kerala, Andhra Pradesh, Karnataka, Goa and Union Territory of Pondicherry) paid higher price during the last two years (₹ 5.1 to ₹ 7.3 per unit as against MCP of ₹3.5 per unit) to procure power. On the other hand, sellers in W3, E1 and E2 bid areas (Chhattisgarh, Orissa, West Bengal, Sikkim, Bihar and Jharkhand) received lower price (₹ 2.8-2.9 per unit as against MCP of ₹ 3.5 per unit) due to transmission contraints. These trends indicate the need for strengthening WR-SR and ER-SR links (W3, E1, E2 to S1 and S2 *i.e.* generation

[18] ***Coordination forum was constituted by MOP in February 2008 under Section 166 (1) of the Electricity Act, 2003 for smooth and coordinated development of power system in the country. The forum is chaired by Chairman, CERC and inter-alia had the following members- Chairperson CEA, Member (Power Systems) of CEA, Members of CERC, CEO of CTU, representatives from generating companies, both PSEs and private. Additional Secretary/Joint Secretary, MOP is the member convenor. The Coordination Forum held its last meeting in March 2010.***

[19] ***Number of hours congestion occurred/ Total number of hours in a month.***

[20] ***The country is divided into 12 bid areas (IEX) for power exchange transactions. The criterion for defining these areas is the location of the physical constraints in the structure of transmission network, including national and/or control area borders. In case of congestion across a transmission corridor, the net sale of upstream areas will not flow to downstream deficit areas. The cleared prices in all areas i.e. Area Clearing Prices are adjusted so that the flow of power across transmission corridor is same as available transfer capability.***

surplus to power deficient states). However, comparison with inter-regional corridors augmentation plans for the XII Plan ***(Annexure 3.3)*** revealed that no links were planned for the ER-SR corridor and 6400 MW only has been planned for WR-SR corridor (16 *per cent* of total inter-regional augmentation of 40500 MW).

(iv) As regards the argument that there is no congestion in long term power exchange, there is zero margin (WR-SR) /negligible margins (ER-SR, WR-NR)[21] as of March 2014 in three out of six inter-regional corridors over and above the capability required to cater to long term customers. Allocation of 276.83 MW power from Indira Gandhi Super Thermal Power Station, Jhajjar, Haryana to Andhra Pradesh made by MOP (customers receiving allocation from Central Sector Generating Stations are long term customers in terms of CERC Regulations of August 2009) had to be kept in abeyance (May 2014) due to the absence of available margins in May 2014. This indicated that transmission constraints were being faced by long term customers also.

Thus, though technically the 'National Grid' had come into existence with the synchronous inter-connection of SR with WR on 31 December 2013, there is a need and scope for making the inter-connections robust enough by augmenting inter regional power transfer capability to fully achieve the objectives of formation of National Grid.

3.1.2 Planning of capacity addition of inter-regional transmission corridors without giving due regard to increase in their power transfer capability

Two parameters *viz*. Transmission Capacity and Transfer Capability are relevant for assessing the capacity of inter-regional corridors. Transmission capacity of a corridor is arrived at by adding the ratings of all transmission lines connecting two regions. Transfer capability on the other hand, is the measure of the ability of the corridor, as a whole, to reliably move power from one region to another. Transfer capability is often less than the transmission capacity in view of system limitations and strength of the weakest link in the corridor. While transmission capacity is decided by physical characteristics of components and is static in nature, transfer capability is assessed by system operators considering system conditions such as generation, customer demand *etc* and is dynamic. For example, WR-NR corridor has nine lines and the sum of the physical ratings comes to 4220 MW which is denoted as its transmission capacity whereas the transfer capability of the corridor was 2000 MW (2011-12). A part of the Transfer Capability is kept as a 'Reliability margin' to handle contingencies and errors in assumptions and the balance capability, called Available Transfer Capability (ATC) is offered for scheduled power flows.

NLDC assesses the Total Transfer Capability -TTC (full capability including reliability margin) of 12 inter-regional corridors (considering power flow in both the directions across the six corridors i.e. WR-NR, NR-WR and so on) based on off-line simulation studies and real

[21] ***ER-SR margin was 93 MW in March 2014 (00 to 05 hours and 10-19 hours) and WR-NR margin was 219 MW in March 2014.***

time data. TTC so arrived at is declared on the web sites of RLDCs and NLDC for information of users who may enter into contracts for transfer of power, apply for grant of open access, *etc*. Thus, TTC is a significant factor that should be considered to assess the needs of augmentation of inter-regional capacity. However, PGCIL assesses the need for augmentation of capacity of inter-regional corridors based only on 'Transmission capacity' and does not monitor augmentation of TTC. While NLDC declares TTC in short time horizon (three months and below), such declaration in the long run was not being done by PGCIL though it was required to do so as per 'Procedure for making application for Grant of long term access and medium term open access to Inter state transmission systems' approved by CERC.

PGCIL increased (2007-12) the transmission capacity of inter-regional transmission corridors by 13900 MW. However, TTC increased from 9400 MW in 2008-09 to only 11530 MW in 2011-12. During 2011-12, TTC decreased by 750 MW as compared to that in 2010-11 (reduction in ER-SR by 350 MW, ER-NR by 100 MW, ER-NER by 100 MW and WR-ER by 200 MW).

Further, in the Annual Report for 2011-12, PGCIL indicated that cumulative inter-regional power transfer capacity of National Grid was 28000 MW. However, this being equal to summation of ratings of all transmission lines, was basically transmission capacity as against the actual power transfer capability denoted by TTC which was 11530 MW as detailed in Table 3.2 given below.

Table 3.2

TTC and transmission capacity of inter regional corridors

Corridor	Transmission Capacity (As on 31.3.2012)	TTC (Highest during 2011-12)	%age of TTC to Transmission capacity	Capital Investment made in XI Plan (`₹ in crore)	%age of Total Investment
WR-NR	4220	2000	47	465	11
WR-ER	4390	1000	23	1009	24
ER-NER	1260	500	40	-	-
WR-SR	1520	1000	66 *	-	-
ER-NR	10030	4200	42	2706	63
ER-SR	3630	2830	78 *	106	2
Total	**25050 #**	**11530**		**4286**	**100**

In addition to 25050 MW comprising of 220 kV and above lines, 132 kV lines also exist along various inter-regional corridors.

* Higher TTC due to HVDC links through which power flows can be regulated.

It can be seen that TTC as a percentage of transmission capacity was less than 50 in four out of six inter-regional corridors and was less than 30 *per cent* in case of WR-ER. Thus, for better appreciation of ability of transmission network to transfer power across regions it would be a useful good practice if TTC is also declared and disclosed alongwith transmission capacity.

MOP did not offer any remarks regarding non-declaration of TTC by PGCIL in the long and medium term. However, it was contended in the Exit Conference (April 2014) that non-materialisation of assumed facilities hampered the loadability and hence TTC at a given instant might not match with the planned figure. Further POSOCO added in the Exit conference that even in Europe when the transmission capacity was of the order of 1000 MW, TTC was of the order of 60-70 per cent and when the transmission capacity increased in the range of 10000-20000 MW, TTC reduced drastically to the order of 20 to 30 per cent.

The reply is to be viewed against the fact that TTC does not increase commensurately with the increase in transmission capacity. It is thus essential to monitor and declare it in the long run as per the requirements of CERC regulations. This view was also held by POSOCO in their comments on draft National Electricity Plan to CEA when they emphasised (May 2012) that quantifying growth of transmission capacity in terms of inter regional capacity was an inadequate index of performance. POSOCO added that it was the transfer capability across regions that was important.

3.1.3 Development of inter-regional corridors

The bulk of the inter-regional augmentation efforts achieved in XI Plan and planned for XII Plan have been across the ER-NR and ER-WR corridors to wheel power from the pit-head power plants in the coal rich ER to the demand centers in the north and the west. Similarly there were plans to build a network in the 'chicken neck'[22] area of NER so that the hydro potential of NER could be tapped and power could be brought to NR and WR through NER-ER-WR corridors. 63 *per cent* of total inter-regional transmission capacity of 25050 MW[23](cumulative at the end of XI Plan) was concentrated along these corridors. (***Annexure 3.3)***. Audit examination revealed the following:

(i) Significance of short-tie *vis a vis* long-tie for import of power by NR

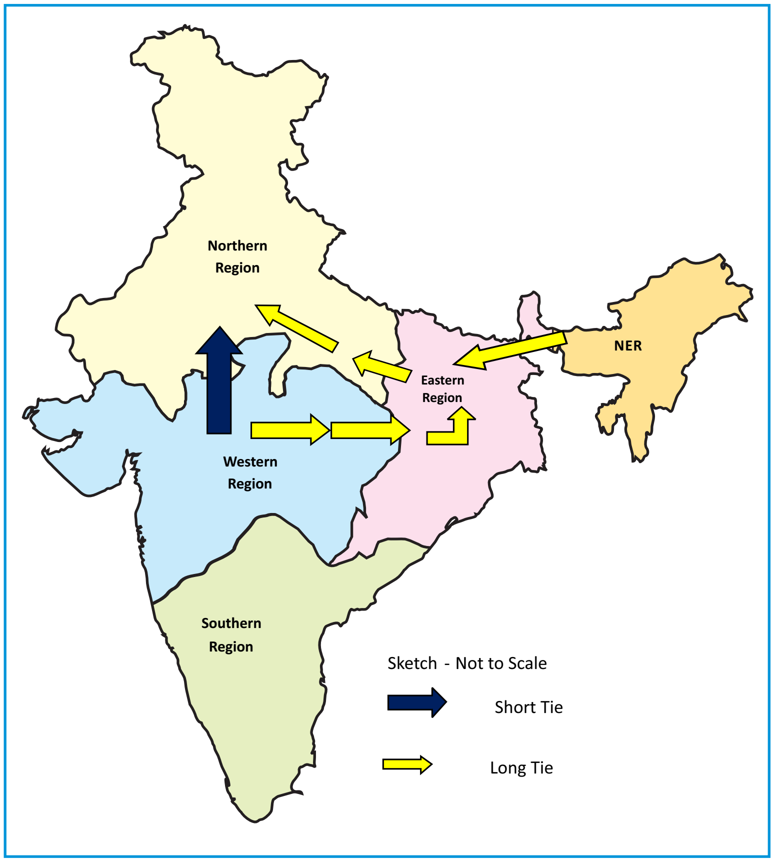
Offline simulation studies conducted by an Expert Group constituted by MOP following the two major Grid disturbances of 30 and 31 July 2012 had shown that the WR-NR link was the 'short tie' (Transmission link shorter in length and tying/connecting two regions) for import of power by NR and in the case of loss of the short tie, the longer tie of WR-ER-NR could also be lost due to angular separation and power swings[24]. This meant that import by NR was dependent on the transfer capability of the 'short tie' rather than that of the 'long tie' (depicted

[22] *Formally, Siliguri Corridor, a narrow strip of territory connecting north eastern states to the rest of India.*

[23] *Transmission capacity i.e. summation of ratings of individual lines.*

[24] *The rotors of generators connected to the grid run at the same electrical speed and in case of small disturbances affecting the speed, restorative forces bring back the rotors to the same speed. However, for large disturbances, the restorative forces may be unable to bring all the generators to the same speed. If this happens, the angular difference between the generators goes on increasing (Angular separation) which causes large variations in voltage and power flow in lines.*

in map given below). Hence high level of augmentation of the longer tie *i.e*. ER-NR, ER-WR and NER-ER-WR without appropriate augmentation in WR–NR would not yield desired results for transmission of increased power to NR.



Thus, due consideration was required to be given to aspects relating to angular separation and power swings while planning inter linkages of various regions.

MOP stated (March 2014) that the issues of angular separation and power swings were considered as along with Agra-Gwalior double circuit link (765 kV charged at 400 kV) another double circuit viz. 400 kV Zerda-Kankroli was also planned. MOP added that to address the issue, three additional links[25] were planned in the WR-NR corridor which were in different stages of implementation.

The reply is to be viewed against the fact that though Agra-Gwalior and Zerda-Kankroli were both of 400 kV, the power flow handled by the former was 72 *per cent* of the entire WR-NR flows while the latter could take only 9.47 *per cent* of flow (during 2011-12).Thus, power flows through the backup system did not materialise as planned. Further TTC of WR-ER (1000 MW) was only half of TTC of WR-NR (2000 MW) with the result that once the WR-NR tie was lost, sufficient capacity was not available in WR-ER route for required power flows. As regards additional links in WR-NR corridor, there is a need to prioritise their implementation.

[25] ***(Gwalior –Jaipur 765 kV (2 single circuits), Champa-Kurukshetra (800 kV HVDC) and Jabalpur – Orai (765 kV double circuit).***

(ii) Impact of up gradation of link on reliability of WR-NR corridor

WR-NR corridor had faced seasonal congestion during high demand periods and actual power flows (monthly) had breached TTC of the corridor on five occasions between 2009-10 and 2012-13. Agra-Gwalior double circuit line was the trunk line of the corridor which was upgraded from 400 kV voltage level to 765 kV in March 2013. As per the advisory issued (May 2013) by POSOCO to the constituents, the upgradation created a 765 kV line in parallel with a 220 kV network without any 400 kV system in the Agra-Gwalior-Bina section of WR-NR inter-regional corridor. The impact of such a formation was that in the event of loss of both the circuits of 765 kV line, there would be a 'cascade tripping' of 220 kV network. Onset of the contingency *i.e*. tripping of one of the circuits of 765 kV Agra-Gwalior actually happened on 11 June 2013 and POSOCO had to curtail energy flows to avert a major grid disturbance.

MOP stated (March 2014) that the upgradation was planned for strengthening the WR and NR inter-connection to facilitate higher power transfer. To address reliability considerations, three additional links had been planned which were under different stages of implementation.

The reply is to be viewed against the fact that WR-NR TTC, which was enhanced from 2000 MW to 5700 MW in May 2013 following the upgradation, was rolled back in October 2013, due to reliability considerations. Thus, the upgradation to 765 kV line in the WR-NR corridor which was fraught with the risk of 'cascade tripping' as per advisory of POSOCO, worsened an already delicate nature of WR-NR interconnection {discussed in para 7.4.5 (b) titled 'Inter-connection of NR with neighbouring regions} till the new links are implemented. This is further evident from the fact that the number of instances when RLDCs/NLDC issued congestion notice for WR-NR corridor increased from five in 2012-13 to 23 in 2013-14 (till February 2014).

3.1.4 Congestion due to delayed planning and approval of transmission system for transfer of power from generation projects

PGCIL did not have a policy to firm up the time for commissioning of generation linked transmission projects. As CERC regulations on "Grant of Connectivity, Long Term Access and Medium Term Open Access" allow injection of infirm power (*i.e.* power generated by a power station prior to its date of commercial operation) for a period of six months since synchronization of the power plant, commissioning of a transmission system associated with a generation project should precede the date of commercial operation of the generating station at least by six months. However, there was delay in commissioning of transmission system[26] associated with generation projects, in the State of Odisha due to which there was congestion in evacuation of power in the State.

As an illustration, it was noticed that seven generating projects[27] in Odisha involving installed capacity of 10090 MW of Independent Power Producers (IPPs) were scheduled for

[26] ***Transmission Phase-I generation projects in Odisha Part B***

[27] ***Sterlite, GMR, Nav Bharat, Monnet, Jindal, Lanco Babandh, and Ind Bharat***

commissioning between February 2010 and December 2013. However, BOD of PGCIL approved the transmission system associated with these generating projects only in December 2010 with scheduled completion by December 2013 *i.e.* coinciding with the commissioning of the last project. The delay on the part of PGCIL to plan the transmission system resulted in congestion in evacuation of power from four units of 600 MW each of Sterlite project commissioned between October 2010 and April 2012[28]. Also one unit (350 MW) of Kamalanga TPP of M/s GMR was commissioned in March 2013 while execution of the associated transmission system by PGCIL was still in progress (April 2014).

MOP stated (March 2014) that

(i) Out of seven generation projects, only two projects have been commissioned as of January 2014. If the associated transmission system was commissioned matching with the committed schedule, the same might remain unutilised till the time the generation project actually got commissioned.

(ii) Under Section 10 of Electricity Act, 2003, it is the duty of every generating company to co-ordinate with the CTU for transmission of electricity generated by it; but the generators have submitted the LTA applications late, repeatedly revised them and also delayed signing of agreement for payment of transmission charges. Generators had not completed their dedicated lines connecting the power stations to the pooling substations, though PGCIL had commissioned the substations in March 2013.

(iii) The projects were connected to the grid through interim arrangement and the transmission corridors required for evacuation of power were planned to be commissioned progressively by December 2014.

The reply is to be viewed against the facts that:

(i) The transmission system was not ready even for two projects which were commissioned, though it is an agreed principle that transmission should precede generation.

(ii) As regards the statement that the generators had not yet built their dedicated line from the generating plant to the pooling station, it is seen that CEA and PGCIL agreed in the meeting held on 15 September 2009 to provide an interim arrangement of loop-in-loop out[29] (LILO) of an inter-regional line to provide connectivity from the plant to the pooling substation, though as per the Bulk Power Transmission Agreement signed with the generator, it was the responsibility of the generator to build the dedicated line for bringing electricity from the plant to the point of connection in the grid.

(iii) As per CEA (Technical standards for connectivity to the Grid) Regulations, 2007, when a request for connection is received, the CTU shall carry out interconnection study and

[28] ***14 October 2010, 29 December 2010, 16 August 2011 and 25 April 2012.***

[29] ***The interim arrangement was that one circuit of Rourkela-Raipur – 400 kV double circuit (inter regional) would be looped in and looped out at Sterlite power station.***

determine modifications required on the existing grids to accommodate the inter-connection. Interim connectivity through LILO was given in the above two cases, without adequacy of transmission system for evacuation of power which was causing congestion in Chhattisgarh and adjoining areas[30].

3.1.5 Sub-optimal utilization of transmission lines

Presently, transmission of electricity in India is carried mainly through a grid made up of 400 kV Alternating Current (AC) network (comprising 71505 ckm of PGCIL network). PGCIL also built 22 transmission lines (4833 ckm) of high voltage level of 765 kV mainly to augment the power transfer capability[31]. However, out of these 22 lines, 14 lines were initially charged[32] at 400 kV. PGCIL justified high capacity lines in the initial stage itself on the grounds of future hydro potential and possible Right of Way (ROW) constraints[33] that would be faced during subsequent upgradation. However, the operational status (March 2014) of the 765 kV lines revealed that two of these lines (Kishenpur - Moga I and II) remained undercharged at 400 kV level for more than thirteen years (yet to be upgraded) while four lines had remained under charged at 400 kV for more than five years. (Two of them upgraded during the last one year and two lines *viz.*, Tehri-Meerut I and II were yet to be upgraded). Two of the 765 kV lines (Satna-Bina-I and Seoni-Wardha-I) were regularly kept 'open' (taken off the grid through a switching mechanism) to control high voltage, indicating inadequate power flow through them.

The implication of charging 765 kV lines at a lower voltage level of 400 kV is that the beneficiaries, who share the capital cost incurred on these transmission lines, pay for 765 kV lines[34] though actual operation of the lines is at 400 kV. Based on benchmark cost fixed by CERC vide order dated 27 April 2010, the extra cost incurred on laying of these four 765 kV lines which are undercharged at 400 kV lines was ₹158.46[35] crore (recoverable in the tariff period of 35 years). PGCIL, however, does not suffer any revenue loss as it recovers its investment, as the 'as built' capital cost is recovered through tariff.

MOP stated (March 2014) that PGCIL constructed higher capacity lines keeping in mind future hydro generation potential and also to overcome right of way and environmental issues; CEA's Transmission planning criteria allowed adoption of higher voltage levels for final system and operating one level below in the initial stage; investment in capital cost of substations

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30 ***As per POSOCO's feedback to CEA and PGCIL on system constraints.***

31 ***765 kV line can carry over 4000 MW of power while 400 kV line can carry around 2000 MW.***

32 ***Charged means the electric circuit is closed and power is allowed to flow through the line. 'Not-charged' means the line is not connected to the grid, the circuit is kept 'open' or kept idle on air. Keeping the line 'not charged' (or charged at a lower voltage level) is resorted to because charging the line without corresponding quantum of electricity flow would lead to voltage fluctuations and resultant grid problems.***

33 ***Right of way denotes the right for placing of electric lines for transmission of electricity along the path through which such lines pass through; 765 kV transmission towers occupy more space (64-69 m) than 400 kV transmission towers (46-52m).***

34 ***Transformer and associated bays at higher voltage level are constructed later and capital cost to that extent is postponed.***

35 ***Worked out on the basis of difference in minimum cost of laying 765 kV line (₹ 60.65 lakh) and 400 kV line (₹ 43.97 lakh) per ckm with standard porcelain insulation, single circuit and Aluminium Conductor Steel Reinforced Moose. Total length of four 765 kV lines charged at 400 kV being 950 km. (i.e. ₹ 16.68 lakh (₹ 60.65 lakh less ₹ 43.97 lakh) X 950 km).***

was deferred thereby relieving tariff burden to that extent; and the undercharged lines would progressively be brought up to their full voltage level.

The fact remains that out of the useful life of 35 years of the transmission projects, there are two cases where 13 years went by just waiting for generation to come up. There may be a need to achieve a proper balance between capacity creation and operational requirement so as to ensure optimum utilisation of transmission network.

Despite a network of 1,00,200 circuit kilometres (ckm) of transmission lines in the grid (40739[36]ckm added during 1 April 2007 to 31 March 2013), PGCIL has not put in place a mechanism for assessing utilisation of transmission lines with the result that, there were pockets of congestion as explained in para 3.1.4 *supra* and areas of redundancy evident from analysis of Line Loading' of 40 of 45 interregional lines[37] in six corridors through a ratio of average power flow and maximum loadability (***Annexure 3.4).*** Average utilisation of 33 out of 40 inter-regional lines ranged between 0 to 30 *per cent* in all inter-regional corridors except WR-SR and ER-SR during 2011-12. 478 (68 *per cent*) out of 706 intra-regional lines[38] in five regions had average utilisation of 0-30 *per cent*. Utilisation was especially low in ER and NER regions.

Absence of mechanism to assess efficiency of network construction results in infirmities in system development in the form of skewed power flow across lines (WR-NR)[39], low line load factor, planning 'surprises' such as power flows in directions opposite to those envisaged while planning (ER-WR and SR-WR)[40] etc.

Regarding underutilisation of transmission lines, MOP stated (March 2014) that transmission serves a public service function and sometimes additional lines may have to be built[41] towards this objective; another aspect of public service is that after interconnection of grids, the frequency of the entire system also stabilizes.

In the Exit Conference (April 2014) also, MOP was of the view that the focus should be on availability of transmission system and not on its utilisation.

This stand is to be viewed against the provisions given in tariff policy notified by MOP in January 2006 which laid down that the overall tariff framework for transmission pricing should

[36] ***100200 Ckm (as on 31.3.2013) minus 59461 ckm (as on 31.3.2007) = 40739 ckm.***

[37] ***For which data was available.***

[38] ***For which data was available***

[39] ***In WR-NR corridor 72 per cent of power flow was through one link viz. Agra-Gwalior link***

[40] ***ER-WR corridor was planned to carry power from ER to WR in the planning horizon but in the operating horizon, the power flows were from WR to ER. Similar is the case for SR-WR interconnection***

[41] ***This has been explained though an example - The transmission in the Kashmir Valley is connected to Jammu region through two 400 kV lines and two 220 kV lines. During winters due to reduced generation at Uri hydro power station and other hydro power stations in the Kashmir valley coupled with heavy power demand due to winters, the Kashmir valley imports a substantial quantum of power from the Jammu region. There have been instances in the winter of 2007, 2012 and 2014 when due to heavy snowfall, these lines went under breakdown near the Pir Panjal mountain range leading to islanding of Kashmir valley and blackout. Due to adverse weather conditions, restoration of the transmission system is also delayed as even helicopters find it difficult to land. The Kashmir Valley faces a serious power crisis during this period leading to great discomfort amongst the public. This situation can be mitigated only if additional lines over alternate route from Samba to the Kashmir Valley is constructed.***

be such as not to inhibit planned development/augmentation of the transmission system, but should discourage non-optimal transmission investment. The policy further states that financial incentives and disincentives for Central Transmission Utility (CTU) and State Transmission utility (STU) should be implemented around key performance indicators (KPI) which would include efficient network construction, system availability and loss reduction. While norms had been laid down for system availability based on which incentives are paid to PGCIL, norms had not been evolved for assessing efficiency of transmission network construction and loss reduction which prevented an assessment of the impact of sub-optimal utilisation of transmission assets.

3.1.6 Access to transmission corridors

Transmission service provider is a key intermediary between the generator and distributor of electricity and unless access to transmission corridor is provided, generation capacity is bottled up[42]. Access to the transmission system is given to users through Long Term Access (LTA), *i.e*., for period exceeding 12 years but not exceeding 25 years or through Medium Term Open Access (MTOA), *i.e*., for periods exceeding 3 months but not exceeding 3 years[43] or through Short Term Open Access (STOA), *i.e*., for a period up to one month at one point of time. Further, as per CERC Regulations[44], the LTA customer and the MTOA customer shall have priority over STOA customer for use of the inter-state transmission system. The STOA customer shall be eligible for use of inter-state transmission system after LTA and MTOA customers by virtue of (i) inherent design margins (ii) margins available due to in-built spare transmission capacity created to cater to future load growth or generation addition, and (iii) margins available due to variation in power flows.

Examination of the extent of margins in inter-regional transmission corridors revealed that the average margins available under category (i) and (ii) above for STOA (*i.e.* margins available after considering the LTA/MTOA) were in the range of 41 to 85 *per cent* of Total Transfer Capability (TTC) across six inter-regional corridors. Based on above margins, there were rejections of STOA requests by POSOCO for purchase in NR (657.61 MW) and SR (898.58 MW) approximately during April 2007 to November 2012. Besides, PGCIL curtailed (February 2012) MTOA by 785 MW[45] in respect of 17 applications pertaining to SR, due to lack of margins.

This showed that in some corridors (WR-NR, ER-SR and WR-SR), the margins, despite appearing to be large were not sufficient during peak demand months to cater to open access demands. However, substantial quantum of allocated transfer capability remained unutilised

[42] ***Any constraint in the transmission chain from generation of power to load leads to a situation where generation has to be backed down. This is referred to as bottling of power.***

[43] ***Regulations do not envisage grant of access for period ranging from three years to 12 years.***

[44] ***Grant of LTA and MTOA is governed by CERC Regulations dated 7.8.2009 on 'Grant of Connectivity, Long-term Access and Medium-term open Access in inter-state transmission and related matters'. Grant of short term open access is governed by CERC Regulations dated 25.1.2008 (amended on 20 May 2009) regarding 'Open Access in inter-state transmission Regulations 2008'. The nodal agency for grant of LTA and MTOA is the CTU while the nodal agency for grant of STOA is RLDC.***

[45] ***Against the MTOA request of 1846.5 MW for the period 1February 2012 to 31 May 2012, MTOA granted was 1062 MW***

as the LTA/MTOA/STOA applicants who had been granted access had not utilised it while seeking scheduling of electricity ***(Annexure 3.5).*** Thus, there was a scope for POSOCO to optimally utilise variations in power flows and margins arising out of non scheduling of power by applicants to reduce rejections of STOA applications.

MOP stated (March 2014) that as per the Indian Electricity Grid Code, LTA customers had the freedom to seek schedule at one and half hour notice; considering this flexibility, corridor has to be made available for long term; in case the same was allocated for STOA or power exchange transactions assuming that the corridor would not be utilised by LTA customers, and if they later sought schedule, there would be congestion; STOA transactions would then have to curtailed; this would make STOA market highly uncertain unless the CERC laid down clear ground rules for long term customers under 'Use it or lose it' approach; POSOCO could do little for optimum utilisation without such an explicit mandate from CERC.

As the gap between access granted to customers and schedule actually availed by them appeared significant, there might be a need to evolve a system for offering such un-requisitioned capability to others who might utilise the same. As NLDC had the mandate to achieve maximum economy and efficiency in the operation of national grid, POSOCO may need to consider moving an appropriate proposal for optimum utilisation of un-availed transfer capability before CERC.

In the Exit Conference held on 15 April 2014, while MOP stated that there is a need to study the audit suggestion, CERC representative stated that they would examine the proposal, when received from POSOCO, in consultation with stake holders.

3.2 Scope for reducing time taken in planning activities

As per provisions contained in Works & Procurement Policy and Procedure (WPPP) of PGCIL, a time limit of eight weeks has been prescribed for approval of Feasibility Report (FR) by CMD after in-principle clearance from Central Electricity Authority (CEA). PGCIL, however, clarified that projects were finalized after joint studies with CEA; as such, the date of Regional Standing Committee meeting, in which project was approved, had been taken as the date of in-principle approval by CEA.

Examination of 20 selected projects in Audit revealed that against eight weeks stipulated in WPPP for obtaining internal clearance of FR from CMD, time of 11 weeks to 142 weeks was actually taken in obtaining such clearance after approval of 20 selected projects by the concerned Regional Standing Committee.

While assuring that PGCIL would put all efforts to adhere to the time limit for preparation and approval of FR/DPR, MOP stated (March 2014) that

(i) Despite CMD approval in eight weeks, there might be delay due to non-availability of RPC approval or GOI approval under Section 68.

(ii) In five out of nine system strengthening schemes, FR had been approved before either RPC/GOI approval. Excessive delay in two cases (Sasan/ Mundra Ultra Mega Power Projects and Northern regions system strengthening scheme V) was to align the same with the concerned generation projects which were getting delayed.

The reply, however, does not deny the fact that PGCIL did not adhere to the time limit for preparation and approval of DPR by CMD as prescribed in WPPP. Moreover, fulfilling its own obligations in time would have enabled PGCIL to pursue RPC and GOI for faster approvals. Further, in respect of six out of the above 20 projects, approval to FR was obtained from CMD, between 7 and 58 weeks after approval of these projects by RPC and sanction of these projects under Section 68 of the Electricity Act, 2003. The fact remains that Mundra UMPP was commissioned ahead of schedule and three units of Sasan UMPP had also been commissioned[46] but the related system strengthening transmission projects were anticipated to be commissioned in December 2014.

3.3 Submission of proposal for Forest clearance

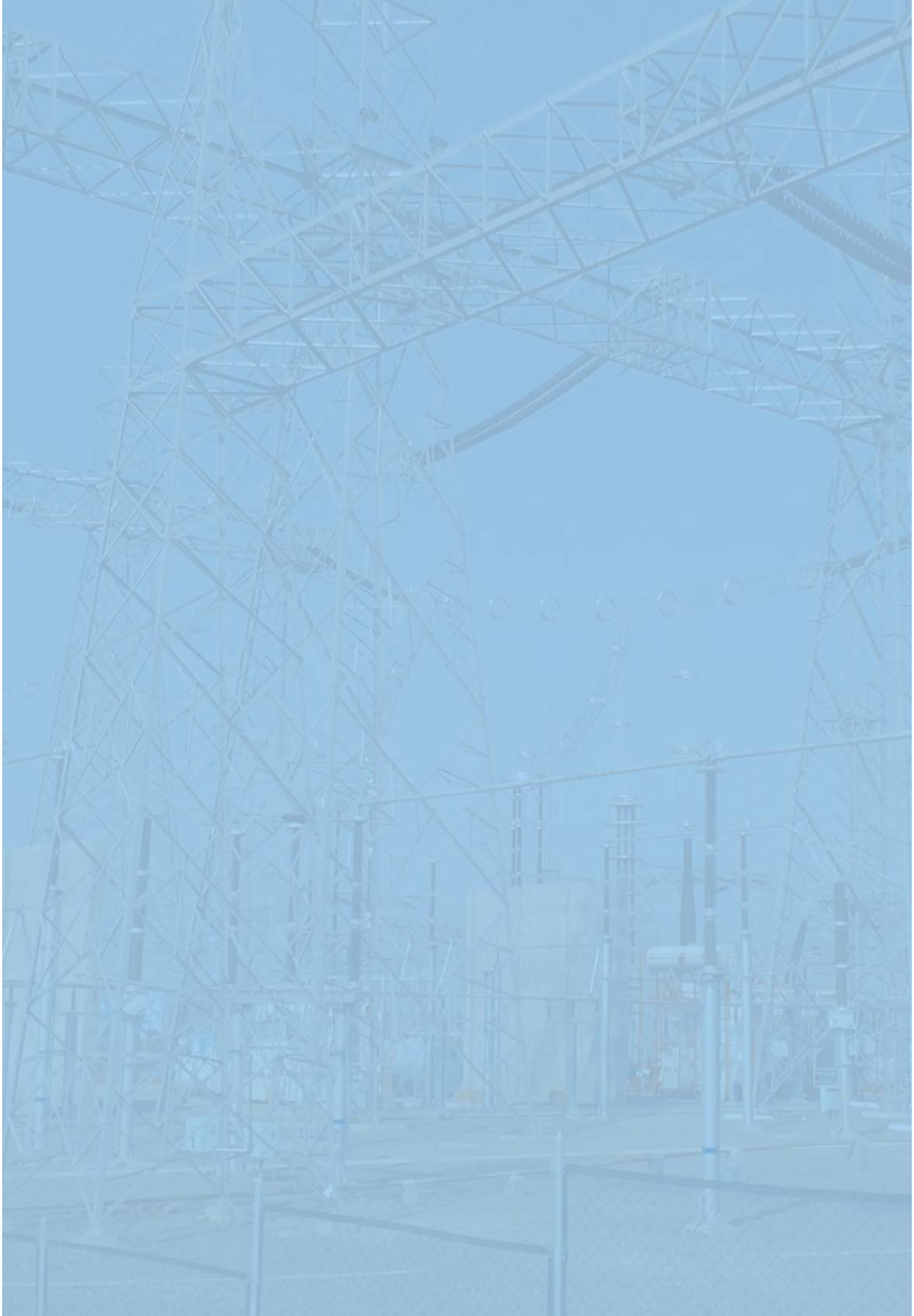
PGCIL had not laid down any timelines for submission of applications for forest clearances after completion of detailed survey. Out of 164 forest clearance applications submitted by PGCIL during January 2005 to May 2012 for execution of 20 projects selected for audit, 81 applications were submitted after 3 to 41 months of completion of detailed surveys. Further, in nine[47]out of 20 selected projects (***Annexure- 3.6),*** even the earliest application for forest clearance was submitted after investment approval of the respective project. In the remaining eleven projects also, applications for forest clearance in respect of all stretches of transmission lines were not filed by PGCIL before investment approval.

MOP stated (March 2014) that various measures such as advance expenditure for survey work in forest and river crossings, targets for submission of forest proposals through internal MOU, dedicated forest coordinates in all regions etc. have been initiated to minimise the controllable delays on its part.

Audit appreciates the measures initiated by PGCIL to expedite forest clearance. However, there is a need for PGCIL to monitor the situation closely to assess the effectiveness of the measures initiated in terms of minimising delays in obtaining forest clearance.

[46] ***As per monthly report of CEA on broad status of power projects in the country –March 2014***

[47] ***Kahalgaon-II, Sasan (UMPP), Parbati-III HEP, Generation Projects in Odisha-Part B, SRSS-VII, System Strengthening in Northern Region for Sasan & Mundra (UMPP), SRSS-III, NRSS-XVIII, and 765 kV System for Central Part of Northern Grid (Part-III) projects.***



CHAPTER - 4

Targets and Achievements

XI Plan (2007-2012) noted that planning and operation of the transmission system had shifted from regional level to national level necessitating the need for a strong all-India grid. Towards this aim, XI Plan stipulated target of inter-regional transfer capacity of 17000 MW.

4.1 Performance vis-à-vis targets

Against the XI Plan target of 17000 MW, PGCIL achieved 13900 MW of inter-regional capacity and there was a shortfall of 3100 MW. PGCIL prepared an Investment Plan of ₹54,982 crore for constructing inter-state transmission systems during XI Plan which also included inter-regional lines.

MOP stated (March 2014) that the shortfall was due to annulment of South- West HVDC Back-to-Back Project and delay in forest clearance of Ranchi –WR Pooling point 765 kV single circuit line.

The reply regarding delay in forest clearance is to be viewed against the fact that the proposal for forest clearance for Ranchi-WR pooling point, 765 kV Single circuit line[48] was submitted by PGCIL in August 2010 *i.e.* with a delay of two years from investment approval of the project in August 2008.

4.2 Fixation of Targets in MOU

PGCIL had been signing Memorandum of Understanding (MOU)[49] with its Administrative Ministry *viz*, MOP every year and had secured 'Excellent' rating (the highest rating) in each of the five years between 2007-08 and 2011-12.

Examination in audit revealed scope for refinement in the process of fixation of targets for MOU as follows:

(i) MOU Targets for inter-regional capacity addition fixed less than Plan targets

The XI Plan target for inter-regional capacity addition was 17000 MW. Against this, year-wise MOU targets and achievements during XI Plan (2007-08 to 2011-12) are given in Table 4.1

[48] ***Ranchi-Sipat (Jharkhand) 756 kV Single circuit line***

[49] ***Memorandum of Understanding (MoU) as applicable to CPSEs is a negotiated document between the Government of India (i.e. the concerned administrative Ministry) and the Management of the CPSE specifying clearly the objectives of the Understanding and the obligations of both parties. MoU is meant to evaluate the operating performance of the CPSE which includes the progress of project implementation through fixation of targets for various parameters.***

Table 4.1

MOU targets and achievement during XI Plan

Year	MOU Targets (MW)	MOU Achievements(MW)
2007-08	Nil	Nil
2008-09	3300	3800
2009-10	2600	Nil
2010-11	Nil	Nil
2011-12	4200	5600
TOTAL	**10100**	**9400**

It is noted that:

- MOU targets for 2007-12 were fixed less than XI plan target by 6900 MW (17000 MW minus 10100 MW). In two years (2007-08 and 2010-11) MOU targets were fixed at 'Nil'
- Achievements during 2009-10 were less than MOU target.
- No MOU targets were fixed in the first year (2007-08) of XI Plan indicating delay in initial start-up of projects.

MOP stated (March 2014) that year-wise targets were not envisaged in XI Plan and that at the time of setting targets for MOU, the inter-regional lines which were expected to be commissioned in the coming year, based on readiness of generation project/system requirement, were included.

The reply is to be viewed against the fact that details of XI Plan targets in terms of year-wise MOU targets would have helped PGCIL in ensuring effective monitoring of achievement of XI plan targets.

(ii) Decreasing weightage to Non-Financial Parameters

As per DPE Guidelines, non-financial performance parameters fixed should be SMART (Specific, Measurable, Attainable, Result-oriented, Tangible) and consistent with the Annual Plan/Budget/Corporate Plan of the CPSE. MOU signed by PGCIL included ten[50] major non- financial parameters. There was dilution of weightage in respect of the following important non-financial parameters related to project implementation and network availability over the years in the MOU signed by PGCIL as given in Table 4.2 (dilution depicted in bold italics):

[50] ***Quality, Customer satisfaction, Business development, R&D for sustained & continuous innovation, Project implementation, Commercial targets, Human resource development, Environment and social management of new projects, Operational targets and Inventory management.***

Table 4.2

Details of MOU parameters where weightage was decreased

Criteria	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13
Customer satisfaction (no. of trippings)	4	4	2	2	***1***	***0.5***
Availability of transmission system	13	13	13	***7***	***6***	***5***
Project implementation	20	20	19	*20*	***10***	***8***

Thus, significant parameters reflecting performance of PGCIL in the core activity relating to availability of transmission systems and implementation of projects were progressively scaled down.

MOP stated (March 2014) that weightage of these parameters were decreased since new parameters were introduced under the category of non-financial parameters and the points had to be re-allocated.

The fact however remains that higher reduction of points was made from the above parameters (which represent the performance of PGCIL in the core areas) as compared to reduction from other parameters. *e.g.* in 2011-12 three new parameters with total weightage of 15 points were introduced. Against this, 12 points were reduced from the above three parameters as indicated in Table 4.2 while balance points were reduced from other eight parameters. ***(Annexure.4.1)***

CHAPTER - 5

Investment Approval and Project Funding

5.1 Investment approval

The Report on the Working Group on Power for XI Plan *inter alia* stated (February 2007) that it is desirable that the project is defined to finer details to the extent possible at the Feasibility Report (FR)/Notice Inviting Tender (NIT) stage for effective planning and scheduling of project(s) besides minimization of resources. The Report further provided that detailed survey should be carried out before start of procurement process to avoid large quantity variations during execution which could be a cause of dispute/delay. Works & Procurement Policy and Procedures (WPPP) of PGCIL stipulated that walkover survey be conducted to identify the Bill of Quantities (BOQ) [51] and other details/information for preparation of FR of the project. WPPP, however, required that detailed survey of forest stretches and river crossings should be carried out before preparation of BOQ and cost estimates. Thus WPPP limits the exercise of detailed survey only to forest stretches and not to the whole line route, advised by the Working Group on Power.

PGCIL, however, as a practice did not conduct detailed surveys of forest stretches before preparation of BOQ and cost estimates, as stipulated in WPPP. Quantities for the purpose of FR were estimated based on forest atlas, topo-sheet[52]and walkover survey of the area resulting in significant variations at the time of actual execution of projects.

In test checked 20 projects, actual length of 17 transmission lines in 12 projects had variations as compared to FR line length ***(Annexure 5.1)***. In 11 transmission lines, actual length was less while in six transmission lines, the actual executed length was more. The difference in executed length as compared to FR length in four cases was less than 10 *per cent*, in four cases between 10 to 20 *per cent*, in four cases between 20 to 30 *per cent* and in five cases it was more than 30 *per cent*.

MOP stated (March 2014) that variations in line length considered in FR vis-a-vis actual constructed in most cases had been due to (i) change in the sub-station location, since at the time of preparation of FR, the locations for new sub-stations were tentatively identified and at the time of execution of projects, due to land acquisition Right of Way issues, line route was required to be changed, which was beyond the control of PGCIL; and (ii) detailed survey in forest area was undertaken as a parallel activity to primarily expedite submission of forest clearance proposals; MOP, however, assured that PGCIL was making all efforts to minimise the variation, such as more detailing at the FR stage by use of various tools like Google map, satellite images, topo- sheets, *etc*.

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[51] ***Bill of Quantities is a list containing all items and their respective quantities, rate, etc. to be supplied by the contractor, under a given contract***

[52] ***Topo-sheet or Topographic sheet essentially contains information about an area like roads, railways, settlements, lands, rivers, electric poles, etc. According to their usage they may be available at different scales.***

The reply is to be viewed against the fact that variations at the time of execution of projects were possible to be minimised by conducting detailed survey before the start of procurement process. There is a need to adhere to the advice of the Working Group on Power through appropriate modifications in the relevant provisions of WPPP.

5.2 Non-adjustment of STOA charges from project cost

Transmission charges for use of inter-state transmission system fall under three categories *viz*. Long term Access (LTA) charges, Medium term open access (MTOA) charges and Short term open access (STOA) charges. As per CERC (Open Access in Inter-state Transmission) Regulations, 2004 read with CERC order dated 30 January 2004, PGCIL was allowed to retain 25 *per cent* and 12.5 *per cent* of STOA charges collected in intra regional and inter regional transmission systems respectively and the balance was to be adjusted towards reduction in the transmission charges payable by Long-term customers. While allowing retention of STOA charges, CERC in its order dated 30 January 2004 stated that, "...25% of the revenue received from the short-term customers shall be retained by the transmission licensee, which is expected to be utilised in the core activity of building new transmission system." CERC amended (September 2013) the relevant Regulation relating to collection and disbursement of transmission charges (*i.e*. 75:25 and 87.5:12.5 ratios for intra-regional and inter-regional transmission system usage respectively) and provided that STOA charges had to be returned by CTU (PGCIL) to long term customers through adjustment of monthly transmission charges payable by them.

PGCIL received ₹ 906.49 crore between 2004-05 and 2012-13 on account of the above mentioned 25 *per cent* (12.5 *per cent* in case of inter regional) component of STOA charges but did not maintain project-wise details of inter-regional/intra regional transmission schemes where such STOA charges were utilised. This meant that PGCIL had used this as a revenue stream for itself instead of using it for funding new transmission systems/schemes, which would have resulted in reduction of tariff of such schemes to be recovered from customers.

MOP stated (March 2014) that as per CERC mandate, PGCIL had been utilising STOA charges in core activities of building new transmission system and for discharging CTU activities. MOP further stated that based on the rich experience, expertise, technical knowhow and intellectual assets possessed by PGCIL in the power transmission field, certain large and important activities which were difficult to monetize were performed by PGCIL such as carrying out Transmission System Planning activities in line with the National Electricity Plan, capacity building of State Utilities and DISCOMs, ATC/TTC declaration, communication planning, protection audit carried out for State Utilities, inputs for competitive bidding, coordination & support to State Transmission Utilities (STUs) viz., providing advanced simulation software and organizing training programs for their personnel and R & D and Technology Development. MOP contended that CERC Regulations did not have any provision for adjusting the project cost with STOA charges and added that PGCIL had filed a review petition with CERC, in respect of the amendment made by CERC in September 2013 regarding full STOA charges to be retained by long term customers.

The reply that the STOA charges were utilized in core activities of building new transmission system is to be viewed against the fact that details of projects wherein such charges were utilized were not available with PGCIL. In the absence of project-wise accounting/disclosure while filing tariff petition for new transmission systems, the condition on which PGCIL was allowed to retain the charges *i.e.* utilization of the funds in building new transmission systems, remained unfulfilled. As regards the claim that the charges were also utilised for discharging CTU activities, the stand is not in line with CERC Order dated 30 January 2004 which envisaged utilisation of charges in the core activity of 'building new transmission system'. Thus, the conditions stipulated by CERC for retention of STOA charges were not followed by PGCIL which resulted in denial of the benefit of reduction in the cost of new transmission projects to the extent of ₹906.49 crore between 2004-05 and 2012-13.

5.3 Non-utilisation of Power System Development Fund

The "Power System Development Fund" (PSDF) was constituted (June 2010) under the CERC (Power System Development Fund) Regulations, 2010 by aggregating the funds available in the following four individual funds/Accounts maintained by RLDCs:

- *Unscheduled Interchange Charges Pool Account Fund* - The fund contained amounts that are payable/receivable by generators and discoms, for deviations from schedule, depending on whether the deviations has improved or worsened the grid frequency.
- *Congestion Charge Account*– RLDCs levied Congestion charge on real time, on entities causing congestion and the charges are distributed to entities relieving congestion.
- *Congestion Amount (Market splitting charge)* – Levy of congestion amount is a methodology adopted by power exchanges for congestion management, by splitting the market into a surplus part and a deficit part and adjusting the prices in the two markets[53].
- *Reactive Energy Charges Account* – Reactive energy charges are payable by discoms and generators who had a net drawal/injection of reactive energy under high/low voltage conditions.

The above charges are settled between those entities who pay and those who need to receive and the surplus amount in the four accounts is transferred to PSDF on a monthly basis. The funds are to be utilised for purposes specified in the respective CERC Regulations *viz.* to relieve congestion including but not limited to carrying out specific system studies to optimise

[53] ***If the flow exceeds the capacity at the common price for the whole market area, it is split in a surplus part and a deficit part. The price is reduced in the surplus area (sale > purchase) and increased in the deficit area (Purchase> sale). This will reduce the sale and increase the purchase in surplus area. In the same way, it will reduce the purchase and increase the sale in the deficit area. Thus, the needed flow is reduced to match the available transfer capability. This method of managing congestion is known as market-splitting.***

the utilisation of the inter-regional links, installation of special protection schemes, installation of shunt capacitors, VAR[54] compensators, series compensators and other reactive energy generators. The fund can also be utilised for creation of additional transmission capacity for relieving congestion and capacity building measures and training of participants of power exchanges, SLDC operators etc. Administration of PSDF was vested with a Management Committee (MC) appointed by CERC having Chief Executive Officer, POSOCO as its Chairman and having representatives from RPC, RLDCs and independent external members. The amount in PSDF as on 31 December 2013 was ₹ 6301.64 crore. (**Annexure 5.2**). Apart from nominal utilisation of ₹ 22 lakh (For meeting travel expenses, audit fees, sitting fees to Members, etc.), the fund remained unutilised since it was constituted. The accounts of PSDF were kept outside CERC Account as well as NLDC account and the unutilised balance was invested in treasury bills and flexi deposits of Indian Bank. In this connection, it is seen that a document titled 'Procedure for disbursement of funds from PSDF' was formulated by the MC and submitted to CERC for its concurrence in December 2010. As per correspondence exchanged by administrators of PSDF with CERC in September 2012, non-receipt of concurrence of CERC to the said procedure has been cited as the reason by the MC for the inability to discharge the functions assigned to it under the PSDF Regulations. Examination of the PSDF Regulations, however, revealed that the MC is vested with the power to prepare detailed procedure for disbursement from the Fund consistent with the provisions of the regulations but disbursement from the Fund shall not be made without the approval of CERC. In other words, it is the disbursement that requires CERC approval and not the procedure.

During the period of three years (December 2010 to December 2013), the MC received proposals for 16 projects, total estimated cost of which was ₹ 655.02 crore, for funding from PSDF, which were kept pending.

In January 2014, a Cabinet Note moved by MOP was approved wherein scheme for operationalisation of PSDF including eligible projects, appraisal committee and monitoring mechanism, etc, were mentioned. It was decided that the Fund, which hitherto remained outside the Government Account Framework[55], would be brought under Public Account.

POSOCO stated (February 2014) that the MC of PSDF not only submitted the procedure for disbursement from the Fund to CERC for approval, but was continuously pursuing the matter with CERC. However, as the procedure was not approved, MC could not start disbursement from the Fund. POSOCO was also of the view that in the regulatory regime, the procedure, even though made under CERC Regulation would have weight only if approved by CERC.

POSOCO's reply indicates that due to avoidable administrative issues, funds lying in PSDF were not utilised towards relief of congestion and system strengthening projects.

MOP informed in the Exit Conference (April 2014) that an initiative had since been taken for proper accounting and utilisation of PSDF.

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[54] ***VAR – Volt-ampere reactive***

[55] ***All Government moneys come under three accounts viz., the Consolidated Fund of India, Contingency Fund and Public Account and all three accounts are audited by the Comptroller and Auditor General of India.***

CHAPTER - 6

Project Implementation and Execution

Award of contract involves contract packaging, cost estimation, finalization of qualifying requirements (QR) and bidding documents, calling of tenders, evaluation of bids and finalization of award.

Examination of each of the above stages in respect of 424 contracts pertaining to 20 projects selected for audit awarded at corporate office and 60 contracts[56] (relating to construction of colony, boundary wall, site levelling, *etc*.) awarded by Regional offices in connection with execution of above 20 projects, revealed areas for improvement as follows:

6.1 Cost estimation

Cost estimation is a vital and important step ensuring reasonableness of cost to complete a project or acquire a service. This serves as a benchmark for establishing the reasonableness of rates quoted by bidders. Therefore, it is important that cost estimate is worked out in a realistic and objective manner keeping in view the prevailing market rates, last purchase prices, economic indices for the raw material/labour, other input costs, IEEMA[57] formula and assessment based on intrinsic value, *etc*.

PGCIL prepares cost estimates using Schedule of Rates (SOR) for different items, based on unit rates of three latest contracts. SOR is reviewed every quarter and in the case of conductor and tower packages, material price indices are also considered.

Examination in audit revealed that at the time of approval of WPPP (September 2001), the Cost Estimate Manual was in the 'draft' stage and WPPP mentioned that 'NIT' cost estimate would be prepared by Cost Engineering Department as per the guidelines provided in the Cost Estimate Manual which was under approval of the Management at that time. The Cost Estimate Manual has, however, not been approved by Board of PGCIL (March 2014).

Further, in 212 out of 424 contracts pertaining to 20 selected projects reviewed in audit, award values compared with estimated costs varied ranging from (-) 70 *per cent* to (+) 74 *per cent*. In 55 contracts, award value was more than 10 *per cent* (ranging from 11 *per cent* to 74 *per cent*) of the estimated cost.

MOP stated (March 2014) that (i) though formal approval to Cost Estimate Manual was not taken at that time, it was subsequently approved in August 2013. Meanwhile, improvements in the methodology of preparing cost estimate had been recorded in the Schedule of Rates (SOR) which was being prepared according to the advice of Chief Technical Examiner (CTE) of Central Vigilance Commission and were approved by Competent Authority at regular intervals; (ii) in order to capture the latest market trend, further improvement is done in costing process *viz.* frequency of preparation of SOR is now done on bi-monthly instead of quarterly basis, cost of conductor and tower steel parts, reinforcement steel and concreting is worked

[56] ***NR I: 3, NR II:7, WR I: 16, WR II: 11, SR I: 6. SR II: 5, ER I: 5, ER II: 1, NER: 6.***

[57] ***Indian Electrical and Electronic Manufacturers Association***

out on the basis of material indices published by RBI/IPC/IEEMA *etc*. so as to capture cost of items in line with material price trend.

The fact however, remains that the Cost Estimate Manual was approved by ED (Engineering) and was yet to be approved by the Board of Directors (BOD) of PGCIL.

6.2 Delay in finalisation of contracts

In terms of WPPP of PGCIL, taking investment approval date as 'zero date', PGCIL finalized Master Network (MNW) of each project, indicating contract wise dates for start and finish of various activities such as award, commencement of supply/erection, completion of supply/ erection, *etc*. For ensuring completion of projects in time, it was necessary that various contracts required for execution of the main project were awarded in such a way that each contract was completed by the scheduled completion date. It was, however, noticed in audit that delay in award of 57 contracts resulted in extension of scheduled project completion dates of their respective main projects by four to 830 days and consequently delayed the concerned projects.

Further analysis revealed that delay was due to: (i) delayed funding tie up with World Bank (in case of ERSS-I[58], East-West Transmission Corridor and WRSS-II[59] projects), and (ii) excessive time taken by Management in award of contracts.

WPPP stipulated timelines for the entire process of award of contracts as per which contracts to be executed with domestic funding should be completed within 20 weeks from the date of opening of the bids till issue of Letter of Award. A timeframe of 28 weeks is allowed in the case of multi-lateral funding for the award process. Against these benchmarks, range of time actually taken by PGCIL in award of 424 contracts selected for Audit is shown in Table 6.1.

Table 6.1

Time taken in award of contracts

Projects under Domestic funding		Projects under Multilateral funding	
Time taken in finalisation of Contract (in weeks)	**No. of contracts finalised**	**Time taken in finalisation of Contract (in weeks)**	**No. of contracts finalised**
Within benchmark of 20 weeks	92	Within benchmark of 28 weeks	87
20 - 30	70	28 - 40	46
30 - 40	51	40 - 50	11
40 - 50	26	Above 50	10
Above 50	31	-	-
Total	**270**	**Total**	**154**

179 contracts (92 plus 87 contracts *i.e.* 42 *per cent*) were thus finalized within the prescribed time frame of 20/28 weeks while 245 contracts (58 *per cent*) were finalized beyond the prescribed time frame.

[58] *Eastern Region System Strengthening Scheme-I.*
[59] *Western Region System Strengthening Scheme-II.*

MOP stated (March 2014) that the timeline stipulated in WPPP for finalisation of contract is indicative and aspirational considering the best efforts and presuming that there would be no hindrance beyond control in award of contracts; however constraints were inevitable in any project such as acquisition of land for various sub-stations, changes in taxes and duties by the Government during evaluation / award process, capacity and capability constraints, change in the Transmission Scheme elements and linkage of Transmission system with Generation project. Regarding delays in funding tie-up, MOP stated that this was due to more time taken during clarifications/assessment/post bid discussions.

The reply is to be viewed against the fact that delays would result in PGCIL losing additional Return on Equity (ROE) of 0.5 *per cent* and revenue from tariff would be deferred.

6.3 Delay in commissioning of projects

Time is the essence of every contract so as to ensure completion of the project as per schedule. At the time of seeking investment approval, scheduled timeline for completion of project is laid down. From 1 April 2009 onwards CERC has specified benchmark timelines for transmission projects, (from date of investment approval by the Board of Directors till date of commercial operation) ranging from 24 months to 42 months, depending on plain area, hilly terrain *etc.* and provided that additional Return on Equity amounting to 0.5 per cent would be applicable if these timelines were met. Hence PGCIL decided to fix scheduled timelines accordingly for projects taken up after 1 April 2009.

Out of 20 projects selected for audit, four projects were approved by PGCIL after 1 April 2009 when CERC benchmark timelines became applicable while the remaining 16 projects were approved by PGCIL before 1 April 2009. Status regarding commissioning of these projects is given in Table 6.2 (Details in ***Annexure 6.1***).

Table 6.2
Status of commissioning of projects

Range of delay in commissioning/anticipated commissioning of projects beyond scheduled date / CERC benchmark* (in months)	Projects approved before 1.04.2009		Projects approved after 1.04.2009	
	Completed projects (No.)	Ongoing projects (No.)	Completed projects (No.)	Ongoing projects (No.)
NIL	1	-	-	-
1 - 10	5	-	-	1
11 - 20	2	1	-	1
21 - 30	3	1	1	1
31 - 40	0	0	-	-
Above 40	1	2	-	-
Total	**12**	**4**	**1**	**3**

*For projects approved after 1 April 2009

Out of 20 projects selected for examination in Audit, only one was completed within the scheduled time. Delay was above 20 months in nine projects. Time taken in acquisition of land, handing over site and providing approved drawings to contractors, release of advance to contractors and forest clearance had contributed to delays which were possible to have been controlled by PGCIL, with more effective planning and monitoring.

CERC regulations allow charging tariff for transmission system elements that are ready for regular service but are prevented from providing such service for reasons not attributable to PGCIL. Accordingly, delay in commissioning of projects beyond their scheduled date of commissioning had financial implications for PGCIL. Revenue (the impact of which was not possible to be quantified in audit pending issue of final tariff orders in these cases) was deferred for the periods of delays in commissioning of projects.

Further, as per CERC (Terms and Conditions of Tariff) Regulations, 2009, for projects commissioned within the scheduled timeline from April 2009 to March 2014, an additional Return on Equity (RoE) at the rate of 0.50 *per cent* is allowed over the life of the project. Due to delays in four projects approved after 1 April 2009 (in the audit sample of 20 projects), PGCIL would also have to forego this additional return on equity of approximately ₹350.28 crore based on approved project cost (***Annexure 6.2***) over the project life of 35 years from the date of commissioning.

MOP stated (March 2014) that

- reasons for delay were actually beyond reasonable/direct control of PGCIL as (i) land acquisition process involved State Governments and resistance from land owners had to be handled; (ii) delay in drawings was due to change in scope necessitated due to varying geographical conditions and Right of Way issues; (iii) forest clearance was a cumbersome process leading to delays.
- CERC timelines were actually meant for incentivizing exceptional performance/early completion because these timelines did not consider the time required for tendering (5-6 months) and margins for right of way, forest clearance, law and order problems, *etc*. MOP had also constituted a Task force on transmission projects which recommended suitable time margins depending on the involvement of forest, national park/wildlife sanctuaries, right of way/land acquisition constraints, law and order problems, size of the project etc. CERC has subsequently increased the timeline by six months considering these practical problems.
- indemnification process for matching transmission project timelines with that of generation projects provides for compensation to be paid by the generator to the extent of IDC[60]of Transmission Projects equivalent to transmission component for a period of six months. Therefore, wherever the generation project was likely to be delayed more than

[60] ***Interest during construction***

six months, it was generally felt prudent to delay completion of transmission lines so as to match the completion with that of anticipated generation schedule, as far as possible.

- there has been no incidence of bottling up of generation due to delay in transmission projects for transfer of power under Long Term Access.

MOP, however, assured (March 2014) that PGCIL had initiated certain measures like negotiated/consent purchase of land, simplifying of forest clearance procedure through intervention of MOP, *etc*. which were expected to help in faster implementation of projects in future.

Reply needs to be viewed against the following:

(i) While considering the views of stakeholders at the time of finalisation of Tariff Regulations 2014-19, CERC did not accept the plea of PGCIL that land acquisition and Right of Way issues were factors beyond control of PGCIL. Accordingly, Tariff Regulations 2014-19 stipulated only force majeure events and change in law as uncontrollable factors.

(ii) Task Force was constituted (February 2005) by MOP for identifying ways and means to implement transmission projects within 24 months' time frame. Task force in its Report (August 2005) recommended suitable margins for ROW/forest clearance etc. However, subsequently CERC rationalised the timelines with effect from 1 April 2009 considering views and submissions of various stakeholders. PGCIL did not complete three out of four projects in the Audit sample[61], even within the extended period of six months allowed under the new Tariff Regulations (2009-14).

(iii) the general principle in commissioning of transmission system is that transmission has to precede generation and CERC Regulations permit earning of revenue by PGCIL even if the associated generation project is not ready.

(iv) As regards the claim that there was no bottling of power, the fact remains that pending commissioning of Odisha Part B transmission project, power was evacuated through interim arrangements leading to congestion in the network as brought out in para 3.1.4 *supra*.

[61] ***Odisha Part B, Krishnapatnam, Sasan & Mundra and 65 kV central part of Northern Grid Part-III***

CHAPTER - 7

Grid Management

Electricity is produced at lower voltages (10000 volts to 25000 volts *i.e.* 10 kV to 25 kV) at generating stations and is stepped up to higher voltages[62] (220,000 volts to 765,000 volts *i.e* 220 kV to 765 kV) for transportation in bulk over long distances through transmission lines. Transmission lines are interconnected at switching stations and sub stations to form a network called the power 'Grid'.

7.1 Organisation of Power Grid

Power Grid or National Grid in the country is divided into five regional Grids namely Northern, Western, Eastern, North Eastern and Southern Grids. While first four Grids operated in synchronised[63] manner since August 2006, the Southern Grid has also been synchronously connected to the rest of the Grid through commissioning of single circuit of Raichur-Sholapur 765 kV line on 31 December 2013. The Western, Eastern and North Eastern Grids are together called the 'Central' Grid. The Northern and Southern Grids were subsequent addition in August 2006 and December 2013 respectively to the Central Grid. An overview of the components of National Grid is given in ***Annexure 7.1***. Operation of National Grid is a coordinated activity among various interfaces/agencies with MOP at the apex policy level at the Centre and PGCIL/ POSOCO through Load Despatch Centers (LDCs) at the operational level of the hierarchy (Block diagram given in ***Annexure 7.2***).

7.2 Grid Management

Electricity flows at close to the speed of light (2,97,600 kms per second) and must ideally be used, the instant it is produced. Electricity flows freely along all available paths from generators to the loads in accordance with the laws of Physics - dividing among all connected flow paths in the network, in inverse proportion to the resistance to such flow. Power flow in the Grid is managed through a process called 'Load Despatch', which involves balancing the load[64] and generation through a 'Scheduling' mechanism. Under this mechanism, power stations and distribution utilities inform their intended quantum of generation and drawal respectively for the next day to LDCs of their control area[65]. LDCs match the generation and drawal of all utilities in their control area with reference to the power transfer capability[66] and

[62] ***Operating transmission lines at high voltages reduces transmission losses due to heating and allows power to be shipped economically over long distances. Further it is economical to transport electricity than transport fuel for generating power.***

[63] ***Synchronization is the process of matching the speed and frequency of a generator or other source of electricity generation to a running network.***

[64] ***Load – The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy consuming equipment of the consumers.***

[65] ***An electrical system bounded by interconnections (tie-lines), metering and telemetry, where it controls its generation and / or load to maintain its interchange schedule with other control areas whenever required to do so and contribute to frequency regulation of the synchonously operating system. There are 150 control areas in the country.***

[66] ***Transfer capability refers to the amount of electric power that can be passed through a transmission network from one place to another having regard to reliability considerations.***

prepare the schedule each day, for the next day. For scheduling, a day is divided into 96 time blocks, each of 15 minutes duration and revisions are carried out in the schedule in real time depending on network conditions and feedback from the utilities. Thus, the 'Schedule' is a program drawn for the generating stations and distribution utilities**.** However, when power actually flows through the Grid, it may differ from the Schedule due to various reasons such as variation in energy supplied by the generating stations, variation in load from the forecast values, frequency and voltage fluctuations in the Grid, *etc.* Such variations in flows are called 'Unscheduled Interchange' or UI. LDCs, organized in hierarchical form (flow chart given in ***Annexure 7.3***) for smooth functioning of the Grid, monitor the power flows within their control areas through power system visualization tools and give necessary instructions to utilities through telephone calls and fax messages. Control of power flow across the Grid under normal operating conditions is achieved through physical action by utilities *i.e.* increase/decrease in generation by generating stations and connection/disconnection of feeders by distribution utilities as well as switching operations such as taking in/out a line. As these actions take some time, emergencies are handled by automatic actions through 'Special Protection Systems' which would instantaneously trip identified loads whenever a specific contingency occurs.

7.3 Classification of Grid Disturbances

A Grid Disturbance (GD) is a state of the power system under which a set of generating units/transmission elements trip in an abrupt and unplanned manner affecting power supply in a large area and/or causing the system parameters to deviate from normal values in a wider range. CEA is mandated with the responsibility of prescribing Grid Standards. As per CEA's Grid Standards, GDs are classified on a scale of one to five[67] depending on the severity of the antecedent generation or load lost. There were 816 instances of GD between April 2007 and September 2013. Analysis of region-wise and year-wise break-up of GDs for the period revealed that GDs of higher category (GD-3 and above) occurred on 69 occasions (8.46 *per cent* of total 816 instances). Number of GDs showed a mixed trend i.e. increase in numbers from 2008-09 (83 GDs) to 2009-10 (124 GDs); marginal decrease in 2010-11 (112 GDs); increase in 2011-12 (144 GDs) and decrease in 2012-13 (127 GDs). However, during 2013-14, up to September 2013 itself, number of GDs increased sharply to 176 as against 127 during 2012-13. WR had no higher category GDs and had only GD-1 disturbances. ER had the highest number of GDs (276 including 34 ungraded[68] GDs), followed by NR (233). Highest number (59) of GD-3 to GD-5 categories of GDs occurred in NER, out of which 19 were of GD-5 category.

Examination in audit revealed that the classification format of grid disturbances had a further scope for improvement as detailed below:

[67] ***Category GD-1 – When less than 10 per cent of the antecedent generation or load in a regional Grid is lost;***
GD–2-When 10 per cent to less than 20 per cent of the antecedent generation or load in a regional Grid is lost;
GD–3-When 20 per cent to less than 30 per cent of the antecedent generation or load in a regional Grid is lost;
GD–4-When 30 per cent to less than 40 per cent of the antecedent generation or load in a regional Grid is lost;
GD–5-When 40 per cent or more of the antecedent generation or load in a regional Grid is lost.

[68] ***GDs prior to notification of Central Electricity Authority (Grid Standards) Regulations 2010 were not graded.***

(a) There was no system/requirement to capture 'near-miss[69]' situations, though early warning of a major GD could be a near-miss before that[70].

(b) Grid standards did not capture seriousness in cases where load is lost in more than one region or cases where a region gets isolated from inter-connected regions indicating failure of synchronisation.

(c) Reporting framework did not mandate estimation of energy not served due to GD and revenue loss to users of the Grid.

PGCIL appreciated (March 2013) the audit observations and stated that these would be referred to CEA.

In the Exit Conference held on 15 April 2014, CEA agreed to consider the audit suggestion.

7.4 Major Grid Disturbances of 30 and 31 July 2012

There was a major GD in Northern Region at 0233 hours on 30 July 2012 leading to disturbance of the Northern Grid. Subsequently, there was another GD at 1300 hours on 31 July 2012 resulting in disturbance of Northern, Eastern and North-Eastern regional Grids[71]. Estimated population of 30 crore in eight States and one Union Territory[72] and estimated population of 60 crore in 21 States and one Union Territory[73] were affected respectively. The total load affected was 36000 MW on 30 July 2012 and 48000 MW on 31 July 2012.

CERC, in exercise of its power to regulate inter-State transmission of electricity under Section 79 (1) (C) of the Electricity Act, 2003, in its *suo-moto* order dated 1 August 2012 directed CEO of POSOCO and CMD of PGCIL, to investigate these Grid disturbances and submit a report within a week from the date of issue of its order. POSOCO/PGCIL submitted their report to CERC on 9 August 2012. CERC conducted four hearings on this report with the last hearing on 23 April 2013. CERC Order on the GD was issued on 22 February 2014 wherein violations of CERC Regulations by various entities were identified and action was proposed against them.

Besides, in order to investigate the reasons for the above two GDs and to suggest remedial measures, MOP also constituted (3 August 2012) a four member Enquiry Committee. The Committee in its report (GOI Report) dated 16 August 2012 opined that no single factor was responsible for the disturbances. The Committee attributed the disturbances to weak inter-regional corridors due to multiple outages, high loading on 400 kV Bina - Gwalior –Agra link

[69] *'Near miss' may be considered as an event that signals a system weakness that, if not remedied, could lead to significant consequences in the future.*

[70] *The major GD of 30 and 31 July 2012 were preceded by a near-miss situation on 29 July 2012.*

[71] *As per CEA's Grid Standards, the disturbance on 30 July 2012 falls under category GD-5 (GD 5 pertains to those disturbances when 40 per cent or more of the antecedent generation or load in a regional Grid is lost). On 31 July 2012 the disturbances were of GD 5 in three regions viz. NR, ER and NER and GD 1 in WR.*

[72] *Delhi, UP, Haryana, Rajasthan, Himachal Pradesh, Punjab, J & K, Uttaranchal and Chandigarh.*

[73] *Delhi, UP, Haryana, Rajasthan, Himachal Pradesh, Punjab, J & K, Uttarakhand, Sikkim, Assam, Tripura, Mizoram, Manipur, Arunachal Pradesh, Nagaland, Meghalaya, Bihar, Jharkhand, West Bengal, Orissa and parts of Madhya Pradesh and Union Territory of Chandigarh.*

and subsequent loss of the Bina-Gwalior link and inadequate response by State Load Despatch Centres (SLDCs) to RLDCs' instructions to reduce over drawal by power utilities of NR and under drawal/excess generation by utilities of WR.

Examination in audit of occurrence and management of GDs of 30 and 31 July 2012 with reference to above two reports, relevant records of proceedings and order of CERC[74] and the report (April 2004) of the US-Canada Power system Outage Task Force on the causes and recommendations of the US-Canada blackout of August 2003 revealed the following:

7.4.1 Deficiencies in planning shutdown of trunk line

POSOCO/PGCIL's report to CERC stated that transmission links between WR and NR got depleted progressively starting with planned outage on the high capacity Bina-Gwalior-Agra link. Power demand scenario of NR *vis-à-vis* availability of transmission links from WR to NR indicated that:

- Power consumption in NR generally increased during June-August every year during 2007-12 **(**Graph in ***Annexure 7.4)*** mainly due to 'weather beating' and agricultural loads. However, demand in WR remained lower during this period. This led to increased power flow from Western region towards Northern region during this period.

- Nine lines with a total transfer capability (TTC) of 2400 MW were available for flow of power from WR to NR. 72 *per cent* of flow ***(Annexure 7.7*)** during 2011-12 was through 400 kV Gwalior-Agra link (double circuit), which showed that this was the trunk line between WR-NR[75].

- Actual power flow through WR-NR corridor in July 2011 was 2291 MW which exceeded TTC of 1900 MW available at that time, underscoring the WR-NR transmission constraints in July. Existence of congestion in this corridor was further evidenced by the fact that RLDCs/NLDC levied congestion charges[76] on two occasions for the WR-NR corridor in July 2011.

PGCIL sought (e-mail/fax dated 23, 25 and 26 July 2012) shutdown of the Bina-Gwalior-Agra link from POSOCO for upgrading this line from 400 kV to 765 kV. Despite being aware of the criticality of this line for importing power to NR in peak season, the shutdown was allowed by NLDC from 26 to 29 July 2012 after reducing TTC of WR-NR from 2400 MW to 2000 MW[77].

The procedure laid down in IEGC for transmission outage envisaged a three stage outage planning process. In the first stage, annual outage plan is to be finalized by Regional Power

[74] ***As displayed on website of CERC.***

[75] ***Bina-Gwalior link (double circuit) is the feeder link in WR for the Gwalior-Agra inter-regional link.***

[76] ***CERC Regulations on 'Measures to relieve congestion in real time' permit RLDCs/NLDC to levy congestion charges over and above energy charges if demand for power exceeds TTC.***

[77] ***Shutdown of Agra-Gwalior I line was allowed from 0800 hours to 1900 hours of 26 July 2012 for preparatory work. For Bina-Gwalior II upgradation, shutdown was allowed from 1000 hours of 27 July 2012 to 1800 hours of 29 July 2012; for Agra-Gwalior II, shutdown was allowed from 1000 hours of 28 July 2012 to 1800 hours of 29 July 2012.***

Committee (RPC) in coordination[78] with all parties concerned and in consultation with RLDC/NLDC. In the second stage, monthly review of transmission outage planning is required to be carried out at RPC level through the Operation Coordination sub-committee (OCC) of RPC. In the third stage, any outage approved by RPC is actually availed only after RLDCs permit the same depending on system conditions. Further, outage of inter-regional lines and all outages necessitating reduction in TTC and/or curtailment of transactions are availed only after concurrence of NLDC, which conducts system studies to identify precautions required to be taken for the same.

In the subject shut-down of July 2012, the first two stages were not followed and PGCIL's request was directly handled by Northern Regional Load Despatch Centre (NRLDC) and NLDC. NLDC reduced TTC from 2400 MW to 2000 MW to accommodate the shutdown in high demand period at a time when the users needed it the most, which was not in line with its role to ensure optimum utilization of power resources, as stipulated in Para 1.2.2 of 'Operating Procedures for National Grid'. Thus the shutdown was sought and availed at short notice without timely notice to the constituents, which was against the principle of advance planning envisaged under IEGC through a three stage coordinated process. Moreover, reduction of TTC due to the shut down was uploaded on NLDC web-site at 1000 hours on 26 July 2012 though the actual shut down started at 0825 hours on 26 July 2012.

MOP stated (March 2014) that the shut down became urgent in view of large power exchange requirements of NR through NR-WR interregional links and was planned for commissioning ahead of the Sasan UMPP whose anticipated completion schedule was December 2012; as such all civil and electrical works of line and sub-station were expeditiously completed and up-gradation work was planned for commissioning in July 2012; through various forums and meetings of the RPCs, beneficiaries are made aware of all projects under various stages of execution which is suffice to say that the beneficiaries were kept updated about this shut down also. MOP, however, assured that after the GDs, there has been improvement in outage planning at RPC level and the outage plan is discussed a day in advance of the OCC meeting.

The reply needs to be viewed against the following facts:

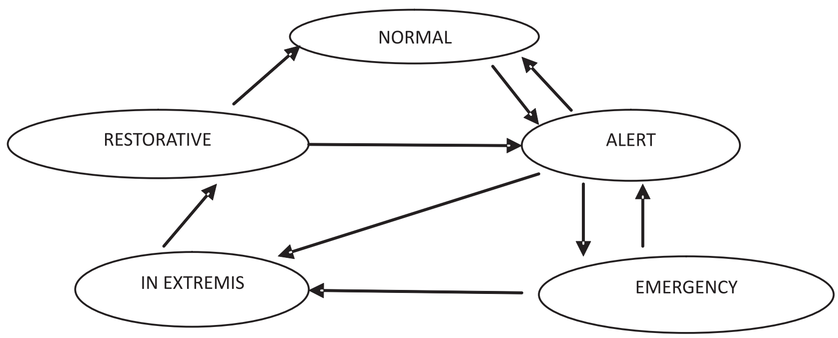
Reply does not address why up-gradation work of the line was not scheduled during lean season; further, the work for up-gradation which was intended to increase the transfer capability was ultimately completed in March 2013 and NLDC allowed higher TTC of 5700 MW in May 2013; however, the increased TTC of 5700 MW was rolled back in October 2013 due to reliability issues encountered in the WR-NR corridor after upgradation. Moreover, knowledge of projects under various stages of execution to constituents cannot be construed as information on outage planning of a crucial transmission element; in this case NRLDC and NLDC not only did not insist on RPC approval i.e. first and second stages of outage planning

[78] ***The advantage of such coordination is that the users of the network are aware of transfer capability that would be affected by the shut down and can seek deferment of shut downs if it affects their requirements and the RPC can take a considered decision.***

but also consciously approved a long outage of an inter-regional trunk line during peak season; presence of the antecedent loading upto 2900 MW which was more than the ATC of 2200 MW on the WR-NR corridor on 25 July 2012 (prior to the outage) gave an indication of what was in store if an outage was allowed on the trunk line of the corridor; it is seen that the first stage of the outage planning process *viz.* annual outage plan has not yet been initiated.

7.4.2 Handling of the disturbance by System Operators at NLDC/RLDCs

In system operator's parlance, a power system can be in any of the five states[79] (as shown below in diagram) and can traverse to any of the states as per the arrows indicated.



(States of Power System[80])

The system operators have their best chance of control in the 'Normal' and 'Alert' states though damage control methods are available for each state[81]. During the Grid disturbaces on 30 and 31 July 2012 also, the system went through these states but RLDCs/NLDC allowed the system to deteriorate to the 'in extremis' (uncontrollable cascade) state as explained below:

(a) Deficiency in declaring TTC and scheduling transfer of power

TTC[82] for inter-regional corridors is declared by NLDC on its web site, based on which RLDCs 'schedule' power. Northern RLDC (NRLDC) was thus expected to ensure that the quantum of power scheduled to be despatched to NR was not in excess of the Available Transfer Capability (ATC)[83] declared by NLDC. While assessing TTC, a principle called 'N-1 criterion' is followed for maintaining reliability which ensures that the system remains in secure condition

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[79] ***In the 'normal' state, all system variables are within the normal range and no equipment is being overloaded. The 'Alert' stage denotes onset of instability, the 'emergency' stage denotes abnormal but controllable phase and the 'in extremis' stage refers to the uncontrollable cascade phase. The 'restorative' state represents a condition in which control action is being taken to reconnect all the facilities and to restore system load.***

[80] ***Source: As provided by POSOCO.***

[81] ***'Alert' - Generation re-despatch; 'Emergency' - fault clearing, excitation control, fast valving, generation tripping, generation runback, HVDC modulation and load shedding; 'In extremis' - load shedding and controlled separation.***

[82] ***Total Transfer Capability of a transmission network means the amount of electric power that can be transferred reliably over the inter-control area transmission system under a given set of operating conditions considering the effect of occurrence of the worst credible contingency. Here credible contingency means the likely-to-happen contingency, which would affect the Total Transfer Capability of the inter-control area transmission system.***

[83] ***Available Transfer capability (ATC) is equal to TTC minus transmission reliability margin fixed corridor wise by NLDC to ensure that the interconnected network is secure under a reasonable range of uncertainties in system conditions.***

even after loss of the most important generator or transmission facility (single contingency)[84]. CERC regulations [85] provided that NLDC might revise TTC on day-ahead basis depending upon system conditions.

While permitting shutdown of Bina-Gwalior-Agra line-II, NLDC had reduced TTC of WR-NR from 2400 MW to 2000 MW from 27 to 29 July 2012 (1900 Hrs) which stood restored on 29 July (1900 Hrs) to 2400 MW. NLDC, however, did not consider the need for restricting TTC of WR-NR to 2000 MW for 30 July 2012 on 29 July 2012 itself, though contingencies began to pile up, as explained below:

- While assessing the transfer capability for the WR-NR corridor as 2000 MW on 26 July 2012, the worst credible contingency considered was outage of Gwalior-Agra line I, the most heavily loaded line in the WR-NR corridor. All other lines were assumed to be available. However, after the beginning of shut down on 27 July 2012, three[86] of the remaining seven lines (excluding HVDC) tripped and a 'near-miss' situation happened at 1510 hours on 29 July2012**,** indicating onset of instability and the need to review TTC.
- NLDC did not revise TTC (from 2400 MW to 2000 MW) though the line under shut down (Bina-Gwalior-Agra- line II) was not returned to service[87]. Consequently, NRLDC allowed import of power ranging between 1941 MW and 2139 MW in 10 time blocks from 0000 hours to 0230 hours on 30 July 2012, against actual ATC of 1800 MW.

Similar inadequacies in declaring TTC of WR-NR corridor by NLDC after the Grid disturbance at 0233 hrs on 30 July 2012 were also observed. NLDC's assessment (1100 hours on 30 July 2012) of TTC of WR-NR as 2000 MW (ATC-1800 MW) for 30 and 31 July 2012 based on availability of all lines (except the under shutdown line of Agra-Gwalior-II and Agra-Gwalior-I Line on N-1 criterion), was on the higher side[88] as two more lines (*i.e.*Badod-Kota and Zerda-Kankroli) were also not available at that time. Accordingly, overloading of WR-NR links persisted on 31 July 2012 also and ultimately led to the second Grid disturbance at 1300 hours on 31 July 2012 when actual load of WR-NR corridor reached 1891 MW.

Further, NRLDC scheduled 2442 MW to 2629 MW of power through WR- NR corridor on 30 July 2012 from 0000 hrs to 0230 hrs prior to GD as against the already higher declared TTC of 2400 MW (ATC of 2200 MW). Thus, even the schedule was higher by 642 MW to 829 MW when compared with the ATC of 1800 MW fixed during planned shutdown of lines (26 to 29 July 2012).

[84] ***Single contingency means the worst single outage event of transmission line, generator, transformer, or substation bus bar.***

[85] ***CERC (Measures to relieve congestion in real time operation) Regulations, 2009***

[86] ***(i) 400 kV Zerda-Kankroli, (ii) 200 kV Badod-Morak and (iii) 200 kV Badod-Kota***

[87] ***The probability of extension of shut down was very high in this case because against three days shut down requested by PGCIL for up gradation work at Gwalior end, two days shut down was allowed.***

[88] ***As per the basis used by NLDC for declaring TTC, effect of the outage of Badod-Kota and Zerda-Kankroli links on TTC would have been to the extent of 200 MW reducing the ATC to 1600 MW. e.g. while declaring TTC for 15.9.2012 to 25.9.2012, TTC was enhanced by 100 MW due to restoration of 400 kV Zerda-Kankroli line. Similarly, while declaring TTC for 16.1.2013 to 17.1.2013, TTC was reduced by 100 MW due to shutdown of 220 kV Kota-Badod line.***

Thus, there were weaknesses in due diligence by NLDC and RLDCs in declaring TTC/ ATC and scheduling of power across WR-NR corridor on 29 and 30 July 2012 which contributed to GD on 30 and 31 July 2012.

MOP stated (March 2014) that TTC/ATC did not matter for reliability (as per US/Canada Blackout Report) and added that TTC reduction involved detailed simulation studies which would have taken at least two hours, curtailing STOA would have taken another 2 hours and thereafter physical action of restricting over drawal/ under drawal would have taken further time. PGCIL argued that it resorted to the last step as it constituted affirmative physical action. Regarding higher scheduling of power, MOP stated that the operators faced dilemma in such cases; if the operator did not curtail the transactions beyond the planned outage hours and if the transmission system was not restored, there could be a compromise on grid security and the operator would get the blame. If he curtailed the transactions for the entire day and if the transmission system was back, the market players would counter the system operator; either way, the system operator function was tight roped.

The reply needs to be viewed against the following facts:

(i) Power flows through a corridor may be scheduled and unscheduled. While scheduled power flows are planned and regulated by RLDCs on 'day ahead basis' depending on TTC of the corridor, unscheduled power flows happen in real time and need to be controlled through coordinated and physical action by power utilities. Unlike in the USA, where TTC was arrived at a week before, (as mentioned in the USA/Canada blackout Report), in the Indian context, it is on a day ahead basis. Therefore, TTC has relevance in India so far as regulating scheduled power flows is concerned.

(ii) Actual power flow data for 0000 hrs to 0230 hrs on 30 July 2012 just prior to GD at 0233 hrs on 30 July 2012 revealed that overloading on WR-NR corridor beyond 2000 MW (TTC at which the WR-NR corridor was operating during 26 to 29 July 2012 when the Agra-Bina Gwalior-II line was under planned shutdown) was 26 MW to 218 MW[89] indicating that it was possible to relieve overloading through proper scheduling of power within TTC of 2000 MW. Even with Bina-Gwalior-Agra-II line remaining unavailable till 8 August 2012, any further Grid disturbance was averted by reducing TTC to 1250 MW.

(iii) POSOCO clarified that in real time operation, the system operator had little control as actions were generally automatic through relays and System Protection Schemes (SPS). Therefore, day ahead planning called for more diligence, which was not observed in this case.

(iv) The argument regarding operator's dilemma did not stand to reason because in terms of the 'Procedure for scheduling of collective transactions' approved by CERC, the

[89] ***Excluding loading on Mundra- Mohindergarh line for which TTC and scheduling is done separately.***

timeline for scheduling collective transactions did not end at 1300 hours. NLDC could have revisited the same till 1800 hours (i.e. by the time the status of Bina-Gwalior-Agra line II not coming back to service on 29 July 2012, was clear).

(b) WRLDC's role in the grid disturbance

As per report of POSOCO to CERC, the main strategy to control the overloading of WR-NR lines was to back down generation in WR, reduce under-drawal by WR utilities and reduce over drawal by NR utilities. These three activities were required to be carried out simultaneously for the desired result. Voice recordings of conversations between the control room staff of RLDCs and messages issued by them provide the record of steps taken in implementing the strategy. Examination of the voice recording revealed that WRLDC was unwilling to order generators to back down and suggested that NLDC should try to reduce over drawal by NR. (Excerpts from NLDC control room telephonic conversations in **Annexure 7.5**)

WRLDC did not instruct the State power utilities (SPUs) to stop under-drawal which was as high as 50 *per cent* of their scheduled drawal till 2137 hours on 29 July 2012. Thereafter, till 0010 hours of 30 July 2012, the messages did not mention specific action required on the part of SPUs. Generating stations including over-injecting ones were not asked to back down except Sipat unit of NTPC which was injecting 660 MW of infirm power (*i.e.* power generated by a power station prior to its date of commercial operation). Another Generating Station in the private sector *viz*. Coastal Gujarat Power Limited, Mundra having 800 MW capacity was injecting infirm power into the Grid but was not asked to back down. Finally, at 0021 hours of 30 July 2012, WRLDC endorsed a copy of NLDC 'fax' asking the WR States to reduce under drawal, which was the first clear message to SPUs about the action required on their part. Further, WRLDC did not direct Indira Sagar Hydro Power Plant[90] to reduce generation, though specifically instructed by NLDC, in the same message. Thus, GD could not be averted as WRLDC neither ordered generation back down nor issued proper instructions to SPUs in WR to reduce under drawal.

MOP stated (March 2014) that under drawal could be controlled through different methods such as removing load restrictions on consumers so that more load could be served within the State, reducing State's own Generation or reducing State's requisition from central sector plants or IPPs coming under RLDC's jurisdiction. SLDCs were best placed to take a holistic view else it would lead to frequent disputes between the State utilities and generating stations.

The argument that instructing generation back down would have invited commercial disputes is not convincing as IEGC has provisions {Clause 6.5 (27)} empowering RLDCs to order generation back down to protect Grid security. Further, WRLDC did instruct tripping of hydro power station of MPSEB[91] at 0257 hours of 30 July 2012, *i.e.* after the GD.

[90] ***Hydro power plants had the advantage of abrupt tripping unlike thermal generators which are gradually backed down.***
[91] ***Madhya Pradesh State Electricity Board***

(c) Hierarchical differences

NLDC was responsible for monitoring inter-regional lines and though NLDC was at the apex level of LDCs, its control room team was manned by junior staff as compared to those manning RLDCs. Review of voice recordings of telephonic conversations among NLDC and RLDCs revealed that NRLDC and ERLDC had inkling about the impending collapse and ERLDC alerted NLDC about the need to issue firm instructions to WRLDC which was not cooperating in the exercise of relieving loading on WR-NR corridor. However, NLDC operator was not able to assertively convey instructions to his counterpart in WRLDC and there was hesitation in the manner in which the serious subject of under drawal was broached/handled by NLDC operator, with WRLDC. (Excerpts from NLDC control room telephonic conversations in **Annexure 7.5**)

MOP stated (March 2014) that taking suggestions of Audit in a positive manner, POSOCO had already further strengthened posting of staff in NLDC Control Room.

(d) Inadequate off-line simulation study

Off-line simulation studies[92] are undertaken after major GDs to evaluate various alternatives that could have helped in averting the disturbance. One of the sub-groups of the GOI enquiry committee constituted to investigate GDs was assigned “Analysis of Grid disturbance on 30 and 31 July 2012 and simulation of the event”. The sub-group stated that for specific answers to the disturbance of the Grids, a detailed load flow and transient stability simulation of the NR, ER- NER and WR Grids was required. The required study was not undertaken by the Task Force which was constituted by MOP in December 2012 for power system analysis.

MOP stated (March 2014) that POSOCO has since conducted the detailed offline simulation study and prepared a Report. MOP agreed that simulation as part of the Enquiry Committee findings would have been a more transparent and credible way rather than any in-house study by one agency considering the significance of assumptions involved in any simulation study.

7.4.3 Role of other agencies which aggravated the disturbance

Ensuring integrated operation of the Grid is a collective responsibility of various agencies. There was scope and need for clearly delineating the responsibilities of other agencies involved in Grid operation, as discussed below:-

(a) Heavy Underdrawal/Overdrawal by State power utilities

As per the hierarchical system in which LDCs operate, the LDCs at the state level are required to comply with the instructions of the respective RLDCs. While RLDCs give verbal/ written instructions, physical action by way of reducing load can be achieved only if the SLDCs,

[92] ***Power system engineers use a technique called power flow simulation to reproduce known operating conditions at a specific time by calibrating an initial simulation to observed voltages and line flows. The calibrated simulation can then be used to answer ‘what-if’ questions to determine whether the system was in a safe operating state at that time. In the offline simulation study, the sequence of events as they occurred during the Grid disturbance is simulated to corroborate the findings of analysis done about the event.***

in turn, go for manual load shedding *i.e*. switching off power supply to areas depending on the quantum of load shedding required, category of consumer *etc*. RLDCs issued fax messages and made phone calls to SLDCs during the night of 29 July 2012 (two messages were also issued on 31 July 2012) to further instruct NR utilities to reduce over drawal and WR utilities to reduce under drawal. Despite this, five states[93] in NR and seven States/UTs[94] in WR did not comply with RLDCs' instructions and resorted to over drawal and under drawal respectively, as shown in ***Annexure 7.6***, which further contributed to Grid disturbance on 30 and 31 July 2012.

PGCIL confirmed (March 2013) the above position.

(b) Non-implementation of Special Protection Scheme

NRLDC moved a proposal (August 2010) to Northern Regional Power Committee (NRPC) for implementation of a Special Protection Scheme (SPS) to handle contingency arising due to sudden interruption of import by NR from WR through 400 kV Agra- Gwalior line. The proposal indicated that tripping of Bina-Gwalior circuits (in Agra-Gwalior-Bina line) resulted in rush of power flow through other interconnections of NR with WR and ER leading to overloading of networks with a potential to cause cascade tripping in large part of Grid. SPS envisaged shedding of loads in NR to be achieved within 500 milliseconds in such a contingency. This particular contingency had actually occurred thrice *i.e*. 28 November 2009, 7 December 2009 and 1 July 2010. NRPC approved (November 2010) the proposal and directed that PGCIL should implement it on priority. However, the target dates for implementation of the SPS were postponed by NRPC with the result that PGCIL did not implement SPS until after two GDs of 30 and 31 July 2012. SPS was partly implemented by PGCIL in August 2012.

MOP stated (March 2014) that generation back down in WR was to be identified and finalised by NRPC in coordination with Western Region Power Committee (WRPC); however, locations of generation back down were not identified; locations of load shedding were also altered many times by state utilities, last in the series was 24 July 2012. MOP, added that NRPC intimated, locations for generation back down in WR on 15 July 2013 and SPS had since been implemented by PGCIL.

The fact remains that timely action on implementation of SPS would have acted as a protective mechanism to avert GDs on 30 and 31 July 2012.

7.4.4 Restoration procedure

'Power System Restoration Procedures' of NLDC recognised that a weaker system that had a well-tested plan for emergency procedures for restoration might be more reliable than a stronger system with no such plan. These procedures further indicated that in the event of a blackout, the initial moments were extremely precious and it required the right decision to be taken at first instance for speedy restoration of the system. Though both the 'Bottoms up' and

[93] ***Uttar Pradesh, Punjab, Haryana, Rajasthan and Uttarakhand***
[94] ***Gujarat, Madhya Pradesh, Maharashtra, Chattisgarh, Goa, Dadra and Nagar Haveli and Daman and Diu.***

'Top down' approaches[95] were adopted while restoring power supply during GDs of 30 and 31 July 2012, 13.27 hours and 2.45 hours to 5 hours were taken for full restoration in different regions, on the two days respectively**.** Priority was given to restore traction (Transmission lines feeding Railway loads) which took one to eight hours on 30 July 2012 and 17 minutes to ten and half hours on 31 July 2012. In this connection, GOI enquiry found that after extending start-up power, most of the generating units took considerable time in 'lighting up[96].

Hydro Stations, which were required to play a significant role in restoration[97] as they had to produce power first, which was then extended through the lines to thermal stations, took time to black start[98]. There was a gap of one hour between the Grid disturbance (0233 hours on 30 July2012) and the time when the first Hydro Station black started (0340 hours on 30 July 2012) indicating loss of precious time. The other Hydro Stations took more time in black starting and took more than seven hours [99] to begin generation.

MOP stated (March 2014) that the restoration involved coordination among various groups (power stations, sub-stations, RLDC, NLDC etc.) and added that on 30 and 31 July 2012, the restoration time had been much less, as compared to other international grid disturbance incidences.

The reply is to be viewed against the fact that the restoration on 30 July 2012 turned out to be 'temporary' as the system collapsed in a bigger way the next day, on 31 July 2012. This would underline the need for putting in place clear benchmarks to assess the status of restoration of the system after a GD.

7.4.5 Long term and systemic issues relating to Grid Management

Examination in audit revealed that there was a scope for eliminating systemic inadequacies such as absence of warning system, weak inter regional connections and so on, in Grid management. These are discussed below:

(a) Warning System

Indian Electricity Grid Code (IEGC) has put in place a system of 'event reporting' as part of Grid management. However, an early warning mechanism by way of declaration of emergency status was not envisaged in IEGC. Report on the US-Canada blackout of August 2003, which offered a case study, had *inter alia*, mentioned that a transmission emergency existed when the system's line loadings and voltage/reactive levels were such that a single

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[95] ***Bottoms up approach –Use 'Black start facility (Building the grid after a grid disturbance) available within the region among hydro, gas and some thermal power stations to start producing power, add loads step by step and build blocks of restored areas;***
Top down approach - Take power from other regions which remain connected to initiate restoration in the affected region.

[96] ***Lighting up is used in the context of coal fired generating units and refers to the starting up of the boilers using oil (could be either Light Diesel Oil or Low Sulphur Heavy Stock or Heavy furnace Oil) depending on the boiler design. Only after this process is complete, the steam turbine can be rolled and the generator synchronized to the main grid.***

[97] ***As they can begin generation almost immediately since no 'lighting up' of boiler was involved.***

[98] ***Building the grid after a grid disturbance***

[99] ***Chamera Unit II started at 1017 hours i.e. 0744 hours after the blackout at 0233 hours.***

contingency could threaten the reliability of the interconnection. The Report further stated that the North American Electrical Reliability Council (NERC) Operating Manual defined various types of emergency such as 'capacity emergency' and 'energy emergency'. There would appear to be a need to introduce similar provisions in the IEGC to deal with situations of GD with potential cascading effect.

MOP noted (March 2014) the observation for taking up the matter with appropriate regulatory authorities.

(b) Inter-connection of NR with neighbouring Regions

One of the indicators of strength of bonds between regions is the distribution of power flow among various links during real time operation. *Inter-se* distribution of power flow among inter-regional links indicated that power transmission to and from NR depended on two trunk lines *viz*. 400 kV Agra-Gwalior (for WR-NR) and 400 kV Muzaffarpur– Gorakhpur (for ER-NR). Regular heavy power flows during the last three years **(*Annexure 7.7*)** indicated high-risk of isolation of NR in the event of outage of these lines.

PGCIL went in for a planned shutdown of one of the circuits of the 400 kV Agra-Gwalior link. The power flows, however, could not be handled by other links which tripped/went on forced outage much before their loadable limits and the system eventually collapsed on 30 and 31 July 2012. There is thus, a need to strengthen the bonding of NR with the connecting regions which would ensure more dispersed power flow across existing links.

MOP stated (March 2014) that to address the issue many additional links have already been planned between NR and WR viz. Gwalior(WR) – Jaipur(NR) 765 kV 2x single circuit line, Champa (WR) – Kurukshetra (NR) ±800 kV, 6000 MW HVDC bipole line, Jabalpur(WR)–Orai (NR) 765 kV D/c line which were under different stages of implementation.

MOP may consider advising PGCIL to expedite the commissioning of proposed linkages and review the adequacy thereof to ensure a reasonably dispersed power flow.

(c) ***Regulatory tools to deal with congestion***

CERC (Measures to relieve congestion in real time operation) Regulations, 2009 define 'congestion' as a situation where the demand for transmission capacity exceeded ATC. NLDC/RLDCs have been empowered to levy congestion charge[100] to relieve congestion in real time for which CERC approved 'real time congestion management procedure' under clause(2) of Regulation No. 4 *ibid*. On 30 and 31 July 2012, NLDC/NRLDC did not kick-in congestion charges though the WR-NR and ER-NR corridors faced congestion. NLDC attributed this to limiting provisions in CERC Regulations. In this connection, GOI enquiry report had pointed out that there was no provision in regulations that restrained NLDC from applying congestion

[100] ***Congestion charge may be imposed on a regional entity or entities causing congestion and paid to any regional entity or entities relieving congestion. The rate of congestion charge is ₹5.45 per unit which was in the nature of a commercial deterrent in bringing down congestion.***

charges but detailed procedure on 'real time congestion management' did restrain NLDC from applying congestion charges. The GOI enquiry report added that the procedure was inconsistent with the regulations.

There was a scope for further improvement in levy of congestion charges proposed in 'Detailed Procedure for relieving congestion in real time operation' as discussed below:-

(i) NLDC proposed that congestion charges would be applied simultaneously on all entities in the upstream[101] and downstream[102] areas. The approved procedure indicated that at frequency below 50 Hz congestion charge would be levied for over drawal or under injection in the importing control area and at frequency above 50 Hz congestion charge would be levied for under drawal or over injection in the exporting control area.

(ii) As per NLDC's proposal, if congestion is caused by forced outage, open access transactions shall be curtailed first followed by revision of TTC. However, as per approved procedure, no congestion charge was to be applied in such cases.

Application of congestion charge differently for frequencies above and below 50 Hz could give an impression that congestion was a problem linked to frequency. This notion had an adverse impact in controlling congestion on 30 July 2012 as one of the SLDCs, (SLDC, Maharashtra), in response to the line loading message of WRLDC, stated that below 50 Hz overdrawing constituents were responsible (for congestion). The actual situation was that the underdrawal by WR utilities was causing congestion of the WR-NR corridor. The second condition mentioned above prevented RLDCs from levying congestion charge on 30 and 31 July 2012 as there were forced outages.

Apart from the above, clause 5.4.2 of IEGC enjoined upon States to resort to load shedding if the frequency fell below 49.5 Hz. However, problems arising from under drawal and their impact on line loadings needed to be addressed more adequately in IEGC. The focus of the provisions in IEGC was mainly to discourage overdrawal by beneficiaries. Amendments to address the problems arising out of under drawal were introduced in IEGC only after the GDs of 30 and 31 July 2012.

PGCIL stated (March 2013) that they had taken up procedural difficulties in levying congestion charges with CERC which had since amended (April 2013) the procedure accepting the earlier stand of NLDC. In the Exit Conference (April 2014) representative of CERC stated that necessary changes had been carried out in the regulations.

(d) Unscheduled Interchange of power flows

Financial settlement of energy exchanges across the Grid is carried out through a mechanism called Availability Based Tariff (ABT). ABT comprises three components: (a) capacity charge, towards reimbursement of the fixed cost of the plant, linked to the plant's

[101] ***Exporting region***
[102] ***Importing region***

declared capacity to supply MWs[103], (b) energy charge, to reimburse the fuel cost for scheduled generation, and (c) Unscheduled Interchange (UI) [104] charge, a payment for deviations from schedule, at a rate dependent on the system frequency. While 'Scheduled' power is supported by contracts between buyers and sellers, UI flows are settled subsequently by RLDCs which maintain the UI Accounts.

The UI mechanism was based on the philosophy that the 'Schedule' was meant to serve as operational and commercial datum and the parties were perpetually encouraged to deviate in the direction beneficial for the interconnection *i.e*. towards enhancing overall optimization and/or improving frequency. UI was, thus, meant to be a sort of 'Seesaw' to keep the frequency within range through commercial incentives and disincentives[105]. The broad frame work was that the over drawing Discoms and 'under injecting' generators compensated monetarily the under drawing Discoms and over injecting generators respectively. The UI mechanism found wide acceptance among the stakeholders in view of its various benefits[106] and the National Electricity Policy, 2005 stated that the ABT mechanism (UI was a component of ABT) has enabled a credible settlement mechanism for intra-day power transfers from licensees with surpluses to licensees experiencing deficits.

Analysis of power flows across major inter-regional corridors during 2009-10 to 2011-12 revealed that the quantum of UI formed a significant portion of the total flows and was even more than scheduled flows in some months, as can be seen from ***Annexure 7.8.*** However, congestion arose when the cumulative flows *i.e*. Scheduled and UI outstripped the TTC of the corridors **(**illustrated in **Annexure 7.9**).

Though UI mechanism had beneficial results on certain fronts such as frequency control, better utilisation of transmission and generation resources *etc*., there were areas which posed challenges in Grid management as discussed below:

(i) Need for due regard to N-1 principle

Power system operation is based on a principle called the N-1 criterion according to which, transfer capability is assessed considering outage of the most important element. Thus, while

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[103] ***In case the average availability actually achieved over the year is higher than the specified norm for plant availability, the generating company gets a higher payment. In case the average availability achieved is lower, the payment is also lower. Hence the name 'Availability Based Tariff'.***

[104] ***UI in a time block is the difference between actual and scheduled generation or actual and scheduled drawal for a generator or a beneficiary respectively.***

[105] ***The fundamental parameter that measures the stability of the grid is its frequency which depends on the number of revolutions per minute (RPM) of the generators that are connected to the Grid. Frequency remains the same throughout an AC electrical system and if the frequency is 50 Hz, it means that all the generators connected to the grid are operating at the same speed. Closer the frequency is to 50 Hz, the better it is both for the power generating equipments at the power stations and the appliances at the consumer end. If persistent under frequency occurs it means that somewhere there is 'leaning on the grid' i.e. drawal of unscheduled electricity from the grid which depresses system frequency. The graded UI table is designed in such a way that in case of low frequency, the Discoms are encouraged to underdraw while the generators are encouraged to over inject. On the other hand, when the frequency is higher than the permitted range, it means that there is less demand for power or the tendency to detach from the grid. Under such conditions, the UI charges encourage the Discoms to overdraw and the generators to back down.***

[106] ***Grid operators – UI brought about frequency control and promoted grid stability; Discoms- Commercial incentives for underdrawals and the facility of overdrawing from the grid depending on the frequency; Generators- Commercial incentives for over-injection depending on frequency; Investors (Beneficiaries, CTU, GOI) – Optimum utilization of resources.***

preparing to schedule energy exchanges across the Grid, a reserve capability is maintained to take care of the worst single contingency in real time operation. Additional reserve by way of a reliability margin is also kept to handle any unforeseen contingencies/errors in assumptions, *etc*. However, both these reserves could get depleted depending on the quantum of UI flows and occurrence of contingencies during real time operation. For example, during GD on 30 and 31 July 2012, the worst single contingency actually happened (outage of Bina Gwalior-I line) and reliability margin of 200 MW for WR-NR proved inadequate to handle additional contingencies. With the depletion of all reserves, the corridor faced a 'cascade' of trippings. Thus, UI mechanism did not factor in the N-1 criterion which is fundamental to power system operation.

(ii) Commercial considerations by Discoms

It may be economical for a Discom to draw power through UI, even at penal slabs, rather than purchase power through organised sale channels like power exchanges or bilateral trade. This is because Unscheduled Interchange (UI) charges are levied at rates stipulated in CERC Regulations (rates notified in April 2010), while short term sale prices are market determined and vary according to demand-supply gap. In majority of the months during April 2011 to October 2012, the average UI rate was lower than the short term sale price for power sold through bilateral trades. Test check of two overdrawing States *viz.* Uttar Pradesh and Haryana, during April 2011 to September 2012, indicated that out of 14 months when overdrawal was made by these states, UI rates were less than bilateral trade rates in 11 and 10 months respectively.

Commercial considerations of Discoms to purchase power through UI instead of power exchanges/bilateral trades which are part of scheduled flows, may have the tendency to escalate congestion in the Grid. Therefore, there is a need for POSOCO to take up with CERC, the desirability of linking UI prices with exchange prices. It is also relevant to note, in this connection that, though as per CERC Regulations, UI rates were required to be notified by CERC every six months, the rates were not notified for more than two years, until September 2012, which was after the GD on 30 and 31 July 2012.

(iii) Demand-supply gap of States

Electricity being a concurrent subject under the Constitution of India, ensuring power supply involves combined efforts of the Central and State Governments. State Governments have their own generating stations and undertake efforts like capacity addition, bilateral procurement from surplus states, buying power from power exchanges *etc*, to meet the increasing demand for power. While States can avail entire power generated from the power plants owned by their respective SPUs, power generated by central sector power plants located in States is allocated as per fixed guidelines which stipulated as follows:-

- Up to 2010:

  (a) 15 *per cent* capacity was kept at the disposal of GOI

  (b) 10 *per cent was* allocated to the State in which the project was located (Home State)

  (c) 75 *per cent* of power was allocated to the States in the region including Home State

- From January 2011

  Modified guidelines, as below, for application in respect of thermal power plants of NTPC and Nuclear Power Corporation of India were approved by Cabinet in January 2011.

  (a) 15 *per cent* capacity is kept at the disposal of GOI

  (b) 50 *per cent* allocated to the State in which the project is located (Home State)

  (c) 35 *per cent* of power is allocated to other States in the region excluding Home State.

  Analysis of demand-supply data in NR during 2011-12 in audit revealed that:

- Demand-supply gap was not uniform among States. In eight States and one Union Territory in NR, demand supply deficit in Delhi, Haryana and Chandigarh was less than 100 MUs during the year while the same was significantly high ranging from 305 MUs to 9223 MUs in remaining six states. Normally a power deficient State might tend to overdraw from the Grid while a power surplus State might tend to under draw. This trend was seen in six out of eight States and one Union Territory of NR (***Annexure 7.10***). Delhi had consistently under drawn and earned UI revenue of ₹1261.44 crore during April 2011 to October 2012 while Uttar Pradesh had consistently overdrawn during 2011-12 and dues on account of UI had accumulated to ₹974.42 crore as on 31 March 2012 and further increased to ₹2529.71 crore as on 31 March 2013.

- It was possible for Discoms of power surplus States to seek a higher schedule of power and actually draw less power than the schedule in real time. Through under drawal of power as compared to the power scheduled for them, it was possible for power surplus States to earn UI revenue. As large inequalities in availability of power have the potential of increasing UI which may contribute to congestion in the Grid, it is necessary for MOP to address this issue during the process of allocation of power to States from central sector power plants.

- Over dues of UI payments aggregating ₹ 2570.86 crore as of March 2013 indicated that States were able to overdraw from the Grid without immediately paying for it. There is thus, a need for MOP to curb the practice through appropriate penal provisions[107].

(iv) Inter play between UI and congestion mitigation measures

UI mechanism is focussed on frequency based control whereas 'line loading' may or may not be dependent on frequency. There may be situations when the frequency is within the operating range but one or more critical elements of the transmission system may be overloaded. However, UI mechanism remunerates under drawing and over injecting SPUs for all frequencies within the prescribed frequency band. This may run counter to congestion mitigation measures being tried by RLDCs to bring down 'line loading'.

[107] ***CERC has levied (May 2006) a token penalty of ₹ one lakh on UPPCL for in-disciplined over drawal from the Grid.***

During the GD of 30 July 2012, the frequency was within the prescribed band. It was thus favourable for SPUs in WR to earn UI income through under drawals and over injection and they were reluctant to reduce under drawals or over injection as is evident from communication received (at 22.33 Hrs on 29 July 2012) from SLDC, Maharashtra. Such reduction could have relieved the heavy loading of WR-NR corridor. UI Regulations did not have provisions to suspend UI mechanism during times of congestion and emergency which may affect the efforts of RLDCs to ease congestion aggravated by under drawals.

WR Utilities {Generating Stations (Regional) and State Discoms} had earned UI income of ₹73.05 core during the four days from 27 July 2012 to 30 July 2012, though under drawal and over injection by WR utilities was causing congestion in the WR-NR corridor. It was possible for an SPU to earn UI income either by seeking a higher schedule than what was required or through load shedding and both the strategies were being adopted by Discoms in WR. Hence under drawal and over injection got rewarded in the UI mechanism even as it had the potential to aggravate congestion and threaten Grid security. This anomaly needs to be addressed.

POSOCO stated (June2013) that they had taken up the issue of restriction of UI volumes with CERC.

In the Exit Conference (April 2014) CERC representative stated that the new Regulations have been notified recently which limit UI irrespective of the frequency of the system and that time may be given to see their impact.

(e) Inadequacies in human resource management

RLDCs/NLDC operate a shift system while deploying personnel for manning the control rooms. Review of the procedures in this regard revealed the following:

- ***Long night shifts***

The duration of night shift is 11 hours 20 minutes as against six hours 40 minutes for morning and afternoon shifts. Long night shifts are likely to cause fatigue and loss of concentration among personnel. Duration of night shift needs to be reviewed *vis-à-vis* time duration of day shifts so as to reduce the possibility of errors due to fatigue.

- ***Capacity building of system operators***

Broad requirements of training/capacity building prescribed for system operators were 'three' level certification of system operators (basic, specialist and management level); renewal of certificate every three years and continuing professional development through various refresher courses and advanced level training courses. A comparison of the status of fulfilment of the requirements by the system operators employed in RLDCs/NLDC indicated that 58 *per cent* of the control room staff had not undergone the basic level training (Short term course of power system operators). Advanced level training was yet to be imparted to operators (March 2013). Non-executives were also deployed in the control rooms (nearly 50 *per cent* in shift groups) and no minimum requirement of certification was prescribed for them.

PGCIL appreciated (March 2013) the audit observations.

7.4.6 Impact of Grid disturbances on 30 and 31 July 2012

Grid disturbances cause economic loss to Generating Stations, Distribution Utilities, Trading agencies and end users such as households, industrial units, *etc*. who have to incur extra expenditure on alternative sources to produce power during the outage period. These also have an unquantifiable adverse impact on maintenance and delivery of essential services including medical treatment and emergencies. Neither GOI Enquiry Report of August 2012 nor PGCIL/POSOCO's report dated 9 August 2012 to CERC mentioned about these losses. In reply to an Audit query, POSOCO informed that energy not served *i.e*. energy that would have been served to consumers on a normal day of the same period, due to two GDs was 390 million units on 30 July 2012 and 366.80 million units (MUs) on 31 July 2012. This works out to around one third of total average energy produced in a day (average energy per day is 2400 MUs while the energy not served for the two days was 757 MUs).

Thus, a large part of the country had to go without electricity for hours due to GDs on 30 and 31 July 2012. As discussed in the preceding paragraphs, the situation was possible to have been avoided if

(i) PGCIL had carried out outage planning during lean season,

(ii) NLDC had reviewed TTC and contingency status timely and conveyed instructions to WRLDC assertively,

(iii) SLDCs had acted upon the instructions of RLDCs promptly to reduce over drawal/ under drawal/ over injection.

Systemic improvements by way of introduction of warning system to convey emergencies to constituents, strengthening of interregional corridors, effective regulatory tools to deal with congestion and UI mechanism would further improve Grid Management.

MOP stated (March 2014) that the high level Technical Enquiry Committee constituted by the Government of India after the GDs had already analyzed the incident in depth and came to the conclusion that no single factor was responsible for grid disturbances on 30th and 31st July 2012. Similarly, POSOCO and CTU's report to the CERC had also highlighted the systemic issues which needed serious attention. MOP was of the view that highlighting issues such as approval of 400 kV Bina-Gwalior-Agra outage during peak season, non-revision of TTC and lack of actions in real time by RLDCs/NLDC as the reasons for the grid disturbances would result in the larger issues getting lost.

MOP however assured that the observations by Audit had been taken note of and efforts were being made to continuously improve the system by all concerned.

The fact remains that the GDs were initiated by the outage of the Bina-Gwalior-Agra link during peak season which was planned without following the due procedure (Para 7.4.1). This was further compounded by non-revision of TTC and higher scheduling of power (para 7.4.2 (a)).

During discussion in the Exit Conference (April 2014), MOP accepted that the happenings leading to GDs of 30 and 31 July 2012 as brought out by Audit point to the need for bringing out systemic changes and a tighter control over TTC.

7.4.7 Remedial measures taken after GDs of July 2012

POSOCO and PGCIL have, however, taken remedial measures to improve grid operation after the two GDs of 30 and 31 July 2012,which included the following:

(i) Senior officials were deployed on control room duty.

(ii) Special Protection Scheme was implemented for the contingency of outage of Agra-Gwalior circuit.

(iii) Permissible frequency band was tightened from 49.5 – 50.2 Hz to 49.7– 50.2 Hz.

(iv) The procedure for congestion management was amended to give more operational freedom to RLDCs to handle congestion.

(v) An advanced version of software was procured to improve the quality of power system simulation studies.

Apart from the above, petitions filed by POSOCO in CERC to improve real time data availability (called ‘telemetry’) at RLDCs, amendments to Indian Electricity Grid Code, new deviation settlement mechanism, automatic demand management by SLDCs, *etc* were under various stages of consideration by CERC. These are expected to further improve Grid Management.

CHAPTER - 8

Monitoring System

8.1 Project Monitoring

PGCIL monitors projects through a two tier monitoring system at both pre-award and post-award stage of contracts. For corporate level monitoring, Corporate Monitoring Group (CMG) and for Regional level monitoring, Planning Environment & Social Management (PESM) Departments of the concerned regions are the responsibility centers.

8.2 Pre-award monitoring

While WPPP prescribed monthly pre-award meetings at the level of Executive Director (Contract Services) and review meetings at the level of Director (Projects) once in two months, the same were held after an average gap of four months during March 2007 to April 2012. Minutes of meetings were not maintained.

During these meetings, Executive Director (Contract Services)/Director (Projects) had instructed that early supply of inputs/ finalisation of qualification requirements for timely floating of NIT, *etc* be examined. A review of 47 cases where specific dates were targeted in meetings held during April 2007 to March 2012 to complete pre-award activities revealed that in 16 cases, compliance was delayed by one to 13 months Further, details of follow up action on decisions taken, if any, in previous meetings were not on record.

8.3 Post-award monitoring

8.3.1 Monthly Progress Reports

WPPP laid down that Regional PESM Department was required to submit Monthly Progress Report (MPR)[108] to the Corporate Centre. Corporate Monitoring Group at corporate level was thereafter, required to submit a region-wise summarized Management Information System (MIS) report to CMD and all Directors.

The format of MPR was, however, not standardized and different formats were used by different Regions for sending the information. A test check of 21 MPRs[109] of all nine Regions pertaining to March 2010, March 2011 and March 2012 revealed that status in respect of various relevant issues, such as sub-vendor approval, PGCIL's obligations, site activities *etc.* were not included, though it was required as per WPPP. Moreover, CMG at corporate level did not furnish summarized MIS as required to be submitted to Directors/CMD.

[108] ***containing complete information relating to projects along with exception reports identifying critical areas and action taken report in respect of action plan decided in previous meeting.***

[109] ***Out of 27 MPRs (three each for nine Regions) six MPRs (SR-I for March 2011, SR-II for March 2010, ER-I for March 2010 & March 2012 and NR-I for March 2010 & March 2011) were not furnished by the Management.***

8.3.2 Project Review Meetings

WPPP of PGCIL provided that, for better coordination amongst various departments at Corporate Office and Regions as well as smooth execution of projects, Region-wise Project Review Meetings (PRMs) shall be held and chaired by the Executive Director of respective Region, once in two months.

Review of records, however, revealed that PRMs were not held at prescribed intervals as meetings ranging between three and 12 were held[110] by Regions against 30 meetings required to be conducted by each Region during 2007-2012.

8.3.3 Quarterly Performance Review at MOP level

In addition to project monitoring system at PGCIL's level as discussed above, MOP also monitored the performance of PGCIL projects every quarter. However, status of quarterly performance review meetings held during 2007-12 revealed that such meetings were not held for two quarters (third quarter of 2007-08 and fourth quarter of 2011-12) and 14 meetings were held with delays ranging from three months to six months. This needs to be viewed in the context that only one out of 20 projects selected for audit, was completed within the scheduled time.

8.4 Project completion reports

PGCIL did not have the system of preparing project completion reports after completion of projects to bring out at one place all technical and financial details of the project, major problems faced during implementation and specific initiatives/actions taken to solve them. Such reports could be used to bring on record any special process or methodology adopted and its experience/achievement as well as any important aspects to be kept in view in future projects.

MOP noted (March 2014) the audit observations contained in paras 8.2, 8.3 and 8.4 and assured that these would be suitably addressed in revised WPPP/ERP.

[110] ***WR I-12, WR II-09, NR I-09, NR II-07, NER-07, SR I-05, SR II-03, ER I-03 and ER II-03.***

CHAPTER - 9

Conclusion and Recommendations

9.1 Conclusion

One of the major objectives of formation of PGCIL was to bring about integrated operation of the regional transmission systems by undertaking construction of inter-regional links. This was to facilitate the growth of economic exchange of power (replacing costly energy transactions within a region with cheaper ones from another region to reduce the cost of power) which would ultimately lead to formation of a 'National grid' and ensure better utilisation of available generation resources. The process of integration of regional grids was progressively taken up from 1990s and with the synchronisation of Southern Grid with the rest of the grid on 31 December 2013, the entire Indian power transmission grid is now being operated at the same frequency and load generation balance is achieved at a national level, completing the technical process of formation of 'National Grid'. However, when viewed in terms of congestion scenario and low level of inter-regional power transfer capability, the objective of formation of 'National Grid' remains to be fully achieved.

Power exchange data showed that percentage of time congestion occurred above 75 *per cent* increased from two months in 2010-11 to all the 12 months in 2012-13. Similarly, volume of electricity that could not be cleared due to congestion (as a percentage of the actually cleared volume), went above 75 *per cent* for 3 months in 2011-12 and increased to five months in 2012-13. Impact of congestion was visible in large variations in the electricity prices over the regions. Comparison of Market Clearing Prices (price for cleared transactions in the whole country, if there is no congestion at all) with the Area Clearing Prices[111] in Indian Energy Exchange showed that buyers in S1 and S2 bid areas (States of Tamil Nadu, Kerala, Andhra Pradesh, Karnataka, Goa and Union Territory of Pondicherry) paid higher prices during 2011-13 (₹ 5.1 to 7.3 per unit as against Market Clearing Price of ₹3.5 per unit) to procure power. On the other hand, sellers in W3, E1 and E2 bid areas (Chhattisgarh, Orissa, West Bengal, Sikkim, Bihar and Jharkhand) received lower prices (₹ 2.8-2.9 per unit as against Market Clearing Price of ₹ 3.5 per unit) due to transmission constraints. Thus, there remains a need for strengthening WR-SR and ER-SR links (W3, E1, E2 to S1 and S2 *i.e.* generation surplus to power deficient states) to fully achieve the benefits of a 'National grid'.

XI Plan (2007-2012) noted that planning and operation of the transmission system had shifted from the regional level to the national level necessitating the need for a strong all-India grid. Towards this end, XI Plan stipulated target of inter-regional transfer capacity of 17000 MW. Against the XI Plan target of 17000 MW, PGCIL achieved 13900 MW of inter-regional capacity leaving a shortfall of 3100 MW in achievement. While shortfall to the extent of 1000 MW was due to annulment of one of the projects, the remaining shortfall of 2100 MW was

[111] ***In case of congestion across a transmission corridor, the cleared prices in different areas i.e. Area Clearing Prices (ACP) are adjusted so that the flow of power across transmission corridor is same as available transfer capability.***

due to controllable factors like delay in submission of proposal for forest clearance and land acquisition issues. MOU targets for PGCIL for 2007-12 were fixed at 10100 MW which fell short of XI plan target by 6900 MW (17000 MW minus 10100 MW). In two years (2007-08 and 2010-11) MOU targets were fixed at 'Nil'.

Capacity augmentation in inter-regional corridors was assessed by PGCIL based on addition of physical capacity of individual lines connecting two regions without taking into account its total power transfer capability (TTC). Cumulative transmission capacity at the end of XI Plan arrived at by adding physical capacity of all inter-regional lines was 25050 MW against which the cumulative transfer capability was only 11530 MW. In fact, inter-regional TTC showed a decline from 12280 MW in 2010-11 to 11530 MW in 2011-12. TTC of a corridor, *i.e.* the ability of a transmission corridor to move power from one region to another, is often less than the physical transmission capacity due to system limitations. Thus, for better appreciation of ability of transmission network to transfer power across regions it is necessary that TTC is also declared and disclosed alongwith transmission capacity.

Import of power by NR is mainly through WR-NR and WR-ER-NR corridors. Import by NR is dependent on the transfer capability of 'short-tie' of WR-NR rather than that of the 'long tie' of WR-ER-NR. However, bulk of the inter-regional augmentation (63 *per cent* of total inter-regional transmission capacity of 25050 MW (cumulative at the end of XI Plan) was concentrated along the long-tie. Hence, high level of augmentation of the longer tie *i.e.* ER-NR, ER-WR and NER-ER-WR would not yield desired results for transmission of increased power to the NR as the short tie *i.e.* WR-NR is not adequately augmented.

PGCIL has not put in place a mechanism for assessing utilisation of transmission lines with the result that there were pockets of congestion, as well as areas of redundancy. As an illustration, in Odisha region, there was congestion in the transmission network due to interim 'Loop in Loop out' arrangements made for evacuation of power from Independent power producers without ensuring adequacy of the transmission system. On the other hand, out of 22 high voltage 765 kV lines, six lines remained undercharged at 400 kV for more than 5 years out of which two lines remained undercharged for more than 13 years. During 2011-12, average utilisation of 33 out of 40 inter-regional lines ranged between 0 to 30 *per cent* in all inter-regional corridors except WR-SR and ER-SR. In case of intra-regional lines, 478 (68 *per cent*) out of 706 lines in five regions had average utilisation of 0-30 *per cent* only.

The Country faced a severe Grid disturbance (GD) on 30 and 31 July 2012 which resulted in 757 million units of energy not being served (compared to total generation of 2400 million units per day) to users. The proximate cause for the major GD of 30 July 2012 (involving NR) and 31 July 2012 (involving Northern, Eastern and North-Eastern Regions) was ill-timed shut down of the trunk line (400 kV Bina - Gwalior-Agra) between WR and NR for four days (26 to

29 July 2012) in peak season due to construction work. While the shutdown initially planned for four days got extended due to non-completion of work, TTC on WR-NR corridor that was curtailed from 2400 MW to 2000 MW during initially planned shutdown was not restricted to 2000 MW by NLDC in the extended shutdown though the system had faced a near miss situation on 29 July 2012. TTC was not reviewed on WR-NR corridor on 30 July 2012 which led to scheduling of power by RLDCs beyond the capacity of system. Over scheduling coupled with over-drawals by NR SPUs and under-drawals/over-injection by WR SPUs overloaded the system beyond control, which ultimately led to 'cascade tripping' of alternate paths. WRLDC did not instruct WR generators to back down power generation and did not convey proper instructions to SPUs to reduce under drawal of power, which was a major cause for GD. SPUs in NR and WR did not comply with RLDCs' instructions which contributed to over- loading of lines.

Systemic issues such as absence of early warning mechanism by way of declaration of emergency status, fragile interconnection of NR with connecting regions due to skewed *inter-se* distribution of power flow among the links, heavy volume of Unscheduled Interchange (UI) flows due to commercial consideration, demand-supply gap and inter-play between UI and congestion mitigation measures contributed to GD in July 2012.

Works and Procurement Policy of PGCIL limits the exercise of detailed survey of transmission line route only to forest stretches, contrary to advice of Working Group on power for XI Plan constituted by Planning Commission, which suggested that detailed survey should be carried out before start of procurement process. 179 contracts (42 *per cent*) were finalized within the prescribed time frame of 20/28 weeks while 245 contracts (58 *per cent*) were finalized beyond the prescribed time frame. Thus, contracts could not be finalised within the stipulated time frame in majority of the cases. Delay in award was due to delayed funding tie up with World Bank (in case of ERSS-I[112], East-West Transmission Corridor and WRSS-II[113] projects), and excessive time taken by PGCIL in contract finalisation.

Out of 20 projects selected for Audit, only one was completed within scheduled time and delay was above 20 months in nine projects. Time taken in acquisition of land, handing over site and providing approved drawings to contractors, release of advance to contractors and forest clearance had contributed to delays which were possible to have been controlled by PGCIL, with more effective planning and monitoring.

PGCIL also lost the opportunity of earning ₹350.28 crore during the project life towards additional return on equity, which could have been earned in terms of CERC Regulations, for commissioning of projects within the prescribed timeline in case of projects approved after 1 April 2009.

[112] ***Eastern Region System Strengthening Scheme-I***
[113] ***Western Region System Strengthening Scheme-II***

Monitoring mechanism for implementation of transmission projects, though in place, needed further strengthening as the project review meetings were not held as per the prescribed frequency of once in two months. Against 30 meetings required to be held during 2007-12, meetings ranging between three and twelve were held in various regions. Minutes of the pre award meetings as well as follow up action on the decisions taken in the previous meetings were not recorded.

Between 2004-05 and 2012-13, PGCIL received ₹906.49 crore as part of STOA charges that were required to be used for building new transmission systems as per regulations and orders of CERC. However, PGCIL did not maintain project-wise details of transmission schemes where these STOA charges were utilised with the result that new transmission systems/ schemes were deprived of reduction of capital cost.

9.2 Recommendations

Based on the audit findings discussed in the foregoing chapters, the following recommendations are made to facilitate improvement in the planning, implementation of transmission projects and management of Grid:-

(i) CEA and PGCIL may enhance capacity of interregional corridors appropriately based on analysis of data regarding power transfer requirements between regions to fully achieve the objective of formation of 'National Grid'.

(ii) PGCIL may disclose and monitor the key parameter of TTC in the long and medium term as per CERC regulations and for better appreciation of the transfer capability of the system.

(iii) MOP may evolve norms for assessing efficiency of transmission network and loss reduction in accordance with the tariff policy.

(iv) POSOCO may study the possibility of developing a system for offering un-requisitioned inter-regional transfer capability to needy users and consider making a proposal in this regard before CERC.

(v) To expedite project execution, PGCIL may initiate advance action to conduct detailed survey of forest stretches and submit forest clearance proposals before investment approval of the project.

(vi) Since long shut down to carry out construction work was the starting point for two major GDs, POSOCO may stipulate tolerance limits for antecedent line loadings and 'no-go' periods for key corridors for allowing long shut downs to prevent GDs. POSOCO may also consider taking up with CERC an appropriate warning system that specifies responsibility centres that would be tasked with informing constituents about state of emergency of the system.

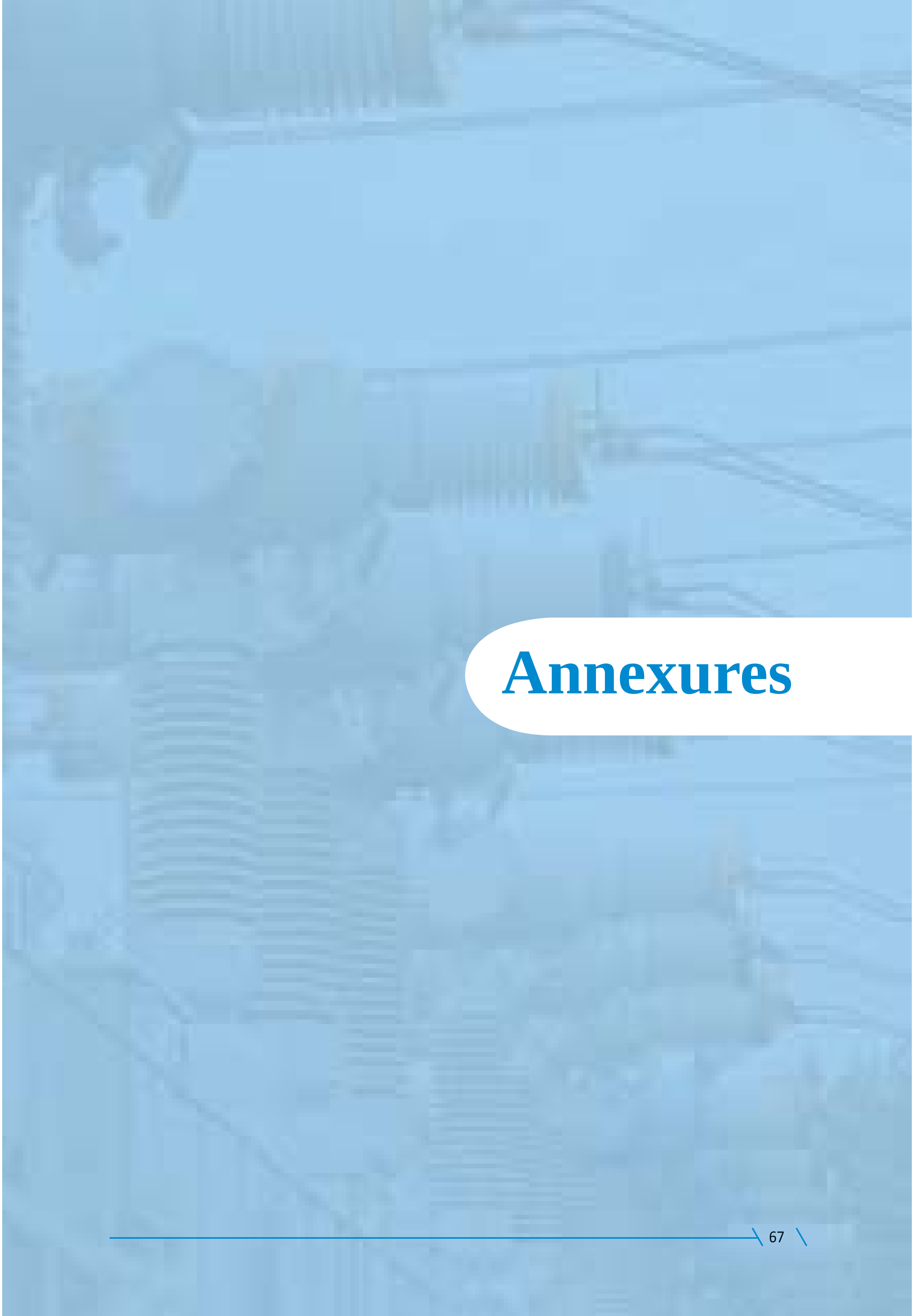
(vii) In order to improve diligence in declaring TTC and scheduling power, POSOCO may critically review the existing practices in this regard to ensure secure grid operation.

MOP was generally in agreement with the audit recommendations.

New Delhi **(PRASENJIT MUKHERJEE)**
Dated : 14 July 2014 **Deputy Comptroller and Auditor General**
and Chairman, Audit Board

Countersigned

New Delhi **(SHASHI KANT SHARMA)**
Dated : 15 July 2014 **Comptroller and Auditor General of India**



Annexures

Annexure- 2.1

(As referred to in Para 2.5)

(A) List of projects selected for Performance Audit

Sl. No.	*Project Name*	*Date of Investment Approval*	*Approved cost (₹ in crore)*	*Scheduled date of completion*
Generation linked projects				
1	Kahalgaon Stage-II (Phase-I) Transmission System	October 2004	1772	July 2007
2	Transmission System Associated with Barh	December 2005	3779	September 2009
3	Common Scheme for 765kV Pooling Station and Network Associated with DVC & Maithon RB Project, etc. and Import by NR & WR via ER.	August 2008	7075	August 2012
4	Transmission System Associated with Mundra Ultra Mega Power Project.	September 2008	4824	September 2012
5	Transmission System Associated with Sasan Ultra Mega Power Project.	November 2008	7032	November 2012
6	Transmission System Associated with Parbati-III HEP.	July 2006	557	January 2010
7	Kaiga 3 & 4 transmission system (Balance lines).	March 2005	588 1007 (Revised)	December 2007
8	Transmission System for Phase-I Generation Projects in Odisha –Pt. B.	December 2010	2743	December 2013
9	Common System associated with ISGS Projects in Krishnapatnam area of Andhra Pradesh.	August 2011	1637	August 2014
System strengthening projects				
10	System Strengthening-VII of SR.	April 2005	279	July 2009
11	System Strengthening in Northern Region for SASAN & MUNDRA (UMPP).	December 2009	1217	August 2012
12	Western Region System Strengthening Scheme-II.	July 2006	5221	July 2010
13	Northern Region System Strengthening Scheme-V.	June 2006	721	June 2009
14	East-West transmission corridor strengthening scheme.	June 2006	804	June 2009
15	Western Region System Strengthening Scheme-X.	January 2009	665	January 2012
16	System Strengthening Scheme III of Southern Region (SRSS-III)	October 2004	285	April 2007
17	Eastern Region System Strengthening Scheme-I (ERSS-I)	October 2006	976	October 2009
18	Northern Region System Strengthening Scheme-XVII.	February 2009	510	November 2011
Other projects				
19	765kV System for Central Part of Northern Grid (Part-III).	October 2009	1075	April 2012
20	North East/Northern Western Interconnector-I.	February 2009	11130	August 2013

(B) Details of sample selected for Performance Audit

Description of projects	Completed		Ongoing		Total	
	No. of projects	Approved cost (₹ in crore)	No. of projects	Approved cost (₹ in crore)	No. of projects	Approved cost (₹ in crore)
Total population:						
Generation Linked	34	43,903	30	49,911	64	93,814
System Strengthening	41	17,279	19	13,118	60	30,397
Other projects	8	1,929	12	18,692	20	20,621
Total	**83**	**63,111**	**61**	**81,721**	**144**	**1,44,832**
Sample selected:						
Generation Linked	5	24,483	4	5,945	9	30,428
System Strengthening	7	9,192	2	1,486	9	10,678
Other projects	1	1,075	1	11,130	2	12,205
Total	**13**	**34,750**	**7**	**18,561**	**20**	**53,311**
Percentage of total population	**16%**	**55%**	**11%**	**23%**		
Overall percentage of money value being covered	**14% in terms of number and 37% in terms of value**					

Annexure - 3.1

{As referred to in Para 3.1.1}

Details of installed capacity within region and transfer capability of the respective inter-regional corridor

Corridor	Export Region	Installed capacity (MW) in export region (as on 31-03-2012)*	TTC (MW)**	TTC as a %age of Installed Capacity
WR-NR	WR	64394	2000	3.11
WR-ER	WR	64394	1000	1.55
ER-NER	ER	26286	500	1.90
WR-SR	WR	64394	1000	1.55
ER-NR	ER	26286	4200	15.98
ER-SR	ER	26286	2830	10.77

Source: * CEA monthly report on Installed capacity for March 2012.

**Higher TTC (zero revision) declared by NLDC in any month during 2011-12 considered.

Annexure 3.2

(As referred to in Para 3.1.1)

Details of Congestion in Power Exchanges

Month	Percentage of volume of electricity that could not be cleared due to congestion to the actual cleared volume						Percentage of the time congestion occurred during the month					
	Indian Energy Exchange			Power Exchange of India Limited			Indian Energy Exchange			Power Exchange of India Limited		
	2010-11	2011-12	2012-13	2010-11	2011-12	2012-13	2010-11	2011-12	2012-13	2010-11	2011-12	2012-13
April	2	16	24	8	52	243	35	**79**	**100**	34	**79**	**100**
May	1	2	4.09	3	7	38.58	7.53	28	**99.97**	8.06	36	**100**
June	3	2	4.84	2	8	32.02	15.83	18	**76.67**	15.69	21	**80.42**
July	0.6	4	5.07	1.2	9	49.80	5.11	42	**79.77**	5.24	44	**84.71**
August	6.9	3	9.90	2.7	14	**118.72**	8.06	39	**98.96**	16.26	47	**99.44**
September	0.0	1	18.04	2.7	4	**172.71**	10.56	30	**98.75**	11.25	40	**100**
October	7	5	7.66	16.5	11	**128.08**	45.43	**72**	**95.97**	49.17	**76**	**97.41**
November	5.4	9	17.01	51.7	12	**122.25**	47.50	47	**100**	55.83	50	**100**
December	1.7	16	17.43	18	33	**156.59**	34.14	**78.6**	**99.97**	38.71	**79.2**	**98.59**
January	2	21	20.94	7	**124**	63.14	53	**94**	**99.60**	57	**93**	**98.76**
February	8.5	38	21.42	22.4	**256**	74.93	**88.69**	**99.57**	**100**	**84.23**	**100**	**100**
March	10	42	25.19	58	**274**	61.41	**95**	**100**	**100**	**96**	**100**	**100**

Note: Source of data: CERC web site - Monthly Report on short term transaction of electricity by Market monitoring cell of CERC.

Comparison of market clearing prices (MCP) and area clearing prices (ACP) in Indian Energy Exchange

(figures in ₹)

Year	MCP (Rs. Per kWhr)	ACP > MCP (by 50 paise)		ACP < MCP (by 50 paise)									
		S1	S2	A1	A2	E1	E2	W1	W2	W3	N 1	N2	N3
2010-11	3.6	4.4	4.5	-	-	-	-	-	-	-	-	-	-
2011-12	3.5	5.1	5.3	-	-	-	-	-	-	-	-	-	-
2012-13	3.5	6.9	7.3	-	-	2.9	2.9	-	-	2.8	-	-	-

Note: The above amounts are the charges per unit of electricity. Other charges such as transmission charges, losses and other levies are payable extra.

'-' indicates the difference between ACP and MCP was less than 50 paise per unit of electricity.

Annexure 3.3

(As referred to in Para 3.1.1 and 3.1.3)

Details of Cumulative Inter Regional transmission capacity at the end of XII Plan

Corridor (i)	Transmission Capacity expected at the end of XI Plan (ii)	Expected addition during XII Plan (iii)	Cumulative transmission capacity at the end of XII Plan (iv) = (ii)+(iii)
ER-SR	3630	0	3630
ER-NR	10030	7900	17930
ER-WR	4390	8400	12790
ER-NER	1260	1600	2860
NR-WR	4220	10200	14420
WR-SR	1520	6400	7920
NER/ER-NR/WR	0	6000	6000
TOTAL	**25050**	**40500**	**65550**

Annexure 3.4

(As referred to in para 3.1.5)

Average utilisation of Inter-regional lines during 2011 – 12

Corridor	Total No. of Lines analysed	Utilisation range							
		0-30%		31%-50%		51%-75%		76%-100%	
		No. of Lines	%age of lines to total lines of region	No. of Lines	%age of lines to total lines of region	No. of Lines	%age of lines to total lines of region	No. of Lines	%age of lines to total lines of region
WR-NR	9	8	***89***	1	11	-	-	-	-
ER-NR	9	7	***78***	1	11	1	11	-	-
WR-ER	7	7	***100***	-	-	-	-	-	-
ER-SR	4	3	***75***	-	-	-	-	1	***25***
ER-NER	8	8	***100***	-	-	-	-	-	-
WR-SR	3	-	-	-	-	2	67	1	***33***

Average utilisation of intra-regional transmission lines during 2011-12

Name of Region	Total No. of Lines analysed (excluding lines having 0 power flow)	Utilisation range									
		0-30%		31%-50%		51%-75%		76%-100%		>100%	
		No. of Lines	%age of lines to total lines of region	No. of Lines	%age of lines to total lines of region	No. of Lines	%age of lines to total lines of region	No. of Lines	%age of lines to total lines of region	No. of Lines	%age of lines to total lines of region
NR	176	125	71	39	22	11	6	1	1	0	0
ER	111	87	78	15	14	5	4	4	4	0	0
WR	173	95	55	30	17	36	21	8	5	4	2
NER	118	95	81	22	19	1	1	0	0	0	0
SR	128	76	59	42	33	6	5	1	1	4	3

Annexure-3.5

(As referred to in Para 3.1.6)

Comparison of unused access with STOA rejected

(Figures in MW)

	WR-NR						ER-NR							
Year/ Month	**TTC**	**LTA & MTOA**	**STOA granted**	**Total Acess granted**	**Schedule**	**Unused access (1)**	**TTC**	**LTA & MTOA**	**STOA granted**	**Total Acess granted**	**Schedule**	**Unused access (2)**	**Total Unused access for NR import (1+2)**	**Rejected STOA**
2009-10				**(A)**	**(B)**	**A-B***				**(C)**	**(D)**	**C-D**		
Apr-09	1300	0	1100	1100	-16	1100	1800	914	586	1500	200	1300	2416	0
May-09	1300	0	1100	1100	205	895	2000	1110	590	1700	966	734	1629	99
Jun-09	1300	0	1100	1100	611	489	2500	1291	909	2200	1083	1117	1606	391
Jul-09	1500	0	1300	1300	994	306	2500	1482	718	2200	1361	839	1145	507
Aug-09	1500	0	1300	1300	1079	221	2800	1478	1022	2500	1795	705	927	364
Sep-09	1500	0	1300	1300	1048	252	2800	1512	988	2500	1664	836	1088	1220
Oct-09	1500	0	1300	1300	907	393	2800	1700	800	2500	1523	977	1370	343
Nov-09	1500	0	1300	1300	883	417	2800	1414	1086	2500	1628	872	1289	67
Dec-09	1500	0	1300	1300	869	431	2900	1398	1202	2600	1484	1116	1547	10
Jan-10	1500	0	1300	1300	1030	270	1800	1058	542	1600	1427	173	443	123
Feb-10	1500	0	1300	1300	789	511	2300	1061	939	2000	1167	833	1344	28
Mar-10	1500	0	1300	1300	455	845	2400	1009	1091	2100	674	1426	2271	0
2010-11														
Apr-10	1500	0	1300	1300	533	767	2900	1226	1374	2600	446	2154	2921	52
May-10	1500	0	1300	1300	721	579	2900	1118	1482	2600	927	1673	2253	14
Jun-10	1800	0	1600	1600	1219	381	3200	1315	1585	2900	1914	986	1367	7
Jul-10	1800	0	1600	1600	1365	235	4000	1124	2576	3700	2148	1552	1787	1
Aug-10	1900	0	1700	1700	1490	210	4300	1331	2669	4000	1990	2010	2220	0

Year/ Month	WR-NR TTC	WR-NR LTA & MTOA	WR-NR STOA granted	WR-NR Total Acess granted	WR-NR Schedule	WR-NR Unused access (1)	ER-NR TTC	ER-NR LTA & MTOA	ER-NR STOA granted	ER-NR Total Acess granted	ER-NR Schedule	ER-NR Unused access (2)	Total Unused access for NR import (1+2)	Rejected STOA
Sep-10	1900	0	1700	1700	959	741	4300	1331	2669	4000	1228	2772	3513	0
Oct-10	1900	0	1700	1700	383	1317	3500	1111	2089	3200	1414	1786	3103	16
Nov-10	2000	0	1800	1800	70	1730	3500	1050	2150	3200	1348	1852	3582	0
Dec-10	1900	0	1700	1700	305	1395	3500	957	2243	3200	1452	1748	3143	0
Jan-11	1900	0	1700	1700	1038	662	3500	1258	1942	3200	1298	1902	2563	0
Feb-11	1900	0	1700	1700	790	910	2500	1007	1193	2200	757	1443	2354	0
Mar-11	1900	0	1700	1700	670	1030	3000	950	1750	2700	631	2069	3100	0
2011-12														
Apr-11	1900	0	1700	1700	593	1107	3000	979	1721	2700	726	1974	3081	0
May-11	1900	0	1700	1700	872	828	3000	1199	1501	2700	1316	1384	2212	0
Jun-11	1900	0	1700	1700	1181	519	3500	1027	2173	3200	1536	1664	2183	66
Jul-11	1900	0	1700	1700	1576	124	4000	1027	2673	3700	2116	1584	1708	428
Aug-11	1900	0	1700	1700	1480	220	4200	1027	2873	3900	1803	2097	2317	116
Sep-11	1900	0	1700	1700	1045	655	4100	1014	2786	3800	880	2920	3575	29
Oct-11	1900	0	1700	1700	270	1430	4100	1049	2751	3800	628	3172	4602	66
Nov-11	2000	0	1800	1800	-345	1800	3500	944	2256	3200	1107	2093	4239	0
Dec-11	2000	0	1800	1800	3	1797	3500	944	2256	3200	1323	1877	3673	0
Jan-12	2000	0	1800	1800	505	1295	3400	977	2123	3100	1572	1528	2823	5
Feb-12	2000	0	1800	1800	436	1364	3400	977	2123	3100	1481	1619	2983	3
Mar-12	2000	0	1800	1800	-143	1800	3100	977	1823	2800	1330	1470	3413	0

*negative figure in schedule has been ignored

Note: 1. (-) sign denotes EXPORT from NR and (+) sign denotes IMPORT to NR

2. The above analysis shows broad trend regarding unutilised capability. There may be intra day anamolies in the trend.

Annexure-3.6

(As referred to in Para 3.3)

Statement indicating delays in submission of proposals for forest clearances after investment approval in respect of 20 projects selected for audit

S.N.	Project Name	Investment Approval date	Scheduled date of completion of project	Forest proposal application dates (First & Last indicated in bold)
1	Kahalgaon-II	October 2004	July 2007 (October 2008)	29.10.05/09.09.05/16.01.06/29.11.05/ 14.11.05/30.07.05/**24.01.05**/09.09.06/ 30.09.05/18.02.06/26.12.06/08.05.06/ **30.01.07**/18.11.06
2	Barh	December 2005	September 2009 (June 2012)	15.02.07/08.03.07/22.01.07/02.11.06/ 29.01.07/23.05.07/22.05.07/08.06.07/ 05.06.07/28.04.07/28.02.07/08.01.07/ 27.11.06/**09.02.08**/01.04.07/**25.06.05**
3	DVC Maithon	August 2008	August 2012 (Project not yet complete)	25.09.10/25.09.10/07.06.10/01.12.09/ 04.05.10/03.08.10/**15.03.08**/24.03.08/ 20.01.09/29.03.08/17.08.10/22.02.11/ 19.04.11/11.08.10/14.11.09/14.11.09/ 06.09.11/04.05.11/01.04.11/10.06.11/ 0**6.09.11**/18.02.10/27.08.10/17.02.10
4	Sasan UMPP	November 2008	November 2012	**14.05.09**/22.07.09/28.05.10/24.12.10/ 09.04.12/16.07.12/07.05.12/**31.08.12**
5	Mundra UMPP	September 2008	September 2012	**21.07.08**/21.07.08/23.02.10/11.07.09/ 0**2.09.11**/24.02.10
6	Parbati-III HEP	July 2006	January 2010	**26.02.07**/17.03.07/20.10.08/**30.06.09**/ 23.03.09
7	Kaiga 3 & 4 lines)	March 2005	December 2007	17.05.05/07.08.04
8	Generation Projects in Odisha -Part B	December 2010	December 2013	**07.01.12**/24.05.12/**24.09.12**/26.07.12
9	ISGSProjectsin Krishnapatnam area of AP	August 2011	August 2014	04.08.11
10	SRSS-VII	April 2005	July 2009	03.06.08/09.06.08
11	SS in N R for SASAN & MUNDRA UMPP	December 2009	August 2012	**11.5.12**/30.4.12/11.5.12/14.12.10 /**15.11.10**
12	WRSS-II	July 2006	July 2010	**04.01.10**/30.10.09/30.07.09/13.07.09/ 12.10.07/01.12.06/23.02.06/17.05.06/ 19.06.06/19.06.06/17.03.06/19.04.06/ **23.01.06**

S.N.	Project Name	Investment Approval date	Scheduled date of completion of project	Forest proposal application dates (First & Last indicated in bold)
13	NRSS-V	June 2006	June 2009	29.05.08/**21.06.08**/04.03.06/18.05.07/ 08.10.07/05.12.06/11.12.06/07.12.06/ 21.08.07/06.3.06/0**4.03.06**/06.03.06/ 03.03.08/08.10.07
14	E/W Tr. corridor SS	June 2006	June 2009	03.01.06/07.02.08
15	WRSS-X	January 2009	January 2012	-
16	SRSS-III	October 2004	April 2007	16.09.05
17	ERSS-I	October 2006	October 2009	20.12.06/08.09.07/05.05.08/02.09.06/ **15.07.06**/28.02.08/**21.01.09**
18	NRSS-XVIII	February 2009	November 2011	20.08.10/18.12.10/**23.06.10/12.3.11**
19	765kV System for Central Part of Northern Grid (Part-III)	October 2009	April 2012	01.05.11/07.07.11/27.06.11/02.06.11/ **01.08.11/30.08.10**
20	N E / N W Interconnector-I	February 2009	August 2013	20.09.10/21.09.10/09.07.11/30.04.09/ 25.05.09/07.01.10/19.10.10/22.10.10/ 20.12.10/27.08.10/**21.07.11**/31.12.09 /30.07.10/16.07.09/**27.09.07**/12.05.09/ 17.07.08/31.07.09/05.06.08/13.4.09/ 02.03.10

Note: Date in bracket in third column indicates date of commissioning of last element of transmission project

Annexure 4.1

{As referred to in Para 4.2 (ii)}

Non Financial Performance Evaluation Parameters fixed in MOU

S. No.	Parameter	2008-09	2009-10	2010-11	2011-12	2012-13
		Weightage given in the MOU				
1	Quality	2	2	1	1	0.5
2	**Customer Satisfaction**	4	**2**	2	**1**	**0.5**
3	Business Development	2	2	2	2	1
4	R & D for Sustained & continuous innovation	2	2	2	5	5
5	**Project Implementation**	20	**19**	20	**10**	**8**
6	Commercial Targets/Revenue from telecom Business	2	2	3		
7	Human Resource Development(Management)	2	-	-	5	5
8	Environment and Social Management	2	2	2		
9	**Availability of Transmission system**	13	13	**7**	**6**	**5**
10	Ratio of Inventory to Gross profit	1	1	1		
11	*Rajiv Gandhi Grameen Vidyutikaran Yojna*		5	5	5	5
12	*Corporate Social Responsibility*			5	5	5
13	*Compliance of Corporate Governance*				5	5
14	*Sustainable Development*				5	5
15	*Compliance of DPE Guidelines*					5
	Total	**50**	**50**	**50**	**50**	**50**

Observations:

1. Only one Non-mandatory Parameter 'Rajiv Gandhi Vidyutikaran Yojna' was included in the year 2009-10 with weightage of 5 points. Out of 5, 3 points were reduced from crucial parameters, customer satisfaction and Project Implementation.

2. In the year 2010-11 one mandatory parameter *i.e.* 'Corporate social responsibility' was included with a weightage of 5 points. However, 6 points were reduced from the important parameter 'Availability of transmission system' alone.

3. In the year 2011-12 three new mandatory parameters were included (Human resource Management, Compliance of Corporate Governance and Sustainable Development) with a weightage of 5 each and for one parameter 'R&D for sustainable development' points were increased from 2 to 5. Out of these 18 points, 12 points alone were reduced from the parameters Project implementation (10 points), Customer satisfaction (1 point) and Availability of transmission system (1 point).

4. In the year 2012-13 one new mandatory parameter 'Compliance of DPE Guidelines' has been included with weightage 5 points. Out of these 3.5 points has been reduced from the above mentioned three important parameters.

Annexure- 5.1

(As referred to in Para 5.1)

Statement showing variation in lengths of transmission lines as per FR and as actually constructed.

S.N.	Name of project	Name of Transmission Line	FR Line length (km)	Executed Line length (km)	Percentage Variation
1	Transmission System associated with Barh	Barh-Balia 400 kV D/C(Quad)	195.00	242.66	(+)24.44
2	Transmission System associated with Kahalgaon (stage-II)	Kahalgaon-Patna-Balia 400 kV D/C (Quad)	368	452.50	(+)22.96
3		Biharsharif-Balia 400 kV D/C (Quad)	166	241.79	(+)45.66
4		Balia –Mau (UPPCL) 400 kV D/C	20	9.12	(-)54.40
5	Transmission System associated with Kaiga 3 & 4	LILO of Kolar-Sriperumbudur 400 kV S/C line at Melakottaiyur	40.00	30.67	(-)23.33
6	East-West transmission Corridor strengthening	Ranchi- Rourkela 400 kV DC	170	144.94	**(-)14.71**
7	NRSS V	400 kV D/C Bhiwadi - Agra line	216	209	(-)3.20
8	System strengthening for Sasan & Mundra	LILO of both circuits of Nathpa-Jhakri-Abdullaur 400 kV D/C (Tripple Snowbird) Line at Panchkula 2 x 25 km)	51	49	(-)3.90
9	DVC & Maithon Right Bank	Lucknow 765/400 kV new substation - Lucknow 400/220 kV existing substation 400 kV Quad 2 X D/C line	80	2.86	**(-)96.42**
10		Ranchi 765/400 kV new substation - Ranchi 400/220 kV existing sub-station 400 kV Quad 2 X D/C line	110	144	(+)30.91
11	Sasan UMPP	Indore-Indore (MPPTL) 400 kV D/C line at Sasan	60	49.73	(-)17.12
12	Mundra UMPP	Mundra-Jetpur 400 kV D/C (Tripple Snowbird)	328	336	(+)2.40
13		Gandhar-Navsari 400 kV D/C	134	102.15	(-)23.77
14		LILO of both circuits of kawas-Navsari 220 kV D/C at Navsari	50	40.49	(-)19.02
15	WRSS X	LILO of Sipat-Seoni 765 kV S/C line at WR Pooling Station near Sipat	40	7.91	(-)80.23
16	SRSS-III	Neelamangla –Somanhally 400 kV D/C T/L	50	42	(-)16
17	ERSS-I	Jamshedpur-Baripada 400 kV D/C (ACSR)	135	141	(+)4.44

Source: Feasibility reports of respective projects and information regarding transmission lines furnished by the Management of PGCIL vide letter dated 08.01.2013 and 31.03.2014.

Annexure 5.2

(As referred to in Para 5.3)

Statement showing year wise details of unutilised balance in Power System Development Fund

(Rs. In crore)

Date	Unscheduled Interchange Charges	Congestion Revenue	Congestion Charges	Reactive Energy Charges	Total	Interest income	Amount Utilised	Investment of PSDF amount (Including cumulative Interest amount)
31.03.2011	1340.28	457.04	2.13	25.91	1825.36	40.25	0.03	1825.29
31.03.2012	2067.02	1143.07	7.74	27.41	3245.24	199.05	0.05	3425.77
31.03.2013	2496.25	1765.41	7.9	29.22	4298.78	307.59	0.05	4716.07
31.12.2013	3585.52	1922.27	10.32	30.1	5548.21	306.98	0.09	6301.64

Annexure- *6.1*

(As referred to in Para 6.3)

Statement showing scheduled dates of completion as per Investment Approval, dates of actual/anticipated completion and delay with reference to Investment Approval

S.N.	Project Name	Investment approval date	Scheduled date of completion as per Investment Approval	Actual/ anticipated date of completion	Delay in completion (actual/anticipated) with reference to scheduled date of completion as per Investment approval	Delay range (in months)
		(1)	(2)	(3)	(4)=(3) – (2) months	
Generation linked projects						
1	Kahalgaon Stage-II (Phase-I) Transmission System	October 2004	July 2007	December 2007	5	1 – 10
2	Transmission System Associated with Barh	December 2005	September 2009	December 2010	15	11 - 20
3	Common Scheme for 765kV Pooling Station and DVC & Maithon RB Project, etc.	August 2008	August 2012	March 2014	19	11 - 20
4	Transmission System Associated with Mundra Ultra Mega Power Project	September 2008	September 2012	June 2014	21	21 – 30 (ongoing project)
5	Transmission System Associated with Sasan Ultra Mega Power Project	November 2008	November 2012	September 2013	10	1 - 10
6	Transmission System Associated with Parbati-III HEP	July 2006	January 2010	October 2013	45	Above 40
7	Kaiga 3 & 4 transmission system (Balance lines)	March 2005	December 2007	Mysore-Kozikhode T/L uncertain	More than 40	Above 40 (ongoing project)
System strengthening projects						
8	System Strengthening-VII of SR	April 2005	July 2009	August 2009	1	1 -10
9	Western Region System Strengthening Scheme-II	July 2006	July 2010	December 2012	29	21 - 30
10	Northern Region System Strengthening Scheme-V	June 2006	June 2009	March 2010	9	1 - 10

S.N.	Project Name	Investment approval date	Scheduled date of completion as per Investment Approval	Actual/ anticipated date of completion	Delay in completion (actual/anticipated) with reference to scheduled date of completion as per Investment approval	Delay range (in months)
		(1)	(2)	(3)	(4)=(3) – (2) months	
11	East-West transmission corridor strengthening scheme	June 2006	June 2009	June 2011	24	21 - 30
12	Western Region System Strengthening Scheme-X	January 2009	January 2012	March 2012	2	1 - 10
13	System Strengthening Scheme III of Southern Region	October 2004	April 2007	April 2007	-	NIL
14	Eastern Region System Strengthening Scheme-I	October 2006	October 2009	May 2014	55	Above 40 (ongoing project)
15	Northern Region System Strengthening Scheme-XVIII	February 2009	November 2011	December 2013	25	21 - 30
16	North East/ Northern Western Interconnector-I	February 2009	August 2013	June 2015	19	11 -20 (ongoing project)

Projects approved after of CERC Regulations 2009

S. No	Project Name	Completion time as per CERC Regulations (in months)	Date of Investment Approval	Actual/ anticipated date of completion	Actual/ anticipated time taken in completion from investment approval (in months)	Delay beyond benchmark completion period (in months)	Delay range (in months)
1	765kV System for Central Part of Northern Grid (Part-III)	30	October 2009	Jan 2014	51	21	21 -30
2	SASAN & MUNDRA (UMPP)	32	December 2009	December 2014	60	28	21 -30 (ongoing)
3	Generation Projects in Odisha -Part B	32	December 2010	December 2014	48	16	11 -20 (Ongoing)
4	ISGS Projects in Krishnapatnam area of Andhra Pradesh	32	August 2011	August 2014	36	4	1 – 10 (Ongoing)

Annexure- 6.2

(As referred to in Para 6.3)

Statement showing loss of incentive of 0.5 per cent additional Return on Equity due to late commissioning of projects with reference to scheduled completion period as per CERC Regulations.

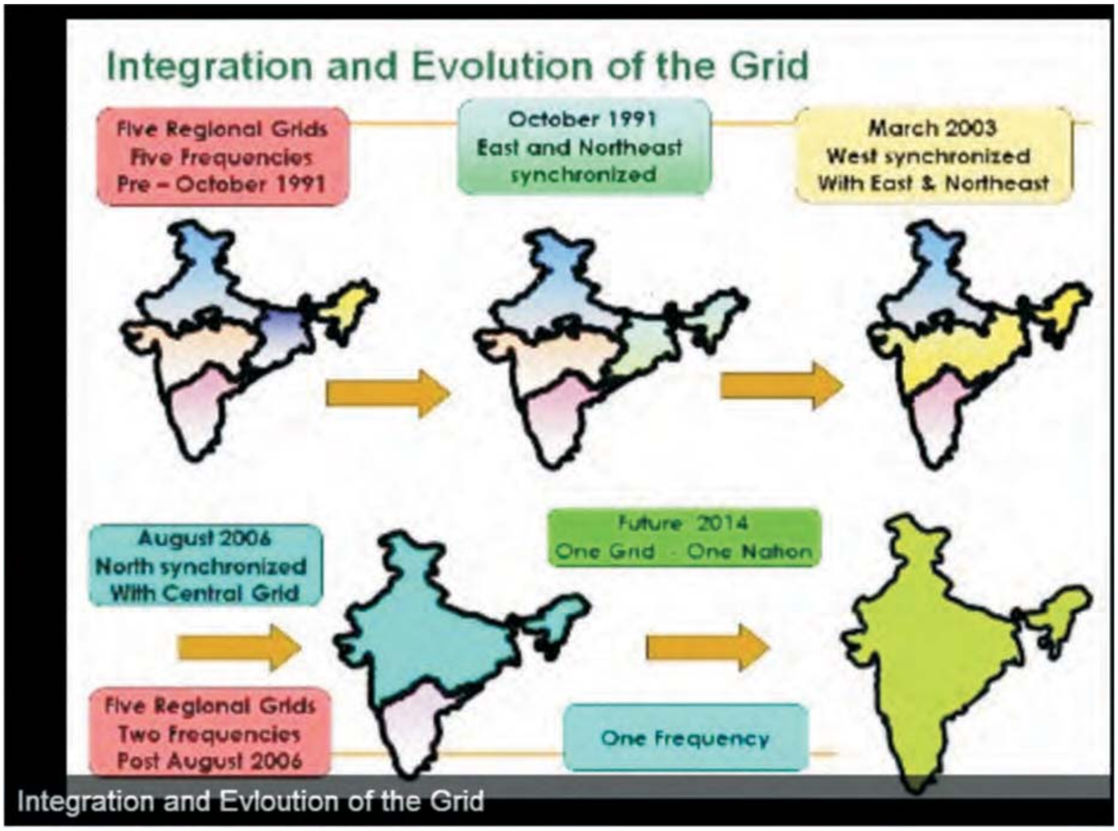
Sl. No.	Project Name	Date of Investment Approval	Approved cost (₹ in crore)	Scheduled date of completion	Equity Capital (₹ in crore)	CERC Incentives (0.5 %) – (₹ in crore
1	Generation Projects in Odisha Part B	December 2010	2743	December 2013	822.9	4.1145
2	Krishnapatnam area of Andhra Pradesh	August 2011	1637	August 2014	491.1	2.4555
3	System strengthening of NR for SASAN & MUNDRA (UMPP)	December 2009	1217	August 2012	365.1	1.8255
4	765kV System for Central Part of Northern Grid (Part-III)	October 2009	1075	April 2012	322.5	1.6125
						10.008

Total of additional Return on Equity of 0.5 per cent forgone over the project life of 35 years: ₹10.008 crore X 35 years = ₹ 350.28 crore.

Annexure – 7.1

(As referred to in Para 7.1)

Overview of Indian Power Grid

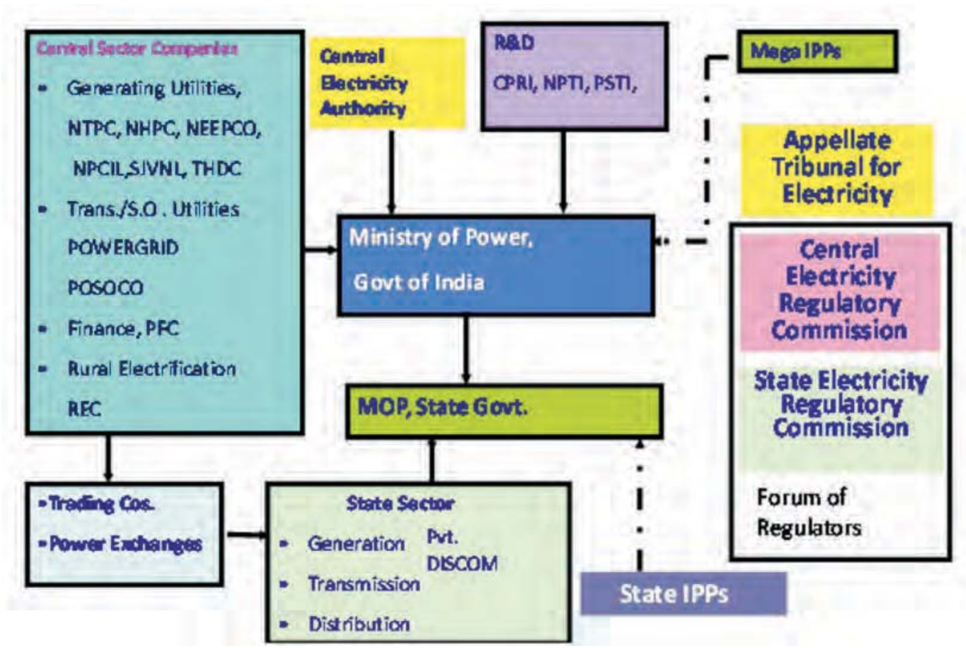


Note: Southern Grid synchronized on 31 December 2013 with rest of the Grid.
Source: Website of POSOCO

Annexure – 7.2

(As referred to in Para 7.1)

Indian Power Sector - Institutional Arrangement

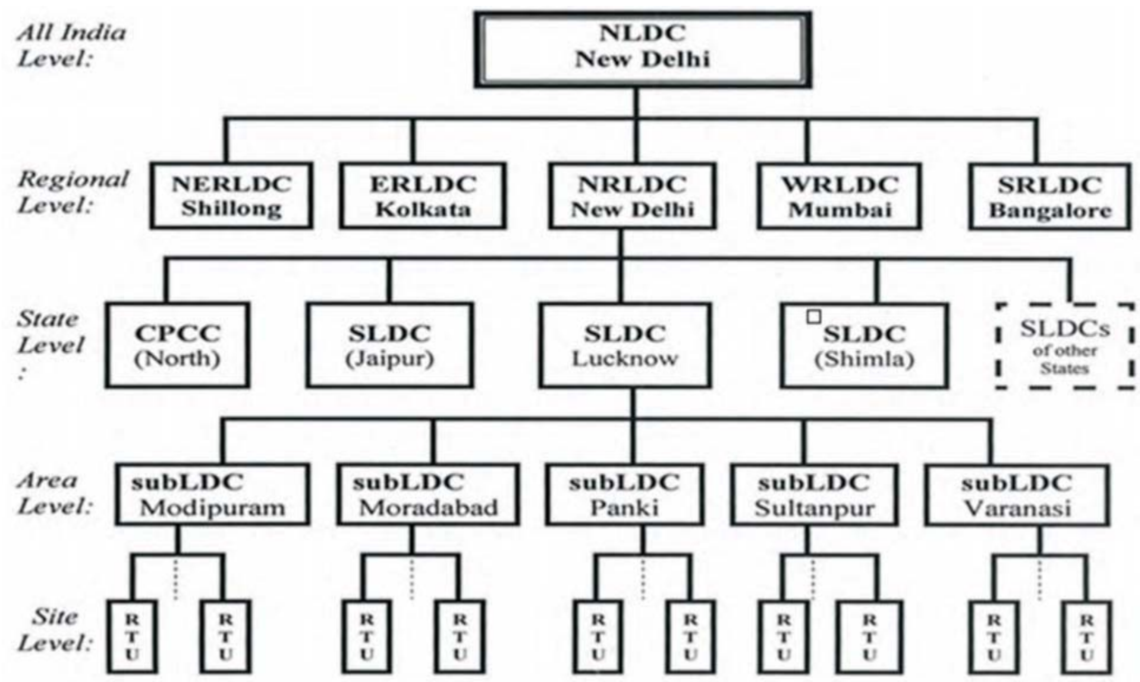


Source: As provided by POSOCO vide e-mail dated 27 December 2012

Annexure – 7.3

(As referred to in Para 7.2)

Typical Flow chart showing hierarchical form of Load Despatch Centres

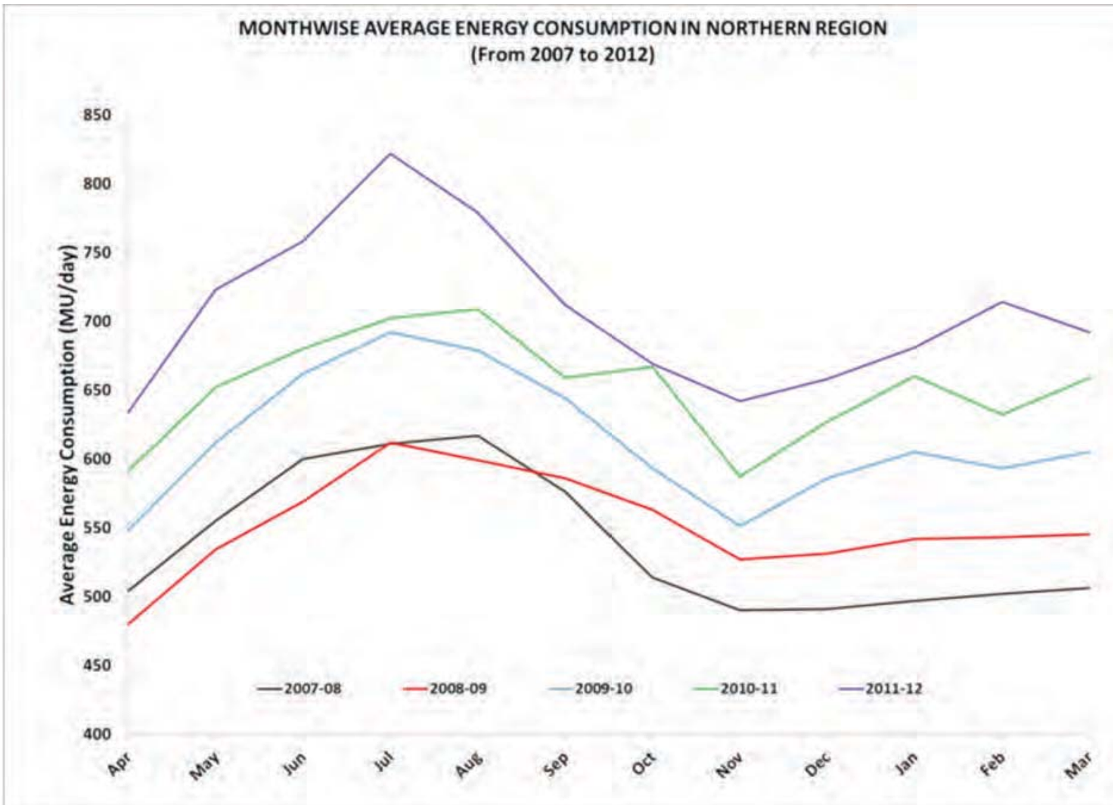


Hierarchical Structure of Power System Control Centres

Annexure 7.4

(As referred to in para 7.4.1)

Graph showing Average energy consumption in Northern Region during 2007-08 to 2011-12



MONTHWISE AVERAGE ENERGY CONSUMPTION IN NR (From 2007 to 2012)					
					(All figures are in MUs per day)
-	2007-08	2008-09	2009-10	2010-11	2011-12
Apr	504	480	548	591	634
May	555	534	612	652	723
Jun	600	569	662	680	758
Jul	611	612	692	702	822
Aug	617	599	679	709	779
Sep	576	586	644	659	712
Oct	514	563	593	667	669
Nov	490	527	551	587	642
Dec	491	531	586	627	658
Jan	497	542	605	660	681
Feb	502	543	593	632	714
Mar	506	545	605	659	692

Annexure- 7.5

(As referred to in para 7.4.2 (b) and (c))

Table showing excerpts of telephonic conversation between NLDC and RLDC staff on 29 July 2012.

29 July 2012 at 2243 (ERLDC advising NLDC to order WRLDC to back down generation	
ERLDC	*Toh ye paanch line overloaded hai toh agar koi ek trip karega toh kafi musibat ho jayegi.*
NLDC	*Achha, achha.*
ERLDC	*Toh aap WR ko thoh ek dam extremely aap ek dam immediately aap boliye ki wo back down kare apna generation.*
NLDC	*Achha, achha.*
ERLDC	*Ya nahi to WR apna NR ke through power pass on kare agar kar sakta hai.*
NLDC	*NR se nahi kar sakta hai, Gwalior-Agra ek out hai.*
ERLDC	*Ha agar nahi kar sakta toh he has to back down.*
NLDC	*Achha, achha. theek hai.*
ERLDC	*Theek hai na.*
NLDC	*Ok, ok.*
ERLDC	*Or NR ko over drawal band karna hai.*
NLDC	*Ha , ha theek theek.*
ERLDC	*Toh ye toh nahi toh bilkul system aaj jayega.*
NLDC	*Theek, theek sir karte hain.*
ERLDC	*Toh aap ise seriously lijiye.*

29 July 2012 at 2328 (ERLDC advising NLDC to be firm with WRLDC)	
ERLDC	*Janab WR se to humko koi farak nahi, lagta hai ki badh gaya hai unka*
NLDC	*WR toh…*
ERLDC	*Aap unke pechhe thoda lagiye ki what are they doing?*
NLDC	*Aree bada bekar hai sir unko…*
ERLDC	*Ji sir aap unko bar bar message dijiye, wo aise chhodne se nahi hoga.*
NLDC	*Theek hai mai bat karta hu.*
ERLDC	*Nahi nahi bilkul hi bat nahi, aap bar bar unko msg dijiye.*
NLDC	*Nahi nahi mai de raha hu.*
ERLDC	*Kahe jaha jaha underdrawal hai usko kam karaye.*
NLDC	*Nahi, theek hai. Theek hai.*
29 July 2012 at 2331 (NLDC asking WRLDC to reduce under drawal in a rather timid way)	
NLDC	*'Ha Sir, ye thoda ye apna Sir under drawal control kar sakthe ho Sir Aap'.*
WRLDC	*Hmm.*
NLDC	*Kyonki Sir Ye WR-NR ki Sir Vo Gwalior Agra ek shutdown pe hai. Us pe overloading ho rahi hai Sir aur ye ER corridor ki sari lines overload ho rahi hain.*
WRLDC	*Frequency bhi to kam hai, aapki…*
NLDC	*frequency kam hai vo to baat hai lekin thoda system constraint hai na ab kya karain sab ER kee lines*
WRLDC	*overdrawl kam karaiye na NR ka*
NLDC	*NR ka OD, usko bhi msg kiye hain, Sir aap bhi kar sakte hain to aap bhi dekhiye*

Annexure- 7.6

{As referred to in Para 7.4.3 (a)}

Overdrawal by NR states and Underdrawal by WR states during 30 & 31 July Grid Disturbances

Name of the State	Over-drawal or Under-drawal	No. of time blocks (Out of 18 time blocks between 2200 hours of 29 July 2012 and 0230 hours of 30 July 2012) in which overdrawal/underdrawal was made by States				No. of time blocks (Out of 12 time blocks between 1000 hours to 1300 hours of 31 July 2012) in which overdrawal/under-drawal was made by States			
		<100 MW	100<500 MW	500<1000 MW	>1000 MW	<100 MW	100<500 MW	500<1000 MW	>1000 MW
Northern Region									
Punjab		0	6	11	0	0	3	9	0
Haryana		0	0	13	5	0	2	8	2
UP		0	0	0	18	1	1	0	0
Rajasthan	Over-drawal	7	0	0	0	0	4	8	0
Uttarakhand		10	1	0	0	0	11	0	0
Western Region									
Gujarat		0	1	15	1	1	2	2	0
MP		0	14	3	1	1	11	0	0
Maharashtra		0	11	7	0	0	0	11	1
Chhattisgarh		9	7	0	0	0	12	0	0
Goa	Under-drawal	16	0	0	0	1	0	0	0
Dadra and Nagar Haveli		18	0	0	0	12	0	0	0
Daman and Diu		18	0	0	0	12	0	0	0

Annexure-7.7

{As referred to in Para 7.4.5(b) & 7.4.1}

NR Imports- Statement showing inter-se distribution of power flows among the links

Sl. No.	Inter-regional corridors	Inter-regional links	2009-10		2010-11		2011-12	
			Power flow (in MUs)	Share within the corridor (%age)	Power flow (in MUs)	Share within the corridor (%age)	Power flow (in MUs)	Share within the corridor (%age)
1	WR-NR	HVDC Vindhyachal back to back line	1541.33	14.63	1573.78	15.59	1427.39	15.51
		220 kV Auraiya-Malanpur	2.16	0.02	4.21	0.04	34.23	0.37
		220 kV Ujjain-Kota	1238.58	11.75	388.49	3.85	244.49	2.66
		400KV Agra-Gwalior	5990.96	56.85	7001.37	69.35	6622.30	71.98
		400 kV Kankroli-Zerda	1764.83	16.75	1128.01	11.17	294.65	3.20
		400 kV Bhinmal-Zerda	0.00	0.00	0.00	0.00	577.02	6.27
		Sub-total	10537.86	100.00	10095.86	100.00	9200.08	100.00
2	ER-NR	400 kV Barh-Balia	0.00	0.00	0.00	0.00	782.72	5.61
		HVDC Sasaram back to back (Bypass w.e.f. 1 December 2008)	1511.65	9.93	1359.09	9.21	929.77	6.66
		400KV Muzzafarpur-Gorakhpur	6127.18	40.27	5830.16	39.51	5491.16	39.36
		220/132 kV lines	678.64	4.46	527.32	3.57	1138.56	8.16
		400 kV Patna-Balia	3733.13	24.53	4050.99	27.45	2746.95	19.69
		400 kV Biharshariff-Balia	3164.98	20.80	2988.67	20.25	2861.70	20.51
		Sub-total	15215.58	100.00	14756.23	100.00	13950.86	100.00

Annexure – 7.8

{As referred to in Para 7.4.5(d)}

Proportion of Unscheduled Interchange among total power flows through key Inter-regional Corridors during 2009-10 to 2011-12

Year	WR-NR				WR-ER				WR-SR				ER-NR			
	No. of months in which UI as a percentage of Actual Power Flow was				No. of months in which UI as a percentage of Actual Power Flow was				No. of months in which UI as a percentage of Actual Power Flow was				No. of months in which UI as a percentage of Actual Power Flow was			
	0-10%	11%-30%	31%-50%	> 50%	0-10%	11%-30%	31%-50%	> 50%	0-10%	11%-30%	31%-50%	> 50%	0-10%	11%-30%	31%-50%	> 50%
2009-10	1	5	4	2	0	0	0	12	6	0	1	5	1	10	1	0
2010-11	1	3	4	4	0	0	0	12	10	2	0	0	3	6	2	1
2011-12	2	4	2	4	0	2	2	8	12	0	0	0	6	4	1	1

Annexure- 7.9

(As referred to in para 7.4.5 (d))

Extent of Utilization of Power Transfer Capability 2012-13

(Figures in MW)

	WR-NR				ER-NR				ER-NER			
Month	**Month-wise ATC**	**Actual Flow**	**Surplus Capacity (ATC – Actual Flow)**	**Percentage (Surplus Capacity / ATC)X100**	**Month-wise ATC**	**Actual Flow**	**Surplus Capacity (ATC – Actual Flow)**	**Percentage (Surplus Capacity / ATC) X100**	**Month-wise ATC**	**Actual Flow**	**Surplus Capacity (ATC – Actual Flow)**	**Percentage (Surplus Capacity / ATC) X100**
Apr-12	1800	691.57	1108.43	61.58	2500	1366.83	1133.17	45.33	400	342.11	57.89	14.47
May-12	2000	1152.61	847.39	42.37	2700	1983.53	716.47	26.54	450	311.68	138.32	30.74
Jun-12	2000	1472.63	527.37	26.37	2800	1900.18	899.82	32.14	465	173.31	291.69	62.73
Jul-12	2000	1809.38	190.62	9.53	3700	2400.5	1299.5	35.12	455	116.17	338.83	74.47
Aug-12	2000	1265.42	734.58	36.73	4700	1782	2918	62.09	455	141.72	313.28	68.85
Sep-12	2000	1253.43	746.57	37.33	4700	1816.64	2883.36	61.35	525	125.38	399.62	76.12
Oct-12	2200	1311.9	888.1	40.37	3700	2072.86	1627.14	43.98	565	94.76	470.24	83.23
Nov-12	2200	892.46	1307.54	59.43	3200	1548.26	1651.74	51.62	465	299.82	165.18	35.52
Dec-12	1400	852.82	547.18	39.08	2700	1789.17	910.83	33.73	455	357.53	97.47	21.42
Jan-13	1500	2004.64	-	-	2050	1715.87	334.13	16.30	415	345.43	69.57	16.76
Feb-13	1500	1339.57	160.43	10.70	2400	1305.52	1094.48	45.60	415	327.38	87.62	21.11
Mar-13	1500	1602.69	-	-	2200	1332.66	867.34	39.42	365	422.04	-	-
	Surplus Month = 9				Surplus Month = 12				Surplus Month = 11			
	Congestion Month = 3				Congestion Month = 0				Congestion Month = 1			

Month	WR-ER			
	Month-wise ATC	**Actual Flow**	**Surplus Capacity (ATC – Actual Flow)**	**Percentage (Surplus Capacity /ATC) X100**
Apr-12	700	587.03	112.97	16.14
May-12	700	619.5	80.5	11.50
Jun-12	700	902.18	-	-
Jul-12	700	964.11	-	-
Aug-12	700	583.97	116.03	16.58
Sep-12	700	396.71	303.29	43.33
Oct-12	700	41.16	658.84	94.12
Nov-12	400	25.72	374.28	93.57
Dec-12	400	2.69	397.31	99.33
Jan-13	1100	52.42	1047.58	95.23
Feb-13	1100	23.36	1076.64	97.88
Mar-13	1100	22.85	1077.15	97.92
	Surplus Month = 10			
	Congestion Month = 2			

1. Sign ‘- ’ denotes excess of Actual Flow over ATC.
2. Percentage less than 10% considered as congestion.
4. ER - SR and WR-SR not included as these are mainly HVDC Links.

Annexure – 7.10

{As referred to in Para 7.4.5 d(iii)}

Energy Requirement *vis a vis* Energy Availability of Northern States and Net overdrawal or underdrawal during 2011-12

State Name	Requirement	Availability	Deficit(-)		No. of Months in which there was Net		Remarks
	(MUs)	(MUs)	(MUs)	(%)	Over drawl	Under drawal	
Chandigarh	1,568	1,564	-4	-0.3	3	9	Nominal deficit. Generally in Under drawl mode.
Delhi	26,751	26,674	-77	-0.3	0	12	Nominal deficit. Always in Under drawl mode.
Haryana	36,874	35,541	-1,333	-3.6	10	2	Deficit and Over drawl in most of the months.
Himachal Pradesh	8,161	8,107	-54	-0.7	5	7	Nominal deficit. Under drawl in majority of months.
Jammu & Kashmir	14,250	10,889	-3,361	-23.6	6	6	High deficit. Equal pattern of Over drawl and Under drawl
Punjab	45,191	43,792	-1,399	-3.1	4	8	Deficit. Yet Under drawl in majority of months.
Rajasthan	51,474	49,491	-1,983	-3.9	12	0	Deficit. Over drawl in all the months.
Uttar Pradesh	81,339	72,116	-9,223	-11.3	9	3	High Deficit. High Over drawl.
Uttarakhand	10,513	10,208	-305	-2.9	10	2	Deficit. Generally in Over drawl mode.

List of abbreviations used in the Report

Sl. No.	Term used in Report	Description
	A	
1.	AC	Alternating Current
2.	ABT	Availability Based Tariff
3.	ACP	Area Clearing Price
4.	ATC	Available Transfer Capability
	B	
5.	BOD	Board of Directors
6.	BOQ	Bill of Quantity
7.	BPTA	Bulk Power Transmission Agreement
8.	BSE	Bombay Stock Exchange
	C	
9.	CEA	Central Electricity Authority
10.	CEO	Chief Executive Officer
11.	CERC	Central Electricity Regulatory Commission
12.	CSGS	Central Sector Generating Station
13.	Ckm	Circuit Kilometer
14.	CMD	Chairman-cum-Managing Director
15.	CMG	Corporate Monitoring Group
16.	CPCC	Central Project Coordination and Control Centre
17.	CPSEs	Central Public Sector Enterprises
18.	CS	Contract Services
19.	CTE	Chief Technical Examiner
20.	CTU	Central Transmission Utility
	D	
21.	DC	Double Circuit
22.	DOCO	Date of Commercial Operation
23.	DPR	Detailed Project Report
	E	
24.	ED	Executive Director
25.	ER	Eastern Region
26.	ERLDC	Eastern Region Load Despatch Centre
27.	ERP	Enterprise Resource Planning
28.	ERSS	Eastern Region System Strengthening Scheme
	F	
29.	FPO	Follow-on Public Offer
30.	FR	Feasibility Report

Sl. No.	Term used in Report	Description
	G	
31	GD	Grid Disturbance
32	GoI	Government of India
	H	
33	HVDC	High Voltage Direct Current
	I	
34.	IDC	Interest During Construction
35.	IEDC	Incidental Expenditure during Construction
36.	IEEMA	Indian Electrical and Electronic Manufacturers Association
37.	IEGC	Indian Electricity Grid Code
38.	IEX	Indian Energy Exchange
39.	IIT	Indian Institute of Technology
40.	IPO	Initial Public Offer
41.	IPPs	Independent Power Producers
42.	ISGS	Inter State Generating Station
43.	IT	Information Technology
	K	
44.	kV	Kilo Volt
45.	KPI	Key Performance Indicators
46.	kWh	Kilo Watt Hour
	L	
47.	LD	Liquidated Damages
48.	LDC	Load Despatch Centre
49.	LILO	Loop In Loop Out
50.	LTA	Long Term Access
	M	
51.	MCP	Market Clearing Price
52.	MC	Management Committee
53.	MIS	Management Information System
54.	MNW	Master Network
55.	MoEF	Ministry of Environment and Forest
56.	MoP	Ministry of Power
57.	MOU	Memorandum of Understanding
58.	MPR	Monthly Progress Report
59.	MPSEB	Madhya Pradesh State Electricity Board
60.	MT	Metric Tonne
61.	MTOA	Medium Term Open Access

Sl. No.	Term used in Report	Description
62.	MUs	Million Units
63.	MVA	Mega Volt Ampere
64.	MW	Mega Watt
	N	
65.	NEP	National Electricity Plan
66.	NERC	North American Electrical Reliability Council
67.	NER	North Eastern Region
68.	NERLDC	North Eastern Region Load Despatch Centre
69.	NIT	Notice Inviting Tender
70.	NLDC	National Load Despatch Centre
71.	NPTI	National Power Training Institute
72.	NR	Northern Region
73.	NRLDC	Northern Region Load Despatch Centre
74.	NRPC	Northern Regional Power Committee
75.	NRSS	Northern Region System Strengthening
76.	NSE	National Stock Exchange
	O	
77	OCC	Operation Coordination sub-committee
	P	
78.	PAT	Profit After Tax
79.	PESM	Planning Environment and Social Management
80.	PGCIL	Powergrid Corporation of India Limited
81.	POSOCO	Power System Operation Corporation Limited
82.	PSDF	Power System Development Fund
83.	PRM	Project Review Meeting
84.	PXIL	Power Exchange India Limited
	Q	
85	QR	Qualifying Requirement
	R	
86.	RLDC	Regional Load Despatch Centre
87.	RM	Reliability Margin
88.	RoE	Return on Equity
89.	ROW	Right of Way
90.	RPC	Regional Power Committee
91.	RPM	Revolutions Per Minute
92.	RTU	Remote Terminal Unit
93.	R&D	Research & Development

Sl. No.	Term used in Report	Description
	S	
94.	SC	Single Circuit
95.	SCADA	Supervisory Control and Data Acquisition
96.	SCPSP	Standing Committee for Power System Planning
97.	SOR	Schedule of Rates
98.	SLDC	State Load Despatch Centre
99.	SPS	Special Protection Scheme
100.	SPU	State Power Utility
101.	SRLDC	Southern Region Load Despatch Centre
102.	SRSS	Southern Region System Strengthening
103.	SR	Southern Region
104.	STOA	Short Term Open Access
105.	STU	State Transmission Utility
	T	
106.	TPS	Thermal Power Station
107.	TTC	Total Transfer Capability
	U	
108.	UI	Unscheduled Interchange
109.	UMPP	Ultra Mega Power Project
110.	UPPCL	Uttar Pradesh Power Corporation Limited
	W	
111.	WPPP	Work and Procurement Policy & Procedure
112.	WRLDC	Western Region Load Despatch Centre
113.	WR	Western Region
114.	WRSS	Western Region System Strengthening Scheme

Glossary of Technical Terms

S. No	Technical Terms	Description
1	**Availability Based Tariff (ABT)**	Financial settlement of energy exchanges across the Grid is carried out through a mechanism called Availability Based Tariff. ABT comprises three components: (a) capacity charge, towards reimbursement of fixed cost of the plant, linked to the plant's declared capacity to supply MWs, (b) energy charge, to reimburse the fuel cost for scheduled generation, and (c) Unscheduled Interchange (UI) charge, a payment for deviations from schedule, at a rate dependent on the system frequency.
2	**Alternating Current (AC)**	Alternating Current: or AC changes periodically with time.
3	**Area Clearing Price (ACP)**	Area clearing price is the clearing price for electricity transacted through power exchanges, for the respective bid areas.
4	**Available Transfer Capability (ATC)**	Available Transfer capability is equal to Total transfer capability minus transmission reliability margin fixed corridor-wise by National Load Despatch Centre to ensure that the interconnected network is secure under a reasonable range of uncertainties in system conditions.
5	**Angular separation**	The rotors of generators connected to the grid run at the same electrical speed and in case of small disturbances affecting the speed, restorative forces bring back the rotors to the same speed. However, for large disturbances, the restorative forces may be unable to bring all the generators to the same speed. If this happens, the angular difference between the generators goes on increasing (Angular separation) which causes large variations in voltage and power flow in lines.
6	**Bottling of power**	Any constraint in the transmission chain from generation of power to load leads to a situation where generation has to be backed down. This is referred to as bottling of power.
7	**Black start**	Building the Grid after a grid collapse is termed as 'black start' of the Grid
8	**Bottom up approach**	Under this approach used in restoration of power following partial or total grid collapse, black start facility available within the region among hydro, gas and some thermal power stations is used to start producing power, loads are added step by step and blocks of restored areas are built progressively.
9	**Congestion**	CERC Regulations define congestion as a situation where the demand for transmission capacity exceeds the available transfer capability.
10	**Circuit kilometer (ckm)**	Product of the number of circuits forming part of a transmission line and the length of transmission line in kilometre.
11	**Cascade tripping**	Uncontrolled successive loss of system elements triggered by an incident. Cascade tripping results in wide spread service interruption which cannot be restrained from sequentially spreading beyond an area pre-determined by appropriate studies.
12	**Central Transmission Utility**	Clause 2(10) of the Electricity Act, 2003 defines Central Transmission Utility as any Government company which the Central Government may notify under sub-section (1) of section 38 of the Act. PGCIL has been notified by the Central Government as Central Transmission Utility.
13	**Contingency**	Unexpected failure or outage of system components, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.
14	**Direct Current (DC)**	Direct Current or DC is steady and does not change with time.
15	**Double Circuit (DC)**	A double-circuit transmission line has two circuits.

S. No	Technical Terms	Description
16	**Element**	Any electric device with terminals that may be connected to other electric devices, such as a generators, transformer, circuit, circuit breaker, *etc*.
17	**Energy Emergency**	A condition when a system or power pool does not have adequate energy resources to supply its customers' expected energy requirements.
18	**Feasibility Report (FR)**	Feasibility report is a document containing evaluation and analysis of the potential of proposed project based on extensive investigation and research to support the process of decision making.
19	**Frequency**	The number of complete alternations or cycles per second of an alternating current measured in hertz. The standard frequency in India is 50 Hz**.**
20	**Grid disturbance**	A Grid Disturbance (GD) is a state of the power system under which a set of generating units/transmission elements trip in an abrupt and unplanned manner affecting the power supply in a large area and/or causing the system parameters to deviate from the normal values in a wider range.
21	**High Voltage Direct Current (HVDC) system**	HVDC system comprises of point-to-point lines through which system operators can regulate flow of electricity.
22	**Infirm power**	Power generated by a power station prior to its date of commercial operation.
23	**Inter Regional lines**	Lines connecting two regions are called Inter Regional lines.
24	**Intra Regional lines**	Transmission lines connecting locations within the region are called Intra regional lines.
25	**Long Term Access**	Long Term Access (LTA) means the right to use the inter-state transmission system for a period exceeding 12 years but not exceeding 25 years.
26	**Long tie**	Long tie means Transmission link longer in length and tying /connecting two regions.
27	**Load Shedding**	The process of deliberately removing (either manually or automatically) pre-selected customer demand from a power system in response to a abnormal condition, to maintain the integrity of the system and minimize overall outages.
28	**Lighting Up**	Lighting up is used in the context of coal fired generating units and refers to the starting up of the boilers using oil (could be either Light Diesel Oil or Low Sulphur Heavy Stock or Heavy furnace Oil) depending on the boiler design. Only after this process is complete, the steam turbine can be rolled and the generator synchronized to the main grid.
29	**Load**	The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.
30	**Market clearing Price (MCP)**	The market clearing price is the clearing price for cleared transactions in the whole market when there is no congestion.
31	**MNW**	Master Network (MNW) of the projects indicating contract wise dates for start and finish of various activities such as award, commencement of supply/erection, completion of supply/erection, *etc*.
32	**MVA**	MVA *i.e.*, mega volt ampere is a unit of measurement of apparent power in an electrical circuit. This unit of measurement can be used only in AC circuits. Transformers used in power transmission are rated in MVA.
33	**Million Unit (MU)**	Kilowatt-hour (kWh), *i.e.* one kilowatt of power expended for one hour of time, is called a 'Unit'. A collection of one million units is called 'MU'.
34	**N-1 Criterion**	Power system operation is based on a principle called 'N-1 criterion as per which transfer capability is assessed considering outage of the most important element. This ensures that the system remains in secure condition even after loss of the most important generator or transmission facility.

S. No	Technical Terms	Description
35	**Open Access**	Open access means the non-discriminatory provision for the use of transmission lines or distribution system or associated facilities with such lines or system by any licensee or consumer or a person engaged in generation in accordance with the regulations specified by the Appropriate Commission.
36	**Open line**	Open line means a line taken off the grid through a switching mechanism.
37	**Offline Simulation**	Power system engineers use a technique called power flow simulation to reproduce known operating conditions at a specific time by calibrating an initial simulation to observe voltage and line flows. The calibrated simulation can then be used to answer 'what if' questions to determine whether the system was in safe operating state at that time.
38	**Over drawal**	Over drawal means utilizing more than their share of central sector generation by discoms.
39	**Outage**	The period during which a generating unit, transmission line, or other facility is out of service. Outages are of three types (i) Planned outage: It refers to outage for carrying out maintenance work, construction related activities *etc.*(ii) Forced outage: a condition in which the element is unavailable due to unanticipated failure. (iii) Emergency outage: the element is taken out of service to carry out urgent repairs etc.
40	**Power swing**	Rotors of synchronous machines interconnected by AC lines tend to run at the same electrical speed in steady state. When the power system experiences small disturbances, restorative torques bring back the machines to synchronism (i.e. same electrical speed). This response is characterized by an oscillatory behavior since the underlying equations which determine the transient behavior are like those of a spring-mass system. The oscillations are called 'swings' and are seen in practically all parameters including line power flows. The oscillations die down if damping is adequate.
41	**Power Utility**	The entity that owns or operates facilities for generation, transmission, distribution, or sale of electric energy primarily for use by the public.
42	**Rating**	The operational limits of an electric system facility or element under a set of specified conditions.
43	**Reliability**	Reliability refers to the degree of performance of the elements of the bulk electric system that results in adequate and secure delivery of electricity to the consumers. Electric system reliability can be assessed through two indicators *viz.*, adequacy and security.
44	**Reliability Margin (RM)**	Reliability Margin (RM) means the amount of margin kept in the total transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.
45	**Right of Way (ROW)**	Right of Way (ROW) with reference to transmission projects means right for placing of electric lines for transmission of electricity along the path through which such lines pass through.
46	**SCADA**	Supervisory Control and Data Acquisition System: a system of remote control and telemetry used to monitor and control the electric system.
47	**Single Contingency**	Sudden, unexpected failure or outage of a system facility or element (generating unit, transmission line, transformer, *etc*.).
48	**Synchronization**	In an alternating current electric power system, synchronization is the process of matching the speed and frequency of a generator or other source of power to a running network.

S. No	Technical Terms	Description
49	**Scheduled Power**	Power stations and distribution utilities inform their intended quantum of generation and drawal respectively for the next day to LDCs of their control area. LDCs match the generation and drawal of all utilities in their control area with reference to the power transfer capability and prepare the schedule each day, for the next day. For scheduling, a day is divided into 96 time blocks, each of 15 minutes duration. Thus, the 'Schedule' is a program drawn for the generating stations and distribution utilities. Energy exchanges as per the schedule is referred to as scheduled power.
50	**Short tie**	Short tie means Transmission link shorter in length and tying /connecting two regions.
51	**Short Term Open Access**	Access provided to a generator or seller of power for transmission of power for a short term period (*i.e.* for a period up to one month at a time). POSOCO is the Nodal agency for grant of short term open access under CERC Regulations.
52	**Single circuit**	A single circuit transmission line has only one circuit.
53	**Special protection scheme (SPS)**	An automatic protection system designed to detect abnormal or pre determined system conditions, and take corrective actions other than and/ or in addition to the isolation of faulted components.
54	**Transfer Capability**	Transfer capability refers to the amount of electric power that can be passed through a transmission network from one place to another having regard to reliability considerations.
55	**Transmission Capacity**	Transmission capacity is equal to summation of ratings of individual lines.
56	**Transmission Corridor**	An interconnected group of lines and associated equipment for movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric system.
57	**Transient Stability**	The ability of an electric system to maintain synchronism between its parts when subjected to a disturbance and to regain a state of equilibrium following the disturbance.
58	**Trip**	Refers to the automatic opening of the conducting path provided by a transmission line by the circuit breaker. These openings or "trips" are to protect the transmission line during faulted conditions.
59	**Total Transfer Capability (TTC)**	Total Transfer Capability of a transmission network means the amount of electric power that can be transferred reliably over the inter-control area transmission system under a given set of operating conditions considering the effect of occurrence of the worst credible contingency. Here credible contingency means the likely-to-happen contingency, which would affect the Total Transfer Capability of the inter-control area transmission system.
60	**Top down approach**	Top down approach adopted in restoration of power following a partial or total grid collapse involves taking power from other regions which remain connected to initiate restoration in the affected region.
61	**Unscheduled Interchange**	Unscheduled Interchange (UI) is the under Drawal/Over drawal or under injection/over injection when compared to the scheduled power
62	**Underdrawal**	Under drawal mean taking less than its share of central sector generation by state discoms.
63	**Voltage**	The electrical force, or "pressure," that causes current to flow in a circuit, measured in volts.