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Nigeria Energy Sector Reform Project
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National Electric Power Authority of Nigeria

Priority Reforms for the Nigerian Electricity Market

Final Report

Submitted by

Nexant

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Executive Summary

1 INTRODUCTION

Nexant has been contracted by USAID to provide technical assistance for corporate restructuring of the National Electric Power Authority (NEPA). The objective of the project is to provide recommendations on priority reforms for the transition stage electricity market, which will transform NEPA into an Initial Holding Company (IHC) with profit-oriented New Business Units (NBUs) for generation, transmission and distribution.

The project scope of work covers the following deliverables:

- Market rules covering the services that the NBUs provide to each other
- Financial mechanisms for market transactions between the NBUs
- Reorganization Plan to enhance the management functions of the Distribution Companies (DisCos)
- Plan for new market organizations, namely the Market Operator and the Market Operation Committee
- Financial restructuring plan for NEPA
- Approach to vesting assets and liabilities to the NBUs

This report aims to provide practical strategies that build upon existing processes and structures at NEPA and take into account the constraints facing the Nigerian electricity sector over the next few years.

2 TRANSITION STAGE ELECTRICITY MARKET

Figure ES-1 shows the market structure recommended for the transition stage electricity market. NEPA will be unbundled into NBUs for generation, transmission and distribution. The GenCos will sell energy to the DisCos, the TransysCo will provide energy wheeling and ancillary services and the IHC will provide executive management and shared corporate services such as finance and human resources. The fundamental quality of the transition stage electricity market is that it is a cost-based pool designed to link the many diverse NBUs owned by NEPA under formal market rules.

The key reforms recommended for the transition stage are:

- A formal set of market rules governing the inter-relationships and responsibilities of the market players including the DisCos, TransysCo, the GenCos, the Market Operator and any new trading licensee(s)
- Cost-reflective financial transactions between the NBUs
- A Market Operator for billing and settlements
- A Market Operation Committee to oversee the market and resolve disputes

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- NEPA Corporate Headquarters transformed into the Initial Holding Company;
- Some central services devolved from HQ to the NBUs, and authority limits enhanced at the NBUs
- TransysCo incorporated
- Staffing and capacity-building at the NBUs
- Financial restructuring
- Separation of accounts to the NBU level
- Groundwork for the introduction of the Nigeria Electricity Regulatory Commission (NERC).

The recommended target commencement date for initial market operations is 3rd quarter 2003.

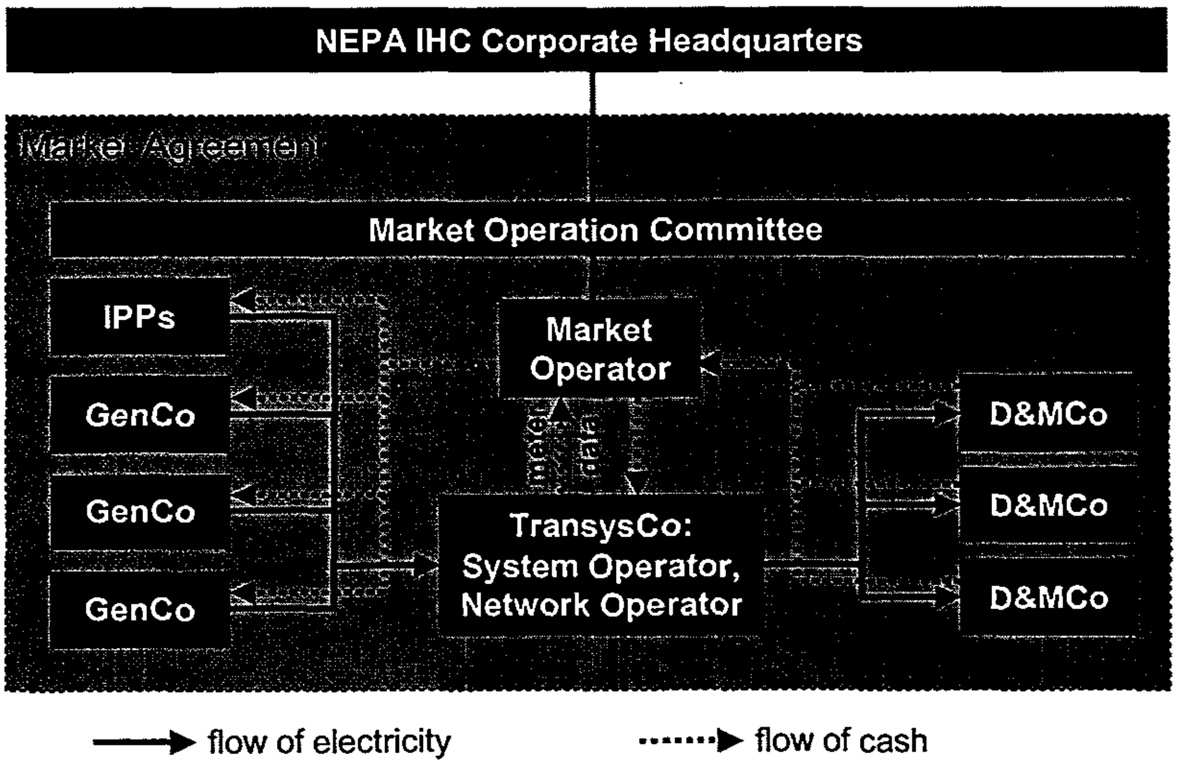

Figure ES-1: Transition Stage Market Structure

From a practical standpoint, the reforms that can be introduced during the transition stage are limited by fundamental constraints on the development of the sector. The primary roadblock is the severe cash shortage that NEPA faces. All of the DisCos are loss-making and unable to pay the full cost of the transmission and generation services provided by TransysCo and the GenCos. As a result, available funds must be carefully rationed to the NBUs in a way that "shares the pain" of inadequate cash resources. Likewise, there is a shortage of energy production and as a result energy must be rationed to the DisCos according to fair and transparent rules.

3 PRIORITY REFORMS FOR THE TRANSITION STAGE ELECTRICITY MARKET

The following sections summarize key reforms recommended for the transition stage electricity market.

3.1 Market Rules

The market rules define the commercial relationships between the GenCos, TransysCo, the DisCos, the Market Operator, Corporate Headquarters and any new trading licensee(s). The market rules cover the essential functions and processes of the electricity market: wholesale trading between companies in the market-place; connection and use of transmission system; generation planning; generation dispatch; and transmission system operations.

The following market rules will govern the transition stage market:

- Market Operator – The market rules set up a Market Operator to administer wholesale transactions between the NBUs. The Market Operator will have the following duties: operate the Charges Model; prepare Statements of Account, which are like invoices between the NBUs; manage cash transfers; administer the grid meter data collection and reporting system; and recalculate settlements for actual versus forecast quantities according to the process for quarterly reconciliation.
- Market Operation Committee – The Market Operation Committee will oversee the operation of the wholesale electricity market and represent each stakeholder on matters of common interest. The committee will report direct to the executive management of NEPA. The following key issues for setting up the Market Operation Committee can be addressed in the next stage of work: membership; procedures; relationship to NERC, when formed; staffing of the Committee Secretariat; facilities; and budget.
- Load allocation – There is insufficient generation capacity to meet system demand. As a result, load must be shed on a continuous basis. NEPA has a process for calculating the load allocation and an operations protocol to implement load shedding. The market rules will govern the load shedding scheme and provide the required communications protocol, and these must be harmonized with the new, unbundled industry structure.
- Bulk Supply Charges, cash allocations and settlements – The transition stage market will require cost-reflective financial transactions between the NBUs. The market rules define the pricing formulas and the procedures and responsibilities for financial settlements.
- Grid Metering – The net output of the GenCos and IPPs will be metered, and the energy supplied from the grid to the DisCos will be metered. The market rules cover grid metering principles and standards and specify procedures for reading grid meters company-wide.

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During the transition stage, a comprehensive Market Agreement covering the agreed market rules and signed by all NEPA NBUs will provide a straightforward approach to institute commercial relationships. The agreement will have a wide scope covering all generation- and transmission-related services and all financial transactions. The Market Agreement has the following advantages:

- During the transition stage, the financial and operational performance of any NBU will impact all of the NBUs. For example, anything that impacts the cash receipts of the DisCos will have a ripple effect on all NBUs. These inter-dependencies are readily captured in a Market Agreement between all of the affected parties.
- The Market Agreement will allow the NBUs to gain experience in a commercial environment while the system of bilateral contracts is readied. The Market Agreement can be completed and signed within a matter of months and this will expedite the start date for market operations.
- The bilateral contracts market will have a development curve running well into 2004 to address serious internal and external constraints on NEPA that create complex financial and operational inter-dependencies between the new market players. In particular, the cash and load allocation mechanisms recommended for the transition stage market will not work for the bilateral contracts market. These will have to be reformulated and this will involve important policy tradeoffs and consensus building.

3.2 Bulk Supply Charges and Cash Allocation

Financial transactions between the NBUs will be administered by the Market Operator according to two separate mechanisms for 1) accounting-based bulk supply charges to the DisCos for generation and transmission services and 2) cash allocations to the NBUs on the basis of greatest need.

Bulk Supply Charges – The bulk supply charges to the DisCos are designed to cover the costs-of-service of the TransysCo and the GenCos and the payment requirements of the IPP contracts. The components of cost-of-service are operating expenses, depreciation, interest, taxes and return on equity. Each DisCo will be charged a pro rata share of generation and transmission costs based on the DisCo's demand relative to the total system demand. For example, the cost of transmission service will be allocated among the DisCos based on their relative peak MVA demand. Charges will be differentiated into fixed and variable components. Variable charges cover GenCo fuel costs and the energy-related costs of IPPs, whereas fixed charges cover all other generation and transmission costs.

Cash Allocation – Charges will be used for accounting purposes. However the system of cash disbursements from the Market Operator to the NBUs will not be directly related to the charges. Instead, cash will be allocated to the NBUs and Corporate Headquarters on the basis of prioritized cash needs. There will be a special cash incentive for any DisCo that exceeds a pre-agreed target for collections performance.

The following financial procedures are recommended for the transition stage market:

- The Market Operator will set charges and cash allocations quarterly on a forecast basis according to the results of a spreadsheet financial model developed for this purpose. Quarterly updates are required primarily due to the uncertain availability of generation from month to month, which affects the sales revenues and collections of the DisCos.
- The Market Operator will be responsible for: the collection of all necessary technical and financial data; the operation of the charges model; submission of statements of accounts to/from each NBU; allocation and transfer of the funds collected by the DisCos to all of the NBUs; and quarterly reconciliation for actual versus forecast.
- Each DisCo will deposit its cash receipts in a "collection" bank account controlled by the Market Operator. The Market Operator will transfer cash from the collection bank accounts into a central "remittance" bank account. The Market Operator will use the remittance bank account to transfer funds by way of standing orders to the NBUs on the 15th and end of each month.
- At the end of each quarter and upon submission of actual returns from all NBUs, the charges model will be re-worked to adjust the charges and cash allocations for uncontrollable variances between actual and forecast. For example, if the actual supply of generation to the DisCos is higher than forecast, this will affect billings, cash collections, charges and cash allocations. Any end-of-quarter adjustment affecting cash will be brought into the subsequent quarter's cash allocation.
- NBUs will have to operate within their cash allocations. Any expenditure above approved allocations will require Corporate Headquarters sanction and will be funded from cash set aside for emergency requirements. For this system to work efficiently, NBUs will have to be afforded increased authority limits over budgeted expenditures.
- Individual DisCos will be rewarded for their operational performance measured in terms of cash collection in Naira per kWh of bulk energy supplied from the grid. Realistic targets will be set each quarter and such targets will be used in the charges model. Each DisCo that exceeds its target will receive a set percentage of the additional cash that it has generated as a result of its performance.
- The financial statements of the NBUs will reflect the charges and cash allocations. Each GenCo and TransysCo will show a revenue line item on its income statement for its bulk supply charges to the DisCos. The unrecovered charges (i.e. the difference between charges and cash allocation) will show on the cost side. The resulting financial performance will therefore reflect the net recovered bulk supply charges. For each DisCo, the full cost of bulk supply will be shown as part of its cost of operations. In addition, the uncollected end customer billings will be charged against profits. The resulting profit or loss will therefore reflect the true measure of financial performance based on full settlement of bulk supply charges.

The foregoing approach to electricity market transactions is the best practical option during the transition stage while the FGN addresses the problems associated with inadequate tariff levels, extensive non-payment and the differential impact of the uniform national tariff on the DisCos. The recommended financial arrangements are more objective, more transparent, and less

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discriminatory than current practices, and will give the NBUs more control of their own finances. The new system for financial transactions will provide the NBUs with experience similar to cost-based regulation, which someday will be used by the NERC in its oversight of the power sector.

3.3 Reorganization Plan

A key challenge for the corporate restructuring exercise is how to transition the organization from central command-and-control to local autonomy. The NBUs must be empowered as independent profit centers. Functions that are now handled by HQ and the Sectors must be devolved to the NBUs. In the first step during the Initial Holding Company stage, some common services will remain at HQ. In the second step, the IHC will dissolve and all HQ services will be devolved to the NBUs and the trading licensee for bulk purchases from IPPs.

The following reorganization measures are recommended during the transition stage electricity market.

TransysCo – The Transmission and Operations Sector organizations will be subsumed under the TransysCo and managed centrally, whereas Regions and Stations will remain as operating units within TransysCo. NEPA is moving quickly to set-up and incorporate TransysCo in line with the *Transmission Development Project Strategy Plan* (Red Electrica, March 2003).

DisCos – The existing Zonal organizations will be elevated to DisCo status during the IHC market stage. The Districts and Undertakings will remain operating units subsumed under the DisCos. DisCos will have executive management responsibility of the regional distribution service territories, and therefore the management capabilities at DisCo Headquarters will need to be enhanced. Figure ES-2 shows an organogram for the management team at DisCo Headquarters.

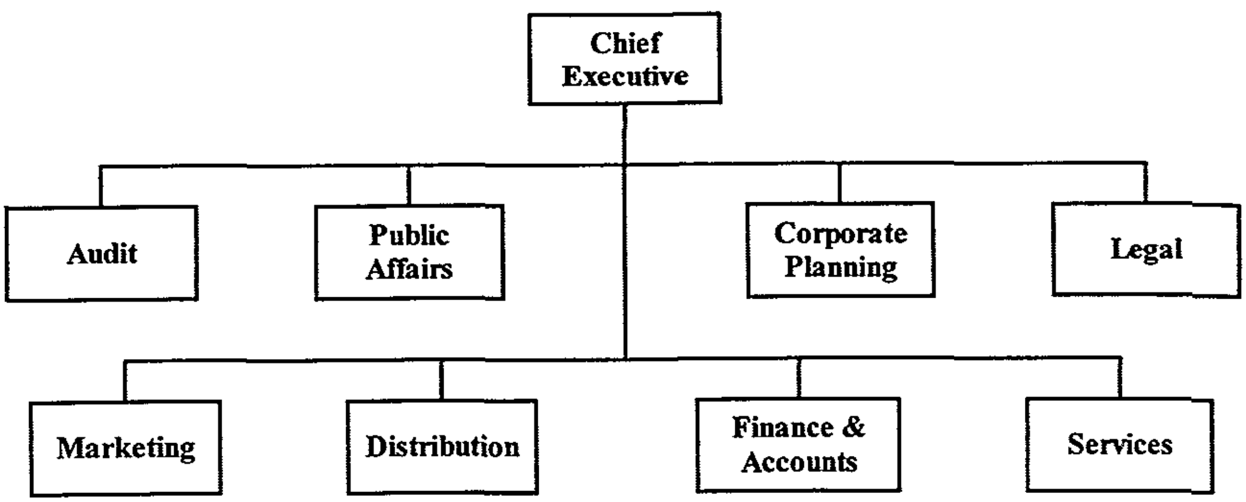

Figure ES-2: DisCo Headquarters Management Team

The DisCo will be an independent profit center under the IHC. DisCo HQ will be responsible for executive management and provision of some central services to the Districts such as planning and construction, protection, metering programs, corporate planning, personnel and administration, procurement and legal services. The following management positions will have expanded responsibilities and scope:

- The General Manager of the DisCo will have executive authority, like a CEO.
- The Assistant General Managers for Distribution and Marketing will have executive management responsibility for their line organizations and report to the GM DisCo. The Commercial Managers in the Districts will report to the AGM Marketing at DisCo HQ, and the Distribution Managers in the Districts will report to the AGM Distribution at DisCo HQ.
- The AGM Finance and Accounts will have expanded responsibilities similar to the Chief Financial Officer of a stand-alone company.
- A new position AGM Services will manage central services for personnel and administration, procurement, property, IT and communications.
- New management positions for legal services and corporate planning will help to establish the DisCos as autonomous profit centers.

GenCos – The generation sector will be split into six GenCos consisting of one company for each of the four thermal stations and two hydro companies (Kainji and Jebba combined plus Shiroro as stand alone). A key question is whether central services like executive management, engineering, project management, contract management, procurement, finance and accounting should be devolved to the plant level during the pre-privatization transition stage. The need for organizational enhancements at the GenCos will depend on 1) the potential to improve overall organizational efficiency of the generation sector and 2) the future privatization scheme. If the companies will be spun off from NEPA under ROT contracts, O&M agreements or asset sales, the new third-party operators will most likely create their own organization structures regardless of what structures NEPA puts in place in the interim transition period. These issues can be explored further in the next stage of work.

Market Operator – The Market Operator will be a small unit responsible for administering the terms and conditions of the Market Rules. The primary duties of the Market Operator will cover bulk supply charges and cash allocations, preparing accounting statements for market transactions and managing the settlements process.

Corporate Headquarters – As the independent NBUs are formed, Corporate Headquarters will reorganize accordingly. Central services such as HR, medical, treasury, procurement, security and industrial relations will increasingly devolve from Corporate Headquarters to the NBUs. In the first step, while the IHC is in place, some common services will remain at HQ. In the second step, all residual common services will be devolved to the NBUs and other licensee(s), and HQ will be dissolved.

The reorganization process should be carefully orchestrated according to the following principles: 1) NEPA employees should be given first priority for new positions; 2) new positions should be widely advertised at all NEPA locations and all staff should be informed about the restructuring plan to help them decide their career moves; 3) candidate selection should be in accordance with NEPA's Recruitment and Promotion Manual.

3.4 Financial Restructuring Plan

The objective of financial restructuring is to establish the books of account of the unbundled NBUs. The main steps are 1) clean-up NEPA's balance sheet, 2) allocate the remaining assets and liabilities amongst the NBUs and Corporate HQ, and 3) prepare opening balance sheets for the NBUs.

NEPA Balance Sheet Clean-up – The following summarizes the recommended approach to clean up NEPA's balance sheet:

- Power sector debt obligations – NEPA and FGN should agree on how to handle past debts incurred by FGN for power sector investments. At present, FGN obligations to external lenders for power sector investments are US$2.7 billion, whereas NEPA records show debt due to the FGN of US$387 million. The overall difference is US$2.3 billion. The key policy question is whether the FGN or NEPA should be liable for the difference. Considering the objective to privatize NEPA, it would not be prudent to saddle NEPA with such a huge debt burden at the present time. All or most of the debt should be converted to equity (i.e. written off) with the goal to keep the company's debt/equity ratio under 20% and minimize the need for tariff increases to cover increased debt service obligations.
- Backlog of government unpaid electricity bills – The non-payment of electricity bills by local and state government is a major issue that needs to be seriously addressed prior to privatization of the DisCos. The total government debt to NEPA for unpaid electricity bills is estimated at N12.8 billion (US$100 million). The outstanding balance is unlikely to be ever collected by NEPA; therefore it should be cleared from NEPA's books by way of set-off against debt to equity conversion.
- Overdue VAT and gas purchase liabilities – NEPA's books of account reflect overdue or uncollected VAT on electricity bills of Naira 6.5 billion, and disputed amounts due to the National Gas Company (NGC) of Naira 4.3 billion. These liabilities are unlikely to be paid; therefore they should be cleared from NEPA's books by way of set-off against debt to equity conversion.
- Customer accounts receivable – NEPA's recorded customer accounts receivables are grossly over-stated in terms of their ultimate recoverability. It is therefore necessary to identify and write-off all irrecoverable debts in the books of DisCos.

NBU Opening Balance Sheets – The financial restructuring plan provides a list of categories of assets and liabilities that are presently recorded in corporate HQ books but should be allocated to individual NBUs. The following points summarize the recommended approach to unbundle NEPA's accounts to the NBUs and create the opening balance sheets:

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- Fixed assets registers – Local consultants are compiling fixed assets registers for each NBU as of December 31, 2001. The agreed next steps are as follows: 1) revalue fixed assets based on valuations provided by PB Power; 2) allocate fixed asset values for recording in the books of the NBUs; 3) HQ to notify NBUs of additions to fixed assets in 2002; and 4) NBUs to take physical inventory of fixed assets and update fixed asset registers as necessary.
- Vesting of loans to Successor Companies – The following principles are recommended for vesting of NEPA loans to its Successor Companies: 1) on-going loans should be vested to the companies concerned, e.g. The World Bank loan for the transmission development project should be transferred to TransysCo; and 2) the remaining restructured debt should be allocated to operational NBUs based on their respective equity, i.e. same debt/equity ratio to apply across the board.

4 NEXT STEPS

NEPA has adopted an ambitious timeline for the power sector reform project. By the end of the 2nd Quarter 2003, the company plans to inaugurate TransysCo, incorporate the NBUs and announce the NBU management teams. By the end of the 3rd Quarter 2003, the transition stage market design will be completed and the set up of NERC will be underway.

4.1 Timetable for Priority Reforms

The next steps for setting up the transition stage market are as follows:

- Agreements, systems and procedures for shadow market operations – The shadow market can be inaugurated by 1 July 2003 in time for the 3rd Quarter budget cycle. Key milestones include: finalize and obtain approvals for the market rules, the bulk supply charges and the initial cash allocations; set up banking arrangements for cash flows; approve new financial authority limits for the NBUs; staff and provide the essential requirements of the Market Operator function; and develop a workable system for compiling grid meter data.
- Reorganization of the NBUs for functional independence – The following steps can be completed by 3rd Quarter 2003: approve new positions, revised organograms, reporting linkages and job descriptions for the NBU management ranks; conduct a fair and transparent executive staff selection process; and obtain NEPA Board of Director (BoD) approvals for selected candidates.
- Financial restructuring of NEPA's debts and assets – Nexant has recommended a financial restructuring plan to clean up NEPA's balance sheet. The plan will require obtaining Ministry of Finance approval to write off NEPA's debts to FGN and irrecoverable accounts.
- Unbundling of accounts to the NBUs – Unbundling of accounts will require completing the NBUs' fixed assets registers, allocating HQ assets, loans and liabilities to the NBUs and preparing opening balance sheets. The target completion date for these tasks is June 30, 2003.

Successful implementation of the transition stage market will require coordination of a wide range of activities, inputs and approvals involving NEPA management and staff, BoD, FGN, Ministry of Power and Steel, Ministry of Finance, Bureau of Public Enterprises and consultants. A task force approach will drive the process forward.

4.2 Restructuring Task Forces

A task force consists of: 1) a chairperson most likely drawn from the ranks of NEPA EDs; 2) a task manager to plan, schedule and coordinate activities, assign responsibilities, monitor progress and obtain resources and management approvals; 3) an inter-disciplinary task team drawn from relevant NEPA divisions and other agencies; and 4) consultants, if required. Task forces can be organized to address the following reform activities:

- DisCo, TransysCo, GenCo and IHC Corporate Headquarters Set-up Teams – These task forces can finalize the management structures and management-level job descriptions for the NBUs, reengineer core processes at the NBUs and IHC HQ consistent with the transition stage market structure, manage the overall set-up of the NBUs and guide the change process company-wide. Set-up Teams have already been appointed for DisCos, TransysCo and GenCos with the relevant NEPA EDs serving as chairpersons. A fourth task force will be required for IHC Corporate Headquarters.
- Executive Staffing Task Force – This task force can manage the recruitment, selection and appointment of individuals to new management positions at the NBUs.
- Market Operations Task Force – This task force can cover the following reforms: new systems and processes for load allocation, grid metering, settlement, exchange of information and dispute resolution; completion of the market agreement; and set-up of the Market Operator and the Market Operations Committee.
- Financial Task Force – This task force can finalize the bulk supply charges and cash allocations to the NBUs, institute banking and accounting arrangements for the settlement system, prepare the NBUs' opening balance sheets, develop and implement proposals on financial restructuring and advise on tariff issues.

4.3 USAID Technical Assistance Program

USAID is sponsoring Nexant for the remainder of 2003 to assist NEPA with implementation of the transition stage electricity market. Table ES.1 presents a work plan for the USAID-Nexant technical assistance program. The work plan will provide technical assistance to NEPA in the following areas: TransysCo set-up; DisCo set-up; restructuring of Corporate Headquarters; market operations and financial transactions; and financial restructuring. The program is flexible and activities can be added or amended to meet the needs of the electricity sector reform program.

Table ES.1: Nexant Work Plan for USAID Technical Assistance on Electricity Market Reforms

Nexant Activities	Finish
1. Tools and Planning Assistance for NEPA Restructuring Task Manager(s)	Q4 2003
2. Set up Transition Stage Market	
▪ Finalize charges and cash allocations	Q2
▪ Finalize Market Agreement	Q3
▪ Opening balance sheet for TransysCo	Q3
▪ Technical advice on financial restructuring	Q4
3. Set up Market Operator	
▪ Terms of Reference	Q2
▪ Procedures and work processes	Q3
4. Set up Market Operation Committee	
▪ Implementation Plan	Q3
▪ Procedures and work processes	Q4
5. Pilot DisCo(s)	
▪ Forecasting and business planning	Q3
▪ Enhance core functions: management, F&A, Corp Planning, HR, etc	Q4
6. IHC Corporate Headquarters	
▪ Reorganization Plan to decentralize core functions	Q3
▪ Re-engineer F&A, HR, Admin, etc	Q4

1.1 PROJECT BACKGROUND

Nexant has been contracted by USAID to provide technical assistance to NEPA on corporate restructuring. The overall objective of the USAID technical assistance program is to advise NEPA management on key initiatives to reshape the company for improved performance during the transition to privatization.

This report has been developed by Nexant in cooperation with a counterpart team appointed by the NEPA Managing Director. The project builds upon the foundation provided in the *National Electricity Policy Draft* (NERA, March 2001), the *Electric Power Sector Reform Bill of 2003* and the *Blueprint for Corporate Restructuring of the Nigeria Electric Power Sector* (PwC, July 2002).

The objective of the project is to provide recommendations on priority reforms for the transition stage electricity market, which will transform NEPA into an Initial Holding Company (IHC) with profit-oriented New Business Units (NBUs) for generation, transmission and distribution. The project aims to provide a practical restructuring strategy that builds upon existing processes and structures at NEPA and takes into account the constraints facing the electricity sector over the next few years.

The project scope of work covers the following deliverables:

- Market rules covering the services that the NBUs provide to each other
- Financial mechanisms for market transactions between the NBUs
- Reorganization Plan to enhance the management functions of the Distribution Companies (DisCos)
- Plan for new market organizations, namely the Market Operator and the Market Operation Committee
- Financial restructuring plan for NEPA
- Approach to vesting assets and liabilities to the NBUs

1.2 OBJECTIVES

Corporate restructuring is vital for each NBU to take responsibility for managing not only its operational performance, but also its financial performance, as if it were an independent enterprise. In the short run, the restructuring exercise will establish the means to track the performance of the NBUs and reform the dysfunctional system whereby local managers have to seek permission in Abuja for even minor expenditures, and budgets carry little weight for the actual disbursement of funds.

In the long run, restructuring will contribute to better overall performance for the electricity sector and facilitate the transition from NBUs to private companies. The ultimate objectives of the corporate restructuring exercise are: the separation of transmission and system operations

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from generation; the establishment of a transmission company; the establishment of a number of competing, privately owned generation companies from existing NEPA generating facilities; and the establishment of a number of distribution companies which will also be privatized.

1.3 ROADMAP FOR THE FUTURE DEVELOPMENT OF THE ELECTRICITY SECTOR

The national electricity policy envisions three distinct stages in the reform of the electricity sector. In the transition stage, NEPA will be unbundled into NBUs within an Initial Holding Company. There will be a shadow market for wholesale transactions between the NBUs. The medium term market will feature bilateral contracts between successor companies spun-off from NEPA. In the long run the market will be opened to more competition.

This report focuses exclusively on the Initial Holding Company (IHC) stage, which will establish the groundwork to spin off the successor companies. The IHC stage will provide the opportunity to introduce commercial practices at the NBUs, to introduce new market functions and to establish commercial relationships between the NBUs. Even though the IHC is considered a transient structure and not an end in itself, it should be carefully planned and implemented as a starting point for future reforms.

1.3.1 Constraints

From a practical standpoint, the reforms that can be introduced in the immediate term are limited by fundamental constraints on the development of the sector. The following key constraints have been considered in the transition stage market design:

- Retail tariffs are below cost of service and collected revenues are inadequate to sustain proper maintenance and investment requirements. All of the DisCos are loss-making and unable to pay the full cost of the transmission and generation services provided by TransysCo and the GenCos. As a result, available funds will have to be carefully rationed to the NBUs according to fair and transparent rules that "share the pain" of inadequate cash resources.
- The uniform national tariff impacts some DisCos more than others. The customer mix and cost profiles vary significantly from one DisCo to another, resulting in unequal profitability and financial strength.
- There is no provision for direct government subsidies to individual NBUs, and none of the NBUs are credit-worthy. In the near term, the individual NBUs will not be able to obtain financing for their own investment programs separate from Corporate Headquarters.
- Energy production is insufficient to meet system demand; therefore available energy must be rationed.
- The NBUs have historically functioned as operating units with minimal profit orientation and inadequate commercial focus. There is a pressing need to strengthen the NBUs to prepare them to function as profit centers.

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The cash shortage stands out as a primary roadblock for instituting a commercial electricity market with cost-based pricing for transactions between the NBUs. The problem is illustrated by the case of Lagos South DisCo. Figure 1-1 compares Lagos South DisCo's cash collections per unit of energy sold against the average cost-of-service to produce and deliver the energy. Lagos South collects in cash about two-thirds of the full cost of supplying energy to its customers.

The company's cash collection is roughly equal to the cost of the generation and transmission services that it consumes. If Lagos South were to pay the full cost of generation and transmission, there would be no cash left over for its own distribution and marketing costs and the company would face insolvency.

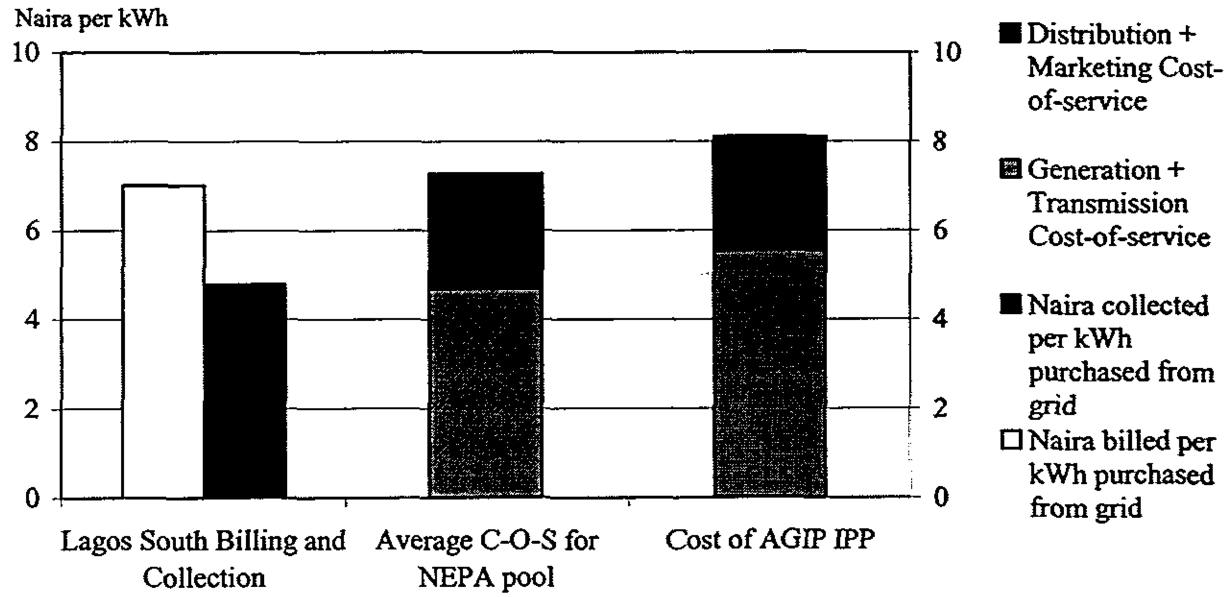

Figure 1-1: Cash Collection versus Cost of Energy Supplied for Lagos South DisCo

Lagos South has the highest cash collection per kWh of sales and the lowest distribution and marketing costs out of all the DisCos. The financial positions of the other DisCos are weaker, in some cases significantly weaker. In summary, all of the DisCo's are loss-making and they cannot afford to pay the full cost of generation and transmission services.

All of the NBUs are dependent upon the *DisCos' cash collections performance*. For example, if Lagos South's collections were to decrease, then by necessity it would pay less of the cost-of-service of the GenCos and TransysCo and less of the cost of NEPA's IPP purchases. It would also provide a lower subsidy to the other weaker DisCos. If its cash collections were to be siphoned off for its own uses, for example to cover the cost of a direct purchase from an IPP, then by necessity it would pay a lower portion of NEPA's overall cost-of-service and the other NBUs would suffer. If its ration of energy from the grid were to decrease its sales would go down, its cash collections would decrease, and it would pay a lower portion of the overall cost-of-service and the other NBUs would suffer.

The initial stage market rules must lay out transparent and fair mechanisms for cash and energy allocation that recognize the reality that if any NBU's rations were to increase or decrease it would impact all of the other companies. This dictates the need for a consensus agreement among all market players to govern commercial relationships during the transition stage market. In the early going, this will take the form of a joint agreement on how to share the deprivation of inadequate cash and energy resources.

1.3.2 Transition Market Stage

Figure 1-2 shows the market structure recommended for the transition stage electricity market. NEPA will be unbundled into NBUs for generation, transmission and distribution with a residual headquarters organization for shared corporate services. The primary objectives of this market structure are to transform HQ into the IHC, to commercialize the NBUs and to establish the Market Operator and the Market Operation Committee.

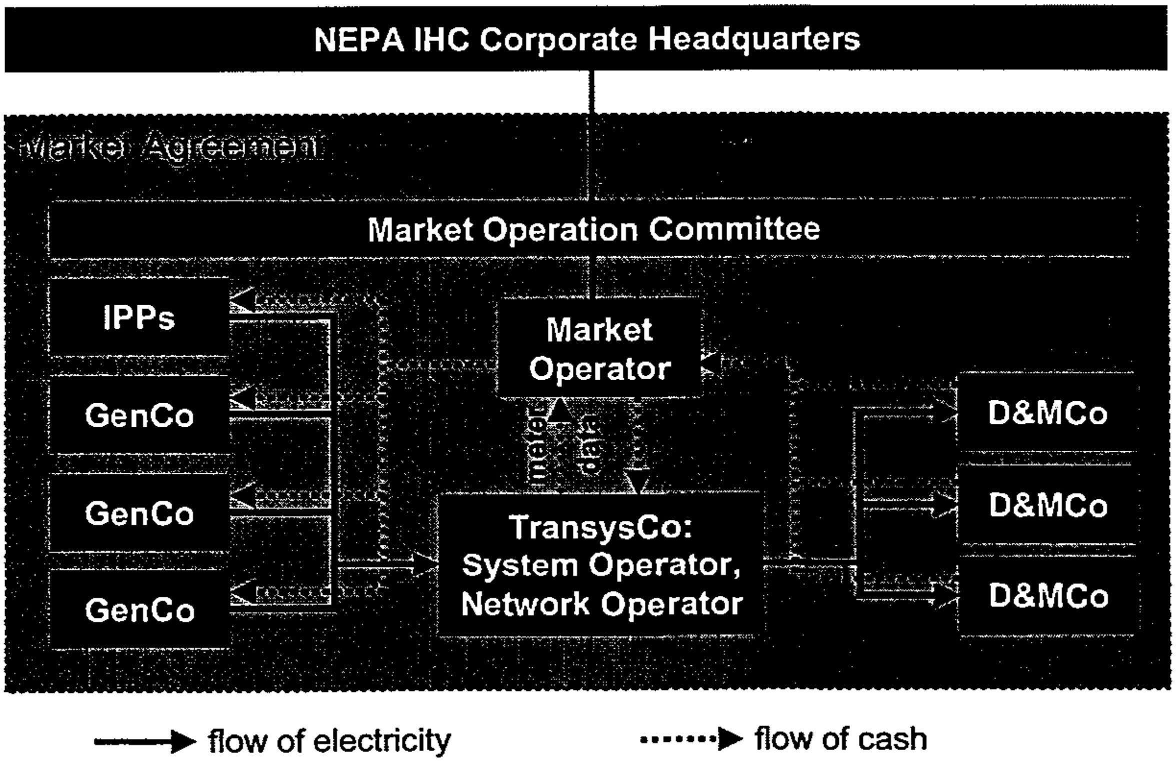

Figure 1-2: Transition Stage Market Structure

The key reforms to be instituted during the IHC stage are:

- A market agreement among all the market players including the DisCos, TransysCo, the GenCos, the Market Operator and the trading licensee that handles purchase from IPPs, when formed

- Bulk supply charges to DisCos based on cost-of-service pricing principles
- Cash allocation to NBUs based on prioritized use of cash company-wide
- Market Operator for billing and settlements
- Market Operation Committee to oversee the market and resolve disputes
- NEPA HQ transformed into the Initial Holding Company
- Some central services devolved from HQ to the NBUs, and authority limits enhanced at the NBUs
- TransysCo incorporated
- Staffing and capacity-building at DisCos and GenCos
- Financial restructuring
- Separation of accounts to the NBU level
- Groundwork for the introduction of the Nigeria Electricity Regulatory Commission (NERC)

The recommended target commencement date for initial market operations is 3rd quarter 2003.

1.3.3 Bilateral Contracts Market Stage

In the future, power will be traded primarily on the basis of bilateral contracts between GenCos and DisCos so that each DisCo will have a portfolio of power purchase contracts with various GenCos and each GenCo will have a portfolio of sales contracts. The market rules will be instituted through an integrated system of contracts including the bilateral power purchase contracts, the transmission services agreement, interconnection agreements etc.

The transition from the IHC stage to bilateral contracts is yet to be worked out, for example bilateral contracts might be instituted uniformly to all DisCos, or the DisCos might graduate to bilateral contracts on a case-by-case basis. The timing for the implementation of the bilateral contracts market is still to be determined.

The key reforms to be instituted in the bilateral contracts stage are:

- NBUs established as stand-alone licensed companies
- IHC dissolved with residual central services devolved to the NBUs
- Formation of a trading licensee responsible for power purchases from existing IPPs and on-sale to DisCos
- Market-based bulk supply charges and DisCo revenue mechanism, with provisions for revenue incentives
- Increased funding to the DisCos from sources that could include: 1) higher customer tariffs; 2) improved billing and collections performance; 3) federal and/or state government subsidies; 4) borrowing; and 5) cross-subsidies between DisCos

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- New agreements:
  - Bilateral contracts between DisCos and GenCos
  - Transmission services agreement and grid code
  - Ancillary services agreement, imbalance tariffs or balancing market
  - Power pooling and settlements agreement
- DisCos responsible for planning their own generation capacity requirements
- NERC up and running

1.4 PRIORITY REFORMS FOR TRANSITION MARKET STAGE

This report provides recommendations on the following key reforms for the transition stage electricity market:

- Market Rules – The market rules define the commercial relationships between the GenCos, TransysCo, the DisCos, the Market Operator and IHC.
- Bulk Supply Charges to DisCos – Bulk supply charges account for the costs of the generation and transmission services provided to the DisCos. The bulk supply charges are determined using a spreadsheet model based on cost-of-service pricing principles. Cost-of-service is defined as the sum of operating costs, depreciation, taxes, interest and profit. Bulk supply charges are used for accounting purposes only and not for cash payment requirements, as described below.
- Cash Allocation to NBUs – The cash allocation mechanism rations the available cash to the NBUs based on a transparent process for budget prioritization. In the foreseeable future, a significant cash shortfall relative to cost-of-service is predicted, therefore cash will have to be allocated amongst NBUs based on need. The cash allocation is calculated using a spreadsheet model.
- Money flows – Funds are collected from end-use customers by the DisCos and transferred in total to the Market Operator, who in turn makes cash payments to all of the NBUs, HQ and the trading licensee for IPP purchase based on the agreed cash allocation methodology.
- Reorganization Plan – The Reorganization Plan covers new management positions that will be created at the NBUs and HQ during the transition stage market. The objectives of the reorganization plan are to decentralize functions from HQ to the NBUs, transition HQ into the IHC, begin the process to prepare the NBUs for independence and create the Market Operator and Market Operation Committee.
- Financial Restructuring Plan – The financial restructuring plan recommends a package for cleaning up debts and customer receivables and outlines the activities required to allocate assets & liabilities to the NBUs, prepare the fixed assets registers, and prepare the opening balance sheets.

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1.5 OVERVIEW OF REPORT

The rest of this report is divided into the following sections:

- Section 2: Market Rules – Presents recommendations on rules covering load allocation, bulk supply charges, grid metering, settlement, role of the Market Operator, role of the Market Operation Committee and generation expansion planning.
- Section 3: Bulk Supply Charges and Cash Allocation – Recommends methodologies for setting bulk supply charges and cash allocations, recommends cash flow and banking arrangements, and provides procedures for forecasting charges and cash payments and for reconciliation of actual versus forecast.
- Section 4: Reorganization Plan – Identifies new positions to be created during the *transition stage* to establish the DisCos and the Market Operator.
- Section 5: Financial Restructuring Plan – Recommends the financial restructuring of NEPA's balance sheet and an approach to vesting assets and liabilities to the NBUs.
- Section 6: Next Steps – Lists priority reform activities for the transition stage market and recommends an approach for NEPA to manage the corporate reform process.
- Appendix A: Draft Market Agreement – Presents a preliminary version of the Market Agreement as a starting point for consensus-building.
- Appendix B: Charges Model – Provides an introduction and user's manual for the charges model, which is used to forecast bulk supply charges and NBU cash allocations.
- Appendix C: Executive Job Descriptions for DisCo HQ and Market Operator – Provides job descriptions for the new and enhanced positions identified in the Reorganization Plan.

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2.1 INTRODUCTION

The national electricity policy envisions that during the initial transition stage electricity market, NEPA will be unbundled into semi-autonomous New Business Units (NBUs) [1] within an Initial Holding Company. There will be a shadow market for wholesale transactions between the NBUs governed by market rules administered by a Market Operator.

This section recommends a set of market rules to govern wholesale transactions between the NBUs during the transition stage electricity market. Over time these market rules can evolve ultimately to suit the post-privatization stage electricity market, as provided in the *Electric Power Sector Reform Bill of 2003.*

2.2 OBJECTIVES OF MARKET RULES

The market rules define how the wholesale electricity market works and how the parties in the market relate to each other. The proposed transition stage market rules meet the following general objectives:

- Simplicity – The market rules must initially be simple and easy to understand and operate because none of the players has experience in a commercial market environment. Greater complexity can be added at later stages.
- Sustainability – The timetable for further change in the electricity sector is uncertain. The market rules must be flexible to evolve over time.
- Viability – The first priority of the market rules must be to meet the immediate cash needs of all New Business Units. In the longer term the market rules must ensure sufficient revenue to the NBUs so that they can invest and grow their businesses to meet the needs of customers. Of course the market rules alone will not guarantee the long-term viability of the sector; the FGN (or Regulator) must also do its part to increase tariffs to economic levels.

The transition stage market rules will achieve the following specific objectives:

- Establish an initial market structure and an independent body, the Market Operator, to manage market transactions;
- Support unbundling and setting up the NBUs;
- Encourage commercial behavior at NBUs;
- Improve revenue generation and collection through an incentive mechanism for greater cash collection by the DisCos.

1 The NBUs will be eleven distribution companies (DisCos), six generating companies (GenCos), a transmission company (TransysCo) and NEPA Corporate Headquarters.

- Provide a practical approach to implement the *Corporate Restructuring Implementation Blueprint* (PwC, July 2002); and
- Provide a framework for the future development of the market.

2.3 FRAMEWORK FOR ELECTRICITY TRADING

Figure 2-1 depicts the responsibilities and inter-relationships between the various players in the electricity industry. The following list summarizes the basic obligations of the players in the wholesale electricity market during the transition stage:

- TransysCo – TransysCo will be responsible for providing grid services, including wheeling power from the GenCos to the DisCos, grid system operations, generation and transmission dispatch, interconnections, metering and ancillary services.
- GenCos – The GenCos will be responsible for selling energy to the DisCos through the wholesale market and providing ancillary services to the grid.
- DisCos – The DisCos will buy energy from the GenCos through the wholesale electricity market and sell energy to end customers. The DisCos will be responsible for collecting the cash receipts from end customers used to fund all of the NBUs.

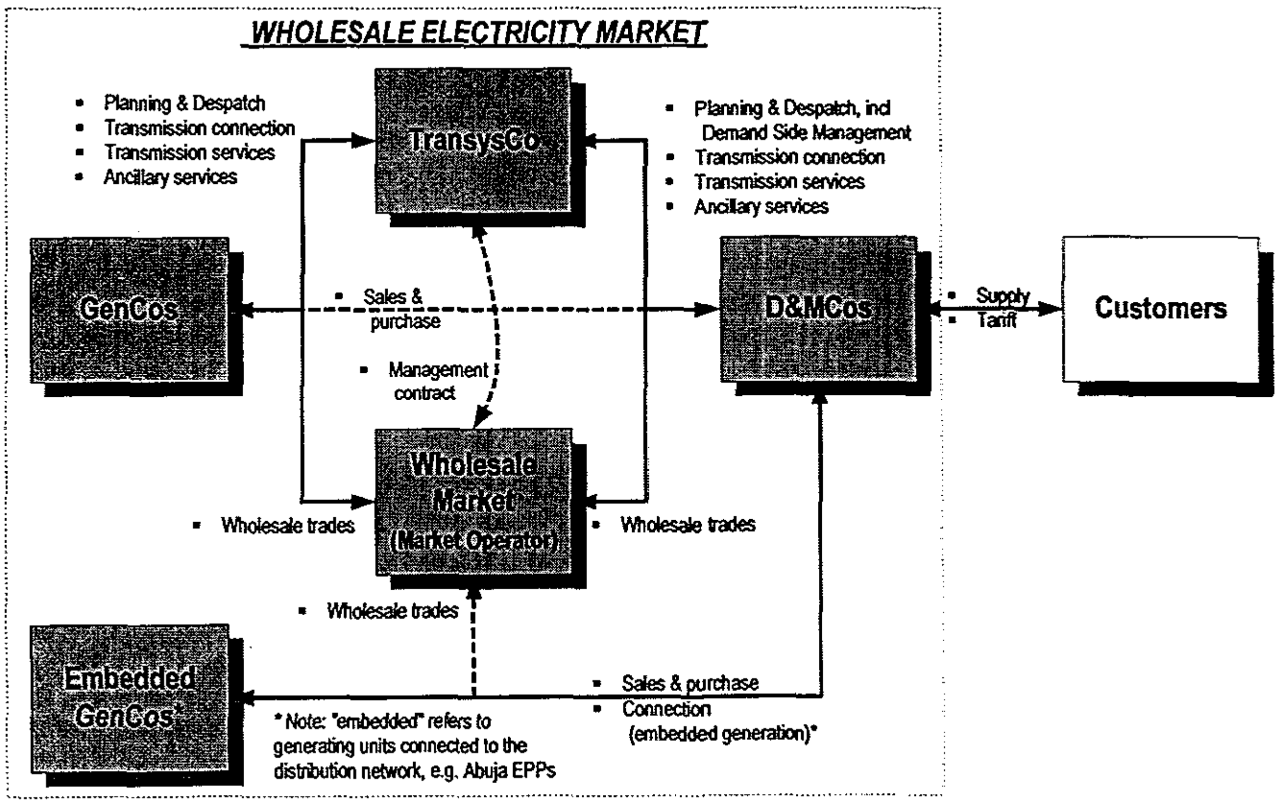

Figure 2-1: Inter-Relationships between Market Players

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Two new organizations, the Market Operator and the Market Operation Committee, will be responsible for administration and oversight of the wholesale electricity market. These organizations will have the following duties:

- Market Operator – The Market Operator will administer the market rules and the system of charges and cash payments.
- Market Operation Committee – The Market Operation Committee will oversee the administration of the market.

2.4 MARKET RULES

This section presents the proposed terms and conditions for the following key elements of the market rules for the transition stage market:

- Market administration and oversight
- Bulk Supply Charges and cash allocation
- Revenue incentives
- Load allocation
- Grid metering
- Settlement
- Planning for new IPPs

2.4.1 Market Administration and Oversight

The basic structure of market administration and oversight is shown in Figure 2-2. A Market Operator will administer 1) the meter data collection and reporting systems for power flows from GenCos to DisCos via TransysCo; and 2) financial transactions between the NBUs. A Market Operation Committee will oversee the market and report to executive management.

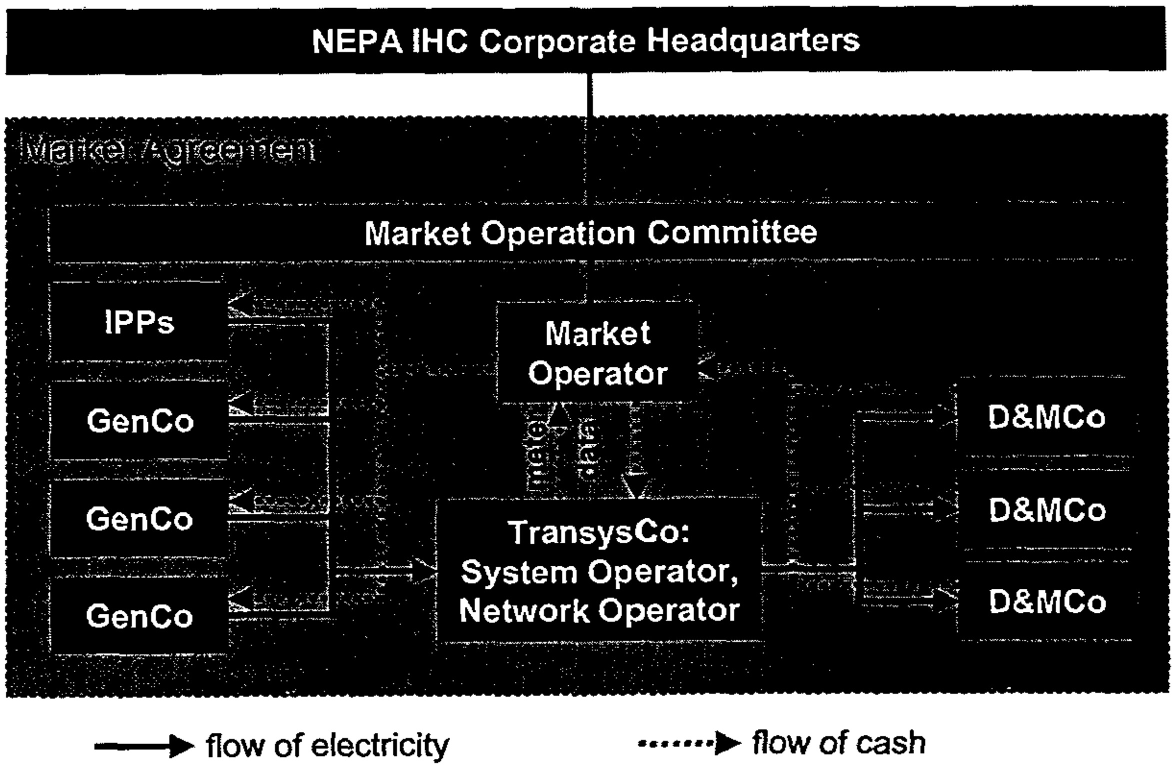

Figure 2-2: Market Administration and Oversight

The following sections discuss the roles of the Market Operator and the Market Operations Committee.

Market Operator

An impartial, independent and competent Market Operator will manage the following functions:

- Collect the forecast demand, budget and meter data required for calculating Bulk Supply Charges and for settlement.
- Consolidate meter data received from TransysCo to calculate the MWh of electricity generated by GenCos, MWh and MVarh received by each DisCo, transmission losses and peak MW and MVA of each DisCo.
- Operate the Charges Model to:
  - Calculate Bulk Supply Charges;
  - Determine the payments due from DisCos to the Market Operator and payable from the Market Operator to DisCos, GenCos, TransysCo and NEPA HQ;
  - Prepare Statements of Account for the NBUs.
- Manage the transfer of money, i.e. instruct banks to transfer cash receipts and to make payments to DisCos, GenCos, TransysCo and NEPA HQ.

- Administer the process of quarterly reconciliation to recalculate charges and cash payments for actual versus forecast quantities and adjust Statements of Account and cash payment requirements accordingly.

Market Operation Committee

A Market Operation Committee (MOC) will oversee the operation of the wholesale electricity market and represent each segment of the electricity sector on matters of common interest. The MOC will have the following responsibilities:

- Define the terms of reference for the Market Operator;
- Ensure the efficient administration of the Market rules;
- Resolve disputes among the NBUs related to the market rules;
- Approve changes to the Charges Model;
- Represent the industry in discussions with the Regulator;
- Change the market rules as the industry evolves; and
- Provide a forum for the discussion of matters of mutual interest, for example the future development of the electricity market in Nigeria, market pricing, tariffs, the promotion of competition, regulation of the electricity industry and investments required to meet future demand.

The MOC will answer to NERC once NERC is formed. Until then, it will report direct to the executive management of NEPA. The following key issues for the MOC can be resolved in the next stage of work: membership, procedures, secretariat, facilities and equipment and budget.

2.4.2 Bulk Supply Charges and Cash Allocation

The market rules cover the methodology to determine Bulk Supply Charges and cash allocations. Bulk Supply Charges account for the cost-of-service of generation and transmission provided to the DisCos, whereas cash allocations account for the rationing of available cash to the NBUs according to budget priority. A complete description of charges and cash is provided in Section 3 of this report

2.4.3 Incentives

Regulated revenue incentives are common features of mature power industries, however in the case of a chronically under-funded utility sector such as Nigeria it is difficult to discriminate between controllable and uncontrollable factors affecting performance. The first edition of the market rules therefore has limited ambitions for introducing incentives; it is more important to reach an agreement that is easy to understand and implement.

There are two cash incentives built into the market rules. First, NBUs will be expected to operate within their approved budgeted expenditures and cash allocations. On this basis, NBUs will be permitted to retain any savings they may achieve through efficiency improvements or other stringent expenditure control measures. Second, the performance of DisCos will be measured in terms of cash collection per kWh of bulk supply and those who outperform their targets will be rewarded with extra cash.

The market rules do not contain an explicit cash incentive for TransysCo to reduce transmission losses, however there is provision for a separate charge to the DisCos for transmission network losses. Making the cost of transmission losses explicit may focus management attention on this area.

2.4.4 Load Allocation

One of the major challenges facing NEPA is insufficient power to meet customer demand for electricity. This arises because there is simply not enough generation capacity installed, and is made worse by high transmission network losses. As a result, load must regularly be shed (disconnected), and NEPA has a process for calculating the load allocation and a procedure to implement load shedding at the Districts. The current load allocation has evolved through a complex political process.

There are several issues concerning load allocation. The first is that the load allocation model is based on transmission regions, and will need to be adapted to DisCo service territories consistent with the new, unbundled industry structure. The second is that the procedure for load shedding will also need to be adapted to the DisCos, i.e. Operations will in future instruct the DisCos to shed load rather than passing instructions via a Regional Control Center direct to District sub-stations as at present. Figure 2-3 shows recommended changes to the load allocation procedures to address these two issues.

A third potentially more difficult problem is the need to make the process for calculating the load allocations more transparent. At present load allocation is calculated on the basis of the historical peak demand at each sub-station, exempted demand and the generation available at the time. Exempted demand[2] is the demand that will be met in full, and is decided by NEPA management. In a commercial environment, the process must be both fair and transparent since many companies will have competing claims for scarce generation resources.

The formula for calculating load allocation needs to be revised. An alternative basis for load allocation could be a certain minimum load for each DisCo (based on the current exempted demand or a percentage of peak), with allocation above the minimum based on some consideration of expected revenue collection per kWh sold. Whilst this would be more effective in bringing cash resources it would penalize DisCos that have a low tariff customer mix and poor collection rates by reducing the amount of power they would receive and hence be able to sell, thus reducing their revenue still further.

The minimum revision will be to establish formal guidelines for granting exempted demand status to customers.

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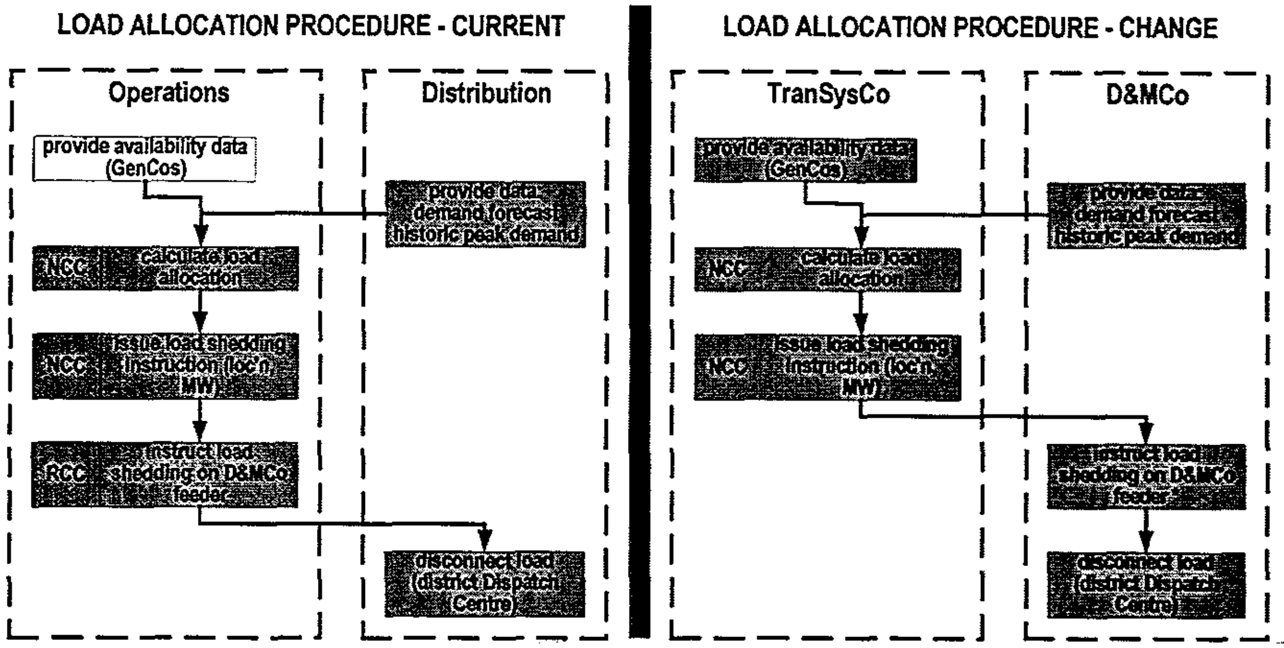
[2] There are two categories of exempted demand: national interest (e.g. Abuja Federal Capital Territory, which is not required to shed load, except in exceptional circumstances) and industrial (e.g. cement companies, who always receive at least a minimum load to avoid problems in their industrial processes that would arise from an instantaneous shutdown).



NCC = National Control Centre (TransysCo)
RCC = Regional Control Centre (TransysCo)

* D&MCo HQ receives instruction and instructs district Dispatch Centre

Figure 2-3: Recommended Changes to Load Allocation Procedure

2.4.5 Grid Metering

The initial market rules will cover basic grid metering principles and standards relating to the provision, ownership and reading of meters. Meters should be capable of recording the following parameters: MWh, peak MW, MVArh and peak MVA. It is important to record peak MVA for DisCos as the capacity (size) of transmission infrastructure installed to meet demand is determined by MVA, not MW. MWh and peak MW are important for determining energy and capacity payments. In the early stages of the transition market there will be no charges for reactive power (MVArh).

The metered quantities are used to determine the charges payable by DisCos as shown in Table 2.1.

Table 2.1: Metered Parameters for Determining Charges to DisCos

Parameter	to calculate:
▪ MWh sent out to the grid by each generating unit, which is the MWh generated, net of on-site consumption by generator transformers and auxiliary equipment and by other users (such as lighting and ventilation)	Variable Generation Charges: Fuel Charges; Transmission Losses Charges
▪ MWh delivered to DisCos' distribution feeders	
▪ MWh transferred at lower voltage between distribution zones	
▪ Peak MW for each DisCo	Fixed Generation Charge (Demand Component)
▪ Peak MVA for each DisCo	Transmission Services Charge Fixed Generation Charge (Trans Losses Component)

GenCos' Grid Metering

The interface between the GenCo and TransysCo is at the High Voltage side of the generator transformer for each generating unit. An important principle for GenCo grid metering is measuring the net electricity delivered to the transmission network (MWhnet). Net electricity delivered is the MWh generated by a generating unit, net of generator transformer losses and electricity consumption by auxiliary equipment, lighting, ventilation etc.

MWhnet = MWhgross – generator transformer losses – on-site power consumption

The problem, however, is that meters to measure net electricity are not yet in place. This will not matter in the short term because a percentage correction factor can be applied for each generating unit, but will need to be addressed in future. A separate issue is that metering will be required for 11kV feeders from power stations such as Egbin and Afam that supply power directly to DisCos.

DisCos' Grid Metering

The interface between TransysCo and the DisCo is on the distribution feeders, i.e. the low voltage side of the sub-station transformer. Ownership of and responsibility for distribution grid meters has been placed with the Marketing sector of NEPA HQ. Ownership and responsibility should be transferred to TransysCo, which could afford to maintain the expertise and capability to install, maintain and calibrate grid meters since it would then have the economies of scale that would arise from having responsibility for all grid metering across the country.

Distribution feeders that transfer electricity between zones are not all metered. Where metering is not available for an inter-zone feeder it will be necessary to apply a percent allocation factor for each DisCo to the electricity delivered via the (metered) incoming distribution feeder from the transmission system (see Figure 2-4 below for an example).

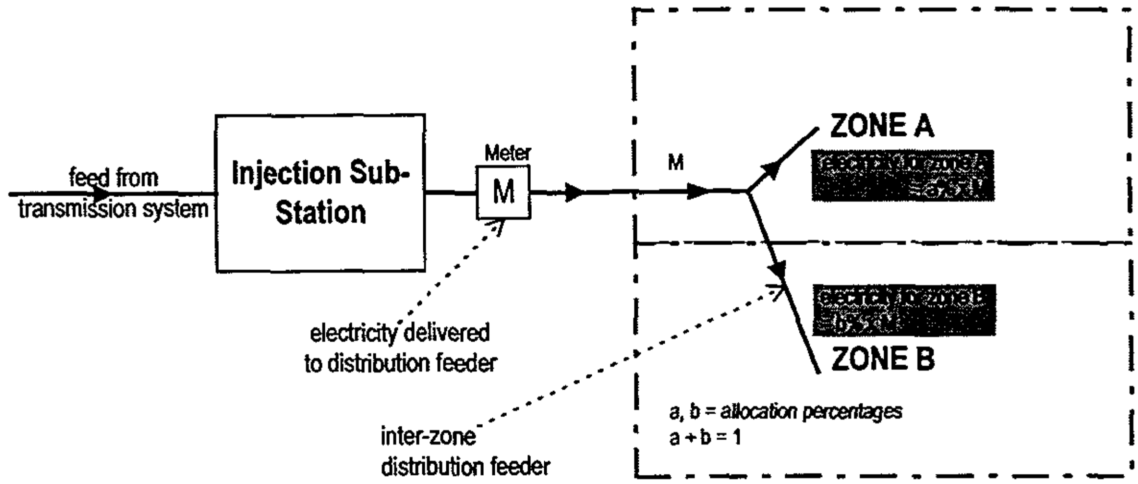


Figure 2-4: Determination of Inter-Zone Power Flow

Meter Reading Frequency

The market rules define the duration of a Metering Period as one hour; all new grid meters are capable of recording hourly measurements. This is sufficiently small to give confidence in the readings so that abnormal trends arising from absence of readings or inaccuracy can be identified quickly, and will also simplify future development as the electricity market moves to allocate costs more accurately and hence to shorter Settlement Periods. Readings would be aggregated over each Settlement Period. Systems for meter data collection and reporting will need to be developed in the next phase of work.

2.4.6 Settlement

This section summarizes the financial settlement process between the market participants, which is presented in more detail in Section 3. Figure 2-5 shows the process for charges determination and financial settlement, and indicates the entities responsible for each part of the process.

The following procedures will be used for settlement during the transition stage:

- Forecast charges and cash allocations – At the beginning of each quarter the Market Operator calculates the Bulk Supply Charges to the DisCos and the cash allocations to the NBUs based on budget and forecast data, and notifies each NBU.
- Cash transfers – Figure 2-6 shows the cash management process. The DisCos' cash receipts are placed in collections bank accounts controlled by the Market Operator, and then transferred at the end of each week to a central remittance account also controlled by the Market Operator. The Market Operator transfers funds by way of standing orders to the NBUs on the 15th and end of each month according to the budgeted cash allocations.

- End-of-quarter statements and adjustments – At the end of each quarter, the Market Operator issues a Statement of Account to each business unit, which records measured quantities, payments due and cash allocation. This statement is similar to an invoice but is prepared by the Market Operator, not the NBU. The Market Operator also reworks the Charges Model to determine any adjustments that may be required to reconcile actual results with forecast. Variances in cash flows between actuals and budgets are brought into the subsequent quarter's cash allocation.

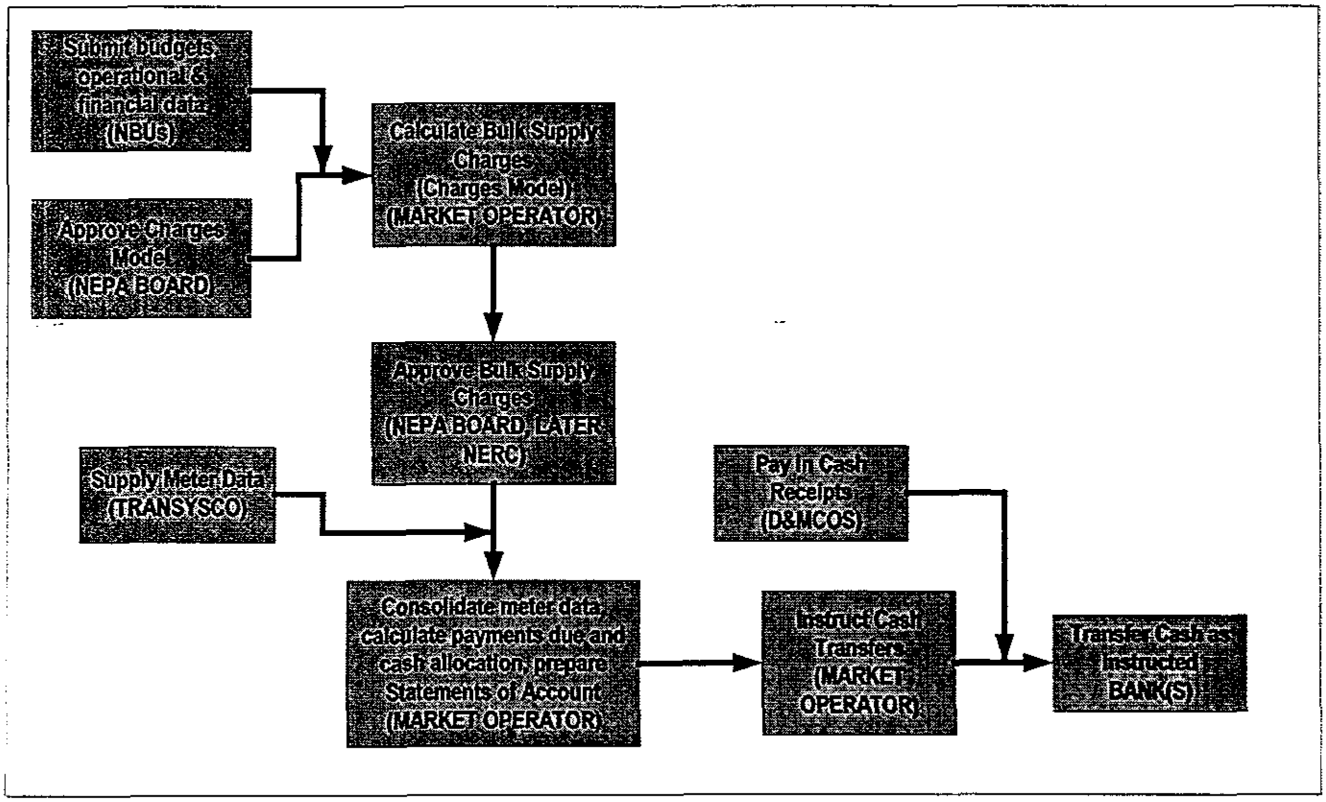


Figure 2-5: Charges and Settlement – Process and Responsibilities

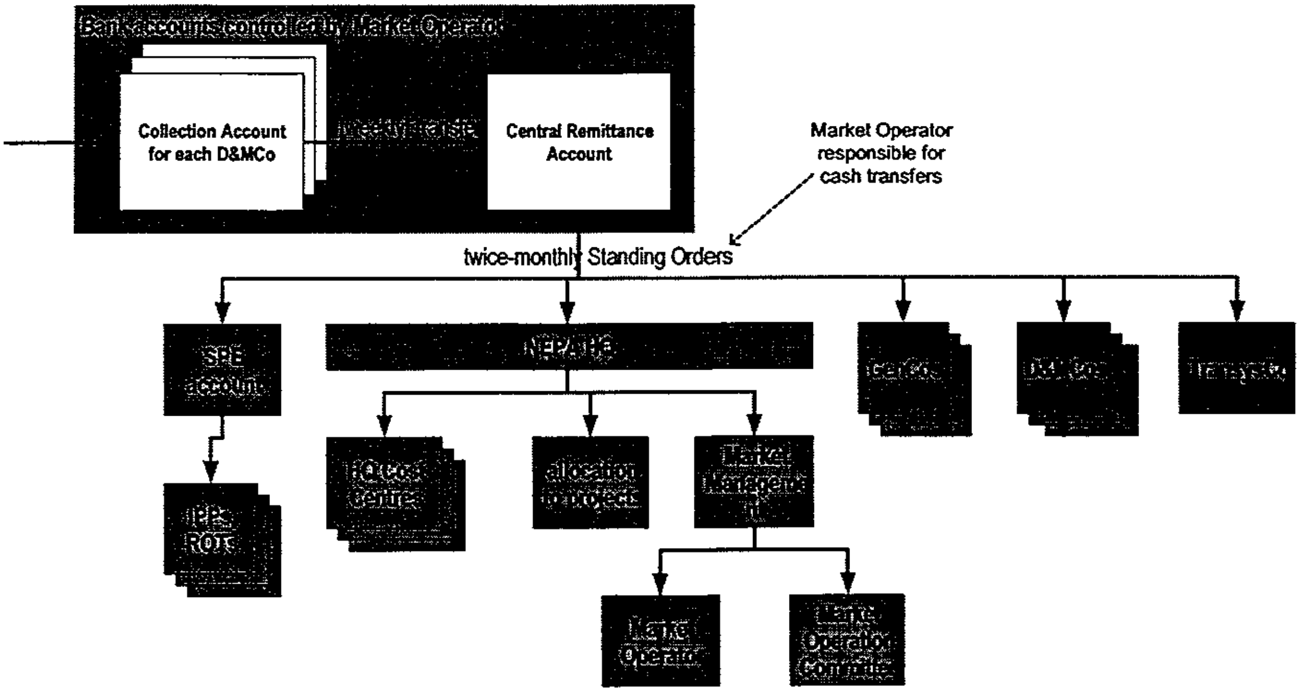


Figure 2-6: Cash Management Process

2.4.7 Planning for New IPPs

In the future, each DisCos will plan and procure new sources of generation to meet the demands of its customers. At present, however, all of the DisCos are loss-making and should not be allowed to make their own IPP purchases since such obligations would adversely affect the financial strength of all the other NBUs.

While the industry as a whole is cash-starved and cash rationing is enforced, only the IHC will have the means to procure new power supplies. Any new power supplies purchased by NEPA will have to be shared communally among the DisCos, and Corporate HQ (or alternatively the trading licensee that purchases from IPPs for resale to DisCos) will handle the financial transactions. Therefore the planning function for new IPP purchases should reside in IHC corporate HQ for the time being.

The DisCos and TransysCo will have the following roles for system expansion planning:

- The DisCos will provide demand and revenue forecasts that will feed into the generation expansion plan developed at IHC HQ; and
- TransysCo will work with the generation planners in IHC HQ to ensure efficient integration of new generation within the existing grid system.

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The Market Operation Committee will have a role approving capacity expansion plans and resolving differences among the DisCos relating to the choice of IPP (e.g. plant type, developer, fuel supply, plant location, transmission connection and system extension, etc.).

2.5 MARKET AGREEMENT

A single comprehensive Market Agreement covering the agreed market rules will provide a straightforward approach to institute commercial relationships between the NBUs during the transition stage electricity market. The Market Agreement can be signed by all NEPA GenCos, DisCos and TransysCo. The basic function of the agreement is to regulate the standards of and payment for services traded between the NBUs. The agreement has a wide scope covering all generation- and transmission-related services and all financial transactions. It provides a simple and expedient means to initiate the transition stage market prior to the bilateral contracts stage.

This section provides an overview of the proposed Market Agreement. A preliminary draft Market Agreement is shown in Appendix A. Note that the appendix is intended for illustration only; the agreement will require additional development and negotiation between the affected parties prior to signing.

2.5.1 *Scope of the Market Agreement*

The scope of the Market Agreement will initially be three-fold, covering the sale and purchase of electricity between GenCos and DisCos via the Market Operator, the provision of transmission services, and grid codes and standards.

Note that eventually the provision of transmission services will be governed by a transmission license, Connection and Use of System Agreements and a Grid Code, and will no longer be part of the Market Agreement, which will leave the Market Agreement as a wholesale trading agreement only.

MARKET AGREEMENT SCOPE

- Wholesale electricity trade (sale & purchase)
- Transmission services
  - Transmission Connection and Use of System
  - Ancillary services
- Codes and standards
  - elements of future Grid Code

2.5.2 Market Agreement Pros and Cons

In the near term, the transition stage market can be governed under the following alternative arrangements:

- An informal "hand-shake" agreement on the market rules between the NBUs;
- A comprehensive Market Agreement covering the full range of agreed market rules; or
- A hastily assembled system of agreements, regulations, codes and standards to institute a preliminary version of the bilateral contracts market.

The Market Agreement option is recommended for the near term. The informal market rules alternative amounts to "business as usual" and this could encourage complacency at the NBUs. The bilateral contracts approach has been established as the ultimate goal for the sector, however it will take substantial time and resources to implement in full and there is no compelling reason to rush out a preliminary version.

The advantages of a relatively simple Market Agreement for the transition stage market are as follows:

- The Market Agreement will allow the NBUs to gain experience with agreed commercial rules in a market environment while the bilateral contracts are readied.
- The Market Agreement is a progressive step that will change any perceptions of "business as usual."
- A single comprehensive Market Agreement is the simplest, most straightforward approach to institute the transition stage market rules. It can be completed and signed within a matter of months, and this will expedite the start date for market operations.
- During the transition stage market, the financial and operational performance of any NBU will impact all of the NBUs. For example, anything that impacts the cash receipts of the DisCos will have a ripple effect on all NBUs. These inter-dependencies are readily captured in a Market Agreement between all of the affected parties.
- The bilateral contracts market will require a development curve to address the following requirements:
  - New policies and solutions must be developed to address serious internal and external constraints on NEPA that create complex financial and operational inter-dependencies between the new market players.
  - In particular, the cash and load allocation mechanisms recommended for the transition stage market will not work for the bilateral contracts market. These will have to be reformulated, and this will involve important policy tradeoffs and consensus building.
  - A cash allocation mechanism will be required as long as the industry as a whole remains under-funded, in particular while electricity tariffs remain below the cost of service.
  - Consultants must be retained to develop the system of contracts for the bilateral market covering power purchases between the GenCos and DisCos, the Transmission Services Agreements, a Power Pool Agreement, Interconnection Agreements, the grid code, licenses, etc. This work will most likely extend well into 2004. In the meantime, the wholesale market can function under the simpler Market Agreement.
- The Market Agreement can change over time as the bilateral contracts market is formed. It is conceivable that the market agreement will persist for some time into the bilateral contracts stage with some of the NBUs remaining party to the Market Agreement even as others graduate to bilateral contracts. Ultimately the Market Agreement can transition to a voluntary power pooling or balancing services agreement between the companies spun-off from NEPA.

There is no major downside to establishing a temporary Market Agreement, except to the extent that it may provide a false sense that the transition stage market rules will persist indefinitely.

2.5.3 Future Agreements for the Wholesale Electricity Market

In a mature unbundled electricity market, the market rules are contained in a complex system of agreements, regulations, codes and standards. Table 2.2 presents a list of the commercial arrangements that will be required for the future wholesale electricity market.

Table 2.2: Typical Contractual and Regulatory Framework for Wholesale Electricity Market

Service	Agreements, Codes and Standards	Parties
Wholesale trade in market-place	Pooling & Settlement Agreement, Power Exchange Master Agreement, Market Agreement	GenCos DisCos Energy traders
Sales & purchase	Bilateral Power Purchase Agreement	GenCos
	Firm Power Sales Agreement	DisCos
Connection to transmission network	Connection Agreement Grid Code	TransysCo GenCos DisCos
Transmission services	Transmission Licence	Government or Regulator TransysCo
	Use of System Agreement	TransysCo GenCos DisCos
Ancillary services	Ancillary Services Agreement	TransysCo GenCos
		TransysCo DisCos
Supply	Supply Agreement, Retail tariff	DisCos Customers

2.5.4 Regulation of Market Agreement

The wholesale electricity market will initially be regulated by the NEPA IHC executive management level, which will have the power to direct the Market Operation Committee and Market Operator regarding the principles governing the financial and operational performance of the market. This role will be taken over by NERC, when formed.

Section 3 Bulk Supply Charges and Cash Payment Requirements

3.1 OVERVIEW OF FINANCIAL TRANSACTIONS BETWEEN NBUS

This section proposes a framework for the financial transactions between the NBUs during the transition stage market. There will be two pricing mechanisms, one for accounting-based *charges* from the GenCos and TransysCo to the DisCos and a separate mechanism for *cash allocations* to each NBU and to IHC HQ. Charges will be based on full cost-of-service (CoS), including depreciation on revalued fixed assets and return on equity. Cash allocations will be based on a fair system to ration cash receipts from end customers according to greatest need company-wide.

The charges and cash allocations will be set quarterly in advance by the Market Operator using a spreadsheet model developed for this purpose. A description and user's manual for the charges model are provided in Appendix B.

3.1.1 Electricity Market Transactions

The transition stage electricity market will consist of the following transactions:

- GenCos will sell electricity to DisCos for resale to end-use customers.
- A trading licensee will aggregate NEPA's IPP purchases and resell the power to the DisCos for resale to customers. For now this function will reside in Corporate HQ.
- TransysCo will provide transmission services for the wheeling of power from the GenCos to the DisCos and HV customers.

Figure 3-1 shows the flow of charges administered by the Market Operator on behalf of the NBUs and the trading licensee for bulk purchases from IPPs. The Market Operator is responsible for (a) the collection of all necessary technical and financial data, (b) the operation of the bulk supply charges and cash allocation model, (c) submission of statements of accounts to each NBU, (d) allocation and transfer of funds to NBUs, and (e) quarterly reconciliations and adjustments.

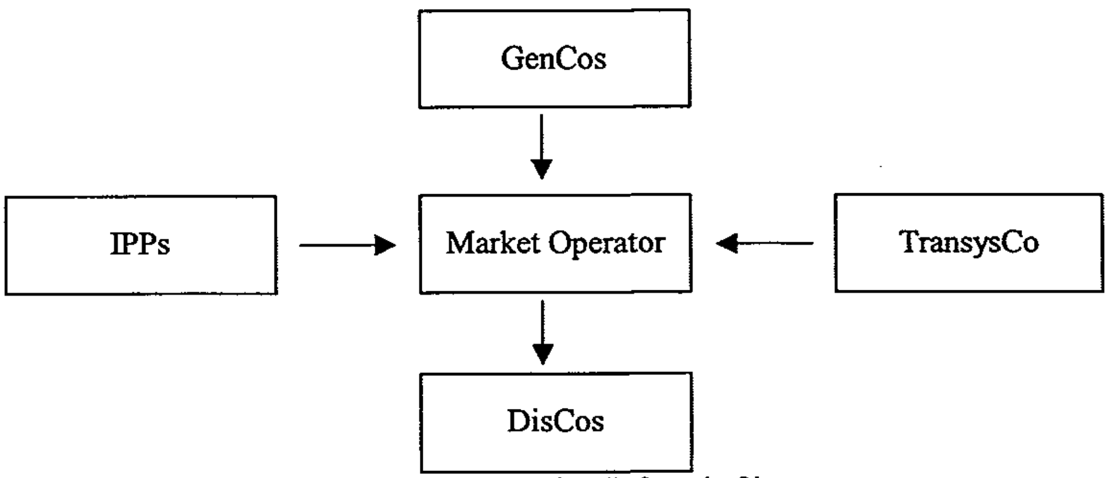

Figure 3-2: Flow of Bulk Supply Charges

The source of funds for all the power sector organizations ultimately is the end use customers. The funds are collected by the DisCos and transferred to the Market Operator, who in turn makes payments to the all NBUs based on the cash allocation methodology.

3.1.2 Pricing

The pricing framework for the transition stage market is designed to meet the following key objectives:

- Provide a fair and transparent basis of:
  - Setting bulk supply charges
  - Allocating available cash resources among NBUs
- Establish a more transparent and effective system of budgeting and monitoring.
- Make NBUs accountable for their operational and financial performance.
- Provide incentives for efficiency.

The following financial arrangements are recommended during the transition stage market:

- Cost-of-service based bulk supply charges for generation and transmission services to DisCos based on their respective demands on the system.
- Quarterly invoices from GenCos and TransysCo to the Market Operator and from the Market Operator to the DisCos.
- Company-wide sharing of available cash resources collected from end customer billing on a fair and equitable basis. Since collected end customer billings are below CoS and inadequate to meet revenue requirements:
  - Cash must be allocated among NBUs on a "needs basis."
  - CoS-based charges will be used only for accounting and profitability measurement.
- Increased spending authority for NBUs.
- An enhanced budget process that reduces HQ oversight of NBU spending and at the same time encourages the NBUs to live within their allocated cash resources.
- Quarterly reporting and monitoring of operational and financial performance of market participants.

3.1.3 Financial Constraints for the Transition Stage Market

The following constraints must be taken into account for the design of the financial arrangements between the NBUs during the transition stage:

- There is a single uniform national tariff schedule for all end use customers, regardless of the costs or customer mix of individual DisCos. It includes large subsidies among customer classes.
- Tariff levels are too low and do not provide adequate revenues to support a reasonable profit for the power sector.
- There are significant problems associated with network losses, both technical and non-technical, and with non-payment of electricity bills by end use customers. The DisCos

have as yet been unable to take effective steps to address these issues. The problem varies widely among the DisCos.

- The Government will provide no operational subsidies to the power sector, except for (a) contributions towards fuel and capacity charges of the Abuja EPP, and (b) subsidized fuel prices.

Figure 3-2 summarizes NEPA's average cost-of-service for energy supplied to end customers compared with the average billing per kWh delivered and the average cash collection per kWh delivered. There is a huge difference between costs and cash collections. This problem limits the extent that commercial financial arrangements are possible between the NBUs during the transition stage and prompts the need for a cash allocation mechanism separate from the accounting-based charges.

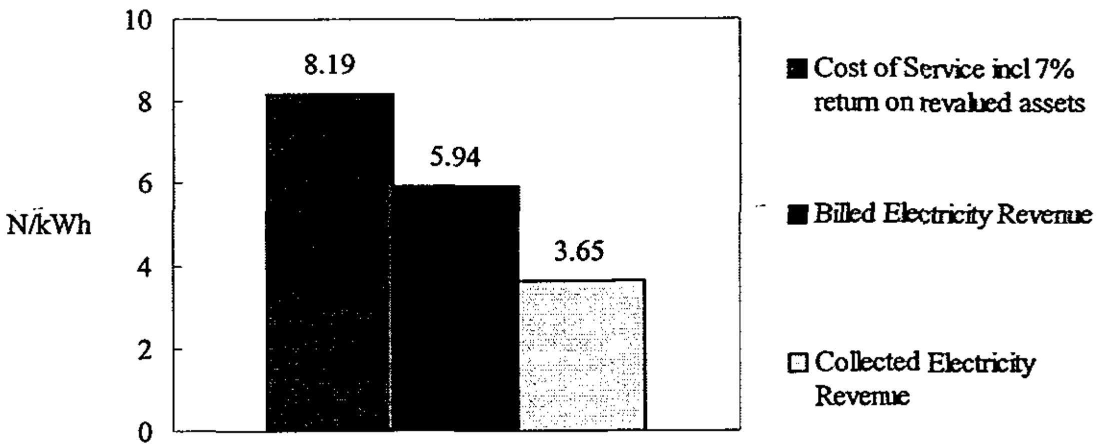

Figure 3-2: Cost of Service vs. Billed Revenue vs. Collected Revenue

The impact of the cash shortfall must be reflected in the financial statements of the NBUs in order to assess their true profitability. The following accounting practices are recommended:

- GenCos and TransysCo – The revenue side of the income statements for the GenCos and TransysCo will show the bulk supply charges accruing from the DisCos and the cost side will show the non-payment of these charges. The bottom line will therefore reflect the companies' financial losses relative to full cost of service.
- DisCos – Bulk supply charges for generation and transmission services will be shown as operating costs on the DisCos' income statements. Uncollected end customer billings will be charged against profits. The resulting profit or loss will therefore reflect the true measure of financial performance based on full settlement of bulk supply charges. The non-payment of bulk supply charges will be deducted below the line to arrive at the net profit or loss based on actual cash payments by DisCos for generation and transmission services.

3.2 BULK SUPPLY CHARGES

Bulk supply charges for generation and transmission services are based on the costs to meet the DisCos' demands on the grid system. Charges are set according to a budget forecast prepared at the start of each quarterly budget cycle using the charges model. The following sections recommend the process to forecast generation and transmission charges to the DisCos during the transition stage market.

3.2.1 Cost of Service

Bulk supply charges for generation and transmission services are set equal to cost of service. Figure 3-3 shows the components of cost-of-service for the GenCos, TransysCo and the DisCos. In general, the components of cost of service are operating expenses, depreciation, interest, taxes and return on equity.

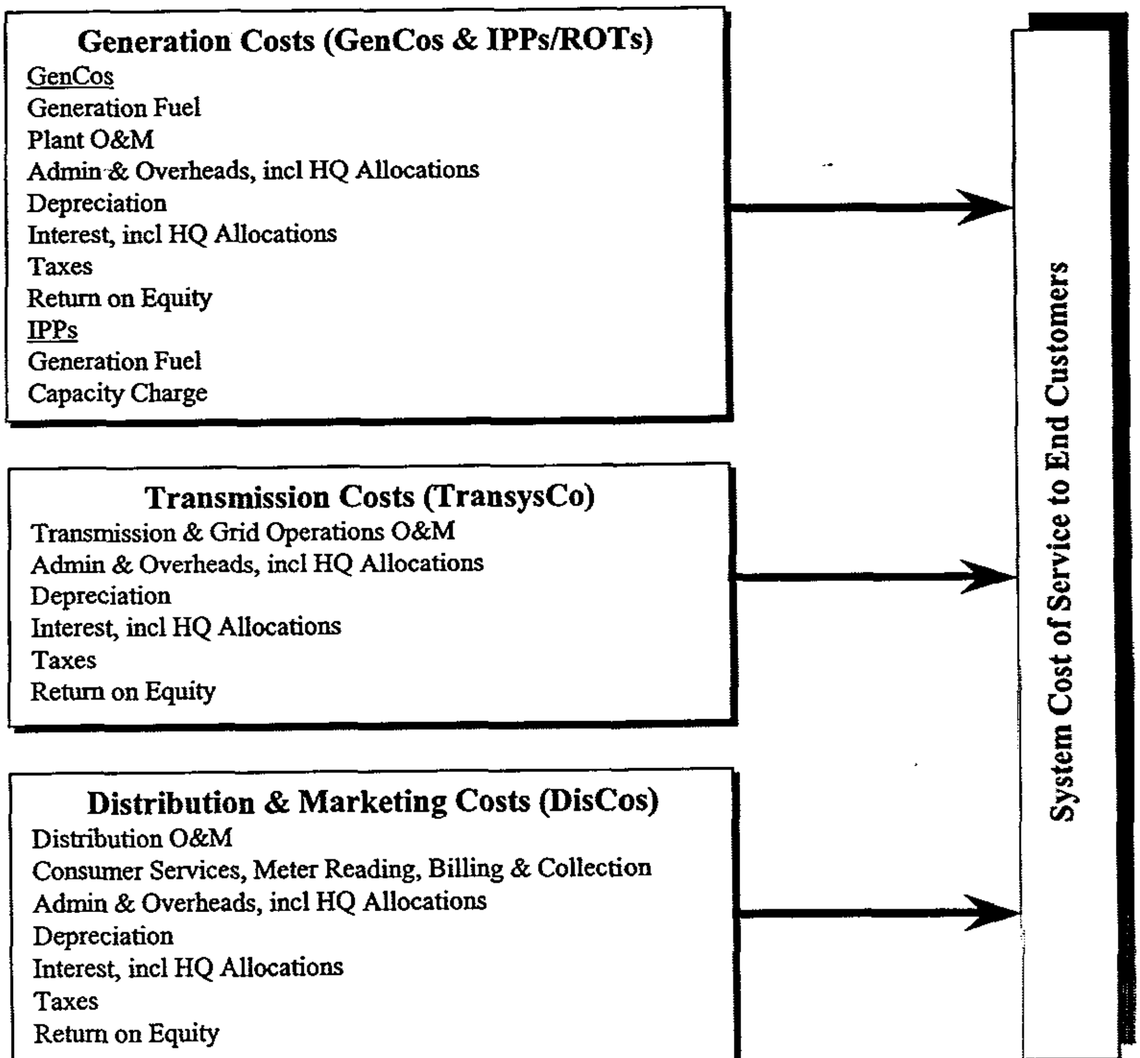

Figure 3-3 Make-up of Cost of Service

Cost of service is a function of the underlying financial and accounting information. The following key issues must be addressed for the calculation of cost of service:

- Basis for depreciation, i.e. replacement cost or historical
- Level of long term debt service
- Target profit

Fixed Assets Valuation and Depreciation

The charges model has the facility to select two alternative bases of fixed assets valuation and depreciation thereon. The two alternatives are:

- Depreciated replacement cost basis
- Historical net book value basis

The selected basis of valuation will have a considerable impact on the costs of service for each NBU and for the sector as a whole, and consequently on the bulk supply charges. The depreciation charge under the depreciated replacement cost basis will be much higher than under the historical cost basis.

The pros and cons of the two alternatives are summarized below:

Depreciated Replacement Cost Basis

Pros

- Reflects true cost of asset usage
- Makes realistic provisions for asset renewal

Cons

- Valuations are subjective

Historical Net Book Value Basis

Pros

- Historical costs are not subjective

Cons

- Reliable historical cost data is not available in NEPA
- Inadequate provision is made for asset renewal
- Does not reflect true cost of asset usage

The historical costs and net book values of fixed assets, as recorded in NEPA's books, have eroded considerably over the years due to the cumulative impact of depreciation of the Naira and domestic inflation. In addition, inappropriate accounting practices of expensing capital costs in previous years have led to the understatement of historical costs of fixed assets. It is therefore recommended that the depreciated replacement cost basis should be adopted for the calculation of bulk supply charges. The charges model uses the fixed asset values provided in the *Valuation of the Assets of NEPA* (PB Power for BPE, March 2002).

Long-term Debt Service

NEPA's debt service requirements will impact the bulk supply charges. Section 5 presents several debt restructuring options for consideration by NEPA and the FGN. The charges model assumes that the FGN will accept the recommended option of conversion to equity of all long-term debt, as recorded in NEPA's books. However, if the FGN chooses to pass on to NEPA the large outstanding power sector debt owing to donors then the implications on cost of service, bulk supply charges and end customer tariffs will be substantial.

Return on Equity

The charges model provides flexibility for the user to input a target rate of return on equity (ROE), which is used in the model to set the "allowable profit" for each NBU. The ROE can be set individually for each NBU or uniformly for each sector or for all NBUs. This report adopts a uniform ROE for all NBUs of 7% based on revalued fixed assets.

3.2.2 Charges for Generation and Transmission Services

The costs of all the GenCos, IPPs and TransysCo are passed through as charges to the DisCos and to the unit handling sales to high voltage customers and exports. The following steps are used to determine the charges:

- Line item budget forecasts are prepared for all of the NBUs, the IPPs and corporate HQ at the start of each quarterly cycle;
- Costs are classified as variable or fixed;
- Costs are also classified as generation-related or transmission-related; and
- Costs are then aggregated into the charge components, which are allocated to the DisCos based on relative demand.

Table 3.1 shows the components of bulk supply charges to the DisCos. In summary, there are three main categories of charges: 1) Fixed Generation Charges, which cover GenCo fixed costs and IPP capacity charges; 2) Variable Generation Charges, which cover GenCo fuel costs and energy charges of IPPs; and 3) Fixed Transmission Services Charges which cover the costs of TransysCo facilities and services. For the time being, only fuel and IPP energy charges are classified as variable, however other possible variable costs such as manpower and plant maintenance costs directly associated with the level of activity can be identified later when NEPA's accounting system is enhanced to provide this level of detail.

Table 3.1: Components of Bulk Supply Charges to DisCos

Component of Charge	Basis for Allocation
Fixed Generation Charges	
▪ Demand Charge	MW Demand
▪ Transmission Losses Charge	MVA Demand
Variable Generation Charges	
▪ Fuel Charge	MWh Supplied
▪ Transmission Losses Charge	MWh Losses
Fixed Transmission Services Charge	MVA Demand

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The following summarizes the components of the bulk supply charges to the DisCos:

- Variable Generation Charges – There are two components to the variable generation charges:
  - Variable Energy Charge – Covers a DisCo's share of the actual variable costs of generation of GenCos and IPPs delivered to a DisCo at its points of interconnection to the transmission grid. The charge is in proportion to the DisCo's MWh demand to the system MWh demand.
  - Variable Transmission Losses Charge – Covers a DisCo's share of the variable costs of GenCos and IPPs to supply transmission losses for wheeling energy to the DisCo. The charge is in proportion to the DisCo's MWh demand to the system MWh demand.
- Fixed Generation Charges – There are two components to the fixed generation charges:
  - Fixed Generation Demand Charge – Covers a DisCo's share of the fixed cost of generating capacity supplied by GenCos and IPPs to meet the DisCos' aggregate demand. The charge is in proportion to the DisCo's forecast MW demand to the system forecast MW demand at the time of the system peak.
  - Fixed Transmission Losses Charge – Covers a DisCo's share of the fixed cost of generating capacity supplied by GenCos and IPPs to cover forecast transmission system losses. The charge is in proportion to the DisCo's forecast MVA demand to the system forecast MVA demand at the time of the system peak.
- Fixed Transmission Service Charge – Covers a DisCo's share of the cost of transmission facilities and services to transmit power from the GenCos to the DisCos. The charge is in proportion to the DisCo's forecast MVA demand to the system forecast MVA demand at the time of the system peak.

3.2.3 Charges for Off-Grid Supply

Off-grid supply to DisCos can come from 1) embedded generation, i.e. generating units connected to the distribution network and 2) energy flows between DisCos on the low voltage grid. Charges for embedded generation are calculated according to the relevant power purchase contract. Charges from one DisCo to another for energy flows and associated distribution losses for energy wheeled on the low voltage grid will be set equal to the average bulk supply charge for on-grid generation and transmission services.

3.2.4 Charges for Headquarters Costs

All of the NBUs are charged for services provided by the Sector and Corporate Headquarters. Sector head office costs are allocated to each NBU based on the NBUs own costs relative to total sector costs. Corporate HQ costs are allocated to each NBU based on NBUs own costs relative to total NEPA costs. For purposes of such allocations, fuel, depreciation and bulk supply charges are excluded from costs.

3.3 CASH PAYMENT REQUIREMENTS

The Market Operator will use the charges model to prepare a quarterly forecast of the cash collections by the DisCos and to calculate cash allocations to the NBUs and corporate HQ. For the foreseeable future while collected end customer billings are below the cost-of-service and inadequate to meet NEPA's total revenue requirements, there is a need to ration the cash resources among the NBUs.

The charges model has a facility to apply three alternative cash rationing methods. The user can choose any alternative by changing a simple switch in the data input worksheet.

3.3.1 Cash Available for Allocation

As a first step, the model calculates the total cash pool available for allocation among the NBUs. This calculation is common to all three cash allocation alternatives in the model. The cash pool is determined as follows:

- Total Cash Receipts:
  - Billing collections from end customers
  - Less: Meter maintenance charge collections from end customers
  - Less: VAT collected from end customers
  - Add: Connection and reconnection fees collected from end customers
  - Add: Government subsidy available for operations (e.g. for Abuja EPP fuel and capacity costs)
  - Add: All other receipts
  - = Total cash Receipts
- Less: Amounts set aside for:
  - Past obligations
  - Incentive payments in respect of previous year
  - Emergency requirements
  - Repayment of LT borrowing (does not apply to Alternative C)
  - Repayment of ST borrowing and overdrafts
- Add: ST borrowing and additional overdraft facility for operations
- Balance = cash pool available for allocation to NBUs

3.3.2 Alternative A for Cash Allocation

The cash pool is allocated in the following order of payment priorities:

- Salaries and allowances

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- HQ costs
- Generation fuel charges
- EPP, IPP and ROT charges
- Plant management and RCM fees
- The remaining available cash is allocated among the operating NBUs based on the remaining unmet cost-of-service of individual NBU relative to total NEPA.

3.3.3 Alternative B for Cash Allocation

The cash pool is allocated in the following order of priorities:

- All cash operating expenses
- Interest charges
- Corporate income taxes
- The remaining available cash is allocated among the operating NBUs based on the remaining unmet CoS of individual NBU relative to total NEPA. The remaining unmet CoS in this case is equal to depreciation of fixed assets.

3.3.4 Alternative C for Cash Allocation

The cash allocation is on "needs" basis for each NBU. The cash pool is allocated in the following order of priorities:

- All cash operating expenses
- Debt service payments, including repayment of LT loans
- Corporate income taxes
- The remaining available cash is allocated among the NBUs based on "prioritized" investment requirements. The prioritization of investments needs will be determined at each level of the organization and finally approved by NEPA executive management.

3.3.5 Chosen Alternative for Cash Allocation

Table 3.2 presents the pros and cons of the three cash allocation alternatives.

Table 3.2: Pros and Cons of Cash Allocation Alternatives

A. CoS Basis	B. Prioritized CoS Basis	C. "Needs" Basis
Pros	*Pros*	*Pros*
▪ Maximum flexibility given to NBUs to manage their cash ▪ Transparent process	▪ All cash operating expenditure is met in full ▪ NBUs have flexibility to decide on their own	▪ Cash is directed where needed ▪ Fixed assets valuation & depreciation is not

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Cons ▪ Basis of fixed assets valuation becomes critical ▪ Cash may end up in the wrong places ▪ Surplus cash may be misused	investments from depreciation element of cash allocation ▪ Transparent process *Cons* ▪ *As for A, although not to the same extent*	brought into the calculation *Cons* ▪ Investment prioritization may not be objective ▪ May not be transparent ▪ To a large extent, same process as today as determined by HQ

NEPA management has decided that, for the time being and in view of limited available cash resources, Alternative C will be used as the basis of cash allocation among the NBUs. This is to ensure that any available cash surplus after meeting operational requirements and debt service obligations is directed where it is most needed in terms of investment requirements. The chosen alternative is not the ideal solution but the best available practical option. In the long run, when collected revenues are sufficient to recover the full cost-of-service, Alternative A will apply.

3.3.6 Cash Flows and Banking Arrangements

Figure 3-4 illustrates the cash flows between NBUs via the Market Operator.

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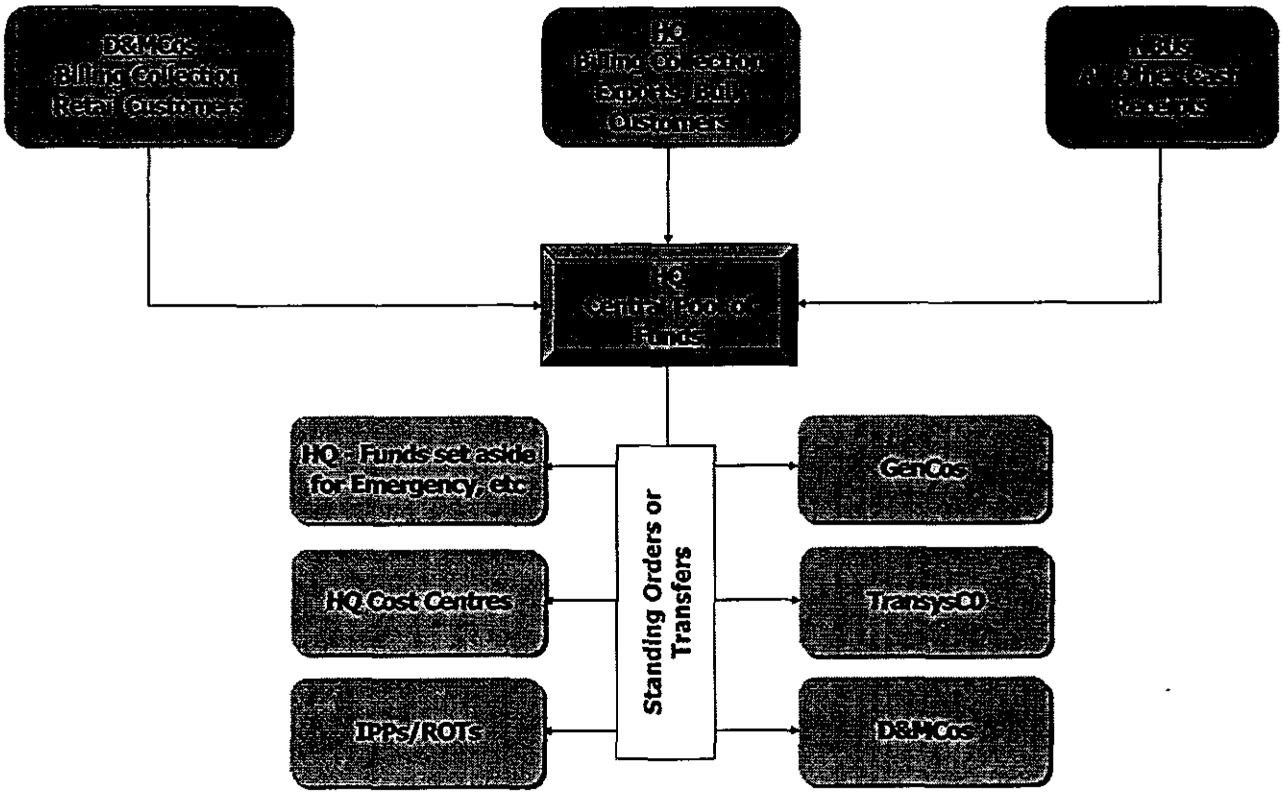

Figure 3-4: Cash Flows between NBUs

The following procedures and practices are recommended for cash flows and banking arrangements:

- Billing collections from end customers and all other cash receipts will be placed in separate "collection" bank accounts at each NBU controlled by the Market Operator.
- All cash receipts will be transferred at the end of each week to the Market Operator. In the case of large DisCos, the Market Operator may decide to transfer cash receipts more frequently, even on a daily basis if the sums involved are large. Currently, the DisCos transfer cash twice monthly after "deductions at source" for cash allocated to them for part of their own requirements. The current practice leads to financial losses to NEPA because cash lying idle in the bank accounts of the DisCos attracts no interest, whereas an overdraft from the HQ bank account attracts significant interest charges. In order to facilitate weekly or more frequent transfers, DisCos will not be able to retain funds due to them, i.e. deductions at source.
- Remittances to HQ will be deposited into a central pool of funds placed in a separate "remittance" bank account. The Market Operator will operate this account.
- The Market Operator will transfer funds by way of standing orders to the NBUs on the 15th and end day of each month.

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- NBUs will be expected to operate within their cash allocations. Any additional expenditure above approved budgets will require HQ sanction and will be funded from cash set aside for emergency requirements.

3.3.7 Meter Maintenance Charges and VAT

The DisCos will remit the meter maintenance charges and VAT collected from customers to the Market Operator together with collections for energy charges. The Market Operator will return the cash related to meter maintenance charges to the DisCos in the subsequent month so that the DisCos can use these funds to procure customer meters. The Market Operator will transfer the collected VAT to HQ for settlement with the Treasury.

3.4 END-OF-QUARTER ADJUSTMENTS FOR ACTUAL VERSUS FORECAST

At the end of each quarter and upon submission of actual returns from all NBUs, the Market Operator will re-work the charges model to reflect the actual operational and financial performance data and administer the following end-of-quarter adjustments:

- The bulk supply charges will be adjusted for variances between actuals and budgets.
- Variances in cash flows between actuals and budgets will be brought into the subsequent quarter's cash allocation. Any cash surplus will be added to cash receipts and any cash shortfall will be deducted as repayment of overdraft or borrowing.

3.5 FINANCIAL AUTONOMY & AUTHORITY LIMITS

The success of transition stage market will depend to a large degree on the level of financial autonomy given to the NBUs. The existing business practices of NEPA lead to operational inefficiencies. Authority levels of field managers are very limited and bureaucratic procedures requiring sanctions from top management at HQ invariably involve unnecessary delays and costs. The following actions are recommended for improving commercial efficiency:

- NBUs should be afforded greater financial autonomy by providing field managers with increased authority limits over approved budgeted expenditures. The chief executives of the NBUs should have total responsibility for their quarterly cash allocations.
- Greater financial autonomy must be accompanied with the strengthening of the internal audit function at the NBUs.

3.6 FINANCIAL INCENTIVES FOR GOOD PERFORMANCE

In order to encourage improvements in operational and financial performance, it is necessary to introduce an incentive mechanism to reward or penalize NBUs for their individual performance. The performance measurement must be simple and easy to monitor so that it is transparent and easily understood. The following performance incentives are recommended:

- Spending Cap Incentive – All NBUs will manage their expenditures to not exceed their cash allocations. NBUs will be permitted to retain any savings they may achieve through efficiency improvements or other stringent expenditure control measures. Such savings can be used for investments or maintenance of plant and equipment. Any expenditure above approved budgets will require HQ sanction and will be funded from cash set aside for emergency requirements. Budget performance will be measured in terms of net savings over a calendar year to offset any quarterly deficits against quarterly surpluses. This spending cap incentive mechanism will require an enhanced budgeting process.

- Collections Incentive – Individual DisCos will be rewarded for their operational performance in terms of cash collection in Naira per kWh of bulk energy supply. The inputs required to measure collections performance are straightforward and devoid of subjective assessments. The installation of grid meters in recent months will enable the accurate or more reliable measurement of bulk supply, and cash collections from end customers are obtained from an independent external source, i.e. bank statements. Realistic targets will be set each quarter and such targets will be used in the charges and cash allocation model. Actual performance will be measured against targets at the end of each quarter and DisCos will be rewarded for "net" favorable performance over the calendar year by way of additional cash allocation in the following year. Each operating DisCo that has exceeded its target will be provided a set percentage (to be determined by NEPA management) of the additional cash that it has generated as a result of its performance. Negative performers will not be penalized, as cash already allocated to them on "needs" basis cannot be reduced.

Incentives for GenCos and TransysCo are not recommended at this point in view of inadequate maintenance and lack of investments over the years that has led to the poor condition and unreliability of the generating assets and the transmission network. It would be difficult to assess management performance in terms of plant availability, energy output, fuel efficiency, transmission outages, etc as managers may have very limited effective control over such matters.

3.7 CHARGES MODEL RESULTS FOR FIRST QUARTER 2003

The following tables show a sample of forecast results from the charges model for the first quarter 2003. Table 3.3 shows GenCo statistics, Table 3.4 shows TransysCo statistics and Table 3.5 shows DisCo statistics.

Table 3.3: GenCo Statistics

Plant	Peak Load, MW	Energy Output, GWh	BSC Demand N/kW/mo	BSC Energy N/kWh	Cost of Service N/kWh	Cash Alloc % of CoS
Kainji	243	333	1,106	0.006	2.4	21%
Jebba	423	394	471	0.006	1.5	26%
Shiroro	447	902	421	0.002	0.6	30%
Afam	248	365	1,004	0.228	2.3	21%
Sapele	146	233	766	0.202	1.6	58%
Delta, Calabar, Oji	386	768	723	0.213	1.3	40%
Egbin, Ijora	964	1,702	844	0.148	1.6	17%
IPPs	305	545	1,356	1.474	3.8	100%
Total	**3,162**	**5,242**	**832**	**0.258**	**1.7**	**49%**

Table 3.4: TransysCo Statistics

Peak Demand (kVA)	3137 kVA
Fixed Charge	575 N/kVA per month
Average Fixed Charge	1.1 N/kWh supplied
Cash Allocation as % of "Own" Cost-of-service	20%

Table 3.5: DisCo Statistics

DisCo	Peak MW	E GWh	CoS Naira per kWh	BSC Naira per kWh	Own CoS N / kWh	Billed Naira per kWh	Collct Naira per kWh	Billed as % CoS	Collct as % CoS	Collct as % of Billed	Cash Allctn % CoS
Abuja	238	411	7.3	4.1	3.2	4.6	2.6	63%	35%	55%	44%
Benin	262	452	8.0	4.3	3.7	4.9	2.3	62%	29%	46%	38%
Enugu	276	476	10.0	5.3	4.7	4.9	2.8	49%	28%	57%	48%
Ibadan	358	618	8.2	4.6	3.6	6.5	3.9	80%	48%	61%	59%
Jos	130	224	10.0	4.6	5.4	5.7	3.5	57%	35%	61%	39%
Kaduna	180	311	7.5	4.1	3.4	5.6	3.1	75%	41%	55%	37%
Kano	157	272	11.0	6.3	4.7	6.4	4.6	58%	42%	72%	50%
Lag N	539	931	6.7	4.7	2.1	6.4	4.4	95%	65%	68%	45%
Lag S	425	734	7.3	4.7	2.6	7.0	4.8	96%	66%	68%	53%
PH	174	301	13.9	7.5	6.4	5.9	3.5	43%	25%	60%	36%
Yola	64	110	17.0	4.3	12.7	5.9	2.4	35%	14%	41%	22%
Total	**2,851**	**4,927**	**8.2**	**4.7**	**3.5**	**5.9**	**3.7**	**73%**	**45%**	**61%**	**45%**

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4.1 INTRODUCTION

A key challenge for the corporate restructuring exercise is how to transition the organization from central command-and-control to local autonomy. To meet this challenge, NEPA has initiated the process of unbundling generation, transmission and distribution to establish commercially oriented New Business Units (NBUs). The NBUs will be empowered as independent profit centers at the same time that the corporate headquarters and the Sector organizations in Abuja will be reconstituted as the Initial Holding Company (IHC) Headquarters. The basic plan for setting up the NBUs is provided in *Corporate Restructuring of the Nigerian Electric Power Sector: Description of Recommended Industry Structure* (PwC, April 2002).

The focus of the following Reorganization Plan is on the DisCos and the Market Operator. Other NEPA divisions are considered elsewhere: TransysCo is covered under the *Transmission Development Project*, and the reorganization plans for IHC HQ and the GenCos are left for the next stage of work.

4.1.1 Overview of Reorganization

Corporate restructuring will impact each hierarchical level of the NEPA organization as follows:

- Headquarters – A strong Headquarters organization historically has exerted a high degree of control over the regional operating units. In the new market structure, functions that are handled by HQ will be devolved increasingly to the NBUs. In the first step during the transition stage market, some common services will remain at HQ. In the second step, the IHC will dissolve and all HQ services will be devolved to the NBUs and the trading licensee for bulk purchases from IPPs.
- Sectors – The Distribution, Marketing, Generation, Transmission and Operations Sectors are functional divisions that provide executive oversight for the regional operating divisions. NEPA plans to reduce the spans of control of the Distribution, Marketing and Generation Sectors and, at the same time, increase the autonomy of the local DisCos and GenCos. The Transmission and System Operations Sectors will be subsumed under TransysCo.
- Distribution & Marketing Zones – Under the present company structure, the Zones have limited responsibility for coordination of local Operating Units (Districts and Undertakings). In the future, the Zones will become DisCos with increased authority for the financial and operational performance of the local Operating Units. This will require a redefinition of responsibilities between the Sector level and the DisCos, and between the DisCos and the Operating Units.
- Transmission and Generation Regions – Under the present company structure, the Regions have limited responsibilities for oversight and coordination of Operating Units at the facility level. In the future, the Transmission Regions will be subsumed under TransysCo. The Generation Regions will be replaced by GenCos.

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- D&M Districts and Undertakings, Transmission Stations and Generation Stations – These divisions are classified as Operating Units responsible for local system operating performance. In the future, the Operating Units will be subsumed under the NBUs.

4.1.2 Restructuring NEPA into New Business Units

The Reorganization Plan aims to improve operations in the near term by strengthening management capability at the local level and de-emphasizing command-and-control from headquarters in Abuja. Despite the difficult issues that must be addressed to restructure the company quickly in the wake of years of under-funding and mismanagement of the power sector, there is significant potential to improve performance in the near term by enhancing local capabilities and responsibilities. International experience shows that utility companies, in particular distribution companies, are best managed at the regional level close to the customers, rather than in one centralized location, especially for a country as large as Nigeria.

The recommendations in this report anticipate that the following NBUs will be formed during the transition market stage:

- The Transmission and Operations Sectors will be subsumed under the TransysCo and managed centrally, whereas Regions and Stations will remain as operating units. NEPA is moving quickly to set-up and incorporate TransysCo. The plan for TransysCo is shown in the *Transmission Development Project Strategy Plan* (Red Electrica, March 2003).
- DisCos – The existing Zones will be elevated to DisCo status and take over executive management responsibility for the regional distribution service territories. The Districts and Undertakings will remain as operating units reporting to DisCo Headquarters. Local management of the distribution and marketing functions is a major change from the status quo, since the Distribution and Marketing Sectors at NEPA headquarters have traditionally exerted executive management responsibility for all aspects of the regional distribution and marketing line organizations.
- GenCos – The generation sector will be split into six GenCos consisting of one company for each of the four thermal stations and two hydro companies (Kainji and Jebba combined plus Shiroro as stand alone). At the present stage of the reform program, it is not clear whether resources should be used to enhance the GenCos to function as self-contained profit-centers, or whether the GenCos should remain operating units for the time being while the Sector and regional organizations continue in their present roles providing central services like executive management, engineering, project management, contract management, procurement, etc. The need for organizational enhancements at the GenCos will depend on how the companies will be spun off from NEPA. For example, in the case of ROT contracts, O&M agreements or outright asset sales, the new third-party operators will most likely create their own organization structures regardless of what structures NEPA puts in place in the interim transition period. These issues can be explored further in the next stage of work.

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As the independent NBUs are formed, Corporate Headquarters will reorganize accordingly. Central services such as HR, medical, treasury, procurement, security and industrial relations will increasingly devolve from HQ to the NBUs. In the first step, while the IHC is in place, some common services will remain at HQ. In the second step, all residual common services will be devolved to the NBUs and other licensee(s), and the IHC will be dissolved.

4.1.3 Objectives of the Reorganization Plan

The Reorganization Plan is intended to provide an action-oriented guide to required changes in functions, structure and staffing to establish operational DisCos as soon as possible in the initial stage electricity market. The main objective of the plan is to create commercial profit-oriented DisCos with enhanced organizational structures and staffing for increased responsibility and independence.

The plan contains recommendations in the following areas:

- new and expanded functions of the DisCo headquarters organization;
- revised management-level organizational charts for DisCo HQ;
- functions of the new Market Operator and the Market Operation Committee;
- job descriptions for new posts and for existing posts with expanded duties;
- process to recruit and select new executive positions; and
- ideas for training programs.

4.2 NEW FUNCTIONS

The DisCos and the market organizations will be challenged to handle new and expanded functions in the initial stage electricity market. This section provides an overview of the required organizational changes.

4.2.1 New DisCo Functions

A primary objective of NEPA's restructuring program is to give the DisCos greater autonomy over their day-to-day operations and more control over their own performance. Services and functions that are now handled at HQ and the Sectors will be devolved down to the NBU level.

The following functions need to be expanded at the DisCos:

- Distribution Line Organization – At present, an AGM Distribution reporting to the Zonal GM serves the District distribution organizations. The responsibilities of this position can be expanded significantly as the position is upgraded to head the distribution line organization at the DisCo. The Distribution Managers in the Districts can report direct to the AGM Distribution instead of the GM of the DisCo, and this will free the GM for important responsibilities as head of the company. In addition, grid metering and rural electrification can fall under the AGM Distribution. Central services that are now provided by the Distribution Sector organization in NEPA HQ will be devolved under the AGM Distribution at the DisCo and the DisCos will take on primary responsibility for all

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aspects of distribution operations, maintenance, construction, engineering and rural electrification activities within their service territories.

- Marketing Line Organization – At present, the AGM Marketing at the Zone reports to the ED Marketing in NEPA HQ. In the new market structure, the DisCo will take over executive management of the marketing function.
- Finance and Accounts – As the DisCos assume overall authority over their commercial performance, finance and accounts responsibilities will expand at the DisCos. Eventually the head of F&A at the DisCo will be like a Chief Financial Officer of an independent company.
- Personnel and Administration – NEPA Conditions of Service limit the DisCo's scope of responsibility to employees in the JS5-SS3 classification. For any employee above this classification matters such as recruitment, promotion, etc. must be referred back to, and handled by, HQ. As part of the overall objective to establish independent NBUs, the scope of responsibilities in personnel and administration must be expanded beyond this limitation.
- Performance Management – This function will need to expand beyond monitoring the performance of the business unit to include restructuring implementation and corporate planning for an independent company.
- Procurement – The procurement function will need to expand significantly as authority limits are increased and the DisCos assume overall responsibility for procurement at the same time that the roles of the Distribution and Marketing Sectors diminish.
- Information Technology (IT) – This function will have to expand to meet the demands of a stand-alone company for more complex IT systems and automation.

Some important support services for the DisCos will remain at the Distribution and Marketing Sectors in HQ in the short term. However, ultimately all such functions will be decentralized and placed within the independent DisCos.

4.2.2 New Market Functions

Two new organizations are proposed for the transition stage market: a Market Operator and a Market Operations Committee. The following sections list the responsibilities of these new functions, their locations within NEPA, and their staffing requirements.

Market Operator – The Market Operator will be responsible for administering the terms and conditions of the Market Agreement. NEPA has decided that the Market Operator will reside within the new TransysCo. The duties of the Market Operator will include the following:

- forecast bulk supply charges and cash allocations for wholesale market transactions;
- collect and report the grid meter data used in billing;
- prepare accounting statements for market transactions;
- manage settlements between market participants; and

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- manage the process for quarterly reconciliation of actual versus forecast.

The Market Operator will liaise closely with HQ F&A, since its primary responsibilities are related to the role of HQ F&A for company-wide budgeting and treasury. The staffing and position levels for the Market Operator unit will depend on what functions, if any, that the unit will take over from HQ F&A. These organizational issues can be addressed in the next phase of work. Appendix C provides a sample job description for the Market Operator.

Market Operation Committee – The Market Operations Committee will oversee the wholesale electricity market. Its membership will comprise representatives of the various market players. The Committee will develop the terms of reference for the Market Operator, ensure efficient administration of the Market Agreement, resolve disputes among parties to the Agreement, approve changes to the Charges Model and serve as a forum for discussion. The following key issues for setting up the Market Operation Committee must be addressed: membership; procedures; relationship to NERC, when formed; staffing of the Committee Secretariat; facilities; and budget. These issues can be resolved in the next stage of work.

4.3 DISCO REORGANIZATION

Functional independence for the DisCos will involve creating several new positions, changing some existing positions to reflect broader job descriptions and changing some reporting relationships.

4.3.1 Overview of DisCo Reorganization

Figure 4-1 presents the proposed generic management level organization chart for DisCo headquarters. The DisCo will be an independent profit center under the IHC. DisCo HQ will be responsible for executive management and provision of central services to the Districts, such as corporate planning, technical planning and construction, protection, metering programs, personnel and administration, procurement and legal services. Districts and Undertakings will remain semi-autonomous operating units responsible for day-to-day management of local operations.

The following management positions at DisCo HQ will have expanded responsibilities:

- The GM of the DisCo will have executive management authority, like the CEO of an independent company.
- The AGMs for Distribution and Marketing at DisCo HQ will have expanded executive management responsibilities for their line organizations.
- The AGM Finance and Accounts at DisCo HQ will have expanded responsibilities similar to the Chief Financial Officer of a stand-alone company.
- A new AGM Services will manage central services for personnel and administration, procurement, property, IT and communications.
- New management positions for legal services and corporate planning will help to establish the DisCos as autonomous profit centers.

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4.3.2 Changes to Distribution and Marketing Line Organizations

The Reorganization Plan contains significant changes in the distribution and marketing line organizations from the Sectors to the DisCos to the Districts. The Distribution Managers at the Districts, who currently report direct to the GM at the Zone, will instead report to the AGM Distribution at the DisCo, who will have expanded executive control over the DisCo's entire distribution line organization. Likewise, the Commercial Managers in the Districts will report to the AGM Marketing at the DisCo, who will have expanded executive control over the company's entire marketing line organization. The AGM Marketing at the DisCo, who currently reports to the ED Marketing at the Sector, will instead report to the DisCo GM.

Separating the administration of the distribution and marketing line organizations at the Districts and Undertakings is considered the preferred approach, however there is some consideration for an optional structure in which District Managers would be in charge of both distribution and marketing in their Districts, and the District Manager position would report direct to the GM of the DisCo and not to an AGM in DisCo HQ. Under this option, AGM Marketing and AGM Distribution at the DisCo could be combined into an AGM Technical Services serving semi-autonomous Districts.

A primary advantage of the optional structure is that it minimizes any potential conflicts between the distribution and marketing line organizations at the District level, since they both report to a single management authority at the District. However this objective can be achieved under the preferred line organization structure by instituting a workplace agreement at the Districts covering 1) the sharing of support services at the Districts between the distribution and marketing line organizations, and 2) a process for local issue resolution between the Distribution Manager and the Commercial Manager.

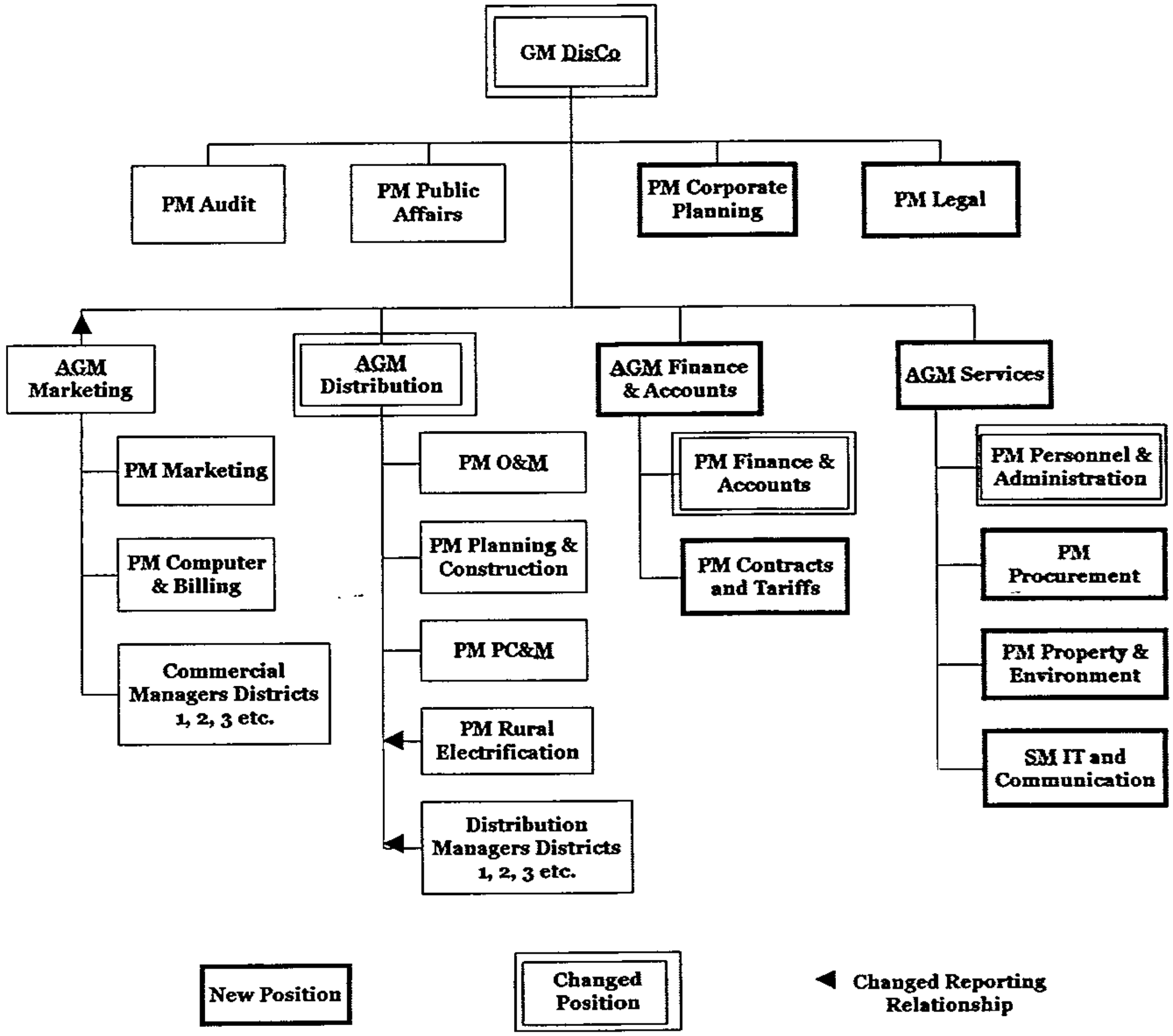

Figure 4-1: Proposed DisCo HQ Management Structure

4.4 MANAGEMENT POSITIONS AT DISCO HEADQUARTERS

The following key management positions will be significantly enhanced or newly created at DisCo Headquarters:

- GM DisCo
- AGM Distribution
- AGM Finance & Accounts (new)
- AGM Services (new)

- PM Corporate Planning (new)
- PM Legal (new)
- PM Finance & Accounts
- PM Contracts and Tariffs (new)
- PM Personnel & Administration
- PM Procurement (new)
- PM Property & Environment (new)
- SM IT & Communication (new)

The following sections summarize the duties and reporting relationships for the new positions. Appendix C provides detailed job descriptions for all of the enhanced and newly created executive positions.

4.4.1 AGM Finance and Accounts

When the Zone is elevated to DisCo status, the responsibilities of DisCo Finance and Accounts Department will expand as financial authority is devolved from Abuja. The new and expanded F&A functions at the DisCos will include:

- accounting for NBU revenues, costs, assets and liabilities;
- consolidating accounting returns of districts;
- financial management reporting;
- reviewing and consolidating revenue and capital budgets of districts and submission of NBU budgets;
- justifying requests for funds for capital investment projects;
- managing funds and cash flow reporting;
- reporting treasury activities to HQ;
- financial forecasts;
- tariff analysis and cost of service calculations; and
- inputs to the DisCo business plan.

In the current Zonal Structure, a PM Finance and Administration reporting to the GM is responsible for financial, accounting and administrative matters. The Reorganization Plan proposes a new AGM Finance and Accounts to meet the expanded responsibilities of the job. The post will address only finance- and accounting-related functions, and administration services will be shifted under the new AGM Services.

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4.4.2 AGM Services

The AGM Services will provide the following central services: personnel and administration, property and environment, procurement, and IT and communications. Creating a new executive position for AGM Services at DisCo HQ reflects the fact that the DisCos will have increasing responsibility for managing their own corporate services independent of IHC in Abuja.

The Services Department should be separate from the Finance and Accounts Department with separate managers for the following reasons:

- This avoids a potential conflict between the treasury function of Finance and Accounts and the administration of services involving disbursements i.e. human resources, procurement, IT and property management.
- Similar functions should be consolidated together; finance and accounts in one unit, and all corporate and administrative services in another.
- The heads of the two departments will require different sets of skills. Combining the two departments into one would make the span of responsibility overly broad and unwieldy.

4.4.3 PM Corporate Planning

The responsibilities of the PM Corporate Planning will include: preparing a business plan; advising the GM on transition issues related to restructuring and privatization; preparing and managing regulatory filings; preparing sales, revenue and demand forecasts; and monitoring and reporting on the performance of the line organizations. The DisCos currently have a position for performance management that can be upgraded to cover the full range of corporate planning activities. The post should report direct to the GM.

4.4.4 PM Legal

As stand-alone companies, the DisCos may need to have a separate function addressing legal affairs. Initially, this position will resolve local legal disputes, advise on union issues and assist the GM on other day-to-day legal matters. Eventually this position can take on additional responsibilities for regulatory filings. This function may not be needed in the initial stage at all of the NBUs; each DisCo should assess their own need for this function.

4.4.5 PM Contracts and Tariffs

The DisCo will need new functions for contract management and tariffs. The contract management function involves monitoring compliance with contract terms and conditions, managing invoices, dispute resolution, developing contract amendments, coordinating the preparation of new contracts, interfacing with treasury, legal and other departments, etc. The tariffs function involves determining the company's revenue requirements and preparing tariff design recommendations.

The responsibilities of the new position will include the following:

- actively participate in the development of the Market Agreement;

- ensure the company's compliance with the Market Agreement;
- manage and assess its impact on the DisCo;
- manage the DisCo's RCM Contracts, which are currently managed from NEPA HQ;
- ensure the timely and complete gathering and dissemination of data from other departments required to meet the terms of the Market Agreement;
- assess the adequacy of end user and bulk power tariffs and conduct analyses to support recommendations to amend tariff levels; and
- manage the preparation of the tariff filings to NERC.

The PM Contracts and Tariffs should report to AGM F&A. The Finance and Accounts Department will have the most immediate access to financial data required to comply with the terms of the Market Agreement and to evaluate tariff levels.

4.4.6 PM Procurement

In its new role, the DisCo will have greater financial autonomy and broader authority limits so that the DisCo does not have to seek HQ approval for routine and planned expenditures. As part of expanding authority limits, the procurement function should be upgraded at the DisCo. As stand-alone business units, and eventually fully independent companies, DisCos must have enhanced authority to procure supplies, equipment, spare parts and machinery in order to function efficiently.

The Zone currently has an SM Procurement reporting to the AGM Distribution. The SM Procurement position should be upgraded to a PM Procurement reporting to the AGM Services.

4.4.7 PM Property & Environment

The DisCo will be responsible for all property development and management within its service territory, and for ensuring compliance with environmental regulations on property and land use. These functions will need to be enhanced as the DisCos gain autonomy from HQ in Abuja. Property management is a corporate function, therefore this post should report direct to the AGM Services.

4.4.8 SM IT and Communication

The unbundled DisCos will need to develop more advanced IT capabilities for data gathering, analysis and dissemination, reporting requirements, contract monitoring and compliance, enhanced cash management, budgeting and other finance and accounting activities. Increased IT automation will allow the DisCos to move more rapidly in achieving autonomy.

The Zones currently have an SM Communications reporting directly to the AGM Distribution. The expanded position SM IT and Communication should report to the AGM Services since this post serves the entire organization.

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4.5 EXECUTIVE STAFFING PROCESS

This Reorganization Plan provides a process to recruit, select and appoint new management positions for the transition stage market. In general, NEPA should state and adhere to the following basic principles:

- Establish clear criteria and steps from the outset.
- Identify roles and responsibilities.
- Set a firm timetable and milestones.
- Ensure transparency.
- Highlight the principle of merit, i.e. the best candidate for each position.

NEPA has well-established guidelines for recruitment, promotion, appointments, post creation, transfers and a variety of other related activities. These rules can be used for staffing the new and expanded management positions at the NBUs. Nevertheless, this section presents some specific recommendations and highlights key existing NEPA procedures and rules that need to be followed.

4.5.1 Creating New Management Positions

Creating the new management positions should be straightforward. NEPA rules and conventional practice allow the MD to approve the creation of new positions up to and including the PM level. New AGM positions may require the approval of the Ministry of Power and Steel. However, if proposed and supported by senior NEPA management, particularly the MD, this should not be difficult to accomplish.

4.5.2 Recruitment and Promotion

NEPA's *Recruitment and Promotion Manual* (April 1995) contains application forms, rules for forming selection committees, ranking procedures, processes for short-listing and interviews, etc. The following are some additional considerations:

- Who can apply for the new positions? – Candidates can be either promoted or recruited from within NEPA for these positions (different processes govern each, according to the *Recruitment and Promotion Manual*). The difficulty of opening the posts to individuals outside NEPA is that, by convention, posts should first be opened to current NEPA employees, and the National Union of Electricity Employees has expressed its opposition to the practice of hiring non-NEPA employees on contract for posts. Positions at the level GM and above should be advertised internally and externally. Positions below GM should be advertised externally only in the event that the internal recruitment exercise fails to produce a suitable candidate.
- How are positions advertised? – Current methods should be utilized within NEPA to as broad an audience within the Authority as possible at all locations.

- How do candidates apply for positions? – The application process should be in accordance with 1) the requirements of the *Recruitment and Promotion Manual*, using applications and other forms, and 2) NEPA Conditions of Service (COS)

4.5.3 Selection and Appointment

The following are the most important questions regarding the process for selection and appointment:

- Who selects the candidates? – The *Recruitment and Promotion Manual* stipulates a process for short-listing candidates, as well as the formation and make-up of selection committees.
- What is the composition of the interview/selection committees? – According to the *Manual*, for posts graded SM2 and SM3 (SM and PM, respectively), an interview panel comprises five people; (a) GM (P&A); (b) GM in the sector where post is; (c) AGM in the trade of the job; (d) AGM Personnel; and (d) Assistant Manager/Officer I (P&A). Also, NEPA should consider hiring a respected outside consultant to sit on the interview/selection panel. This could be a person familiar with a restructured utility industry, and specifically with the types of professionals required in a commercial distribution company. The MD should be involved in the final approval of any selected candidate for positions of AGM and above.
- What are the criteria for selection? – The *Recruitment and Promotion Manual* provides "Promotion Interview Rating Forms" as a quantitative tool to grade candidates. Candidates can be evaluated based on their match for the job descriptions provided in this report.

4.5.4 NEPA Conditions of Service

The following sections of NEPA's Conditions of Service will have an impact on the staffing process for new posts, and will need to be taken into consideration:

- §31.1.1 – For all positions in the classification SS2 and above (which includes PMs and SMs), it is necessary to ensure national spread.
- §31.3 – All appointments must be made in accordance with the Delegation of Authority Register, Headquarters Circular No. 21/2001, issued by the MD on September 17, 2001 updated the Register to state that interviews, recruitment, promotion, posting and deployment of staff in the PM and SM classifications are under the authority of Sector Headquarters. In addition, Circular No. 6/2002 issued by the GM HRM on June 7, 2002 specifically states that, although field GMs are authorized to fill some vacancies, "positions of SS2 and above shall be the responsibility of Corporate Headquarters to fill."

NEPA will need to address the impact on HQ jobs as functions are decentralized to the NBUs. Specifically, as more and more responsibilities are assumed by the NBUs, there may be a reduction in staffing levels at IHC HQ. As such, NEPA will need to address the following relevant Conditions of Service:

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- §132.8.1 – Outlines the general conditions under which pensions and gratuities are paid, including "on compulsory retirement for the purpose of facilitating improvements/reorganization in the Authority so that greater efficiency or economy may be affected."
- §132.15 – Abolition of Office: "If due to the reorganization within the Authority it is considered necessary to abolish or scrap an office and the incumbent cannot be offered a suitable alternative post," then an additional amount is paid to the employees on top of the normal pension and gratuity.
- §132.28 – If redundancy occurs when an employee's job is restructured or eliminated due to organizational changes or as a result of contraction of available work, then the employee is declared redundant.
- §132.29 – Redundancy benefit: an employee who has served less than 5 years shall be entitled to 3 weeks salary for each completed year of service.

The impact on HQ jobs will be mitigated by the increase in employment opportunities at the NBUs. There are several new posts and greatly expanded functions in some existing activities, such as finance and accounts and personnel and administration, which will need to be filled. New positions/functions at the NBUs can allow excess or underutilized staff at IHC HQ and the Sector levels the opportunity to continue and advance their careers in the electricity sector.

4.6 TRAINING

Training should be an integral part of the unbundling process, and specifically a component in preparing the NBUs for autonomy in a competitive market. As functions are added and/or expanded, staff will need to be trained in a variety of areas. For example, the following training is recommended:

- Regulation of competitive markets and market pricing
- Contractual and commercial relationships in an unbundled and privatized electricity industry.
- Tariff analysis and regulation.
- Financial and economic concepts – An understanding of tariffs and pricing, financial and regulatory economic concepts is required. Staff will need to have skills in financial accounting, economic and financial modeling, asset valuation, tariffs and pricing and utility economics.
- Planning – The DisCos will require training on new functions for corporate planning, load forecasting and resource planning.

NEPA should consider using an outside consultant to develop training programs for key personnel. The programs would identify specific courses, workshops, internships, study tours and sources of funding.

In addition to training for staff in new and expanded posts, NEPA should provide re-training for staff in IHC HQ whose posts will be restructured, abolished, or devolved to the NBUs. In this way, the social impact of the decentralization and unbundling process will be somewhat mitigated.

The following provides an example of an external training program that can help prepare NEPA for the restructured electricity market.

University of Cape Town Executive and Management Education

The University of Cape Town offers courses in a variety of subjects relevant to NEPA and the NBUs. The one-year *Executive and Management Education* program at the Graduate School of Business is recommended for staff able to take a leave of absence or it is possible to attend selected modules on a short-term basis. The following are summaries for two of the relevant modules.

- *Managing Reform and Regulation in Electricity, Gas, Telecommunications and Water Industry in Africa* – This intensive 5-day course is aimed at equipping managers and leaders in government, regulatory authorities and utilities to strategically manage far-reaching restructuring and change in the electricity, gas, telecommunications and water industry in Africa. The course provides a detailed understanding of regulatory frameworks and instruments to achieve desired economic, social and environmental goals within the context of restructuring.
- *Frontiers in Managing Reform and Regulation in the Electricity Industry in Africa* – This intensive 5-day course can be viewed as a follow-on to the first course mentioned above and is a more advanced course.

There are also courses offered in Financial Accounting and Corporate Finance. More information on the courses offered can be found at http://www.gsb.uct.ac.za/iirr.

Section 5 Financial Restructuring Plan

5.1 OVERVIEW OF FINANCIAL RESTRUCTURING

The main objective of financial restructuring is to establish the New Business Units on a sound financial base that will ensure their future financial viability. The financial viability of the NBUs will be governed in part by the levels of debt vested to them and the adequacy of electricity tariffs in relation to costs.

Financial restructuring requires the following steps:

- Clean-up NEPA's balance sheet
  - Power sector debt, i.e. long-term loans
  - Cross-debts with the Government
  - Unfunded liabilities and obligations
- Allocate the remaining assets and liabilities amongst the NBUs and Corporate Headquarters
- Present opening balance sheets for the NBUs

This section puts forward recommendations on financial restructuring of NEPA's balance sheet and vesting of its assets and liabilities to the NBUs.

5.2 POWER SECTOR DEBT

This section:

- Reviews the existing power sector debt (long-term loans);
- Considers the policy issues involved;
- Examines the debt restructuring options available to NEPA and the Government;
- Considers the financial and tariff implications for the future under each of the alternative options considered; and
- Recommends the preferred debt restructuring options for implementation.

5.2.1 Existing Long-Term Loans

There are significant differences between the Government and NEPA with respect to the outstanding long-term loans of the power sector. The position as of December 31, 2001 is summarized below:

- Loan Balances as per Government – Table 5.1 summarizes the power sector debt obligations due by FGN to external lenders as of December 31, 2001 as recorded in the books of the Debt Management Office (DMO) of the Ministry of Finance. FGN obligations to external lenders amount to **US$2.7 billion**, of which 89% is overdue.

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- Loan Balances as per NEPA – Table 5-2 summarizes the existing long-term loans on NEPA's books as of December 31, 2001 and as forecast to December 31, 2003. Debt due to FGN as per NEPA records amounts to **US$387 million.**
- In summary, there is a huge difference between DMO debt records and NEPA debt records. Overall Difference: **US$2.3 billion**

Table 5.1: External Power Sector Debt as per FGN[1,2] (in US$ Millions)

Existing Debt	Loan Date	Obligations		Total Debt	Utilized for
		Overdue	Future		
Japan (Marubeni)	Nov 1981	1,733.6	121.0	1,854.6	Egbin plant
France - BFCE	July 1982	352.2	58.7	410.9	Egbin plant
France - Banque Paribas	Oct 1979	288.7	27.8	316.5	Jebba plant
IBRD 3116-UNI	June 1990	0.0	63.7	63.7	Gen/Dist rehab
Japan	July 1974	12.5	0.0	12.5	Kainji dam
Italy	July 1964	3.5	0.0	3.5	Niger dam
Germany (Various)	1970-90	16.3	0.0	16.3	Gen/Dist rehab
Various Other	-	9.5	33.8	43.3	-
Total Loans	-	2,416.4	304.9	2,721.3	-
% of Total	-	89%	11%	100%	-

Table 5.2: Long-Term Loans as per NEPA Books[3] (in US$ Millions)

Existing Debt (excluding new loans since 2001)	At Dec 31, 2001			At Dec 31, 2003 (forecast)		
	Loans	Overdue Debt Srv	Total Debt	Loans	Overdue Debt Srv	Total
World Bank Loans	37.8	131.0	168.7	34.0	115.4	149.4
German Loans	12.4	3.8	16.3	12.5	5.1	17.5
Other Loans	0.0	4.5	4.5	0.0	3.6	3.6
FGN Serviced Loans	0.0	197.1	197.1	0.0	161.4	161.4

1 Source: Overdue obligations extracted from a report prepared by Messrs. Momoh Y Obaro &Co for BPE. Details of future obligations were obtained by Nexant from DMO.

2 The tables assume that bank loans (UBA/UBN) relating to the rehabilitation of the Delta and Afam power plants will be settled in full by December 31, 2003 out of the proceeds of ROT agreements for Afam and Sapele.

3 Does not include details of new loans added since January 1, 2002, such as the World Bank loan for transmission development project.

FGN Naira Loans	49.7	51.0	100.7	33.6	62.5	96.1
Local Bank Loans (UBA/UBN)	156.8	18.0	174.8	0.0	0.0	0.0
Total Long-term Loans	256.7	405.4	662.1	80.1	348.0	428.0
% of Total	39%	61%	100%	19%	81%	100%

Table 5-3 summarizes the differences between FGN and NEPA loan records as of December 31, 2001:

Table 5-3: Differences between FGN and NEPA Loan Records

Item	US$ Millions
Total Debt as per NEPA records	662
Less Loans not in DMO records	
▪ FGN Naira Loans	- 101
▪ Local Bank Loans	- 175
NEPA Records for FGN Power Sector Debt Obligations	387
DMO Records for FGN Power Sector Debt Obligations	2,721
Difference between NEPA and DMO records	2,335

The large differences between the NEPA and FGN DMO loan records are due to the following underlying factors:

NEPA Records

- Unpaid foreign debt service over the years has been recorded in Naira at historical exchange rates. Thus the underlying liabilities, which are in foreign currencies, are understated in terms of the Naira.
- No provision is made for interest or penalty interest on overdue and unpaid debt service.
- The terms of on-lending from FGN to NEPA are different to those between FGN and external lenders.

FGN (DMO) Records

- FGN has accumulated unpaid debt service obligations over the past 20-30 years. Significant liabilities for interest and penalty interest have therefore piled on over the years.
- Since the underlying obligations are due in foreign currencies, the liabilities in terms of the Naira have mushroomed.
- To illustrate the size of these problems, consider the following:

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- Liabilities relating to the construction in the early 1980's of the Egbin power plant amount to US$2.2 billion or N288 billion at today's exchange rates. The equivalent Naira value at the historical exchange rates of the mid 1980's amounted to N3.5 billion.
- The total drawings from the Japanese facility were about US$600 million at the time of plant commissioning, compared to today's outstanding debt to Japan of US$1.8 billion.

5.2.2 Debt Restructuring Policy Issues

FGN must decide how much of the power sector debt will be carried on NEPA's books. This will determine the leverage or debt/equity ratios of NEPA and its successor companies. The key issues are:

- Who should meet the overdue sector debt burden: taxpayers and/or electricity customers? In what proportion should the burden be shared?
- The majority of FGN debt is overdue and attributable to past usage of electricity assets. NEPA has not met its debt service obligations for many years principally due to inadequate electricity tariffs. Is it fair to expect future electricity customers to pay for past costs?
- To what extent is the FGN prepared to approve tariff increases on account of debt service?

Looking forward to the power sector's commercialization and subsequent privatization, most new investments in distribution and generation will be financed with private capital. It is important to restructure NEPA's long-term debt such that tariffs are both affordable and at the same time permit incoming private investors to recover the cost of new investments.

The restructuring of NEPA provides a one-time opportunity to write off long-term debt to minimize the burden on future investors. The alternative is to force the reformed electricity industry to carry the heavy cost of past lending malpractice, i.e. poor enforcement by FGN of its loan agreements with NEPA and poor financial oversight and diligence on behalf of the FGN and the donors that have lent to NEPA and continued to lend to NEPA despite the fact that it was not servicing its existing debt-stock.

5.2.3 Options for Restructuring Existing Debt

The following options for restructuring the power sector debt should be considered:

- Option 1 – Convert to equity all outstanding debt ("Best" Case).
- Option 2 – Convert to equity all overdue debt service; outstanding loans to be serviced on existing terms.
- Option 3 – No debt to equity conversion. Overdue debt service to be repaid over 5 years, and outstanding loans to be serviced on existing terms.

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- Option 4 – No debt to equity conversion. All outstanding debt is consolidated into a single US$ loan with level annual payments over 15 years at 7% interest.
- Options 5 to 8 – Create a single US$ loan with level annual payments over 15 years at 7% interest. The value of the loan will be determined according to the following alternative debt/equity ratios:
- Option 5 – 20% debt/equity ratio at 12/31/03
- Option 6 – 30% debt/equity ratio at 12/31/03
- Option 7 – 35% debt/equity ratio at 12/31/03
- Option 8 – 40% debt/equity ratio at 12/31/03 ("Worst" Case).

Table 5-4 summarizes the financial and tariff impacts under the debt restructuring options.

Table 5-4: Debt Restructuring Options and Impacts on Tariffs [4]

Option		Existing and Future New Debt				Required Tariff Increases for Existing Debt Only			
		D/Equity Ratio		Debt in US$ Million		Over 5 Years		Over 10 Years	
		12/03	12/06	12/03	12/06	Bill	Coll	Bill	Coll
1	Full conversion	2%	17%	76	808	0%	0%	0%	0%
2	Convert ODS, service loans on	3%	18%	156	870	2%	2%	1%	1%

[4] This analysis is based on the following assumptions:

- Power sector equity is calculated on the basis of revalued fixed assets.
- *Debt balances as at end 2003 and 2006 include forecast drawings on new loans contracted since January* 2002 (World Bank loan for the transmission development project) and the anticipated new loans for the inter-connection with Benin (ADB loan facility of US$18 million) and the two new power plants (2x670MW) at Okitipupa and Papalanto (Chinese loan facilities of US$416 million).
- The tariff implications are calculated in terms of debt service requirements for the existing debt only. The calculations for future revenue requirements do not take account of 1) debt service requirements with respect to new loans contracted since January 1, 2002 and 2) other additional revenue requirements to meet increasing costs (e.g. inflationary increases, increases in maintenance costs in "real" terms, higher energy costs of new IPPs, etc).
- In terms of financial sustainability, it would be necessary to implement the indicated tariff increases on "collected" basis. In other words, the collected tariff would go towards financing the debt service.
- The tariff increases represent averages over 5 or 10 years. This means that the increase required in Year 1 (i.e. 2004) will be greatest and declining thereafter in terms of forecast electricity sales (increasing sales and forecast improvements in collection rates over the years will dilute the average revenue required to meet the declining or constant debt service obligations). It therefore follows that the tariff increase required in Year 1 will not be less than the averages indicated above. For example, under Option 3, a minimum tariff increase of 12% (on collected basis) would need to be implemented effective January 1, 2004.

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	existing terms								
3	No conversion. Repay ODS over 5 yrs & service loans	11%	23%	504	1,009	9%	12%	6%	7%
4	No conversion. Consolidate existing debt into a new loan	11%	32%	504	1,211	11%	15%	9%	12%
5	No conversion. Achieve 20% D/E ratio @ 12/03	20%	44%	993	1,639	20%	25%	16%	20%
6	No conversion. Achieve 30% D/E ratio @ 12/03	30%	61%	1,703	2,295	35%	45%	29%	36%
7	No conversion. Achieve 35% D/E ratio @ 12/03	35%	72%	2,139	2,699	45%	57%	37%	46%
8	No conversion. Achieve 40% D/E ratio @ 12/03 [5]	40%	84%	2,649	3,169	56%	71%	46%	57%

The following observations are made on the results shown in the table:

- Option 1 involves the conversion into equity of the entire debt portfolio existing at December 31, 2001. The value of such debt at yearend 2003, as recorded in NEPA's books, is estimated to amount to Naira 61.4 billion (US$ 428[6] million equivalent). This is the "Best" Case scenario with zero net tariff impact. The debt/equity ratio is estimated to reach 17% by end 2006.
- Option 2 involves the conversion into equity of the overdue debt service relating to the existing debt at December 31, 2001. The value of such debt as at end 2003, as recorded in NEPA's books, is estimated to amount to Naira 49.9 billion (US$ 348 million equivalent). A tariff increase of 2% would need to be implemented effective 1/1/04. The debt/equity ratio is estimated to reach 18% by end 2006.
- Option 3 will involve no debt to equity conversion. Starting 1/1/04, the overdue debt service will be repaid over 5 years and the remaining loans will be serviced according to the original lending terms. The value of such debt, as recorded in NEPA's books, is estimated to amount to Naira 61.4 billion (US$ 428 million equivalent). A tariff increase of 12% would need to be implemented effective 1/1/04. The debt/equity ratio is estimated to reach 23% by end 2006.
- Option 4 will involve no debt to equity conversion. The entire debt portfolio of Naira 61.4 billion (US$ 428 million equivalent) as recorded in NEPA's books will be consolidated into a single new US$ loan with level annual payments over 15 years at 7% interest. A tariff increase of 12% would need to be implemented effective 1/1/04. The debt/equity ratio is estimated to reach 33% by end 2006.

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5 Under Option 8, the debt at 12/31/03 corresponds almost to the power sector debt obligations of FGN (as per DMO records).

6 Converted at the forecast exchange rate of 143.5 Naira to 1 US$ at December 31, 2003.

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- Options 5 to 8 will involve no debt to equity conversion. Instead, the recorded debt portfolio in NEPA's books will be substituted with a higher value US$ loan of US$ 428 million with level annual payments over 15 years at 7% interest. The loan value will vary according to the level of the debt/equity ratio assumed under each of the four sub-options. The financial and tariff consequences of each of these sub-options are detailed below:
  - Option 5 – Increase NEPA's recorded debt by US$ 469 million to provide a new consolidated debt of US$ 897 million, giving a debt/equity ratio of 20% as of December 31, 2003. A tariff increase of 25% would need to be implemented effective 1/1/04. The debt/equity ratio is estimated to reach 44% by end 2006.
  - Option 6 - Increase NEPA's recorded debt by US$ 1,177 million to provide a new consolidated debt of US$ 1,605 million, giving a debt/equity ratio of 30% as of December 31, 2003. A tariff increase of 45% would need to be implemented effective 1/1/04. The debt/equity ratio is estimated to reach 61% by end 2006.
  - Option 7 - Increase NEPA's recorded debt by US$ 1,613 million to provide a new consolidated debt of US$ 2,041 million, giving a debt/equity ratio of 35% as of December 31, 2003. A tariff increase of 57% would need to be implemented effective 1/1/04. The debt/equity ratio is estimated to reach 72% by end 2006.
  - Option 8 - Increase NEPA's recorded debt by US$ 2,121 million to provide a new consolidated debt of US$ 2,549 million, giving a debt/equity ratio of 40% as of December 31, 2003. A tariff increase of 71% would need to be implemented effective 1/1/04. The debt/equity ratio is estimated to reach 84% by end 2006. This is the "Worst" case scenario. The debt level under this option will be almost equal to the power sector debt owed by FGN to external lenders.

5.2.4 Recommended Debt Restructuring Option

The following recommendations are put forward:

- Options 1 or 2 should be considered for implementation. The debt/equity ratios will be under 20% by end 2006 with zero or minimal tariff impact.
- Options 3 or 4 may be considered for implementation if the Government agrees to the needed 12% tariff increase effective January 1, 2004 just for servicing of existing debt. The debt/equity ratio will reach 33% by end 2006. Option 4 is preferred over Option 3 as the debt service profile under the former is levelized over the years and the debt portfolio is also simplified into a single loan.
- Options 5 to 8 are considered unsustainable in terms of required tariff increases and high gearing levels.

5.3 CROSS DEBTS WITH GOVERNMENT

The non-payment of electricity bills by Government[7] is a major issue that needs to be seriously addressed before the privatization of DisCos. Unless the Government provides direct compensation (an unlikely prospect), potential investors will insist on payment mechanisms that ensure prompt settlement of electricity bills by Government. Ideally, such mechanisms should be fully operational and seen to be working before the bidding process for the sale of DisCos gets off the ground.

The Government needs to address the following key questions:

- How to clear the accumulated backlog of unpaid electricity bills of Government?
- What mechanisms need to be put in place to ensure prompt settlement by Government in the future?

5.3.1 Unpaid Government Electricity Accounts to Date

As of September 2002, the following amounts were due from Government on account of its electricity bills:

- Armed Forces: N4.6 billion
- State & Local Governments: N3.8 billion
- Federal Government Ministries: N3.0 billion
- Federal Government Agencies & Parastatals: N1.4 billion
- Total Government Unpaid Electricity Accounts: **N12.8 billion (US$100 Million)**

A significant portion of the outstanding balance is unlikely ever to be collected by NEPA. It is therefore proposed that the entire balance should be cleared from NEPA's books by way of set-off against debt to equity conversion.

5.3.2 Mechanism for Settlement of Future Government Electricity Bills

NEPA and the Government should agree and implement a mechanism as soon as possible to ensure that Government pays its electricity bills in future. This challenging task will be especially difficult to resolve since it involves several layers of Government. Any agreement between the parties must address the following key issues if the set mechanism is to have a reasonable chance of success:

- Government must make adequate budgetary allocations for electricity charges.
- Government customers should issue monthly standing instructions to their banks for direct payments to NEPA. The banks could be instructed to transfer funds to NEPA either (a) on presentation of electricity bills or (b) according to fixed sums agreed in advance between the parties. For delinquent customers, the Ministry of Finance should

[7] In this section, Government refers to collective Government, including Federal, State and Local Governments and their agencies and parastatals.

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have the right to make direct payments to NEPA by way of deductions at source. For this purpose, DisCos would need to install customer meters, as Government customers would be unwilling to settle non-verifiable bills.

5.4 OVERDUE VAT & GAS LIABILITIES

NEPA's books of account reflect the following overdue liabilities:

- Overdue or uncollected VAT on electricity bills of Naira 6.5 billion, including interest of about Naira 2.0 billion
- Disputed amounts due to the National Gas Company (NGC) of Naira 4.3 billion. The overdue balance relates to a pricing dispute for gas supply between 1994 and 2001.

The above liabilities are unlikely to be paid, as NEPA does not have the resources to settle them. These liabilities should be cleared from NEPA's books by way of set-off against debt to equity conversion.

5.5 FINANCIAL RESTRUCTURING PLAN

The various recommendations contained in the foregoing sections, are summarized in Table 5-5 in the form of a financial restructuring plan for NEPA.

Table 5-5: Financial Restructuring Plan [8] (in Billion Naira)

Action	Option 1	Option 2
Convert debt to equity	61.4	49.9
Write-off electricity accounts of Government	- 12.8	- 12.8
Write-off overdue or uncollected VAT	6.5	6.5
Write-off disputed NGC liability	4.3	4.3
Total	**59.4**	**47.9**

NEPA should hold discussions with the Government as soon as possible to consider the various debt restructuring options detailed above and agree on a financial restructuring plan. NEPA should also present these plans to the relevant donors to seek their agreement.

5.6 OPENING BALANCE SHEETS OF NBUS

Under the new framework of internally unbundled generation, transmission and distribution businesses, accountability and responsibility will be devolved downwards and management performance will be judged at each level of the organization based on operational and financial results. Local management will only take ownership and responsibility of their actions if they are involved in the decision making process, have more control over their budgets and are better informed about the true costs of their operations, including the cost of power delivered to them.

[8] The balances shown are forecasts as of December 31, 2003.

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For this purpose it will be necessary to institute fundamental changes to existing practices in accounting, budgeting, cash management and financial reporting at all levels of the business. This section addresses a critical component of the corporate restructuring exercise: the unbundling of NEPA's accounts to the NBUs.

5.6.1 Fixed Assets

The fixed assets of NEPA are presently recorded in the books of the corporate HQ. No accounting records for fixed assets are maintained at the NBUs. NEPA is taking the following steps to unbundled the fixed assets to the NBUs:

- Local consultants are compiling fixed assets registers for each NBU.
- The registers will record historical costs and accumulated depreciation of all assets as of December 31, 2001.
- Agreed Next Steps:
  - Revalue fixed assets based on valuations of PB Power.
  - Allocate fixed asset values as at December 31, 2001 for recording in the books of the NBUs.
  - Additions to fixed assets in 2002 to be notified by HQ to the NBUs for recording purposes.
  - NBUs to take physical inventory of fixed assets and update fixed asset registers as necessary.

5.6.2 Vesting Of Loans to Successor Companies

The following principles are recommended for vesting of NEPA's loans to the NBUs:

- On-going loans should be vested to the companies concerned (e.g. The World Bank loan for the transmission development project should be transferred to TransysCo).
- The remaining restructured debt (as per the selected debt restructuring option) should be allocated to the NBUs based on their respective equity (i.e. same debt/equity ratio to apply across the board). The allocated loans will be vested by way of loan agreements between NBUs and FGN on identical terms and conditions.

5.6.3 Customer Accounts Receivable

The recorded customer accounts receivable in DisCos' books are grossly over-stated in terms of their ultimate recoverability. General provisions for bad debts are only recorded in corporate HQ books. Provisions for bad debts as of December 31, 2000 reached 90% of the recorded balances of DisCos. It is therefore necessary to write-off all irrecoverable debts in the books of the DisCos. The DisCos should take the following actions:

- Prepare detailed listings of all irrecoverable debts.
- Seek approval for the write-off of identified irrecoverable debts.

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- Write-off irrecoverable debts.

5.6.4 Allocation of Assets & Liabilities to NBUs

The following assets & liabilities recorded in corporate HQ books should be allocated to individual NBUs:

- Operational fixed assets
- Sector head office fixed assets other than those at HQ
- Completed capital project costs
- Provisions for irrecoverable customer accounts
- Employee advances
- Inventory in central stores
- Customer deposits
- Deferred customer contributions

In addition to the above, NBUs will retain all assets and liabilities that are currently recorded in their individual books of account (e.g. cash and bank, inventory, customer accounts receivable, etc).

The following assets & liabilities should be retained in corporate HQ books:

- Corporate HQ fixed assets & investments.
- All current assets and liabilities that are not allocated to NBUs, including all debtors (other than customer accounts) and creditors that relate to transactions or obligations accruing prior to the corporatization of successor companies. Liabilities and obligations in respect of all employee entitlements up to the date of legal transfer will therefore remain with corporate HQ.
- Unfunded pension obligations and accrued liabilities for other employee entitlements should be fully provided for in the books of corporate HQ.

5.7 TARGET FINANCIAL RESTRUCTURING COMPLETION DATE

The target completion date for all the above tasks and the preparation of opening balance sheets of NBUs is June 30, 2003. The target date has been discussed with the Finance & Accounts Department at Corporate HQ.

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6.1 INTRODUCTION

NEPA has adopted an ambitious timeline for power sector reforms. By the end of the 2nd Quarter 2003, the company expects to incorporate the NBUs, announce NBU managements and inaugurate TransysCo. By the end of the 3rd Quarter 2003, the transition stage market design will be completed and the set up of the National Electricity Regulatory Commission will be underway. Meeting these timelines will require a rigorous management approach with team members assigned specific tasks and provided with adequate resources to fulfill their missions.

This section provides recommendations on 1) priority implementation steps that NEPA must address to meet its timeline for the transition stage market and 2) an efficient project management approach to move the process forward.

6.2 NEXT STEPS FOR TRANSITION STAGE MARKET IMPLEMENTATION

This section lists activities and timelines for the following transition stage market reforms:

- Agreements, systems and procedures for shadow market operations
- Bulk supply charges and cash allocations to the NBUs
- Reorganization Plan to establish functionally independent DisCos and institute the Market Operator
- Financial restructuring of debts and liabilities and unbundling of accounts to NBUs

A summary table of priority reform activities along with recommended due dates and responsibilities is provided at the end of this section.

6.2.1 Market Operations

The shadow market can be inaugurated by July 2003 in time for the 3rd Quarter budget cycle. The following activities must be completed in advance of market operations:

- *Complete the Market Agreement.*
  - Agree on transition stage market rules
  - Obtain NEPA management approval for market rules
  - Build consensus among representatives of all NBUs and other market players on the terms and conditions of the Market Agreement
  - Revise the Draft Market Agreement to reflect approved market rules and negotiated terms and conditions
  - Finalize Market Agreement
  - Obtain any required Ministry of Power and Steel and FGN approvals
  - Sign Market Agreement

- Finalize bulk supply charges and initial cash allocations (see details in next section).
- Set up the following banking arrangements:
  - a central remittance account;
  - a collection account for each DisCo; and
  - standing orders for bank transfers.
- Set up the Market Operator function
  - Determine staffing and reporting relationship within TransysCo
  - Develop procedures and work processes
  - Provide the essential requirements for facilities, equipment, systems, Statement of Account templates, etc.
- Decide the Market Operation Committee's role, authority, relationship to NEPA Board, composition, procedures, secretariat, budget, etc.
- Appoint the Market Operation Committee and its secretariat.
- Complete the minimum required grid metering, or at least put in place procedures to calculate net generation for each GenCo and actual energy received by each DisCo.
- Establish procedures and systems for grid meter data collection and delivery to the Market Operator for consolidation.
- Establish procedures and responsibilities at the DisCos and IHC HQ for forecasting demand, revenues and budget requirements.

6.2.2 Bulk Supply Charges and Cash Allocation

Nexant has already developed the spreadsheet Charges Model to calculate bulk supply charges and cash allocations. The model has several optional cash allocation methods depending on the policy decisions of NEPA management. The choice of method for the transition stage market has been discussed with NEPA executive management. The remaining tasks involve executive and board approvals, finalizing the model inputs and results and enhancing authority limits at the NBUs consistent with the new financial system.

The following steps can be completed in the 2nd Quarter 2003:

- NEPA executive management and the Finance and Restructuring Committees of the Board of Directors approve Charges Model principles and processes.
- NEPA Finance and Admin Department update the data inputs in the Charges Model for the second quarter of 2003.
- NEPA F&A test run and verify bulk supply charges and cash allocation results for the 2nd quarter 2003.
- GM F&A finalize budget data inputs and calculate bulk supply charges and cash allocations for the shadow market starting 3rd quarter 2003.

- ED F&A implement the following steps to enhance NBU authority limits and increase financial autonomy:
  - Develop and submit revised authority limits to MD
  - Obtain NEPA executive management, BoD and FGN approvals
  - Distribute circular on new authority limits company-wide
- Nexant and NEPA F&A provide training on the Charges Model to the NBUs.

6.2.3 Reorganization Plan

This report recommends organizational changes to establish DisCos and the Market Operator for the transition stage market structure. The organizational changes at TransysCo are covered in the *Transmission Development Project Organigram Chart Manual* (Red Electrica, March 2003). Nexant and Red Electrica have discussed these changes with NEPA counterparts. The remaining tasks involve executive and board approvals of the new and modified positions followed by candidate screening, selection and approval.

The following steps can be completed in time for shadow market operations beginning 3rd Quarter 2003:

- Approve new positions, job descriptions, revised organograms and reporting linkages for new and enhanced positions at the NBUs.
- Call for applications for new positions.
- If required, select outside consultant to assist in short-listing and interviewing.
- Compile shortlist of candidates and form interview panels.
- Conduct interviews of candidates.
- Prepare interview panel reports with recommendations.
- NEPA MD and BoD approve selected candidates for each new post. Note: new AGM positions may require approval by the Minister of Power and Steel upon the recommendation of the MD.
- Issue appointment letters to approved candidates.
- Selected candidates assume positions.

6.2.4 Financial Restructuring

Nexant has recommended a financial restructuring plan to clean up NEPA's balance sheet and to vest the company's assets and liabilities to the NBUs. Implementing the plan will require a concerted effort by NEPA to obtain intergovernmental cooperation and ministry approvals and to avoid delays and red tape.

The financial restructuring plan consists of the following steps:

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- NEPA Management, BoD and the Finance Committee of the Board review and approve financial restructuring principles and processes.
- NEPA MD submits financial restructuring proposals to FGN (MP&S and MoF).
- Ministry of Finance approves financial restructuring package.
- NEPA F&A completes fixed assets registers for each NBU:
  - Local consultant for historical book values to 12/31/01 (already in progress)
  - HQ transactions for 2002 passed back to NBUs
  - Physical inventory of fixed assets
  - Revaluations of PB Power incorporated in the books
- Clean-up customer accounts receivable:
  - GM F&A prepares listing of irrecoverable debts as of 12/31/02
  - NEPA MD seeks approval for write-off of irrecoverable accounts from BoD and Ministry of Finance
  - FGN approves write-off
  - GM F&A completes the accounting to write-off irrecoverable debts as of 12/31/02
- Mechanism for future settlement of Government electricity bills:
  - F&A and Marketing EDs prepare proposals to Federal, State and Local Government
  - Negotiate Government agreements and approvals
- GM F&A allocates HQ assets & liabilities to NBUs and prepares opening balance sheets of the NBUs by 30 June 2003
- ED F&A vests loans to successor companies by 1 January 2004

6.3 MANAGING THE CORPORATE RESTRUCTURING PROCESS

Efficient implementation of corporate restructuring will require coordination of a wide range of activities, inputs and approvals involving NEPA management and Board of Directors, FGN, Ministry of Power and Steel, Ministry of Finance, Bureau of Public Enterprises and consultants. A task force approach will drive the process forward.

6.3.1 Task Force Structure

A task force team has the following elements:

- Chairperson – The chairperson is responsible for supporting the project with adequate resources, issuing appointment letters for task force members and providing overall guidance and day-to-day decision-making. This position is most likely drawn from the ranks of NEPA EDs. For example, the important work of setting up the NBUs has been assigned to the relevant EDs. Chairpersons can be nominated by the Managing Director and approved by the BoD.

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- Task Manager – The role of the task manager is to plan activities, set milestones, provide a schedule, assign responsibilities, monitor progress, obtain resources and management approvals, define consultants' scopes of work, resolve problems, report progress to executive management and coordinate day-to-day execution. The task manager reports administratively to the task chairperson. The task manager and the responsible executive seek approval on key decisions and proposals from the MD and/or from the standing committees of the BoD, and serve on the relevant committee(s) of the BoD. Task managers are most likely drawn from the ranks of the NEPA GMs and AGMs, however in some instances the task force chairperson can also serve as task manager.
- Task Team – The task team is an inter-disciplinary group of experts from relevant NEPA divisions and other agencies. The team develops and recommends solutions to restructuring issues and implements these solutions company-wide.
- Consultants – Consultants will be required for some of the task forces to work with the Task Manager to plan and implement the task scope of work.

6.3.2 Task Force Organization

Task forces can be organized to address the following reform activities:

- DisCo, TransysCo, GenCo and IHC Corporate Headquarters Task Forces – These task forces can finalize the management structures and management-level job descriptions for the NBUs, reengineer core processes at the NBUs and IHC HQ consistent with the transition stage market structure, manage the overall set-up of the NBUs and guide the change process company-wide. Set-up Teams have already been appointed for DisCos, TransysCo and GenCos with the relevant NEPA EDs serving as chairpersons. A fourth task force is required for IHC Corporate Headquarters.
- Executive Staffing Task Force – This task force can manage the recruitment, selection and appointment of individuals to new management positions at the NBUs.
- Market Operations Task Force – This task force can cover the following reforms: new systems and processes for load allocation, grid metering, settlement, exchange of information and dispute resolution; completion of the Market Agreement; and set-up of the Market Operator and the Market Operations Committee. The Market Operations Task Force can report to the chief executive of TransysCo. It may be possible to combine this task force under the TransysCo Set-up Team.
- Financial Task Force – This task force can finalize the bulk supply charges and cash allocations to the NBUs, institute banking and accounting arrangements for the settlement system, prepare the NBUs' opening balance sheets, develop and implement proposals on financial restructuring and advise on tariff issues. The Financial Task Force can report jointly to the ED F&A and the ED TransysCo. The task force can obtain key approvals from the Finance Standing Committee of the BoD.
- Other Task Forces – Other task forces can be formed as needed to cover incorporation of subsidiary companies, NBU boundaries, training programs etc.

6.4 ROLE OF CONSULTANTS

Consultants can play a vital role in the corporate restructuring process. At present, consultants are working with NEPA and BPE in the following relevant areas:

- Priority reforms for the transition stage market (Nexant);
- Set up of TransysCo (Red Electrica);
- Valuation of fixed assets (PB Power);
- Preparation of NBU asset registers (local accountants); and
- Change management (Accenture).

In the coming months, NEPA will require additional on-the-ground technical assistance for restructuring implementation. The role of the consultants will be to advise the NEPA task forces on options and recommendations for executive decision-making, and to work side-by-side with the task managers and executives.

6.4.1 USAID Technical Assistance Program

USAID is sponsoring Nexant for the remainder of 2003 to assist NEPA with implementation of the transition stage electricity market. Nexant will advise NEPA in the following areas:

- Planning and managing the reform process;
- Consensus-building on and completion of the Market Agreement;
- Calculation of bulk supply charges and cash allocation among the NBUs;
- Preparation of opening balance sheets for TransysCo and possibly other NBUs;
- Advice on financial restructuring;
- Implementation of the Market Operator function;
- Implementation of the Market Operation Committee;
- Restructuring Plan for IHC Corporate Headquarters;
- Reengineering of core processes at Corporate HQ and a pilot DisCo(s); and
- Other activities to be determined.

Table 6.1 presents a work plan for the USAID-Nexant technical assistance program.

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Table 6.1: Work Plan for USAID-Nexant TA on Electricity Market Reforms

Nexant Activities	Finish
1. Tools and Planning Assistance for NEPA Restructuring Task Manager(s)	Q4 2003
2. Set up Transition Stage Market	
▪ Finalize charges and cash allocations	Q2
▪ Finalize Market Agreement	Q3
▪ Opening balance sheet for TransysCo	Q3
▪ Technical advice on financial restructuring	Q4
3. Set up Market Operator	
▪ Terms of Reference	Q2
▪ Procedures and work processes	Q3
4. Set up Market Operation Committee	
▪ Implementation Plan	Q3
▪ Procedures and work processes	Q4
5. Pilot DisCo(s)	
▪ Forecasting and business planning	Q3
▪ Enhance core functions: management, F&A, Corp Planning, HR, etc	Q4
6. IHC Corporate Headquarters	
▪ Reorganization Plan to decentralize core functions	Q3
▪ Re-engineer F&A, HR, Admin, etc	Q4

The foregoing work plan will serve the following restructuring task forces:

- TransysCo Set-up Team (and/or Market Operations Task Force)
- Financial Task Force
- DisCo Set-up Team
- IHC Corporate Headquarters Task Force

The USAID technical assistance program is flexible to meet the needs of the sector reform program. For example, the following additional activities can be considered:

- Functions for generation and transmission planning and IPP contracting
- MIS and Performance Reporting System for Corporate Headquarters
- Technical assistance to the GenCo Set-up Team
- Draft agreements for bilateral contracts market stage
- Study Tour to learn experience of other countries
- Other TA at request of NEPA

6.4.2 Bilateral Contracts Market Design

Consultants will be required to plan and implement the bilateral contracts market to follow the transition stage market. The activity should start before yearend 2003 and cover the following tasks:

- Provide a practical plan to address fundamental financial constraints on the development of the electricity sector.
- Develop new commercial mechanisms for bulk supply charges, cash allocation and load allocation to replace the transition stage mechanisms.
- Develop and implement the following integrated set of agreements:
  - Bilateral Power Purchase Agreements
  - Pooling and Settlement Agreement
  - Transmission Use of System Agreement
  - Ancillary Services Agreement
  - Transmission Interconnection Agreement
  - Grid Code
  - Operating Licenses
- Review procedures used by the Market Operator for metering and billing and revise as necessary consistent with the bilateral contracts market design.
- Establish the trading licensee for bulk purchases from IPPs and resale to DisCos.

BPE is now in the process of recruiting consultants to come on board in the fall to assist with the restructuring and privatization program.

6.5 SUMMARY OF PRIORITY REFORM ACTIVITIES

Table 6.2 provides a summary list of priority reform activities with due dates and responsibilities.

Table 6.2: List of Priority Reforms with Due Dates and Responsibilities

Activity	Due	Responsibility
Transition Stage Market Operations		
Finalize Market Agreement	Q3	ED TransysCo, Nexant

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Activity	Due	Responsibility
Set up the Market Operator function: ▪ Determine staffing and reporting relationship within TransysCo ▪ Develop procedures and work processes ▪ Provide facilities, equipment, systems, etc. ▪ Candidate selection	Q3	ED TransysCo, ED F&A, GM HR, Nexant
Set up banking arrangements for Market Operator: ▪ a central remittance account; ▪ a collection account for each DisCo; and ▪ standing orders for bank transfers.	Q2	ED F&A
Design Market Operation Committee	Q2	ED CP&S, Nexant
Appoint Market Operation Committee and its secretariat	Q3	MD, BoD
Complete the minimum required grid metering	Q2	ED TransysCo
Establish procedures and systems for grid meter data collection and delivery to Market Operator	Q2	ED TransysCo, Nexant
Establish procedures and responsibilities for forecasting demand, revenues and budgets	Q2	ED F&A, Nexant
Bulk Supply Charges and Cash Allocation		
Presentation to NEPA executive management and BoD on charges and cash	April	Nexant
Approve Charges Model principles and process	Q2	ED F&A, MD, BoD
Update data inputs in Charges Model for the 2nd quarter of 2003	Q2	PM Mgmt Accounts, Nexant
Shadow run of Charges Model for 2nd quarter 2003	Q2	GM F&A, Nexant
Update data inputs in Charges Model for the 3rd quarter of 2003	Q2	GM F&A, Nexant
Implement bulk supply charges and cash allocation for 3rd quarter 2003 shadow operation	Q2	GM F&A, Nexant

Activity	Due	Responsibility
New financial authority limits for NBUs:		
▪ Submit revised authority limits to MD	Q2	ED F&A
▪ Management approval	Q2	MD
▪ Board approval	Q2	Chairman
▪ FGN approval	Q3	Min of Finance
Reorganization Plan for DisCos		
Approve DisCo Organizational Structure ▪ Organograms and reporting linkages ▪ Approve creation of new posts ▪ Approve job descriptions	Q2	MD
Issue call for Applications for new posts	Q2	GM HR
Deadline for submission of Applications	Q2	GM HR
Select consultant for short-listing and interviews	Q2	MD and GM HR
Shortlist compiled; interview panels formed	Q2	GM HR
Appoint Interview Panels	Q2	MD
Conduct candidate interviews	Q2	Interview Panels
Report with recommendations sent to MD	Q3	Interview panels
Approval of selected candidates for each new post	Q3	MD
Approved candidates issued appointment letter	Q3	GM HR
Candidates notification of acceptance	Q3	Candidate
Candidates begin work in posts	Q3	
Financial Restructuring Plan		
Presentation to NEPA executive management	April	Nexant
Approve principles and process		
▪ Management	May	ED F&A
▪ Finance Committee of the Board	Q2	MD
▪ Board	Q2	Chairman
Submit financial restructuring proposals to MoF	Q2	MD, Nexant
FGN approval in principle of financial restructuring package	Q2	Min of Finance

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Activity	Due	Responsibility
Complete fixed assets registers for each NBU:		
▪ Historical book values to 12/31/01	Q2	AGM Accts
▪ HQ transactions for 2002 passed to NBUs	Q2	AGM Accts
▪ Physical inventory of fixed assets	Q3	NBU GMs
▪ Revaluations incorporated in the books	Q3	GM F&A
Prepare listing of irrecoverable customer accounts receivables as of 12/31/02	Q2	NBU AGMs/PMs F&A
Approval for write-off of irrecoverable accounts		
▪ Management	Q2	GM F&A
▪ Finance Committee of the Board	Q2	ED F&A
▪ Board	Q2	MD
▪ FGN	Q2	MD
▪ FGN approval for write-off	Q3	Min of Finance
▪ Write-off debts as of 12/31/02	Q3	GM F&A
Allocate HQ assets & liabilities to NBUs	Q2	GM F&A, Nexant
Mechanism for Government electricity bills:		
▪ Submit proposals to FGN, State and Local	Q2	ED F&A, ED Mktng
▪ Government approvals (various)	Q3	MoF, Fin. Depts.
Opening balance sheets of NBUs	Q2	GM F&A, Nexant
Vesting of loans to successor companies	Q1 2004	ED F&A

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Appendix A
Draft Market Agreement

The following Draft Market Agreement can be used as a starting point for further development work.

Draft Market Agreement
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WHEREAS :

it is agreed that the well-being of the Nigerian economy and of its people depends on the efficient and reliable supply of affordable electricity;

the Parties together constitute the major part of the electricity industry in Nigeria;

the Parties have agreed that the commercial relationships between the Parties relating to the bulk sale, purchase and transmission of electrical energy shall for the time being be governed by this Market Agreement;

the Parties agree that the terms of this Market Agreement shall be subject to review and approval by the Regulator;

this Market Agreement is expected to remain in force until bilateral contracts between generators and suppliers, as envisaged by the Blueprint for the restructuring of the electricity sector in Nigeria produced by the Bureau of Public Enterprises, are established;

It is hereby agreed that:

1 DEFINITIONS AND INTERPRETATIONS

1.1 Definitions

"Ancillary Services" means XXX;

"***Ancillary Services Agreement***" means any agreement between TransysCo and a GenCo or DisCo regarding the provision of Ancillary Services;

"***Auxiliary Load***" means the Electricity used by auxiliary equipment or otherwise consumed at a *Generating Unit or Power Station* in the production of Electricity;

"Back-up Metering Equipment" means XXX;

"***Business Day***" means a weekday, Monday to Friday inclusive, other than a public holiday;

"***Charges Model***" means the computer-based spreadsheet model described in Schedule D for calculating the charges and cash payments due to and from each of the Parties. The Charges Model is operated and maintained by the Market Operator with financial information supplied by GenCos, DisCos, and TransysCo;

"***Collection Account***" means a bank account as described in section 6.1;

"***Commencement Date***" means the first day of July, 2003;

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"Confidential Information" means XXX;

"Connection Agreement" means XXX;

"Cumulative Cash Shortfall" means XXX;

"Delivered Energy" means XXX;

"***Delivery Point***" means the point at which electricity is delivered from the Transmission Network to DisCos and to Large Industrial Consumers;

"***Dispatch***" means the right of the System Operator to issue instructions or its issuance of instructions from the Electricity Control Centre in accordance with Prudent Utility Practices and this Agreement to schedule and control the operation of a Power Station Unit in order to commence, increase, decrease or cease the Electricity delivered into the Transmission Network or to schedule and control the operation of transmission equipment;

"***Dispatch Instruction***" means an instruction issued by the System Operator on a daily, hourly or real-time basis requesting the Dispatch of generation, transmission or distribution equipment to provide, to transmit or to accept Electricity or Ancillary Services under this Agreement;

"***DisCo***" means a Distribution Company listed in Schedule A that distributes and sells electricity received from the High Voltage Transmission Network to electricity consumers by means of its Distribution Network;

"***Distribution Network***" means the system of distribution lines, cables, equipment, structures and supports, substations and other facilities owned, operated and maintained by a DisCo for the purpose of distributing electricity to customers;

"***Electricity***" means electrical energy, as measured in megawatt-hours (MWh);

"***Electricity Generated***" means the Electricity produced by a Generating Unit, as measured at the generator terminals;

"***Fiscal Year***" means twelve (12) months beginning on 1 January and ending on 31 December.

"***Fixed Generation Tariff***", in Naira per MW, has the meaning defined in section XXX.

"***Fixed Transmission Charge***", in Naira per MVA, has the meaning defined in section XXX.

"***Fixed Transmission Losses Tariff***", in Naira per MW, has the meaning defined in section 5.4.2;

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"***Force Majeure Event***" shall mean any event or circumstance or combination of events or circumstances that is beyond the reasonable control of a Party and that on or after the date of execution of contract, materially and adversely affects the performance by such affected Party of its obligations under or pursuant to this Agreement including a Party's ability to deliver or receive Electricity; provided, however, that such material and adverse effect could not have been prevented, overcome or remedied in whole or in part by the affected Party through the exercise of diligence and reasonable care;

"***Forced Outage***" means the interruption, in whole or in part, of the capability to generate Electricity of a Generating Unit or Power Station that: (i) is not a request by TransysCo in accordance with this Agreement; (ii) is not a Scheduled Outage or a Maintenance Outage and (iii) is not a Force Majeure Event;

"***GenCo***" means a generation company listed in Schedule A that owns one or more Power Stations;

"***Generating Unit***" means a generating unit listed in Schedule B.1 that generates electricity for sale to DisCos;

"Generation Metering Point" means XXX;

"***Grid Code***" means the code published by TransysCo and approved by the Regulator, as amended from time to time, that sets out the policy, rules and procedures for the operation of and for connection to the Transmission Network;

"***High Voltage***" means 132 kilovolts and above;

"***Hz***" means Hertz, that is a frequency of one cycle per second;

"***Initial Holding Company***" the company formed from NEPA, constituted in accordance with the Electricity Power Sector Reform Act;

"***Injection Sub-Stations***" means the sub-stations at which electricity is delivered from the national grid network to DisCos and which are listed in Schedule B.2.

"***IPP***" means an Independent Power Producer, which is a company that owns and operates one or more Power Stations, whose capacity and electrical energy is sold under a Power Purchase Agreement. For the avoidance of doubt, companies that own and operate power stations that have ROT (Rehabilitate, Operate and Transfer) contracts are included in the definition of IPP;

"Integrating Pulse Meters" means XXX;

"Integrating Pulse Recorders" means XXX;

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"***Maintenance Outage***" means an interruption or reduction in the capability to generate, to transmit or to receive electricity that: (i) is not a Scheduled Outage; (ii) has been scheduled and allowed by TransysCo and (iii) is for the purpose of performing work on specific components, which should not, in the reasonable opinion of the operator, be postponed until the next Scheduled Outage;

"***Market Agreement***" means this agreement;

"***Market Operator***" means the administrator of this Market Agreement, according to Section 9.1;

"***Market Operation Committee***" means the committee established in accordance with Section 9.2 to oversee the management and operation of this agreement;

"***Maximum Capability***" means the maximum output in MW of which a Generating Unit is capable during a Metering Period;

"***Maximum Dependable Capacity***" means the amount of capacity associated with each Generating Unit that is available on a continuous basis as expressed in MW;

"***Metering Equipment***" means equipment installed for the purpose of measuring Electricity, Peak Demand and Peak Load, as described in section G.3.1;

"***Metered Party***" means a GenCo, IPP or DisCo whose output or demand, as appropriate, is being metered;

"***Metering Period***" means the period over which the delivery and receipt of Electricity is metered, measured, recorded and priced. This period shall be one (1) hour beginning at zero minutes past the hour;

"***Metering Points***" means the Metering Points listed in Schedule B;

"***MVA***" means megavolt-ampere;

"***MVArh***" means megavolt-ampere reactive hour;

"***MW***" means megawatt;

"***MWh***" means megawatt-hour, i.e. the product of power in MW and time in hours.

"***National Electricity Control Centre***" means TransysCo's National Electricity Control Centre (NECC), located in Shiroro, or such other control centre designated by TransysCo from time to time (but not more than one at any time) from which the System Operator shall Dispatch the Units and Transmission Network;

"***NBU***" means a New Business Unit, being an autonomous field or headquarters unit of NEPA, the field units being GenCos, TransysCo and DisCos;

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"*NEPA*" means the National Electric Power Authority of Nigeria and its successor Initial Holding Company;

"*Net Electricity Generated*" means the electricity generated by a Generating Unit during a Metering Period, as defined in Section 7.3, measured in MWh;

"*Network Operator*" means the Network Operator division of TransysCo, which develops and maintains the Transmission Network;

"*Operating Capabilities*" means the operating capabilities of each Generating Unit or Injection Sub-Station as advised to TransysCo by the operator of the facilities in accordance with the Grid Code or, in the absence of a Grid Code, Schedule G;

"*Operating Records*" means those records that GenCos, TransysCo and DisCos are required to maintain in accordance with section 12.7

"*Peak Demand*" means the maximum demand, in MW, measured during a Settlement Period as calculated in accordance with section 7.7;

"*Peak Load*" means the maximum load, in MVA, measured during a Settlement Period as calculated in accordance with section 7.8;

"Primary Metering Equipment" means XXX;

"*Regulator*" means the Nigerian Electricity Regulatory Commission;

"*Parties*" means those legal entities listed in Schedule A, as amended from time to time, comprising the major Generation Companies, transmission company (TransysCo) and Distribution Companies of the Federal Republic of Nigeria;

"*Power Station*" means one or more Generating Units located together and under common ownership by a single GenCo;

"*Prudent Utility Practice*" means the exercise of engineering and operational judgement to build, install, maintain and operate equipment for the generation, transmission and distribution of electricity in accordance with good practice followed by the electric utility industry world-wide. Prudent Utility Practices are a spectrum of possible practices, methods and acts which can reasonably be expected to accomplish the desired result at reasonable cost consistent with high levels of reliability and safety;

"Reactive Energy"; means XXX;

"Reasonable and Prudent Operator" means XXX;

"*Regulator*" means the Nigeria Electricity Regulatory Commission (NERC)

"***Remittance Account***" means the account established by the Market Operator for the settlement of payments among the Parties;

"***Schedule of Charges***" shall have the meaning given in section XXX.

"***Scheduled Outage***" means an interruption or reduction in the capability to generate, to transmit or to receive electricity that has been planned and approved by TransysCo at least one calendar month in advance;

"***Settlement Period***" means the period for which the Market Operator will settle the accounts of the Parties, which begins at 12 noon on the first day of the quarter and ends at 12 noon on the first day of the third month after – the quarters beginning on the first days of the months of January, April, July and October each year;

"Statement of Account" shall have the meaning given in section XXX;

"***System Emergency***" means a condition or situation that, in the sole opinion of the System Operator, affects or is likely to affect its ability to maintain safe, adequate and continuous transmission of electricity, or presents or is likely to present a physical threat to persons and/or property or the security, integrity or reliability of the Transmission Network;

"***System Operator***" means the Operations division of TransysCo;

"***Term***" means the duration of this Market Agreement as defined in Section 3;

"***Termination Date***" means the date on which this Market Agreement is terminated in accordance with Section 3;

"***TLF***" means Transmission Loss Factor, calculated in accordance with section 7.9;

"***Total Delivered Energy***" shall have the meaning given to it in section 7.9;

"***Total Generated Energy***" shall have the meaning given to it in section 7.9;

"***transmission***" means the transport of electricity from GenCos to DisCos by means of a Transmission Network. The terms "***transmit***" and "***transmitting***" shall be construed accordingly;

"***Transmission Equipment***" means equipment that is part of the Transmission Network;

"***Transmission Loss Factor***" means the factor calculated in accordance with Section 7.9 that represents the percentage loss of electrical energy within the Transmission Network;

"***Transmission Network***" means the national system of transmission lines, cables, equipment, structures and supports, substations and other facilities owned, operated and maintained by TransysCo for the purpose of transmitting electricity;

"*TransysCo*" means a company or entity that owns and operates a Transmission Network in Nigeria;

"TransysCo Accepted Scheduled Outage" means XXX;

"Use of System Agreement" means XXX;

"*Variable Generation Tariff*", in Naira per MWh, has the meaning defined in section 5.4.3;

"*Variable Transmission Losses Tariff*", in Naira per MWh in section 5.4.4;

1.2 Interpretations

The following rules of interpretation and conventions shall apply in this Agreement, unless the context otherwise requires:

i) the singular shall include the plural and vice versa;

ii) the masculine shall include the feminine and neutral and vice versa;

iii) "includes" or "including" shall mean "including without limitation";

iv) reference to a Section or Schedule shall mean a Section or Schedule of this Agreement, as the case may be, unless the context otherwise requires;

v) reference to a given agreement or instrument shall be a reference to that agreement or instrument as amended or supplemented through the date as of which such reference is made provided, however, that references to the Grid Code shall be to the most current effective version thereof, unless otherwise specified

vi) unless the context otherwise requires, references to any law shall be deemed reference to such law as it may be amended, replaced or restated from time to time;

vii) section headings and other headings are for the ease of reference only and shall not be deemed to form any part of the context or to affect the interpretation of this Agreement.

2 SERVICE UNDER THE AGREEMENT

2.1 Sale and Purchase of Bulk Electricity

2.1.1 Generation Companies

GenCos shall make available Maximum Dependable Capacity and Ancillary Services from each of their Units in accordance with the terms and conditions of this Agreement. All services shall be delivered with reference to the current Operating Capabilities, agreed Scheduled Outages and notified Maintenance Outages and Forced Outages of each Generating Unit.

2.1.2 Distribution Companies

Each DisCo shall have the right to receive electricity in accordance with the terms of this Market Agreement and such codes and other agreements that may exist between the Parties concerning the allocation of electricity among DisCos.

2.2 Transmission Service

2.2.1 Transmission of Electricity

TransysCo shall transmit electricity from Generating Units to DisCos, who shall receive and pay for the same subject to the terms and conditions of this Agreement.

2.2.2 TransysCo to be a Reasonable and Prudent Operator

TransysCo shall operate and maintain the Grid in compliance with the Grid Code or, in the absence of such Grid Code, in accordance with Prudent Utility Practice.

2.2.3 Connection to the Transmission Network

TransysCo shall permit Generating Units and DisCos to remain connected to the Metering Points specified in Schedule B over the Term of this Agreement for the purpose of the production or receipt of electricity. Metering Points may be added or deleted by mutual agreement between TransysCo and the Party concerned, and Schedule B shall be amended accordingly.

2.2.4 Settlement Metering Data

TransysCo shall provide grid meter data to the Market Operator for settlement purposes in accordance with Schedule H.3.

2.2.5 Interruption of Transmission

Notwithstanding any other provision of this Agreement, TransysCo may interrupt or reduce receipt of electricity at a Delivery Point or delivery of electricity at a Generation [redacted] Point for a period of time for the purpose of testing, adding to, altering, repairing, replacing or maintaining the Transmission Network, or for any other purpose that requires interruption or reduction in the transmission of electricity.

TransysCo shall notify the affected GenCos and DisCos as early as possible of its intention to interrupt or reduce the transmission of electricity or of circumstances that may affect the reliability of transmitting electricity. Further, TransysCo shall use all reasonable efforts to reach agreement with the affected Parties on the timing of the interruption or reduction, with the objective of minimising the impact on the affected Parties.

TransysCo shall use all reasonable efforts to minimise the interruption or reduction in the transmission of electricity.

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3 TERM OF AGREEMENT

3.1 Termination

This Market Agreement shall commence on the Commencement Date and shall continue in force until terminated by the Market Operation Committee in accordance with this Section provided however that the agreement may not be terminated until suitable alternative arrangements have been agreed and are ready to be implemented.

3.2 Termination Notice

If the Market Operation Committee decides to terminate this Agreement it shall give all Parties proper notice in accordance with Section 25. This Agreement shall be deemed to be terminated on the date six (6) months after the issuance of a notice to terminate by the Market Operation Committee subject to the approval of the Regulator.

3.3 Obligations upon Termination

Upon expiration or termination of this Agreement, the Parties shall have no further obligations hereunder except for obligations that arose prior to such expiration or termination and obligations that expressly survive such expiration or termination pursuant to this Agreement.

4 OBLIGATIONS OF THE PARTIES

4.1 Compliance with laws, Codes and Standards

Each of the Parties agrees that during the Term of this Market Agreement it will comply, to the extent applicable, with the Grid Code and any other codes and standards that may be drawn up and approved by the Regulator and with all statutory and regulatory requirements for the time being in force that apply to the performance of its obligations under this Agreement.

4.2 Licences

Each of the Parties agrees that during the Term of this Market Agreement it will obtain and keep current all regulatory, environmental and other licences, permits and approvals as may be required by law for the satisfactory performance of its obligations under this Market Agreement.

4.3 Prudent Utility Practice

Each of the Parties agrees that during the Term of this Market Agreement it will maintain and operate its generating equipment, transmission system or distribution system as appropriate in accordance with Prudent Utility Practice.

4.4 Dispatch

4.4.1 Operation

Generation and Distribution Companies agree to operate their plant and equipment in accordance with dispatch instructions issued by the System Operator, subject to the Operating Capabilities of plant and equipment and Prudent Utility Practice.

4.4.2 Dispatch Instructions

The System Operator shall dispatch generation and distribution plant and equipment by means of Dispatch Notices given in accordance with Schedule H.2, and shall give GenCos and DisCos the maximum possible notice of required load changes and switching requirements. Subject to the Operating Capabilities of the plant and equipment concerned, a Party shall promptly operate its generation or distribution plant and equipment in accordance with each Dispatch Notice. A Party shall use best efforts to comply with each Dispatch Notice; provided, however, that the Party shall immediately notify TransysCo if, in the Party's opinion, the Party is unable to comply with such Dispatch Notice.

4.4.3 Economic Dispatch

The System Operator shall dispatch generating stations with the objective of meeting demand over the course of a year at the lowest cost.

4.4.4 Voltage and Frequency Standard

The System Operator shall use its best endeavours to dispatch generation and distribution plant and equipment to maintain frequency and voltage within the bounds established by the Grid Code. In the absence of a Grid Code the bounds shall be:

i) VOLTAGE: nominal voltage ± [6]%

ii) FREQUENCY: 50 Hz ± [2] Hz

4.4.5 Allocation of Delivered Energy

TransysCo shall deliver available electrical energy to Delivery Points in accordance with the agreed guidelines for power allocation in Schedule C.

4.5 Provision of Information

4.5.1 Planning

The Parties agree to provide such information to the System Operator as it may reasonably require to meet its economic dispatch, operational and planning requirements. In the absence of a Grid Code approved by the Regulator the Parties agree to exchange information in accordance with Schedule H.1.

4.5.2 Events

The Parties agree to inform the System Operator as soon as reasonably practicable of any events or conditions affecting or likely to affect their ability to comply with Dispatch Instructions.

4.5.3 Charges Model

GenCos, DisCos, TransysCo and other NBUs shall provide the Market Operator with such financial and other information as it shall require to operate the Charges Model.

4.5.4 Other Information

The Parties agree to provide the Market Operator with such information, including forecast demand, load and energy requirements, budget and cost information and actual metered quantities and accounting data, as it may reasonably require to carry out its role as described in section 9.1. Such information shall be provided in a timely manner, according to a timetable that will be prepared by the Market Operator and agreed by the Market Operation Committee.

5 BULK SUPPLY CHARGES

5.1 Charges Model Information

All NBUs shall provide the Market Operator with such market forecast information as it shall require to operate the Charges Model, of the type and form set out in Schedule D.

5.2 GenCo Charges

5.2.1 Fixed Capacity Charges

Fixed Capacity Charges shall be the total fixed costs for GenCos as set out in Schedule D.3.2.

5.2.2 Energy Charges

Energy Charges shall be the variable cost per MWh for each Generating Unit as set out in Schedule D.3.

5.3 TransysCo Charges

5.3.1 Transmission Services Charge

The Total Transmission Services Charge shall be as set out in Schedule .

5.4 Charges for DisCos

The Market Operator shall calculate charges for each DisCo, which shall comprise the following:

i) Fixed Generation Tariff, which will be applied to the Peak Demand in MW drawn during the Settlement Period;

ii) Variable Generation Tariff, which will be applied to the total Delivered Energy during the Settlement Period;

iii) Fixed Transmission Losses Tariff, which will be applied to Peak Demand;

iv) Variable Transmission Losses Tariff, which will be applied to Delivered Energy;

v) Fixed Transmission Charge, which will be applied to the Peak Load in MVA during the Settlement Period.

5.4.1 Fixed Generation Tariff

The Fixed Generation Tariff payable by a DisCo shall be calculated as follows.

$$\text{Fixed Generation Tariff} = (1 - \text{TLF}) \times \text{average capacity charge}$$

where the average capacity charge shall be the total sum payable to GenCos and IPPs by way of fixed and capacity-related charges divided by the sum total of Peak Demands forecast for all DisCos during the Settlement Period.

5.4.2 Fixed Transmission Losses Tariff

The Fixed Transmission Losses Tariff payable by a DisCo shall be calculated as follows.

$$\text{Fixed Transmission Losses Tariff} = \text{TLF} \times \text{average capacity charge}$$

where the average capacity charge is as defined in section 5.4.2 above

5.4.3 Variable Generation Tariff

The Variable Generation Tariff shall be equal to the total sum payable to GenCos and IPPs by way of variable charges for electrical energy, divided by the Total Generated Energy.

5.4.4 Variable Transmission Losses Tariff

The Variable Transmission Losses Tariff shall be calculated as follows:

$$\text{Variable Transmission Losses Tariff} = \text{Variable Generation Charge} \times \frac{\text{TLF}}{(1 - \text{TLF})}$$

5.4.5 Fixed Transmission Services Tariff

The Fixed Transmission Services Tariff shall be the Total Transmission Services Charge divided by the sum total of Peak Demands forecast for all DisCos during the Settlement Period

5.4.6 Ancillary Services

The charge for any Ancillary Services received by TransysCo during the Settlement Period shall be deemed to be included in the Fixed Generation Tariff.

5.5 Bulk Supply Charges Schedule

At least fifteen (15) days prior to the beginning of each Settlement Period, the Market Operator shall prepare a Bulk Supply Charges Schedule for each NBU in the format set out in Schedule E.1, based on forecast information provided by the NBUs in accordance with section 5.1.

6 CASH TRANSFERS

6.1 Bank Accounts

6.1.1 Bank Accounts of the Market Operator

The Market Operator shall prior to the Commencement Date establish a bank account, the Remittance Account, for the settlement of payments among the Parties.

The Market Operator shall also prior to the Commencement Date establish bank accounts for the receipt of revenues from DisCos, to be known as Collection Accounts, and shall advise DisCos of the relevant account names and numbers and names of the banks prior to the Commencement Date.

6.1.2 Bank Accounts of the Parties

Each of the NBUs shall advise the Market Operator within one week of the Commencement Date of the details of their bank accounts into which payments shall be made by the Market Operator in accordance with the terms of this agreement.

6.2 Cash Payments

6.2.1 DisCo Revenues

DisCos shall pay all cash collections and other revenues into the Collection Accounts set up by the Market Operator.

6.2.2 Cash Allocation

At least fifteen (15) days prior to the beginning of each Settlement Period, the Market Operator shall calculate the cash allocation to each NBU in accordance with the cash allocation rules in Schedule F as determined by the Market Operation Committee. The Market Operator shall include the cash allocation in the Bulk Supply Charges Schedules notified to NBUs.

6.2.3 Standing Orders

At least seven (7) days prior to the beginning of each Settlement Period, the Market Operator shall notify the relevant bank of the payments to be made from the Remittance Account to the bank account of each NBU on the 15th and last days of each month of the Settlement Period. The amount of each standing order shall be the cash allocation for the relevant NBU as determined in section 6.2.2 above.

The Market Operator shall also implement standing orders to transfer cash from the Collection Accounts to the Remittance Account on a regular basis.

6.2.4 Cash Allocation Shortfall

If the balance of the Remittance Account is insufficient to meet the sum of cash allocation standing orders as determined above, all standing orders shall be reduced by the same percentage such that the sum of the payments to be made equals the balance in the Remittance Account. The shortfall will be accounted for as a Cumulative Cash Shortfall.

6.2.5 Cash Allocation Surplus

If the balance of the Remittance Account is above that required to meet the cash allocation standing orders as determined from the Charges Model further payments shall be made in the following order of priority to:

i) clear outstanding payments due to NBUs up to the Cumulative Cash Shortfall, which shall be reduced by the amount paid;

ii) incentive payments to DisCos to be set aside and paid at the end of each year;

iii) NEPA Headquarters for further allocation to a Contingency Fund and to an Investment Account set up for the purpose of funding necessary investment to improve the quantity, quality and reliability of electricity supplied to consumers in Nigeria (*Alternative C*);

iv) in proportion to the cost of service, including depreciation and return on assets as determined by the Charges Model and actual metered quantities measured in accordance with Section 7 (*Alternative B*).

7 DETERMINATION OF QUANTITIES

7.1 Metering Points

For purposes of measurements, each Party acknowledges that its Metering Points are those specified in Schedule B. A Party and TransysCo shall agree on any additions or changes to that list of Metering Points one (1) month prior to any such additions or changes occurring.

7.2 Standards for Metering Equipment

The specification, installation and maintenance of Metering Equipment shall conform to the standards specified in the Grid Code or in the absence of a Grid Code pursuant to Schedule B.

7.3 Meter Data Collection

Within seven (7) days after the end of a Settlement Period TransysCo shall provide meter data for the Settlement Period to the Market Operator for the purposes of settlement. The meter data to be supplied shall comprise Net Electricity Generated, Delivered Energy, Peak Demand and Peak Load for each Metering Point in each Metering Period.

7.4 Generated Energy

The Net Electricity Generated in MWh produced by a Generating Unit during the Settlement Period shall equal the sum of the Electricity generated by that unit less Auxiliary Load consumed by that unit during each Metering Period and aggregated over the Settlement Period. Metered loads of plant and equipment that are required to operate the Power Station or are otherwise consumed by that Power Station but that cannot be properly assigned to a specific Generating Unit will be summed over the Settlement Period and deducted from the Generating Unit output in proportion of the Electricity Generated by that Generating Unit to the total Electricity Generated by the Power Station in the Settlement Period.

7.5 Reactive Energy

The reactive energy in MVArh for the Settlement Period shall also be recorded for each Metering Point. MVArh leading and MVArh lagging shall both be recorded.

7.6 Delivered Energy

The Delivered Energy in MWh received by a DisCo shall be the sum of the energy metered at all of the DisCo's Delivery Points listed in Schedule B.2 during each Metering Period and aggregated over the Settlement Period. Electricity inflows to a DisCo shall be considered for settlement purposes as positive, and Electricity outflows as negative.

7.7 Peak Demand

The total demand received by a DisCo during each Metering Period shall be the sum of the Electricity metered at all of the DisCo's Delivery Points listed in Schedule B.2. The Peak Demand of such DisCo shall be the highest value of total demand recorded during any Metering Period in the Settlement Period, divided by the duration of a Metering Period in hours. Electricity inflows to a DisCo shall be considered for settlement purposes as positive, and electricity outflows as negative.

7.8 Peak Load

The maximum load in MVA during a Settlement Period shall be determined for each Delivery Point. The Peak Load for each DisCo shall be the sum of the maximum load recorded during the Settlement Period at each of its Delivery Points listed in Schedule B.2. Electricity inflows to a DisCo shall be considered for settlement purposes as positive, and electricity outflows as negative.

7.9 Transmission Loss Factor

The Transmission Loss Factor (TLF) shall be calculated for each Settlement Period as follows:

$$\text{Transmission Loss Factor} = 1 - \frac{\text{Total Delivered Energy}}{\text{Total Generated Energy}}$$

where:

Total Delivered Energy shall be the sum of all Delivered Energy received by DisCos during the Settlement Period.

Total Generated Energy shall be the sum of Net Electricity Generated from all GenCos and IPPs during the Settlement Period.

8 SETTLEMENT

8.1 Data Notification

All NBUs shall submit meter and financial data for settlement to the Market Operator within fifteen (15) days after the end of the Settlement Period. The data shall be of the same types and in the same format as stated in Schedule D.

The payment due to IPPs for fixed and capacity-related costs shall be determined by NEPA HQ in accordance with the terms of their Power Purchase Agreements and notified to the Market Operator within fifteen (15) days after the end of the Settlement Period.

8.2 Recalculate Bulk Supply Charges

Within twenty-one (21) days of the end of each Settlement Period the Market Operator shall recalculate the Bulk Supply Charges using the actual metered quantities as determined in accordance with Section 7.

8.3 Reconciliation

8.3.1 DisCo Payments Due

The Market Operator shall calculate the total payments due from each DisCo as follows:

i) Fixed Generation Charge = Fixed Generation Tariff x Peak Demand

i) Fixed Transmission Losses Charge = Fixed Transmission Losses Tariff x Peak Demand

ii) Variable Generation Charge = Variable Generation Tariff x Delivered Energy

iii) Variable Transmission Losses Charge = Variable Transmission Losses Tariff x Delivered Energy

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iv) Fixed Transmission Services Charge = Fixed Transmission Services Tariff x Peak Load

8.3.2 Payments due to GenCos

The payment due to GenCos and IPPs for fixed and capacity-related costs shall equal the amounts notified in accordance with section 8.1.

The Market Operator shall calculate energy payments due to GenCos and IPPs as the product of the Net Electricity Generated for a Generating Unit and the variable cost for that unit as notified in accordance with section 8.1.

8.3.3 Payments due to TransysCo

The payment due to TransysCo shall equal the amounts notified in accordance with section 8.1.

8.3.4 Cash Allocation Adjustment

The Market Operator shall re-calculate the cash allocation to each NBU for the Settlement Period in accordance with the cash allocation rules in Schedule F as determined by the Market Operation Committee. Any difference compared with the cash allocation calculated prior to the Settlement Period shall be carried forward to the next Bulk Supply Charges Schedule to be issued by the Market Operator.

8.4 Statements of Account

Within thirty (30) days after the end of a Settlement Period the Market Operator shall issue to each Party a Statement of Account for the Settlement Period, including its electricity received, transmitted or generated as may be and the resulting payments due to or payable by the Party in relation to the previous Settlement Period. The Statements of Account to each Party shall be in the relevant format specified in Schedule E.2.

9 MARKET OPERATION & MANAGEMENT

9.1 The Market Operator

The role of the Market Operator is to administer effectively this Market Agreement in accordance with the terms and conditions. The activities of the Market Operator shall include the following and other activities as may be determined by the Market Operation Committee:

i) calculating charges payable to TransysCo and Generation Companies according to the Charges Model.

ii) enabling settlement by effecting the transfer of cash among the Parties in accordance with the Charges Model.

9.2 Market Operation Committee

9.2.1 Role of the Market Operation Committee

The Parties shall establish a Market Operation Committee, whose purpose shall be to:

i) define the terms of reference for the Market Operator;

ii) ensure the efficient administration of the Market Agreement;

iii) resolve disputes among the Parties insofar as they arise from the application of this agreement;

iv) make such changes to this agreement as shall promote efficient operation by the Parties;

v) be a forum for the discussion of matters of mutual interest, with special regard to the development of the electricity market in Nigeria, market pricing, the promotion of competition, regulation of the electricity industry and investments required to meet future demand.

9.2.2 Membership of the Market Operation Committee

The membership of the Market Operation Committee shall comprise one member nominated by each of the following:

Market Operator

TransysCo

Regulator

Finance & Accounts

Distribution Companies

Generation Companies

The members shall elect a Chairman who shall serve for a period of one year. The chairmanship shall rotate between representatives of Transmission, Distribution and Generation Companies. The Chairman shall appoint a Secretary to the Committee.

If a member is unable to attend a meeting, a substitute may be nominated to take his/her place, who shall be able to exercise the same rights of participation and voting in the meeting.

9.2.3 Procedures

The Market Operation Committee shall develop procedures for the smooth running of the committee, in particular voting procedures that permit effective decision-making whilst protecting the rights of minority members.

10 REGULATORY APPROVAL

The Parties agree that the terms and conditions set out in this Agreement and any modifications made thereto pursuant to Section 11 may be subject to review and approval by the Regulator. To the extent that the Regulator shall withhold approval of any term or condition set out in this Agreement, the Parties shall make reasonable endeavours to negotiate and agree to such terms and conditions that shall receive approval by the Regulator.

11 CHANGES

11.1 *Agreement of Rates*

The energy and capacity charges in this Market Agreement shall be revised each quarter by the Market Operation Committee, and Schedule E shall be amended accordingly. In the event of a failure to agree as determined by the procedures of the Market Operation Committee (Section 9.2.3) the dispute shall be referred to the Regulator for determination in accordance with Section 12.3.

11.2 Changes to contract terms and conditions

The Parties may agree to change the terms and conditions of this Market Agreement. Any Party may propose a change, which shall be discussed by the Market Operation Committee. The implementation of a change to the terms and conditions of this agreement shall require a two-thirds majority of the Market Operation Committee to vote in favour. The Parties agree that any such changes may be subject to review and approval by the Regulator in accordance with Section 10.

11.3 *Incentives*

The Parties may in future agree to incentives related to generation availability, unit heat rate, peak demand requirements and other indicators relating to the performance of any or all of the Parties. The form of such incentives shall be agreed by the Market Operation Committee and this Market Agreement shall be amended accordingly.

11.4 Future Agreements

This Market Agreement shall be amended in accordance with Section 11.2 to take account of payments made under Connection Agreements and Use of System Agreements and of incentives associated with such agreements when such agreements come into effect.

This Market Agreement shall also be amended in accordance with Section 11.2 to take account of the terms and conditions, including charges, of Ancillary Services Agreements.

12 BOILERPLATE:

12.1 Communications and Notices

Except as otherwise expressly provided in this Agreement or required by law, all notices, consents, requests, demands, approvals, authorizations and other communications provided for in this Agreement shall be in writing and shall be sent by personal delivery, certified mail, return receipt requested, facsimile transmission or by recognized overnight courier service, to the intended Party at such Party's address set forth in Schedule A. Any notices that may be given orally and are given orally shall be confirmed in writing. All such notices shall be deemed to have been duly given and to have become effective:

i) upon receipt if delivered in person or by facsimile, including oral instructions that are later confirmed in writing;

ii) two (2) days after having been delivered to a courier for overnight delivery.

12.2 Default

The Market Operation Committee shall be responsible for developing and administering procedures for default by one or more Parties to the Agreement.

12.3 Dispute Resolution

(i) by Market Operation Committee

(ii) by the Regulator

12.4 Governing Laws

This Agreement and the rights and obligations hereunder shall be interpreted, construed and governed by the laws of the Republic of Nigeria and the Parties irrevocably submit to the jurisdiction of the courts of Nigeria.

12.5 Force Majeure

12.5.1 Notification Obligations

If by reason of a Force Majeure Event a Party is wholly or partially unable to carry out its obligations under this Agreement, the affected Party shall give TransysCo or TransysCo shall give the affected Party as appropriate notice of the Force Majeure Event as soon as practicable, but in any event, not later than forty-eight (48) hours after the affected Party becomes aware of a Force Majeure Event.

12.5.2 Duty to Mitigate

The affected Party shall use all reasonable efforts to mitigate the effects of a Force Majeure Event, including, but not limited to, the payment of reasonable sums of money by or on behalf of the affected Party, which sums are reasonable in light of the likely efficacy of the mitigation measures.

12.5.3 Delay Caused by Force Majeure Event

So long as the affected Party has at all times since the occurrence of the Force Majeure Event complied with the obligations of Section 12.3 and continues to so comply, then the affected Party shall not be liable for any failure or delay in performance of its obligations during the existence of such Force Majeure Event.

12.6 Limitations of Liability

12.6.1 General

No Party shall be liable to another Party in contract, tort, warranty, strict liability or any other legal theory for any indirect, consequential, incidental, punitive or exemplary damages. No Party shall have any liability to another Party except pursuant to, or for breach of, this Agreement; provided, however, that this provision is not intended to constitute a waiver of any rights of one Party against another with regard to matters unrelated to this Agreement or any activity not contemplated by this Agreement.

12.6.2 Indemnification for Fines and Penalties

Any fines or other penalties incurred by a Party for non-compliance with laws of Nigeria shall not be reimbursed by any other Party but shall be the sole responsibility of the non-complying Party.

12.7 Operating Records

12.7.1 GenCo Operating Records

For a period of thirty-six (36) months from creation of the records, each GenCo shall maintain and make available for audit by the Market Operation Committee or such persons that the Market Operation Committee may appoint complete Operating Records for each Generating Unit. Such records shall include:

i) information for each Metering Period on delivered Electricity (MWh) and delivered Reactive Energy (MVARh);

ii) the Maximum Capability in MW of each Generating Unit in each Metering Period;

iii) Power Station licenses and permits;

iv) copies of operating and/or maintenance agreements for the unit;

v) records of Scheduled Outages, Maintenance Outages and Forced Outages;

vi) records of maintenance, overhauls and inspections performed;

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vii) all backup documents required to support GenCo statements, invoices, charges and computations made pursuant to this Agreement.

12.7.2 TransysCo Operating Records

12.7.3 DisCo Operating Records

12.7.4 DisCo Operating Records

12.7.5 Maintenance of Operating Records

All Operating Records and data shall be maintained for a minimum of thirty-six (36) months after the creation of such record or data; provided, however, that each Party shall not dispose of or destroy any such records after such thirty-six (36) month period unless the Party desiring to dispose of or destroy any such records gives thirty (30) days prior written notice to the other Party, generally describing the records to be destroyed or disposed of, and the Party receiving such notice does not object thereto in writing within ten (10) days.

12.7.6 Right to Audit

The Market Operation Committee may audit a Party's books, accounts and documents relating to invoices, statements, charges and computations no more frequently than once each calendar year, and only once following expiration or termination of this Agreement. The Market Operation Committee exercising its right to audit under this Section shall give the audited Party not less than thirty (30) days prior written notice of the audit. Books or records requested in any audit shall be available for inspection by the Market Operation Committee at the offices of the Party being audited between 9:00 A.M. and 3:00 P.M. on Business Days. Any audit under this Section shall be completed not more than thirty-six (36) months after the records were created. Any audit right herein shall be limited to the books and accounts of the Party and shall not extend to the books and accounts of the parent or any other affiliate of the Party. The expense of any audit shall be borne solely by the auditing Party. All information provided during the course of an audit shall be treated as confidential in accordance with section 12.8.

12.7.7 Obligations under Law

Nothing in this Agreement shall override any obligation a Party may have under applicable laws to maintain books and records for periods longer than thirty-six (36) months nor shall this Agreement override any obligation a Party may have to make books and records available for audit by the Nigeria Electricity Regulatory Commission or any other entity. Nothing in this Agreement is intended to limit in any manner the authority of Nigeria Electricity Regulatory Commission to audit the books and records of a Party or the manner in which such audit is noticed or conducted.

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12.8 Confidential Information

12.9 ASSIGNMENT

Neither Party shall assign any of its rights or obligations under this Agreement without the prior written consent of the other Party, which shall not be unreasonably withheld or delayed; provided, however, that in considering whether to give such consent, the creditworthiness and legal, technical and financial competency of the intended assigns shall be taken into account.

12.10 WAIVER OF RIGHTS

No waiver by a Party of any default or defaults by another Party in the performance of any of the provisions of this Agreement shall operate or be construed as a waiver in the future of any other or further default or defaults whether of a like or different character. Neither the failure by a Party to insist on any occasion upon the performance of the terms, conditions and provisions of this Agreement nor time or other indulgence granted by one Party to another shall act as a waiver of such breach or acceptance of any variation or the relinquishment of any such right or any other right hereunder, which shall remain in full force and effect. For the avoidance of doubt any waiver by a Party of the obligations of another Party shall be evidenced by a written statement signed by a duly authorized representative of such Party.

(Signature Pages Follow)

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13 SIGNATURE PAGES

IN WITNESS WHEREOF, the parties hereto have caused their duly authorised representatives to execute and deliver this Agreement as given below.

Party	Authorised Signature
	____________________ (signature for Party) name: ____________________ position: ____________________ date:
	____________________ (signature for Party) name: ____________________ position: ____________________ date:
	____________________ (signature for Party) name: ____________________ position: ____________________ date:

Schedules to the Market Agreement

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SCHEDULE A PARTIES TO THE MARKET AGREEMENT {TBC}

The Parties to this Market Agreement, their nominated representatives and contact details for Communications and Notices are:

Party	**Contact Details for Communications and Notices**
Market Operator	Nominated representative: name position Address: Fax:
Generation Companies	
Egbin Generating Company	
Delta Generating Company	
Shiroro Generating Company	
Kainji & Jebba Generating Company	
Afam Generating Company	
Sapele Generating Company	
Ajaokuta Generating Company	
Okitipupa Generating Company	
Papalanto Generating Company	
Licensee for IPP Purchases	blank
Transmission Company	
TransysCo:	
Distribution Companies	
Abuja Distribution Company	
Benin Distribution Company	
Enugu Distribution Company	
Ibadan Distribution Company	
Jos Distribution Company	
Kaduna Distribution Company	
Kano Distribution Company	
Lagos North Distribution Company	
Lagos South Distribution Company	
Port Harcourt Distribution Company	
Yola Distribution Company	
Unit responsible for Exports & HV Sales	blank

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SCHEDULE B METERING POINTS {TBC} (RESPONSIBILITY: GRID METERING)

This Schedule lists the Metering Points at the interfaces between the Transmission Network and Generation Companies and between the Transmission Network and Distribution Companies.

B.1 Generation Metering Points

This Agreement applies to the Power Stations listed below. The Metering Points between Generation Companies and TransysCo are listed below and identified on the single line electrical drawings included in this Schedule:

Power Station Name	Unit Reference	Generation Metering Point	Meter Details
Egbin	Unit 1	Meter ID. Drawing No.	Voltage: Meter type: Serial No. Metering accuracy: Date of last calibration/check: Reading Incidence: Metering Capability:
	Unit 2		
	etc.		

Technical Notes:

Meter ID (meter identification): Each meter shall have a unique reference number, sufficient to uniquely define the meter.

Meter Details:

- Voltage is the nominal voltage of the line being metered, e.g. 33kV.
- Meter type is the class of meter, e.g. Class 1
- Metering accuracy is the overall accuracy of the metering installation, i.e. meter plus voltage and current transformers.
- Reading Incidence is the frequency at which readings are taken and stored, e.g. hourly.
- Metering Capability: the measures which the meter is capable of recording, e.g. MWh, peak MW, peak MVA, MVArh.

ADD SINGLE LINE ELECTRICAL DRAWINGS FOR EACH POWER STATION SUB-STATION

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B.2 Delivery Points

This Agreement applies to the Injection Sub-Stations listed below. The Metering Points between Distribution Companies and TransysCo are listed below and identified on the single line electrical drawings included in this Schedule:

Injection Sub-Station Name	Feeder Reference	Delivery Point	Meter Details
		Reference: Drawing No.	Voltage: Meter type: Metering accuracy: Date of last calibration/check: Reading Incidence: Metering Capability:

ADD SINGLE LINE ELECTRICAL DRAWINGS FOR EACH INJECTION SUB-STATION

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SCHEDULE C LOAD ALLOCATION {TBC}

Rules for allocating limited resources of power among the DisCos.

SCHEDULE D MARKET FORECAST INFORMATION {TBC}

D.1 DisCo Data

D.1.1 Forecast DisCo Electricity Demand Period: ____________________

DisCo	sub-station / feeder name/ref.	Delivered Energy MWh	Peak Demand MW	Peak Load MVA
Abuja				
Benin				
Enugu				
Ibadan				
Jos				
Kaduna				
Kano				
Lagos North				
Lagos South				
Port Harcourt				
Yola				

Note some sub-stations supply more than one zone. The percentage split between the zones should be recorded here according to historical records until adequate grid metering data become available.

D.1.2 DisCo Budget / Cost Data

Period: ____________________

DisCo	Category 1 million Naira	Category 2 million Naira	Category 3 million Naira	Total million Naira
Abuja				
Benin				
Enugu				
Ibadan				
Jos				
Kaduna				
Kano				
Lagos North				
Lagos South				
Port Harcourt				
Yola				

D.2 TransysCo Data {TBC}

D.2.1 Transmission Losses

Period: ____________________

Transmission losses for the period are forecast at [__]%, expressed as a percentage of Net Electricity Generated.

D.2.2 TransysCo Budget / Cost Data

Period: ____________________

	Category 1 million Naira	Category 2 million Naira	Category 3 million Naira	Total million Naira
TransysCo				

D.3 GenCo Data

D.3.1 Generation MW and Capability {TBC}

GenCo	Power Station Name	Unit Reference	Installed Capacity MW	Unit Capability * MW	Availability during Period
Egbin	Egbin	Unit 1 …			
Delta					
Shiroro					

GenCo	Power Station Name	Unit Reference	Installed Capacity MW	Unit Capability * MW	Availability during Period
Kainji & Jebba					
Afam					
Sapele					
Ajaokuta					
Okitipupa					

Notes:

- * Unit Capability = current capacity of a Generating Unit

D.3.2 GenCo Budget / Cost Data – Fixed Costs

Period: ____________________

GenCo	Category 1	Category 2	Category 3	Total
Egbin				
Delta				
Shiroro				
Kainji & Jebba				
Afam				
Sapele				
Ajaokuta				
Okitipupa				
Papalanto				

D.3.3 GenCo Budget / Cost Data – Variable Costs

Period: ____________________

GenCo	Power Station Name	Unit Reference	Variable cost* Naira per MWh
Egbin	Egbin	Unit 1 …	
Delta			
Shiroro			
Kainji & Jebba			
Afam			
Sapele			
Ajaokuta			
Okitipupa			
Papalanto			

* Variable cost per MWh of Net Electricity Generated

D.4 IPP Data {TBC}

D.4.1 Generation MW and Capability

Period: ____________________

IPP	Power Station Name	Unit Reference	Installed Capacity MW	Unit Capability * MW	Availability during Period
Abuja EPP – Aggreko	1	1	5	5	100%
		2	5	5	100%
		3	5	5	100%
	2	1	5	5	100%
		2	5	5	100%
		3	5	5	100%
Abuja EPP – Geometric					
AES	Lagos Barge				
Shell	Afam				

Notes:

- * Unit Capability = current capacity of a Generating Unit

D.4.2 IPP Cost Data

Period: ____________________

GenCo	Fixed / Capacity Charge million Naira	Variable Cost per unit Naira per MWh	Net Electricity Generated MWh
Abuja EPP – Aggreko			
Abuja EPP – Geometric			
AES			
Shell			

Notes:

- The Fixed / Capacity Charge is the amount that is expected to be payable, taking into account unavailability, Liquidated Damages, etc.
- Net Electricity Generated is the amount that the IPP is expected to generate, taking into account minimum take requirements and expected unavailability through Forced Outages, Scheduled Outages and Maintenance Outages.

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D.5 Headquarters NBU Data {TBC}

D.5.1 Headquarters Budget / Cost Data

Period: ____________________

Headquarters NBU	Category 1 million Naira	Category 2 million Naira	Category 3 million Naira	Total million Naira
MD Sector				
F&A				
CP&S				
Distribution & Marketing HQ				
Generation HQ				

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SCHEDULE E BULK SUPPLY CHARGES {TBC}

E.1 Bulk Supply Charges Schedule

E.1.1 Bulk Supply Charges Schedule for DisCos

Issued by the Market Operator **Date**

company name
FAO contact
address details

Bulk Supply Charges Schedule for Period ________________

Item	**Unit**	**Forecast requirement**	**Price per unit Naira**	**Forecast payments million Naira**
Delivered Energy	MWh			
Peak Demand	MW			
Peak Load	MVA			
			Total forecast	

Cash Allocation Summary

Forecast transfer from Collection Account	
Cash allocation to designated DisCo Account	

E.1.2 Bulk Supply Charges Schedule for GenCos and TransysCo

Issued by the Market Operator **Date**

company name
FAO contact
address details

Cash Allocation Summary

Forecast transfer from Collection Account	
Cash allocation to designated DisCo Account	

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E.2 Statements of Account

E.2.1 Statement of Account for DisCos

Issued by the Market Operator **Date**

company name
FAO contact
address details

Statement of Account for Period ________________

Item	**Unit**	**Units used**	**Price per unit Naira**	**Amount due million Naira**
Delivered Energy	MWh			
Peak Demand	MW			
Peak Load	MVA			
			Total due	
			Amount received	
			Amount overdue	

Cash Transfer Summary

from Collection Account	
to designated DisCo Account	

Note: the amount received will be equal to the cash transferred from the Collection Account less the cash transferred to the DisCo Account. The amount overdue will be equal to the total due less the amount received.

E.2.2 Statement of Account for GenCos

E.2.3 Statement of Account for TransysCo

E.2.4 Statement of Account for Licensee for Purchases from IPPs

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E.2.5 Statement of Account for Headquarters New Business Units

SCHEDULE F CHARGES MODEL AND CASH ALLOCATION RULES {TBC}

How Bulk Supply Charges are determined, and rules for cash allocation among the NBUs.

SCHEDULE G GRID METERING CODE {TBC}

In the absence of a Grid Metering Code, whether or not as part of the Grid Code, this Schedule shall apply, in accordance with Section 7.2. The standards in this Schedule establish the requirements for metering the Active (MWh) and Reactive (MVARh) energy, and the Active (MW) and Reactive (MVAR) Demand at each Metering Point.

G.1 General

G.1.1 Responsibilities of the Parties

It shall be the responsibility of GenCos, DisCos and TransysCo to demonstrate that their Metering Equipment meets all the technical requirements and standards set forth in this Schedule. TransysCo and the Metered Party shall accept a Metering Point only if they are both satisfied that all the relevant requirements of this Schedule are met.

G.1.2 Metering Equipment Security

TransysCo shall take all reasonable steps to prevent unauthorized interference with Metering Equipment and shall provide seals and other appropriate devices to prevent unauthorized alteration of site settings and calibrations. The Metering Equipment cubicles shall be completely and securely locked and sealed and any register on equipment shall be visible and accessible. TransysCo shall also provide appropriate security against unauthorized access and against corruption of data in transmission.

G.2 Location Principles:

G.2.1 Generation grid meters

Generation grid meters shall be installed so as to enable the Net Electricity Generated of a Generating Unit and Power Station to be measured. The interface between the Transmission or Distribution Network, as appropriate, and the Generating Unit shall be the network (high voltage) side of the HV bushing of the generator transformer.

G.2.2 Distribution grid meters

Distribution grid meters at injection sub-stations shall be located at the distribution voltage side of the transformer.

G.2.3 Electricity and Reactive Power Metering

Integrating pulse meters shall be provided at every Metering Point to record Electricity, Peak Demand and Peak Load data (measurement units MWh, MW and MVA respectively) for use in market settlement.

G.3 Minimum technical specification

G.3.1 General

The Metering Equipment at the Metering Point shall consist of:

i) Instrument transformers;

ii) Lightning protection;

iii) Revenue class meters;

iv) Integrating pulse recorder(s) and time source;

v) All interconnecting cables, wires and associated devices, i.e., test blocks, pulse repeaters, loading resistors, etc.; and clocks.

G.3.2 Voltage Transformers

The voltage transformers shall comprise three (3) units for a three-phase set, each one of which complies with international standard IEC 186 for metering and is of the 0.5 accuracy class or better. These voltage transformers shall be connected wye-wye with both star points grounded to a ground grid of acceptable resistance and shall provide a four-wire secondary connection.

The voltage drop in each phase of the voltage transformer connections of the same accuracy and class shall not exceed 0.2V. It shall be connected only to a meter with a burden that shall not affect the accuracy of measurement.

G.3.3 Current Transformers

The instrument current transformers shall comprise three (3) units for a three-phase set, each one of which complies with international standard IEC 185 for metering and is of 0.5 accuracy class or better. It is preferred that two current transformer cores with corresponding number of secondary coils per phase be provided between the connection box and the terminal of the metering element on the meter so that the current transformer connections for checking meter pulses can be completely separated from those provided for the revenue meters of this Schedule. . The current transformer preferred rated secondary current output shall be either 1 or 5 amperes. The neutral conductor shall be effectively grounded at a single point and shall be connected only to a meter with a burden that shall not affect the accuracy of measurement.

G.3.4 Integrating Pulse Meters

Meters shall be of the three-element type rated for the required site, comply with IEC 687 for static watt-hour meter or international standard IEC 521 for other types and be of the accuracy class of 1 or better. These meters shall be rated for use on a 3-phase, 4-wire, 50 Hz system, even if applied to a three-phase three-wire system. The meters shall measure and locally display at least the MW, MWh, MVA, MVArh and cumulative demand, with the features of time-of-use, outage records and pulse output.

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A cumulative record of the parameters measured shall be available on the meter. Bi-directional meters shall have two (2) such records available. If combined Active and Reactive Power meters are provided, then a separate record shall be provided for each measured quantity and direction. The loss of auxiliary supply to the meter shall not erase these records.

Pulse output shall be provided for each measured quantity. The pulse output shall be from a 3-wire terminal with pulse duration of the range 40 to 80 milliseconds (preferably selectable) and with selective pulse frequency or rate. The minimum pulse frequency shall comply with IEC 338 for the shortest integration period and the accuracy class of the meter. Pulse output shall be galvanically isolated from the voltage/current transformers being measured and from the auxiliary supply input terminals. The insulation test voltage shall be 1000VAC, 50Hz and applied for one minute.

All Integrating Pulse Meters shall be capable of electronic downloading of stored data or manual on-site interrogation.

All Integrating Pulse Meters shall have fail safe storage for at least two (2) months of integrated demand data and be capable of retaining readings and time of day for at least two (2) days without an external power source.

G.3.5 Integrating Pulse Recorders

Integrating Pulse Recorders shall be capable of recording integrated demand periods adjustable between fifteen (15) minutes and sixty (60) minutes.

Each recorder shall be capable of electronic data transfer through dedicated telephone lines or TransysCo's communication channels or manual downloading of data on-site.

The integrating pulse recorders shall provide a record for reference at a future time. The record shall be suitable for reference for a period of at least one (1) year after it was generated. The integrating pulse recorder shall be regularly interrogated and the record shall also be maintained at the recorder for two (2) complete Settlement Periods between one (1) interrogation or sixty (60) days, whichever is longer.

The time reference used with the demand recorder shall ensure that the demand period accuracy of this integrating pulse recorder is with a time error of no more than ±1 second.

All revenue metering installations shall record time based on Nigerian standard time.

The start of each demand period shall be within ± 30 seconds of the standard time.

Reprogramming of integrating pulse recorders shall be done immediately if time error exceeds two (2) minutes and within three (3) months if time error exceeds one (1) minute.

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G.4 Testing and Maintenance

G.4.1 Instrument Transformers

Test on the instrument transformers shall be done by a party authorized by TransysCo and Metered Party at least once every five (5) years or as the need arises due to questions on accuracy. The tests shall be carried out in accordance with this Schedule or an agreed equivalent international standard.

G.4.2 Instrument Transformer Burdens

Instrument transformers shall not be connected to a load beyond its rated burden and shall be operated at the optimum burden range to achieve maximum accuracy of the metering system. Regular testing of compliance as to the burden shall be done at least once a year. Loading resistors for compensating low burdens may be allowed as long as accuracy level is sustained.

G.4.3 Meters

TransysCo and Metered Party shall test and seal the meters at least once a year and recalibrate or replace such meters if found to be outside the acceptable accuracy stipulated in this Schedule.

G.4.4 Request for Test

TransysCo or Metered Party may request a test of installed metering equipment if they have reason to believe that the performance of the equipment is not within the accuracy limits set forth in this Schedule. The test shall be done by an independent party authorized by the Regulator. If the meter equipment fails the test, the Party who owned the metering equipment shall be responsible for the costs of the test. If the meter equipment passes the test, the Party who requested the test shall pay for the test costs.

G.4.5 Maintenance

The Primary and Backup Metering Equipment at the Metering Point shall be maintained by TransysCo and Metered Party, respectively. All test results, maintenance programs and sealing records shall be kept for the life of the equipment. The equipment data and test records shall be made available to authorized parties.

G.5 Meter Reading

G.5.1 General

TransysCo shall download integrating pulse metering data for billing and payment purposes. Metered Party shall be provided full access to the data for Metering Points.

G.5.2 Combination of Pulses

The pulses from two or more meters may be combined into one (1) integrating pulse recorder provided all the requirements of this Schedule are met. In each hour, one of the time periods shall commence on the hour. The meter pulses that need to be integrated into the recorder are:

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i) Electricity (MWh) and Demand (MW);

ii) Reactive energy (MVArh);

iii) Load (MVA)

G.5.3 Onsite Meter Reading

Provisions shall be made by TransysCo to permit on-site as well as remote interrogation of the integrating pulse recorder. All the metering systems shall have the capability of electronic data transfer. During the transition period, on-site metering and manual data transfer shall be allowed. If on-site meter reading is necessary, it shall be witnessed by authorized representatives of all concerned Parties on the date and time stipulated in this Agreement.

G.5.4 Running Totals

Running totals of the Active and Reactive energy and Active and Reactive Demand shall be available for each measured quantity. Combined meters which measure both the Active / Reactive energy and Active / Reactive Demand output from the Grid shall have the running totals available for each measured quantity.

G.5.5 Primary Metering Equipment

Each GenCo shall ensure that the quantity of Electricity delivered to TransysCo pursuant to this Agreement shall be recorded by Primary Metering Equipment at each Metering Point.

G.5.6 Backup Metering Equipment

TransysCo may install, at its own cost, Backup Metering Equipment at any Metering Point where TransysCo receives Electricity; provided that such equipment shall not be installed in a manner that interferes with Primary Metering Equipment.

G.5.7 Check Metering Equipment

A metered Party may install, at its own cost, Metering Equipment for checking purposes at any Metering Point or Receiving Point where a Party delivers Electricity; provided that such equipment shall not be installed in a manner that interferes with Primary Metering Equipment or Backup Metering Equipment.

G.5.8 Metering and Recording of Readings

Electricity (MWh) and Reactive Energy (MVARh) delivered and received from each Generating Unit or the Transmission Network shall be metered and recorded hourly at each Metering Point.

G.5.9 Preparation of Settlement Period Statement

In preparation of the Statement of Account for the Settlement Period, the quantity of Electricity, which is measured and stored hourly in the meters for the duration of the Settlement Period shall be recorded. Each Metered Party shall maintain a log, electronically or otherwise, of all such

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meter readings. Measurements recorded shall be delivered to TransysCo, electronically or manually within 48 hours.

G.5.10 Unavailability or Inaccuracy of Primary Metering Equipment

If Primary Metering Equipment is unavailable, fails or proves to be inaccurate pursuant to Section 4.13 such that there is, for a period, no or no sufficient measurement of the quantity of Electricity being delivered and received, the quantity of Electricity shall be measured or determined as follows:

G.5.11 Backup Metering Equipment

By Backup Metering Equipment or if such Metering Equipment should not exist or should prove to be inaccurate pursuant to Section 4.13 then

G.5.12 Check Metering Equipment

By reference to Party's Metering Equipment used for checking (if any) or if such check Metering Equipment should prove to be inaccurate pursuant to Section 4.13 then

G.5.13 By Agreement

By agreement between the Parties having regard to the degree of inaccuracy in Primary Metering Equipment or quantities of Electricity delivered and received at that Receiving Point during periods of similar conditions when Metering Equipment was functioning in a satisfactory manner.

G.5.14 Testing

Each Party shall at its own expense test or procure the testing of the Metering Equipment for which it is responsible and which is used for the purposes of this Agreement at least once every year and supply a certificate as to accuracy to the other Party within ten (10) Business Days of completion of the test. The Party carrying out the test shall give reasonable notice to the other Party, and shall give the other Party the opportunity to be present to witness the test. Either Party may, upon giving reasonable notice to the other Party, request a test of the other Party's Metering Equipment at any time during the term of this agreement, provided that such requests are limited to one (1) per year per Metering Point.

G.5.15 Sealing of Metering System

The meters and clocks of the Primary Metering Equipment and Back-Up Metering Equipment shall be sealed by Party and TransysCo jointly. Such seals shall be broken only by the Party responsible for such Metering Equipment and only for the purpose of Section 4.11 or 4.13. The other Party shall be given at least forty-eight (48) hours advance notice of the breaking of seals. Such notice shall specify the time at which a meter seal will be broken and the other Party shall be given the opportunity to be present when such seal is broken. Upon completion of any works pursuant to section 4.13 or testing pursuant to Section 4.11 the meter and clocks of Primary Metering Equipment and Back-Up Metering Equipment shall be re-sealed if such seals were broken.

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G.5.16 Repair, Replacement or Recalibration of Metering Equipment

When any component of Primary Metering Equipment is found to be outside acceptable limits of accuracy or otherwise not functioning properly, Party shall forthwith repair, recalibrate or replace such component of Primary Metering Equipment at its expense. Similarly, when any component of Back-up Metering Equipment is found to be outside acceptable limits of accuracy or otherwise not functioning properly, TransysCo shall forthwith repair, recalibrate or replace such component of Back-Up Metering Equipment at its expense. Upon the completion of any maintenance or repair , or replacement of any component in, Primary Metering Equipment or Back-Up Metering Equipment, the Metering Equipment shall be recalibrated. Upon completion of recalibration the Metering Equipment shall be tested.

G.5.17 Rights of Access

G.5.17.1 Rights of Access

TransysCo and a metered Party shall each, within reason, allow the other to have a right of access to read Metering Equipment and shall take all necessary steps to ensure that its employees and contractors do not tamper with Metering Equipment, and shall immediately notify the other Party upon becoming aware of any such tampering.

G.5.17.2 Authorized Representatives of Party and TransysCo

For purpose of Section G.5.17.1, the term "Party" shall be deemed to include the employees and authorized agents and contractors of the metered Party and the term "TransysCo" shall be deemed to include the employees and authorized agents and contractors of TransysCo.

G.5.17.3 Metering Equipment on Party's Property

Where Backup Metering Equipment at any Metering Point is or is proposed to be located on any property owned or occupied by Party, Party hereby grants to TransysCo authority to install, test, maintain, read, inspect, replace, repair, operate or remove Backup Metering Equipment all under the supervision and in accordance with the procedures of the Party together with reasonable rights of access to such property in accordance with Section XXX. Such right of access shall extend to removal by TransysCo of Backup Metering Equipment at any time following the Termination Date.

G.5.17.4 Right of Access to Party's Property

The following shall apply to the rights of access conferred by Section XXX:

where practicable, TransysCo shall give Party reasonable notice of the work TransysCo proposes to undertake and shall request permission from Party, which shall not unreasonably be withheld;

in carrying out such work, TransysCo shall minimize the inconvenience to Party to the fullest extent possible and shall observe safe working practices and Party's safety procedures at all times; and

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ownership of all Metering Equipment installed or previously installed by TransysCo or on TransysCo's behalf on Party's property shall remain the property of TransysCo or of its agent or assigns as the case may be.

G.5.17.5 Rights of Access to TransysCo's Property

Party shall, subject to the terms and conditions as apply to TransysCo under Sections XXX and XXX (with the necessary amendments), have the same rights of access to any property owned or occupied by TransysCo where any Primary Metering Equipment or Check Metering Equipment used to determine Electricity delivered by Party is presently or is proposed to be located, for the purpose of installation, maintenance, testing or verification of the same.

G.5.17.6 Right of Access to View Metering Equipment of Other Customers of Party

If Party is delivering Electricity to any other party and the determination of the quantity of Electricity delivered and received by TransysCo is affected by the delivery to the other party, Party shall use its reasonable endeavors to allow TransysCo to view or read the metering equipment used to measure the Electricity delivered to any such other party.

G.5.18 Connection and Disconnection

Once installed, only persons jointly authorized by the metered Party and TransysCo shall be permitted to connect, disconnect, unseal or undertake any activity involving Primary Metering Equipment.

SCHEDULE H SYSTEM OPERATOR {TBC}

H.1 Information Requirements

In the absence of a Grid Code, the exchange of information between the Parties shall be governed by this Schedule.

H.1.1 Minimum Technical Standards

TransysCo shall define the minimum technical standards for all plant and equipment that is to be connected to the Transmission Network.

H.1.2 Operating Capabilities

H.1.2.1 As Installed

Gencos and DisCos shall advise TransysCo of the as-installed operating capabilities and other parameters of plant and equipment in the format that TransysCo shall specify.

H.1.2.2 Notification

Gencos and DisCos shall advise TransysCo immediately of any changes to the operating capabilities and other parameters of plant and equipment.

H.1.3 Forecasts

Quarterly Forecast of DisCos' Requirements for Electricity

No later than thirty (30) days before the beginning of a Settlement Period each DisCo shall provide TransysCo and the Market Operator with a non-binding forecast representing its then current best estimate of monthly Electricity and monthly peak day capacity for the Settlement Period. TransysCo shall aggregate the forecasts of DisCos' requirements for Electricity and add its best estimate of expected transmission losses to determine TransysCo's Requirements for Electricity.

Monthly Forecast

Weekly Forecast

Day-Ahead Forecast

H.1.4 Outage Planning

H.1.4.1 Gencos

Scheduled Outages

GenCos shall be entitled to take a Generating Unit out of operation or reduce the operating capability of the unit to repair and/or maintain the unit. The dates and times of the outages and any changes to those dates and times shall be determined in accordance with this Section.

Submission of Scheduled Outages Programme

Each GenCo shall provide to TransysCo, by July 1 of each year, its proposed Programme of Scheduled Outages for all its Generating Units for the next Calendar Year.

TransysCo Acceptance of Scheduled Outages Programme

Within forty-five (45) days following submission of a GenCo's proposed Programme of Scheduled Outages, TransysCo will issue a notice to the GenCo with its acceptance of the proposed Programme, or if unacceptable, TransysCo will revise the proposed Programme and issue a notice to the GenCo with a revised Programme of Scheduled Outages. The revised Programme will provide for Scheduled Outages of the same length, and as close to the proposed dates as possible. The Programme of Scheduled Outages included in this notification from TransysCo shall be designated as TransysCo Accepted Scheduled Outages Programme.

Revisions to TransysCo Accepted Scheduled Outages Programme

Subsequent to the issuance of an acceptance notice by TransysCo, either Party may request a revision to the TransysCo Accepted Scheduled Outages Programme by giving the other Party written notice of sixty (60) Days. For TransysCo requested revisions, GenCos shall use all reasonable effort to comply with the request. For GenCos requested revisions, TransysCo shall consider and approve such requests if they do not materially reduce reliability or increase the cost of meeting the anticipated requirements of DisCos.

Maintenance Outages

As and when a GenCo determines a need for a Maintenance Outage, the GenCo shall provide TransysCo with as much notice as possible. The GenCo shall provide information regarding duration of work, desired start date and time, and latest possible start date and time for such outage. TransysCo shall work with GenCos to schedule Maintenance Outages at times that have the lowest impact on system reliability, its ability to meet anticipated loads, and operating costs.

Forced Outages

GenCos shall have the right to interrupt, in whole or in part, delivery of Electricity and/or Ancillary Services from a Generating Unit for such time and to the extent that, in GenCo's judgment and in accordance with Prudent Utility Practices, operating conditions at the Power Station require such action or an adverse operating condition affecting the safety of the Generating Unit or other plant or personnel requires such action. As soon as practical, a GenCo shall give TransysCo notice of the occurrence of a Forced Outage, the expected extent and

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duration of the Forced Outage, the expected time when the Generating Unit shall be capable of resuming delivery of Electricity and/or Ancillary Services and the expected Operating Capabilities of the unit after the Forced Outage ends. The GenCo shall keep TransysCo informed of any developments that will affect either the duration of the Forced Outage or the Operating Capability of the Generating Unit during or after the end of the Forced Outage.

H.1.4.2 DisCos

DisCos shall advise TransysCo of changes to the anticipated demand at injection sub-stations arising from planned or forced outage of plant or equipment in the Distribution Network.

H.2 Dispatch Instructions

H.2.1.1 Recording of Telephone Communications

All Parties agree to allow all telephoned voice communications between Parties pertaining to the operation and Dispatch of Generating Units and/or distribution equipment to be recorded electronically. Any copies or transcripts of such recordings shall be supplied to the other Party pursuant to their request.

H.2.2 Generation Dispatch Procedure

Form, Format and Frequency of Communication with each Genco...

Quarterly Forecast of TransysCo's Requirements for Electricity

No later fifteen (15) days before the beginning of a Settlement Period, TransysCo shall provide each GenCo with a non-binding forecast representing TransysCo's then current best estimate of monthly Electricity and monthly peak day capacity that TransysCo will require each Generating Unit to provide each month during the next Settlement Period.

H.2.3 Load Allocation Procedure

Form, Format and Frequency of Communication with each DisCo.

H.3 Settlement Meter Data

TransysCo shall provide grid meter readings to the Market Operator for settlement purposes as follows:

i) Readings shall be provided for each grid meter, defined by its unique meter ID (see Schedule B). The readings shall be grouped for each DisCo or Generating Unit as appropriate.

ii) Readings shall be provided for each hour of the Settlement Period.

iii) By 12 noon on Thursday of each week TransysCo shall provide check grid meter readings for the week to 12 noon on Monday.

iv) By 12 noon of the fourth day following a *Settlement* Period TransysCo shall provide grid meter readings for the Settlement Period just ended.

By the seventh day of each Settlement Period the Market Operator shall send a statement of quantities to TransysCo, Gencos, the licensee for IPP purchases and DisCos.

Appendix B

Charges Model

Prepared for
National Electric Power Authority of Nigeria

Charges Model for the Nigerian Electricity Market

Submitted by
Nexant

April 2003

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Table of Contents

1. OVERVIEW OF CHARGES MODEL

This report presents the Bulk Supply Charges and Cash Allocation Model ("charges model"), which is used to determine charges and cash payment requirements between the New Business Units (NBUs) of NEPA that participate in the Nigerian wholesale electricity market. This report contains the following sections:

- Section 1 – provides an overview of the charges model.
- Section 2 – describes the concepts used in the model.
- Section 3 – provides sample outputs and results from the model.
- Section 4 – provides the mathematical formulation of the charge components.
- Section 5 – provides a user's guide to the model.

1.1 What is the Bulk Supply Charges & Cash Allocation Model?

During the transition stage wholesale electricity market there will be two pricing mechanisms, one for accounting-based *charges* from the GenCos and TransysCo to the DisCos and a separate mechanism for *cash allocations* to each NBU and to Corporate HQ. Charges will be based on full cost-of-service (CoS), including depreciation on revalued fixed assets and return on equity. Cash allocations will be based on a fair system to ration cash receipts from end customers according to greatest need company-wide.

The reason for a cash allocation mechanism separate from the charges is that end-use customer billing collections at present are below revenue requirements for expenses, debt service obligations and investment needs, the cash allocations to individual NBUs will be below their CoS. In consequence, DisCos will not be in a position to pay in full the bulk supply charges of GenCos and TransysCo.

The charges model is an Excel spreadsheet used to calculate:

- The allocation of HQ costs to each NBU;
- The Cost-of-Service (CoS) of each NBU;
- The bulk supply charges from GenCos and TransysCo to DisCos; and
- Cash allocations between all NBUs and cost centers at Corporate Headquarters.

The financial and technical data inputs to the model come from NEPA's approved quarterly budgets. The charges and cash allocations are set quarterly in advance by the Market Operator using the charges model. The cash allocations in turn set the cash standing orders payable on the 15th and end of each month.

1.2 Electricity Market Transactions

The Bulk Supply Charges & Cash Allocation Model determines the flow of revenues and cash payments among the following NBUs and cost centers of NEPA:

- The six GenCos plus the trading unit that purchases power from IPPs and Rehabilitate-Operate-Transfer Generating Stations ("ROTs")
- TransysCo
- The eleven DisCos
- The trading unit that sells to high voltage customers in the domestic market and abroad (treated as a shadow distribution company for the purposes of the model)
- The sector head offices and NEPA Corporate Headquarters (to become the Initial Holding Company (IHC) in the near future). The administration and overhead expenses of these cost centers are allocated to the operating NBUs: Sector HO costs are allocated to NBUs within the sector and HQ costs allocated amongst all NBUs.

The transition stage electricity market will consist of the following transactions:

- GenCos will sell electricity to DisCos for resale to end-use customers.
- A trading licensee will aggregate NEPA's IPP purchases and resell the power to the DisCos for resale to end-use customers. For the time being this function will reside in Corporate Headquarters.
- TransysCo will provide transmission services for the wheeling of power from the GenCos to the DisCos and HV customers.

Figure B-1 shows the framework for wholesale market transactions during the transition stage of the market. Table B-1 depicts all of the NEPA NBUs and cost centers, both existing and expected.

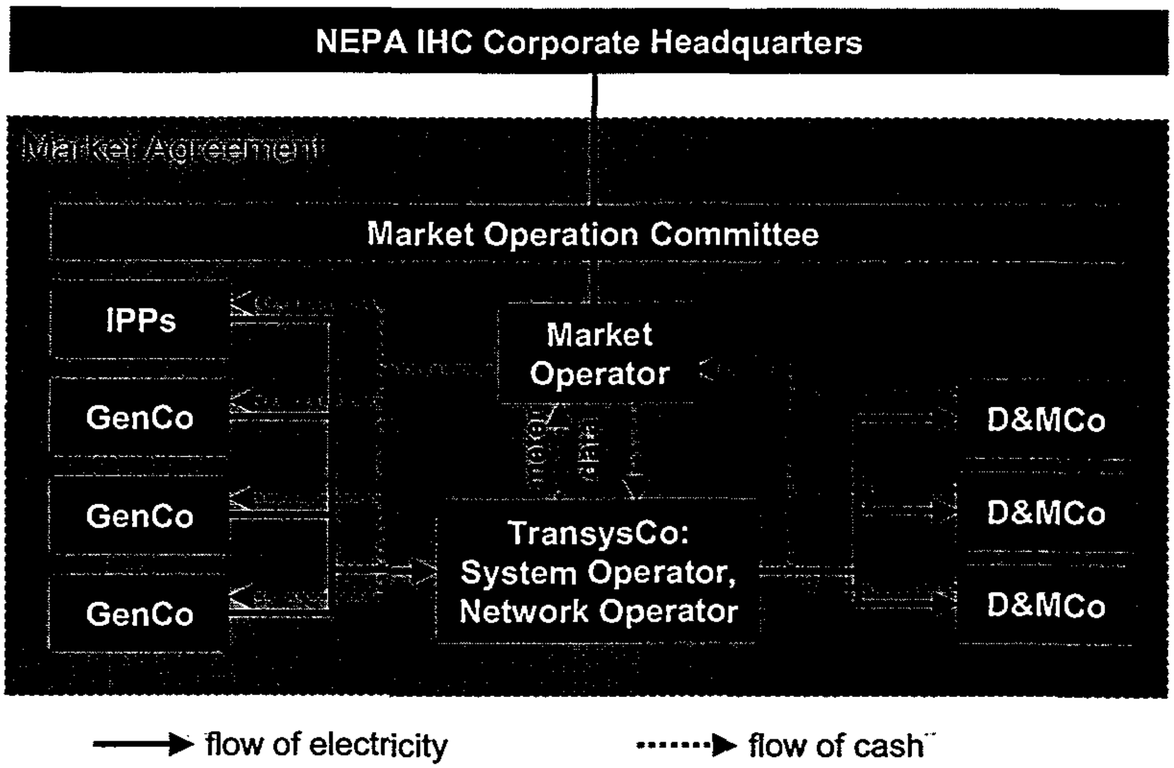

Figure B-1: Framework for Transactions During Transition Stage Electricity Market

Table B.1: List of NEPA NBUs and Cost Centers and Other Market Participants

Generation	Distribution	Others
▪ Kainji and Jebba GenCo ▪ Shiroro GenCo ▪ Afam GenCo ▪ Sapele GenCo ▪ Delta, Calabar and Oji GenCo ▪ Egbin and Ijora GenCo ▪ Other New GenCo ▪ *Ajaokuta* ▪ *Okitipupa* ▪ *Papalanto* ▪ *Trading Licensee for IPPs* ▪ Gen Sector Head Office	▪ Abuja ▪ Benin ▪ Enugu ▪ Ibadan ▪ Jos ▪ Kaduna ▪ Kano ▪ Lagos North ▪ Lagos South ▪ Port Harcourt ▪ Yola ▪ *Unit serving HV Customers* ▪ *Unit serving Exports* ▪ Dist & Marketing H.O.	▪ TransysCo ▪ NEPA Corporate HQ

Note: Entities not yet in existence are shown in *italic*.

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Figure B-2 shows the flow of charges administered by the Market Operator on behalf of the NBUs and the trading licensee for bulk purchases from IPPs. The source of funds for all the power sector organizations ultimately is the end use customers. The funds are collected by the DisCos and transferred to the Market Operator, who in turn makes payments to the all NBUs based on the cash allocation methodology.

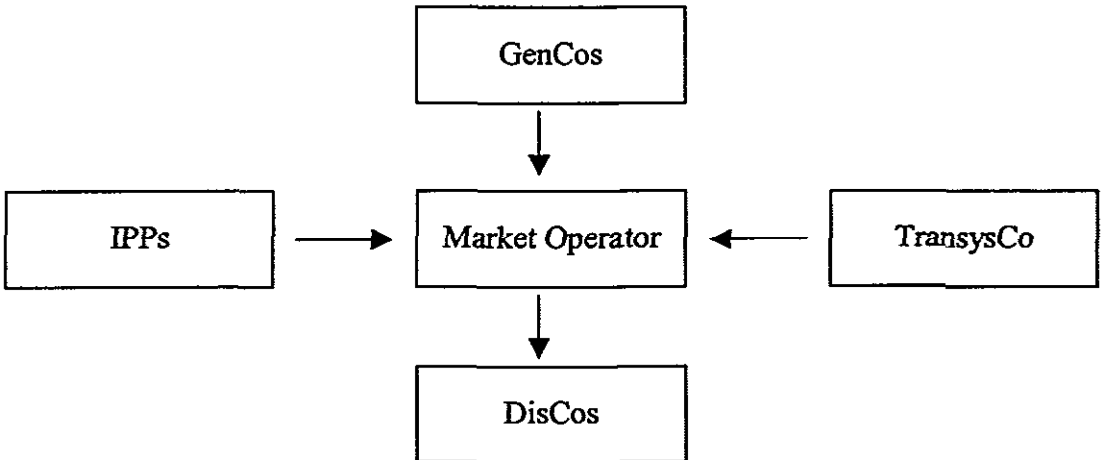

Figure B-2: Flow of Bulk Supply Charges

1.3 Software and Hardware Requirements

The Bulk Supply Charges & Cash Allocation Model is an Excel spreadsheet developed on Microsoft Windows xp. It is recommended to load the program on an IBM-compatible PC with an advanced Pentium processor and ample available memory.

2. DETERMINATION OF CHARGES AND CASH PAYMENT REQUIREMENTS

2.1 Quarterly Process to Set Charges

Bulk supply charges and cash payment requirements are estimated at the start of each quarter. Figure B-3 provides a flow diagram for the process to set charges and cash payment requirements.

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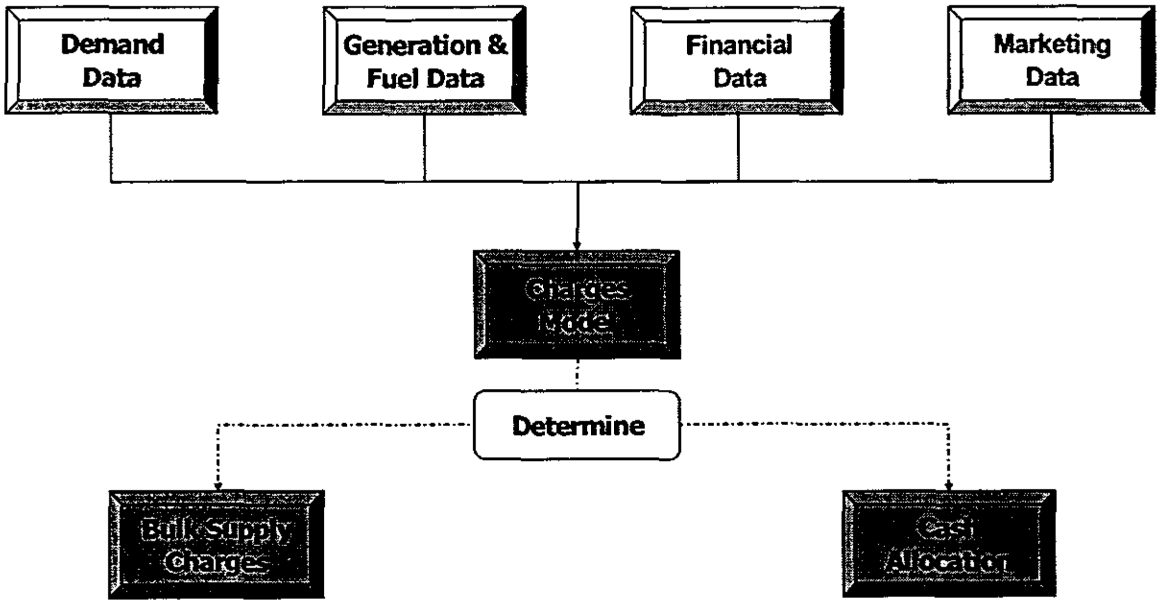

Figure B-3: Bulk Supply Charges & Cash Allocation Model Flow Diagram

2.2 Inputs to Charges Model

The model requires the following operational input data for the forecast period:

- For each GenCo and IPP/ROT:
  - Average monthly available capacity (MW)
  - Average monthly peak load (MW)
  - Average monthly capacity factor (%)
  - Auxiliary losses (%)
  - Fuel consumption per kWh of generation
- For TransysCo:
  - Transmission losses (%)
- For each DisCo:
  - Load allocation (peak MW & GWh)
  - Distribution losses (%)
  - Energy for own use (GWh)
  - Free energy supply to employees and pensioners (GWh)
  - Energy purchase/sale to other DisCos at LV level (GWh)
  - Energy purchase from auto generators (GWh)

  - Exports (GWh)
  - Collection rate (%)
  - Number of customers
  - Number of new connections
- For all NBUs:
  - Number of employees

In view of the transmission and distribution network constraints, TransysCo will forecast the load that can be evacuated from each generating plant. The load allocation (peak demand and energy supply) to DisCos will be determined by the load allocation committee.

The model requires the following financial inputs for the forecast period for each NBU (as applicable):

- DisCo average revenue:
  - Electricity revenue (N/kWh)
  - Monthly meter maintenance charge (Naira per customer)
- Operating costs:
  - Payroll
  - Generation fuel prices
  - Tariffs for IPPs/ROTs
  - Repairs & maintenance
  - Transport & travel
  - Administration & overheads
- Other cash receipts:
  - DisCo connection and reconnection fees
  - All other
- Debt service and borrowing:
  - Interest due
  - Long-term loan repayments due
  - Interest to be paid (depending on cash availability)
  - Long-term loan repayments to be paid (depending on cash availability)
  - Repayment of short-term loans and overdrafts
  - Additional short-term borrowing and overdrafts
- Fixed assets:

- Net book values (historical and revalued)
- Asset lives/depreciation rates
- Capital investments (IGR)

- Funds set aside at HQ:
  - Emergency requirements
  - Other requirements
- Other inputs:
  - Escalation factors for operating costs (if applicable)
  - Corporate income tax rate
  - VAT rate
  - Number of hours in the forecast period
  - Number of months in the forecast period
  - Exchange rate Naira/US$
  - Return on equity (%)
  - Debt/equity ratio

2.3 Calculation of Charges

2.3.1 Generation and Transmission Charges

The costs of all the GenCos, IPPs and TransysCo are passed through as charges to the DisCos and to the unit handling sales to high voltage customers and exports. The following steps are used to determine the charges:

- line item budget forecasts are prepared for all of the NBUs, the IPPs and corporate HQ at the start of each quarterly cycle;
- costs are classified as variable or fixed;
- costs are also classified as generation-related or transmission-related; and
- costs are then aggregated into the charge components, which are allocated to the DisCos based on relative demand.

The model calculates the full cost-of-service (CoS) of each NBU. The bulk supply charges of GenCos and TransysCo are determined by their respective CoS. The cost-of-service of each NBU is determined using the following equation:

Cost-of-service

= Own operating expenses, including depreciation

\+ Allocated HQ costs

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+ Bulk supply charges (for DisCos)
+ Interest, including HQ allocations
+ Taxes
+ Return on equity

Table B-2 shows the classification of costs as either fixed or variable.

Table B-2: Fixed and Variable Components of Cost of Service

Fixed Costs	Variable Costs
O&M and overhead costs Depreciation Capacity charges of IPPs/ROTs Interest Return on equity	Generation fuel Energy charges of IPPs/ROTs

Table B-3 shows the components of bulk supply charges to the DisCos. In summary, there are three main categories of charges: 1) Fixed Generation Charges, which cover GenCo fixed costs and IPP capacity charges; 2) Variable Generation Charges, which cover GenCo fuel costs and energy charges of IPPs; and 3) Fixed Transmission Services Charges which cover the costs of TransysCo facilities and services. For the time being, only fuel and IPP energy charges are classified as variable, however other possible variable costs such as manpower and plant maintenance costs directly associated with the level of activity can be identified later when NEPA's accounting system is enhanced to provide this level of detail.

Table B-3: Components of Bulk Supply Charges to DisCos

Component of Charge	Basis for Allocation
Fixed Generation Charges	
▪ Demand Charge	MW Demand
▪ Transmission Losses Charge	MVA Demand
Variable Generation Charges	
▪ Fuel Charge	MWh Supplied
▪ Transmission Losses Charge	MWh Losses
Fixed Transmission Services Charge	MVA Demand

The following summarizes the components of the bulk supply charges to the DisCos:

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- Variable Generation Charges – There are two components to the variable generation charges:
  - Variable Energy Charge – Covers a DisCo's share of the actual variable costs of generation of GenCos and IPPs delivered to a DisCo at its points of interconnection to the transmission grid. The charge is in proportion to the DisCo's MWh demand to the system MWh demand.
  - Variable Transmission Losses Charge – Covers a DisCo's share of the variable costs of GenCos and IPPs to supply transmission losses for wheeling energy to the DisCo. The charge is in proportion to the DisCo's MWh demand to the system MWh demand.
- Fixed Generation Charges – There are two components to the fixed generation charges:
  - Fixed Generation Demand Charge – Covers a DisCo's share of the fixed cost of generating capacity supplied by GenCos and IPPs to meet the DisCos' aggregate demand. The charge is in proportion to the DisCo's forecast MW demand to the system forecast MW demand at the time of the system peak.
  - Fixed Transmission Losses Charge – Covers a DisCo's share of the fixed cost of generating capacity supplied by GenCos and IPPs to cover forecast transmission system losses. The charge is in proportion to the DisCo's forecast MVA demand to the system forecast MVA demand at the time of the system peak.
- Fixed Transmission Service Charge – Covers a DisCo's share of the cost of transmission facilities and services to transmit power from the GenCos to the DisCos. The charge is in proportion to the DisCo's forecast MVA demand to the system forecast MVA demand at the time of the system peak.

2.3.2 *Charges for Off-Grid Supply*

Off-grid supply to DisCos can come from 1) embedded generation, i.e. generating units connected to the distribution network and 2) energy flows between DisCos on the low voltage grid. Charges for embedded generation are calculated according to the relevant power purchase contract. Charges from one DisCo to another for energy flows and associated distribution losses for energy wheeled on the low voltage grid will be set equal to the average bulk supply charge for on-grid generation and transmission services.

2.3.3 *Charges for Headquarters Costs*

All of the NBUs are charged for services provided by the Sector and Corporate Headquarters. Sector head office costs are allocated to each NBU based on the NBUs own costs relative to total sector costs. Corporate HQ costs are allocated to each NBU based on NBUs own costs relative to total NEPA costs. For purposes of such allocations, fuel, depreciation and bulk supply charges are excluded from costs.

2.4 Cash Payment Requirements

The Market Operator will use the charges model to prepare a quarterly forecast of the cash collections by the DisCos and to calculate cash allocations to the NBUs and corporate HQ. The

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model calculates the standing orders for the settlement of the cash allocation due to each NBU. The model has a facility to apply three alternative cash rationing methods. The user can choose any alternative by changing a simple switch in the data input worksheet.

2.4.1 Cash Available for Allocation

As a first step, the model calculates the total cash pool available for allocation among the NBUs. This calculation is common to all three cash allocation alternatives in the model. The cash pool is determined as follows:

- Total Cash Receipts:
  - Billing collections from end customers
  - Less: Meter maintenance charge collections from end customers
  - Less: VAT collected from end customers
  - Add: Connection and reconnection fees collected from end customers
  - Add: Government subsidy available for operations (e.g. for Abuja EPP fuel and capacity costs)
  - Add: All other receipts
  - = Total cash Receipts
- Less: Amounts set aside for:
  - Past obligations
  - Incentive payments in respect of previous year
  - Emergency requirements
  - Repayment of LT borrowing (does not apply to Alternative C)
  - Repayment of ST borrowing and overdrafts
- Add: ST borrowing and additional overdraft facility for operations
- Balance = cash pool available for allocation to NBUs

2.4.2 Alternative A for Cash Allocation

The cash pool is allocated in the following order of payment priorities:

- Salaries and allowances
- HQ costs
- Generation fuel charges
- EPP, IPP and ROT charges
- Plant management and RCM fees
- The remaining available cash is allocated among the operating NBUs based on the remaining unmet cost-of-service of individual NBU relative to total NEPA.

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2.4.3 Alternative B for Cash Allocation

The cash pool is allocated in the following order of priorities:

- All cash operating expenses
- Interest charges
- Corporate income taxes
- The remaining available cash is allocated among the operating NBUs based on the remaining unmet CoS of individual NBU relative to total NEPA. The remaining unmet CoS in this case is equal to depreciation of fixed assets.

2.4.4 Alternative C for Cash Allocation

The cash allocation is on "needs" basis for each NBU. The cash pool is allocated in the following order of priorities:

- All cash operating expenses
- Debt service payments, including repayment of LT loans
- Corporate income taxes
- The remaining available cash is allocated among the NBUs based on "prioritized" investment requirements. The prioritization of investments needs will be determined at each level of the organization and finally approved by NEPA executive management.

2.4.5 Chosen Alternative for Cash Allocation

NEPA management has decided that, for the time being and in view of limited available cash resources, Alternative C will be used as the basis of cash allocation among the NBUs. This is to ensure that any available cash surplus after meeting operational requirements and debt service obligations is directed where it is most needed in terms of investment requirements.

2.5 End-of-Quarter Adjustments for Actual Versus Forecast

At the end of each quarter and upon submission of actual returns from all NBUs, the Market Operator will re-work the charges model to reflect the actual operational and financial performance data and administer the following end-of-quarter adjustments:

- The bulk supply charges will be adjusted for variances between actuals and budgets.
- Variances in cash flows between actuals and budgets will be brought into the subsequent quarter's cash allocation. Any cash surplus will be added to cash receipts and any cash shortfall will be deducted as repayment of overdraft or borrowing.

3. INPUT AND OUTPUT WORKSHEETS

The Bulk Supply Charges & Cash Allocation Model consists of a number of linked worksheets. Each worksheet falls into one of the following categories:

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- Input sheets – One basic worksheet "Data Input" for the input of technical and financial data required by the model. Certain data inputs are also required under the "FA" (fixed assets) and "Debt Service" worksheets.
- Intermediate calculation sheets – Calculation sheets show intermediate results including the Income Statements, Cost of Service, Bulk Supply Charges and Unit Rates, and Cash Allocations for each NBU.
- Monthly Charges and Cash – One worksheet that shows summary monthly results of quantities, charges and standing orders for each NBU. These statistics will be used for the preparation of the quarterly statements of accounts for each NBU.

Table B-4 provides a list of the worksheets that comprise the Bulk Supply Charges & Cash Allocation Model.

Table B-4: Charges Model Worksheets

No.	Worksheet	Type	Purpose
1	Read Me	Information	Provides a basic overview of the model.
2	Income Statements	Calculation	Calculates the income statements and the return on equity for each NBU.
3	Technical	Calculation	Calculates the technical data used to allocate costs to determine line item charges for each NBU. Calculates factors used to allocate charges.
4	CoS & BSC	Calculation	Calculates the Cost of Service (CoS) for each NBU and bulk supply charges to DisCos. Calculates unit bulk supply charges.
5	Monthly Charges & Cash	Results	Summarizes monthly supply and charges data (technical, unit rates and bulk supply charges) and monthly cash allocation ("standing orders") for each NBU, and monthly cash transfers from DisCos. This spreadsheet serves as the source of data for preparation of quarterly statements of account.
6	Op Costs	Calculation	Calculates for each NBU: (a) the operating costs by category and (b) allocates Sector HO costs and HQ costs to operating NBUs.
7	Charts	Results	Presents charts for make-up of CoS and CoS compared with billed and collected revenue.
8	IPPs	Calculation	Calculates charges of IPPs and costs of off-grid supply.
9	Fuel	Calculation	Calculates fuel costs of each GenCo and IPP.

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No.	Worksheet	Type	Purpose
10	DisCo Billing	Calculation	Calculates end customer billings and collections of each DisCo, together with average revenue (N/kWh), collection (N/kWh) and % collection rates.
11	Cash A	Calculation	Cash Allocation under Alternative A: Calculates cash inflows for each NBU, cash allocation to each NBU, and cash transfers from DisCos.
12	Cash B	Calculation	Cash Allocation under Alternative B: Calculates cash inflows for each NBU, cash allocation to each NBU, and cash transfers from DisCos.
13	Cash C	Calculation	Cash Allocation under Alternative C: Calculates cash inflows for each NBU, cash allocation to each NBU, and cash transfers from DisCos.
14	FA	Input & Calculation	Input: Fixed asset values and asset lives. Calculates net fixed asset values and depreciation charges for each NBU under both the historical and revalued basis of fixed assets valuation.
15	Debt Service	Input & Calculation	Input: Debt service details for each NBU. Calculates debt service requirements and allocation of HQ interest to operating NBUs.
16	Data Input	Input	Input all the required technical and financial information and select 2 run control parameters: (a) asset valuation basis, (2) cash allocation basis.

The following tables provide samples of the model output worksheets.

SUMMARY INCOME STATEMENTS	GenCos	TransysCo	D&MCos	[illegible]	Inter-co trading	NEPA Total
All figures in 000's Nairas unless otherwise stated						
Operating Revenue						
Electricity revenue from:						
End use customers (Nigeria)	0	0	17,708,537	0	0	17,708,537
Exports	0	0	333,076	0	0	333,076
GenCos bulk supply to D&MCos	8,925,031	0	0	0	(8,925,031)	0
TransysCo charges to D&MCos	0	5,409,971	0	0	(5,409,971)	0
Meter maintenance charges	0	0	1,202,278	0	0	1,202,278
Connection & reconnection fees	0	0	0	0	0	0
Government subsidy for operations	875,000	0	0	0	0	875,000
Other operating revenue	0	0	0	0	0	0
Total Operating Revenue	**9,800,031**	**5,409,971**	**19,243,892**	**0**	**(14,335,002)**	[illegible]
Operating Expenses						
Fuel for own generation	551,547	0	0	0	0	551,547
Fuel for purchased energy from IPP's	792,287	0	0	0	0	792,287
Power purchase from IPP's (excl fuel)	2,126,338	0	6,850	0	0	[illegible]
Power purchase from GenCos	0	0	8,925,031	0	(8,925,031)	0
TransysCo charges	0	0	5,409,971	0	(5,409,971)	0
Salaries & allowances	835,140	573,233	3,051,676	271,197	0	[illegible]
Repairs & maintenance	192,580	138,594	353,806	12,343	0	[illegible]
Transport & travelling	73,373	88,653	224,398	126,665	0	[illegible]
Plant manangement & RCM fees	0	0	556,347	0	0	556,347
Administration & overheads	32,912	68,132	181,309	415,993	0	[illegible]
Allocation of Sector HO & HQ costs	147,078	112,657	566,461	(826,197)	0	0
Bad debts	4,893,957	4,159,503	7,396,609	0	(9,053,461)	[illegible]
Depreciation	2,583,507	1,316,735	2,530,123	0	0	[illegible]
Total Operating Expenses	**12,228,720**	**6,457,506**	**29,202,580**	**0**	**(23,388,463)**	[illegible]
	715,586	(36,711)	7,396,609			
Operating Income	**(2,428,688)**	**(1,047,535)**	**(9,958,689)**	**0**	**9,053,461**	[illegible]
Interest	**54,819**	**69,199**	**75,981**	**0**	**0**	200,000
Non Operating Income - net	**0**	**0**	**0**	**0**	**0**	0
Net Income before Taxation	**(2,483,507)**	**(1,116,735)**	**(10,034,670)**	**0**	**9,053,461**	[illegible]
Corporate Income Tax	**0**	**0**	**0**	**0**	**0**	0
Net Income after Taxation	**(2,483,507)**	**(1,116,735)**	**(10,034,670)**	**0**	**9,053,461**	[illegible]
Return on Fixed Assets	**-7.21%**	**-2.57%**	**-21.02%**			[illegible]

The above Income Statements show the true performance for each Company.
For G&T companies, the non-payment of G&T charges by D&MCos are [illegible]
For D&MCos, the full G&T charges and uncollected end-customer billings are charged to op[illegible]

Adjustments to above Net Income figures for D&MCos ONLY

Net Income after Taxation - As Above	**(10,034,670)**
Non-payment of G&T Costs	8,582,278
Transfer of Surplus Cash to HQ	(89,970)
Net Income after Taxation - As adjusted	**(1,542,363)**
Return on Fixed Assets - As Adjusted	**-3.23%**

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Cost of Service - in 000's Nairas	GenCos	TransysCo	D&MCos	Inter-co trading	NEPA Total
Operating Costs					
Generation, Transmission & D&M Costs					
Fixed costs	5,980,290	2,298,002	4,688,210	0	[illegible]
Variable costs	1,354,472	0	0	0	[illegible]
Total costs	7,334,762	2,298,002	4,688,210	0	[illegible]
Customer Services, Meter Reading, Billing & Collection Costs	0	0	2,782,759	0	[illegible]
Total Operating Costs	7,334,762	2,298,002	7,470,969	0	[illegible]
Less: Export Revenue Collected	0	0	(249,807)	0	[illegible]
Less: Other Operating Revenue	(875,000)	0	0	0	[illegible]
(Other op revenue of D&MCos includes connection & reconnection fees but excludes meter maint charges which are meant for purchase of m[illegible]					
Less: Non Operating Income - net	0	0	0	0	0
Interest	54,819	69,199	75,981	0	[illegible]
Corporate Income Tax	0	0	0	0	[illegible]
Return on Fixed Assets	2,410,450	3,042,769	3,340,983	0	[illegible]
Total Generation Cost of Service	0	0	8,925,031	(8,925,031)	0
Total Transmission & Operations Cost of Service	0	0	5,409,971	(5,409,971)	0
Total Cost of Service G, T & D&M	8,925,031	5,409,971	24,973,128	(14,335,002)	24,973,128
Total Electricity Revenue Collection by Individual D&MCos					[illegible]
% Collection Rate of Individual D&Mcos (based on CoS)					[illegible]

Cost of Service - Naira per kWh of Sales	GenCos	TransysCo	D&MCos	NEPA Total
Generation (Naira per kWh Sent Out)	1.70			[illegible]
Transmission (Naira per kWh Bulk Supply to D&M)		1.10		[illegible]
Generation & Transmission (Naira per kWh Sales to end Customers)			4.70	[illegible]
Distribution & Marketing (Naira per kWh Sales to end Customers)			3.49	[illegible]
Total G,T, D&M (Naira per kWh Sales to end Coustomers)			8.19	[illegible]
Total G,T, D&M (Naira per kWh Sales to end Coustomers) - COLLECTED			12.73	[illegible]
Collected Electricity Revenue from end Customers (N/kWh)			3.65	[illegible]

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Generation & Transmission Charges to D&MCos	D&MCo 1 Abuja Zone	D&MCo 2 Benin Zone	D&MCo 3 Enugu Zone	D&MCo 4 Ibadan Zone	D&MCo 5 Jos Zone	D&MCo 6 Kaduna Zone	D&MCo 7 Kano Zone
G&T Charges % Allocations							
Generation Fixed Charge on Bulk Delivery	8.3%	9.2%	9.7%	12.5%	4.5%	6.3%	5.5%
Generation Variable Charge on Bulk Delivery	8.3%	9.2%	9.7%	12.5%	4.5%	6.3%	5.5%
Generation Fixed Charge for Transmission Losses	8.3%	9.2%	9.7%	12.5%	4.5%	6.3%	5.5%
Generation Variable Charge for Transmission Losses	8.3%	9.2%	9.7%	12.5%	4.5%	6.3%	5.5%
Transmission Fixed Charges	8.3%	9.2%	9.7%	12.5%	4.5%	6.3%	5.5%
G&T Charges (in 000's Nairas)							
Generation Fixed Charge on Bulk Delivery	593,165	653,486	688,125	892,596	323,362	448,550	392,734
Generation Variable Charge on Bulk Delivery	106,125	116,917	123,115	159,697	57,852	80,251	70,265
Generation Fixed Charge for Transmission Losses	37,862	41,712	43,923	56,974	20,639	28,631	25,068
Generation Variable Charge for Transmission Losses	6,774	7,463	7,858	10,193	3,693	5,122	4,485
Total Generation Charges	743,926	819,578	863,021	1,119,460	405,536	562,555	492,552
Transmission Fixed Charges	450,936	496,793	523,127	678,569	245,818	340,997	298,564
Total G&T Charges to D&Mcos before Inter-D&MCo Trading	**1,194,862**	**1,316,371**	**1,386,148**	**1,798,029**	**651,354**	**903,552**	**791,116**
Add: G&T Charges for Energy Flows between D&MCos							
Generation Charge	0	0	(40,075)	0	0	0	0
Transmission Charge	0	0	(24,292)	0	0	0	0
Total G&T Charges for Energy Flows between D&MCos	0	0	(64,366)	0	0	0	0
Total G&T Charges to D&Mcos including Inter-D&MCo Trading	**1,194,862**	**1,316,371**	**1,321,782**	**1,798,029**	**651,354**	**903,552**	**791,116**
Unit Charges for D&MCos							
Generation Fixed Charge on Bulk Delivery - Naira/kW Demand/Month	831.9	831.9	831.9	831.9	831.9	831.9	831.9
Generation Variable Charge on Bulk Delivery - Naira per MWh	258.4	258.4	258.4	258.4	258.4	258.4	258.4
Generation Fixed Charge for Transmission Losses - Naira/kW Losses/Month	831.9	831.9	831.9	831.9	831.9	831.9	831.9
Generation Variable Charge for Transmission Losses - Naira/MWh Losses	258.4	258.4	258.4	258.4	258.4	258.4	258.4
Transmission Fixed Charges - Naira/MVA Demand/Month	574.9	574.9	574.9	574.9	574.9	574.9	574.9
Average G&T Charge on Bulk Delivery - Naira/MWh	2,909.3	2,909.3	2,909.3	2,909.3	2,909.3	2,909.3	2,909.3

Generation & Transmission Charges to D&MCos	D&MCo 8 Lagos Nth Zone	D&MCo 9 Lagos Sth Zone	D&MCo 10 PH Zone	D&MCo 11 Yola Zone	SPE Grid Connected	SPE NG Export	All D&MCos
G&T Charges % Allocations							
Generation Fixed Charge on Bulk Delivery	18.9%	14.9%	6.1%	2.2%	0.3%	1.4%	100.0%
Generation Variable Charge on Bulk Delivery	18.9%	14.9%	6.1%	2.2%	0.3%	1.4%	100.0%
Generation Fixed Charge for Transmission Losses	18.9%	14.9%	6.1%	2.2%	0.3%	1.4%	100.0%
Generation Variable Charge for Transmission Losses	18.9%	14.9%	6.1%	2.2%	0.3%	1.4%	100.0%
Transmission Fixed Charges	18.9%	14.9%	6.1%	2.2%	0.3%	1.4%	100.0%
G&T Charges (in 000's Nairas)							
Generation Fixed Charge on Bulk Delivery	1,344,718	1,059,527	434,208	158,647	24,594	102,623	7,116,326
Generation Variable Charge on Bulk Delivery	240,588	189,563	77,685	28,384	4,400	18,361	1,273,204
Generation Fixed Charge for Transmission Losses	85,833	67,629	27,715	10,126	1,570	6,550	454,234
Generation Variable Charge for Transmission Losses	15,357	12,100	4,959	1,812	281	1,172	81,268
Total Generation Charges	1,686,496	1,328,819	544,567	198,969	30,845	128,706	8,925,031
Transmission Fixed Charges	1,022,281	805,473	330,093	120,606	18,697	78,016	5,409,971
Total G&T Charges to D&Mcos before Inter-D&MCo Trading	**2,708,777**	**2,134,292**	**874,660**	**319,575**	**49,543**	**206,723**	**14,335,002**
Add: G&T Charges for Energy Flows between D&MCos							
Generation Charge	0	0	40,075	0	0	0	0
Transmission Charge	0	0	24,292	0	0	0	(0)
Total G&T Charges for Energy Flows between D&MCos	0	0	64,366	0	0	0	(0)
Total G&T Charges to D&Mcos including inter-D&MCo Trading	**2,708,777**	**2,134,292**	**939,027**	**319,575**	**49,543**	**206,723**	**14,335,002**
Unit Charges for D&MCos							
Generation Fixed Charge on Bulk Delivery - Naira/kW Demand/Month	831.9	831.9	831.9	831.9	831.9	831.9	
Generation Variable Charge on Bulk Delivery - Naira per MWh	258.4	258.4	258.4	258.4	258.4	258.4	
Generation Fixed Charge for Transmission Losses - Naira/kW Losses/Month	831.9	831.9	831.9	831.9	831.9	831.9	
Generation Variable Charge for Transmission Losses - Naira/MWh Losses	258.4	258.4	258.4	258.4	258.4	258.4	
Transmission Fixed Charges - Naira/MVA Demand/Month	574.9	574.9	574.9	574.9	574.9	574.9	
Average G&T Charge on Bulk Delivery - Naira/MWh	2,909.3	2,909.3	2,909.3	2,909.3	2,909.3	2,909.3	

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Sapele GenCo
Statement for Electricity Supply
NEPA HQ: GM, Finance & Accounts

Invoice Period:	**January 1 to March 31, 2003**
Invoice Date:	**January 1, 2003**

Bulk Supply	**Available Capacity (MW)**			**210.000**
	Peak Load (MW)			**146.000**
	Energy Sent Out (GWh)			**232.830**
		Unit Rates		**Total Naira**
Charges	**Fixed Demand Charge**	**Naira/kW/Month**	**765.5**	**335,299,140**
	Variable Charge (Naira)	**Naira/kWh**	**0.202**	**46,927,182**
	Total Charge (Naira)			**382,226,322**
	Less: HQ Cost Allocations included above			**(47,145,061)**
	Charge for "Own" Costs			**335,081,261**
Payment Due	**Settlement %**			**57.65%**
	Total Amount Due for the Quarter			**193,182,183**
Settlement	**Standing Order payable on the 15th and end of each month**			**32,197,031**

TransysCo
Statement for Transmission & Grid Operations Services
NEPA HQ: GM, Finance & Accounts

Invoice Period:	**January 1 to March 31, 2003**
Invoice Date:	**January 1, 2003**

Bulk Supply	**Demand at System Peak (MVA)**			**3,136.610**
	Energy Wheeled (GWh)			**5,241.839**
	Transmission Losses			**6.0%**
	Bulk Supply (GWh)			**4,927.329**
		Unit Rates		**Total Naira**
Charges	**Fixed Charge (Naira)**	**Naira/kVA/Month**	**574.9**	**5,409,970,518**
	Variable Charge (Naira)	**Naira/kWh**	**n/a**	**0**
	Total Charge (Naira)			**5,409,970,518**
	Less: HQ Cost Allocations included above			**(181,856,583)**
	Charge for "Own" Costs			**5,228,113,935**
Payment Due	**Settlement %**			**20.44%**
	Total Amount Due for the Quarter			**1,068,610,500**
Settlement	**Standing Order payable on the 15th and end of each month**			**178,101,750**

Abuja D&MCo
Statement for Bulk Electricity Supply & HQ Costs
NEPA HQ: GM, Finance & Accounts

Invoice Period: January 1 to March 31, 2003
Invoice Date: January 1, 2003

Grid Supply	Demand at System Peak (MW)			237.677
	Demand at System Peak (MVA)			261.445
	Transmission Losses (MW)			15.171
	Bulk Energy Supply (GWh)			410.706
	Transmission Losses (GWh)			26.214
Supply from other D&MCos				
	Off-Grid Supply (GWh)			0.000
	Associated Distribution Losses (GWh)			0.000
Charges (Grid Supply)		Unit Rates		Total Naira
	Fixed Generation Demand Charge	Naira/kW/Month	831.9	593,165,202
	Fixed Transmission Losses Charge	Naira/kW/Month	831.9	37,861,608
	Variable Energy Charge	Naira/kWh	0.258	106,125,030
	Variable Transmission Losses Charge	Naira/kWh	0.258	6,773,937
	Fixed Transmission Service Charge	Naira/kVA/Month	574.9	450,935,844
	Total Charge			1,194,861,621
Charges (off-Grid Supply)				
	Total Charge at effective Bulk Supply Tariff	Naira/kWh	2.909	0
	Total G & T Charges			1,194,861,621
	Settlement %			24.23%
	Amount Due			289,498,229
Charge for HQ Costs				
	D&MCo Sector HO - Admin & Overheads			28,702,885
	NEPA HQ - Admin & Overheads			48,884,602
	NEPA HQ - Interest			6,584,510
	Amount Due (100%)			84,171,997
Payment Due	Total Amount Due for the Quarter			[redacted]

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Abuja D&MCo
Cash Flow Satatement
NEPA HQ: GM, Fianance & Accounts

Period Covered:	**January 1 to March 31, 2003**
Statement Date:	**January 1, 2003**

			Naira
Inflows	**Billing Collections:**		
	Electricity Revenue		746,877,978
	Meter Maintenance Charge		33,480,237
	VAT		39,017,910
	Total Billing Collections		819,376,125
	Connection & Reconnection Fees Collected		0
	Other Receipts (specify)		0
	Standing Orders from HQ (for non self-sustaining NBUs)		0
	Total Cash Receipts		819,376,125
Outflows	**Deductions at Source for "Own" CoS ("Standing Orders")**		373,207,752
	Deductions at Source due on the 15th and end of each month	62,201,292	
	Settlement % for "Own" CoS		65.77%
Surplus	**Due to HQ in respect of:**		446,168,373
	Meter Maintenance Charge	33,480,237	
	VAT	39,017,910	
	Bulk Supply Charges	289,498,229	
	HQ Costs	84,171,997	
	Remaining Surplus to meet shortfalls of other NBUs	0	
	Total	446,168,373	0

Note: Collected meter maintenance charges remitted to HQ will be returned to the D&MCo for procurement of customer meters.

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NEPA HQ: GM, Finance & Accounts
Statement for HQ Costs
Charged to Abuja D&MCo

Invoice Period: January 1 to March 31, 2003
Invoice Date: January 1, 2003

		Naira
Quarterly Charge for HQ Costs		
	D&MCo Sector HO - Admin & Overheads	28,702,885
	NEPA HQ - Admin & Overheads	48,884,602
	NEPA HQ - Interest	6,584,510
	Total Charge	84,171,997

Note: The above sum will be either:
(a) deducted by HQ from bulk supply charges GenCos and TransysCo, or
(b) remitted to HQ as part of remittances to HQ by D&MCos

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4. MATHEMATICAL FORMULATION OF BULK SUPPLY CHARGES TO DISCOS

This section shows the mathematical formulation of the charges for generation.

4.1 Fixed Generation Demand Charge

The Fixed Generation Charge shall be:

$$FGC = [(1\text{-}LF) \times TFGC] \times [FMW \ / \ \sum_{n=1}^{NDisCos} FMW_n]$$

where:

LF = Forecasted Transmission Loss Factor

TFGC = Total Fixed Generation Charge owed by DisCos for Billing Period

$$TFGC = \sum_{i=1}^{NGenCo} FGenCo_i + \sum_{k=1}^{NIPP} CPP_k$$

where:

NGenCo = Number of GenCos in the power market

FGenCo = Fixed Generation Charge owed by DisCos to GenCos for Billing Period

NIPP= Number of IPP and ROT contracts, imports and other non-GenCo power purchase contracts supplying power to the grid

CPP = Capacity Purchase Price owed to IPPs/ROTs, imports etc. for Billing Period

NDisCos = Number of DisCos/SPE in the power market

FMW = DisCo's Forecasted Peak MW for each Month averaged over the quarter

4.2 Fixed Transmission Losses Charge

The Fixed Transmission Losses Charge shall be:

$$FTLC = [LF \times TFGC] \times [FMVA \ / \ \sum_{n=1}^{NDisCos} FMVA_n]$$

where:

LF = Forecasted Transmission Loss Factor as determined by the Bulk Supply Charges & Cash Allocation Model for the relevant quarter

TFGC = Total Fixed Generation Charge owed by DisCos for Billing Period

NGenCo NIPP

$$TFGenCo = \sum_{i=1} FGenCo_i + \sum_{k=1} CPP_k$$

where:

NGenCo = Number of GenCos in the power market

FGenCo = Fixed Generation Charge owed to GenCos by DisCos for Billing Period

NIPP= Number of IPP/ROT contracts, imports and other non-GenCo power purchase contracts supplying power to the grid

CPP = Capacity Purchase Price owed to IPPs/ROTs, imports and other non-GenCo power purchase contracts supplying power to the grid

NP = Number of DisCos/SPE in the power market

PFMVA = DisCo's Forecasted Peak MVA for each Month averaged for the quarter

4.3 Fixed Transmission Services Charge

The Fixed Transmission Services Charge shall be:

$$FTC = FMVA \,/ \sum_{n=1}^{NDisCo} FMVA_n$$

where:

FTC = Fixed Transmission Services Charge for the Billing Period

NDisCo = Number of DisCos/SPE in the power market

FMVA = DisCo's Forecasted Peak MVA for each Month averaged for the quarter

4.4 Variable Generation Charge

The Variable Generation Charge shall be:

$$VGC = TMED \times EP$$

where:

TMED = Total Metered Energy Delivered

$$TMED = \sum_{i=1}^{DP} MED_i$$

where:

DP = Number of Delivery Points

MED_i = Metered Energy Delivered in the Billing Period

EP = Energy Price for that Billing Period

EP = TVGC/TMER

where:

TVGENCO= Total Variable Generation Charge owed by DisCos for Billing Period

$$TVGC = \sum_{j=1}^{NGenCo} VGenCo_j + \sum_{k=1}^{NIPP} EPP_k$$

where:

NGenCo = Number of GenCos in the power market

VGenCo = Variable Generation Charge owed to GenCos by DisCos for Billing Period

NIPP = Number of IPP/ROT contracts, imports and other non-GenCo power purchase contracts supplying power to the grid

EPP = Energy Purchase Price owed to IPP/ROT contracts, imports and other non-GenCo power purchase contracts supplying power to the grid

TMER = Total Metered Energy Received by DisCos in Billing Period

$$TMER = \sum_{j=1}^{NGenCo} MER_j + \sum_{k=1}^{NIPP} MER_k$$

where:

NGenCo = Number of GenCos in the power market

NIPP = Number of IPP/ROT contracts, imports and other non-GENCO power purchase contracts supplying power to the grid

MER = Metered Energy Received from GenCos, IPPs/ROTs, imports and other power providers supplying power to the grid

4.5 Variable Transmission Losses Charge

The Variable Transmission Losses Charge shall be:

VTLC = TL x EP x VTLF

where:

TL = Transmission Losses in Billing Period, expressed in kWh

TL = TMESO - TMEDP

TMER= Total Metered Energy Sent Out in Billing Period

TMEDP = Total Metered Energy Delivered to all DisCos/SPE in Billing Period

$$TMEDP = \sum_{i=1}^{NDisCo} TMED_i$$

where:

NDisCo = Number of DisCos/SPE

TMED = Total Metered Energy Delivered to a DisCo in a Billing Period as determined above

EP = Energy Price for the Billing Period as determined above

$$VTLF = (MWh \,/\, \sum_{n=1}^{NDisCo} MWh_n)$$

where:

NDisCo = Number of DisCos

MWh = DisCo's Measured MWh for Billing Period

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5. USER'S GUIDE

5.1 Using the Bulk Supply Charges & Cash Allocation Model

The Bulk Supply Charges & Cash Allocation Model is an Excel spreadsheet used to determine on a quarterly basis (a) the Cost of service for each NBU, (b) the bulk supply charges of GenCos and TransysCo to DisCos, and (c) the cash payment requirements of each NBU in the Nigeria Power Market. This model was developed by Nexant under funding from USAID. The model has been developed with participation of the restructuring sub-committee on commercial relationships and accepted by the management of NEPA. The first application of the model is scheduled for the quarter starting July 1, 2003.

Using the model requires the following steps:

1. Update the quarterly data in the primary input worksheet "Data Input". Certain input data is also required in "FA" and "Debt Service" worksheets. Input fields are color coded yellow. Do not input data in any other fields and avoid changing formulae. Do not change calculated cells or totals in rows or columns that are colored.

2. Always check the results of the model.

5.2 Colour Coding Of Columns

The model has generally applied the following colors to column headings for individual NBUs within each sector of NEPA:

Generation	"Mauve"
Transmission & Operations	"Pink"
Distribution & Marketing	"Turquoise"
Headquarters (HQ)	"Green"
NEPA Total	"Grey"

Appendix C

Executive Job Descriptions for DisCo HQ and Market Operator

This appendix provides executive job descriptions for the new and changing management positions at DisCo Headquarters and for the Market Operator. The job descriptions provide a guideline for NEPA to use when recruiting, selecting and placing the most suitable candidates in each position. While not downplaying the need to enhance skills in engineering and other traditional utility functions, the position profiles reflect the increasing need for business, management, financial, and commercial capabilities at the NBUs.

JOB DESCRIPTION

POSITION:	**DisCo General Manager**
LOCATION:	DisCo Headquarters
CLASSIFICATION:	
REPORTS TO:	Sector ED in NEPA Corporate HQ (TBD)

JOB SUMMARY:
Chief executive of the company responsible for management and performance monitoring of the departments for marketing, distribution, operations, engineering, finance and accounts, and various corporate and administrative services at DisCo HQ, Districts and Undertakings. Responsible for establishing and monitoring the functions, systems and procedures for the transition stage electricity market.

DUTIES / ESSENTIAL FUNCTIONS:
1. Develop, establish and implement a broad mission and strategic goals for the DisCo.
2. Review and approve company strategies recommended by the DisCo management team and consultants.
3. Define and establish specific technical and business performance objectives.
4. Assess key developments in electricity sector broadly, and local market trends in the DisCo service territory, and incorporate into periodic revision of strategic objectives and shorter-term performance goals.
5. Oversee activities and proper functioning of DisCo HQ, Districts and Undertakings.
6. Supervise the work of AGM Marketing, AGM Distribution, AGM F&A, AGM Services and other direct reports.
7. Review and approve activity reports of each DisCo department, as well as corporate financial performance statements, to determine progress and status in attaining objectives, and revise objectives as needed.
8. Evaluate periodically the performance of senior executives.
9. Provide quarterly progress reports to corporate HQ and liaise as needed with corporate HQ.
10. Lead the change management process at the DisCo company-wide to implement corporate restructuring.
11. Liaise with the public, the press, federal and local governments, unions, NERC, DisCo shareholders and other key external stakeholders.
12. Serve as a member of the DisCo Board of Directors, when formed.

QUALIFICATIONS:
1. Bachelors or Master's degree in engineering, accounting, finance, business, or law.
2. At least 10 years in a senior management position preferred.
3. Age limit of 55 preferred.
4. Experience managing executive teams to achieve established goals and lasting results.
5. Demonstrated experience managing organizations to achieve commercial results, with cost and profit accountability.
6. Strong familiarity with financial, accounting, and management reporting systems.
7. Computer literate in excel required; other relevant programs also preferred.

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JOB DESCRIPTION

POSITION:	**Assistant General Manager, Distribution**
LOCATION:	DisCo Headquarters
CLASSIFICATION:	
REPORTS TO:	GM (DisCo)

JOB SUMMARY:

Responsible for executive management of the following activities:

1. Executive management and operational oversight of all District Distribution Managers.
2. Planning, construction and maintenance of 33kv distribution network
3. Planning, construction and maintenance of LV distribution network.
4. Metering and connections (installation, maintenance and repair, calibration)
5. Workshops facilities associated with construction and maintenance, plus services such as vehicle maintenance and repair.
6. Contracts with third party construction and maintenance companies.
7. Contracts for the provision of engineering, construction and maintenance services.
8. Coordination of operational data required for the Market Agreement.

DUTIES / ESSENTIAL FUNCTIONS:

1. Establish and implement requirements and procedures for Distribution Managers at the Districts to report directly to the DisCo AGM Distribution.
2. Ensure the collection, maintenance, and provision to PM Contracts and Tariffs of all meter data for the Market Agreement and charges model.
3. Establish normal Distribution Operational Procedures and maintenance policies; continuously review and modify as necessary.
4. Establish Distribution System Emergency operational procedures, review regularly and modify as necessary
5. Establish operational procedures for dealing with all classes of customers with regard to load shedding to safeguard the system
6. Prepare plans for the reinforcement of the system to meet load growth.
7. Agree proposals submitted by the Districts for long-term planning of the network
8. Review proposals submitted for the construction and maintenance of all injection substations.
9. Ensure that all distribution returns are rendered by the Districts to DisCo HQ when due.
10. Maintain a library of distribution returns and an inventory of distribution equipment in the zone.
11. Collate and analyze HT faults reports submitted by the Distribution Managers and ensure the prompt clearance. Identify type faults and unreliable equipment and agree plan for rehabilitation or replacement of equipment
12. Prepare a plan for system access outages for maintenance and construction with minimum effect on all classes of customers
13. Establish standards for Network Design and ensure compliance with standards in planning extensions to system
14. Prepare proposed projects for extension and rehabilitation of system and obtain engineering and budget approval for projects
15. Establish procedures for best practice in contract management and ensure all staff comply with procedures in dealing with external contracts
16. In conjunction with the DisCo AGM Marketing, plan, install and/or calibrate Grid HV and LV supply meters as required

QUALIFICATIONS:

1. Bachelor's or Master's degree in electrical engineering; some training or background also preferred in business, economics, finance, planning
2. At least 5 years in a management position preferred.
3. Age limit of 55 preferred.
4. Experience working with/overseeing senior staff to achieve established goals and lasting results

JOB DESCRIPTION

POSITION:	**Assistant General Manager, Finance & Accounts**
LOCATION:	DisCo Headquarters
CLASSIFICATION:	
REPORTS TO:	GM (DisCo)

JOB SUMMARY:

Overall responsibility for the finance and accounting functions of the DisCo. Supervisory function plus hands on participation as needed in the major departmental functions of cash management, accounting, budgeting, financial forecasts, financial analysis and reporting. Assists GM and PM Corporate Planning in formulating and administering DisCo business plan, identifying strategic objectives and shorter-term financial performance goals. Major responsibility for carrying out new and expanded functions at the DisCo level, including:

1. Accounting for DisCo revenues, costs, assets and liabilities.
2. Consolidating accounting returns of districts.
3. Financial management reporting.
4. Reviewing and consolidating revenue and capital budgets of districts and submission of DisCo budgets.
5. Justifying requests for funds for capital investment projects.
6. Managing funds and cash flow reporting.
7. Reporting treasury activities to HQ.
8. Financial Forecasts.
9. Tariff analysis and cost of service calculations.

DUTIES / ESSENTIAL FUNCTIONS:

1. Assist GM and PM Corporate Planning in development of business plan, establishing various performance and operational targets in the short- and long-term.
2. Supervise preparation of monthly financial statements.
3. Submit monthly financial reports to management.
4. Establish and supervise cost accounting procedures & systems.
5. Set up accounting policies.
6. Consolidate District accounts.
7. Submit quarterly revenue & capital budgets and cash flow forecasts and monitor actuals against budgets and forecasts and report variances.
8. Prepare financial forecasts.
9. Establish and maintain a Fixed Asset Register.
10. Monitor levels of accounts receivable.
11. Monitor and analyze end customer tariffs and provide cost of service calculations.
12. Define and establish specific financial and accounting performance objectives and targets, such as increasing collections rate.
13. Oversee activities and proper functioning of, and coordinate functions and operations between, main F&A Sections
14. Interact daily with direct reports and members of the DisCo management team.
15. Evaluate periodically performance of PM direct reports.
16. Provide quarterly progress reports to GM DisCo.

QUALIFICATIONS:

1. Bachelor's or Master's degree in accounting, finance, or business and/or a professionally qualified accountant.
2. At least 5 years in a senior management position preferred.
3. Age limit up to 55 preferred
4. Experience working with mid-level managers to achieve established goals and lasting results
5. Demonstrated experience managing workgroups, and establishing new programs and operating procedures
6. Strong familiarity with financial, accounting, and management reporting systems
7. Computer literate in excel required; other relevant programs also preferred

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JOB DESCRIPTION

POSITION:	**Assistant General Manager, Services**
LOCATION:	DisCo Headquarters
CLASSIFICATION:	
REPORTS TO:	GM (DisCo)

JOB SUMMARY:

This is a new position at the DisCo responsible for managing central services to all of the operating units of the company. This includes a supervisory function as well as active participation as needed in the major departmental functions of personnel and administration, IT and communications, procurement, and property and environment. The AGM Services assists the GM and PM Corporate Planning in formulating and administering the DisCo's business plan, identifying strategic objectives and developing shorter-term corporate performance targets for each of the above functions.

DUTIES / ESSENTIAL FUNCTIONS:

1. Manage policies and resources for the provision of central services for personnel and administration, IT and communications, procurement, and property and environment to DisCo HQ, Districts and Undertakings.
2. Define and establish DisCo-specific performance objectives related to Services functions, such as training of staff, MIS needs assessment and procurement.
3. Oversee activities and proper functioning of, and coordinate functions and operations between, main Services Sections; interact daily with PMs in the Sections.
4. Supervise human resources activities for all company employees in the JS5 – SS3 grades, including employee relations functions, compensation and benefits and training.
5. For personnel matters concerning posts above the SS3 level, consult with GM HR (HQ) and provide inputs concerning matters of appropriate recruitment, selection and appointment, training and/or implementation of benefits.
6. Ensure DisCo correct interpretation and compliance with NEPA Conditions of Service.
7. Liaise with GM HR (HQ) regarding appropriate changes in personnel systems and procedures to promote greater efficiency, cost savings and other benefits for the DisCo.
8. Liaise with local NUEE representatives; report on labor issues to GM (DisCo) and GM Industrial Relations (HQ).
9. Develop and disseminate communications strategies and forums for employees on the change management process as these affect the sector and the DisCo.
10. Oversee all DisCo activities related to property, buildings, leases, equipment, and insurance.
11. Supervise building and facility planning and maintenance.
12. Supervise security services.
13. Provide advice and resources to the Districts on environmental rules and regulations.
14. Direct and coordinate the development and implementation of a DisCo-wide MIS plan.
15. Evaluate periodically performance of PMs.
16. Provide regular progress reports to GM DisCo.

QUALIFICATIONS:

1. Bachelor's or Master's degree in economics, finance, or business.
2. At least 2-5 years in a management position preferred.
3. Age limit up to 55 preferred.
4. Demonstrated extensive knowledge of principles and practices of personnel administration.
5. Effective communication skills, and ability to give leadership to programs and relate well to others.
6. Experience working with managers to achieve established goals and lasting results.
7. Demonstrated experience managing workgroups and establishing new programs and operating procedures

JOB DESCRIPTION

POSITION:	**Principal Manager, Corporate Planning**
LOCATION:	DisCo Headquarters
CLASSIFICATION:	
REPORTS TO:	GM (DisCo)

JOB SUMMARY:
New position in the DisCo to advise the GM and executive management team on all matters related to DisCo performance, setting of strategic and short-term goals, preparing and updating business plans, and monitoring electricity market and general economic conditions affecting the company.

DUTIES / ESSENTIAL FUNCTIONS:
1. Analyze and report on DisCo performance.
2. Prepare business plan.
3. Advise GM on transition issues for restructuring and privatization.
4. Prepare and manage regulatory filings.
5. Prepare sales, revenue and demand forecasts.
6. Prepare long-term financial plan.
7. Prepare and distribute relevant economic information.
8. Assist PM Planning and Construction in evaluation of alternative construction plans.
9. Lead the development of DisCo strategy for the local and national electricity markets.
10. Monitor the competitive business climate, industry trends, technology trends and government/regulatory activities in distribution areas.
11. Lead the development and dissemination of new business strategies for the restructured electricity market.
12. Work with AGMs to prepare business sub-unit plans.
13. Coordinate the change management activities of the DisCo.

QUALIFICATIONS:
1. Degree in economics, business or engineering with Master of Business Administration preferred.
2. At least five years directly related experience in industry or consulting field responsible for major strategic planning projects
3. Ability to interpret management's strategies into successful implementation plans
4. Job history of accomplishments in both regulated and non-regulated environments
5. Excellent communication skills
6. Age limit of 52 preferred
7. Experience working with staff to achieve established goals and lasting results
8. Demonstrated experience managing workgroups and establishing new programs and operating procedures

JOB DESCRIPTION

POSITION:	**Principal Manager, Finance & Accounts**
LOCATION:	DisCo Headquarters
CLASSIFICATION:	
REPORTS TO:	AGM Finance & Accounts (DisCo)

JOB SUMMARY:

Under the direction of the AGM F&A, manage the day-to-day financial and accounting functions of the DisCo.

DUTIES / ESSENTIAL FUNCTIONS:

1. Prepare consolidated monthly financial statements, including profit and loss account, balance sheet and cash flows. Consolidation involves the review and aggregation of the accounting returns of the Districts and Undertakings.
2. Provide direction and monitoring of local F&A staff at the Districts and Undertakings.
3. Assist in preparation and monitoring of quarterly revenue and capital budgets. Report actual against budgets.
4. Prepare monthly management accounts providing (a) key operational and financial performance indicators, (b) financial results, and (c) monitoring against budgets.
5. Ensure implementation and adherence to accounting policies.
6. Maintain proper and reliable books of account, under generally accepted accounting standards, including general ledger, subsidiary ledgers such as accounts payable, fixed assets register, billing and accounts receivable, and stores accounting.
7. Manage the implementation of computer-based systems for accounting and budgeting company-wide.
8. Supervise preparation of payroll and management of staff accounts.
9. Manage banking and cash transactions and all other treasury functions.
10. Collect, maintain, and provide to PM Contracts and Tariffs (in the DisCo) all financial and accounting data needed to comply with Market Agreement requirements in billings and settlements process.

QUALIFICATIONS:

1. Bachelor degree in accounting, finance or business.
2. At least 2-5 years in a management position preferred.
3. Age limit up to 52 preferred.
4. Experience working with/overseeing staff to achieve established goals and lasting results
5. Demonstrated experience managing workgroups, and implementing new programs and operating procedures
6. Strong familiarity with financial, accounting, and management reporting systems
7. Computer literate in excel required; strongly preferred to have familiarity with other relevant programs.

JOB DESCRIPTION

POSITION:	**Principal Manager, Contracts and Tariffs**
LOCATION:	DisCo Headquarters
CLASSIFICATION:	
REPORTS TO:	AGM Finance and Accounts (DisCo)

JOB SUMMARY:

New position at the DisCo. General responsibility for implementing and monitoring the DisCo's commercial relationships, with a focus on administering contracts including the Market Agreement, RCM contracts and future IPP contracts; also responsible for tariff analysis.

DUTIES / ESSENTIAL FUNCTIONS:

1. Establish and monitor the contract administration function for RCM contracts, the Market Agreement and bulk supply transactions.
2. Liaise with the Market Operator on matters of concern, as needed, regarding the Market Agreement and functioning of the transition stage electricity market.
3. Coordinate with other PM Contracts and Tariffs individuals at the DisCos to discuss, assess and decide on emerging issues regarding the Market Agreement and the functioning of the transition stage electricity market in general.
4. Provide written quarterly Report (and special Memos as needed on urgent matters) to AGM F&A (DisCo) on relevant developments and issues in the Market Agreement, the functioning of the transition stage electricity market and the commercial impact on the DisCo.
5. Recommend any required changes to Market Agreement to the AGM F&A (DisCo), with focus on key issues of load allocation, grid metering, charges, settlement, etc.
6. Serve as the DisCo point person for billings and settlements issues.
7. Check and approve accounting statements issued by the Market Operator.
8. Issue information requirements of the DisCo to comply with Market Agreement (for calculation of bulk supply charges and cash allocation) to relevant internal units – for operational data to AGM Distribution, and for marketing information to AGM Marketing.
9. Manage and administer the RCM contractors – resolve disputes, recommend or approve contract changes; manage RCM contractor invoicing.
10. Liaise with the AGM Distribution to set up systems and processes for grid meter data collection and reporting to the Market Operator.

QUALIFICATIONS:

1. Bachelor degree in economics, finance, law or engineering.
2. Familiarity with negotiating and implementing commercial agreements; knowledge of electricity sector or other network/utility industry preferred.
3. At least 2-5 years in a senior management position preferred (equivalent to PM level)
4. Age limit of 52 preferred.
5. Experience working with staff to achieve established goals and lasting results.
6. Demonstrated experience managing workgroups, and establishing new programs and operating procedures.

JOB DESCRIPTION

POSITION:	**Principal Manager, Personnel & Administration**
LOCATION:	DisCo Headquarters
CLASSIFICATION:	
REPORTS TO:	AGM Services (DisCo)

JOB SUMMARY:

Support AGM Services in all human resources development and management activities, as well as administrative services. In the personnel area, for all employees in grades JS5 - SS3, responsible for implementation and management of all aspects of employee relations, employee benefits and compensation programs, and training in accordance with existing NEPA Conditions of Service. In administration, responsible for supporting AGM Services in all corporate affairs.

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DUTIES / ESSENTIAL FUNCTIONS:

1. Implement and communicate employment rules and personnel procedures as contained in the existing Conditions of Service (update and communicate any subsequent amendments, change and circulars.).
2. Administer compensation scheme and benefits programs, including pension, insurance, allowances and medical plan.
3. Handle benefit inquiries and complaints to ensure quick and equitable resolution.
4. Manage recruitment, selection, and placement activities to ensure ongoing and continuous supply of qualified personnel, including a) preparation of job descriptions and b) supervision of (and/or participation in) recruitment process, for example, interview, and ranking, and selection committees.
5. Oversee maintenance of employee records, i.e., detailed excel data base of pertinent personnel information; supervise maintenance of enrollment, application, and claims records for all benefit plans
6. Work with AGM Services and District Managers in analyzing and preparing annual manpower needs/forecast and budget for the DisCo.
7. Investigate & report labor problems referred from the Districts and advise the AGM Services; participate actively in industrial negotiations.
8. Advise the AGM Services on all personnel matters referred from the Districts, including staff disciplinary matters
9. Conduct tours to the Districts and Undertakings to ensure uniform application of personnel policies.
10. Manage employee training and career development activities at the DisCo level, including: supervising a training needs assessment, formulating a training plan at least yearly, and drafting annual budget for training and career development needs.
11. Monitor performance appraisal and measurement programs, management development, and training programs.
12. Administer employment contracts.
13. Assist in the preparation of both operating and capital budgets for the DisCo.
14. Prepare quarterly status reports for AGM Services on all relevant activities and developments.

QUALIFICATIONS:

1. Bachelor's degree in business, organizational behaviour or related field.
2. At least 2-5 years in a personnel management position preferred.
3. Detailed knowledge of principles and practices of personnel administration.
4. Age limit of 52 strongly preferred.
5. Experience working with staff to achieve established goals and lasting results
6. Demonstrated experience managing workgroups and establishing new programs and operating procedures.
7. Strong familiarity with personnel management systems preferred.

JOB DESCRIPTION

POSITION:	**Principal Manager, Procurement**
LOCATION:	DisCo Headquarters
CLASSIFICATION:	
REPORTS TO:	AGM Services (DisCo)

JOB SUMMARY:

The PM Procurement will secure the procurement of engineering and non-engineering related equipment and goods and will be responsible for preparing, administering, reviewing, analyzing, auditing, and negotiating contracts and purchase orders. The PM Procurement will judge competence of vendors and ensure contractual, delivery, and financial compliance.

DUTIES / ESSENTIAL FUNCTIONS:

1. Administer and ensure adherence to NEPA procurement practices and procedures to be followed by vendors and department personnel.
2. Receive incoming requests for services and goods/products/equipment/spare parts, and ensure handling and completion on a priority basis.
3. Ensure that specifications are worded clearly and unambiguously and that terms and delivery dates are reasonable and accurate.
4. Make certain that purchasing documents are properly completed and the terms and conditions of purchases are appropriate.
5. Order items/products/spare parts from requisitions received from group leaders; maintain purchasing records and prepare quarterly summary of purchases.
6. Expedite import process of items (customs clearance) as required.
7. Review vendor invoices for accuracy and adherence to specifications.
8. Supervise and maintain records of vendors' history of delivery and quality of product.
9. Contact vendors on items received which were unsatisfactory.
10. Maintain roster of satisfactorily performing outside vendors/contractors.
11. Recommend major purchases of materials based on anticipated changes in prices or on unusual availability situations.
12. Assure that department records are maintained and that purchases are followed up or expedited when required. Department records should include price histories to provide information on price variances.
13. Prepare quarterly status reports for AGM Services on all relevant activities, developments, price trends, and availability of materials.
14. Assist in the preparation of both operating and capital budgets for the DisCo.

QUALIFICATIONS:

1. Bachelor' degree in business administration, marketing, or accounting.
2. At least 2-5 years experience in contracting/procurement, preferably in government.
3. Purchasing experience, including trading and purchasing practices in foreign countries preferred
4. Good organizational and administrative skills
5. Age limit of 50 strongly preferred.
6. Experience working with staff to achieve established goals and lasting results
7. Demonstrated experience managing workgroups and establishing new programs and operating procedures
8. Computer skills with common office applications.

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JOB DESCRIPTION

POSITION:	**Principal Manager, Property & Environment**
LOCATION:	DisCo Headquarters
CLASSIFICATION:	
REPORTS TO:	AGM Services (DisCo)

JOB SUMMARY:

The PM Property & Environment will maintain up-to-date records of the DisCo's property; carry out wayleave matters and acquisition of land; conduct real estate valuation for purchase or rent; carry out valuation of existing properties for insurance and record purposes; and ensure compliance with land-related environmental issues.

DUTIES / ESSENTIAL FUNCTIONS:

1. Manage the real estate and maintenance of building and structures within the DisCo franchise area, including infrastructure, recreational, and residential facilities.
2. Advise AGM Services on revenue generation through the management of DisCo-owned properties; maintain proper records of all the DisCo's landed properties.
3. Prepare comprehensive list of title documents for acquired lands and up-keep of necessary records.
4. Carry out activities such as site selection, investigation on existing local laws, and compliance with town/country planning by-laws.
5. Assess and ensure payment for compensation of acquired lands.
6. Coordinate activities of wayleave.
7. Maintain records of all payment (compensation, rents and rates) to guard against false claims and double payments.
8. Ensure protection of all landed properties of the DisCo against encroachment.
9. Liaise with Distribution Department and town/country planning authorities for management of wayleave rights and easements.
10. Assist in the preparation of both operating and capital budgets for the DisCo
11. Ensure the proper maintenance of all the DisCos buildings.
12. Prepare quarterly status reports for AGM Services on all relevant activities and developments.

QUALIFICATIONS:

1. Bachelor' degree in business administration, marketing, or accounting.
2. At least 2-5 years experience in property management, preferably in government.
3. Good organizational and administrative skills.
4. Age limit of 50 strongly preferred.
5. Experience working with staff to achieve established goals and lasting results.
6. Demonstrated experience managing workgroups and establishing new programs and operating procedures.
7. Computer skills with common office applications.

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JOB DESCRIPTION

POSITION:	**Senior Manager, IT & Communication**
LOCATION:	DisCo Headquarters
CLASSIFICATION:	
REPORTS TO:	AGM Services (DisCo)

JOB SUMMARY:

This is a new position at the DisCo will be responsible for providing computer and information technology support for on-site and remote access users; and supervising and managing the IT staff. Also responsible for maintenance and repairs of all communications systems and installation of equipment for the DisCo.

DUTIES / ESSENTIAL FUNCTIONS:

1. Design, specify, configure, install and modify equipment for DisCo staff.
2. Research and solve daily problems that may arise and make recommendations for solutions.
3. Work closely with IT staff for planning the activities and daily operations of problem identification and problem solving.
4. Install and test network equipment, servers, databases, and other hardware and software technologies as required.
5. Maintain & administer the company's communication network, including Internet resources.
6. Execute server backups and provide technical assistance in workstation maintenance and network support.
7. Establish preventive maintenance schedules.
8. Establish and follow procedures for tracking repair orders.
9. Assist in the development and design of workshops and other training efforts on telecommunication, Internet, and other topics.
10. Develop a yearly IT plan with specific goals, priorities, and training needs across the DisCo.
11. Assist in the preparation of both operating and capital budgets for the DisCo.
12. Supervise effective maintenance and repairs of communications equipment in the DisCo, such as PABX, telephones, and intercoms.
13. Arrange for the provision and maintenance of all NITEL lines.
14. Prepare technical recommendation for the acquisition of maintenance materials.
15. Direct effective usage of communication equipment.
16. Provide quarterly status report to AGM Services, DisCo.

QUALIFICATIONS:

1. Bachelor's degree in computer science, MIS or equivalent.
2. Experience with LAN technologies, including multiple network operating systems, topologies and protocols, and Wide Area Networking.
3. Strong knowledge of and experience with PC hardware and software technology, including shared network resources, internet access and electronic mail.
4. Demonstrated experience managing workgroups and implementing new programs and operating procedures

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JOB DESCRIPTION

POSITION:	**Market Operator**
LOCATION:	TransysCo Headquarters
CLASSIFICATION:	
REPORTS TO:	ED TransysCo

JOB SUMMARY:

This is a new position in TransysCo responsible for administering the market rules governing the technical and commercial functioning of the electricity sector. The primary duties of the Market Operator will be as follows: operate the charges model; prepare Statements of Account, which are like invoices between the NBUs; manage cash transfers; administer the meter data collection and reporting system for transactions between NBUs; and recalculate settlements for actual versus forecast quantities according to the process for quarterly reconciliation.

The Market Operator will liaise closely with HQ F&A, since its primary responsibilities are related to the role of HQ F&A for company-wide budgeting and treasury. The staffing and position levels for the Market Operator unit will depend on what functions, if any, that the unit will take over from HQ F&A. These issues can be addressed in the next phase of work.

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DUTIES / ESSENTIAL FUNCTIONS:

1. Collect the forecast demand, budget and meter data required for the charges model and for settlement.
2. Consolidate grid meter data to calculate the MWh of electricity generated by GenCos, MWh and MVarh received by each DisCo, transmission losses and peak MW and MVA of each DisCo.
3. Operate the charges model to calculate bulk supply charges and determine the cash payments due from DisCos and payable to DisCos, GenCos, TransysCo and NEPA Headquarters.
4. Prepare and submit quarterly statements of bulk supply charges and cash allocations to DisCos, GenCos, TransysCo and NEPA Headquarters.
5. Manage the transfer of money, i.e. instruct banks to transfer cash receipts and to make payments to DisCos, GenCos, TransysCo and NEPA HQ.
6. Control "collection" bank accounts at each DisCo for billing collections from end customers and all other cash receipts.
7. Manage weekly cash transfers from DisCos.
8. Operate a "remittance" bank account as a central pool of all remittances sent by DisCos to the Market Operator.
9. Transfer cash allocation funds to NBUs and HQ twice monthly.
10. Transfer to HQ all funds allocated for emergency requirements and for VAT collections on receipt of funds from DisCos.
11. Administer the process of quarterly reconciliation to recalculate charges and cash payments for actual versus forecast quantities and adjust Statements of Account and cash payment requirements accordingly.
12. Administer the financial flows arising from the settlement computations among energy buyers and sellers, according to specified rules set out in the Market Agreement.
13. Collect and consolidate quarterly inputs from PM Contracts and Tariffs at the DisCos, and provide written consolidated quarterly reports to NEPA executive management on relevant developments, issues, etc.
14. Participate on the Market Operations Committee.

QUALIFICATIONS:

1. Bachelor's degree in engineering, economics, finance, or law.
2. At least 2-5 years in a management position preferred.
3. Age limit of 52 preferred.
4. Experience working with staff to achieve established goals and lasting results
5. Demonstrated experience managing workgroups and establishing new programs and operating procedures.
6. Familiarity with negotiating and implementing commercial agreements; knowledge of electricity sector or other network/utility industry.
7. Good understanding of financial aspects of the business preferred.