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Energy Sector Management Assistance Program

Background Paper

INTERNATIONAL EXPERIENCE WITH PRIVATE SECTOR PARTICIPATION IN POWER GRIDS

PHILIPPINES CASE STUDY

WORLD BANK GROUP
Energy & Extractives

ESMAP Mission

The Energy Sector Management Assistance Program (ESMAP) is a global knowledge and technical assistance program administered by the World Bank. It provides analytical and advisory services to low- and middle-income countries to increase their know-how and institutional capacity to achieve environmentally sustainable energy solutions for poverty reduction and economic growth. The SIDS DOCK Support Program is funded by Denmark and Japan.

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Contents

FOREWORD

Under the Terms of Reference for Consultancy, funded by the World Bank (WB) - administered Energy Sector Management Assistance Program (ESMAP), the author of this report was commissioned as Consultant to undertake an analytical study covering (a) modalities of private sector participation (PSP) in transmission and distribution (T&D), and (b) implementation of open access (OA) to T&D systems.

This report composes the results of the Consultant's data gathering and review of relevant literature and analytical study of the subject matter.

1.1. Background

To assist WB country clients in developing countries on possible way forward to ensure reliable and affordable supply of electricity, two areas of interest are emerging to policy makers: PSP in T&D, and implementation of OA to T&D systems. A two-track study covering the two said areas is undertaken. The first track is a report on the emerging global issues underpinning developments in the said two areas that is a synthesis of the second track - specific country case studies on PSP in T&D and OA in T&D systems.

1.2. Objective

The objective of this study is to identify options, taking into account the circumstances of the Philippines, and distill lessons learned from the Philippine experience. The World Bank intends to ultimately integrate the herein findings and recommend best practices for private sector participation in T&D systems and open access to T&D grids in a comprehensive ESMAP report.

1.3. Findings and Assessment

1.3.1. Overview of the Philippine Electric Power Industry

The author deemed it appropriate to start the discussion on how the industry was structured prior to and during the reform to rationalize what the Electric Power Industry Reform Act (EPIRA) of the Philippines wants to change, how it was intended to be changed, and the reasons for the change. The EPIRA may be an open manuscript; nevertheless, it is deemed that citing the more relevant portions of the Act in the report would enable the reader to see in a single manuscript, a full account of what is envisaged by the Act and how the Philippine Electricity Industry is progressing and evolving to the desired framework, particularly in the areas of interest of this undertaking, specified in the WB ToR as:

a) Open Access to Transmission and Distribution

b) Private Sector Participation in Transmission and Distribution

The methodology that has been used in coming up with the exposition on all the topics, is to gather the appropriate materials from the internet, and from responsible agencies like the Energy Regulatory Commission (ERC), Power Sector Assets and Liabilities Management Corporation (PSALM), Department of Energy (DoE), National Power Corporation (NPC), National Transmission Corporation (TRANSCO), National Grid Corporation of the Philippines (NGCP), various distribution utilities (DUs), Licensed Retail Electricity Suppliers (RES), big end-users, or wherever the circumstances permit. Direct information has been gathered through formal interviews with focal authorities and personalities who were willing to share their insights, knowledge and expertise as well as informal discussions with certain colleagues, of diverse proficiency and roles in the industry. The WB, through its Manila Office, whenever necessary, provided some assistance in making prior arrangements with the selected resource persons. The Consultant also contributed his own knowledge and experience being a former ERC Commissioner and NPC Senior Manager who in one part of his stint had the opportunity to actively participate in the undertakings of NPC's Privatization Office.

Each main part of the report culminates with the Consultant's own assessment of notable issues and/or relevant additional inputs.

1.3.2. Open Access to Transmission and Distribution

For a competitive and spirited electricity market, both at the wholesale and retail level, it is necessary that Open Access to the Transmission and Distribution Grid is present and effectively working.

This section discusses how open access to the transmission and distribution grid in the country emanated and developed, from the pre-EPIRA regime to how it is now.

Open access means that everyone gets the same treatment on the following main components:

a) Connection to the transmission / distribution grid;

b) Good and quality service upon connection to the grid;

c) Safe, reliable and efficient operation and maintenance of the network system; and

d) Tariff structure, pricing and cost allocation.

These components are the key issues discussed in each of the following policies, rules and regulations governing open access to the transmission and distribution grids of the country:

a) Philippine Grid Code

b) Philippine Distribution Code

c) Wholesale Electricity Spot Market Rules

d) Performance Based Regulation

- Rules for Setting Transmission Wheeling Rates
- Rules for Setting Distribution Wheeling Rates

e) Rules for Setting Electric Cooperatives' Rates

f) Open Access Transmission Service Rules

g) Distribution Services and Open Access Rules

h) Renewable Energy Act.

The section wraps up with the assessment of the author on what more is important for open access to work for its intended purpose.

1.3.3. Retail Competition and Open Access (RC&OA)

RC&OA is discussed as a key topic being the ultimate objective of open access, more so, the EPIRA as a whole.

The discussion on RC&OA will put the reader at the minimum required level of understanding by setting off with the underlying principles, including basic definitions, the motivations and benefits of RC&OA and explaining the rationale behind the EPIRA mandated requisites to the implementation of RC&OA. These preliminary sections elucidate that competition is certainly to protect the interests of the consumer but is believed to be, as well, an incentive to progress.

Following the set off is a discussion on the preparations towards the implementation of RC&OA. Particularly discussed in the Final Report is the groundwork, which has been done by the ERC, from the time of the enactment of the EPIRA up to the present. This imperative groundwork includes all the rules and regulations underpinning the regulatory preparations, which include the following:

a) Rules for the Issuance of Licenses to Retail Electricity Suppliers

b) Code of Conduct for Competitive Retail Market Participants

c) Rules for Customer Switching

d) Rules for the Supplier of Last Resort (SOLR)

e) Rules on Rate Filing by the Supplier of Last Resort

f) Competition Rules and Complaint Procedures

g) Business Separation Guidelines (BSG)

h) Distribution Services and Open Access Rules (DSOAR)

i) Rules for Contestability

j) Rules for Setting Distribution Wheeling Rates

k) Rules for Setting the Transmission Wheeling Rates

l) Rules for Setting Electric Cooperatives' Rates

m) Other pertinent issuances pertaining to the establishment of the timeline for the implementation of RC&OA and the ERC Decision declaring compliance with the EPIRA-mandated requisites to RC&OA.

Important inputs were perceived in the report prepared by Mr. Jess Totten of Austin Texas, an independent international expert, who has been requested by ERC, supported by the United States Agency for International Development (USAID), to review the ERC's rules, determining whether they are adequate to support retail competition. This report covers the highlights and main points of the aforementioned review.

A very critical component is the current work of the Steering Committee (SC) created by the DoE, to define the policies for the commencement of RC&OA. This endeavor of the SC is fully discussed in the Draft Report.

The RC&OA section of the Draft Report culminates with the own insights and assessment of the Consultant.

As indicated in the objectives of this undertaking, the discussion on the Philippines experiences in initiating and progressing towards RC&OA, the assortment of issues and concerns of the different stakeholders, the insights and review of the ERC rules provided by other consultants and the own inputs of the Consultant of this undertaking would enable the recipients of the Final Report to cull the important and relevant lessons learned for appropriate guidance and direction in their own jurisdictions.

1.3.4. PSP in Transmission

The discussion on PSP in Transmission sets off with the rationale for the privatization of the transmission sector to instill awareness and appreciation of the need for the inflow of private capital in transmission.

Following the set off, is a discussion of the experiences of the Philippines in undergoing the pertinent processes towards the privatization of the transmission facilities. From this discussion, the reader can draw together some strategies on the privatization of a massive infrastructure like the Philippine transmission network. Particularly discussed in the initial report are the following:

a) The modality for the privatization: Concession

b) The Bid Process

c) The three (3) failed attempts to privatize

d) The Winning Bid

e) The take over and operation of TRANSCO's transmission facilities by the National Grid Corporation of the Philippines

f) The Regulatory Regime

The interviews and additional review of relevant literature allowed the consultant to identify and distill lessons learned on:

a) Effectiveness of the privatization structure and procedure;

b) Enabling and deterring factors to private sector participation in Transmission;

1.3.5. PSP in Distribution

The Distribution Sector in the Philippines is composed of sixteen (16) private investor owned distribution utilities (PUs), eight (8) municipality or local government owned utilities and one hundred nineteen (119) electric cooperatives (ECs).

A program for risk capital investment in ECs, the Investment Management Contract (IMC) was promoted by the DOE, there have been no takers. However, one EC tried a Management Services Contract scheme. There are also two experiences in PSP in municipality or local government owned utilities: one, a joint venture; and the other, a Distribution Service Management Agreement.

ACRONYMS

ARR	Annual Revenue Requirement
BSG	Business Separation Guidelines
DoE	Department of Energy
DSOAR	Distribution Services and Open Access Rules
DU	Distribution Utility
DWS	Distribution Wheeling Service
EC	Electric Cooperatives
EPIRA	Electric Power Industry Reform Act
ESMAP	Energy Sector Management Assistance Program
IMC	Investment Management Contract
IPP	Independent Power Producer
IRR	Implementing Rules and Regulations
MAP	Maximum Average Price
MAR	Maximum Annual Revenue
MO	Market Operator
MRU	Must Run Unit
NEA	National Electrification Administration
NGCP	National Grid Corporation of the Philippines
NPC	National Power Corporation
OATS	Open Access and Transmission Service Rules
PBR	Performance Based Regulation
PDC	Philippine Distribution Code
PGC	Philippine Grid Code
PSALM	Power Sector Assets and Liabilities Management Corporation
PSP	Private Sector Participation
RC	Retail Competition
RDWR	Rules for Setting Distribution Wheeling Rates
RES	Retail Electricity Supplier
RSECWR	Rules for Setting Electric Cooperatives' Wheeling Rates
RTWR	Rules for Setting Transmission Wheeling Rates
SC	Steering Committee created by the DoE
SO	System Operator
SOLR	Supplier of Last Resort
T&D	Transmission and Distribution
TRANSCO	National Transmission Corporation
USAID	United States Agency for International Development
WB	World Bank
WESM	Wholesale Electricity Spot Market

EXECUTIVE SUMMARY

The Philippine electricity industry has been undergoing restructuring directed and implemented in accordance with the Electric Power Industry Reform Act or EPIRA.

Prior to the EPIRA, central management and control of both generation and transmission in the whole country was under the state-owned National Power Corporation (NPC). Its electricity supply came from its own power plants and from Independent Power Producers (IPPs). It had sole ownership of the transmission grid and was also responsible for central systems planning and systems operations.

Electricity was supplied to end-users by franchised distribution utilities (DUs) which contracted with NPC and/or IPPs for electricity supply and with NPC for transmission of its power supply. There were also end-users not being supplied electricity by the DUs as they were "directly connected" to the transmission grid by sub-transmission assets.

The reformed structure injected by the EPIRA shows the following four sectors composing the electricity industry: generation, transmission, distribution and supply.

a) Generation is competitive and open. Prices for the supply of electricity are regulated by the Energy Regulatory Commission (ERC) for the captive market and are not subject to regulation for the competitive market.
b) Transmission is regulated, and provides open and non-discriminatory access to all electric power industry participants.
c) Distribution is regulated, requires a national franchise and provides open and non-discriminatory access to all users.
d) The DUs' obligation to supply electricity is carved out for the contestable market which shall be open and competitive to DUs with respect to their franchise area and electricity suppliers licensed by the ERC.
e) The EPIRA brought about the accomplishment of the following:
f) NPC's generation, transmission and central dispatch functions as well as the distribution utilities' wires and electricity supply business were unbundled;
g) The ERC, a quasi-judicial regulatory body, was created;
h) The Power Sector Assets and Liabilities Management Corporation (PSALM) was created to take ownership of NPC's assets and manage its privatization with the aim of liquidating all NPC debts and stranded contract costs in an optimal manner;
i) The NPC's power plants and IPPs supplying electricity to the grid have been and are currently still being privatized;
j) The transmission and central dispatch functions were assumed by the newly-created National Transmission Corporation (TRANSCO). Operation and maintenance of transmission assets and the central dispatch functions were later privatized; the concession was awarded to the National Grid Corporation of the Philippines (NGCP);
k) The Wholesale electricity Spot Market (WESM) was created for the key purpose of determining the market clearing price for spot market transactions; it also assumed NPC's centralized merit order dispatch function.

Moreover, Open access (OA) as required by the EPIRA, basically refers to the system of allowing any eligible entity the use of transmission and/or distribution system and associated facilities subject to payment of the charges duly approved by the ERC.

In the Philippines, the key issues of open transmission access – including among others cost allocation, tariff structure, support to and collaboration with the electricity market, connection services, congestion management, network safety and reliability, and protection of the environment – are significantly dealt with by the following rules and regulations, all of which emanated from and in consonance with the EPIRA and its IRR.

a) Philippine Grid Code which establishes the rules, procedures and standards ensuring the safe, reliable, secured and efficient operation, maintenance and development of the high-voltage transmission system in the Philippines;
b) WESM Rules which is intended to ensure the development of an appropriate, equitable and transparent electricity market, along with a safe, reliable, and efficient operation of the power system;
c) Rules for Setting Transmission Wheeling Rates (RTWR) which specify the methodology in setting the maximum transmission wheeling rates that may be charged by the transmission company to its customers;
d) Open Access Transmission Service Rules (OATS Rules), a critical component of which is the transmission provider's non-discriminatory and equitable method of charging and allocating the charges to its transmission customers;
e) Renewable Energy Act of 2008 wherein all stakeholders are mandated to contribute to the growth of the renewable energy industry of the country.

The key issues of open access to the distribution grid are accordingly dealt with by the following rules and regulations:

a) Philippine Distribution Code, which ensures: fair and non-discriminatory access to the distribution system, that the DUs provide reliable, safe and quality service to all its customers, and distribution planning is done in consideration of the requirements of its current and potential customers;
b) WESM Rules which is already discussed under open access to transmission;
c) Rules for Setting Distribution Wheeling Rates (RDWR) which is a methodology in setting the maximum distribution wheeling rates that may be charged by the DUs to its customers for the provision of regulated distribution service;
d) Rules for Setting Electric Cooperatives' Wheeling Rates specifying how the ECs' tariffs are regulated;
e) The Distribution Services and Open Access Rules (DSOAR) setting forth among others the terms and conditions related to the provision of Connection Assets and Services, service to the Captive market, Supplier of Last Resort (SOLR) service to the contestable Market, unbundled Distribution Wheeling Service (DWS) provided to the Contestable Market, and the procedures for establishing regulated service rates for DUs;
f) Renewable Energy Act of 2008 which mandates that: subject to technical considerations and without discrimination and upon request by distribution end-users, the distribution utilities shall enter into net-metering agreements with qualified end-users who will be installing renewable energy system.

Inputs from the Consultant relating to open access to transmission and distribution are:

a) The structure of Distribution Wheeling Rates Charges to End-users should be developed; this may start at the RDWR to appropriately allocate the approved asset related costs and operating expenses into the proper distribution functions;
b) The System Operator needs to be transparent and its procedures and protocols need to be documented for the Market Operator and other interested parties to understand how the SO implements the actual dispatch of generation facilities;

c) There is need to strengthen the ERC to be able to do audits and checks to ensure that in truth and reality, policies, rules and regulations are complied with.

Retail competition is an ultimate objective of the EPIRA; it is the rivalry among Retail Electricity Suppliers (RES) to provide supply services to customers in the contestable market by offering lower rates and added customer services. It is also stressed that the RC&OA framework should consider incentive to progress as a vital driving force.

It is believed that RC&OA, to efficiently operate and successfully achieve its intended objectives, should comply with the following requisites indicated in the EPIRA:

a) Establishment of the WESM is necessary as the wholesale and retail markets mutually reinforce each other;
b) Unbundling is necessary as each of the components of the total cost of electricity is addressed distinct from each other;
c) Implementation of the Cross Subsidy Removal Scheme rationalizes and provides the true cost of electricity to various groups;
d) Privatization of at least 70% of the total capacity of generating assets of NPC in Luzon and Visayas and transfer of the management and control of at least 70% of the total energy output of power plants under contract with NPC to the IPP Administrators are necessary to restrain market power.

Led by the DoE, preparations are now underway for the implementation of retail competition and open access in the Philippines. The following rules have been done:

a) Rules for the Issuance of Licenses to Retail Electricity Suppliers (RES);
b) Code of Conduct for Competitive Retail Market Participants;
c) Rules for Customer Switching;
d) Rules for the Supplier of Last Resort (SOLR);
e) Rules on Rate Filing by the Supplier of Last Resort;
f) Competition Rules and Complaint Procedures;
g) Business Separation Guidelines (BSG);
h) Rules for Contestability.

Other areas which are still lacking are:

a) enhancement of the WESM to handle billing and settlement of retail suppliers who would be among the WESM participants;
b) designation of a central registration body and installation of a mechanism to convey customer switching information and meter data from the DUs to the retail supplier and wholesale market operator.

On RC&OA, the consultant notes the following among others:

a) It is essential to more thoroughly assess the adequacy of generation supply and transmission network to sustain the retail market;
b) The RC&OA is a first-time implementation in the country. Seeking the help of the veritable experts, from other jurisdictions, who have experienced all the prime successes and failures would be most advantageous to the Philippines.

Further, among the EPIRA's policy declarations are the enhancement of private capital inflow and broadening of ownership base in generation, transmission and distribution.

In transmission, the EPIRA mandated the privatization of TRANSCO by either outright sale or a concession contract awarded through competitive bidding. The Concession is for 25 years, renewable up to another 25 years, under the terms and conditions mutually agreed by PSALM, TRANSCO and the Concessionaire.

The Concession includes (a) take over and operation of the regulated transmission business as a going concern, and, (b) carrying on any Related Business in accordance with Applicable Law during the concession period. As a result of the bidding process, the NGCP formally took over and has been operating the facilities and assets of the TRANSCO since January 15, 2009. Subsequently, NGCP obtained a congressional franchise in late 2008, remitted USD987.5 million to PSALM, equivalent to 25% of the US$3.950 billion purchase price and fulfilled all conditions precedent.

The Concession Fee represents the net present value of all future cash flows to the Concessionaire. 25% of the Concession Fee is required to be paid up-front in US$. The remaining 75% will be converted to Philippine Pesos at pre-set exchange rate and payable in deferred payments in Philippine Pesos carrying interest at pre-determined rate spread over a preset amortization profile of up to 15 years. The intent is to mirror a financially "geared" business in line with international practice for similar businesses.

The ERC regulates the Concessionaire mainly through the TWRG. Among the ERC's responsibilities is the determination and approval of the Transmission Wheeling Charges. Its approval is also required before any capital expenditure is undertaken.

A lesson which can be learned is on the aspect of what attracted investors to participate in the competitive bidding process for the privatization of TRANSCO: These are:

a) Transco's strong operational and financial performance;
b) Attractive growth rate in GDP growth and electricity demand;
c) Robust performance-based regulatory framework;
d) Clear privatization structure with economics akin to outright purchase of assets;
e) Transparent and clear bid process and rules; and
f) Sufficient Opportunity for Due Diligence.

Moving on to the distribution sector, the distribution of electric power generated is currently undertaken by 16 investor-owned private utilities, 8 municipality or local government unit owned utilities, and 119 electric cooperatives. All these are regulated by the ERC.

Private sector experiences in distribution deal with municipality or local government unit owned utilities, and electric cooperatives (ECs).

The Investment Management Contract (IMC) Model is applied for ECs. It is a contractual relationship between a willing EC and a willing investor-operator, for the infusion of risk capital and provision of management expertise by the latter to the former, to provide for EC recovery based on improved efficiency, lower costs and systems losses reduction. Its main features are:

a) The EC remains the duly authorized distribution utility and regulated by the ERC;
b) The EC retains ownership and strategic control of its assets, as well as control over setting the standards of service to its customers;
c) The investor-operator shall operate and maintain the distribution utility and provide for its capital expenditures. It will be remunerated where systems loss reduction is achieved and costs are considerably decreased, through an equitable profit-sharing and/or lease option scheme;
d) The member-consumers of the EC, through the EC Board, continue to exercise the rights and responsibilities under its franchise.

The DoE supports only IMC transactions concluded through a transparent and competitive bidding process.

An experience to learn from is when Zambales EC (ZAMECO) entered into an IMC for a period of 5 years with the Philippine Power Distributors Investment Corporation which became effective on December 2, 2002. This was amended and superseded by a Management Services Contract (MSC) dated September 1,

2003. The MSC was a management concession for the general management, administration, operation and maintenance of ZAMECO. Subsequent extensions after the expiration of the said MSC brought about protest actions by the municipal mayors of the towns within the franchise area alleging that the ZAMECO Board was overstaying in its term. This led to a series of court actions, some still pending, and the end of the MSC and its renewal.

Another experience is in the Bohol Province. The Provincial Government was having cash flow problems arising from collection inefficiencies, which compromised its ability to promptly pay its bills to NPC. In addition, it needed funding to improve and expand the distribution system to better serve its consumers. Solutions that were proposed are:

a) a joint venture between the winning proponent and the Province in accordance with the Civil Code in relation to the rehabilitate-own-operate-and-maintain (ROOM) scheme in the Build-Operate-Transfer (BOT) Law;
b) the indebtedness of the Province would be factored in the bid's financial aspect;
c) the purchase price of the utility to be based on the appraised value; and
d) a program on the upgrade of the system.

In the public bidding conducted, the bid of the consortium of Salcon International, Inc. Salcon Limited and Salcon Power Corporation won on the purchase price, which included the debt balance of the Province to Land Bank plus the equity share of the Province in the special purpose company at 30% of the authorized capital stock of the Bohol Light Company, Inc.

Moreover, the Subic Bay Metropolitan Authority bidded out a Distribution Services Management Agreement which is essentially a concession agreement for 25 years: 5 year rehabilitation and a 20 year operation, management and maintenance period in exchange for an upfront fee, which partake the nature of rental. The consortium of Aboitiz Equity Ventures and Davao Light and Power Company won the bid. As a result of the privatization, the distribution tariff was reduced from PhP1.00/kWh to PhP0.5975/kWh.

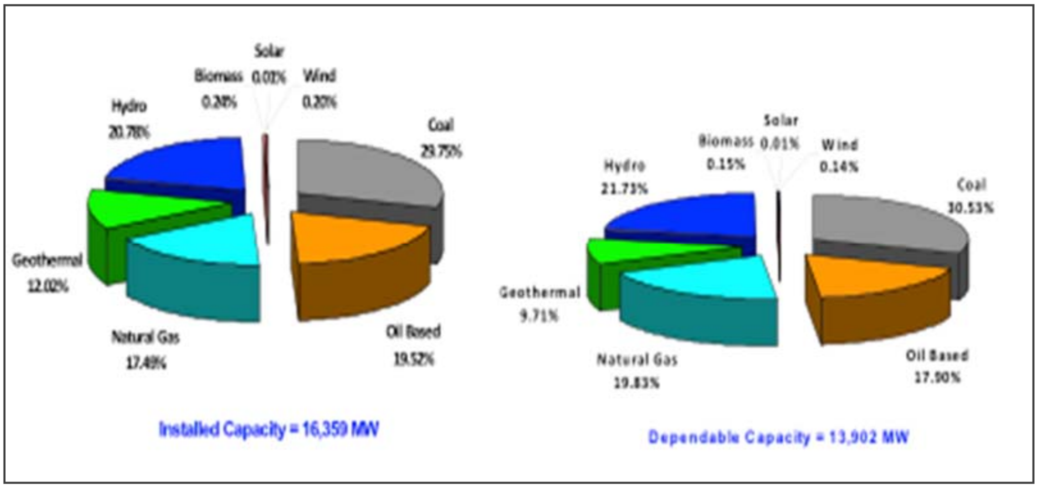
PHILIPPINES CASE STUDY

1. PHILIPPINES' POWER SECTOR OVERVIEW

The stability and reliability of power supply remains a challenge in the Philippines.

In 2010, the total installed and dependable capacity was at 16, 359 MW and 13,902 MW respectively. This is an increase of 632 MW from 2009 as four new power plants were connected to the grid. Three (3) coal-fired power plants were added to the Visayas: 3 x 82 MW of Cebu Energy Development Corporation (CEDC), 2 x 72 MW by Panay Energy Development Corporation (PEDC) and 2 x 100 MW by KEPCO-Salcon. The fourth power plant was the 42 MW Sibulan Hydroelectric Power Plant in Mindanao.

Figure 1.1. Philippines' Total Installed and Dependable Capacities, in MW



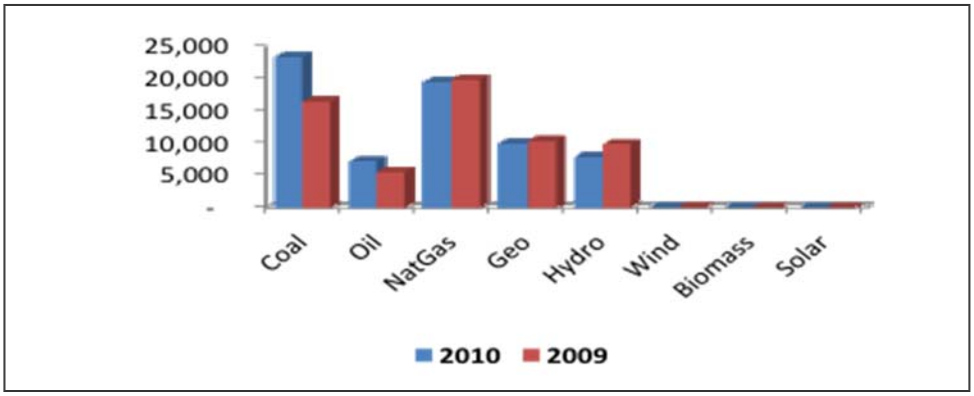
The Philippines' system peak demand was at 10,231 MW

Table 1.1. System Peak Demand, in MW

GRID	2010	2009	Difference	
			MW	%
Luzon	7,656	6,928	728	10.5
Visayas	1,431	1,241	190	15.3
Mindanao	1,288	1,303	-15	-1.2
Philippines*	10,231	8,965	1,266	14.1

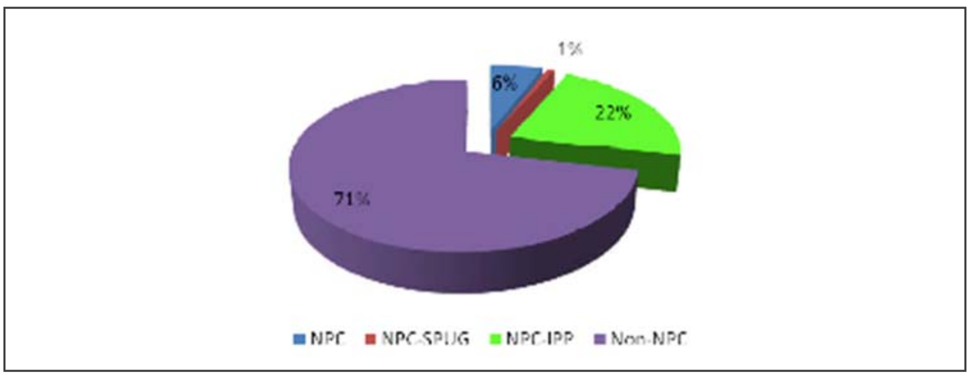
Gross generation all over the country reached 67,743 GWH in 2010.

Figure 1.2. Gross Generation by Plant Type, in GWH



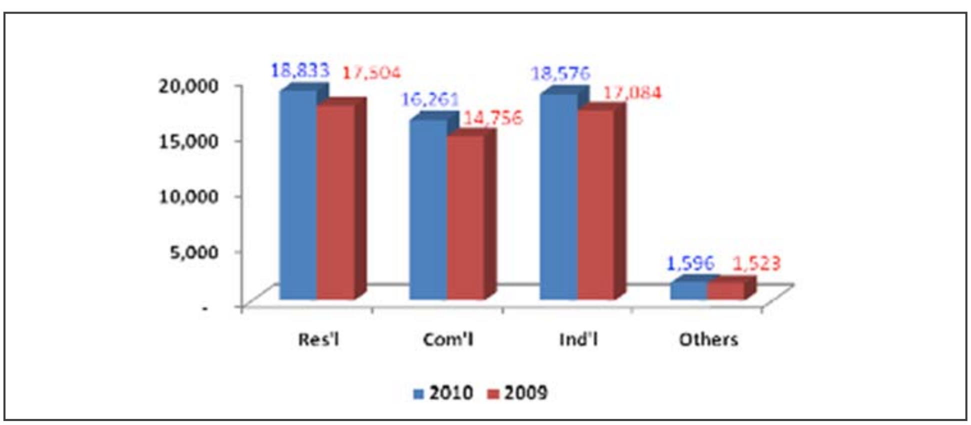
Due to the turnover of the National Power Corporation (NPC) power plants and Independent Power Producer (IPP) contracts, generation from non-NPC generating facilities had a 71.5 percent share.

Figure 1.2. Generation by Ownership, in GWH



Electricity Sales in 2010 grew to 55,266 GWH from 2009's 50,868 GWH, an 8.6 percent increase.

Figure 1.3. Electricity Sales, in GWH



The latest Power Development Plan issued by the Department of Energy was for 2009-2030. It projected the annual average growth rate on the peak demand in Luzon at 4.5 percent, with Visayas and Mindanao slightly higher at 4.6 percent. As the following graphs show, the critical period in Luzon was projected to be in 2011 while that of Mindanao in 2010. Visayas was expected to be in tight supply in 2010 but was relieved with the coming-in of the 3 coal-fired power plants.

Figure 1.4. Luzon Supply-Demand Outlook

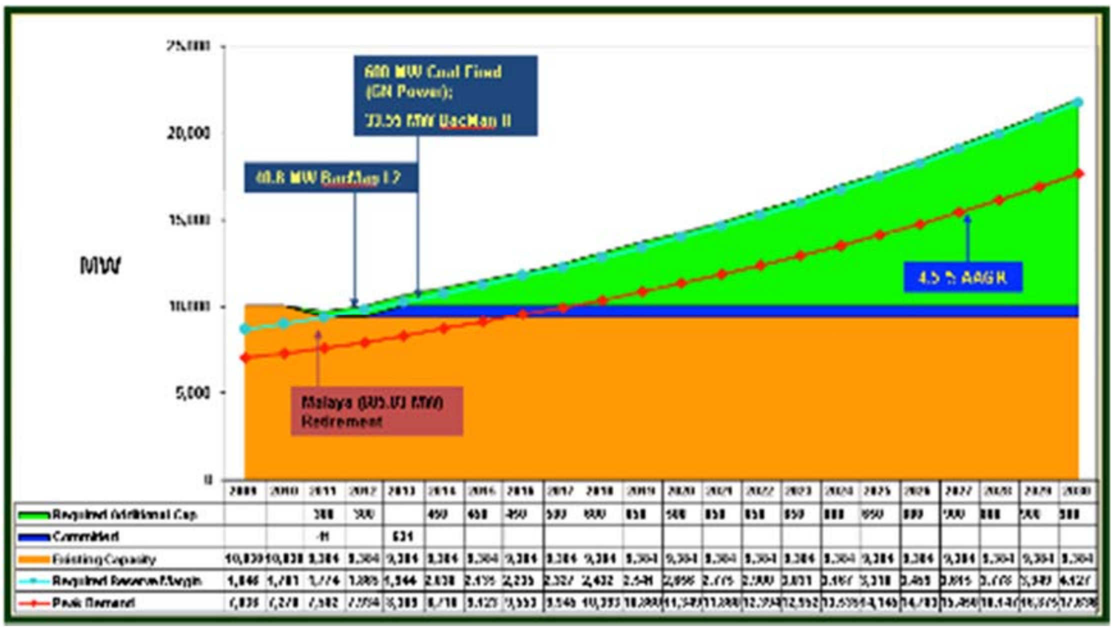


Figure 1.5. Visayas Supply-Demand Outlook

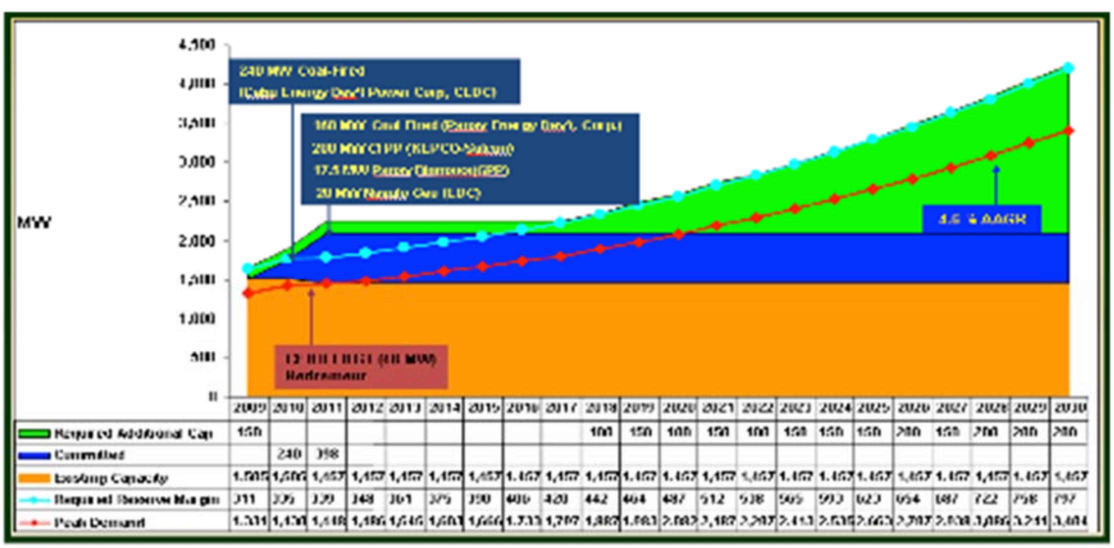
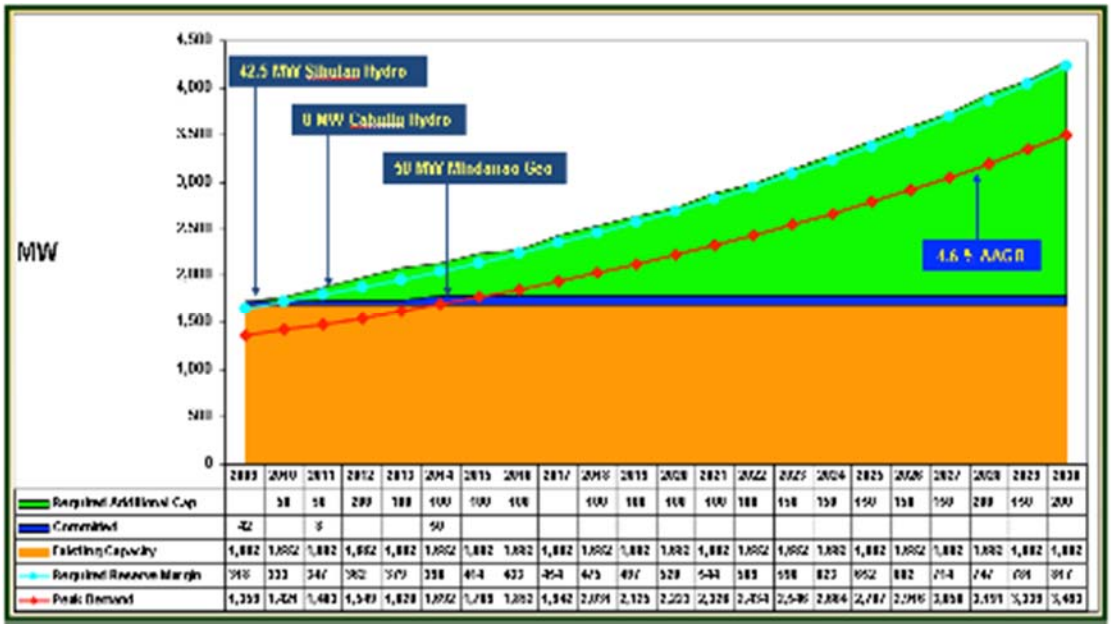


Figure 1.6. Mindanao Supply-Demand Outlook



2. OVERVIEW OF THE PHILIPPINE ELECTRIC POWER INDUSTRY REFORM (EPIRA)

The reforms in the Philippine electric power industry were directed by and being implemented in accordance with Republic Act (RA) No. 9136, the Electric Power Industry Reform Act of 2001, or EPIRA. The EPIRA was passed by the Philippine House of Representatives and the Senate on May 31, 2001 and June 4, 2001, respectively and approved by the President on June 8, 2001. It was published on June 25, 2001 and became effective on July 10, 2001. Its Implementing Rules and Regulations (IRR) was promulgated by the Department of Energy and approved by the Joint Congressional Power Commission (JCPC) on February 27, 2002.

The ultimate goal of the reforms is to attain open access and retail competition in the electric power industry. To attain this, the electric power industry had to be restructured and the assets of the NPC privatized.

2.1. Objectives of the Reform

Section 2 of the EPIRA declares the policy of the Philippine government as follows:

a) To ensure and accelerate the total electrification of the country;
b) To ensure the quality, reliability, security and affordability of the supply of electric power;
c) To ensure transparent and reasonable prices of electricity in a regime of free and fair competition and full public accountability to achieve greater operational and economic efficiency and enhance the competitiveness of Philippine products in the global market;
d) To enhance the inflow of private capital and broaden the ownership base of the power generation, transmission and distribution sectors;
e) To ensure fair and non-discriminatory treatment of public and private sector entities in the process of restructuring the electric power industry;

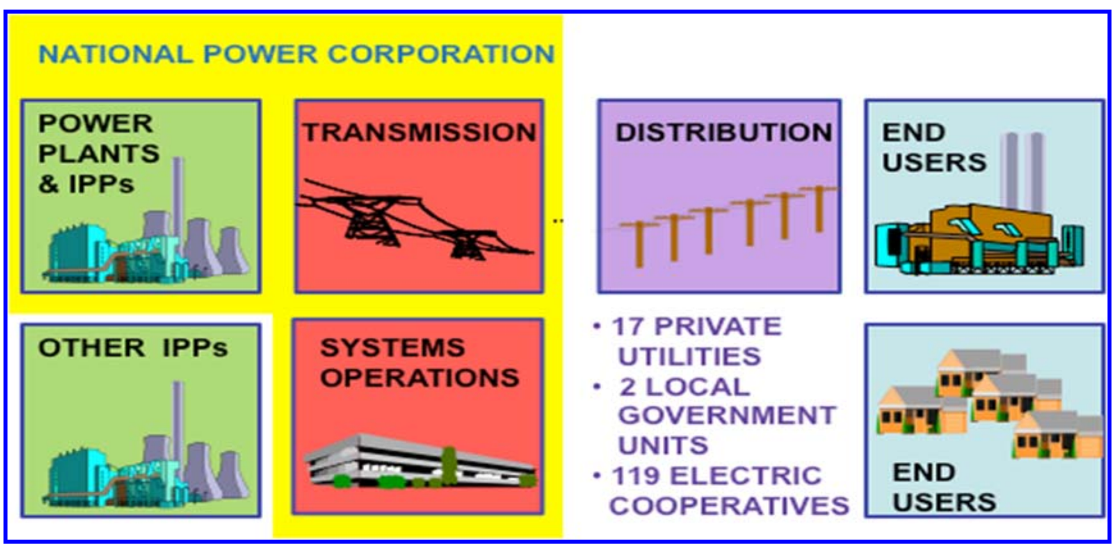
f) To protect the public interest as it is affected by the rates and services of electric utilities and other providers of electric power;
g) To assure socially and environmentally compatible energy sources and infrastructure;
h) To promote the utilization of indigenous and new and renewable energy resources in power generation in order to reduce dependence on imported energy;
i) To provide for an orderly and transparent privatization of the assets and liabilities of the National Power Corporation;
j) To establish a strong and purely independent regulatory body and system to ensure consumer protection and enhance the competitive operation of the electricity market; and
k) To encourage the efficient use of energy and other modalities of demand side management.
l) The above policies are reckoned as the objectives of the EPIRA.

2.2. Structure and Ownership before the EPIRA

As shown in Figure 2.2.1 below, the state-owned NPC was a vertically integrated utility that was responsible for central management and control of both generation and transmission of electricity in the whole country. Its supply of electricity came from its own power plants and from Independent Power Producers (IPPs). It had exclusive ownership of the transmission grid and was also responsible for central systems planning and systems operations. The transmission grid included sub-transmission assets as discussed below.

Electricity was supplied to end-users by distribution utilities that have franchise over a specific geographical area. There were 16 privately-owned distribution utilities, 8 local government owned distribution utilities and 119 electric cooperatives (ECs). The distribution utilities contracted with NPC and/or IPPs for the supply of electricity and with the former for the transmission of its power supply.

Figure 2.2.1. Structure and Ownership before the EPIRA



There were also end-users that were not being supplied electricity by the distribution utility as they were “directly connected” to the transmission grid by sub-transmission assets. Sub-transmission assets were defined in the EPIRA as referring “to the facilities related to the power delivery service below the transmission voltages and based on the functional assignment of assets including, but not limited to step-down transformers used solely by load customers, associated switchyard/substation, control and protective equipment, reactive compensation equipment to improve customer power factor, overhead lines, and the land where such facilities/equipment are located. These include NPC assets linking the transmission system and the distribution system which are neither classified as generation nor transmission."

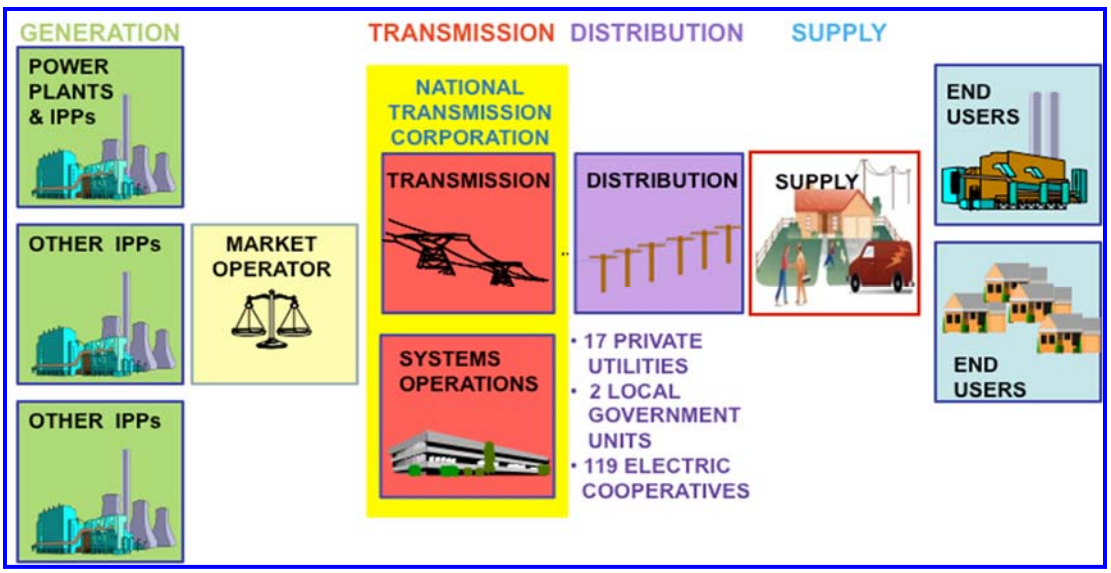
The NPC was under the supervision of the Department of Energy (DoE) which was in-charge of energy policy and the Philippine energy program. The DoE also had supervision over the National Electrification Administration (NEA), which in turn, had supervision over the ECs.

Annex 1 discusses the road traveled by NPC that culminated in the promulgation of the EPIRA.

2.3. Structure injected by the EPIRA

Figure 2.3.1 below shows the envisioned electric power industry, composed of four sectors: generation, transmission, distribution and supply.

Figure 2.3.1. Four Sectors of the Philippine Electric Industry



2.3.1. Generation

Generation of electric power is competitive and open. It is not considered a public utility operation and is not required to secure a national franchise. Prices for the supply of electricity shall be regulated by the Energy Regulatory Commission (ERC) for the captive market and shall not be subject to regulation for the competitive market.

2.3.2. Transmission

The transmission of electric power is a regulated common electricity carrier business that provides open and non-discriminatory access to all electric power industry participants.

The sub-transmission assets are segregated from the transmission facilities in accordance with the levels of transmission and sub-transmission voltage that is set by the ERC, and subsequently disposed to the distribution utilities which shall be responsible for operating, maintaining, upgrading, and expanding said assets.

2.3.3. Distribution

The distribution of electricity to end-users is a regulated common carrier business requiring a national franchise and provides open and non-discriminatory access to all users.

Distribution of electric power to all end-users is undertaken by private distribution utilities, cooperatives, local government units presently undertaking this function and other duly authorized entities, subject to regulation of the ERC. The distribution sector is composed of 16 private distribution utilities; 119 electric cooperatives, 8 municipality or local government owned distribution utilities.

2.3.4. Supply

The distribution utilities' obligation to supply electricity is carved out for the contestable market (customers) which shall be open and competitive to distribution utilities with respect to their franchise area and electricity suppliers that shall be licensed by the ERC. Prices for the supply of electricity to the contestable market shall not be regulated by the ERC.

2.4 Process of Getting There

2.4.1 Restructuring

To attain the four sectors, the NPC's generation and transmission functions as well as the distribution utilities' wires and electricity supply business were unbundled. In addition, the central dispatch function of the NPC was likewise unbundled into physical and systems operation dispatch and merit order dispatch. The former was included in the transmission function and the Wholesale Electricity Spot Market (WESM) was created for the latter.

The transmission function of the NPC was assumed by a newly-created company, the National Transmission Corporation (TRANSCO) which is wholly owned by the Power Sector Assets and Liabilities Management Corporation (PSALM). TRANSCO's authority and responsibility is the planning, construction, and centralized operation of the transmission facilities, including grid inter-connection, and ancillary services. TRANSCO's assets were later privatized and are now being operated by the National Grid Corporation of the Philippines (NGCP).

The generation function of the NPC can be split into grid and off-grid. The power plants and IPPs supplying electricity to the grid have been and are currently still being privatized. Ultimately, NPC will only be responsible for the electricity supply to the off-grid and may entertain private sector participation to fulfill its mission.

The distribution utilities retained its obligation to supply electricity to the captive customers within its franchise area albeit subject to the least cost criteria. However, its obligation to supply electricity to the contestable customers within its franchise area was made open to competition among electricity suppliers.

NPC's centralized merit order dispatch has now been assumed by the WESM, which has been established, composed of the WESM participants, for the purpose of providing and setting the price of actual variations from the quantities transacted under contracts between sellers and purchasers of electricity. The WESM rules provide, among others, procedures for: (a) establishing the merit order dispatch instructions for each time period; and, (b) determining the market-clearing price for such time period.

2.4.2 Privatization of Generation and Transmission

Chapter V of the EPIRA mandates the privatization of the assets of NPC, including the generation assets, real estate, and other disposable assets as well as IPP Contracts, with the exclusion of the assets of the Strategic Power Utilities Group and the Agus and Pulangui Hydro complexes in Mindanao.

It was envisioned that the NPC plants and IPP contracts would be grouped to form generation companies that would have the following characteristics:

1. Financially viable,
2. Broad geographical groupings so there would be no regional companies or consolidation of market power,
3. Does not dominate any part of the market or the load curve, and
4. Attractiveness to potential investors.

In the case of the geothermal complexes, the steam-field assets and generating plants shall be sold together and not separately.

The PSALM was created to take ownership of NPC's assets and to manage its privatization with the objective of liquidating all NPC financial obligations and stranded contract costs in an optimal manner. The prospect was that the privatization proceeds would at least cover NPC's financial obligations.

The PSALM began its privatization efforts in earnest betting on the biggest ticket item, TRANSCO. However, its first two attempts in 2003 were unsuccessful. The TRANSCO privatization then only attracted a lone interested party. The main concern was that the regulatory regime for TRANSCO was not in place and future revenue streams could not be readily estimated.

The WESM was also not yet in place and PSALM was still having difficulty in addressing NPC's Transition Supply Contracts. Thus, PSALM started off with pilot privatization cases of 5 small hydro plants ranging in capacity from 0.4 to 3.5 MW which were successful. This gave PSALM the opportunity to test and fine tune the bidding process and the confidence to go for bigger plants. As of December 31, 2010, PSALM has sold 4,320.33 MW of NPC Plants and 3,345.75 MW of contracted IPP capacity.

Table 2.4.2.1. Generation Plants Sold by PSALM

FUEL TYPE	PLANT NAME	LOCATION	RATED CAPA-CITY	BID DATE	SALES PRICE (US$ MILLION	TURN-OVER DATE
HYDRO	Talomo	Davao, Mindanao	3.5	03/25/2004	1.37	01/19/2005
	Agusan	Bukidnon, Mindanao	1.6	06/04/2004	1.53	03/29/2005
	Barit	Camarines Sur, Luzon	1.8	06/25/2004	0.48	01/21/2005
	Cawayan	Sorsogon, Luzon	0.4	09/30/2004	0.41	06/30/2005
	Loboc	Bohol, Visayas	1.2	11/10/2004	1.43	06/30/2005
	Pantabangan-Masiway	Nueva Ecija, Luzon	112.0	09/06/2006	129.00	11/17/2006
	Magat	Isabela, Luzon	360.0	12/14/2006	530.00	04/25/2007
	Ambuklao-Binga	Benguet, Luzon	175.0	11/28/2007	325.00	07/10/2008
	Amlan	Negros Oriental, Visayas	0.8	12/10/2008	0.23	06/24/2009
	Angat	Bulacan, Luzon	218.0	04/28/2010	440.88	[2]
COAL-FIRED	Masinloc	Zambales, Luzon	600.0	07/26/2007	930.00	04/17/2008
	Calaca	Batangas, Luzon	600.0	07/08/2009	361.71	12/03/2009
GEO-THERMAL	Tiwi-Makban	Albay/Laguna, Luzon	747.5	07/30/2008	446.89	05/25/2009
	Palinpinon-Tongonan	Negros Oriental/Leyte, Visayas	305.0	09/02/2009	220.00	10/23/2009
	Bacon Manito	Sorsogon/Albay, Luzon	150.0	05/05/2010	28.25	09/03/2010
DIESEL / BUNKER	Panay I, Panay III & Bohol	Panay/Bohol, Visayas	168.5	08/12/2008	5.86	03/25/2009
	Power Barge 117	Agusan del Norte. Mindanao	100.0	07/31/2009	16.00	03/01/2010
	Power Barge 118	Davao, Mindanao	100.0	07/31/2009	14.00	02/06/2010
	Limay Combined	Bataan, Luzon	620.0	08/26/2009	13.50	01/18/2010

	Cycle					
	Naga Land-Based	Cebu, Visayas	55.0	10/16/2009	1.00	01/29/2010
THERMAL	Manila Thermal[1]	Manila, Luzon		04/25/2008	2.51	02/20/2009
DIESEL / BUNKER	Aplaya General Santos[1]	Misamis/General Santos, Mindanao		05/25/2009	1.49	10/02/2009
	Cebu II[1]	Cebu, Visayas		01/22/2009	0.46	05/25/2009
Total Luzon, Visayas & Mindanao[3]			4,102.23		3,031.12	
Total Luzon & Visayas[3]			3,897.20			
70% of Total Installed Capacity in Luzon & Visayas			3,370.31			

[1] Decommissioned

[2] Pending turnover to winning bidder due to the Status Quo Ante Order by the Supreme Court

[3] Excluding Angat

FUEL TYPE	POWER PLANT	LOCATION	CON-TRACTED CAPACITY (MW)	BID DATE	SALES PRICE (US$MILLION)
COAL-FIRED	Pagbilao	Quezon, Luzon	700.00	08/28/2009	691
	Sual	Pangasinan, Luzon	1,000.00	08/28/2009	1,070
HYDRO	San Roque	Pangasinan, Luzon	345.00	12/15/2009	450
	Bakun-Benguet	Ilocos Sur/Benguet, Luzon	100.75	12/15/2009	145
NAT GAS	Ilijan	Batangas, Luzon	1,200.00	04.16/2010	870
Total			3,345.75		3,226
70% of Total Contracted Capacity (Luzon & Visayas)					

The privatization of the transmission assets is discussed in detail in section 5 below.

2.4.3 Implementation of Retail Competition and Open Access (RC&OA)

Towards the ultimate implementation of RC&OA, Section 31 of the EPIRA established the pre-conditions as follows:

“Any law to the contrary notwithstanding, retail competition and open access on distribution wires shall be implemented not later than three (3) years upon the effectivity of this Act, subject to the following conditions:

a) Establishment of the Wholesale Electricity Spot Market (WESM);
b) Approval of unbundled transmission and distribution wheeling charges;
c) Initial implementation of the Cross Subsidy Removal Scheme;
d) Privatization of at least seventy percent (70%) of the total capacity of generating assets of NPC in Luzon and Visayas; and
e) Transfer of the management and control of at least seventy percent (70%) of the total energy output of power plants under contract with NPC to the IPP Administrators.”

Corollary to this, Section 3 Rule 12 of the EPIRA Implementing Rules and Regulations (IRR) mandates the ERC to declare the initial implementation of RC&OA as follows:

“The ERC shall, after due notice and public hearing, declare initial implementation of Open Access not later than three (3) years upon the effectivity of the Act, subject to the following conditions:”

a) Establishment of the WESM.
    - For this purpose, the “establishment of the WESM” shall be deemed to have occurred upon the effectivity of the Market Rules by the DoE and initial operation of the Autonomous Group Market Operator (AGMO) pursuant to the WESM.
b) Approval of unbundled Transmission and Distribution Wheeling Charges.

- The ERC shall approve the unbundled rates of NPC and DUs, which shall include the transmission and wheeling charges, within one (1) year from the effectivity of the Act.

c) Initial implementation of the Cross Subsidy Removal Scheme.
   - For this purpose, initial implementation of the cross subsidy removal scheme shall occur on the next billing period after the issuance of ERC approval. The scheme for cross subsidy removal shall include guidelines or a schedule for the removal of each type of cross subsidy and may be altered, modified and/or amended by the ERC.

d) Privatization of at least seventy percent (70%) of the total capacity of generating assets of NPC in Luzon and Visayas.

e) Transfer of the management and control of at least seventy percent (70%) of the total energy output of power plants under contract with NPC to the IPP Administrators.
   - Due to inevitable delays in meeting the aforesaid conditions, the ERC, in its Resolution No. 3, Series of 2007 (A Resolution Indicating the timeline for full Retail Competition and Open Access in Luzon), reiterated the legal requisites to Open Access and identified two (2) other vital requirements that must be in place prior to the start of the Retail Market, namely:

f) the adequacy and establishment of all necessary infrastructures, including, but not limited to: transmission networks, generation supply and the customer switching system; and

g) The promulgation of all pertinent rules and regulations governing open access and retail competition.

3. Open Access

3.1. Definitions

As formulated by World Bank staff upon adoption of certain modifications suggested by Mr. Budak Dilli of Turkey:

“Open access to T&D grid is a prerequisite for a competitive market regime (including the rules and procedures covered in regulations and the pricing arrangements for the connection and the use of the system) that enables a generator or a consumer/buyer of electricity to use the transmission grid/distribution network owned by others. Open access means that everyone gets the same deal, with no discrimination in the opportunity to use T and D grid, or in the cost to use them. The main purpose is to create competition by allowing market agents to buy and sell electricity from/to one another (directly or through a market operator), independently of who owns and operates the power grid. Competition can proceed in stages (with large/wholesale market agents typically given priority), but the existence of multiple sellers (generators) and buyers interacting in the market is usually considered an indispensable feature of an open access regime. In many markets, competition is further enhanced by the introduction of intermediaries such as independent suppliers/traders – i.e., firms that specialize in energy trading, but do not own or operate distribution networks. These firms are allowed to compete with distributors for a share of the final consumers’ market”.

Specifically, in the Philippines, the EPIRA defines open access, in basic terms, as referring to the system of allowing any qualified person the use of transmission and/or distribution system and associated facilities subject to the payment of transmission and/or distribution retail wheeling charges duly approved by the ERC. As such, open access provides non-discriminatory access to transmission and distribution systems to (a) WESM participants, (b) the Transmission Company (the National Grid Corporation of the Philippines, or NGCP, which has been awarded the concession agreement), (c) Distribution Utilities, (d) Economic Zones, (e) Suppliers, (f) IPP Administrators, (g) Market Operator (MO) and (h) End-users in the Contestable Market.

3.2. Rationale and Benefits of Open Access

As given in the aforesaid definition, Open Access is not an end in itself but rather, a pre-requisite to the ultimate objective of the Philippine EPIRA, which is the establishment of a level playing field for a competitive and spirited electricity market (wholesale and retail) in the Philippines.

An intermediate objective is to motivate the much needed mobilization of private sector capital, which has also been indicated as one of the primary objectives of the EPIRA. This intermediate objective would consequently help the promotion of a vibrant electricity market; nevertheless, in itself, the inflow of private capital, is expected to divest the Philippine government from the huge funding requirements for the electrification mission for the country – a basic and crucial necessity in practically every activity or movement, which spells the sustenance, at the least, and the development and growth, to aim more, of the nation.

The generation and distribution businesses would be motivated to invest more on the requirements of the country, where assets of the firm would be optimally used and accordingly yield the levelheaded revenues for them. These generation and distribution sectors are the primary customers of the transmission business; as such, they accordingly support the transmission business in providing a vigorous customer base - the best impetus of most organizations.

3.3. Open Access to the Transmission Grid

3.3.1. Pre-EPIRA Regime

As indicated in Section 2.2 of this report, during the pre-EPIRA regime, NPC had the authority to centrally manage and control both generation and transmission of electricity in the country, including systems planning and systems operations. Even if NPC's supply of electricity came both from its own power plants and from its IPPs, open access to the transmission grid on the side of generation was not much of an issue. Merit order dispatch based on pre-defined technical criteria (which include cost, security, and reliability provided by 'must run' plants, among others) has also been applied both for NPC's own plants and its IPPs, which were also treated like its own plants, because of the 'take or pay' provisions in the IPP contracts. The said treatment of NPC's IPPs in the merit order dispatch, if implemented otherwise, would result in sub-optimal utilization of its generation supply and would disadvantage the corporation itself. However, the problem area could have been that, the NPC being both the generator and the system operator, violating the merit order dispatch was possibly not much of an issue. The aforesaid sub-optimal utilization of generation could have potentially occurred if the merit order dispatch was not appropriately complied with 100% of the time.

Also, during the pre-EPIRA regime, big industries, motivated by the need to have lower rates through bypassing the need to pay distribution charges, were allowed by NPC to directly connect to the transmission grid through sub-transmission lines and not to the distribution network. This was refuted by the DUs citing their authority to supply end-users in their franchise area. To resolve the issue, Section 8 of the EPIRA mandates that the sub-transmission functions and assets shall be segregated from the transmission functions and assets. The sub-transmission assets shall be operated and maintained by TRANSCO until their disposal to qualified DUS which are in a position to take over the responsibility for operating, maintaining, upgrading, and expanding said assets.

3.3.2. EPIRA Regime

With the implementation of the EPIRA, as part of the implementation of open access to the transmission grid, the WESM, independent from generation, transmission, distribution and supply, was established; transmission, generation and system operation, all of which were under the umbrella of NPC, were unbundled.

The transmission and system operation functions are now under the functional umbrella of the NGCP. As such, the NGCP cannot have ownership or interest in the generation sector.

As discussed in Section 2.4.1 of this report, the NGCP now operates and maintains the country's power transmission network which includes approximately 19,500 circuit kilometers of transmission lines and 23,900 MVA of substation capacity. Its primary function is the transmission of electricity through its high-voltage wires, in response to system and market demands: (a) from generator connection points to distribution network and directly connected end-user connection points, between the three major regions of the Philippines (Luzon, Visayas and Mindanao), thereby increasing reliability.

Ultimately, the aforementioned set up is viewed to reduce the overall cost of generation nationally.

NGCP's tasks can be grouped into the following key responsibility areas:

a) System Operation (SO) which involves managing the national grid, dispatching generation and managing the system, including the arrangement for ancillary services. As the SO, NGCP balances the demand and supply of electricity and puts online the right mix of power plants, to serve efficiently all of its customers, which include generators, DUs, ECs and government–owned utilities, eco-zones, industries and directly-connected customers;
b) Network Reliability wherein NGCP provides the appropriate levels of network reliability in accordance with the requirements of the Philippine Grid Code (PGC);
c) Provision of effective, timely and efficient connection services, including metering and related services, to its customers;
d) Delivering services with due consideration to safety requirements and environmental protection; and
e) Efficient and effective services supporting the requirements of the operation and maintenance of the WESM.
f) Additionally, the NGCP operates the sub-transmission assets from its high-voltage delivery points to end-users; these assets have been offered for sale to the DUs in compliance with the requirements of the EPIRA.

3.4. Policies, Rules and Regulations Governing Open Access to the Transmission Grid

Section 9(a) of the EPIRA mandates that as part of its functions and responsibilities, the TRANSCO or its concessionaire, should provide open and non-discriminatory access to its transmission system to all electricity users.

The key issues of open transmission access – including among others cost allocation, tariff structure, support to and collaboration with the electricity market, connection services, congestion management, network safety and reliability, and protection of the environment – are significantly dealt with by the following rules and regulations, all of which emanated from and in consonance with the EPIRA and its IRR.

3.4.1. Philippine Grid Code (PGC)

The PGC establishes the basic rules, requirements, procedures and standards that ensure the safe, reliable, secured and efficient operation, maintenance and development of the high-voltage Transmission System in the Philippines. It identifies and recognizes the responsibilities and obligations of three key independent functional groups: (a) the Transmission Grid Owner, (b) the System Operator, and (c) the Market Operator.

Furthermore, the PGC defines the responsibilities of the MO, SO, grid owner, generators, DUs and other users for generation scheduling. As far as open access to the transmission grid is concerned, the policies, rules and regulations on: criteria for scheduling and dispatch, the procedures for generation scheduling and the central dispatch procedure, when faithfully adhered to, should fairly provide an optimum dispatch schedule, based on market forces and the technical criteria for scheduling and dispatch, without sacrificing power quality and reliability and security of the grid. Taking in hand open access, these are both for the benefit of generators on one side and the suppliers and users on the other side.

Revision of the PGC is underway to make it more in accordance with the current requirements. One important issue that needs to be revisited is the level of Ancillary Services that needs to be provided.

Annex 2 encapsulates the contents of the PGC and its applicability.

3.4.2. WESM Rules

The WESM Rules establish the rules, requirements and procedures governing the operation of the Philippine wholesale electricity market. It is complementary with the Philippine Grid and Distribution Codes, all of which are intended to ensure the development of an appropriate, equitable and transparent electricity market, along with a safe, reliable, and efficient operation of the power system.

Relating specifically to open access, the WESM Rules are, among others, aimed at promoting competition, providing efficient, competitive, transparent and reliable spot market, encouraging market participation, enabling access to the spot market, providing the terms and conditions to which entities may be authorized to participate in the WESM. All these curtail, if not eliminate, entry barriers to the spot market wherein the transmission grid plays an important part.

Open access to the power system is reiterated in Section 1.2.5 (c) of the WESM Rules declaring that the objectives of the spot market are to establish a competitive, efficient, transparent and reliable market for electricity where … (c) third parties are granted access to the power system in accordance with the Act (EPIRA).

Akin to the objective of the PGC to provide a fair and non-discriminatory procedure for connection to the grid, Chapter 2 of the WESM Rules defines the (a) categories of WESM members, (b) procedures for registration as a WESM member, including registration as an intending WESM member, (c) procedure for ceasing to be a WESM member, (d) procedure for suspension of a WESM member and liability of Deregistered WESM members, and (e) procedure for recovery of the MO's costs and expenses.

A summary of the contents of the WESM Rules is provided in Annex 3.

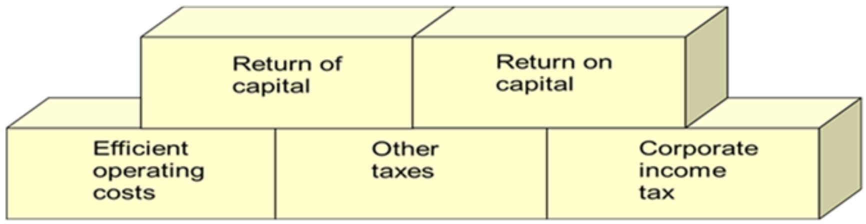
3.4.3. Performance Based Regulation (PBR)

Benefits: Pursuant to the EPIRA and its IRR, the ERC decided that the Performance Based Regulation (PBR) is the most efficient available form of regulation of privately-owned or operated distribution and transmission companies in the Philippines.

Key Features of PBR in the Philippines: The ERC adopted the Revenue Cap approach for the transmission company and the Price Cap approach for the distribution utilities with the following basic characteristics:

a) A Maximum Annual Revenue (MAR) cap is placed on transmission services for a five (5) year price path; while a Maximum Average Price (MAP) cap is placed on distribution services for a four (4) year price path. Prices are set ex-ante with increases linked to inflation and a smoothed efficiency factor (X factor) to reflect the improving efficiencies in price setting and avoid wide price fluctuations;

b) Prices are based on the utilities' revenue requirements, reviewed and approved by ERC subject to public hearings. Revenue requirements are determined based on the following building blocks, taking into account demand forecasts:



c) A performance incentive scheme is introduced to ensure service quality is maintained.

Rules for Setting Transmission Wheeling Rates (RTWR)

The RTWR specifies the methodology (policies, rules and procedures) in setting the maximum transmission wheeling rates that may be charged by the Regulated Entity to its customers for the provision of Regulated Transmission Service.

Details of the RTWR are provided in Annex 4.

3.4.4. Open Access Transmission Service Rules (OATS Rules)

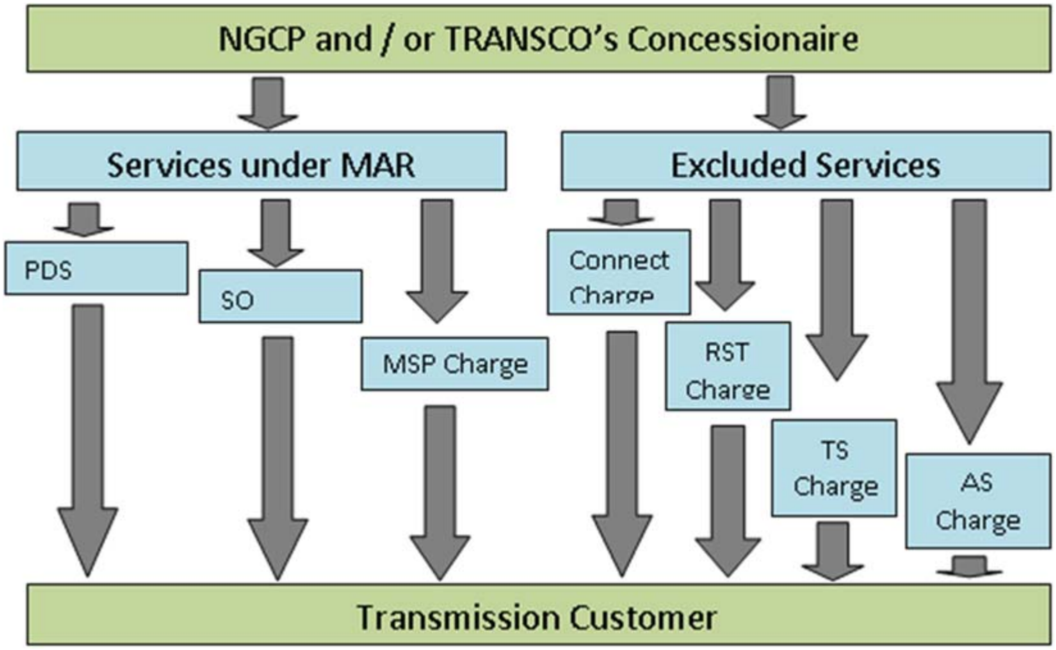
The OATS Rules (available for downloading at the ERC website), have been developed by the ERC based on the IRR of the EPIRA, the Philippine Grid Code and the WESM Rules, subjected to public consultation and approved on December, 2006 .

The OATS Rules significantly cover the essential set of rules and regulations dealing with open access in transmission. The said rules define the responsibilities of the Transmission Provider, the functions of the System Operator and the conditions accepted by the Transmission Customers for receiving the transmission services. Together with the Service Agreements , it constitutes the entire agreement, understanding and arrangement (express and implied) between the Transmission Provider and each Transmission Customer relating to the subject matter of the OATS Rules. (See Annex 5 for details.)

As a way of also ensuring fair and non-discriminatory access to the transmission grid, the OATS Rules set out the terms on which the Transmission Provider shall: (a) connect a Transmission Customer to the grid, (b) provide power delivery, transmission connection, residual sub-transmission, system operation and metering services, (c) perform system operator function, (d) provide services related to management, procurement and dispatch of ancillary services, (e) perform metering service function, and (f) provide services incidental to the above.

Rates and Charges: The fees which the Transmission Provider shall charge are given in Figure 3.4.4.1 .

Figure 3.4.4.1 – Summary of Charges by the Transmission Provider



The different charges indicated above are described below; also provided in Annex 5 are the bases for the allocation of the charges:

a) Services under MAR

Transmission Customers shall pay the following charges for Regulated Transmission Services under a Maximum Annual Revenue (MAR) cap, determined and approved by the ERC through a Regulatory Reset Process, done every Regulatory Period (RP) of five (5) years, under the RTWR.

- Power Delivery Service (PDS) Charge which recovers that proportion of the MAR associated with the cost of conveying electricity through the Grid and the control and monitoring of electricity as it is conveyed through the Grid; the PDS charge is payable by Generation Customers based primarily on the non-coincident peak injections in kW, and by Load Customers based principally on the non-coincident peak demand in kW.
- System Operator (SO) Charge which recovers that portion of the MAR and any other costs approved by the ERC that are associated with the cost of system operation as defined under the WESM Rules; the SO charge is payable by Generation Customers based or the Embedded Generators, and Load Customers.
- Metering Service Provider (MSP) Charge which recovers that portion of the MAR, and any other cost approved by the ERC, associated with the cost of metering services including the provision, installation, commissioning, testing, repair, maintenance, and reading both of meters that are used to measure the delivery of electricity to Customers and of other meters that are used (for the purposes of the WESM) to measure the flow of electricity into or through the Grid; A Metering Service Provider charge shall apply to all Connected Transmission Customers and will vary in accordance with the voltage level of the infrastructure provided by the Metering Service Provider for a Metering Installation.

b) Excluded Services

Excluded service under the RTWR is defined as a service provided under the ordinary course of an electricity transmission business that is neither a Regulated Transmission Service nor a service that is contestable (for these purposes, whether or not a service is contestable is a matter that, if disputed, will be determined by the ERC).

Generation Customers and Load Customers shall pay the following charges for Excluded Services and other Services:

- Connection Charge which recovers the reasonable costs, associated with providing Connection Assets, defined as the assets connecting a single connected Transmission Customer's Facilities to the Grid, including land required for the Connections Assets; connection charges are payable by Load Customers on existing and new Connection Asses, for the period until the Connection Assets are sold to Qualified DUs at each connection point, and payable by Generation Customers relating to their specific Connection Assets.
- Residual Sub-transmission (RST) Charge, payable by Load Customers, which recovers costs of sub-transmission assets defined as the Sub-transmission Assets as identified in the ERC Rules for the Approval of the Sale and Transfer of TRANSCO's Sub-transmission Assets and the Acquisition by Qualified Consortiums, less any asset that is no longer owned by the Transmission Provider or that has been reclassified as a Transmission Asset by resolution of ERC;
- These two aforementioned assets are defined to allow Connection Charges and Residual Sub-transmission Charges to recover costs of Sub-transmission Assets which the EPIRA requires to be sold by the Transmission Provider.
- Technical Service (TS) Charges wherein a prospective Transmission Customer shall pay the costs of any System Impact Studies (SIS) or Facilities Studies arising from its Service Application. In performing the SIS or Facilities Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing Grid Impact Studies (GIS) and any other relevant studies. The Prospective Transmission Customer shall not be assessed a charge for any existing studies. However, the Prospective Transmission Customer shall be responsible for charges associated with any modifications to existing studies that are reasonably necessary to evaluate the impact of the Prospective Transmission Customer's request for service from the Grid.
- Ancillary Services Charges as determined by the ERC and published in a separate Ancillary Services Procurement Plan (ASPP) and/or the Ancillary Services Cost Recovery Mechanism (ASCRM), or their successor documents.

The key points on the allocation of charges are discussed in Annex 5.

3.4.5. RA 9513 or the Renewable Energy Act of 2008

The Renewable energy Act of 2008 (RA 9513) aims to achieve the following with regards to renewable energy resources such as but not limited to: biomass, solar, wind, hydro, geothermal and ocean energy:

a) Accelerate exploration and development;
b) Increase utilization;
c) Encourage development and utilization; and
d) Establish the necessary infrastructure and mechanism to carry out the mandates.

The mandates of RA9513 pertinent to open access to the transmission grid are discussed in Annex 6.

3.5. Open Access to the Distribution Grid

Section 23 of the EPIRA mandates that as part of its functions, a distribution utility (DU) shall have the obligation to provide distribution services and connections to its system for any end-user within its franchise area consistent with the distribution code. Any entity engaged therein shall provide open and non-discriminatory access to its distribution system to all users.

The Philippine Distribution Code (PDC), even prior to the EPIRA, akin to the PGC which has been previously discussed, ensures: (a) fair and non-discriminatory access to the distribution system, (b) that the DUs provide reliable, safe and quality service to all its customers, (c) distribution planning is done in consideration of the requirements of its current and potential customers.

Like the PGC, the PDC is currently undergoing revisions to make it more in accordance with the current situation and environment.

Also, as previously mentioned, the WESM Rules is complimentary with the Philippine Grid and Distribution Codes, all of which are intended to ensure the development of an appropriate, equitable and transparent electricity market, along with a safe, reliable, and efficient operation of the power system.

In addition, to the PDC and the WESM Rules, the key issues of open and non-discriminatory access to the distribution grid, is dealt with under the following policies, rules and regulations:

3.5.1. Rules for Setting Distribution Wheeling Rates (RDWR)

The RDWR specifies the methodology (policies, rules and procedures) in setting the maximum distribution wheeling rates that may be charged by the Regulated Entity to its customers for the provision of Regulated Distribution Service.

The RDWR is adopted as a performance based form of regulating private DUs. The concepts, characteristics and features are similar to the RTWR; the main difference is that the Maximum Average Price (MAP) cap is placed on Regulated Distribution Services for a four (4) year price path instead of a Maximum Annual Revenue cap placed on Regulated Transmission Services for a five (5) year price path.

The key features of RDWR are provided in Annex 7. The similarity with the RTWR will be noted.

3.5.2. Rules for Setting Electric Cooperatives' Wheeling Rates

The ECs tariffs have been regulated using what is called a "cash flow" methodology. In this form of regulation, the EC's requirements to meet its payroll, operation and maintenance expenses, and debt service are calculated for a given base year on a cash basis. This becomes the Annual Revenue Requirement (ARR) on which the distribution rates are designed. Approval of tariff adjustments are done through a judicial process that takes between 3 to 6 months for a single case from application to ERC approval.

If the 119 ECs all filed their rate cases together on a single day and given the most optimistic turn-around of 3 months per case, all of the rate cases would have been decided in 30 years, if the cases were handled sequentially. Even if the ERC took on 3 cases simultaneously, it would still have taken 10 years to finish all of the cases. Clearly, there would be regulatory lag.

In September 2009, the ERC promulgated the new regulatory methodology for on-grid ECs called the "Rules for Setting Electric Cooperatives' Wheeling Rates" or RSECWR.

Details on the RSECWR are provided in Annex 8.

3.5.3. Distribution Services and Open Access Rules (DSOAR)

The DSOAR sets forth the terms and conditions related to the provision of Connection Assets and Services, service to the Captive market, Supplier of Last Resort (SOLR) service to the contestable Market, unbundled Distribution Wheeling Service (DWS) provided to the Contestable Market, redistributors' service to sub-meter users.

Furthermore, the DSOAR sets forth the procedures for establishing regulated service rates for DUs.

The general contents and relevant key points included in the DSOAR are discussed in Annex 9.

3.5.4. RA 9513 or the Renewable Energy Act of 2008

This is also discussed under item 3.4.5 above. In addition to the aforementioned discussion, the following is the relevant section for DUs.

Section 10. Net-metering for Renewable Energy: Subject to technical considerations and without discrimination and upon request by distribution end-users, the distribution utilities shall enter into net-metering agreements with qualified end-users who will be installing RE system.

The ERC, in consultation with the NREB and the electric power industry participants, shall establish net metering interconnection standards and pricing methodology and other commercial arrangements necessary to ensure success of the net-metering for renewable energy program.

The distribution utility shall be entitled to any Renewable Energy Certificate resulting from net-metering arrangement with the qualified end-user who is using an RE resource to provide energy and the distribution utility shall be able to use this RE certificate in compliance with its obligations under RPS.

3.6. Assessment

Drawing from the definition of Open Access, it means that everyone is treated fairly and in non-discriminatory terms and conditions dealing with these key issues:

a) Connection to the transmission / distribution grid;
b) Good and quality service upon connection to the grid;
c) Safe, reliable and efficient operation and maintenance of the network system; and
d) Tariff structure, pricing and cost allocation.

It is observed from the above discussions that with the EPIRA and its IRR, all the policies, rules and regulations including among others the PGC, PDC, WESM Rules, OATS, DSOAR, RTWR, RDWR, the related rules on retail competition which are currently underway, and the continuing changes and improvements on the rules and regulations, Open Access to the Transmission and Distribution Grid in the Philippines, are endeavored to be dealt with appropriately.

Nonetheless, one area which may be considered for development is the design and structure of Distribution Wheeling Rates Charges to End-users. This is crucial, as a defect in the rate structure proposed by the DUs, if not bound by the appropriate rules and policies, may run counter to the objectives of the EPIRA, removal of cross subsidy to name one.

Rules on distribution rate designs may start at the RDWR which can provide the ERC approved Regulatory Asset Base related costs (Return of Capital and Return on Capital) and Operating Expenses, including Taxes for allocation into the appropriate distribution functions.

It is also recognized that development and implementation of the rules is one thing, while, on the other hand, ensuring that the rules are altogether adequately complied with, is another thing. If the latter is not efficient and effective, the former shall not be bound to appropriately achieve the objectives that they were meant to accomplish.

One case in point is the criteria and protocol for the Central Dispatch of Generation Facilities, Ancillary Services, and Loads, both in the normal course of operation and in the event of a notified emergency which shall be defined by the SO and form part of the OATS Rules after approval by the ERC. The author understands that this is not yet obtainable.

It was drawn from one of the interviews that there is need for the Market Operator and the Market Participants to understand the protocols used by the System Operator in their dispatch procedures. As per the WESM Rules, the MO determines the dispatch schedule of generation facilities and such schedule is submitted to the SO which is under the NGCP organization. The SO provides central dispatch of all generation facilities to loads connected, in accordance with the dispatch schedule given by the MO. However, it could be possible that the SO may deviate from the dispatch schedule due to the discretion of the SO, based on its Dispatch Protocols (e.g. MRUs need to be online, etc.).

The SO needs to be transparent and its procedures and protocols need to be documented (which as mentioned above are not yet available), for the MO and other qualified interested parties to understand how the SO implements the actual dispatch of generation facilities.

This brings to the main point of the assessment: It is deemed beneficial to strengthen the regulatory body and the related agencies, to be able to do audits, checks and inspections, to ensure that in reality and in truth, policies, rules and regulations are complied with.

4. Retail Competition and Open Access (RC&OA)

In the Philippines, Retail Competition and Open Access have usually been put and discussed together. Being the ultimate objective of the EPIRA, and being a currently active and reputed undertaking, the RC&OA is discussed as a separate key topic.

4.1. Definitions

Open access has been defined in the earlier sections. Retail competition is the rivalry among Retail Electricity Suppliers, or the RES, to provide supply services to customers in the contestable market by offering lower prices and added customer service benefits or other incentives. Contestable customers are end-users who have the power to choose their preferred retail electricity supplier rather than automatically purchasing supply from their respective distribution utility in their franchise area.

Customers which qualify to become contestable under ERC's Rules for Contestability can choose their preferred RES based on the offered cost (which is not regulated) of generated power and other customer services and incentives. In the event that the customer fails to choose their RES or the RES' inability to provide electricity, the Rules for the Supplier of Last Resort, implemented by the ERC, ensures the provision of continuous supply of electricity to contestable customers (see section 4.4.2 c).

Costs of transmission and distribution, both of which are regulated, do not form part of the decision points, thus open access is essential for retail competition to work.

As mentioned, implementation of RC&OA is among the ultimate objectives of the EPIRA. It matters therefore that its implementation would be in consonance with the underlying principles and would achieve the benefits expected of the EPIRA.

4.2. Rationale & Benefits of RC&OA

Industry restructuring with the ultimate goal of moving towards competition, is in expectation of bringing better advantages (price and non-price) in comparison to regulation. The benefits most anticipated are that consumers pay lower rates than provided under regulation and receive reliable service as well. On a more comprehensive scale, the consumers may be benefitted directly through their individual electricity bills for their own consumption and indirectly through businesses, commerce, other industries and in totality the growth and development of the country impinged on by competition in the electricity industry.

The motivation for RC&OA is very well depicted by Herbert Hoover in his quotation:

"Competition is not only the basis of protection to the consumer, but is the incentive to progress".

The "protection to consumer" component has been alluded to in Section 2 (b) and (f) of the EPIRA declaring as among the policies of the state: "to ensure the quality, reliability, security and affordability of the supply of power and to protect the public interest as it is affected by the rates and services of electric utilities and other providers of electric power".

Likewise, the "incentive to progress" aspect has been put across in Section 2 (c) similarly declaring as among the policies of the state: "to ensure transparent and reasonable prices of electricity in a regime of free and fair competition and full public accountability to achieve greater operational and economic efficiency and enhance the competitiveness of Philippine products in the global market". Accordingly, alongside protecting public interest, the pursuit for quality, reliability, security and affordability of the supply of power seeks to ultimately power the growth and development of the nation. With this end in view, comes to fore Section 2 (d), another policy of the state in the EPIRA, which, is certainly a fundamental driving force in a developing country like the Philippines. The said policy is stated as: "to enhance the inflow of private capital and broaden the ownership base of the power generation, transmission and distribution sectors". Thus, as the World Bank has indicated, private sector participation in transmission and distribution, T & D, (not to discount generation) and OA in T & D are emerging areas of interest to policy makers in developing countries.

It is in this framework that the development and implementation of OA & RC should be carried on.

4.3. Rationale for the Mandated Requisites to RC&OA

It is believed that RC&OA cannot efficiently operate and successfully achieve its intended objectives without complying with the requisites indicated in Section 31 of the EPIRA as previously mentioned. The following provides the underlying principles for such requirements:

4.3.1. Establishment of the Wholesale Electricity Spot Market (WESM)

The wholesale and retail markets mutually reinforce each other.

The wholesale market:

a) shall be a source of supply of the electricity retailer,
b) shall be relied on in terms of turning up with rational cost of generated power from the interplay of market forces;
c) shall be a critical source of valid and correct information for the retailer and the customer in their decision making process;
d) has the mechanism for generating the bills for wholesale spot buyers including the Retail Electricity Supplier (RES).

A competitive wholesale market is imperative for the benefits of retail competition to be achieved. The wholesale market plus a non-discriminatory access to the transmission grid, and certainly, an efficient transmission network, allows the retail electricity suppliers to buy even from distant generators and curtails the exercise of market power by local generators. Also, it is the source of supply of the RES when its bilateral contract quantities are not sufficient and, as well, the place to sell its bilateral contract quantities in excess of their customers' requirements.

A competitive wholesale market provides:

a) the appropriate price signals to wholesale customers including the RES;
b) information on grid utilization and congestions to transmission grid operators;
c) actual market prices to the participating generation companies;
d) information on potentials of different plant locations to upcoming generation companies to be used for their plant designs.

These are all necessary to achieve the benefits of retail competition.

On the other hand, the retail market boosts up the wholesale market in making it more competitive as it provides more demand side players.

4.3.2. Approval of Unbundled Transmission and Distribution Wheeling Charges

As mentioned, in the EPIRA, there are four sectors: generation, supply, transmission and distribution. The first two are not regulated and are in a competitive environment, while the last two remain regulated. Each of the sectors, distinct from each other, has their own particular rules and regulations.

Unbundling is necessary as each of the components of the total cost of electricity is addressed distinct from each other. It allows the regulator (ERC, in the case of the Philippines) and the planner (DOE, and the individual utility owners) to assess the individual performance of the groups involved, understand where problems lie or where support is necessary, and make policy decisions towards the betterment of the whole industry. It also allows the customer to see and understand the cost for each service they are paying.

Importantly, unbundling is an important prelude to open access or non discriminatory access to transmission and distribution systems.

4.3.3. Initial Implementation of the Cross Subsidy Removal Scheme

In the old regime, cross-subsidies have been used as a mechanism to balance the effect of price increase on certain categories of customers. This has the following adverse effects:

a) higher tariffs for some categories of consumers who are perceived to have the capability to pay and lower tariffs for those who have been paying low historically;
b) wrong signals to consumers who pay low, thus resulting in inefficient and unproductive use of scarce electricity; and,
c) de-stabilizing effect on the operation of the utility in the long run because those who pay high may switch to self-generation.

Thus, to make the reforms successful, EPIRA has included Section 74 (Annex 10) to address the Cross Subsidy Removal Scheme.

Privatization of at least seventy percent (70%) of the total capacity of generating assets of NPC in Luzon and Visayas; and transfer of the management and control of at least seventy percent (70%) of the total energy output of power plants under contract with NPC to the IPP Administrators.

As previously mentioned, prior to the implementation of the EPIRA, the generation sector was dominated by NPC. The following all supplied electricity to NPC: NPC-owned and operated plants, NPC-owned but

IPP operated plants, and IPP-owned and operated plants. There were also IPP-owned and operated plants that sold electricity to customers other than NPC.

The objective of these last two pre-requisites for OA & RC, defined by the EPIRA, is mainly to restrain market power. It is perceived that completion of the two items indicated in 3.3.4 above, would bring the market to a competitive level and would curtail the opportunity to exercise market power (defined as the ability to profitably maintain price above competitive levels in significant amounts of time).

Corollary to the above, the EPIRA has also mandated that: "No company or related group can own, operate or control more than thirty percent (30%) of the installed generating capacity of a grid and/or twenty-five percent (25%) of the national installed generating capacity".

Due to inevitable delays in meeting the aforesaid conditions, the ERC, in its Resolution No. 3, Series of 2007 reiterated the legal requisites to Open Access and identified two other vital requirements that must be in place prior to the start of the Retail Market, namely:

a) the adequacy and establishment of all necessary infrastructures, including, but not limited to: transmission networks, generation supply and the customer switching system; and
b) the promulgation of all pertinent rules and regulations governing open access and retail competition.

Adequate generation supply means the electric power system is able to supply the total electricity demand and energy requirements of the customers and the system, considering both scheduled and unscheduled outages of all system components. This is essential for the protection of the consumers through a competitive and reasonable pricing in the wholesale and retail market. Inadequate generation supply can give the generators the ability to exercise market power; however, significantly more than what is adequate may tilt the supply and demand balance, and this is de-motivating to and can re-direct the generation sector which could in the long run, be detrimental to the best interests of the country.

Adequate generation supply should be coupled with an evenly adequate transmission network, which is defined as one that can support the capacity being supplied by generators and the demand being drawn by the customers. Network congestion results in inadequate transmission capacity, this consequently leads to limited supply in a certain area causing electricity prices to increase as more expensive supply has to be sourced to meet the demand. An adequate transmission network is thus, likewise, essential for a competitive and reasonable pricing in the wholesale and retail market.

Further, the customer switching system infrastructure is a basic requirement for the system to work efficiently and to attain the full benefits of RC&OA.

The pertinent rules and regulations governing retail competition and open access put in place a comprehensive legal and procedural framework for RC&OA. They serve as the guidebook or handbook, addressing practically all market issues and concerns, and the basis by which market participants will plan, manage, decide, act and behave. These rules and regulations are necessary for RC&OA to work effectively, efficiently and in an organized manner and to ultimately attain the objectives anticipated by the EPIRA.

4.4. Current Environment & Future Plans

This part of the report encapsulates and highlights the significant aspects of the preparations, efforts and strategies towards the development and implementation of RC&OA in the Philippines. This section, handy in itself, finds meaning and importance in imparting what needs to be done and the lessons learned with the Philippine experience. Furthermore, it provides forward-looking or advanced experience which may yet to be encountered by other jurisdictions.

These are the highlights of preparations that have been and are being done towards the suitable implementation of RC&OA (See Annex 11 for details):

The ERC issued the Rules for the Issuance of Licenses to Retail Electricity Suppliers (RES), which prescribes the qualifications and criteria for issuing licenses to the RES. The said rules also introduced the Local RES, which are DUs intending to set up local RES business. ERC has issued sixteen RES licenses as of January, 2012.

Furthermore, it has issued the following necessary Rules and Resolutions, copies of which are all found in ERC's website:

a) Code of Conduct for Competitive Retail Market Participants which protects customers by establishing standards of behavior for marketing electricity;
b) Rules for Customer Switching governing the commercial transfer of a customer from one RES/Local RES to another;
c) Rules for the Supplier of Last Resort (SOLR) which encourages contestable customers to choose their supplier of electricity upon the commencement of retail competition and open access; and ensures the provision of continuous supply of electricity to contestable customers in the event of RES' inability to provide electricity.
d) Rules on Rate Filing by the Supplier of Last Resort which provides the SOLR with a uniform filing system for applications for the approval of SOLR rate / charges to the affected Contestable Market; and ensures recovery of the allowable premium and reasonable return associated with the SOLR service;
e) Competition Rules and Complaint Procedures which prohibits anti-competitive behavior and abuse of market power; and specifies the appropriate penalties and remedies for such behaviors;
f) Business Separation Guidelines (BSG) prescribing the clear separation of business operations and accounts between the regulated and non-regulated business activities of electric power industry participants;
g) Distribution Services and Open Access Rules (DSOAR) prescribing the rules and regulations pertaining to the provision of services by a DU to captive and contestable customers, the RES, other DUs, and generators, under the new competitive environment;
h) Rules for Contestability which clarifies and establishes the conditions, timelines and eligibility requirements for end-users to become part of the contestable market;

Moreover, as part of its mandate to establish and enforce a methodology for setting transmission and distribution wheeling rates and retail rates for the captive market of a distribution utility, the ERC has also promulgated the following rate setting rules all of which are performance based:

i) Rules for Setting Distribution Wheeling Rates;
j) Rules for Setting the Transmission Wheeling Rates; and
k) Rules for Setting Electric Cooperatives' Wheeling Rates.

It is noted that the above ERC issuances, pertain to and are necessary for the well-ordered performance of ERC's regulatory functions over retail competition.

These rules are all important preparatory steps to retail competition; nevertheless, issues have been raised on other equally important preparatory steps which were still lacking, such as:

l) preparation of the WESM to handle billing and settlement of retail suppliers who would be among the WESM participants;
m) designation of a central registration agent/body to maintain records of the customer-supplier relationship; and

n) development and installation of a mechanism or a system to convey customer switching information and meter data from the DU to the retail supplier and wholesale market operator.

Two Important milestones occurred :First was, when ERC declared on June 6, 2011, compliance with the preconditions for the initial implementation of RC&OA and commencement on December 26, 2011, six months after the Decision; and second was, when the Department of Energy (DoE), mandated by the EPIRA, to supervise the restructuring of the electric power industry and formulate such rules as may be necessary issued on June 17, 2011, a Department Circular creating the Steering Committee (SC) that would define the policies for the commencement of RC&OA, ensuring that the appropriate conditions for the implementation of RC&OA are in place.

Specifically, the aforementioned DoE Circular defines the following responsibilities of the SC:

a) Review existing rules and procedures on RC&OA; develop and recommend policies to implement systems and processes;
b) Develop the timelines and action plan necessary to ensure the smooth transition to full competitive environment;
c) Coordinate with pertinent entities to implement the regular monitoring and feedback mechanism;
d) Provide a forum for relevant recommendations;
e) Formulate an information and education campaign about the RC&OA.

As part of the learning process, it is important to note issues, concerns and recommendations that came about after the aforesaid milestones.

a) Deferment of the commencement of RC&OA, as the December 26, 2011 date declared by ERC was not viable.
   - The stakeholders have pointed out that deferment of the commencement date was necessary to allow time for:
     - the establishment of the Central Registration Body (CRB) and the agent for net settlement;
     - contestable market to engage in more detailed preparation;
     - proper evaluation of governing rules and regulations; and
     - all appropriate preparations for transition to the new environment.
b) Concerns on: whether RES and contestability will be mandatory (some customers would want to remain captive), whether the wholesale and retail market will be handled separately, directions towards the establishment of the CRA/CRB, Settlement Agent and B2B, the need for clear guidelines on the source of fund for the establishment of the infrastructure and the concomitant mechanism for recovery of the investment and sustenance of the operations.
c) Pricing Issues particularly that contestable customers have potential difficulty in securing supply contracts with no price offers from RES. Thus, the SC is considering obliging the RES to publicly make known its offer prices and that ERC should require the RES to submit its price offer and publish the same in the ERC website.
   - Other pricing issues as well as issues on the management of contracts, metering rules, development of the accounting, billing and settlement manual and suggestions on the SOLR that came about are included in the discussions in Annex 11.

There are also important lessons learned on the report of Mr. Jess Totten of Austin Texas who has been commissioned to review the retail open access rules adopted by ERC. The major findings and conclusions indicated in the report are included in Annex 11.

Important and useful report highlights that are worth noting are:

a) The following Rules adopted by the ERC were said to be adequate:

- Rules on Customer Switching;
- Amended Distribution Service Open Access Rules;
- Business Separation Guidelines;
- Code of Conduct for Competitive Retail Market Participants;
- Amended Distribution Service Open Access Rules;
- Rules for the Supplier of Last Resort (SOLR) for the Contestable Market;
- Competition Rules and Complaint Procedures; and
- Rules for the Issuance of Licenses to Retail Electricity Suppliers (RES).

b) The mark-up in the SOLR rate is proper because of the costs and risks involved; however, permitting the SOLR to carry over its unrecovered costs is problematic since costs incurred for one customer may be charged to subsequent customers. It is suggested that the premium permitted in the SOLR rate should already cover all costs and risks associated with providing the service so a subsequent true up would not be necessary.

c) Although the RES is allowed to trade in the real-time market, the current infrastructure does not have the capability. The WESM system needs to be expanded and the market rules modified, to hinder barriers to RES participation in the wholesale spot market.

d) Allowing the contestable customers to opt to remain in regulated service would reduce the size of the market in terms of number of customers; this is detrimental to market competitiveness. Further, this creates a potential source of cross subsidy, as the related revenues in regulated service could advantage the local RES in providing competitive services to the customers who opt to enter the retail market.

In Texas, a partially-regulated rate has been used for residential and small commercial customers for the first five years of retail competition. The drawback is that it gives the DU and its affiliated local RES, a competitive advantage over new market entrants, which would deter market entry and tilt the competitive scales in favor of the DU and its local RES.

e) Competitive metering is not likely to provide benefits to the retail market as it would be hard to for a new market entrant to be competitive with the regulated rate of the DUs which already have the significant scale.

The DoE designated the PEMC as the Central Registration Body (CRB) to: (a) seamlessly integrate RCOA into the WESM operations, (b) develop and manage customer switching, information exchange and settlement of transactions, (c) conduct trainings and consultations.

4.5. Assessment

The complete assessment of the Consultant is written in more detail in Annex 12. The following are the highlights:

It is essential to more thoroughly assess the adequacy of generation supply and transmission network to sustain the retail market.

It has always been stressed that there can be no competition where generation supply and transmission networks are deficient. For the benefit of ensuring the better chances of success of the implementation of RC&OA, it is suggested that ERC carry out further studies and analysis of generation supply and transmission network vis-à-vis consumer demands in the next ten years.

The ERC was consistent with its mandate by the EPIRA, in developing and implementing all the Rules and Regulations pertinent to RC&OA, as all the issuances were necessary for the commission's effective performance of its regulatory functions and other assigned tasks.

On the other hand, the DoE's move to create the Steering Committee to define the policies for the commencement of RC&OA and ensure that the appropriate conditions for the efficient transition to RC&OA are in place, is in accordance with its mandate under the EPIRA. It should be a welcome development, as the preparatory actions for a project as significant as the RC&OA, traversing different sectors, should indeed be synchronized and coordinated.

There should be no conflict between ERC's regulatory function and the DoE's overseer responsibilities. However, it could have been more likely for the responsible agencies to have their outputs aligned and to have achieved the timelines set by the EPIRA, if they had collaborated at the outset and worked towards a common goal.

It should be a lesson learned that delays in the implementation of the RC&OA also deny the contestable market of the benefits of the "power of choice".

The preparatory steps taken by ERC, essentially motivated by its mandate, are to a large extent necessary towards the implementation of the RC&OA. The ERC can now further focus on its regulatory functions including but not limited to the following, which should not be in conflict with the SC's undertaking:

a) Define more specific rules and clear-cut formula on the SOLR rate which would serve as the basis of the Commission in evaluating even-handedly the proposed SOLR rates;
b) Enhance the Competition Rules and Complaint Procedures to address the intricacies of Retail Competition as differentiated from Competition in the Wholesale Market; Strategize on spotting retail market abuses and defining the appropriate penalties;
c) Strategize on how to ensure that the pertinent RC&OA development and implementation costs as well as the continuing operating costs would be transparent, reasonable and practical and how these costs would be reasonably recovered by the investors / financiers and equitably charged to the end-users;
d) Plan on how to promote competition in and encourage development of the retail market.

The following are also deemed important areas of attention by those who will be involved in the development of the RC&OA:

a) Taking note of Herbert Hoover's quotation, competition should enhance both protection to the customer and incentive to progress; thus, more policies should be adopted to minimize entry barriers to retail competition; both sides, the customer and the seller, should be evenhandedly taken care of.
b) Policies to provide the opportunity for demand side responsiveness for both the wholesale and the retail market. The opportunity to make consumption decisions for retail customers would give customers not just a choice of its supplier (customers can either buy direct from a generator or through a RES or bid into the WESM) but the ability to respond to price changes.
c) Prior to assigning the task of developing the retail market mechanism, decisions should have been made on who will finance the project and how the investor(s) would be recompensed.

As discussed in more detail in Annex 12, it is suggested that the development of the retail market mechanism should apply the systems development concepts and techniques to provide a basis in going through the courses of actions towards the ultimate goal of implementing the RC&OA.

As a necessary fundamental process, there is a need to define goals, targets and objectives. Certainly, the goal in general to implement the RC&OA needs to be dissected into more detailed objectives such as: to protect public interest as it is affected by the rates and services of electric utilities; to enhance the competitive operation of the electricity market; to enhance the inflow of private capital and broaden the ownership base of the power generation, transmission and distribution sectors, etc. (the aforementioned are just examples which were lifted from Section 2 of the EPIRA).

The above exemplification is driving at this point: if the objectives are to protect public interest as it is affected by the rates and services of electric utilities, on one side; and to enhance the competitive operation of the electricity market and/or to enhance the inflow of private capital on the other side; then it should be made a policy or a rule that the qualified end-users in the contestable market should not be given the option to remain captive as it would be running against the objectives of enhancing the competitive operation of the market and enhancing the inflow of private capital.

The first tangible output after the definition of targets, goals and objectives, would be the rules, et al, one of the five fundamental components of an information processing system, mentioned in Annex 12. This is one of the pre-requisites before even going to the design and development of the IT system.

There's need to develop the Retail Market Rules in the same way that there are WESM Rules.

DoE has indicated the need to reconcile the manner of RES switching (whether monthly, yearly, etc.) with ensuring the security of supply and mitigating the impact on prices. It is the author's view that the impact of switching would be more on individual prices and would probably have less influence on the security of supply. There may be a need to give attention to this and the necessary direction to PEMC for its development of the RCOA mechanism.

The cost of the system will ultimately be passed on to the customers; it would thus be prudent to manage the cost as well as the project timeline through a well-organized process.

In addition to hardware and software solutions, objectives can also be achieved by processes that are better done manually, reinforced by the appropriate procedures, done by qualified personnel in the organization. PEMC's proposal should also cover these imperative components of an information processing system.

Security and confidentiality should appropriately be handled with all the people and procedures components in the IT system.

The system to be developed by PEMC, conceivably covers the activities from the submission of retail market contracts, retail market bids, customer switching, up to PEMC billing / settlement with retail market customers and generation of all the required information. External processes like the RES contracting with customers, billing and settlement between the RES and its customers, allocation of distribution and transmission costs to the contestable customers, regulatory compliances, etc., need to be defined for areas outside of the PEMC system.

The DoE should declare a realistic RC&OA opening date, considering all the requisites and relevant parameters, for the participants to prepare and be indeed ready and equipped for the implementation of RC&OA.

The RC&OA is a first-time implementation in the country, with all its uniqueness and distinct characteristics. Seeking the help of the veritable experts, from other jurisdictions, who have experienced all the prime successes and failures, in the development and implementation of their own RC&OA, would be most advantageous to the Philippines. The hiring of experts already has precedents in the implementation of the EPIRA. Consultants were hired in the formulation of the WESM Rules, training of the stakeholders, and the development of Market Dispatch Optimization Model (MDOM) of the wholesale market.

5. Private Sector Participation in Transmission

5.1. Rationale and Objective of PSP in Transmission

Among the policy declarations of the EPIRA, as embodied in its Section 2 (d) is the enhancement of the inflow of private capital and the broadening of the ownership base in the generation, transmission and distribution sectors. Thus, Section 8, created the National Transmission Corporation or TRANSCO that assumed from the National Power Corporation, the authority and responsibility for the planning, construction and centralized operations and maintenance of the high voltage transmission facilities, including grid interconnections and ancillary services. Further, the EPIRA mandated the privatization of the TRANSCO in Section 21 by either outright sale or a concession contract awarded through competitive bidding. The same section and the EPIRA IRRs also provide further framework for the privatization of TRANSCO which includes the following:

a) The buyer/concessionaire shall be responsible: for the improvement, expansion, operation and/or maintenance of the grid and the operation of related businesses; comply with the Grid Code and the Transmission Development Plan (TDP) as approved; and, comply with the key performance targets and standards of the ERC;
b) The sub-transmission functions and assets shall be segregated from the transmission functions and assets and shall be operated and maintained by TRANSCO or its buyer or Concessionaire until their disposal to qualified distribution utilities;
c) PSALM and TRANSCO shall secure a nationwide franchise for and in behalf of the buyer/concessionaire;
d) In case a concession contract is awarded, the concession period shall be for a period of twenty five (25) years, subject to review and renewal for another twenty five (25) years;
e) Upon expiration or termination of the concession contract, the transmission facilities and assets and the franchise shall revert to TRANSCO
f) Provisions for performance and financial guarantees; and
g) In case of joint venture/consortium with foreign members/participants, the buyer's/concessionaire's foreign partner shall be financially and technically capable with proven domestic and/or international experience and expertise as a transmission system operator of a comparable capacity and coverage as the Philippines; and
h) The award shall result in maximum present value proceeds to the National Government.

5.2. The Privatization of TRANSCO

The National Grid Corporation of the Philippines or NGCP formally took over and has been operating the facilities and assets of the TRANSCO since 12:00 AM of January 15, 2009. The NGCP is the corporate vehicle of the consortium of Monte Oro Grid Resources Corporation, Calaca High Power Corporation, and State Grid Corporation of China which offered the highest financial bid of US Dollars 3.950 billion that exceeded the Reserve Price and won the TRANSCO concession through competitive bidding on December 12, 2007. Subsequently, NGCP obtained a congressional franchise in late 2008, remitted USD987.5 million to PSALM, equivalent to 25% of the USD3.950 billion purchase price, fulfilled all conditions precedent and signed the Deed of Transfer.

There were three attempts to privatize TRANSCO prior to its successful bidding in December 12, 2007 that has put the TRANSCO Concession in the private hands of NGCP.

The first attempt was in 2003. On July 14, 2003, the privatization bidding and awards committee for TRANSCO declared a failure of bidding for its twenty five (25) year concession contract. It failed at the pre-qualification stage as only one party, Singapore Power International, submitted the lone pre-qualification proposal on the July 11, 2003 deadline. A minimum of two (2) pre-qualification proposals needed to be submitted to proceed with the bid process.

A second attempt was immediately put into process but suffered the same fate as the first attempt.

The third attempt was in 2006-2007. The privatization process hurdled the pre-qualification stage with three pre-qualified bidders: 1) the consortium of Triratna Holdings, US-based Newbridge Asia IV L.P. and Malaysian power firm Tenaga Nasional BHD.; 2) the consortium of Monte Oro Grid Resources Corporation and State Grid Corporation of China; and, 3) the consortium of Filipino-owned investment firm Citadel Holdings Inc. and Italian power grid operator Terna SPA. However, on the February 25, 2007 deadline for the submission of bids, only the consortium of Citadel Holdings Inc. and Terna SPA submitted a bid. A minimum of two bids is required to proceed with the bid process. As such, the bidding was declared a failure. Under the procurement law and the bidding procedures adopted for the TRANSCO procedure, after two failed biddings, a negotiated deal may be entered with the sole bidder. However, the decision was to re-bid.

Finally, the fourth attempt was successful. The privatization of the Facilities and Assets of the TRANSCO was by a Concession awarded to the highest Concession Fee bid from a qualified bidder through a competitive bidding process.

5.2.1. Concession

The Concession is for twenty five (25) years, renewable up to another twenty five (25) years, under terms and conditions that may be mutually agreed by PSALM, TRANSCO and the Concessionaire. The winning bidder will be required to obtain a congressional franchise to operate a public utility, which will be a condition precedent to the closing of the privatization transaction.

The Concession shall include (a) the take over and operation of TRANSCO’s regulated transmission business as a going concern, and, (b) carrying on any Related Business in accordance with Applicable Law during the concession period. The Concession transfers effective economic ownership to the Concessionaire while the legal title to the immovable assets remains with TRANSCO. As such, at the expiration or termination of the Concession, the Concessionaire is entitled to receive a payment linked to the value of the Regulatory Asset Base (RAB) at that date, in order to recover any un-depreciated investment at that time.

During the concession period, the rights and responsibilities of the Concessionaire are:

a) to construct, install, finance, manage, improve, expand, operate, maintain, rehabilitate, repair, refurbish and replace the Transmission Assets, save that with regards the Sub-transmission Assets, this obligation shall only be to operate and maintain the Sub-transmission Assets which have not been disposed by TRANSCO;
b) to prepare the Transmission Development Plan and to implement such projects in the TDP as may be authorized by the ERC;

c) to provide Transmission Service and enter into connection agreements with Transmission Customers;
d) to procure such Ancillary Services as necessary to support safe and reliable operation of the Transmission Assets;
e) to bill and collect from Transmission Customers for its own account such charges as the Regulated Entity may lawfully demand; and
f) To collect the Universal Charge payable by end users and self-generating entities not connected to a distribution utility and remit the same to PSALM, all in accordance with Applicable Law, including the EPIRA.

The ERC shall regulate the Concessionaire who shall be the sole representative of the Regulated Entity (as between TRANSCO and itself) before the ERC.

Performance Security. A Performance Security is required as of the Commencement Date, and in effect throughout the Concession Period up to 30 days from the Termination Date. The Performance Security is in the form of an irrevocable standby letter of credit in an amount equal to 2% of the concession fee.

5.2.2. Concession Fee

The Concession Fee, in US Dollars, will represent the net present value of all future cash flows to the Concessionaire. Twenty five percent (25%) of the Concession Fee will be required to be paid up-front in US Dollars. The remaining seventy five percent (75%) will be converted to Philippine Pesos at a pre-defined exchange rate and payable via deferred payments in Philippine Pesos carrying interest at a pre-determined rate spread over a pre-determined amortization profile of up to fifteen (15) years. The intent is to mirror a financially "geared" business in line with international practice for similar businesses.

5.2.3. Bid Process

A PSALM Privatization Bidding and Awards Committee was constituted by the PSALM Board of Directors, to implement the proposed privatization of the Facilities and Assets of TRANSCO and the Bidding Process. To assist the said committee, a Technical Working Group, composed of representatives from PSALM, TRANSCO, the DoE, the DoF, the Department of Justice (DoJ) and the Department of Budget Management (DBM), was formed.

An interested party should submit an expression of interest, an executed confidentiality agreement and undertaking and pay a participation fee of five thousand US dollars (US$5,000.00) to be a Prospective Bidder.

The bidding process consisted of four (4) stages as follows:

1. Stage One: Due Diligence,
2. Stage Two: Pre-qualification,
3. Stage Three: Technical Proposal and Financial Bid, and,
4. Stage Four: Selection of the Winning Bidder.

Stage One: Due Diligence. Limited to Prospective Bidders and Pre-qualified Bidders, each conducts and is solely responsible for its own due diligence investigation of the Facilities and Assets, review of the Transaction Documents, and matters relating to the Bidding Procedures. Covered by the "Data Room and Due Diligence Procedures", this can be carried out through four avenues: one, review of confidential materials in a Data Room and Data CD Rom, specifically created for the transaction, Meetings; two, meetings with, presentations from, and discussions with TRANSCO management; three, site visits; and four, requests for additional information.

Stage Two: Prequalification. To be a Pre-qualified Bidder, Prospective Bidders have to submit a pre-qualification proposal that fully complies and "passes" the following pre-qualification criteria:

a) Technical Pre-qualification Criteria: a technical partner who is a transmission system operator which operates and maintains an electricity transmission system of at least 6,000 circuit kilometers of transmission lines operating at 115 kV or higher and including within it a system operating at no less than 230 kV and having a peak demand of at least 6,000 MW. The technical partner must also hold a minimum of five percent (5%) equity stake, directly or indirectly, in the Concessionaire.
b) Financial Pre-qualification Criteria: the technical partner must have a net asset value or market capitalization of at least Five Hundred Million US Dollars (US$500,000,000.00).
c) Citizenship Criteria: the consortium must demonstrate that the Concessionaire will be at least sixty percent (60%) owned by Philippine citizens or corporations or organizations organized under the laws of the Philippines.
d) Filipino Investor Criteria: The largest Filipino Investor has a net asset value or market capitalization of at least Three Hundred Million US Dollars or the ability to fund an equity investment in the same amount as certified under oath by a Qualified Bank who, or any of its affiliates, do not have any equity interest in the Prospective Bidder.
e) Foreign Investor Criteria: The largest Non-Filipino investor has a net asset value or market capitalization of at least One Hundred Seventy Five Million US Dollars (US$175,000,000.00) or the ability to fund an equity investment in the same amount as certified under oath by a Qualified Bank who, or any of its affiliates, do not have any equity interest in the Prospective Bidder.
f) Cross-Ownership Undertaking Criteria. Issuance of an undertaking by the Prospective Bidder and each of its Members, to conform to Section 45 of the EPIRA and its IRRs, not to hold any interest, directly or indirectly, in any Generation Company, Distribution Utility, IPP Administrator and Supplier as defined in the IRRs.
g) Composition Maintenance Criteria. Issuance of an undertaking that each of the Qualifying Members of the Prospective Bidder shall each continue to be a Member of the Pre-qualified Bidder and maintain their respective equity thresholds from the submission of the Pre-qualification Proposal until the earlier of the Commencement Date or the expiration of the Financial Bid Validity Period.
h) Equity Undertaking Criteria. The prospective bidder and each of its members, including the member that satisfies the Financial Pre-qualification Criteria and the Technical Re-qualification Criteria will undertake under oath that such Member (i) shall contribute in the aggregate to the Concessionaire, directly or indirectly, at least five percent (5%) of the Concessionaire's total capital from Commencement Date and in accordance with the Final Transaction Documents; and (ii) is allowed under the laws of the country having jurisdiction over it to make such contribution/investment required in (i) above.
i) No Conflict of Interest Criteria. Certification from the Prospective Bidder that it and each of its Members or Affiliates of its Members that they did not participate in the valuation of the Facilities and Assets on behalf of the Government, PSALM, TRANSCO, ERC, DOE or DOF or any of their advisors or lenders.
j) Improvement and Undertaking Criteria. Undertaking that the Concessionaire shall improve and expand the Facilities and Assets in accordance with the Final Transaction Documents and Applicable Law.

k) Full compliance in form and substance with the information and requirements of Pre-qualification, including the accuracy, authenticity, completeness, truthfulness, veracity and validity of the said information and requirements.
l) Full conformity to the prescribed Form of Pre-qualification Proposal.

Each Pre-qualification proposal shall be evaluated on a "pass-fail" basis. Full compliance to and passing all the Pre-qualification Criteria will merit a "Passed" rating. Absent full compliance and failure in some or all of the Prequalification Criteria shall obtain a "Failed" rating. A Prospective Bidder that has obtained a "Failed" rating may petition for a reconsideration and submit necessary documentation to support its petition upon which a final decision will be rendered.

There should be at least two Prospective Bidders who submits their Pre-qualification Proposal for the Pre-qualification Stage to proceed. Otherwise, a failure in the Bidding will be declared and the bidding process terminated.

In addition, there should be at least two Prospective Bidders whose Pre-qualification Proposals have been rated "Passed" in order to proceed to Stage Three of the Bid Process. Otherwise, a failure in the Bidding will be declared and the bidding process terminated.

Stage Three: Technical and Financial Bid. Only Pre-qualified Bidders are allowed to submit a bid and be eligible for selection as a Winning Bidder. It will be a two-envelope bid process consisting of a Technical Bid and a Financial Bid.

The Technical Bid is to confirm that the information and requirements that was the basis for granting the Pre-qualified Bidder status remain valid and that the Pre-qualified Bidder confirms its agreement to the final documentation.

The Financial Bid will be a "price-only" bid on a single financial parameter, the Concession Fee, and will be evaluated solely on the same.

Stage Four: Selection of a Winner. The evaluation of Bids will be a two-stage process. The First Bid Envelope containing the Technical Bid shall be opened and evaluated first. The Technical Bid is going to be evaluated on a "pass-fail" basis. The "passed" ratings shall be subject to verification and validation. Only if there are at least two Pre-qualified Bidders who submitted Bids and at least one of them obtained a "passed" rating on its Technical Bid, will the Second Bid Envelopes containing the Financial Bids be opened and evaluated. Otherwise, the bidding will be declared a failure and the bid process terminated. The Financial Bids will be evaluated based on the highest and has equaled or exceeded the Reserve Price. In case of a tie, an auction will be conducted between and among the Pre-qualified Bidders submitting the tied highest bids. The winning bid is the highest bid that has equaled or exceeded the Reserve Price. In case none of the Financial Bids meets the Reserve Price, the bidding will be declared a failure.

In the event of a failed bidding, negotiations may, but shall not be required, be entered into with one or more Persons for the award of the Concession, in accordance with applicable law.

5.2.4. Transaction Documents

The following are the Transaction Documents:

a) Direct Agreement
b) Concession Agreement
c) Construction Management Agreement
d) Interim Assignment Agreement
e) Accounts Agreement

f) Deed of Transfer

5.2.5. Winning Bid

The winning bid was for a concession fee of Three Billion Nine Hundred Fifty Million United States Dollars (US$3,950,000,000.00). The upfront payment of twenty five percent (25%) was Nine Hundred Eighty Seven Million Five Hundred Thousand US Dollars (US$987,500,000.00). The remaining balance of Two Billion Nine Hundred Sixty Two Million Five Hundred Thousand US Dollars (US$2,962,500,000.00) was converted to Philippine Pesos at the fixed exchange rate of Forty Two Pesos and Seventy Five Centavos (PhP42.75) for every One United States Dollar (US$1.00). This amounted to a balance of One Hundred Twenty Six Billion Six Hundred Forty Six Million Eight Hundred Seventy Five Thousand Pesos(PhP126,646,875,000.00) that would paid in 40 semi-annual payments with interest equal to the Philippine Dealing System (PDS) Treasury Fixing or "PDST-F" 10 year benchmark rate plus two hundred thirty (230) basis points (2.3%).

5.2.6. Transfer of TRANSCO's Business

From Commencement Date, the Concessionaire shall exercise all of TRANSCO's rights and discharge all of TRANSCO's liabilities (except as excluded below) and perform all its obligations under all existing contracts. It shall also manage the construction and completion of all Projects Under Construction that have not been commissioned and/or placed in service. TRANSCO shall also transfer title to the Transferable Assets by executing a Deed of Transfer.

TRANCO's retained liabilities include: the loans contracted by NPC relating to Transmission Assets; claims relating to existing rights of way prior to Commencement Date; and, obligations to employees under employee agreements.

5.3. Current Regulatory Regime

The ERC was created by the EPIRA as the independent quasi-judicial regulatory body for the electricity industry. Among its responsibilities is the determination and approval of the Transmission Wheeling Charges. Its approval is also required before any capital expenditure is undertaken. In addition, the ERC has the original and exclusive jurisdiction over all cases contesting rates, fees, fines and penalties imposed by the ERC as well as all cases covering disputes between and among participants or players in the energy sector.

On May 29, 2003, the ERC published the "Guidelines on the Methodology for Setting Transmission Wheeling Rates for 2003 to around 2027" (TWRG) which sets a performance-based regulatory regime (PBR) and the methodology in determining the rates that may be charged for the provision of transmission services. The methodology is discussed in Section 3.4.3.

The TWRG set out 5-year regulatory periods with the exception of the First Regulatory Period (FRP) which covered only three years from January 1, 2003 to December 31, 2005.

For the Second Regulatory Period (January 1, 2006 to December 31, 2010) and the Third Regulatory Period (January 1, 2011 to December 31, 2015), a revenue cap price control is applied. For subsequent periods, the ERC shall review the form of price control. A revenue cap, a price cap, or a hybrid cap may be adopted.

Prior to the start of the Second and Third Regulatory Periods, the ERC determined the annual revenue requirements for each regulatory year of the regulatory period using a forward looking analysis of inflation, demand, sales, capital expenditures and weighted average cost of capital. The annual revenue requirement is determined using the following "building blocks": operating expenditures, return of assets (depreciation of the Regulatory Asset Base), return on assets (weighted average cost of capital applied on the Regulatory Asset Base), corporate income tax and other taxes. The annual revenue requirements of the regulatory period are then smoothed to avoid rate shocks which result in the revenue cap for each regulatory year of the regulatory period. The annual revenue caps are allowed to adjust annually for inflation and other parameters if particular economic parameters are triggered.

On a regulatory year to year, the TWRG assures that the utility is able to achieve the revenue cap as any over-recovery or under-recovery of a regulatory year's revenue cap is deducted or added, respectively, to the next year's revenue cap, albeit subject to side constraints.

Savings on cost targets set by the ERC shall be retained by the utility for a period of five (5) years and is shared with consumers after the fifth year. Overruns on cost targets are borne by the utility.

NGCP started collecting TRANSCO's annual revenue requirement for regulatory year January 1, 2009.

5.4. Performance

As previously discussed under the RTWR, as part of the performance-based regulatory regime for the transmission provider, an incentive scheme is provided to reward performance over a set standard and penalize underperformance. During the 2nd Regulatory Period, if the quality of service delivery was above the targets set during the Reset, the Regulated Entity could earn an annual incentive of up to 3% of the 2006 MAR. Conversely, if the quality of service fell below the targets, a penalty of up to 3% of the 2006 MAR could be applied. The following indicators were used as components of the second regulatory period PIS:

(a) System Interruption Severity Index (SISI) – measures the ratio of the unserved energy to the system peak load:

(b) Frequency of Tripping per 100cct-km (FOT) – measures the number of forced line outages (both transient and sustained) per 100 cct-km initiated by the automatic tripping of protection relays:

(c) System Availability (SA) or circuit availability as a proportion of total circuit time – refers to the availability or percentage of the system being considered to be on-line during the evaluation period:

(d) Frequency Limit Compliance (FLC) – refers to the percentage of time during the rating period that the system frequency is within the allowable range of 60 ± 0.3 Hz:

(e) Voltage Limit Compliance (VLC) – refers to the percentage of the number of voltage measurements during the rating period that the voltage variance did not exceed ± 5% of the nominal voltage of all busses (Luzon – 230 kV & 500 kV, Visayas – 230 kV/138 kV, Mindanao – 138 kV) monitored at the high side of the substation. Monitoring times are at peak load hours of 11 am, 2 pm and 7 pm and off-peak hour at 2 am. These hours represent the times when the bus voltages are expected to be not at their normal levels.

Performance was measured separately for each indicator on each grid: Luzon, Visayas and Mindanao, providing a total of fifteen (15) separate annual measures of grid performance. The target for each performance indicator was set based on the average historical performance over the previous five years. A dead band of one standard deviation each side of the target performance level was set, where no reward or penalty is applied. The reward or penalty was determined in linear fashion if the performance was outside of the dead band and up to a level of two standard deviations above or below the target. If the performance was materially better than the historical level, a reward is applied and if performance deteriorated significantly below the historical level, a penalty is applied. It was necessary to give weight to each of the fifteen (15) performance measures to determine what portion of the total available reward or penalty is to apply to each measure.

Table 5.4.1 below shows the actual performance of the Regulated Entity for each measure for each of the first four years of the second regulatory period. Performances that earn a reward are shown in bold and those that incur a penalty are shown in italics. The remaining performances fall within the dead band for each indicator.

Table 5.4.1 Actual Performance of the Regulated Entity

	2006	**2007**	**2008**	**2009**
Luzon				
SISI	**7.54**	**10.26**	**9.54**	*28.70*
FOT	**5.25**	**4.17**	**3.99**	**4.27**
SA	99.31	**99.53**	**99.46**	99.30
FLC	99.91	100.00	99.99	100.00
VLC	87.91	91.32	**93.21**	**95.07**
Visayas				
SISI	**33.55**	**39.91**	**83.56**	208.32
FOT	**4.25**	**4.13**	**4.54**	**3.63**
SA	**99.78**	**99.72**	**99.59**	**99.40**
FLC	*96.31*	*97.42*	99.05	98.76
VLC	*96.84*	*98.20*	98.79	*98.42*
Mindanao				
SISI	**19.72**	**4.41**	**10.43**	**16.73**
FOT	**5.10**	**3.76**	7.95	**2.62**
SA	**99.77**	**99.67**	99.34	**99.57**
FLC	**99.96**	*99.11*	99.94	*99.50*

Over the first four years of the second regulatory period, the performance has been significantly better than its historical performance. Attention should be geared towards the year 2009 inasmuch as this was the year NGCP took over TRANSCO. As can be gleaned from the above table, NGCP's performance maintained, if not improved on TRANSCO's performance except for SISI for Luzon and Visayas. The SISI in Luzon was greatly affected by the breakdown of a critical substation serving the MERALCO franchise area, which resulted in severe congestions while that of Visayas was mainly due to the unavailability of power. It can be said that the Visayas situation was not under the control of NGCP; however, that of Luzon was clearly within its control. This latter observation was highlighted in ERC's NGCP's Final Determination for the 3rd Regulatory Period.

The ERC noted that severe congestion problems routinely occur on the grid, and, while not causing an outage, are managed through the dispatch of more expensive out of merit generation. While this has no impact on the Regulated Entity, it raises the cost of electricity to consumers.

The ERC commented that NGCP's approach to grid planning has only slightly changed from the approach taken before the restructuring of the National Power Corporation and the introduction of WESM. Projects were prioritized purely on the basis of expected energy not served (EENS), notwithstanding the fact that clause 5.2.1.1 of the Grid Code requires the grid owner to identify congestion problems that may result in increased outages or raise the cost of service significantly. However, the information provided to the ERC in support of the Capex forecast showed no evidence that the Regulated Entity had discussed its grid planning priorities with the Philippine Electricity Market Corporation (PEMC) or with consumer representatives. There was little evidence in any of the information provided to the ERC that the need to improve the operation of WESM was one of the factors taken into account when planning the development of the grid.

The Regulated Entity's grid planning criteria is based on a requirement to design the grid network to avoid loss of load in the event of a single network element outage under an extreme generation dispatch scenario. For example, one dispatch scenario used for the Luzon grid is the maximum south – dry scenario where all generators in the south part of the network are assumed to be simultaneously at their maximum dispatch. It is not clear that this dispatch scenario is realistic as it implies that lower cost generation north of Manila is assumed not to be dispatched. The use of deterministic planning criteria based on extreme generation dispatch criteria can lead to the sub-optimal investment planning decisions. For example, such an approach is likely to favor a project to address a low probability loss of load situation under the extreme dispatch scenario in preference to a project intended to alleviate a serious but commonly occurring grid constraint. This is because the grid constraint does not result in a loss of load.

Such a planning decision would not be in the interest of consumers, who must regularly bear the higher cost of the generation that is routinely dispatched, to avoid the grid constraint. In a sense, the low probability loss of load scenario described above is an n-2 contingency as it requires both a line or transformer outage and the network to be working well outside its normal operating parameters, presumably as a result of some other extreme situation.

Thus the ERC concluded that NGCP's approach to grid planning appears not to be in the best interests of the consumer, as it does not ensure the minimization of the total electricity costs that consumers must pay.

To address this, the ERC required the NGCP to formally review its approach to grid planning in order to develop planning criteria that will better support the operation of the WESM and the objective of minimizing the total cost of electricity to consumers. This planning review must include meaningful consultation with industry stakeholders including PEMC, generators, distributors and consumers. The ERC has also drafted a new Transmission Planning Guidelines, which it is currently being subjected to public consultation.

In addition, the ERC noted that while NGCP has submitted its strategy on addressing the present ancillary services deficiency, the strategy was brief and contained few specifics. There was no analysis of the quantity of each of the different types of ancillary service required by each grid and no procurement targets. Strategies to address current shortages were noted only in very high level, non-specific terms. It provided little evidence that NGCP has a meaningful plan in place to actively address the current shortages of ancillary services.

Interviews with stakeholders showed that with the privatization of TRANSCO, NGCP could now better respond to outages and other technical problems with a reasonable turn around, the availability of information and customer service were a concern. It was highlighted that information can now only be obtained following a formal communication protocol. Promptness of reply is also an issue. The need for better customer relationship was also brought up.

It is noted that the ERC has included additional performance indicators on the above observations in NGCP's 3rd Regulatory PIS. In addition to all indicators used in the PIS for the second regulatory period which were set to more stringent targets for most measures, the following three new indicators were added:

a) A congestion availability indicator (ConA) that measures the availability of a subset of lines and transformers on the Luzon grid. The network elements to be included have been specified by the ERC because they are considered critical to the successful operation of WESM and the avoidance of congestion on the grid;
b) An ancillary services availability indicator (ASAI) that measures the availability of ancillary services on each of the three grids for each hourly charging period; and
c) A customer satisfaction indicator (CSI) that measures the extent to which customers with direct connections to the grid, including generators, distribution utilities and directly connected individual customers, are satisfied with the level of service provided by the NGCP. Customer satisfaction will be measured by customer responses to an annual survey conducted by an external research provider using an objective and quantitative scoring system.

5.5. Assessment

As a lesson learned, these factors were deemed to have attracted investors to participate in the competitive bidding process for the privatization of TRANSCO:

5.5.1. Strong Potential for Good Operational and Financial Performance

TRANSCO was considered the "crown jewel" of the government's privatization program. It is the sole national electricity transmission company which has a strong operational and financial performance. It is among the largest corporations in the Philippines.

5.5.2. Attractive Growth Rate

At the time of the bid process, the Philippines had an annual GDP growth rate of 5.4% in 2006 which was expected to continue to grow at a compound annual growth rate of 5.3% over the next four years. Demand for electricity was expected to grow around 4% annually during the period 2006-2010. Actual GDP growth in the first quarter of 2007 was 6.9%, the country's highest in 17 years. Corollary to this, growth in electricity demand was expected to surpass projections.

5.5.3. Robust Regulatory Framework

The privatization of TRANSCO benefitted from a legislated comprehensive restructuring and privatization framework, the EPIRA.

Consistent with the EPIRA, the ERC had promulgated a performance-based regulatory framework which laid down the parameters by which TRANSCO would be regulated. At the time of the bid process, the ERC had set the revenue cap for TRANSCO for the period 2006 to 2010. A clear and transparent regulatory regime is fundamental to the success of TRANSCO's privatization.

5.5.4. Clear Privatization Structure

A clear privatization structure with economics similar to outright purchase of assets made the transaction attractive. A concession agreement for 25 years, renewable for another 25 years, subject to mutual agreement by the parties defines the period by which investors could recoup their investments. A provision for payment to the Concessionaire linked to the value of the Regulatory Asset Base at the time of termination or expiration of the Concession ensures that the investor will be able to recover any un-depreciated investment at that time. This provision also ensures that the Concessionaire will continue to invest on the transmission network even late into the term of the concession and protects the Concessionaire in case TRANSCO terminates Concession.

While the winning bidder is required to obtain a franchise from Congress to operate a public utility (with the assistance of PSALM), this was made as a condition precedent to the closing of the transaction which allows the winning bidder to walk away from the transaction if such franchise is not obtained or the conditions of the franchise are materially different from the Concession Agreement.

The payment of the transaction consideration, the Concession Fee, was made attractive by the requiring an upfront payment of only 25% and the deferred payment of the balance under precise terms and conditions set prior to the final bid. PSALM calls this a pre-geared investment.

5.5.5. Transparent and Clear Bid Process and Rules

Interested prospective bidders were provided with written Bidding Process, Procedures and Rules. This included the identification of four stages of the bidding process and the corresponding time frame for: 1. Due diligence process; 2.Prequalification Process; 3.Technical and Financial Bid; and Selection of Winner. Specific procedures and rules were detailed for each process including the prequalification criteria as well as the evaluation criteria for the bids. A clear single financial parameter, the Concession Fee, for the financial bid made the bidding simple and more transparent.

Prospective bidders were also allowed to review and submit two rounds of comment on proposed transaction documents which were made available early in the process.

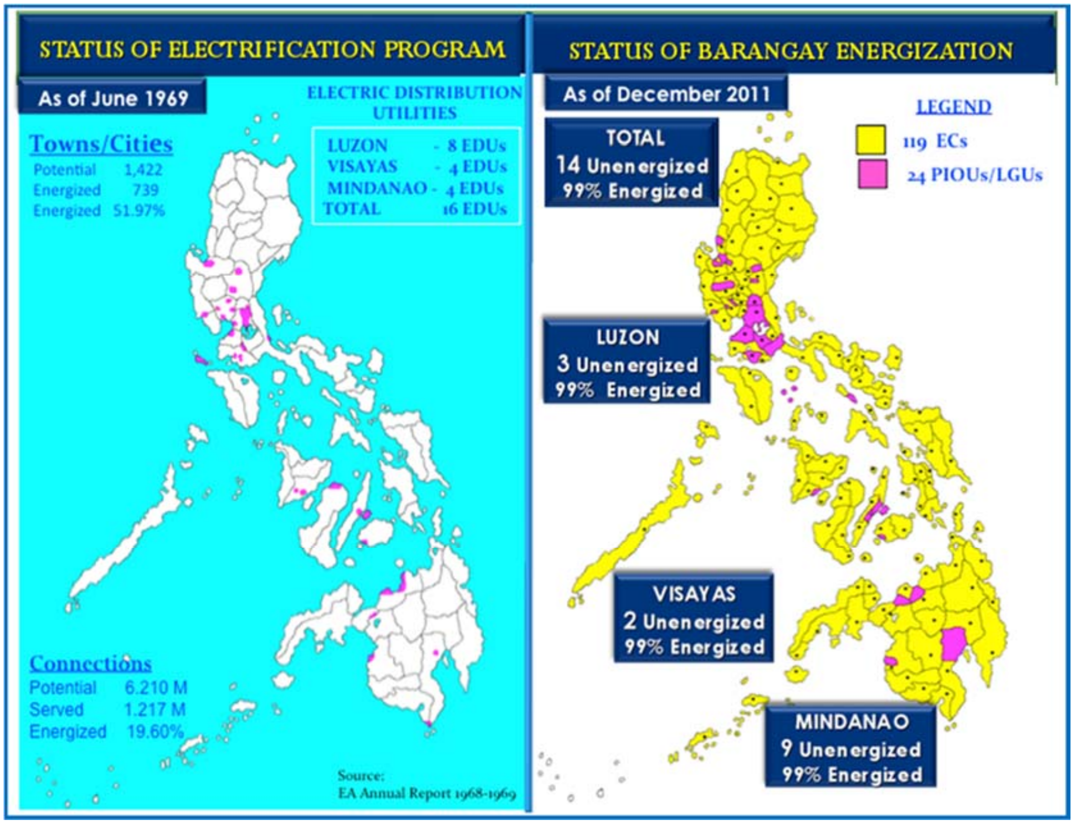
5.5.6. Sufficient Opportunity for Due Diligence

The length of the bid process, approximately 18 weeks long, was designed to give bidders sufficient time to conduct their financial, legal, regulatory and technical due diligence. Bidders were provided with due diligence procedures, and a CD ROM set of pertinent data and information relevant to the transaction. A Data Room was made available. Meetings with and presentations by TRANSCO to bidders were also conducted. Site visits were also undertaken.

6. PRIVATE SECTOR PARTICIPATION IN DISTRIBUTION

The Philippine's distribution sector is composed of 16 privately-owned utilities, 8 municipality or local government unit owned utilities, and 119 electric cooperatives.

Figure 6.1



The performance of the distribution sector as of December 31, 2011 is given in Table 6.1 below

Table 6.1

Electric Distribution Utilities	Municipalities/ Cities			Barangays			Connections		
	Coverage	Energized	%	Coverage	Energized	%	Coverage	Served	%
Electric Cooperatives	1,475	1,475	100	36,063	36,049*	99.9	12,160,000	9,250,713	76
Meralco	111	111	100	4,322	4,322	100	4,979,955	4,931,696	99
PIOUs/LGUs/ Others	48	48	100	1,628	1,622	99.6	1,486,000	1,195,000	80
TOTAL PHILIPPINES	1,634	1,634	100	42,013	41,993	99.9	18,625,955	15,377,409	83

6.1. Investor-Owned Private Distribution Utilities

The following comprise the 16 investor-owned private distribution utilities:

a) Manila Electric Company (MERALCO)
b) Dagupan Electric Company (DECORP)
c) San Fernando Electric Light and Power Company (SFELAPCO)
d) Clark Electric Distribution Company (CEDC)
e) Angeles Electric Company (AEC)
f) Tarlac Electric Inc. (TEI)
g) Cabanatuan Electric Corporation (CELCOR)
h) La Union Electric Company (LUECO)
i) Ibaan Electric and Engineering Corporation (IEEC)
j) Visayan Electric Company (VECO)
k) Mactan Electric Company (MECO)
l) Panay Electric Company (PECO)
m) Cagayan Electric Power and Light Company, Inc. (CEPALCO)
n) Iligan Light and Power, Inc. (ILPI)
o) Davao Light and Power Company (DLPC)
p) Cotabato Light and Power Company (CLPC)

6.2. Municipality or Local Government Unit Owned Utilities

These are the 8 Municipality or Local Government Unit owned utilities:

a) Bohol Light Company, Inc.
b) Subic Enerzone Corporation (SEZC)
c) Olongapo Public Utilities Department
d) Bauan Electric Light Service
e) Concepcion, Romblon
f) Banton Island, Romblon
g) Corcuera, Romblon
h) Burias Island, Masbate

6.3. Electric Cooperatives

There are 119 Electric Cooperatives or ECs, 98 on grid and 21 off grid.

The government's rural electrification program is the umbilical cord of the ECs. The following timeline was culled from the presentation and interview with Dr. Adolben A. Flores, Director of MAG-SAO of the National Electrification Program:

1960: Rural electrification then was characterized by small generating units (30-60 kW capacity) serving only one poblacion on a dusk-to-midnight basis and generally for lighting purposes only. To carry out the country's electrification policy, the Philippine Congress enacted R.A. 2717, declaring the state policy of providing cheap and dependable electric power for the promotion of agricultural and industrial development of the country. The Electrification Administration was created and the law provided PhP twenty five (25) million to make loans to be lent to electric utilities for the construction of power generating plants and transmission and distribution systems in order to serve the countryside.

1964: Despite the creation of the agency, electrification on the country side still did not take off. In 1964, the United States Agency for International Development (USAID) conducted a national survey of the country's power situation. The country's electrification program was moving slowly because private utilities continued to ignore the rural areas. The study estimated that a 20-year program designed to achieve 40% electrification of the Philippines would require around PhP750 Million. In addition, the study recommended the adoption of the rural electric cooperative system as developed in the United States (US). Subsequently, the National Rural Electric Cooperative Association (NRECA) of the US was contracted to conduct a feasibility study on the creation of two pioneering local electric cooperatives envisioned to jumpstart the Philippine's own electric cooperative system. One was the Misamis Oriental Rural Electric Cooperative (MORESCO) in Mindanao which would purchase power from the NPC and distribute it to its consumers. The other was the Victoria-Manapla-Cadiz Rural Electric Service Cooperative (VRESCO) which would generate and distribute its own power.

1969: In this year, the National Electrification Administration (NEA) was created by Republic Act No. 6038. The NEA was mandated to pursue the total electrification of the country by creating ECs based on area coverage. The ECs, in turn were tasked to extend electric service to all households within their franchise, including areas where population was sparse. In the same year, the US government granted US$3.5 Million to finance the two pilot ECs which were energized in 1970. Encouraged by the success of MOESCO and VRESCO, NEA started to organize and energize 36 more ECs in 36 provinces. The USAID granted an additional US$20 Million loan to the Philippine government. NEA lent this to the 36 ECs, not as cash loans but rather in the form of equipment and materials necessary to build the infrastructure and energize the system.

1972: In this year, Presidential Decree 40 (PD 40) established the basic policies for the electric power industry:

a) The attainment of total electrification on an area coverage basis, which is declared policy of the State, shall be effected primarily through:
    - the setting up of island grids with central/linked-up generation facilities; and
    - the setting up of cooperatives for distribution of power.
b) The setting up of transmission line grids and the construction of associated generation facilities in Luzon, Mindanao and major islands of the country, including the Visayas, shall be the responsibility of the National Power Corporation as the authorized implementing agency of the State.
    - Plant additions necessary to meet the increase in power demand of the area embraced by any grid set up by the NPC shall be constructed and owned by the NPC.
    - In areas not embraced by the NPC grid, the State shall permit cooperatives, private utilities and local government to own and operate isolated grids and generation facilities subject to State regulation.
c) The distribution of electric power generated by the NPC shall be undertaken by:
    - Cooperatives
    - Private utilities
    - Local governments
    - Other entities duly authorized subject to state regulation.
d) Within the area embraced by a grid set up by the NPC, the state shall determine privately-owned generating facilities which should be permitted to remain in operation.
e) It is the ultimate objective of the State for the NPC to own and operate as a single integrated system all generating facilities supplying electric power to the entire area embraced by any grid set up by the NPC.

In addition, Letter of Instruction No. 38 directed the NEA to convert "small private/municipal systems to electric cooperatives" and implement PD 40.

Presidential Decree 269 issued in 1973 transformed NEA into a wholly-owned and controlled government corporation in 1973. Its capital base was increased to PhP1 billion and it was granted the authority to borrow money and acquire corporate powers. NEA was also granted regulatory powers to fix the rates for the ECs and the authority to provide and revoke franchises, a privilege once vested solely on Congress. This was amended by Presidential Decree 1645 in 1979 to increase NEA's capital stock to PhP5 Billion and broadened the lending and regulatory powers of NEA as the lead agency in promoting rural electrification.

From 2 ECs in 1969 to 119 ECs in 2011 -that is quite a feat!

6.3.1. Establishment of an EC

An electric cooperative is a non-stock, non-profit member-owned public utility enterprise designed to provide adequate and reliable electric service at reasonable cost to its members.

It follows an "area coverage" concept where electric service must be extended to all prospective customers in the franchise area (not only the town center but also the outlying barrios), provided that the feasibility of the public utility's entire operation is not impaired. This is usually done in stages where service will be first provided to the densely populated areas then continuously spread out to the more remote consumers. The intent is to develop systems which will be large enough so that the more profitable portions of such system could help absorb the apparently high cost of providing service to the more distant isolated consumers.

6.3.2. Stages of Cooperative Development

Following are the stages of a cooperative development:

a) Preparation of Feasibility Study.
    - This involves the conduct of a project study taking into account, among others, the financial viability of the project, the preliminary engineering works, system cost, area coverage and load forecasts.
b) Organization and Registration of the EC.
    - To facilitate the organization of an EC, public assemblies are held for the purpose of electing members to a District Electrification Committee or DEC. A DEC will have 8 members, one (1) representative each from the following sectors: education, business, farmers/workers, civic organizations, religious groups, government employees, barangay council, and the youth. Each town will have one (1) DEC and its members will elect a Chairman who automatically becomes a member of the interim Board of Directors of the EC. The EC is then formally incorporated and registered with the NEA.
c) Execution of Loans. The EC applies and enters into a loan agreement with the NEA, the loan is repayable in 30 years with a grace period of 5 years at an annual interest rate of 2 or 3 %. The loan will be used to finance the construction and operation of the EC.
d) Pre-construction Engineering. A private architectural and engineering firm is contracted by the EC for the design of the system.
e) Construction. The EC distribution network is then constructed together with headquarter facilities through private contractors or using its own manpower or both. Houses and other establishments are connected to the distribution network.
f) Energization. Upon the completion of the electric system or a portion thereof, the lines are energized to provide electric service. Once all the town centers of an EC is served, the backbone system is deemed energized.

6.3.3. EC Performance

The overall operating performances of the ECs are annually assessed by the NEA through a number of measures, as follows:

a) Categorization. ECs are categorized by letters from a high of “A+” for Outstanding to a low of “E” for no improvement in operations.
b) Classification. ECs are also classified according to size: small, medium, large, extra large or mega large. This classification guides the NEA to establish uniform standards and guidelines for the same class of ECs
c) Color Coding .The ECs are also color coded indicative of the level of supervision and/or assistance required from NEA. The color coding, patterned after the colors of the traffic light, of green, yellow and red.

Annex 13 discusses the above measures in detail.

6.4. Private Sector Participation Experiences in Distribution

6.4.1. Investment Management Contract (IMC) for ECs

The Investment Management Contract (IMC) Model for ECs was the result of a study conducted for the design of private risk capital investment in electric cooperatives in 2001.

In 2004, the DOE issued Department Circular No. 2004-06-007 titled “Promoting Investment Management Contracts as One Measure in Effecting Greater Private Sector Participation in the Management and Operation of Rural Electric Cooperatives Pursuant to Section 37 of Republic Act. No.9136 and its Implementing Rules and Regulations”.

The IMC is one of the programs being supported by the DoE to urge ECs to undertake structural and operational reforms with a view to achieving greater efficiency and lower costs, through collaboration with private investor-operator/s to gain access to private sector capital and management expertise.

The IMC is a contractual relationship between a willing EC and a willing investor-operator, for the infusion of risk capital and provision of management expertise by the latter to the former, to provide for EC recovery based on improved efficiency, lower costs and systems losses reduction. The main features are:

a) The EC remains the duly authorized distribution utility. It continues to be regulated by the ERC.
b) The EC retains ownership of and strategic control of its assets, as well as control over setting the standards of service to its customers.
c) The investor-operator shall operate and maintain the distribution utility and provide for its capital expenditures. It will be remunerated where systems loss reduction is achieved and costs are considerably decreased, through an equitable profit-sharing and/or lease option scheme.
d) The member-consumers of the EC, through the EC Board, continue to exercise the rights and responsibilities under its franchise, such as, but not limited to:
    - Monitoring performance of the investor-operator to ensure compliance with agreed performance standards and deliverables; and
    - Working with the investor-operator to approve and implement an investment program consistent with achieving on-going compliance with the Distribution Code.

To protect the end-users from rate increases and to protect investor-operators from risk that operating surpluses are dissipated through regulated rate reductions and ensure the recovery of their investments, the DoE will consult and petition the ERC for a special regulatory regime which will provide certainty to consumers and potential investor-operators.

The DoE has also appointed the LGU Guarantee Corporation (LGUCC) to manage a credit guarantee program designed to enhance the EC credit worthiness. This program, funded by the Global Environment Facility and the World Bank, aims to provide partial credit guarantees to local Philippine banks for loan to ECs or investor-operators.

The DoE will support only IMC transactions concluded through a transparent and competitive bidding process. Interested ECs may enter into a Memorandum of Agreement with the DoE and NEA to avail the services of a Transaction Advisor as well as set the terms of support the EC will receive at various stages of the IMC transaction process.

There has been no transaction on this model to date.

6.4.2. Management Services Contract for an EC

Prior to the issuance of the DoE Circular on IMC in 2004 referred to in 6.4.1, an electric cooperative, the Zambales Electric Cooperative II (ZAMECO), tried a similar arrangement.

On October 29, 2002, ZAMECO II entered into an "Investment Management Contract" (IMC) for a period of five (5) years with the Philippine Power Distributors Investment Corporation (PPDIC) which became effective on December 2, 2002. This was amended and superseded by a Management Services Contract (MSC) dated September 1, 2003.

The MSC was a management concession for the general management, administration, operation and maintenance of ZAMECO II's business, inclusive of its infrastructure, facilities and other assets. PPDIC shall also provide with or source from 3rd parties, the necessary capital and /or financing requirements to implement the work plan governed by separate "Funding Agreements" mutually agreed and subject to NEA approval. PPDIC was to internally source the fund and recovery is through a performance-based formula which will consider the PPDIC-caused improvement from an agreed baseline financial model.

PPDIC will be paid a Management Fee of 2.5% of ZAMECOII's gross revenue plus 5.0% of its EBITDA (revenue from operation minus operating expenses, before interest, tax, depreciation and amortization). The Value Added Tax (VAT)on the Management Fee will be for the account of ZAMECO II.

The term of the MSC was for 5 years (reckoned from December 2, 2002) and renewable for another 5 years as may be mutually agreed. The MSC could be terminated by: the serious breach by any party and failure to take prompt action to rectify the same.

This was confirmed by the NEA Board on September 3, 2003 under Board Resolution No. 62.

After the MSC's expiration on December 1, 2007, the MSC had 3 provisional extensions. The first extension covered two (2) months, from December 1, 2007 until January 31, 2008 under a reduced Management Fee of 2.25 % of ZAMECO II's gross revenue, plus 2% of EBITDA. The corresponding VAT will be for the account of PPDIC. The second extension covered four (4) months from February 1, 2008 until May 31, 2008 at a fixed management fee of Five Hundred Fifty Thousand Pesos (PhP550,000.00). The third and final extension was for seven (7) months from June 1, 2008 until December 31, 2008 at a fixed management fee of Five Hundred Fifty Thousand Pesos (PhP550,000.00). A Management Services Renewal Contract effective January 1, 2009 until December 31, 2013 was signed on January 5, 2009 at a fixed management fee of Five Hundred Fifty Thousand Pesos (PhP550,000.00).

ZAMECO II registered with the Cooperative Development Authority on December 7, 2007.

The week prior to November 1, 2008, there were protest actions by the municipal mayors of the towns within the franchise area of ZAMECO II alleging that the ZAMECO II Board was overstaying in its term. The NEA on October 29, 2008, in its Resolution No. 03-S-2008 created an Interim Board of Directors and an Officer-In-Charge for ZAMECO II who took over the EC on November 2, 2008. At that time, there were 2 ZAMECO II Boards and General Manager, one supported by the NEA and the other by the CDA. This led to a series of court actions, some still pending, and the end of the MSC and its renewal.

6.4.3. Joint Venture for a Local Government Owned Utility

The Bohol Light and Power Company is the joint venture company of the consortium of Salcon International, Inc., Salcon Limited and Salcon Power Corporation with the Bohol Provincial Government for the Bohol Provincial Electric System.

The Provincial Government was having cash flow problems arising from bill collection inefficiencies, which compromised its ability to promptly pay its power bills to NPC. In addition, it needed funding to improve and expand the distribution system to better serve its consumers. It wanted to raise the quality and reliability of electric service to its constituents.

A USAID funded study on whether or not privatization would remedy the problems of the Province of Bohol's power distribution system was conducted. Among the issues that had to be addressed were: the contractual scheme for the privatization, the indebtedness of the Province to Land Bank, appraisal of the PES, capital requirements for the upgrade of the system, and political acceptability.

The solutions that were proposed are:

a) a joint venture between the winning proponent and the Province in accordance with the Civil Code in relation to the rehabilitate-own-operate-and-maintain (ROOM) scheme in the Build-Operate-Transfer (BOT) Law;
b) the indebtedness of the Province would be factored in the financial aspect of the bid;
c) the purchase price of the PES to be based on the appraised value; and
d) a program on the upgrade of the system.

A public bidding was conducted. There were four bidders. The winning bid of the consortium of Salcon International, Inc. Salcon Limited and Salcon Power Corporation was the purchase price, which included the debt balance of the Province to Land Bank plus the equity share of the Province in the special purpose company at 30% of the authorized capital stock of the Bohol Light Company, Inc, the special purpose company.

6.4.4. Distribution Service Management Agreement for a Local Government Owned Utility

The Subic Bay Metropolitan Authority (SBMA) is the implementing arm of the Bases Conversion and Development Authority for the erstwhile Subic military reservations. Among the mandate of the SBMA is to construct, acquire, own, lease, operate and maintain on its own or through contract the required utilities and infrastructure.

A World Bank funded study for SBMA assessed the opportunities to achieve stable, reliable and sustained supply of electricity to meet its requirements and those of its locators. The SBMA used its Charter and Build-Operate-Transfer (BOT) Law as legal basis for the privatization of its Power Distribution System. The SBMA bidded out a Distribution Services Management Agreement (DSMA), premised on the rehabilitate-operate-transfer (ROT) scheme in the BOT Law. The DSMA is essentially a concession agreement for 25 years in two phases: a five (5) year rehabilitation period and a twenty (20) year operation, management and maintenance period in exchange for an upfront fee, which partake the nature of rental.

A two-step, two-envelope system was employed for the bidding. The first step was the technical bid to ensure compliance to the 5-year rehabilitation program that was pre-determined. The second step was the financial bid with the lone financial bid parameter of the lowest cost of electricity distribution tariff that would be charged to the locators. Three bidders participated.

The consortium of Aboitiz Equity Ventures and Davao Light and Power Company won the bid and established the Subic Ener-Zone Corporation, a special purpose company, for the implementation of the DSMA.

As a result of the privatization, the power distribution tariff was reduced from the previous PhP1.00/kWh to PhP0.5975/kWh.

ANNEX 1: RATIONALE FOR THE ELECTRIC POWER INDUSTRY REFORM ACT

The state-owned NPC was a vertically integrated utility that was responsible for central management and control of both generation and transmission of electricity in the whole country. Its supply of electricity came from its own power plants and from Independent Power Producers (IPPs). It had exclusive ownership of the transmission grid and was also responsible for central systems planning and systems operations. It sold electricity wholesale to distribution utilities: 16 privately-owned distribution utilities, 8 local government owned distribution utilities and 119 electric cooperatives (ECs) which supplied end-users in their geographical franchise area. NPC also sold electricity to end users who were "directly connected" to the transmission grid.

The NPC was created in 1936 by Commonwealth Act 120 to develop the hydropower potentials of the country. Subsequently, RA 6395 revised NPC's charter and extended its corporate life until the year 2050 in 1971. At that time, fuel-fired thermal units were owned by the Manila Electric Company (MERALCO) and other private sector investors.

Martial law was declared on September 21, 1972. Generation capacity was nationalized and NPC was made solely responsible for the construction and operation of all electricity generation, transmission and sub-transmission facilities by virtue of Presidential Decree No. 40 issued on November 7, 1972.

The 1973 oil crisis prompted the country's fuel source diversification strategy. Geothermal energy was tapped and developed and still continues to provide electricity till the current time. In addition, in 1976, the NPC started to build the 620 MW Bataan Nuclear Power Project (BNPP).

In 1983, the government declared a debt moratorium. As a consequence, foreign loan commitments were abandoned and undrawn balances from existing debt facilities were either cancelled or suspended. This severely strained NPC's ability to complete projects. This started NPC's financial problems.

In 1986, after the People Power I bloodless revolution that restored democracy in the country, the government moth-balled the BNPP and Executive Order (EO) 55 transferred its assets and liabilities to the accounts of the National Government.

In 1987, the reform process started with the issuance of EO 215 that amended PD No. 40 and allowed the private sector to generate electricity.

The two foregoing events jeopardized NPC's ability to meet demand as no generating capacity was put in place to replace the BNPP. This led to the power crisis of the early 1990's. To address the situation, RA 6395 or the Electric Power Crisis Act was enacted on September 1991 and reinforced EO 215 to ask the private sector to build power plants dedicated to NPC's use but without any source of government financing. This was the birth of IPPs' investments. This was furthered strengthened by the passage of RA 7718 or the Build-Operate-Transfer (BOT) Law in 1994.

The IPPs were instrumental in solving the power crisis of the early 1990's. Using the same approach, NPC continued to add generation capacity, and put on stream 5,583 MW of IPP capacity from 1991 to 1999. These IPP contracts were under "take or pay" provisions. However, six (6) IPP contracts which were some of the biggest and most expensive, failed to obtain regulatory approval for full-cost pass through. This further strained NPC's finances.

Meanwhile, MERALCO, and other distribution utilities, also contracted their own IPPs owing to EO 215's de-monopolization of NPC's generation function.

The Asian financial crisis of 1997 brought a contraction in demand and the rapid devaluation of the peso. This, together, with the losses from the IPPs' "take or pay" contracts brought havoc to NPC's finances.

All of these contributory events to NPC's financial situation exacerbated NPC's fundamental problem: undercapitalization. The government's paid up and donated capital was merely 3% of its assets. Thus, NPC relied on foreign denominated debt. However, its financing costs were not recoverable under the obtaining "Return on Rate Base" regulatory regime.

The government did not also have the funds to inject additional equity to NPC.

The solution was the reforms envisioned in the EPIRA.

ANNEX 2: A BRIEF ON THE PHILIPPINE GRID CODE

The table below encapsulates the PGC Contents and its Applicability

Chapters	Grid Owner	System Operator	Market Operator	Generation Company	Distribution Utility	Suppliers	Directly Connected End-users
1. Grid Code General Conditions	√	√	√	√	√	√	√
2. Grid Management	√	√	√	√	√	√	√
3. Performance Standards for Transmission	√	√		√	√		√
4. Financial Standards for Generation & Transmission	√	√		√			
5. Grid Connection Requirements	√	√		√	√	√	√
6. Grid Planning	√	√	√	√	√	√	√
7. Grid Operations	√	√		√	√		√
8. Scheduling & Dispatch	√	√	√	√	√	√	√
9. Grid Revenue Metering Requirements	√	√	√	√	√	√	√
10. Grid Code Transitory Provisions	√	√	√	√	√		√

Chapter 5 of the PGC: (a) ensures that the basic rules for connection to the grid or to a user system are fair and non-discriminatory for all users of the same category; (b) specifies the technical, design, and operational criteria at the user's connection point; and (c) lists and collates the data to be required by the grid owner from each category of users as well as the data to be provided by the grid owner to each category of users. Access to data is thus communal, and benefits both the grid owner and its customers as well.

The technical, design and operational criteria, discussed in Chapter 3 of the PGC, includes power quality standards, frequency and voltage variation, harmonics, voltage unbalance, voltage fluctuation and flicker severity, transient voltage variation, grounding requirements, equipment standards, and maintenance standards. All the aforementioned criteria ensure the quality of electric power in the grid, safety in the work area and that the grid will be operated in a safe and efficient manner with a high degree of reliability.

In Chapter 6 - Grid Planning, the grid owner, having the lead responsibility for grid planning, plans the expansion of the grid to ensure adequacy to meet both forecasted requirements (demand side) and the connection of new generating plants (supply side). Thus, both demand and supply requirements are taken into account when planning the development of the grid. The grid owner also identifies congestion problems that may lead to increased outages or raise the cost of service significantly.

ANNEX 3: WHOLESALE ELECTRICITY SPOT MARKET RULES

WESM members may register either as a: (a) Generation Company, (b) Customer, (c) Network Service Provider, (d) Ancillary Services Provider, (e) Metering Services Provider, and / or (f) System Operator (the SO of the transmission company is registered as the SO). Registration in multiple categories is allowed..

While the WESM Rules define the requirements of how to become a WESM member, the rules also provide the grounds for suspension of WESM participants as: (a) Breach of the WESM Rules and (b) Payment default.

The WESM Rules apply to all WESM participants classified as: (a) Market Operator, (b) System Operator, (c) Generation Companies, (d) Ancillary Service Provider, (e) Distribution Utilities, (f) Suppliers, (g) Metering Services Providers, (h) Bulk Consumers / End-users, and (i) Other similar entities authorized by the ERC to become members of the WESM.

Applying to all the above-mentioned WESM participants, the following is the general content of the WESM Rules:

Chapter 1. Introduction

- Purpose and Application of the Rules;
- Responsibilities of the MO who administers the operation of the WESM in accordance with the WESM Rules;
- Responsibilities of the SO who operates the power system in accordance with the WESM Rules, the PGC and any instruction issued by the MO or ERC;
- Governance of the Market by the Philippine Electricity Market Board wherein each sector of the electric power industry is represented;
- Responsibilities of the Philippine Electricity Market Auditor in conducting annual audit of the MO and the settlement system and any other procedures, persons, systems or other matters relevant to the spot market;
- Appointment of members in and responsibilities of the Market Surveillance Committee which monitors and reports the activities of the WESM participants in the spot market;
- Appointment of members in and responsibilities of the Technical Committee which monitors and reports on technical matters relating to the operation of the spot market;
- Enforceability and Amendment of the Rules; and
- Public Consultation Procedures.

Chapter 2. Registration

- Registration of the different categories of WESM Participants;
- Requirements and procedures for ceasing to be a WESM Member;
- Grounds for Suspension of WESM Participants;
- Deregistration of WESM Participants;
- Imposition, structure and level of Market Fees which is a charge on all WESM members covering the cost of administering and operating the market; such charge is filed b the MO with the ERC for approval, consistent with the EPIRA.

Chapter 3. The Market.

This chapter is the heart of the WESM Rules as it sets out the rules governing the market itself, and related matters including but not limited to the:

- Definition of the market network model which is used for the purpose of central scheduling and dispatch, pricing and settlement; pricing zones wherein customer nodes within the same pricing zone are priced the same for electricity consumed; trading interval which at present is one (1) hour and commencing on the hour, and timetable primarily for determining week ahead and day ahead projections and submitting offers, bids and data;
- Procedure for submitting offers, demand bids and data into the spot market,
- Structure and use of the Market Dispatch Optimization Model (MDOM) which is used to maximize the value of dispatched load based on dispatch bids minus (a) the cost of dispatched generation based on dispatch offers, (b) cost of dispatched reserves based on reserves contracted for or when applicable, reserve offers, and (c) the cost of constraint violation based on the constraint violation coefficients;
- Procedures for providing and determining payment for ancillary services;
- Procedures for determining week ahead and day ahead projections;
- Procedures for scheduling and dispatch, treatment of load shedding, and excess generation;
- Determination of market prices;
- Publication of information in accordance with the timetable;
- Procedures for determining settlement amounts and for paying and receiving settlement amounts;
- Determination of prudential requirements; and
- Procedures for supporting transmission rights.

The remaining chapters cover:

- Rules on metering;
- Procedures for dealing with market information and confidentiality;
- Rules and procedures for market intervention and suspension;
- Procedures for enforcement and disputes in line with the principles of self-governance, expeditious, just and least expensive disposition of disputes;
- Procedures for effecting and approval of a change in the WESM Rules and manner of appointment of the members of the Rule Change Committee which assesses whether the proposed changes in the rules are consistent with the WESM objectives, feasible, not entailing unreasonable cost to implement, and more appropriate in achieving the previous, immediately preceding, criteria where the effect of the change is to replace an existing rule;
- Interpretation of the rules; and
- Transitory Provisions.

ANNEX 4: RULES FOR TRANSMISSION WHEELING RATES (RTWR)

The following are the key rules of the RTWR:

Price Control Formula: The fundamental formula used to compute the maximum allowed revenue in PhP, for a Regulatory Year (RY) t is calculated in accordance with the following formula:

MARt = [MARt-1 * (1 + CWIt – X)] – Kt – RBRt

Where:

MARt = MAR for current Regulatory Year

MARt-1 = MAR for Regulatory Year t - 1

CWIt= Change in Weighted Index for Regulatory Year t (which takes into account changes in CPI and US$ exchange rate)

X = efficiency factor for Regulatory Year the computation of which is described below under the section on “Calculation of the Efficiency Factor (X) for the RP”

Kt = Correction Factor to adjust for over / under recovery of revenue in Regulatory Year t - 1

RBRt = 50% of the net income in PhP, derived from related business utilizing assets that form part of the Regulatory Asset Base of the Regulated Entity.

General Building Block Principles:

As part of the Regulatory Reset Process (done before the start of each Regulatory Period) the Regulated entity must submit Revenue Applications which the ERC must review to determine the annual Revenue Requirements (ARR) for each Regulatory Year in the Regulatory Period (RP) based on a forward-looking analysis of forecast cash flow requirements, to ascertain the optimal forecast Revenue Requirements. The ARR must reasonably compensate the Regulated Entity for the economically efficient costs and risks it incurs in providing Regulated Transmission Services, based on a Building Block analysis (as previously mentioned) which uses a “classical” Weighted Average Cost of Capital (WACC).

The Building Block Formula to be used in calculating the ARR is:

ARRt = Opext + Taxm,t+ RegDepnt + [(RABt + WCt) * WACC] + Taxp,t +ITAt

Where:

Opext is the nominal operating and maintenance expenditure for RY t;

Taxm,t is the payment of taxes, other than corporate income tax, for RY t, in nominal terms;

RegDepntis the Regulatory Depreciation for RY t in real terms;

RABt is the Regulatory Asset Base (RAB) for RY t in real terms;

WC_t is working Capital Allowance for RY t which is set at a proportion of the difference between the nominal Opex forecast for that RY and nominal amount of Bad Debts forecast for that RY;

WACC is Weighted Average Cost of Capital calculated using a "classical" formula; the WACC is accordingly changed when the corporate income tax is set to zero;

$Tax_{p,t}$ is the estimated corporate income tax payable by a Regulated Entity in RY t;

ITA_t is the income tax adjustment amount for RY t.

Regulatory Asset Base: Prior to the commencement of a RP, an asset revaluation must be undertaken in accordance with the RDWR. The revaluation must value the material items of plant and equipment either at their optimized deprival value or using some other method of internationally accepted valuation methodology as determined by the ERC or the previous value of the RAB is rolled forward.

Operating and Maintenance Expenditure: Forecasts are made for the coming RP based primarily on historical Opex, changes in the CPI and changes in the RAB.

Capital Expenditure: The Regulated entity must provide its forward forecast of its annual proposed capital expenditure for each RY in the RP. This Capex program must separately identify each Capex project which is forecast to cost PhP50 million or more.

Revenue Smoothing: As a result of the Building Block approach, it is unlikely that there will be a linear increase in the allowed ARR for each RY in the RP. Accordingly, so as to reduce price shocks to Customers and revenue shocks to the Regulated Entity, the ERC will smooth the ARR for each RY in the RP starting at the MAR cap for the last RY in the previous RP. Such smoothed allowed ARR will incorporate a recovery of efficiency savings in cost.

Calculation of the Efficiency Factor (X) for the RP: The Present Value (PV) of the allowed revenue for the last RY in the previous RP and each of the RYs in the current RP must be calculated using the following formula:

$$PV_{t-1} = MAR_{t-1} + ARR_t / (1 + WACC) + ARR_{t+1} / (1 + WACC)^2 +$$

$$ARR_{t+2} / (1 + WACC)^3 + ARR_{t+3} / (1 + WACC)^4 +$$

$$ARR_{t+4} / (1 + WACC)^5$$

The Efficiency Factor (X) can then be calculated for the RP from the solution of the following equation (where only X is unknown):

$$PV_{t-1} = (MAR_{t-1} – P_o) * [1 +$$

$$(1 + Inflation_t – X) / (1 + WACC) +$$

$$(1 + Inflation_t – X) (1 + Inflation_{t+1} – X) / (1 + WACC)^2 +$$

$$(1 + Inflation_t – X) (1 + Inflation_{t+1} – X) (1 + Inflation_{t+2} – X) / (1 + WACC)^3 +$$

$$(1 + Inflation_t – X) (1 + Inflation_{t+1} – X) (1 + Inflation_{t+2} – X) (1 + Inflation_{t+3} – X) / (1 + WACC)^4 +$$

$$(1 + Inflation_t – X) (1 + Inflation_{t+1} – X) (1 + Inflation_{t+2} – X) (1 + Inflation_{t+3} – X) (1 + Inflation_{t+4} – X) / (1 + WACC)^5.]$$

Where: Po is such amount in PhP, as the ERC determines to represent windfall gains and windfall losses in revenue, resulting from exogenous factors, and to reduce price shocks during the transition from the previous RP to the next RP, subject to limitations indicated in the RTWR.

The maximum transmission wheeling rates per customer segment that may be charged by the Regulated Entity for the provision of Regulated Transmission Wheeling Services during the application year is subjected to side constraints (SC). The new rate should be equal to or less than (1 + CWI + SC) * the old rate.

The Transmission Provider is now in its Third Regulatory Period. The ERC may continue to adopt or change the building blocks earlier discussed.

Service Quality Measures and Targets: As part of the Regulatory Reset Process, the ERC implements a performance incentive scheme that rewards or penalizes the Regulated Entity for achieving or failing to achieve the specified target levels of performance.

During the Second RP of the Regulated Entity the following performance indicators were used:

a) System Interruption Severity Index (SISI) which measures the ratio of the un-served energy to the system peak load ;
b) Frequency of Tripping per 100cct-km (FOT) which measures the number of forced line outages (both transient and sustained) per 100cct-km initiated by the automatic tripping of protection relays;
c) System Availability (SA) or circuit availability as a proportion of total circuit time which refers to the availability or percentage of the system being considered to be online during the evaluation period;
d) Frequency Limit Compliance (FLC) which refers to the percentage of time during the rating period that the system frequency is within the allowable range of 60 ±0.3 Hz; and
e) Voltage Limit Compliance (VLC) which refers to the percentage of the number of voltage measurements during the rating period that the voltage variance did not exceed ± 5% of the nominal voltage of all busses (Luzon – 230 kV & 500 kV, Visayas – 230 kV/138 kV, Mindanao – 138 kV)monitored at the high side of the substation. Monitoring times are at peak load hours of 11am, 2pm and 7pm and off-peak hour at 2am. These hours represent the times when the bus voltages are expected to be not at their normal levels.

The following additional indicators were included in the Third RP:

f) Congestion Availability (ConA) which measures the availability of a subset of lines and transformers on the Luzon grid;
g) Ancillary Services Availability Indicator (ASAI) which measures the availability of ancillary services on each of the three grids;
h) Customer Satisfaction Indicator (CSI) which measures the overall satisfaction of customers assessed on the basis of annual customer surveys.

ANNEX 5: THE OPEN ACCESS AND TRANSMISSION SERVICE (OATS) RULES

General Content of the OATS Rules: For a macro view, Table 3.4.3.1 below outlines the general content of the subject rules and its applicability in the various sectors in addition to its general applicability to prospective and current Transmission Customers, Transmission Provider, Transmission Provider acting as System Operator, Transmission Provider acting as WESM Metering Service Provider, and Independent Meter Service Providers:

Table 3.4.4.1: General Content and Applicability of the OATS Rules

Module	Generator	Embedded Generator	Electricity Supplier	Distribution Utility / Electric Cooperative	Directly Connected Load Customer
A - General Terms and Conditions	Applicable	Applicable	Applicable	Applicable	Applicable
B – Connections	Applicable	Not Applicable	Not Applicable	Applicable	Applicable
C - Power Delivery Service	Applicable	Applicable	Not Applicable	Applicable	Applicable
D - System Operator	Applicable	Applicable	Applicable	Applicable	Applicable
E – Metering	Applicable	Applicable	Not Applicable	Applicable	Applicable
F - Rates and Charges	Applicable	Applicable	Applicable	Applicable	Applicable

Highlights of the OATS Rules can be summarized as follows:

General Terms and Conditions: As a way of also ensuring fair and non-discriminatory access to the transmission grid, just like how this was insured by the PGC and WESM Rules, the OATS Rules set out the terms on which the Transmission Provider shall: (a) connect a Transmission Customer to the grid, (b) provide power delivery, transmission connection, residual sub-transmission, system operation and metering services, (c) perform system operator function, (d) provide services related to management, procurement and dispatch of ancillary services, (e) perform metering service function, and (f) provide services incidental to the above.

Connections: Module B defines the terms, conditions, procedures, responsibilities, data and other technical requirements for both the existing connections to the grid as well as new points of connection to the grid or modifications to existing connections to the grid.

Power Delivery Service: In the Oats Rules, constituting the entire agreement together with the service agreement, under Module C, the Transmission Provider undertakes to operate the Grid, in a way that it shall plan, construct, operate, and maintain the Grid in accordance with the PGC in order to provide Connected Transmission Customers with Power Delivery Service (PDS), ensuring that its capital expenditure and operations and maintenance expenditure support the quality and reliability of the PDS. Quality of the PDS refer to accordance with the PGC standards on voltage variations, harmonics, voltage unbalance, voltage fluctuation and flicker severity, transient voltages, and frequency variations. Reliability should be pursued based on targets embodied in the Performance Incentive Scheme determined by ERC in accordance with Article VIII of the Rules for Transmission Wheeling Rates (RTWR).

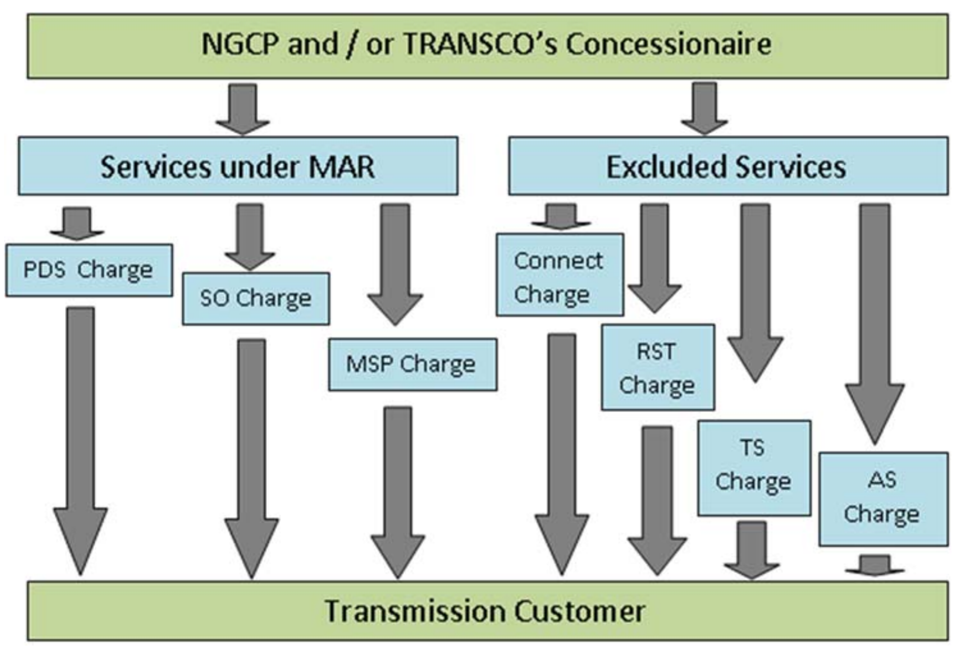
System Operator: Under Module D, the SO shall carry out the central dispatch of Generation Facilities, Ancillary Services, and Loads connected directly or indirectly to the Grid in a manner consistent with the PGC, the WESM Rules and the applicable WESM Manuals and the OATS Rules. The criteria and protocol for Central Dispatch of Generation Facilities, Ancillary Services, and Loads, both in the normal course of operation and in the event of a notified emergency shall be defined by the SO and form part of the OATS Rules after approval by the ERC.

Module D also includes among others, the terms for Load Shedding and Interruptions, Management of Ancillary Services, Management of Energy Imbalance as governed by the WESM Rules and applicable WESM Manuals, Obligations of the Transmission Customers.

Metering: The Transmission Provider undertakes, as per Module E, to provide metering services including: (a) provision of metering equipment to be part of the OATS revenue metering facilities, (b) installation, testing, and commissioning of revenue metering equipment that the Transmission Provider makes available for new OATS metering facilities, (c metering installation, operation and maintenance covering monthly reading and/or retrieval of metered demand and energy data, provision of metering installation data and metered data to the Transmission Customer, and periodic calibration, testing, maintenance and inspection of metering installation and its equipment as prescribed in the PGC.

Rates and Charges: Under Module F, the fees which the Transmission Provider shall charge are given in Figure 3.4.4.1

Figure 3.4.4.1 – Summary of Charges by the Transmission Provider to its Transmission Customers



The different charges indicated above are described below:

a) **Services under MAR.** Transmission Customers shall pay the following charges for Regulated Transmission Services under a Maximum Annual Revenue (MAR) cap, determined and approved by the ERC through a Regulatory Reset Process, done every Regulatory Period (RP) of five (5) years, under the RTWR.

- Power Delivery Service (PDS) Charge which recovers that proportion of the MAR associated with the cost of conveying electricity through the Grid and the control and monitoring of electricity as it is conveyed through the Grid (including any services that support such conveyance, control or monitoring or the safe operation of the Grid); it also includes the cost of operations of the Grid Management Committee and subcommittees under the PGC; the PDS charge is payable by Generation Customers and Load Customers.
- System Operator (SO) Charge which recovers that portion of the MAR and any other costs approved by the ERC that are associated with the cost of system operation as defined under the WESM Rules; such charges include the costs of (1) providing generation dispatch and operation and control services to ensure safety, power quality, stability, reliability and security of the Grid, (2) communication and SCADA, (3) managing and procuring Ancillary Services, and (4) operations of the Grid Management Committee and its subcommittees; the SO charge is payable by generation Customers, Load Customers and Embedded Generators;
- Metering Service Provider (MSP) Charge which recovers that portion of the MAR, and any other cost approved by the ERC, associated with the cost of metering services including the provision, installation, commissioning, testing, repair, maintenance, and reading both of meters that are used to measure the delivery of electricity to Customers and of other meters that are used (for the purposes of the WESM) to measure the flow of electricity into or through the Grid; A Metering Service Provider charge shall apply to all Connected Transmission Customers and will vary in accordance with the voltage level of the infrastructure provided by the Metering Service Provider for a Metering Installation.

b) **Excluded Services.** Excluded service under the RTWR is defined as a service provided under the ordinary course of an electricity transmission business that is neither a Regulated Transmission Service nor a service that is contestable (for these purposes, whether or not a service is contestable is a matter that, if disputed, will be determined by the ERC).

Generation Customers and Load Customers shall pay the following charges for Excluded Services and other Services:

- Connection Charge which recovers the reasonable costs, as defined under Section 1.6.3 of the RTWR, associated with providing Connection Assets, defined as the assets connecting a single connected Transmission Customer's Facilities to the Grid, including land required for the Connections Assets; connection charges are payable by Load Customers on existing and new Connection Asses, for the period until the Connection Assets are sold to Qualified DUs at each connection point, and payable by Generation Customers relating to their specific Connection Assets.
- Residual Sub-transmission (RST) Charge, payable by Load Customers, which recovers costs of sub-transmission assets defined as the Sub-transmission Assets as identified in the ERC Rules for the Approval of the Sale and Transfer of TRANSCO's Sub-transmission Assets and the Acquisition by Qualified Consortiums, less any asset that is no longer owned by the

Transmission Provider or that has been reclassified as a Transmission Asset by resolution of ERC;

These two (2) aforementioned assets are defined to allow Connection Charges and Residual Sub-transmission Charges to recover costs of Sub-transmission Assets which the EPIRA requires to be sold by the Transmission Provider.

- Technical Service (TS) Charges wherein a prospective Transmission Customer shall pay the costs of any System Impact Studies (SIS) or Facilities Studies arising from its Service Application. In performing the SIS or Facilities Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing Grid Impact Studies (GIS) and any other relevant studies. The Prospective Transmission Customer shall be not be assessed a charge for any existing studies. However, the Prospective Transmission Customer shall be responsible for charges associated with any modifications to existing studies that are reasonably necessary to evaluate the impact of the Prospective Transmission Customer's request for service from the Grid.
- Ancillary Services Charges as determined by the ERC and published in a separate Ancillary Services Procurement Plan (ASPP) and/or the Ancillary Services Cost Recovery Mechanism (ASCRM), or their successor documents.

Allocation of Charges: The following is a summary of the key points on how the charges are allocated.

a) Power Delivery Service Charge

PDS Charge Payable by Generation Customers

Generation Customers shall pay a GPDS charge each month for each of its points of receipt, based on the following:

$$GPDS = GBD * GR \qquad \text{where:}$$

GBD or the generator billing determinant, for each point of receipt, shall be the average of twelve (12) monthly non-coincident peak injections in kW, measured in fifteen (15) minute intervals. The GBD for new Generators or those reconnecting to the Transmission Provider's facilities and for those without a 12 month history would be determined by the Transmission Provider from the information provided in the Service Agreement or shall be the sum of the actual monthly non-coincident peak injections in kW divided by the actual number of months until such time that the customer completes the required 12-month billing data.

GR or the Generator PDS Rate is the Generator PDS Revenue (GDR) divided by the sum of Generator billing determinants for all points of receipt, represented by the formula:

$$GR = \frac{GDR}{\sum GBDi}$$

The GDR for each customer segment is that proportion of the Customer Segment Power Delivery Revenue Requirements (PDR) which is to be recovered from Generation Customers determined as:

$$GDR = G * PDR, \text{ where:}$$

G is the percentage determined by ERC, while PDR is that portion of the MAR that is allocated by the Transmission Provider to each ERC-approved Customer Segment and is based on the Regulatory Asset Base (RAB) values relating to the MAR cap approved by the ERC, for the relevant Regulatory Period under the RTWR.

PDR is determined as follows:

$$PDR = \frac{MARt - (SOC + MSP)}{12}$$

Where:

MARt = The Maximum Annual Revenue Cap for the current Regulatory Year as allocated by the Transmission Provider to that Customer Segment.

SOC = The aggregate revenue the Transmission Provider Expects to receive in the current Regulatory Year from System Operator charges from that Customer Segment, where this revenue has been included in the MARt.

MSP = The aggregate revenue the Transmission Provider expects to receive in the current Regulatory Year from Metering Service Provider charges from that Customer Segment, provided that Metering Services remain a Regulated Transmission Service under the RTWR and this revenue has been included in the MARt.

PDS Charge Payable by Load Transmission Customers

$$LPDS = LBD * LR \quad \text{where:}$$

LBD or the load billing determinant, for each point of delivery, shall be the average of twelve (12) monthly non-coincident peak demands in kW, measured in fifteen (15) minute intervals. The LBD for new load customers or for those reconnecting to the Transmission Provider's facilities and for those without a 12 month history would be determined by the Transmission Provider from the information provided in the Service Agreement or shall be the sum of the actual monthly non-coincident peak demands in kW divided by the actual number of months until such time that the customer completes the required 12-month billing data.

LR or the Load PDS Rate is the Load PDS Revenue (GDR) divided by the sum of Load billing determinants for all points of delivery, represented by the formula:

$$LR = \frac{LDR}{\Sigma LBDi}$$

The LDR for each customer segment is that proportion of the Customer Segment Power Delivery Revenue Requirements (PDR) which is to be recovered from Load Customers determined as:

$$LDR = L * PDR$$, where:

L is the percentage determined by ERC, while PDR is that portion of the MAR that is allocated by the Transmission Provider to each ERC-approved Customer Segment and is based on the Regulatory Asset Base (RAB) values relating to the MAR cap approved by the ERC, for the relevant Regulatory Period under the RTWR.

b) **System Operator Charges (SOC).** The SOC payable by each Generator Customer or the Embedded Generator, and the Load Customer each month is computed as follows:

$$SOC = \frac{SORR * BDi}{\Sigma BDi}$$

Where:

SORR is the System Operator revenue requirement or the amount of the Transmission Provider's MAR determined by ERC under the RTWR for the current Regulatory Year attributable to SO services, and any other costs approved by the ERC that are associated with SO costs and the cost of operation of the Grid Management Committee.

BDi is either one of the following:

- Generator billing determinant as determined under the item on PDS Charge for Generation Customers;
- Load Customer billing determinant as determined under the item on PDS Charge for Load Customers; or
- Embedded Generator billing determinant which is the average of the highest twelve (12) non-coincident peak injections in kW, measured in fifteen (15) minute intervals, of the Embedded Generating Plant for the Billing Period.

Σ BDi is the sum of the Generation Customer and Embedded Generator and Load Customer billing determinants for the previous Regulatory Year.

c) **Metering Service Provider Charge (MSC).** The monthly MSC payable by Connected Transmission Customers shall be determined as follows:

$$MSC = \frac{(ODRCm * WACC) + Dm + Lm + Om}{12}$$

Where:

ODRCm is the optimized depreciated replacement cost of the Metering Installation assets for the current Regulatory Year;

WACC is the Weighted Average Cost of Capital for the Regulatory Period as determined by the ERC under the RTWR;

Dm is the depreciation cost of the Metering Installation assets for the current Regulatory Year for each metering asset as determined under the RTWR;

Lm is the annual lease cost charged to the Metering Service Provider for assets used at the Metering Installation and leased by Metering Service Provider; and

Om is the operation and maintenance cost attributable to the provision of metering services for the current Regulatory Year.

d) **Connection Charges.** Where the Service Agreement or another contract between the Transmission Provider and the Connected Transmission Customer specifies the amount that the Connected Transmission Customer shall pay the Transmission Provider for the Connection Assets identified in that contract, the Transmission Connected Customer shall pay the charges specified in that contract.
Where there is no contract containing provisions relating to the allocation of the costs of Connection Assets, the Connected Transmission Customer shall pay a connection charge (CC) each month determined as follows:

$$CC = \frac{((ODRCi * WCi) * WACC) + Di + Oi + Ri}{12}$$

Where:

ODRCi is the optimized depreciated replacement cost of the Connection Asset for the current Regulatory Year;

WC is the Working Capital attributable to the Connection Assets for the Regulatory Year as determined by the ERC at the last regulatory reset for that Regulatory Period, under the RTWR;

WACC is the Weighted Average Cost of Capital for the Regulatory Period as determined by the ERC at the last regulatory reset for that Regulatory Period, under the RTWR;

Di is the depreciation cost of the Connection Asset for the pertinent Regulatory Year for each Connection Asset as determined under the RTWR;

Oi is the operation and maintenance cost attributable to the Connection Asset for the pertinent Regulatory Year.

Ri is the shortfall or surplus in the connection charge collected for that connection Asset in the previous year, increased by an amount to reflect the time value of money calculated using the WACC for the regulatory period as determined by the ERC at the last regulatory reset under the RTWR.

e) Residual Sub-transmission Charges

Where the Service Agreement or another contract between the Transmission Provider and the Connected Transmission Customer specifies the amount that the Connected Transmission Customer shall pay the Transmission Provider for the Residual Sub-transmission Assets identified in that contract, the Connected Transmission Customer shall pay the charges specified in that contract.

Where there is no contract containing provisions relating to the allocation of the costs of Residual Sub-transmission Assets, the Connected Transmission Customer shall pay a Residual Sub-transmission Charge (RSC) each month determined as follows:

$$RSC = \frac{((ODRCs * WCs) * WACC) + Ds + Os + Rs}{12}$$

Where:

ODRCs is the optimized depreciated replacement cost of the Residual Sub-transmission Asset for the current Regulatory Year;

WCs is the Working Capital attributable to the Residual Sub-transmission Assets for the Regulatory Year as determined by the ERC at the last regulatory reset for that Regulatory Period, under the RTWR;

WACC is the Weighted Average Cost of Capital for the Regulatory Period as determined by the ERC at the last regulatory reset for that Regulatory Period, under the RTWR;

Di is the depreciation cost of the Residual Sub-transmission Assets for the current Regulatory Year for each Residual Sub-transmission Asset as determined under the RTWR;

Om is the operation and maintenance cost attributable to the Residual Sub-transmission Assets for the Regulatory Year.

Ri is the shortfall or surplus in the Residual Sub-transmission charge collected for that Residual Sub-transmission Asset in the previous year, increased by an amount to reflect the time value of money calculated using the WACC for the regulatory period as determined by the ERC at the last regulatory reset under the RTWR.

f) Technical Services Charges. As previously indicated, a prospective Transmission Customer shall pay the applicable charges for any SIS or Facilities Study arising from its Service Application. If a single study is sufficient for multiple Prospective Transmission Customers, the cost of that study shall be pro-rated among the said customers, on a basis to be agreed by the parties concerned. If there is no agreement, the basis for pro-rating shall be determined by the ERC.
g) Ancillary Services Charges. Ancillary service charges shall be paid by Connected Transmission Customers and Embedded Generators, except to the extent that the obligation is relieved in part or in whole by an Alternative Ancillary Service Agreement approved by the System Operator.

The Embedded Generator billing determinant for each Embedded Generating Plant shall be the average of the highest twelve (12) non-coincident peak injections in kW, measured in fifteen (15) minute intervals, of that Embedded Generating Plant for the Billing Period for which the Ancillary Services were provided.

The Generator billing determinant for each Generation Customer for each Point of Receipt shall be the average of the 12 monthly non-coincident peak injection in kW, measured in fifteen (15) minute intervals, at that Point of Receipt. The Generator Billing Determinant for new Generators or those reconnecting to the Transmission Provider’s facilities and for those without a 12 month history would be determined by the Transmission Provider from the information provided in the Service Agreement or shall be the sum of the actual monthly non-coincident peak injections in kW divided by the actual number of months until such time that the customer completes the required 12-month billing data.

The Load Billing Determinant for each Load Customer for each Point of Delivery shall be the average of the 12 monthly non-coincident peak demands in kW, measured in fifteen (15) minute intervals, at that Point of Delivery. The Load Billing Determinant for new load customers or for those reconnecting to the Transmission Provider's facilities and for those without a 12 month history would be determined by the Transmission Provider from the information provided in the Service Agreement or shall be the sum of the actual monthly non-coincident peak demands in kW divided by the actual number of months until such time that the customer completes the required 12-month billing data.

h) Billing Adjustments

The Interruption billing adjustment reduces the relevant transmission charges to a Connected Transmission Customer when an Interruption below the level agreed in the Service Agreement is due to Transmission Provider related faults. It does not apply when the Interruption arises from Generation or other non-Transmission Provider related causes or as a result of a Force Majeure Event.

The Curtailment billing adjustment reduces the relevant transmission charges to the Connected Transmission Customer when a Curtailment below the level agreed in the Service Agreement is due to Transmission Provider related faults. It does not apply when the Curtailment arises from Generation or other non-Transmission Provider related causes.

ANNEX 6: MANDATES OF THE RENEWABLE ENERGY ACT PERTINENT TO TRANSMISSION

Section 6. Renewable Portfolio Standard (RPS): All stakeholders in the electric power industry shall contribute to the growth of the renewable energy industry of the country. Towards this end, the National Renewable Energy Board (NREB) shall set the minimum percentage of generation from eligible renewable energy resources and determine to which sector RPS shall be imposed on a per grid basis.

Section 7. Feed-In Tariff System: The ERC in consultation with the NREB shall formulate and promulgate feed-in tariff system rules which shall include, but not limited to the following:

a) Priority connections to the grid for electricity generated from emerging renewable energy resources such as wind, solar, ocean, run-of-river hydropower and biomass power plants within the territory of the Philippines;
b) The priority purchase and transmission of, and payment for, such electricity by the grid system operators;
c) Determine the fixed tariff to be paid to electricity produced from each type of emerging renewable energy and the mandated number of years for the application of these rates, which shall not be less than twelve (12) years;
d) The feed-in tariff to be set shall be applied to the emerging renewable energy to be used in compliance with the renewable portfolio standard.

Section 8. Renewable Energy Market (REM): The DoE shall establish the REM and shall direct PEMC to implement changes to the WESM Rules in order to incorporate the rules specific to the operation of the REM under the WESM.

Section 9. Green Energy Option: The DoE shall establish a Green Energy Option program which provides end-users the option to choose RE resources as their sources of energy.

Section 11. Transmission and Distribution System Development: TRANSCO or its buyer/concessionaire and all DUs, shall include the required connection facilities for RE-based power facilities in the Transmission and Distribution Development Plans: Provided, that such facilities are approved by the DOE. The connection facilities of RE power plants, including the extension of transmission and distribution lines, shall be subject only to ancillary services covering such connections.

Section 13. Government Share: The government share on existing and new RE development projects shall be equal to one percent (1%) of the gross income of RE resource developers resulting from the sale of renewable energy produced and such other income incidental to and arising from the renewable energy generation, transmission, and sale of electric power except for indigenous geothermal energy, which shall be at one and a half percent (1.5%) of gross income.

Section 18. Payment of Transmission Charges: A registered renewable energy developer producing power and electricity from an intermittent RE resource may opt to pay the transmission and wheeling charges of TRANSCO or its successors-in-interest on a per kilowatt-hour basis at a cost equivalent to the average per kilowatt-hour rate of all other electricity transmitted through the grid.

Section 20. Intermittent RE Resources: TRANSCO or its successors-in-interest, in consultation with stakeholders, shall determine the maximum penetration limit of the Intermittent RE-based power plants to the Grid, through technical and economic analysis. Qualified and registered RE generating units with intermittent RE resources shall be considered "must dispatch" based on available energy and shall enjoy the benefit of priority dispatch. All provisions under the WESM Rules, Distribution and Grid Codes which do not allow "must dispatch" status for intermittent RE resources shall be deemed amended or modified. The PEMC and TRANSCO or its successors-in-interest shall implement technical mitigation and improvements in the system in order to ensure safety and reliability of electricity transmission.

ANNEX 7: RULES ON THE DISTRIBUTION WHEELING RATES – KEY FEATURES

Price Control Formula: The fundamental formula used to compute the maximum allowed revenue in PhP, for a Regulatory Year (RY) t is calculated in accordance with the following formula:

$$MAPt = [MAPt\text{-}1 * (1 + CWIt – X)] + St– Kt+ ITAt$$

Where:

MARt = MAP for current Regulatory Year

MARt-1 = MAP for Regulatory Year t - 1

CWIt = Change in Weighted Index for Regulatory Year t (which takes into account changes in CPI and US$ exchange rate)

X = efficiency factor for Regulatory Year t, the derivation of which is described below under the section on “Calculation of the Efficiency Factor (X) for the RP”

St = A Performance Incentive Factor to reward or penalize each Regulated Entity for achieving or failing to achieve specified target levels of performance;

Kt = Correction Factor to adjust for over / under recovery of revenue in Regulatory Year t – 1;

ITAt = Tax adjustment to adjust for over or under recovery of corporate income tax in RY t – 1.

General Building Block Principles:

As part of the Regulatory Reset Process the Regulated entity must submit Revenue Applications which the ERC must review to determine the Annual Revenue Requirements (ARR) for each Regulated Distribution System, for each Regulatory Year in the Regulatory Period (RP). It is based on a forward-looking analysis of forecast cash flow requirements, and must represent the optimal forecast revenue requirements. The ARR must reasonably compensate the Regulated Entity for the economically efficient costs and risks it incurs in providing Regulated Distribution Services, based on a Building Block analysis (as previously mentioned) which uses a “classical” Weighted Average Cost of Capital (WACC).

The Building Block Formula to be used in calculating the ARR is:

$$ARRt = Opext + Taxm,t+ RegDepnt + [(RABt + WCt) * WACC] + Taxp,t$$

Where:

Opext is the nominal operating and maintenance expenditure for RY t;

Taxm,t is the payment of taxes, other than corporate income tax, for RY t, in nominal terms;

RegDepnt is the Regulatory Depreciation for RY t in real terms;

RAB_t is the Regulatory Asset Base (RAB) for RY t in real terms;

WC_t is working Capital Allowance for RY t which is set at a proportion of the difference between the real Opex forecast for that RY and the real amount of Bad Debts forecast for that RY;

WACC is Weighted Average Cost of Capital calculated using a “classical” formula; the WACC is accordingly changed when the corporate income tax is set to zero;

$Tax_{p,t}$ is the estimated corporate income tax, in nominal terms, payable by a Regulated Entity in RY t;

Regulatory Asset Base: Prior to the commencement of a RP, an asset revaluation must be undertaken in accordance with the RDWR. The revaluation must value the material items of plant and equipment either at their optimized deprival value or using some other method of internationally accepted valuation methodology as determined by the ERC or the previous value of the RAB is rolled forward.

Operating and Maintenance Expenditure: Forecasts are made for the coming RP based primarily on historical Opex, changes in the CPI and changes in the RAB.

Capital Expenditure: The Regulated entity must provide its forward forecast of its annual proposed capital expenditure for each RY in the RP. This Capex program must separately identify each Capex project which is forecast to cost at least PhP30 million or 20% of the total annual Capex.

Smoothing: As a result of the Building Block approach, it is unlikely that there will be a linear increase in the allowed ARR for each RY in the RP. Accordingly, so as to reduce price shocks to Customers and revenue shocks to the Regulated Entity, the ERC will smooth the Maximum annual Price caps for each RY in the RP. Such smoothed MAP caps will incorporate a recovery of efficiency savings in cost. It may also include over or under recoveries from the previous RP and / or recovery of regulatory interventions made by ERC in the allowed ARR during the earlier RPs.

Calculation of the Efficiency Factor (X) for the RP: The Present Value (PV) of the allowed revenue for each of the RYs in the current RP must be calculated using the following formula:

$$PV_{t-1} = ARR_t / (1 + WACC) + ARR_{t+1} / (1 + WACC)^2 + ARR_{t+2} / (1 + WACC)^3 + ARR_{t+3} / (1 + WACC)^4$$

After determining PV_{t-1}, the Efficiency Factor (X) can then be calculated for the RP from the solution of the following equation (where only X is unknown):

$$PV_{t-1} = PV_{t-1} = (MAP_{t-1} – P_o) *$$

$$[\{(1 + Inflation_t – X) * FQ_t / (1 + WACC)\} +$$

$$\{(1 + Inflation_t – X) * (1 + Inflation_{t+1} – X) * FQ_{t+1} / (1 + WACC)^2\} +$$

$$\{(1 + Inflation_t – X) * (1 + Inflation_{t+1} – X) * (1 + Inflation_{t+2} – X) * FQ_{t+2}/ (1 + WACC)^3\}+$$

$$\{(1 + Inflation_t – X) * (1 + Inflation_{t+1} – X) * (1 + Inflation_{t+2} – X) * (1 + Inflation_{t+3} – X) * FQ_{t+3} / (1 + WACC)^4\}]$$

Where new variables introduced are:

Po is such amount in PhP, as the ERC determines to represent windfall gains and windfall losses in revenue, resulting from exogenous factors, and to reduce price shocks during the transition from the previous RP to the next RP, subject to limitations indicated in the RTWR; and

FQt is the total amount of energy in kWh that is forecasted to be delivered through the relevant Regulated distribution system, during RY t to distribution connection points.

The maximum distribution wheeling rates per customer segment that may be charged by the Regulated Entity for the provision of Regulated Distribution Wheeling Services during the application year is subjected to side constraints (SC). The new rate should be equal to or less than (1 + CWI + SC) * the old rate.

Service Quality Measures and Targets: As part of the Regulatory Reset Process, the ERC implements a performance incentive scheme for the Third RP that rewards or penalizes the Regulated Entity for achieving or failing to achieve the specified target levels of performance. The scheme has three (3) main streams:

a) Price-linked incentive scheme. The performance of Regulated Distribution Systems is assessed against a number of network performance and service performance measures. If performance levels exceed predetermined targets, Regulated Entities will be financially rewarded or, if performance levels fail to meet predetermined performance targets, Regulated Entities will be financially penalized.
   The reward or penalty will take the form of a performance incentive factor (S-factor) to be used in price control formula. The performance incentive factor will be a weighted performance measure, based on the performance levels achieved against a number of indices over the calendar year preceding each Regulatory Year.

b) Guaranteed Service Levels. A system of Guaranteed Service Levels (GSLs) is introduced for each Regulated Distribution System, in terms of which customers will receive certain guarantees with regard to the responsiveness and effectiveness of Regulated Entities. If these GSLs are not met, predetermined penalties will be paid by the Regulated Entities directly to customers.
c) Information Disclosure. The performance of Regulated Distribution Systems against a further number of performance indices (network and service related) is regularly measured and published.

ANNEX 8: RULES FOR SETTING ELECTRIC COOPERATIVES' WHEELING RATES

In September 2009, the ERC promulgated the new regulatory methodology for on-grid ECs called the "Rules for Setting Electric Cooperatives' Wheeling Rates" or RSECWR.

In the RSECWR, the 98 on-grid ECs were classified into seven (7) groups: A, B, C, D, E, F and G. In addition, a standard customer classification was adopted for all on-grid ECs: residential, low voltage customers (not residential and connected to low voltage not exceeding 1 kV) and higher voltage customers (non residential and connected to medium voltage of greater than 1 kV up to 34.5 kV or higher voltage exceeding 34.5 kV).For each group's customer class, there was a standard initial tariff cap for each tariff components: distribution charge, supply charge, metering charge and members' contribution for capital expenditures. These tariff caps would be for the first regulatory year up to the third regulatory year of a six (6) year regulatory period. The tariff caps may be adjusted at the beginning of the 4th regulatory year based on the cumulative result of a tariff glide path that will be calculated annually for the 1st to the 3rd regulatory year. The calculated cumulative result of the annual tariff glide path for the 4th to the 6th regulatory year will be effected together with the applicable resulting caps of a regulatory reset for the next regulatory period. In the regulatory reset, the classifications will be revisited as well as the standard initial tariff caps for the 1st regulatory year of the incoming regulatory period.

The ECs are divided into three (3) entrant groups where the 1st entrant group's regulatory period is January 1, 2011 to December 31, 2016; the 2nd entrant group's regulatory period is January 1, 2012 to December 31, 2017; and the 3rd entrant group's regulatory period is January 1, 2013 to December 31, 2018.

The ECs' rates as of 2009 were allowed to gradually move up to its respective standard initial tariff caps by its first regulatory year for the first regulatory period.

Development of the RSECWR: The following steps were followed in the development of the RSECWR:

1. Classify ECs into groups.
2. Create standard customer classes
3. Develop the standard initial rate caps per group
4. Determine a tariff Glide Path
5. Provide for transition

1. Classify ECs into Groups

The guiding principles for the EC classification were:

a) Rationality – the classification criteria should have demonstrable relationship with distribution costs;
b) Regulatory Efficiency – optimal number of groups to reduce regulatory lag; and,
c) Simplicity – understandable and implementable.

The 98 on-grid ECs were classified into groups based on the following criteria which had the most impact on the distribution's operating costs: (a) Size – defined as number of customers; and (b) Consumption – defined as mWH sales per customer.

The data set that was used were the ECs.

Group	Number Of ECs	Group Characteristics		Mean kWh consumption per customer	Mean Number Of Customers (in 1,000)
		Customer Consumption (MWH/Year)	Number Of Customers (in 1,000)		
A	11	<1	10 to 25	0.90	29.0
B	16	<1	25 to 50	0.63	61.0
C	5	<1	50 to 100	1.56	32.1
D	17	1 to 2	10 to 50	1.43	37.5
E	28	1 to 2	50 to 100	1.37	68.2
F	15	1 to 3	20 to 150	1,88	89.0
G	6	3 to 5	30 to 150	3.58	82.0
Total	98				

2. Develop New Customer Classes

The ECs had differing customer classes which had to be standardized based on the power delivery voltage used in servicing the customer consistent with the cost of service principle.

<table>
<tr><th>OLD CUSTOMER CLASSES</th><th>NEW CUSTOMER CLASSES</th></tr>
<tr><td>Residential</td><td rowspan="3">Residential Customers</td></tr>
<tr><td>BAPA</td></tr>
<tr><td>Sale for Resale</td></tr>
<tr><td>Small Commercial</td><td rowspan="5">Low Voltage Customers
• Non-residential
• Connected to Low Voltage (Not exceeding 1 kV)</td></tr>
<tr><td>Industrial</td></tr>
<tr><td>Public Buildings</td></tr>
<tr><td>Street Lights</td></tr>
<tr><td>Irrigation/CWS</td></tr>
<tr><td>Large Commercial</td><td rowspan="2">Higher Voltage Customers
• Non-residential
• Connected to Medium Voltage (1 kV up to 34.5 kV)
• Connected to Higher Voltage (higher than 34.5 kV)</td></tr>
<tr><td>Industrial</td></tr>
</table>

3. Develop the Initial Tariff Cap

3.1. Design the Structure

The ECs tariff structure was redesigned to reflect operating and capital costs as follows:

Current Tariff Structure	Revenue Requirements	New Tariff Structure
Distribution Charge Supply Charge Metering Charge	Operations & Maintenance Expenses	Distribution Charge
		Supply Charge
		Metering Charge
	Capital Expenditures	Members' Contribution for Capital Expenditures
	Debt Service	

3.2. Determine the Operating Revenue Requirement per EC Grouping

To determine the operating revenue requirements per EC grouping, the operating costs per kWh for each EC in 2000 were calculated and adjusted to 2008 levels using a wage index. The wage index, based on movements in minimum daily wages in regions other than the National Capital Region, was used because seventy percent (70%) of the operating cost is labor.

The median for the each EC grouping's operating cost per kWh was multiplied by the average kWh sales of the respective group to determine the operating revenue requirement per EC Grouping.

3.3. Functionalize the Operating Revenue Requirement

To functionalize is to assign the operating revenue requirement into the functions of the EC: distribution, supply, and metering which are also the components of the tariff. In the unbundling of the EC rates as called for by the EPIRA, each EC's rate was unbundled using the causation principle into distribution, supply and metering. The averages of these ratios per group were applied to the operating revenue requirement to functionalize it into distribution, supply, and metering costs.

3.4. Allocate the Functionalized Operating Revenue Requirement into Customer Classes

The distribution costs were allocated to the standardized customer classes discussed in 3.5.2.2.above using the EC Groupings' Non-Coincident Peak Demand (NCP) while the average number of customers' ratio was used for supply and metering.

3.5. Determine the Distribution, Supply and Metering Rate Caps

The rate design for the rate caps are as follows:

	Residential	Low Voltage	Higher Voltage
Distribution • Rate design	PhP/kWh	PhP/kWh	PhP/kW
• Determinant	Average kWh Sales	Average kWh	Average kW Sales
Supply • Rate design	PhP/kWh	Per Customer/ Per Month	Per Customer/Per Month
• Determinant	Average kWh Sales	Average Number of Customer per Month	Average Number of Customer per Month
Metering • Rate design	PhP 5.00 plus		

	PhP/kWh	PhP/Per Meter/Per Month	PhP/Per Meter/Per Month
• Determinant	Revenue from fixed rate is calculated; remainder by average kWh sales	Average Number of Customer per Month	Average Number of Customer per Month

3.6. Members' Contribution for Capital Expenditure Rate Cap Per EC Grouping

The ECs' previous rate had a reinvestment fund calculated at five percent (5%) of its unbundled retail rate (total of generation, transmission and distribution charges). This translates to an average of 22% of the distribution, supply and metering charges.

The Members' Contribution for Capital Expenditure Rate Cap per EC Grouping was determined by applying the said 22% ratio to the respective groups' 2008 median operating cost per kWh.

Cognizant that each EC's capital expenditure varies, the EC may collect additional Members' Contribution for Capital Expenditure by securing the consent of its member-consumers for such collection through existing legal procedures, provided that the capital expenditure has been previously approved by the ERC.

3.7. Tariff Glide Path

The standard Initial Tariff Cap will be allowed to move within the 6-year regulatory period.

Annually, a tariff glide path will be calculated using the following formula:

$$\text{Tariff Cap}_t = \text{Tariff Cap}_{t-1} * (1 + I - X + S)$$

Where:

t = incoming year

$t-1$ = current year

I = Index Factor = Percentage Change in CPI – Growth Rate

$I = [\,(CPI_n / CPI_{n-1}) - 1\,] - [\,(kWh_n / kWh_{n-1}) - 1\,]$

CPI = calendar year average regional CPI of EC

kWh = calendar year total kWh sales to all customers

X = Efficiency Factor

$X = [\,(CPE_n / CPE_{n-1}) - 1\,] \times .70$

CPE = number of connections per full time equivalent (FTE)

CPE = BC/FTE

BC = billed connections at the end of year n

FTE = total man-hours of compensable labor for year n divided by 2,080

S = Performance Incentive

The annual tariff glide path for the first three years of the regulatory period will be calculated as follows:

TGPA = TGPn + TGPn+1 + TGPn+2

Where:

n = first regulatory year of the regulatory period

The EC on the start of the 4th regulatory year may move up to the new tariff cap of TGPA if an increase. If TGPA is a decrease, it should be implemented.

The annual tariff glide path for the last three years of the regulatory period will be calculated as follows:

TGPB = TGPn + TGPn+1 + TGPn+2

Where:

n = fourth regulatory year of the regulatory period

TGPB will now be compared with the new rate cap for the next succeeding Regulatory Period of the EC Group to which the EC belongs. If it is below the said new rate cap, the EC may move up to the said new rate cap. However, if it is higher than the said new rate cap, the EC may move up only up to the said new rate cap.

ANNEX 9: DISTRIBUTION SERVICES AND OPEN ACCESS RULES

General Provisions: Under Article I of the DSOAR is explicitly included a section titled “Non Discrimination” which states that all DUs shall make available upon reasonable request all regulated services at rates, terms and conditions that are duly approved by the ERC and shall not unjustly or unreasonably discriminate in the rates, terms, and conditions of service to similarly situated customers. Also included in Article are the following DU Equipment and electric plant standards:

a) The DU shall install only the authorized distribution equipment and generating plants;
b) The electric plant shall be constructed, installed, operated and maintained in accordance with the provisions of the Philippine Electrical Code and the rules and regulations that may be issued by ERC in relation thereto;
c) Every DU furnishing metered electric service shall maintain, to check customers’ watt-hour meter, at least one watt-hour meter standard which shall be calibrated by the ERC at least once a year;
d) Every DU shall adopt 230 volts as its nominal service voltage; the voltage variation shall be maintained in accordance with the PDC;
e) The nominal fundamental frequency shall be 60 Hz;
f) Every DU shall keep a log book or any recording system that would serve as basis in generating reports that the ERC may prescribe;
g) No pole located on or near a public place shall have a one-way sweep exceeding three percent (3%) of its total length and all horizontal wires attached to it shall be pulled up so that their sag shall not be greater than three percent (3%) of the distance between poles;
h) Poles, towers, structures, and transformers shall be marked and numbered by the DU to facilitate identification by the public;
i) Every DU shall keep a comprehensive register of assets, indicating installation date, condition and refurbishment.

Rules Pertaining to Distribution Connection Assets and Services: Article II governs the terms of access and provision of Distribution Connection Assets and Services (DCAS) by a DU to End-users, Generators, and other DUs (Connection Customers). Italso applies to End-users receiving a Connection unlawfully or pursuant to unauthorized use. A DU shall provide DCAS pursuant to the terms and conditions herein to any potential Connection Customer within the DU’s franchise service area requiring such service. A RES is not a Connection Customer but may assist its RES customers in matters pertaining to DCAS. Compliance with Process and Non-discrimination is likewise, explicitly stated as: “The DU and each Connection Applicant shall comply with the processes set out in the DSOAR, Philippine Distribution Code and other applicable laws, rules and regulations for processing of new or modified connection arrangements. The DU shall process all requests involving connections in a timely manner and shall not give preference or discriminate between different Connection Customers or Connection Applicants, subject to any reasonable or justifiable exceptions as may be approved by ERC. Likewise the DU shall not give preference or discriminate between Connection Customers or Connection Applicants based on a Contestable Market End-user’s choice of supply.”

Rules Pertaining to Service to the Captive Market: Article III defines service to the captive market to include all unbundled services necessary to maintain a regular supply of alternating current of approximately 60 hertz which shall be provided by the DU throughout its franchise service area. The

Captive Market includes both residential and non-residential End-users. Insofar as residential consumers are concerned, the DSOAR are intended to complement the Magna Carta for Residential Electricity Consumers. It also defines the terms in applying for captive market supply, the requirement of deposit (essentially equivalent to one month bill amount), for establishment and re-establishment of customer credit, billing and payment terms (bills are served monthly), disconnections and billing disputes.

Rules Pertaining to Distribution Wheeling Service: Article IV governs the terms and conditions of the provision of DWS service by the DU to Retail Electricity Suppliers (RES) including the SOLR, and Generators. DWSs pertain to those services performed by the DUs for the conveyance of electricity through the regulated distribution system as well as the control and monitoring of electricity as it is conveyed throughout the DU system from the points of receipt to the points of delivery. DWS also includes discretionary services, which are customer-specific services for which costs are recovered through separately priced rate schedules, with the recoverable discretionary charges duly approved and authorized by the ERC.

The DUs shall provide DWS for delivery of electricity of the standard characteristics available in the franchise area. The DU shall provide DWS at its standard voltages. Requestors of DWS must obtain from the DU the phase and voltage of the service available before committing to the purchase of motors or other equipment, and the DU is not responsible if the requested phase and voltage of service are not available. The standard Distribution System service offered by the DU may be provided at the voltage level specified under the appropriate service agreement.

The provision of DWS by the DU is subject to the terms of any service agreements, terms and conditions of the tariffs and applicable legal authorities. All charges associated with a DWS provided by the DU must be authorized by the ERC and included as a tariff charge, as provided in the rate schedules.

The article includes the eligibility requirements for DWS as well as the grounds for rejecting DWS Agreement and the terms for metering services. It also specifies that a qualified DU or consortium of DUs that own sub-transmission asset facilities shall ensure non-discriminatory provision of unbundled delivery over its sub-transmission assets to any user, whether that user is connected or not to the sub-transmission.

Additionally, a RES is solely responsible for meeting any applicable WESM requirements. The DU shall not be responsible for any WESM requirements pertaining to a RES or a Contestable Market customer served by a RES.

On billing and related customer service, a RES is fully responsible for determining the billing methods for their customers and payment of all obligations to other market participants. As an option to the RES, the contestable customer of the RES may be billed directly by the DU for DWS, subject to the adoption by the ERC of the dual billing policy.

An End-user in the contestable market is responsible for paying their RES all amounts legitimately billed by the RES but shall not be held responsible for any amount not paid by the RES to other market participants.

In the event a RES fails to pay for DWS by the due date prescribed for the service, the DU shall notify the CRB that service under the DWS agreement will be terminated in seven (7) days. Subject to the adoption by the ERC of the dual billing policy, in the event that a RES customer billed by the DU for DWS fails to pay by the due date, a 48-hour notice of disconnection shall be sent to the customer and the CRB shall be informed of such notice. In the event that the Contestable Customer fails to pay the RES or Local RES for service rendered by due date, the RES or Local RES may send a 48-hour written notice of disconnection to the Contestable Customer.

Any complaint by a contestable customer concerning the service or lack thereof by all power industry participants shall be governed by a separate guideline on dispute resolution for the contestable market to be promulgated by the ERC.

Generator Wheeling in the Distribution System: A DU shall make available at non-discriminatory terms and conditions unbundled DWS to generators that seek to wheel power into, out of, or through the distribution system. A generator connected to the distribution system that seeks to wheel power out of the distribution system shall pay all applicable DWS charges. A generator wheeling power into or through the distribution system shall likewise pay the applicable DWS charges unless those charges are paid to the DU by load-serving entities such as a RES or another DU.

Wheeling for Another Distribution Utility: DUs shall make available, in non-discriminatory terms and conditions, unbundled DWS to other DUs, which seek to wheel power out of or through the distribution system. A DU that seeks to wheel power out of or through the distribution system shall pay all applicable DWS charges unless those charges are paid to the DU by a generator or other load-serving entities such as a RES.

Regulated Service Rates: The focus of Article V of the DSOAR is primarily rate design under the RDWR, covering the allocation of revenue requirements to Customer Segments and converting these into various rate elements paid monthly by the customers within that customer segment.

As part of the policies set forth in the EPIRA, all DUs shall only charge rates that reflect the cost-based unbundled structure set forth in the UFR. At no time may costs or revenues that should be recovered from one unbundled function be shifted onto other unbundled functions. The rate design shall be free of inter-class subsidies, meaning, costs or revenues that should be recovered from one customer segment shall not intentionally be shifted onto other customer segments. The side constraints set forth under the RDWR cannot be used to justify shifting of revenues from one customer segment to another.

The Maximum Average Price cap established under the RDWR, is a company-wide measure and does not address individual rate elements, thus, it is necessary to convert this into specific rate elements.

Calculating the rates for the Application Year is based generally on the following steps:

a) On a per customer segment basis, calculate the average historical rate based on historical revenue and historical consumption; then, compute the projected revenue based on historical rate and projected consumption;
b) Compute the total projected revenue based on historical rates, by adding the projected revenue per customer segment as computed in (a);
c) Compute the total projected revenue based on the MAPt and forecast energy consumption.
d) Allocate the revenue requirements, computed in (c) above to each customer segment based on the proportion of projected revenue per customer segment computed in (a) above over the total revenue requirements computed in (c) above.
e) The rate element for a customer segment shall now be based on the revenue allocation per customer segment computed in (d) above.

A side constraint test is performed on all the computed revenue allocation per customer segment, if at least one customer does not pass the side constraint test, the constrained MAP is computed and the process from a) to e) above is repeated, to come up with the constrained revenue allocation per customer segment.

It is understood in the aforementioned methodology that a new rate structure or new customer segment cannot be introduced during a RP. Such changes or the introduction of a new rate structure can therefore only be made as part of the regulatory reset process.

Functional Allocation of Revenue per Customer Segment Based on the UFR. The ERC incorporates the Uniform Filing Requirements (UFR) as part of the DSOAR. The purpose is to promote consistency and completeness in the DUs' rate filings required by the EPIRA.

The UFR indentifies five (5) functions: generation, transmission, distribution, supply and metering. Where a DU pays for transmission services, these costs shall be separately unbundled in the retail rates of the DU and allocated to all rate classes based on reasonable methods. Similarly, where a DU pays another entity for generation services, such costs shall be separately unbundled in the retail rates and allocated to all rate classes based on reasonable methods. The DUs are also required to unbundle costs and rates associated with the metering function as a sub-function of supply.

The remaining functions, composing the distribution wheeling rates, which are the rate elements under the RDWR, are as follows:

a) Distribution function which refers to the conveyance of electric power by a DU through its Distribution System;
b) Supply function which refers to electricity sales including billing, collection, and other customer services; and
c) Metering which includes metering assets, meter servicing, and meter reading.

The UFR is applied in determining the functional allocation of customer segments' revenue into these elements: The rate design to be proposed by the DUs is now based on the revenue allocation per customer segment per function, which is reviewed and approved by ERC.

There are no rules yet on rate designs, but the ERC plans to conduct studies on the reasonable bases for the appropriate rate structures.

Between Regulatory Resets, under the RDWR, the ERC shall periodically monitor the rate design employed by the DU to ensure consistency with these rules.

Distribution System Losses: Connection customers and the DU shall handle system losses in accordance with the ERC's rules and regulations. A RES shall also pay any applicable distribution System Loss Charge and shall not be responsible for procuring energy to cover distribution system losses. The DU is responsible for procuring all energy related to distribution system losses and will be allowed to recover such costs through ERC approved System Loss Charges, subject to a System Loss Cap.

Redistribution of Electricity: As a general rule, occupants, whether, owners or tenants of units within buildings or single structures must be connected / served directly by the DU which has an existing franchise over the concerned area, unless it is impractical for the DU to provide electric service and/or occupants are not able to satisfy the DU's standard requirements for electric service, or DU waives the right to serve those customers. Rules on Redistribution of electricity are dealt with under Article VI of the DSOAR. Generally, All users, whether deriving electricity from DUs or redistributors, must have equal rights and obligations as embodied in the rules and regulations promulgated by the ERC to protect consumer interest, including but not limited to the Magna Carta for Residential Electricity Consumers, the Distribution Services and Open Access Rules and Republic Act No. 7832 (Anti-Electricity Pilferage Law).

ANNEX 10: CROSS SUBSIDY REMOVAL SCHEME UNDER SECTION 74 OF THE EPIRA

"Cross subsidies within a grid, between grids and/or classes of customers shall be phased out in a period not exceeding three (3) years from the establishment by the ERC of a universal charge which shall be collected from all electricity end-users. Such level of cross subsidies shall be made transparent and identified separately in the billing statements provided to end-users by the suppliers.

The ERC may extend the period for the removal of cross subsidies for a maximum period of one (1) year upon finding that cessation of such mechanism would have a material adverse effect upon the public interest, particularly the residential end-user; or would have an immediate, irreparable, irreparable, and adverse financial effect on distribution utility."

ANNEX 11: PREPARATIONS FOR RETAIL COMPETITION & OPEN ACCESS

The following are the experiences in the Philippines from which other jurisdictions can gain insights and learn from the country's achievements as well as setbacks.

Even more, the third party review of the policies, rules and regulations adopted by the ERC, which has been provided by an expert , as well as the personal assessment and stock knowledge by the author of this report, provide additional and valuable viewpoints for practical consideration.

1. The ERC, having been designated under Section 29 of the EPIRA, to issue licenses to all suppliers of electricity except for distribution utilities and electric cooperatives with respect to their particular franchise areas, issued Resolution No. 1 Series of 2011 adopting the Revised Rules for the Issuance of Licenses to Retail Electricity Suppliers (RES), which prescribed the qualifications and criteria for issuing licenses to the RES, including among other requirements, a demonstration of their technical and financial capability and creditworthiness. The said rules introduced the Local RES which are DUs intending to set up local RES business and also prescribed that entities with existing supply contracts with contestable customers must also secure a RES license from the ERC within ninety days from the declaration of open access. ERC has issued sixteen RES licenses as of January, 2012.

2. Furthermore, as provided in ERC's website , it has, as well, issued the following Rules and Resolutions:

a) Code of Conduct for Competitive Retail Market Participants which protects customers by:
   - establishing standards of behavior for marketing electricity;
   - providing limitations on the relationships between DU and its Local/Affiliate RES;
   - promoting honesty, fairness and transparency in the disclosure of information to customers;
   - ensuring that the DU delivers non-discriminatory service to all customers, regardless of their choice of RES; and
   - establishing the cooling off period which is a period of five (5) business days or longer as per agreement, within which the customer has the right to cancel the Retail Supply Contract it has entered into with the RES or Local RES.
   - requiring the RES or Local RES to provide disclosure statements containing important information including among others, contact details, billing and payment methods, all pertinent charges, circumstances for the early termination of the retail supply contract, rules for contract renewal, etc.

b) Rules for Customer Switching which:
   - establishes the standardized rules and procedures governing the commercial transfer of a customer from one RES/Local RES to another;
   - ensures the efficient and timely exchange of information between and among competitive retail market participants;
   - prescribes the adoption of single billing policy wherein the RES or Local RES will be contracting with other service providers (DU, NGCP, MO, etc.) on behalf of its customers except for Connection Agreement; establishes the processes for billing, processing of payments, and remittance of payments to parties providing services to the customers; and,
   - establishes reportorial requirements and sanctions.

c) Rules for the Supplier of Last Resort (SOLR) which:
   - encourages contestable customers to choose their supplier of electricity upon the commencement of retail competition and open access; and
   - ensures the provision of continuous supply of electricity to contestable customers in the event of RES' inability to provide electricity.

   The Rules for the Supplier of Last Resort prescribes: which shall serve as the supplier of last resort under various circumstances, the conditions for resorting to SOLR, the rules for the notification and provision of customer information to SOLR, the procedures for the assumption of service by the SOLR, the obligations of the SOLR, the terms of SOLR service and the SOLR rate which has been defined as the applicable WESM nodal energy price or the bilateral contract price, whichever is higher, plus a premium to cover incremental administrative and overhead expenses, and a reasonable return thereon, subject to the approval or determination of ERC.

d) Rules on Rate Filing by the Supplier of Last Resort which:
   - provides the SOLR with a uniform filing system for applications by the SOLR for the approval of SOLR rate / charges to the affected Contestable Market, and
   - ensures recovery of the allowable premium and reasonable return associated with the SOLR service;

e) Competition Rules and Complaint Procedures which:
   - prohibits anti-competitive behavior and abuse of market power, and
   - specifies the appropriate penalties and remedies for such behaviors;

f) Business Separation Guidelines (BSG) which:
   - prescribes the clear separation of business operations and accounts between the regulated and non-regulated business activities of electric power industry participants;

g) Distribution Services and Open Access Rules (DSOAR) which:
   - prescribes the rules and regulations pertaining to the provision of services by a DU to captive and contestable customers, the RES, other DUs, and generators, under the new competitive environment;

h) Rules for Contestability. The EPIRA mandates the ERC to allow all electricity end-users with a monthly average peak demand of at least one megawatt (1 MW), for the preceding twelve (12) months, to be the contestable market. Two (2) years thereafter, the threshold level shall be reduced to seven-hundred fifty kilowatts (750 kW). Subsequently, on the basis of its yearly evaluation, the ERC shall gradually reduce the threshold level until it reaches the household demand level.

   The Rules for Contestability developed by ERC:
   - clarifies and establishes the conditions, timelines and eligibility requirements for end-users to become part of the contestable market;
   - defines the procedures in informing eligibility of end-user in the contestable market; and
   - defines metering requirements and responsibilities.

3. Moreover, as part of its mandate to establish and enforce a methodology for setting transmission and distribution wheeling rates and retail rates for the captive market of a distribution utility, the ERC has also promulgated the following rate setting rules:

i) Rules for Setting Distribution Wheeling Rates which is performance based;
j) Rules for Setting the Transmission Wheeling Rates which is likewise performance based; and
k) Rules for Setting Electric Cooperatives' Wheeling Rates which is also performance based.

It is noted that the above ERC issuances, for all intents and purposes, pertain to and are necessary for the well-ordered performance of ERC's regulatory functions, in so far as retail competition is concerned.

These rules are all important preparatory steps to retail competition; nevertheless, issues have been raised on other equally important preparatory steps which were still lacking, such as:

l) preparation of the wholesale market operator to handle the billing and settlement of retail suppliers who would be among the WESM participants;
m) designation or creation of a central registration agent/body to maintain records of the customer-supplier relationship; and
n) development and installation of a mechanism or a system to convey customer switching information and meter data from the DU to the retail supplier and wholesale market operator.

4. On the basis of the authority under Rule 12 Section 3 of the Implementing Rules and Regulations of the EPIRA granted by DoE to ERC, to declare, after due notice and public hearing, the initial implementation of OA & RC, the ERC conducted the required "due notice and public hearing requirement" under Section 3 Rule 12 of the EPIRA IRR.

The first three (3) conditions under Section 31 of the EPIRA were deemed complied with based on the resolutions and decisions ERC has rendered on the various applications for the unbundling of transmission and distribution wheeling charges, removal of cross subsidy, and operation of the WESM both in the Luzon and Visayas grids.

Using as baseline the list of power plants for privatization / disposal and respective capacities, contained in the JCPC Resolution No. 2002-2 dated August 29, 2002, PSALM indicated a 79.56% privatization of the generating assets and a 76.85 transfer of the IPP contracts to IPP Administrators, thereby substantiating compliance with the fourth and fifth requisites for the initial implementation of OA & RC.

Thus, the ERC declared in ERC Case No. 2011-004-RM, on June 6, 2011, compliance with the preconditions for the initial implementation of OA & RC and declared the commencement of OA & RC on December 26, 2011, six months after the Decision.

5. Prior to the actual initiation of retail competition, the ERC, supported by the USAID, requested that the rules be reviewed by an international expert to determine whether they were adequate to support competition at the retail level. Mr. Jess Totten of Austin Texas was commissioned to undertake the review.

6. While the aforesaid review was being undertaken, the Department of Energy (DoE), mandated by the EPIRA under Section 37,to supervise the restructuring of the electric power industry and formulate such rules as may be necessary to implement the objectives of the aforesaid Act, issued on June 17, 2011, Department Circular No. 2011-06-0006, creating the Steering Committee (SC) that would define the policies for the commencement of RC&OA, ensuring that the appropriate conditions for the efficient transition to the implementation of RC&OA are in place.

The SC is composed of the DoE, acting as the chair, and representatives from PEMC, NEA, NPC, TRANSCO, PSALM, NGCP, Department of Finance (DoF) and the Philippine Economic Zone Authority (PEZA) as members.

The last two agencies (DoF and PEZA), together with the ERC, were invited to become members, subject to their acceptance. The ERC was further invited to act as Co-Chair.

The ERC, in its Resolution No. 12 Series of 2011, confirmed to participate in all the SC meetings, as per invitation stated in the DoE Circular; however, the Commission, declined the invitation for it to act as Co-

Chair of the SC, to give the latter, full and sufficient discretion to review the issuances and make policy recommendations relative to the competitive retail market.

Specifically, the aforementioned DoE Circular defines the following responsibilities of the SC:

a) Review existing rules and procedures on RC&OA; develop and recommend policies to implement systems and processes; needed to govern the transactions therein;
b) Develop the timelines and action plan necessary to ensure the smooth transition to full competitive environment;
c) Coordinate with various government agencies or units, industry sectors, and such other entities to implement the regular monitoring and feedback mechanism to concerned parties;
d) Provide a forum for any recommendations on all pertinent rules and guidelines;
e) Formulate an information and education campaign about the RC&OA.

6.1. Among the matters which were initially dealt with by the SC are as follows:

a) The preconditions to the implementation of OA & RC, previously declared by ERC to have been fulfilled as per Commission Decision on ERC Case No. 2011-004 RM, were acknowledged by the SC to have been complied with.
b) The following technical working groups (TWG) were created:
    - Risk Management, headed by the DoE Undersecretary, Atty. Josefina Patricia M. Asirit;
    - Finance, headed by PSALM President Emmanuel R. Ledesma, Jr., and
    - Technical Assessment, headed by Transco President Rolando T. Bacani.

6.2. The TWGs' preliminary groundwork underscored the following issues / concerns / recommendations which were brought up in the consultative meeting with stakeholders:

a) Deferment of the commencement of RC&OA, as the December 26, 2011 date declared by ERC is not viable.
b) The stakeholders have pointed out that deferment of the commencement date is necessary to allow time for:
    - the establishment of the Central Registration Body (CRB) and the agent for net settlement;
    - contestable market to engage in more detailed preparation;
    - proper evaluation of governing rules and regulations; and
    - all appropriate preparations for transition to the new environment.
b) Concerns on: whether RES and contestability will be mandatory (some customers would want to remain captive), whether the wholesale and retail market will be handled separately, directions towards the establishment of the CRA/CRB, Settlement Agent and B2B, the need for clear guidelines on the source of fund for the establishment of the infrastructure and the concomitant mechanism for recovery of the investment and sustenance of the operations.
c) Pricing Issues. Contestable customers have potential difficulty in securing supply contracts with no price offers from RES. Thus, the TWG is considering obliging the RES to publicly make known its offer prices and that ERC should require the RES to submit its price offer and publish the same in the ERC website.
   Other pricing issues to be dealt with include:
    - the safeguards which should be in place to ensure that captive customers will not be left with higher power cost when all the lower-cost generators have been contracted;

- transparency of the RES pricing
- the need for transparent cost allocation between the DUs' regulated and unregulated business;
- the impact of retail competition to captive customers which was suggested to be studied by ERC / NEA.

The following issues on the management of contracts shall also be taken in hand:

- provision of the standard contract terms;
- how to assist the customers in optimal supply contracting;
- policies on the existing contracts.

d) Development of metering rules, policies, standards and protocol concerning:

- synchronized meter reading;
- disconnection protocol for two or more customers connected to a single line;
- accounting and settlement of transactions
- compliance with the requirements of the Distribution Code particularly the installation of a dedicated circuit breaker;
- competitive metering services subject to cost-benefit analysis; and
- prescription of the period of availability of historical metering data so as not to unduly burden the contestable customer.

e) Development of the Accounting, Billing and Settlement Manual considering among others the:

- schedule and frequency of data submission;
- the complete settlement process between the RES and the contestable customer;
- prudential requirements or security deposits;
- settlement timetable;
- procedures and resolution of disputes;
- handling of imbalances; and
- accounting of the energy quantity and cost;
- Development of policies and procedures in case of RES' or customers' delinquency or default wherein the following were suggested:
- the RES and customers should be required to tender security deposits to cover supply, and transmission and distribution services;
- reduction of the deposit requirement for contestable customers under SOLR from two months to one month, considering that the SOLR service is temporary;
- development of the disconnection policies, rules and guidelines; and
- establishing sanctions and penalties for delinquent RES e.g. revocation of license.

f) Issues and/or suggestions on the SOLR:

- the need for the criteria for the designation of the SOLR to be made more clear;
- the premium on SOLR prices should be suspended during the transitory period;
- the designation of the SOLR by its very nature should not preclude the entry of other RES' to supply the demand of contestable customers; and
- the existing DU of the contestable customer shall serve as the SOLR in case the contestable customer fails to make a choice.

g) Other issues / concerns / recommendations include:

- Referring to cross ownership, there is need for full disclosure of ownership and / or control of businesses in the different sectors (generators, system operator, DUs, RES, IMO, etc.);
- the need for the provision of information to be time-bound;
- rules on the confidentiality of information should be addressed;
- setting up of definite timelines for the ERC's approval of the ACAM and BSUP;
- review of the ERC-issued guidelines to ensure responsiveness to the current and future market environment;
- broaden information campaign for the readiness of stakeholders;
- designation of an independent third party as the central registry administrator / body (CRA/CRB) and the mechanism for selection should be clear; and
- PEMC has the technical advantage to be the CRA / CRB.

7. On November 10, 2011, Mr. Jess Totten's report was submitted. The scope of the review included issues that emerged, like the need for additional infrastructures and whether certain recommendations of the DoE Steering Committee, if adopted, would be conducive to a vibrant retail market. The following are the major findings and conclusions indicated in the report:

a) Several retail suppliers were keen on implementing retail competition on the December 26, 2011, the original schedule proposed by ERC, for reasons that several large companies, facing competition from other Asian countries, would take any measure that could reduce their electricity cost. The lack of settlement, registration and data communications mechanisms would create significant risks for retail suppliers. Also, it would pose a risk to all other participants in the wholesale market as they may be incorrectly assigned spot market costs that should be assigned to a retail supplier.
b) On the suggestion to include in the contestable market, companies for which electricity is an important cost of production, even if the company's average consumption is less than one MW, Mr. Totten commented that this suggestion is one way of stimulating market entry, however, he noted that the definition of contestable costumers is presumably based, at least in part, on the statute, rather than on the rules of ERC.
c) The following Rules adopted by the ERC adequately define the responsibilities of participants in the competitive retail market:
    - Rules on Customer Switching; and
    - Amended Distribution Service Open Access Rules.
d) Likewise, the following rules developed by ERC are adequate in addressing unbundling and code of conduct issues:
    - Business Separation Guidelines;
    - Code of Conduct for Competitive Retail Market Participants;
    - Amended Distribution Service Open Access Rules;
    - Rules for the Supplier of Last Resort for the Contestable Market; and
    - Competition Rules and Complaint Procedures.

   According to the report, the above rules are based on the recognition that without a separation of the utility function from the competitive function, there would be opportunities for anti-competitive behavior, discrimination against new market entrants, and subsidization of the utility affiliate's competitive business by captive markets or regulated services; and these behaviors, if permitted, could impair the effectiveness of retail competition.

e) Mr. Totten indicated that the mark-up in the SOLR rate is appropriate because of the costs and risks in performing the service; however, the provision permitting the SOLR provider to carry over SOLR service' unrecovered costs is problematic since costs incurred for one customer may be charged to subsequent customers. Mr. Totten suggests that the premium permitted in the SOLR rate should already cover all cost and risk associated with providing the SOLR service so that there would be no need for subsequent true up.
f) On the unresolved issue pertaining to the designation of a SOLR for directly-connected customers, Mr. Totten suggests that rules for the retail market should be uniform when retail competition is introduced more broadly. Thus, directly-connected customers would be required to obtain supply from a RES and have a SOLR designated for them.
g) On the RES licensing requirements, ERC's Revised Rules for the Issuance of Licenses to Retail Electricity Suppliers already addresses the operating risks of the retail market; this is complemented by PEMC's authority to examine the RES' capability to participate in the wholesale market.
h) Although the rules issued by the ERC consider that a RES would be able to trade in the real-time market, the current market infrastructure does not have the capability. The WESM settlement software needs to be expanded and the market operator would also need to modify the market rules to hinder barriers to RES participation in the wholesale spot market.
i) Similarly, another requirement lacking but considered in the ERC rules, is an electronic system for the handling of key market information among the RES, DUs and WESM. At the least, the system should be able to deal with the data, information and processing requirements pertinent to the switching of a customer from one RES to another. This should provide the pertinent data for the RES to issue bills to its customers and the wholesale market to bill the RES.
j) A third infrastructure requirement not operating yet, but contemplated by the ERC Rules, is a body to handle central registration which in effect, is the official list of customers, served by each RES. Central registration facilitates the wholesale settlement of RES obligations and the transmission of meter data to the RES for billing its customers.
k) The SC recommended the adoption of the PEMC proposal to carry out the settlement and registration functions and to develop an electronic communications system for retailers and other key market participants. Mr.Totten indicated that the system must be designed, developed and tested to be a workable solution. Mr. Totten also noted that there was no clear indication on the source of funding for PEMC's aforementioned undertaking. Once the function is already operating, the funding of the ongoing function, as well as the recovery mechanism for the initial investment, would need ERC's approval.
l) On the SC's recommendation to change the ERC Rules for Contestability, to allow the contestable market to elect not to participate in the competitive retail market, and rather, remain in regulated service, Mr. Totten commented that this would reduce the size of the market in terms of number of customers, and would thus, be detrimental to the competitiveness of the market. Further, this creates another potential source of cross subsidy, as the revenue from customers who opt to remain in regulated service could be used to support the local RES in providing competitive services to customers who opt to enter the retail market.
m) Customers who have little knowledge of competition and little interest in switching suppliers may value the aforesaid option of remaining in regulated service. Mr. Totten mentioned that in Texas, a partially- regulated rate has been established for residential and small commercial customers for the first five years of retail competition. This, however, has a drawback of giving the DU and its affiliated local RES a competitive advantage over new market entrants. The aim might be to provide benefits to the customers but this would deter market entry and tilt the competitive scales in favor of the DU and its local RES.

n) On the SC's recommendation that the ERC adopt rules to permit competitive metering, Mr. Totten pointed out that competitive metering is not likely to provide benefits to the retail market. It would be very tough for a competitive metering company to carry out the required functions (obtain compliant meters, install and service the meters, read the meters and verify the data, and transmit to the RES and market operator) for a price that would be competitive with the regulated rate of the DUs which have the significant scale that a new market entrant would be unable to match.
o) ERC's Licensing Rules appear to be appropriate in that they:
    - ensure entry into the retail market is controlled to preclude the entry of incapable firms; and
    - do not raise inappropriate barriers to entry to the market.
p) ERC's reporting and compliance mechanisms appear adequate, nevertheless, Mr. Totten suggested the following areas of reporting based on the monitoring of the retail market done by the Texas Public Utility Commission, which ERC can consider:
    - establishing performance measures for data flow in the electronic information system and reporting by users of the system on the degree of their compliance with the performance standards; and
    - reporting on the number of customers who switch to a competitive RES and its energy consumption level and associated load.
q) ERC's Rules on Customer Switching appear to be adequate, however, the author could not comment on the system for the electronic data transmission as there was no detailed information available then.
r) Mr. Totten also commented that executing individual wheeling contracts each time a RES gains a customer as per ERC's rules, would be cumbersome. He suggested using blanket wheeling contracts that would cover any customer a REA may have with a DU, or establishing detailed wheeling tariffs, so that a RES taking wheeling service would not need to execute a contract for the service.
s) The Rules on Customer Switching provide that customers may authorize the Central Registration Body (CRB) to release consumption data to a RES or Local Res. This is important to the RES in developing a pricing proposal for the customer. The retail suppliers raised the issue on the availability of such data since there is no CRB yet. In response to this, Mr. Totten suggested that the ERC should consider requiring the DUs to make available, said data to the RES, when authorized by the customer, at no cost or for a cost-based fee.

8. On February 24, 2012, the DoE issued Department Circular No. DC 2012-02-0002, designating the PEMC as the Central Registration Body (CRB) with the following main functions and responsibilities:

a) Review of the WESM rules and pertinent manuals that may be required to ensure the seamless integration of RC&OA into the WESM operations;
b) Development and management of the required systems and processes and information technology system that shall be capable of handling: i) customer switching and information exchange among retail electricity market participants and ii) settlement of transactions in the WESM;
c) Conduct trainings, consultations, and other information dissemination activities for the stakeholders to ensure readiness of all concerned;

In performing the aforesaid functions, PEMC has been required to comply with all DoE directives, submit project implementation plan with cost estimates and timelines, report periodically as may be required, and coordinate with pertinent stakeholders and other government agencies, primarily the ERC, to ensure regulatory support.

The subject DoE circular has also declared that ERC shall support in the regulatory requirements and cost recovery for the aforementioned PEMC's undertaking, in accordance with existing laws and procedures.

ANNEX 12: CONSULTANT'S OWN ASSESSMENT ON THE SECTION ON RETAIL COMPETITION AND OPEN ACCESS

1. Section 4.3 discusses the rationale for the mandated requisites as well as the two (2) other vital requirements identified by ERC, that must be in place prior to the start of the Retail Market.

   The four requirements mandated by the EPIRA have been adequately proven to be complied with, based on the ERC Decision on ERC Case No. 2011-004-RM. In the same decision, the additional requirements pertaining to adequacy of generation supply and transmission network have also been acknowledged by the ERC to be sufficient to sustain the operations of the retail market.

   It is essential to more thoroughly assess the adequacy of generation supply and transmission network to sustain the retail market.

   It has always been stressed that there can be no competition where generation supply and transmission networks are deficient. For the benefit of ensuring the better chances of success of the implementation of RC&OA, it is suggested that ERC carry out further studies and analysis of generation supply and transmission network vis-à-vis consumer demands in the next ten years. This task is practicable and not constraining since the RC&OA implementation cannot be realistically expected to happen in the next six (6) months.

2. The ERC was consistent with its mandate by the EPIRA, in developing and implementing all the Rules and Regulations pertinent to RC&OA, as all the issuances were necessary for the commission's effective performance of its regulatory functions and other assigned tasks. This is underscored as follows:
   - 2.1. The EPIRA mandated task of ERC under Section 29, to issue licenses to all suppliers of electricity to the contestable market, has prompted the commission to promulgate the Rules for the Issuance of Licenses to Retail Electricity Suppliers and the Code of Conduct for Competitive Retail Market Participants;
   - 2.2. The Rules for Contestability support ERC's task to qualify end-users who shall form part of the contestable market;
   - 2.3. The issuance of the three (3) separate rules for distribution, transmission and electric cooperatives' wheeling rates as well as the Rules on Rate Filing by the Supplier of Last Resort, the DSOAR, and the Business Separation Guidelines, was driven by ERC's mandate to establish and enforce a methodology for setting transmission and distribution wheeling rates;
   - 2.4. The Competition Rules and Complaint Procedures are necessary for ERC to carry on its major function under Section 43 of promoting competition, encouraging market development and penalizing abuse of market power;
   - 2.5. The Rules for the Supplier of Last Resort ensure customer choice which is also a mandated ERC function under Section 43; and
   - 2.6. The Rules for Customer Switching is also in support of the interest of the customer.
3. The DoE's move to create the Steering Committee to define the policies for the commencement of RC&OA and ensure that the appropriate conditions for the efficient transition to RC&OA are in place, is in accordance with its mandate under the EPIRA. It should be a welcome development, as the preparatory actions for a project as significant as the RC&OA, traversing different sectors, should indeed be synchronized and coordinated.

4. The preparatory steps taken by ERC, essentially motivated by its mandate, are to a large extent, necessary towards the implementation of the RC&OA. The following tasks and issues can now be further focused on:
   4.1. Define more specific rules on the SOLR rate and what would be the clear-cut formula to serve as the basis of the Commission in evaluating even-handedly the proposed SOLR rates. The formula for the SOLR rates should maintain a good balance between the objective of encouraging contestable customers to choose their supplier and merely the appropriate premium and reasonable return associated with SOLR service;
   4.2. Enhance the Competition Rules and Complaint Procedures to address the intricacies of Retail Competition as differentiated from Competition in the Wholesale Market. One issue brought up by the PEMC is lack of parameters in the Competition Rules to trigger a case of anti-competitive behavior;
   4.3. Strategize on how to ensure that the pertinent RC&OA development and implementation costs as well as the continuing operating costs would be transparent, reasonable and practical, as ultimately, the end-users would be the ones shouldering the costs; the ERC should be able to judiciously estimate how much time, how much money and what and how many other resources should be appropriately spent for the project;
   4.4. Conceptualize how the costs entailed in putting up the Retail Market mechanism would be reasonably recovered by the investors / financiers and equitably charged to the users;
   4.5. Strategize on spotting retail market abuses and defining the appropriate penalties;
   4.6. Plan on how to promote competition in and encourage development of the retail market.

   The above undertakings are not all inclusive; ERC is in the best position to forecast and plan ahead on all the regulatory requirements for the ultimate implementation of RC&OA.

5. The Draft Report was almost complete when the ERC, on April 13, 2012, posted in its website for public consultation, a Resolution, setting aside and rendering ineffective, for purposes of expediency, the following open access and retail competition rules, to allow the completion of the retail market framework within the timeline issued by the DoE:
   5.1. Rules for Contestability;
   5.2. Rules for the Supplier of Last Resort;
   5.3. Rules on Rate Filing by the supplier of Last Resort;
   5.4. Rules on Customer Switching;
   5.5. Distribution Service and Open Access Rules, as Amended, insofar only as the provisions pertain to the operations of competitive retail electricity market.

   It could have been more likely for the responsible agencies to have their outputs aligned and to have achieved the timelines set by the EPIRA, if they had collaborated at the outset and worked towards a common goal.

   It should be a lesson learned, that delays in the implementation of the RC&OA also deny the contestable market of the benefits of the "power of choice".

6. The following are also deemed important areas of attention by those who will be involved in the development of the RC&OA:

6.1. Taking note of Herbert Hoover's quotation that competition should take in hand, both protection to the customer and incentive to progress, more policies should be adopted to minimize entry barriers to retail competition; both sides, the customer and the seller, should be evenhandedly taken care of.

6.2. Policies to provide the opportunity for demand side responsiveness for both the wholesale and the retail market.

At present the buyers in the wholesale market submit only quantity bids and this does not allow customers to manage their consumption patterns. The opportunity to make consumption decisions for retail customers would give customers not just a choice of its supplier (customers can either buy direct from a generator or through a RES or bid into the WESM)but the ability to respond to price changes.

The PEMC President, during the interview, has indicated that they are opening the demand side bidding upon declaration by the DoE. This is a welcome development. The new feature of the system that will be used for the first time will benefit from testing prior to its implementation. In addition, there is a need to train and inform the users on the intricacies of demand side bidding. One concrete example that needs to be explained is: when a customer bids very low and no generator offer would match the bid as all offers are higher, said customer should be aware that he would pay the spot market price which would certainly be higher than his bid. The demand side bidders should be knowledgeable of all the repercussions so they would be able to bid intelligently and strategically into the market. Otherwise, there would be disorder in the opening and implementation of demand side bidding.

6.3. Prior to assigning the task of developing the retail market mechanism, decisions should have been made on who will finance the project and how the investor(s) would be recompensed.

The PEMC has a pending petition with ERC to include this cost as part of the market fees.

6.4. An information / processing system has five (5) fundamental components:

a) Information technology (IT) hardware and software;

b) Data / information;

c) Communication Networks;

d) Policies, rules and regulations;

e) People and procedures.

These five (5) components must come together to serve the purpose for which the retail market mechanism / system would be constructed.

6.5. Further, it is competent practice to necessarily go through the following fundamental processes in a system development project:

a) Define goals, targets and objectives;

b) Analyze the requirements and establish how the above shall be achieved (either through automation, new or change in policies, rules and/or procedures, people / organizations, change in environments, etc. or combinations thereof)

c) Design and define rules, policies, procedures (including input source documents, output information / reports, business processes);

d) Identify people and organizational requirements;

e) Design the IT system (inputs, processes, outputs) and communication network requirements;

f) Develop and test the system;

g) Define the implementation strategies (including the manual procedures and whether to go on a pilot run, immediate turnover to the new system, etc.);

h) Implement / operate the system;

i) Maintain the system.

Applying the above concepts and techniques in the RC&OA project will provide a framework, or in plain terms, a basis in going through the courses of actions towards the ultimate goal of implementing the RC&OA.

6.6. To start with the first fundamental process, there is a need to define goals, target and objectives. Certainly, the goal in general to implement the RC&OA needs to be dissected into more detailed objectives like for example: to ensure quality, reliability, security and affordability of the supply of electric power; to protect public interest as it is affected by the rates and services of electric utilities and other providers of electric power; to enhance the competitive operation of the electricity market; to enhance the inflow of private capital and broaden the ownership base of the power generation, transmission and distribution sectors, etc. (the aforementioned are just examples which were lifted from Section 2 of the EPIRA).

The above exemplification is driving at this point: if the objectives are, let us say, to protect public interest as it is affected by the rates and services of electric utilities and other providers of electric power, on one side; and to enhance the competitive operation of the electricity market and/or to enhance the inflow of private capital on the other side; then it should be made a policy or a rule that the qualified end-users in the contestable market should not be given the option to remain captive as it would be running against the objectives of enhancing the competitive operation of the market and enhancing the inflow of private capital.

Well-defined objectives, therefore, should form the basis of the RC&OA policies, rules and regulations; accordingly, drafting of policies, et al, in the sphere of a common objective and direction, would be more manageable.

6.7. The first tangible output after the definition of targets, goals and objectives, would be the rules, et al, one of the five fundamental components of an information processing system, as mentioned above. This is one of the pre-requisites before even going to the design and development of the IT system.

Applying this to the ongoing RC&OA activities, the rules, et al, will have to be essentially complete before development can be done. The SC is in the right direction to include in the PEMC undertaking, as the designated CRB, to review and propose changes to the WESM rules and other manuals as may be necessary. However, the WESM rules and the related manuals are not all encompassing.

There's need to develop the Retail Market Rules in the same way that there are WESM Rules. It is relevant to mention at this point, PEMC's indication that DoE needs to reconcile the RC&OA policies on the manner of supplier (RES) switching (whether monthly, yearly, etc.) with the mandate of DoE to ensure the security of supply and mitigate the risks of the generation and distribution sectors and the impact on prices. It is the author's view that the impact of switching would be more on individual prices and would probably have less influence on the security of supply. There may be a need to give attention to this and the necessary direction to PEMC for its development of the RCOA mechanism.

One test for the completeness of the rules, et al, is to allow PEMC as the CRB, to submit a proposal on the detailed processes / procedures to be used in the development of the system for the electronic transmission of switching and meter data. If PEMC would be able to design the detailed system processes / procedures, which would be approved by the SC and all groups concerned, without any need for further policies, et al, then the system may be said to be ready for development.

The cost of the system will ultimately be passed on to the customers; it would thus be prudent to manage the cost as well as the timeline through a well-organized process.

6.8. In addition to hardware and software solutions, objectives can also be achieved by processes that are better done manually, reinforced by the appropriate procedures, done by qualified personnel in the organization. PEMC's proposal should also cover these imperative components of an information processing system: people and procedures, which are the most overlooked components but can greatly influence the success or failure of the system. People and procedures are more particularly critical during the period of semi automation which PEMC plans to implement at the start.

Security and confidentiality should appropriately be handled with all the people and procedures components in the IT system.

6.9. The rest of the five components are part of the technical part of the IT system: hardware, software, communication networks, data and information. The last two items, data and information, should nevertheless, be part of the requirements analysis wherein the stakeholders need to be consulted.

6.10. The rest of the processes under Section 4.5.6 should form part of the development and implementation plans, which PEMC is supposed to submit to the DoE under DC 2012-02-0002.

6.11. The system to be developed by PEMC, conceivably covers the activities from the submission of retail market contracts, retail market bids, customer switching, up to PEMC billing / settlement with retail market customers and generation of all the required information. External processes like the RES contracting with customers, billing and settlement between the RES and its customers, allocation of distribution and transmission costs to the contestable customers, regulatory compliances, etc. need to be defined for areas outside of the PEMC system.

6.12. Some RESs affirmed that they are prepared when asked if they are ready with the coming in of RC&OA; however, they have also indicated that there are still some unclear issues: who contracts for transmission, how would the DU allocate its distribution costs to its captive and contestable markets, etc.? Some RESs have indicated that they need more preparation with its billing and settlement systems and procedures.

To some RES, readiness means that they have already organized its pricing strategies and that they are already conducting initial talks with potential customers.

The participants are waiting to hear from the DoE, being the overseer and having the responsibility to ensure that the RCOA would be in order, the declaration of a realistic RC&OA

opening date, considering all the requisites and relevant parameters, for them to prepare and be indeed ready and equipped for the implementation of RC&OA.

6.13. The RC&OA is a first-time implementation in the country, with all its uniqueness and distinct characteristics. Seeking the help of the veritable experts, from other jurisdictions, who have experienced all the prime successes and failures, in the development and implementation of their own RC&OA, would be most advantageous to the Philippines. The hiring of experts already have precedents in the implementation of the EPIRA. Consultants were hired in the formulation of the WESM Rules, training of the stakeholders, and the development of Market Dispatch Optimization Model (MDOM) of the wholesale market.

ANNEX 13: ENSURING ECS' PERFORMANCE

The National Electrification Administration annually assesses the Electric Cooperatives' overall operating performance through a number of measures: categorization, classification, and color coding.

1. EC Categorization.

a) Categorization. ECs are categorized by letters from a high of "A+" for Outstanding to a low of "E" for no improvement in operations. The full list of categories is as follows:

CATEGORY	ADJECTIVE RATING	SCORE
A+	Outstanding	90 & Above
A	Very Satisfactory	75 to 89
B	Satisfactory	65 to 74
C	Fair	55 to 64
D	Poor	30 to 54
E	No Improvement in Operations	29 & Below

b) Criteria. The scores in 6.3.3 a) above are calculated based on a criteria set as follows:

CRITERIA	POINTS	INCENTIVE
Amortization Payment	15	2
Systems Loss	25	2
Collection Efficiency	15	
Payment to GENCO/TRANSCO	15	
Non-Power Cost (Actual vs. Budget)	10	
Energization Sitio Connection	 7 3	 1
Results of Financial Operations	5	
Total	95	5

Amortization Payment to NEA pertains to the ability of the EC to fulfill their loan obligations with NEA and rated according to the promptness of its amortization payment. Incentive points are given to ECs who are able to pay their amortization ahead of their due date.

Systems Loss pertains to the ability of the EC to reduce the power losses in their system.

Collection Efficiency refers to the capability of the ECs to collect consumer accounts receivables.

Payment to Power Supplier and Transmission Provider refers to the ability of the EC to promptly pay its bills to the said entities.

Non-Power Cost refers to the ability of the EC to confine its non-power expenditures within the NEA-approved budget.

Results of Financial Operation measure the ability of the EC to earn a margin.

In addition to the above parameters on which the ECs are assessed, Demerit Points are also given for un-liquidated cash advances to officers and employees.

c) EC Categorization Results

Category	2005	2006	2007	2008	2009	2010	%
A+	58	52	61	62	65	70	58
A	14	15	12	12	15	15	13
B	16	19	13	14	12	10	8
C	10	6	6	4	3	1	<1
D	9	5	4	4	3	5	4
E	10	13	7	4	8	5	4
Not Evaluated	3	10	17	20	14	14	12
Total	120	120	120	120	120	120	100

Note: There are only 119 ECs. Nueva Ecija Electric Cooperative II has two areas, each of which is also evaluated.

2. EC Classification

ECs are also classified according to size. This classification guides the NEA to establish uniform standards and guidelines for the same class of ECs

a) Class. ECs are classified as small, medium, large, extra large or mega large depending on the score they obtain based on the criteria in 6.3.3.b).

CLASS	SCORE
Mega Large	86 to 100
Extra Large	71 to 85
Large	56 to 70
Medium	40 to 55
Small	Below 40

b) Criteria. The criteria and point score used to classify the ECs are as follows:

CRITERIA (Average for last 3 years)	POINTS
Number of service connection	30
Volume of annual MWH sales	40
Circuit kilometers of lines	30
Total	100

c) EC Classification Results

Class	2005	2006	2007	2008	2009	2010	%
Mega Large	34	35	33	36	37	35	29
Extra Large	36	32	31	30	32	34	28
Large	31	26	23	20	24	24	20
Medium	10	10	11	9	7	7	6
Small	8	7	4	5	6	6	5
Not Evaluated	1	10	18	20	14	14	12
Total	120	120	120	120	120	120	100

Note: There are only 119 ECs. Nueva Ecija Electric Cooperative II has two areas, each of which is also evaluated.

3. Color Coding

The ECs are also color coded indicative of the level of supervision and/or assistance required from NEA. The color coding, patterned after the colors of the traffic light, of green, yellow and red.

a) Color Code

COLOR CODE	DEFINITION	SCORE
Green	Good performing EC Less NEA supervision More flexibility in operations	85 & Above
Yellow	Border-liner ECs Needs "case to case" supervision	55 - 84
Red	Poor performing EC Definite NEA intervention	54 & Below

b) Criteria

MEASURES		SCORE
1. EC's Point Score in the Categorization		70
2. Audit Findings • No adverse findings and major procedural lapses • With procedural lapses and/or minor findings • With adverse findings (either on procurement, employees' and officials' benefits, cash advances, malversation of funds)	 10 5 0	10
3. Institutional Strength Demerit Points • Board-Management problem/s • General Manager-Employee relationship problem/s • Non-conduct of Annual General Membership A (AGMA) • Non-conduct of District election	 3 3 2 2	10
4. EC Financial Operating Results		10

• With Net Margin • With Net Loss	10 0	
Total		100

c) EC Color Coding Results

COLOR CODE	2008	2009	2010	%
Green	62	64	70	58
Yellow	29	29	26	22
Red	9	13	10	8
Not Evaluated	20	14	14	12
Total	120	120	120	100

Note: There are only 119 ECs. Nueva Ecija Electric Cooperative II has two areas, each of which is also evaluated.