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Department of Energy

Restructuring and Privatization of the Electricity Industry in the Philippines

Final Report

31 August 1994

Prepared by:

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Prepared for:

Office of Energy, Environment, and Technology
Bureau for Global Programs, Field Support and Research
United States Agency for International Development

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ACRONYMS

ADB	Asian Development Bank
BOT	build-operate-transfer
BUSECO	Bukidnon II Electric Cooperative, Inc.
CENECO	Central Negros Electric Cooperative
Cepalco	Cagayan Electric Power and Light Company
DENR	Department of Environment and Natural Resources
DLPCO	Davao Power and Light Company
DOE	Department of Energy
DSM	demand-side management
EDC	Energy Development Corporation
EDF	Electricite de France
EO	Executive Order
ERB	Energy Regulatory Board
ESCO	energy services company
FPPC	First Private Power Corp.
G&Ts	generation and transmission companies
GWh	Gigawatt hour
ILPI	Iligan Light and Power Co., Inc.
IRP	integrated resource planning
kV	kilovolt
kWh	kilowatt hour
IPP	independent power producer
IPP GenCos	independent power producer generating companies
LRMC	long-run marginal cost
Meralco	Manila Electric Company
MORESCO	Misamis Oriental Electric Cooperative
MW	Megawatt
NAPOCOR	The Philippine National Power Corporation
NEA	National Electrification Administration
NIA	National Irrigation Administration
NPC	National Power Corporation
PASAR	Philippine Associated Smelting & Refining Corp.
PD	Presidential Decree
PDP	Power Development Program
PECO	Pampanga Electric Cooperative
PGI	Philippine Geothermal Inc.
PHILPHOS	Philippine Phosphate Fertilizer, Inc.
PhilRECA	Philippine Rural Electric Cooperative Association

Planco	planning company
PNOC	Philippine National Oil Company
Poolco	power system operations coordination and dispatch organization
PPA	power purchase agreement
ROM	repair-operate-maintain
RORB	return on rate base
RP	Republic of the Philippines
RPC	Regional Power Company
SOCOTECO	South Cotabato Electric Cooperative
SRMC	short- run marginal cost
Transco	Transmission Company
USAID	United States Agency for International Development
VECO	Visayas Electric Company
WB	World Bank
ZAMCELCO	Zamboanga City Electric Cooperative

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EXECUTIVE SUMMARY

The Philippine power sector has experienced dramatic changes over the past six years. After a long and successful program of expansion and infrastructure development until the mid 1980s, there was a period of steady decline as investment in the power sector lagged behind general industrial growth and increasing demands for power. The early 1990s brought on extended brownouts and a further widening of the gap between capacity and demand. The Philippines took aggressive action and initiated a successful program of fast-track power capacity additions through independent power developers, which stabilized the power situation. This program established the Philippines as a leader among ASEAN nations in private power development. However, there was still much work to be done on fundamental restructuring and reform of the electricity industry if sustainable and reliable power capacity was to be secured.

Multilateral development banks and the private sector called for reform and restructuring, and the Energy Act of 1992 was passed by the new administration. The Act created a new Department of Energy (DOE) and provided the mandate for restructuring and privatizing the Philippine electricity industry. In response, Hagler Bailly was commissioned under USAID sponsorship to investigate industry structural and privatization alternatives, recommend a long-run industry structure approach, and develop a detailed work plan to guide the sector through its implementation. The results of this study are focused on assisting DOE and the Philippine National Power Corporation (NAPOCOR) in developing their proposed restructuring and privatization plan for submission to the Government in September 1994.

Over the past six months, Hagler Bailly conducted an in-depth investigation into the strategic issues affecting the performance, efficiency and competitiveness of the electricity industry. This investigation also focused on privatizing NAPOCOR in response to the mandate in the Energy Act. Privatization can take several forms: 1) contracts with the private sector, e.g., purchasing power from private generators, 2) sale of operating assets, and 3) sale of stock ownership in commercial operating entities. NAPOCOR's privatization activities to date fall into the first category and involve the continuation of government financial and contract performance guarantees as well as operating control. That is, NAPOCOR and the government remain very much in the power business and retain the basic responsibility for power supply. While this report supports the continuation of these privatization activities by NAPOCOR for a transition period, its primary focus is on privatization through sale of assets and sale of ownership interests in commercial entities.

Moreover, it is the goal of the recommendations in this report that this privatization be carried out under terms and conditions that reduce or eliminate the government's financial exposure, move the responsibility for power supply to the private sector as much as possible, and constrain the demands of the power sector on the government budget. To accomplish these ends, it became apparent that restructuring and strengthening the industry must provide the foundation for successful privatization. This includes consolidating the distribution utilities and otherwise developing them into financially credible commercial entities that can stand on their own in dealing with power developers.

Throughout this effort, the project team sought the maximum involvement of Philippine organizations and individuals in the electricity industry. Meetings and discussions were held with government organizations (including DOE, the Energy Regulatory Board (ERB), and the National Electrification Administration (NEA)), NAPOCOR, distribution utilities, legal counsel, private independent power project (IPP) developers, the Philippine Electric Plant Owners Association, the World Bank, Asian Development Bank, and USAID. A two-day workshop was also held in Manila, which provided a forum to express views and examine approaches to restructuring. Following the issuance of a draft report, ten additional workshops were held with NAPOCOR, DOE, ERB, NEA, other government agencies, IPP developers, and regional utilities and major end-users to review and seek feedback on the recommendations. All of the workshop participants and those interviewed expressed a uniform conviction that the industry can be made more efficient and reliable, and can provide better service through increased private sector participation and competition. However, views on the exact methodology and ultimate industry structure to achieve these goals varied considerably. Our role has been to analyze the varying points of view, evaluate options and scenarios, and compare the Philippine electricity industry with other countries that have undertaken similar restructuring programs.

To provide an industry structure that will promote reliable electricity supply at the lowest practical cost and promote consensus for action among the diverse industry participants, we developed a recommended approach that:

- stresses the restructuring of generation and transmission into unbundled and focused entities that are manageable while efficient in size and scope, with decision making closer to the customer and clear performance accountability

- seeks to introduce viable competition wherever possible, in particular in generation planning and investment, the dispatch of generation (and efficiency of generation maintenance and operations), sales services to end-users, and demand-side management (DSM) as a resource option.

- provides a framework and incentive program for small utilities to consolidate and collaborate to become efficient, financially credible organizations with whom private sector operators and financial institutions will do business without requiring government guarantees and subsidies

- promotes private sector investment, ownership and control wherever practical, in particular, in the generation sector

- provides planning, operations and policy coordination to optimize for efficient scale and "one system" economies

- requires transparency in regulation and establishes efficiency as the key principle underlying prices throughout the industry.

The result is a long-run industry structure that is tailored to the unique conditions prevalent in the Philippines and can be implemented while maintaining stable and reliable electric supply.

OVERVIEW OF THE INDUSTRY AND NEED FOR STRUCTURAL REFORM

A review of the current structure of the industry and its competitive conditions reveals a heavy vertical integration in generation and transmission, a monopolistic market structure in generation and customer sales, and no competition between demand- and supply-side resources. In other words, competition is substantially lacking. Thus, structural reform along with sector strengthening are needed to lay the groundwork for privatization.

Figure 1 presents a summary overview of the current structure of the industry by functional area, i.e., generation, transmission, distribution "lines" and "sales" services, and customer-side activities. Among the most important structural features are:

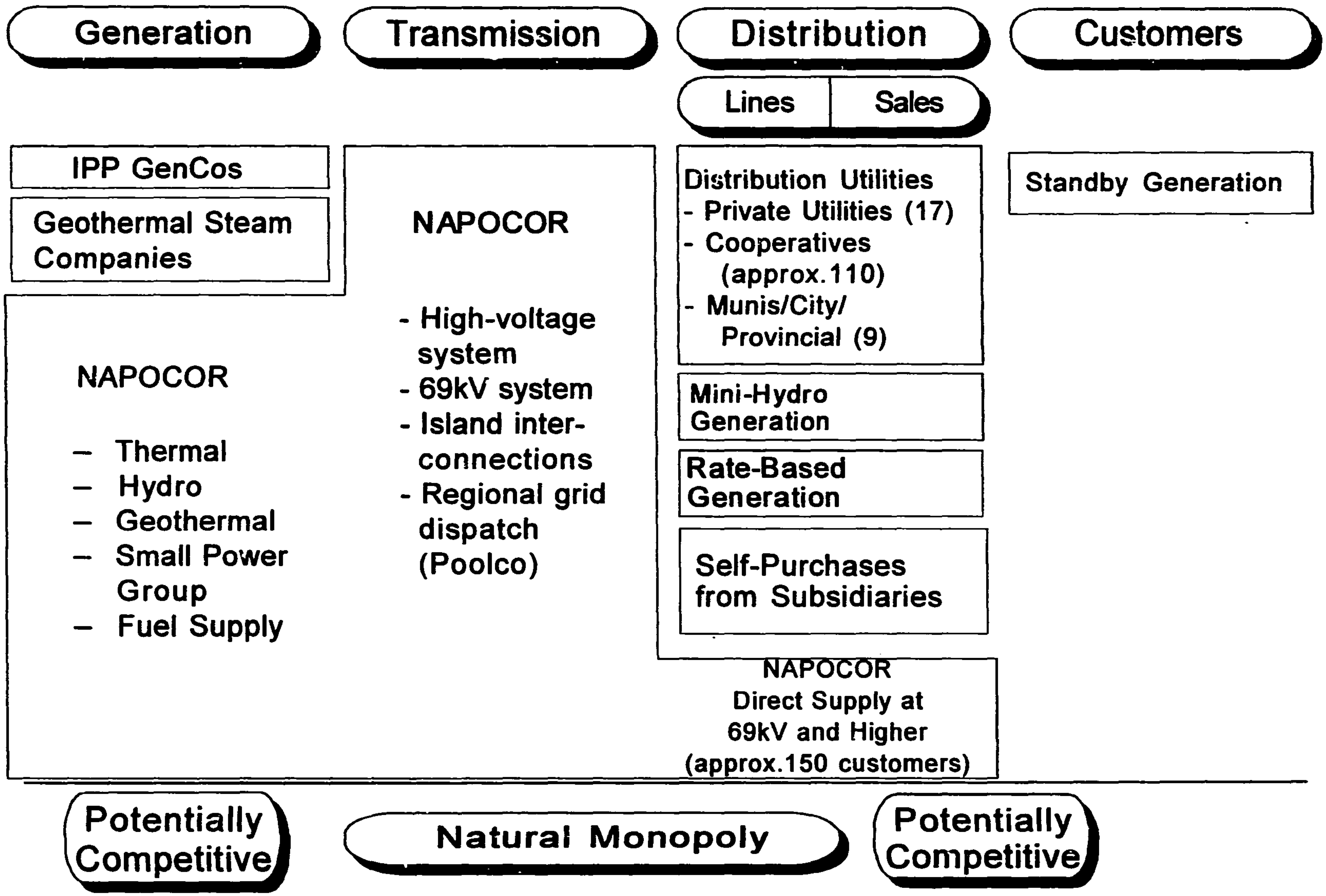
Generation: NAPOCOR is the prime generator of electric power in all regions of the country, covering most thermal plants (including power purchase agreements with IPP producers), geothermal, hydro, and most small-scale generation. A small number of IPP developers have brought plants on-line under the fast-track program, and a number of small-scale cogenerators and standby units are installed by end-users throughout the country.

Transmission: NAPOCOR also plans, develops, and operates the high-voltage backbone transmission system throughout the country and a significant amount of 69 kV lines that can be classified as sub-transmission. NAPOCOR also performs generation dispatch and central power planning, and will operate the planned island interconnection projects. While the major geographical areas are not physically connected, NAPOCOR manages the transmission system as a national grid. As a result, power generation, transmission and dispatch are vertically integrated.

Distribution: The distribution functions are handled by 110 rural electric cooperatives, 17 private distribution companies, and 9 municipal/provincial distribution systems, and by NAPOCOR for 150 directly connected industrial and other customers. Distribution in Luzon is heavily skewed to Meralco, a private distribution company serving the greater Metro

Figure 1

Current Structure of the Philippines Electricity Industry



Manila area. Meralco consumes almost two-thirds of NAPOCOR's total system generation and is more than twenty times the size of the next-largest Luzon utility.

What are the problems and limitations of this structure with respect to promoting competition and fostering an environment where market forces will augment and help supplant regulation as an effective incentive for efficiency and customer service? This question can be addressed by considering how well the current structure meets conditions that are attendant to a competitive electricity industry, namely:

- existence of many sellers and buyers of generation
- ease of bilateral trades between buyers and sellers
- ease of entry into generation
- access to transmission
- transparent pricing
- unbundled core functions
- level playing field among participants
- availability of planning information
- access to end-users through retail wheeling.

A review of the current situation yields the following:

1. NAPOCOR is essentially the only seller of electricity in the wholesale market. It generates almost all non-IPP power supply. It also controls the emerging IPP market, i.e., although there are many buyers from NAPOCOR, it is the only buyer of generation from IPPs.

2. Bilateral trades between sellers and buyers of generation are difficult under the current structure and are heavily dependent on negotiation with NAPOCOR.

3. Entry into the generation market is primarily by bidding on solicitations issued by NAPOCOR. Entry otherwise is by exception only. By virtue of its control of transmission, NAPOCOR plays a key role affecting the feasibility of any generation project proposed by another entity.

4. Access to transmission is only by negotiation with NAPOCOR. There are no standard rights of access, established transmission pricing principles or tariffs.

5. Prices throughout the industry are not transparent. Rates are bundled: they do not separate generation from transmission, demand from energy, or distribution lines service from sales service. Rates contain many subsidies, at both the wholesale and retail levels, resulting in inefficient investment and consumption price signals.

6. Core functions are bundled. NAPOCOR owns and controls generation and transmission.

7. For the above reasons, a level playing field is precluded in the generation and transmission functions among NAPOCOR, distribution utilities and potential generators. NAPOCOR has a substantial advantage. In addition, NAPOCOR enjoys a fuel tax exemption not available to other generators.

8. Reasonable planning information is available. However, this information supports competition only when the items mentioned above are restructured into a truly competitive market.

9. There is no retail wheeling. NAPOCOR has allowed direct connection of numerous customers, bypassing the distribution utility, but there are no clear rules for such direct connections and no retail wheeling tariffs.

Several special factors that influence industry performance also emerged from the review of the industry. These factors must be carefully accounted for in restructuring and privatization.

1. ***Regional considerations***. There are natural regional divisions of the generation business and transmission grids (see the map on the next page). The three major electricity industry regions (Luzon, the Visayas, and Mindanao) are significantly diverse in their generation, transmission, and distribution characteristics.

    - Luzon contains the bulk of thermal plants and a variety of other power sources. It is the prime industrial and commercial consumer, and has the most widely developed transmission system. Luzon also has the most concentrated distribution function in one utility.

    - The Visayas is the most diverse, with multiple islands that are not interconnected, small distribution systems, large rural population, and only one major industrial area (Cebu). Efficient expansion of the electricity industry in the Visayas will require close coordination to develop island interconnections and to share in the output of efficient-sized, capital-intensive indigenous resources.

    - Mindanao has the most widely dispersed rural population, is heavily dependant on hydro power generation, and offers attractive potential for geothermal. Several private utilities of competitive distribution size service the island. A strong concerted effort will be required in Mindanao to develop its indigenous resources on schedule and at competitive costs.

2. ***Unified transmission.*** Given that the three regions are not interconnected and the central role that transmission plays in promoting a competitive market, special considerations must be given to expanding, maintaining and operating the regional grids as one unified transmission system.

3. ***Scale of generation.*** The Visayas and Mindanao electric industries are small in comparison to Luzon, and their size will make the process of introducing competition more difficult. The large capital requirements for developing the hydro and geothermal energy resources in these regions are somewhat at odds with the small size of the distribution companies. In contrast, with the implementation of additional power projects over the next several years, Luzon will have plenty of diverse generation where competition can thrive.

4. ***Meralco dominance of Luzon distribution.*** One large distribution utility (Meralco) dominates the Luzon market, while a large number of smaller utilities make up the balance of distribution in Luzon, the Visayas and Mindanao. Proper regulatory policies and procedures must be in place to ensure competitive behavior and prevent generation market control.

5. ***Distribution utility capabilities.*** There is great disparity in the size, financial strength and management performance of the distribution utilities. Some utilities may perform satisfactorily in a decentralized and competitive market, but most will be significantly challenged. A considerable amount of reform, including consolidation and financial strengthening, must occur in step with the generation, transmission and other restructuring initiatives. For there to be meaningful competition in the generation sector, the distribution utilities must become credible and financeable buyers, able to stand on their own credit without government support. The restructuring approach must provide the opportunity and incentives for this necessary reform.

5\. ***Planning and power supply project execution.*** There is a critical need to maintain some degree of central planning and strong financial entities on each grid to ensure capacity additions are added for future demand. This will be particularly necessary during the transition phases.

6\. ***Absence of DSM/IRP.*** Demand-side management and integrated resource planning are absent in the industry. DSM/IRP will aid in the competitive model being proposed.

7\. ***Strengthening of ERB and DOE.*** These organizations will have expanded tasks and significantly more responsibility under the competitive industry structure. Both organizations will need to respond by strengthening their technical and resource capabilities.

LONG-RUN INDUSTRY STRUCTURE

Figure 2 illustrates the recommended long-run industry structure, which can be characterized as unbundled functions, decentralized planning, and inter-utility operations and planning coordination. This structure meets the conditions specified above for a competitive market and is also responsive to the special factors discussed earlier. The recommended approach will move the Philippine electricity industry away from integration and toward more unbundling and more competition, with emphasis on regulatory oversight in a competitive market.

The long-run industry structure is characterized by the following:

- ***Generation.*** NAPOCOR's generation is unbundled and privatized. The unbundling is accomplished both vertically (separated from transmission) and horizontally (inter- and intra-regional).

  - Existing NAPOCOR generation is privatized through IPP generating companies (IPP GenCos) to the maximum extent possible during the initial stages of restructuring. IPP GenCos are also key participants in developing new power sources, including geothermal.

  - NAPOCOR's hydroelectric properties are spun off to an independent Republic of the Philippines-owned authority which is also responsible for developing new major hydroelectric resources on a national basis (this does not include pumped storage and small hydro).

  - NAPOCOR's Luzon generation is organized initially as an autonomous subsidiary, and subsequently transformed into two to four independent private power companies.

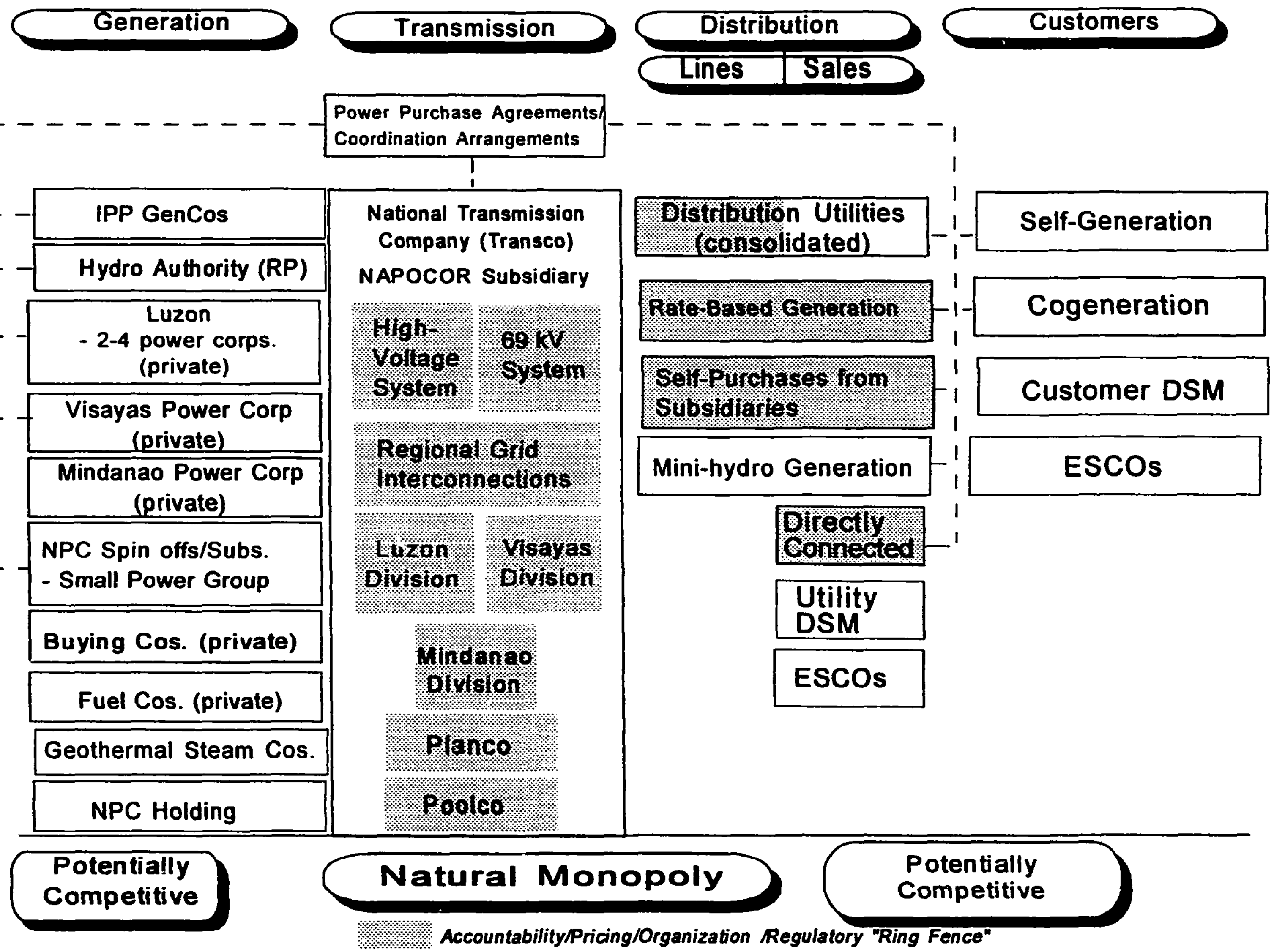
  - NAPOCOR's remaining generation in Mindanao and the Visayas is organized into separate subsidiaries and sold to private operators and investors.

  - Other NAPOCOR activities (e.g., Small Power Group) become subsidiaries and are to the extent possible either privatized or operated on a commercial basis. Any ongoing requirements for subsidies are made transparent.

  - "Buying companies" will emerge as new entrants to combine the buying power of a group of utilities or to act on behalf of a single utility as an agent to secure power supply. This report recommends a program through which utilities will consolidate and form generation or power acquisition companies to develop or acquire their power needs, creating one type of "buying company."

Figure 2

Philippine Industry Structure Based on Unbundled Functions, Decentralized Planning and Inter-Utility Operations and Planning Coordination



- NAPOCOR should withdraw from the fuel supply business, remaining only during the transition phase while fuel supply companies emerge to serve the market. Geothermal steam is produced as currently done.

- A new company, NAPOCOR Holdings, emerges as a streamlined and focused entity whose main functions are transmission and operating and planning coordination.

► ***Transmission.*** The transmission system is established as an autonomous, independently managed subsidiary of NAPOCOR (Transco). This newly created company will develop, operate, and maintain high-voltage systems. Other entities may also develop transmission that is consistent with the Transco national transmission plan, and such transmission will be made available to other users through wheeling tariffs. Transco will operate on a commercial basis, establish fair and non-discriminatory transmission access policies and wheeling tariffs, plan and manage interconnections, perform generation dispatch and other operations coordination (Poolco), and coordinate planning from the national perspective (Planco). Initially, Transco will also own and operate sub-transmission facilities, but these will be systematically sold to distribution utilities or their "buying companies" under a recommended voluntary utility consolidation program.

► ***Distribution.*** The responsibility to plan and provide for power supplies is placed with the distribution utilities, who must prepare integrated resource plans (IRPs) to identify the most cost-effective demand- or supply-side alternatives to meet customer requirements. In preparing IRPs, the utilities would first implement cost-effective DSM and then procure remaining generation requirements through a competitive procedure. The recommended structure puts in place a planning and operating framework to assist the distribution utilities in meeting this new responsibility. The objective is for the utilities to stand behind their commercial commitments without government guarantees and take the risks now shouldered by government. To further assist in meeting this objective, a voluntary consolidation program and a regulatory program, both embodying incentives, are included to help develop the utilities into credible financial entities.

The distribution "lines" function is unbundled from "sales" service through retail wheeling tariffs to enable end-users to competitively procure their power requirements. Initially, only large, directly connected customers meeting threshold size requirements would be permitted to take wheeling service, but these restrictions would be relaxed over time, based on competitive conditions, to embrace a broader definition of consumers to increase competition, check the growth of market power of distribution utilities, and promote efficiency.

Although distribution utilities will be allowed to enter into self-generation or purchase directly from subsidiaries, these investments must be justified through IRP competitive procurement procedures and competitive benchmarks, and are subject to close regulatory oversight.

- *DSM.* Both utility DSM and independent energy services companies (ESCOs) serving the utility's DSM program needs will grow in importance under the new structure, as integrated resource planning principles demonstrate the validity of demand-side options in the resource acquisition process. Customers may also initiate DSM and/or work with ESCOs to develop and sell their DSM potential.

- ***Power purchase arrangements.*** Power purchases between generators (IPP Gencos, power supply utilities) and distribution utilities (and end-users where retail wheeling is in practice) are governed by power purchase agreements, full and partial requirements tariffs, and special tariffs (e.g., backup rates).

- ***Coordination arrangements.*** An important feature is comprehensive planning and operations coordination arrangements covering all grid participants with respect to 1) the system-wide "pooling" and coordinated reliability and generation dispatch services provided by Transco (through Poolco) and 2) coordinated long term capacity planning (through Planco). An integration agreement entered into by all grid participants, a set of rules established by DOE, or a combination thereof, will be subject to regulatory oversight and will govern all grid use and transactions. It will cover such key areas as the capacity obligations of each utility, centralized unit commitment and economic dispatch (short-term spot market interchanges), coordinated maintenance scheduling, provisions for making short- and long-term capacity sales among utilities, coordinated planning, access rights to new generation, and pricing, billing and shared-savings procedures covering transactions between utilities.

- ***Regulatory programs.*** Regulatory programs will support the new industry structure. Pricing practices will be rationalized to provide more accurate price signals and eliminate subsidies; distribution utilities will be consolidated with improved financial credibility and operations performance; and regulatory and policy development capability will be strengthened at ERB and DOE.

This long-run industry structure approach promotes efficiency and competition in several ways. It:

- creates a robust complement of buyers and sellers of generation and facilitates trades among these buyers and sellers

- facilitates ease of entry into generation and assures access to transmission

- unbundles functions and establishes level competitive playing fields
- provides for coordinated planning with readily available planning information
- establishes transparent pricing and performance accountability
- introduces competition through IRP between supply- and demand-side resources, and opens up DSM as a new resource for utilities
- promotes and rewards efficient maintenance and operation of generation facilities.

While this long-run industry structure may represent the "ideal approach," practical considerations will necessitate a phased implementation. It is imperative that the stability and reliability of supply are maintained throughout restructuring, and that prudent steps are taken to avoid any significant stranded asset risks.

THE WORK PLAN: A PHASED APPROACH

Table 1 provides an overview of the three recommended phases of restructuring and privatization. Included in the figure are the time frame, objectives, major activities, and major results for each phase.

Phase 1 (first 4 to 5 years). This phase concentrates on building the strength of the industry, restructuring the transmission and generation sectors, implementing inter-utility coordination arrangements, establishing IRP and all-source competitive procurement, decentralizing planning and decision making, consolidating and building the financial and management capability of distribution utilities to achieve financial viability, and otherwise easing the industry into more competitive markets where more sophisticated management and technical expertise will be required. During this phase, NAPOCOR will also continue to work with the private sector to refurbish and operate its generation facilities. However, more critically, NAPOCOR will prepare to completely privatize its generation activities on each grid, with no residual ownership interest. It might be feasible and even desirable to accelerate the Phase 1 schedule or key steps within it. However, Phase 1 is a logical sequence of steps, and any acceleration of the schedule should not be at the expense of omitting any steps or compromising the completeness and quality of implementation.

Phase 2 (following 2 years). This phase will include a critical evaluation and reassessment of restructuring activities before implementing the final privatization initiatives on each grid. During this phase, it is anticipated that the sale of power subsidiaries in Mindanao and the Visayas would be accomplished. The final privatization scheme for Luzon is more complicated and will require additional restructuring during Phase 2 before NAPOCOR's

Table 1. Phases of Restructuring and Privatization

Phase 1: *Strengthen and restructure industry.*	**Phase 2:** *Evaluate results, implement further restructuring, and privatize.*	**Phase 3:** *Move into final structures and competitive environments.*
Time Frame: 1994-1998 (4-5 years)	**Time Frame:** 1998-1999 (2 years)	**Time Frame:** 1999-2004 (4 to 5 years)
Objectives: Strengthen all sectors and participants; restructure generation and transmission; establish coordination arrangements; consolidate distribution utilities and build capabilities; prepare industry for competition, privatization and decentralization.	**Objectives:** Evaluate results and industry performance; set final restructuring goals; adopt policies that accelerate participants' growth into new structure and responsibilities; privatize generation.	**Objectives:** Achieve full restructuring and decentralized planning; establish fully effective competition in generation, retail sales and resource planning; monitor competitiveness and industry performance
Major Activities: ° Unbundle generation horizontally and vertically ° Unbundle transmission ° Unbundle hydroelectric to Hydro Authority ° Decentralize planning responsibility and adopt IRP ° Establish operations and planning coordination ° Rationalize pricing; introduce retail wheeling ° Consolidate and strengthen distribution utilities ° Promote private participation in generation (IPP bidding, ROMs, etc.) ° Strengthen regulatory and policy agencies ° Streamline NAPOCOR through additional subsidiaries, rationalize staffing levels	**Major Activities:** ° Conduct key evaluations (e.g., competitive conditions, success of IRP, coordination arrangements, distribution utility consolidation) ° Make structural goal adjustments; re-visit workability of alternative competitive models in Luzon; improve coordination arrangements ° Privatize generation: sell Mindanao and Visayas subsidiaries; select and implement final Luzon generation privatization plan ° Expand retail wheeling ° Implement policies to accelerate utilities' adaptation to new structure	**Major Activities:** ° Implement programs determined by assessing development of the industry under the restructuring and privatization initiatives ° Extend practices such as retail wheeling and retail sales competition ° Adopt incentive regulatory schemes proven to be effective ° Monitor competitiveness, market behavior and the potential for market dominance
Major Results: ° NPC power supply subsidiaries in Mindanao, Visayas and Luzon ° NPC national transmission subsidiary responsible for transmission, dispatch and operations coordination, and coordination of planning from national perspective ° RP Hydro Development Authority ° Integrated resource planning by all utilities ° Coordination arrangements to achieve efficient operations and planning ° Transparent, unbundled prices ° Increased private participation in generation ° Consolidated, strengthened and financially viable distribution utilities ° Improved regulatory and policy capabilities ° Streamlined NAPOCOR	**Major Results:** ° Adjustments to structural and ownership goals ° Adjustments to regulatory oversight and policy programs ° Improved IRP and coordinated utility planning ° Enhanced operations coordination; full economic dispatch on all grids ° Privatized generation ° Increased competition: generation, retail sales, supply-side vs. demand-side resources ° Improvements in structure and performance of distribution sector	**Major Results:** ° Full functioning of all utilities under decentralized decision making ° Competitive generation markets ° Competitive retail sales markets ° Widely practiced, state-of-the-art IRP ° Innovative regulatory incentive programs ° Efficient inter- and intra-grid coordinated operations ° Stable, efficient size and financially viable distribution utilities

control is transferred to the private sector. During Phase 2, the potential applicability of a short-run marginal cost (SRMC) or bidding pricing approach will be re-evaluated for Luzon, and the generation assets of the NAPOCOR Luzon subsidiary will be grouped into two or more portfolios and sold to private operators.

Phase 3 (final 4 to 5 years). During this phase, the final restructuring activities will take place and the industry will move into full operation under the decentralized competitive industry scheme.

We believe that the recommendations contained in this study are fully implementable in the Philippines, provide for a basis of consensus, and will best serve the needs of the various power sector entities in maintaining an efficient and reliable power supply. The exact composition of the industry will evolve through the process of restructuring. However, what is most important at this critical juncture is that restructuring actions be initiated without delay. We trust that this report and action plan will serve as a guide and a catalyst to begin the process. The Philippines has an opportunity to establish itself as a forerunner in electricity industry restructuring, just as it has in private power development among the ASEAN community.

CHAPTER 1
INTRODUCTION

Over the past six months, Hagler Bailly has examined numerous issues associated with restructuring the Philippine electricity industry and privatizing the Philippine National Power Corporation (NAPOCOR). We have examined alternative approaches and discussed these broadly throughout the industry. Everyone with whom we have worked, without exception, expressed a conviction that the industry can be improved through restructuring, more competition, and increased private sector participation. However, the views on the nature, extent and pace of change believed to be desirable and feasible range broadly among industry participants. Differences in priorities, business and political philosophy, organizational affiliation, and geographical orientation all contribute to the industry participants' diverse outlooks.

The Philippine electricity industry is achieving a degree of privatization in generation, primarily through NAPOCOR's independent power producer program.[1] The distribution sector is also largely private. However, the nature and extent of private sector participation and the degree of competition in the industry are substantially restricted and will remain so in the absence of structural reform and operational improvements.

Under the current structure, distribution utilities are not responsible for planning and procuring either their power requirements or demand-side resources. As a result, important elements of competition (many and diverse buyers of generation, and demand-side versus supply-side resource acquisition) are missing. Many distribution utilities also lack the financial resources and management expertise to plan and develop power resources in the absence of an industry structure that facilitates collaboration to address these limitations. The fragmentation of many of the distribution utilities, in cooperative and non-cooperative systems alike, is also problematic. A degree of consolidation will be required to make many of these

[1] Privatization can take several forms: 1) contracts with the private sector, e.g., purchasing power from private generators, 2) sale of operating assets, and 3) sale of stock ownership in commercial operating entities. NAPOCOR's "privatization" activities to date fall into the first category, and involve government financial and contract performance guarantees as well as operating control. That is, the government is still very much in the power business; the basic responsibility for power supply remains with the government. While this report supports the continuation of these privatization activities by NAPOCOR for an interim transition period, its primary focus is on privatization through the sale of assets and sale of ownership interests in commercial entities. Moreover, it is the goal of the recommendations in this report that this privatization be carried out under terms and conditions that reduce or eliminate the government's financial exposure and guarantees and responsibility for power supply, as well as reducing the demands of the power sector on the government budget.

systems viable in a competitive market where they must be effective at planning and resource acquisition. NAPOCOR also operates with certain subsidies and social objectives that become more problematic for a private enterprise. In addition, NAPOCOR has not operated under a regulatory environment that enables it to achieve the prices needed to consistently perform on a commercially viable basis and to attract capital to invest in expanding its facilities in an orderly and efficient way.

Structural reform, industry performance improvements, and distribution utility consolidation and financial strengthening are needed to address these and other problems in order to lay the groundwork for further privatization. The basic objective of restructuring and privatization is to establish an industry that will provide reliable electricity supply to all sectors of the economy at the lowest practical costs.

This report presents a restructuring and privatization approach, along with a supporting work plan, that addresses this objective and the industry's problems, and takes into account the diversity of perspectives. While we were concerned with reasonable prospects for consensus and implementation, we also sought to develop an approach that would:

- promote efficient generation planning and investment
- promote efficient operation, maintenance and utilization of in-place generation facilities
- provide for efficient transmission expansion
- promote and reward efficient distribution system expansion and operation
- promote efficient end-use
- provide for efficient prices
- provide for effective electric industry government policy making
- provide competent and transparent regulation.

Many industry structural approaches and privatization strategies are available. These are differentiated by several factors, most notably the extent to which the industry is vertically integrated and centralized; the degree of competition that is established and promoted, particularly in generation and customer sales; the balance of the regulatory scheme between promoting and rewarding effective competition and regulating profits and monopoly power; and the extent of private sector investment, ownership and control. In this regard, the approach recommended here:

- stresses the restructuring of the industry into unbundled and focused entities that are manageable while efficient in size and scope, with decision making closer to the customer and clear performance accountability

- seeks to introduce viable competition wherever possible, in particular in generation planning and investment, dispatch of generation (and efficiency of generation maintenance and operations), sales services to end-users, and demand-side management as a resource option.

- promotes private sector investment, ownership and control wherever practical, in particular in the generation sector

- provides planning, operations and policy coordination to optimize for efficient scale and "one system" economies

- requires transparency in regulation and establishes efficiency as the key principle underlying prices throughout the industry.

By optimizing private investment, more of the nation's funds as well as official development assistance can be invested in other infrastructure and priority projects that are needed to promote economic, job and income growth. In this respect, it is also important to note that the goal is to move the electric industry beyond the current privatization scheme, where private investment continues to rely on government guarantees, to private investment that stands on the creditworthiness of private entities, including the distribution utilities. This places added emphasis on consolidating and strengthening the distribution utilities so that they can enter into viable and financeable commercial transactions for power supplies.

In developing an action plan to support the restructuring and privatization approach, we were cognizant that we are dealing with a process that will extend for several years. In this respect, the action plan incorporates developmental stages that enable immediate action while providing opportunities for reassessment and possible adjustment along the way.

The recommended approach and work plan provide a framework for developing a consensus for action.

CHAPTER 2
CURRENT INDUSTRY STRUCTURE AND POWER SITUATION

Before the recommended long-term structure for the Philippine electricity industry is discussed in Chapter 3, this chapter reviews the current structure and power situation, the important differences across regions, and the challenges that these factors present in terms of supporting privatization and promoting a competitive market.

2.1 OVERVIEW OF PHILIPPINES ELECTRICITY INDUSTRY STRUCTURE

Figure 2.1 depicts the current overall structure of the Philippine electricity industry. Across the top, the industry is functionally divided into Generation, Transmission, Distribution, and Customers (end-users). Distribution is further broken down into the "lines" function (the provision of the electric lines and related facilities needed to deliver power from the transmission grid to the customer's point of use) and the "sales" function (this involves various services to the customer, including sales of kWh and demand-side management (DSM)). A further functional unbundling, which is discussed later and referred to as "Poolco," is the separation of the operation of the grid and dispatch of generation from other transmission activities such as planning and construction. The bottom of the figure indicates whether the functional area is either potentially competitive or a natural monopoly where meaningful competition is not feasible. Note from the figure that the generation and distribution sales functions are potentially competitive, depending on the industry structure approach pursued, whereas transmission, Poolco and the "lines" function of distribution are natural monopolies.[1]

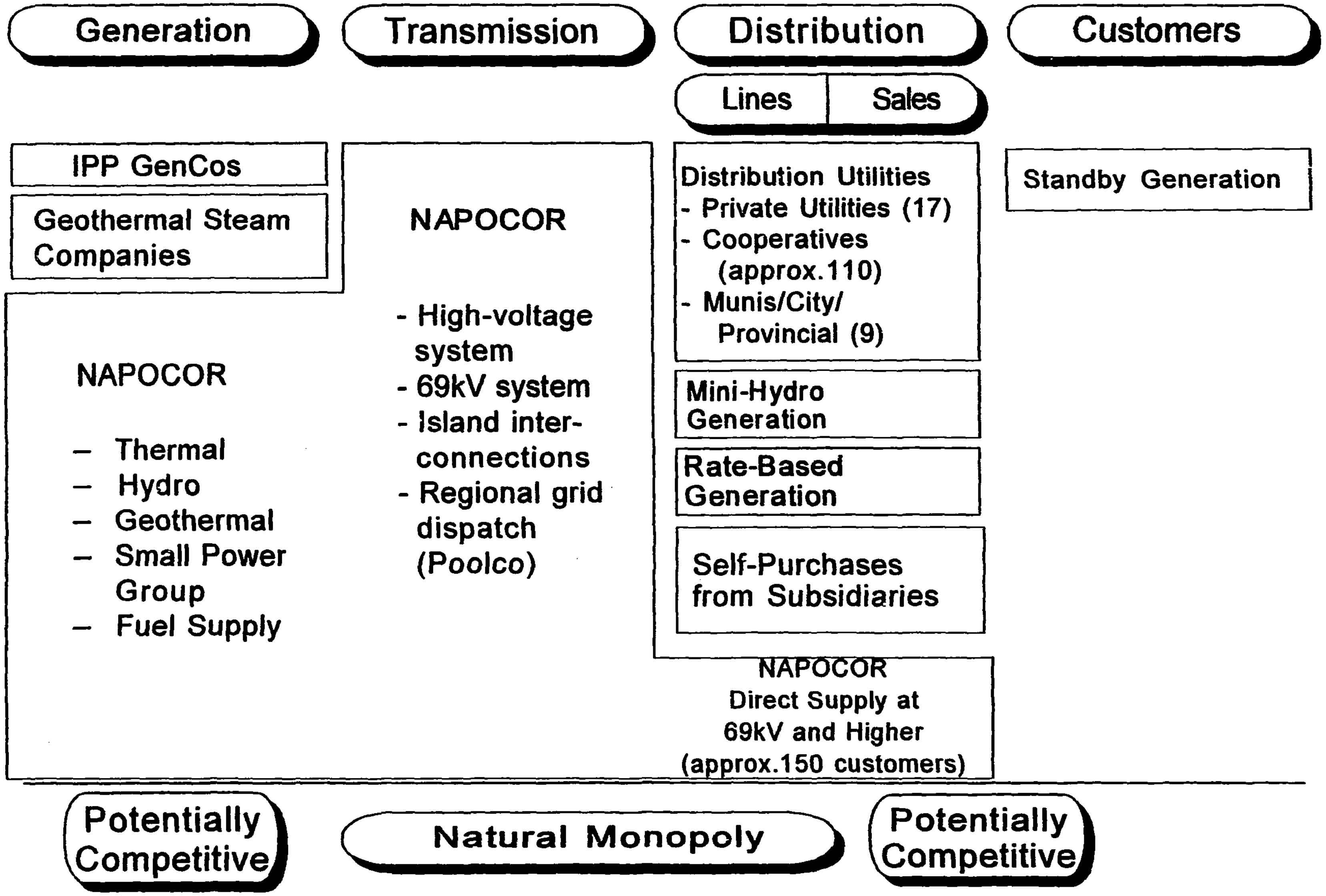
From Figure 2.1, the following features of the industry's structure are noted:

- Under the current structure, power generation is largely controlled by NAPOCOR. NAPOCOR owns and operates power generation facilities associated with geothermal power projects (for practical purposes, all hydro

[1] We acknowledge the work of the New Zealand Privatization Task Force in developing this presentation format. Some industry participants in the Philippines questioned the classification of transmission as a "natural monopoly." Their concern stems from the lack of a workable transmission access and pricing policy, leading these participants to conclude that they can build and operate new transmission at a lower cost than they can obtain on existing facilities owned by NAPOCOR. However, the proper solution to this situation is efficient and fair transmission access and pricing, not the construction and operation of duplicative facilities.

Figure 2.1

Current Structure of the Philippines Electricity Industry



power facilities and the vast majority of thermal capacity). It is also responsible for the electrification of small island grids that are not interconnected with the primary grids (Small Power Utilities Group). NAPOCOR is also in the fuel supply business, providing fuel to its own generation units and to independent power producers (IPPs).

- Independent power producer generating companies (IPP GenCos) currently supplement NAPOCOR-owned generation. These IPP GenCos are new participants in the industry, having been established through the recent "fast track" program to meet generation shortfalls. Their entire output is sold solely to NAPOCOR though long-term power purchase agreements.

- Two geothermal resource development firms produce steam for NAPOCOR's geothermal power plants: Philippine Geothermal Inc. (PGI), a local subsidiary of the U.S.-based Union Oil of California, and Energy Development Corporation (EDC), a subsidiary of Philippine National Oil Company (PNOC). These firms develop and/or operate the steam producing facilities, while NAPOCOR builds and operates the related generation units. The development of a geothermal resource is accomplished through bilateral negotiations and contractual agreements between NAPOCOR, which purchases the steam, and PGI or EDC, which produces the steam. These contracts embody minimum offtake provisions to guarantee revenues to the geothermal resource developer.

- NAPOCOR may play two roles in hydro development. First, it might develop, own and independently operate the entire hydroelectric project if the project is devoted solely to power production. Or, NAPOCOR might work in conjunction with other Republic of the Philippines (RP) agencies, most notably the National Irrigation Administration, when other uses such as irrigation, flood control and drinking water are also involved. For these latter projects, NAPOCOR will own and operate the power generation components.

- NAPOCOR also performs transmission and dispatch functions. NAPOCOR plans, develops and operates the high-voltage backbone transmission system (115 kV to 500 kV). It also owns and operates a significant amount of 69 kV facilities, especially those serving rural electric cooperatives. The 69 kV facilities may serve either a distribution or transmission function. NAPOCOR plans, develops and operates the island interconnections. It also performs all grid dispatch activities. As a result, power generation, transmission and dispatch are vertically integrated under NAPOCOR.

- Distribution entities are quite numerous, with 17 private distribution companies, approximately 110 rural electric cooperatives and 9 municipal, city and provincial distribution systems. There is great disparity in the size, financial strength and performance of these utilities. All of the distribution utilities depend upon NAPOCOR for their power supplies, although some have a minimal amount of supplemental generation from mini-hydro and small thermal units. The largest utility, Manila Electric Company (Meralco), is more than 20 times the size of the next-largest utility.

- NAPOCOR also provides distribution services to approximately 150 customers that are directly connected to the grid at 69 kV or higher. For these customers, NAPOCOR is a fully vertically integrated utility, providing bundled generation, transmission and distribution services under a tariff that also bundles the prices for these services.

- Customers own some generation. This is mostly stand-by units to deal with brown-outs, and the amount is not known with any degree of confidence. Some customers have shown interest in developing cogeneration facilities, and project development is expected in the future.

- NAPOCOR is responsible for developing transmission and generation on a national basis. It prepares the annual Power Development Program (PDP) that documents how the nation's power requirements are to be supplied. Other utilities or private companies seeking to engage in generation must secure permission and accreditation from the Department of Energy (DOE), and in effect, also from NAPOCOR. There is a growing interest among utilities to purchase directly from IPPs, and the largest distribution utility, Meralco, has signed contracts with IPPs for 1,100 MW.

The next section reviews in greater detail the power situation and industry structure on each of the principal grids -- Luzon, Visayas and Mindanao -- corresponding to the major geographical regions of the Philippines. Table 2.1 presents an overview of the grids; each grid is discussed in more detail below. Appendix A contains NAPOCOR's Philippine Power System Development Map depicting the geography of each grid and the location of principal generation and transmission facilities.

2.2 LUZON GRID

2.2.1 Power Situation

In contrast with the other grids, the Luzon grid is relatively large, reflecting the population density and associated economic activity of metro-Manila. The peak demand on the Luzon grid was 3,250 MW in 1992, and in the April 1993 PDP, NAPOCOR projected that peak demand would exceed 5,000 MW for this grid by 1997.

Table 2.1
Overview of Philippine Regional Grids (1992)

	Luzon		Mindanao		Visayas	
Peak Demand (MW)	3,250		723		472	
Load Factor (%)	70.0		51.7		60.3	
Gross Energy Generation by Energy Source	GWh	%	GWh	%	GWh	%
Oil Based	11,927	59.8	806	25.7	703	28.2
Hydro	1,925	9.7	2,333	74.3	12	0.5
Geothermal	4,426	22.2	---	---	1,266	50.8
Coal	1,658	8.3	---	---	511	20.5
Total	19,936	100.0	3,139	100.0	2,492	100.0
No. of NAPOCOR Customers						
Utilities	67		31		33	
Industries	62		20		12	
Other	34		9		10	
Percent of NAPOCOR GWh Grid Sales						
Utilities	91.3		63.2		81.0	
Industries	8.2		36.8		18.9	
Other	0.5		---		0.1	
Percent of Total NAPOCOR GWh Sales	78.5		12.5		8.9	

The diversity of generation is also much greater on the Luzon grid, as shown in Table 2.2. The table indicates that NAPOCOR owns and operates over 4,000 MW of capacity, but that almost 2,000 MW of this capacity is scheduled for retirement within the next 10 years. NAPOCOR also has 1,308 MW currently under contract from the private sector. Some of NAPOCOR's capacity that is now scheduled for retirement might also be offered to the private sector for rebuilding.

Table 2.2
Luzon Grid - Existing Generating Plants

Plant Name	Fuel Type	Capacity (MW)	Commission Date (or Rehabilitation)	Location	Retirement Date
NAPOCOR					
Batann 2	Oil	150	1977	Batann	
Batann GT	Oil	124	1977	Batann	
Calaca 1	Coal	300	1984	Batangas	
Makban	Geothermal	330	1979-1984	Laguna	
Tiwi	Geothermal	330	1979-1982	Albay	
Ambukalo	Hydro	75	1956-1957	Benguet	
Binga	Hydro	100	1960	Benguet	
Caliraya	Hydro	32	1945	Laguna	
Kalayaan	Hydro	300	1982	Laguna	
Angat	Hydro	244	1967	Bulacan	
Pantabangan	Hydro	112		Nueva Eciji	
Magat	Hydro	360		Isabela	
Manila 1-2	Oil	200	1985	Manila	1995
Sucat 1	Oil	150	1986/1989	Paranaque	1999
Sucat 2	Oil	300	1972/1990	Paranaque	2000
Malaya 2	Oil	350	1979/1986	Rizal	1996
Malaya 1	Oil	300	1975/1987	Rizal	1997
Bataan1	Oil	75	1972	Bataan	2002
Sucat 3	Oil	200	1971/1993	Paranaque	2003
Sucat 4	Oil	200	1970/1994	Paranaque	2004
Subtotal		4,123			
PRIVATE SECTOR					
Hopewell GT 1-3	Oil	210	1991	Metro Manila	
Subic Diesel I (Enron)	Diesel	28	1992	Zambales	
Clark Diesel	Diesel	50	1993	Pampangan	
Hopewell GT 4	Oil	100	1993	Metro Manila	
Bataan CC Block A	Oil	300	1993-1994	Bataan	
Enron I	Diesel	105	1993	Batangas	
Bataan CC Block B	Diesel	300	1993-1994	Bataan	
FPPC	Diesel	215	1994	La Union	
Subtotal		1,308			
GRAND TOTAL		5,440			

NAPOCOR's total capacity on the Luzon grid, including IPP contracts, is almost 5,500 MW. However, the actual dependable operating capacity of its plants is well below nameplate rating, and substantial brownouts were experienced in 1993. When NAPOCOR's "fast track" private sector projects come on line, it estimates that the Luzon grid, although on a thin reserve margin, will experience a substantial reduction in brownouts in 1994 (approximately 40 hours). Excluding the generation units scheduled for retirement, the existing long-term NAPOCOR-owned capacity breaks down as follows:

Type	MW	Percent of Total
Oil	884	24
Diesel	698	19
Geothermal	660	18
Hydro	1,123	31
Coal	300	8
Total	3,665	100

The generation situation in Luzon will change materially over the next several years. Table 2.3 presents NAPOCOR's most recent capacity expansion plan. Although this plan is optimistic, both in schedules and amounts, if a substantial portion of it is implemented, generation on the Luzon grid will grow significantly.

2.2.2 Luzon Distribution Structure

The structure of the electricity industry in Luzon, in particular the role of NAPOCOR, is essentially as described above for the overall industry. However, the structure of the distribution sector in Luzon is worth noting. Two features are especially important. One, Meralco has a dominant market share on the Luzon grid. Two, the remainder of the distribution industry is fragmented, and many of these smaller utilities are also financially and managerially weak.

Table 2.3
Scheduled Capacity Additions to Luzon Grid

	Geothermal		Hydro		Coal		Oil/Diesel		Baseload (1)
Year	Project	MW	Project	MW	Project	MW	Project	MW	Total MW
1994	Bac-Man	166					Diesel	215	
	Mak-ban	96							
	Maibarara	11							
1995					Calaca II	300	Diesel	100	
1996					Hopewell	350			
					Hopewell II	350			
					Masinloc I	300			
1997	Del Gallego	120			Masinloc II	300			
1998					Sual I	500	GT	200	
1999			Kalayan 3/4	300	Sual II	500	GT	100	600
			Nalataya B	45					
2000							CC	300	1,800
2001							CC	600	900
							GT	200	
2002			Bakun A/B	45			CC	600	1,200
							GT	100	
2003							GT	100	2,100
2004			Amburayan	93			CC	300	1,500
			Pasil B	20					
2005			San Rogue	390			CC	300	
			Kanan B1	112			GT	100	1,500
			Pasil C	22					
Total		393		1027		2600		3215	9,600
Percent		2.3		6.1		15.4		19.1	57.0%

(1) Fuel type not determined for these units.

Table 2.4 summarizes the distribution structure of the Luzon grid. A complete listing of NAPOCOR's customers on the Luzon grid can be found in Appendix B. From the table, several observations can be made:

Table 2.4
Distribution Structure of Luzon Grid (1992)

	Number of Customers	Sales (GWh)	Load (MW)	Load Factor	Percent of Total Sales: Luzon Grid	Percent of Total Sales: Total NAPOCOR
Utilities:						
Meralco	1	14,447	2,591	63.6	77.8	61.1
Other Private	9	544	124	50.2	2.9	2.3
Cooperatives	51	1,817	481	43.1	9.8	7.7
Other Utilities	6	144	39	42.2	0.8	0.6
Subtotal	67	16,972	3,235	----	91.3	71.8
Directly Connected Customers:						
Top 10 Industrials	10	921	176	49.7	5.0	3.9
Other Industrials	52	595	164	41.4	3.2	2.5
Other Direct Connects	34	103	32	36.2	0.6	0.4
Subtotal	96	1,619	372	----	8.7	6.8
Total	**163**	**18,590**	**3,607**	**58.8**	**100.0**	**78.6**

Note: Loads and load factors are based on a summation of non-coincident peak demands.

- Meralco holds a dominant share of the Luzon market, with 78 percent of total sales in 1992. Note also that Meralco represents 64 percent of NAPOCOR's total sales to all regional grids.

- The other 66 distribution utilities in Luzon are small. There are six utilities with peak demands in the 25 to 30 MW range. All but one of the other utilities have peak demands of less than 20 MW.

- Meralco's load factor of almost 64 percent is the highest of the Philippine utilities. The other utilities generally have poor load factors.

- Although NAPOCOR had 96 directly connected Luzon customers in 1992, they represented only 8.7 percent of NAPOCOR's Luzon sales. Many of these customers are small. The 10 largest directly connected industrials made up well over half of the directly connected sales. Seventy of the customers were less than 5 MW; 56 were below 2 MW. As a class, the load factors for these customers are not necessarily any more attractive than those of the utilities.

Nevertheless, industrial loads are a significant factor on the Luzon grid. Meralco's 1992 industrial sales represented 36.1 percent of its total sales and were the largest Meralco customer group followed by commercial sales (31.1 percent).

Under the restructuring recommendations, large customers are important in two respects. One, they may represent large DSM potential, which will play a more prominent role in the utilities' resource plans. This is particularly true of Meralco, which relative to many other utilities, has more financial strength and management and technical expertise to develop DSM resources. Second, in the longer term, opening up competition for the "sales" service may make some of these large customers attractive to other service providers that can package and tailor services to meet specific customer requirements. This would result in retail wheeling revenues eventually becoming an important source of income for Meralco.

2.3 MINDANAO GRID

2.3.1 Power Situation

NAPOCOR's 1993 Power Development Program projected significant growth on the Mindanao grid. This projection, along with projections by the Asian Development Bank (ADB) and World Bank (WB) provided by NAPOCOR, are summarized in Table 2.5. It shows that NAPOCOR's forecasts are significantly higher than those of ADB and WB.

The existing generation capacity in Mindanao is shown below, and the Power Development Program is presented in Table 2.6.

Plant	Installed Capacity (MW)
Hydro	943.7
Land-based diesel	252.1
Power barges (diesel)	222.6
Total	1,418.4

Table 2.5
Mindanao Grid
System Energy Sales Forecast Comparison

	Actual	Forecast				
	1992	1993	1994	1995	1996	1997
Sales (GWh)						
NAPOCOR	4,160	4,842	5,381	6,027	6,841	7,832
ADB	4,160	4,360	4,513	4,865	5,282	5,764
WB	4,160	4,382	5,039	5,644	6,096	6,583
Growth Rate (%)						
NAPOCOR		17.6	10.0	12.0	13.5	14.5
ADB		4.8	3.5	7.8	8.6	9.1
WB		5.3	15.0	12.0	8.0	8.0

Table 2.6
Mindanao Grid Power Development Program
1994 - 2005

Year	Month	Plant Additions	Installed Capacity (MW)
1994	Mar	BIG Diesel PB #1 NASIPIT	100
	Jun	Augus 1 HEP Unit 1	40
	Aug	BIG Diesel PB #2 MACO	100
1995	Jun	Land-based Diesel (Gen Santos)	50
	Aug	Mindanao Geothermal	40
1996	Jan	Mindanao Geo I	80
	Jan	Land-based diesel (Zambo City)	50
1997	Jan	Leyte-Mindanao Interconnection	
1998	Jan	Tran-River Small Hydro	30
1999	Jan	Mindanao coal-fired project (BOT)	200
2001	Jan	AGUS III HEP	224
2004	Jan	Bulanog-Batang	150
		Pulangi V	300
2005	Jan	Small hydro 1	27
	Jan	Small hydro 2	40

Under these power demand and supply projections, the generation mix in Mindanao is projected as follows:

	Generation Mix Percentages		
	1994	1998	2005
Hydro	81	53	54
Oil	19	38	30
Geothermal	9	10	10
Coal	--	--	6

There are major uncertainties surrounding the power sales outlook in Mindanao. Perhaps most critically, the projected rates of local growth have not materialized. The current sales target for 1994 is 4,120 GWh, which is below actual sales for 1992. Contributing to this lack of growth are the competitive problems of the ferro-alloy industries in Mindanao. NAPOCOR estimates that over 100 MW of ferro-alloy industrial load has been idled because of world competition. Although lower power rates might help the industries become more competitive, it is likely that major investment in process improvement and productivity enhancement will be necessary to restore these firms' strength on the market. It is not clear whether such investment will be forthcoming.

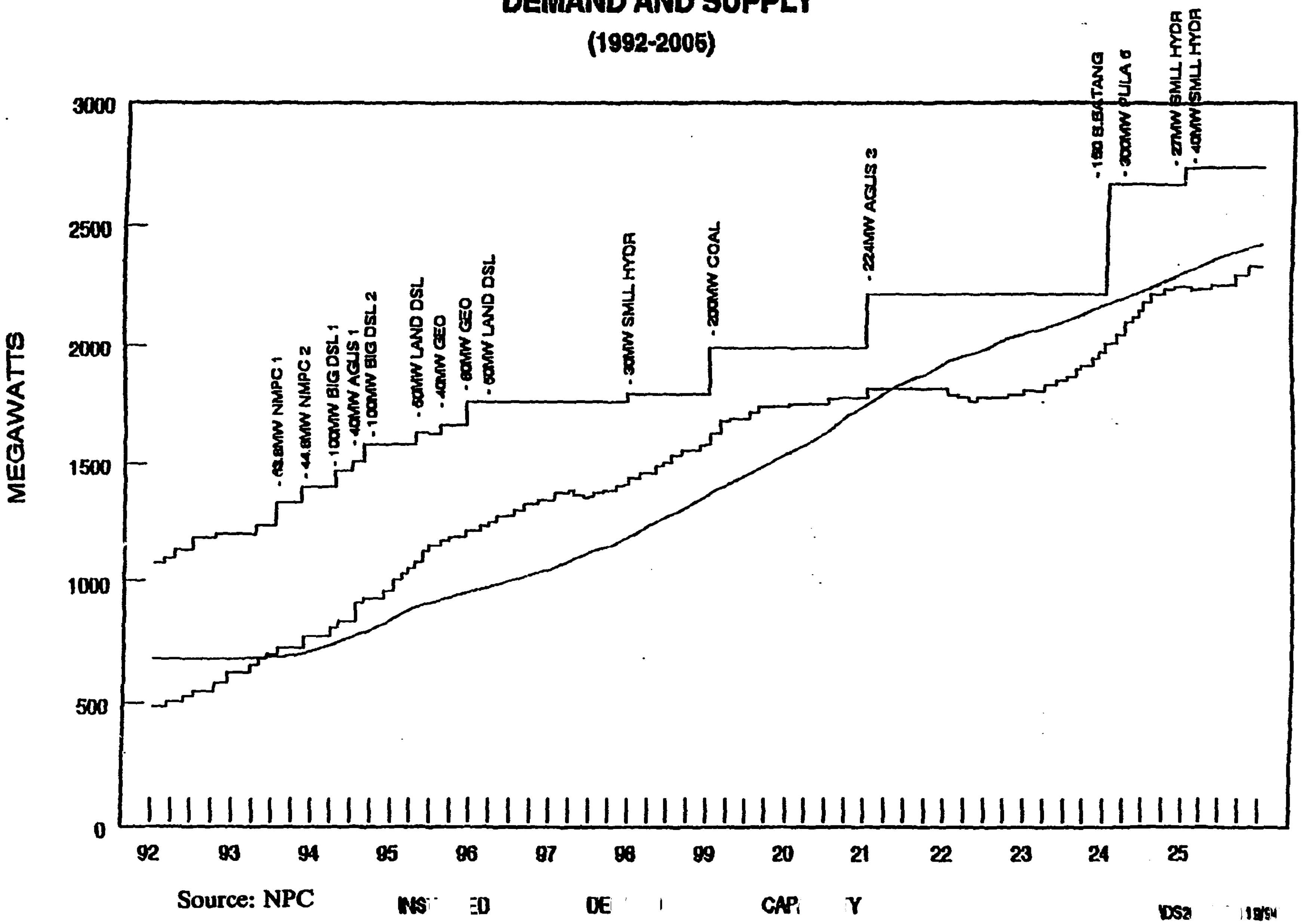
There is also a great deal of uncertainty in the Mindanao Power Development Program. The PDP relies heavily on developing indigenous hydro, coal and geothermal resources. Each of these is problematic to develop. Long and uncertain lead times, social and environmental obstacles, and large up-front capital requirements characterize these resources, particularly hydro and geothermal. None of the Mindanao power development projects is currently on schedule. In particular, the geothermal project is more likely to be completed in 1997 or later rather than by its 1995 scheduled date. The coal plant is rather speculative at this time; none of the recent IPP bids came in at an acceptable price. And the Pulangi hydroelectric project faces difficult social and political hurdles. Adding to the complexity of power supply planning is the fact that actual generation capability is very substantially below installed capacity (see Figure 2.2). And although the hydro conditions are currently very favorable, the region is vulnerable to another extended dry period.

2.3.2 Mindanao Distribution Structure

In contrast with the Luzon grid, there is more balance in the distribution structure in Mindanao. Table 2.7 summarizes the distribution structure of the Mindanao grid. A complete listing of NAPOCOR's customers on the Mindanao grid can be found in Appendix C. From the table, the following observations can be made:

FIGURE 2.2

DEMAND AND SUPPLY
(1992-2005)



Source: NPC

Table 2.7
Distribution Structure of Mindanao Grid (1992)

	Number of Customers	Sales (GWh)	Load (MW)	Load Factor	Percent of Total GWh	
					Mindanao Grid	NPC System
Utilities						
CEPALCO	1	316	73	49.3	10.7	1.3
DLPCO	1	308	74	47.4	10.4	1.3
SOCOTECO II	1	157	34	52.5	5.3	0.7
ZAMCELCO	1	145	31	52.5	4.9	0.6
MORESCO I	1	110	34	36.8	3.7	0.5
ILPI	1	106	22	54.7	3.6	0.5
Other Private	1	42	10	48.9	1.4	0.2
Other Cooperatives	24	680	193	41.2	23.1	2.9
Sub-total	31	1,864	471		63.2	8.0
Directly Connected						
Top 10 Industrials	10	980	226	49.5	33.2	4.1
Other Industrials	10	105	26	46.2	3.6	0.4
Other Direct Connects	9	2			0.1	
Sub-total	29	1,087	252		36.8	4.5
TOTAL	60	2,951	723	46.6	100.0	12.5

- The utilities on Mindanao are small. The distribution utility sector is composed of 31 utilities. Of these, two are approximately 73 MW peak load in size and three are approximately 30 MW peak load. The size then drops to around 20 MW or less.

- On the other hand, the directly connected customer business is substantial and represented almost 37 percent of grid sales in 1992 (and almost 5 percent of NAPOCOR's total kWh sales). Virtually all of this business is concentrated in the largest ten directly connected industrial customers.

- Serving these large customers would be risky for even the largest utilities in Mindanao. As discussed above, this business is volatile and risky, with over 100 MW currently idled due to world competition.

2.4 VISAYAS GRID

2.4.1 Power Situation

There is not yet a single interconnected grid for the Visayas; rather, there are four. This will soon reduce to three upon the completion of the Cebu-Panay interconnection. NAPOCOR plans call for the eventual interconnection of the existing transmission networks into a single Visayas grid as well as interconnection with Luzon and Mindanao.

Table 2.8 presents the sales forecast prepared by NAPOCOR for the Visayas grid. This table shows that the 1993 PDP projected growth from 2,241 GWh in 1992 to 4,510 GWh in 1997, an annual compound growth of 15 percent. In its 1994 budgeting, NAPOCOR revised these sales projections, also shown in the table, to 3,763 in 1997, or an 11 percent annual compound growth. Under either of these sales forecasts, however, the individual grids in the Visayas are small and will remain so for a considerably long period. The relatively small size of the Visayas grids is illustrated in Table 2.9, which shows the current and projected peak loads of each grid. Note that in 1992, the combined peak was 472 MW.

Table 2.8
Visayas Grid Sales Forecast (GWh)

	Actual	Forecast				
	1992	1993	1994	1995	1996	1997
1993 PDP						
Cebu	948	1,178	1,319	1,504	1,731	2,008
Negros-Panay	775	856	1,152	1,290	1,445	1,642
Leyte-Samar	463	538	577	621	683	752
Bohol	55	67	77	86	97	108
TOTAL	2,241	2,639	3,125	3,501	3,956	4,510
September 1993 Revision						
Cebu	948	1,026	1,115	1,386	1,642	1,815
Negros-Panay	775	818	971	1,018	1,128	1,226
Leyte-Samar	463	516	540	596	612	639
Bohol	55	56	66	71	78	83
TOTAL	2,241	2,416	2,692	3,071	3,460	3,763

Before the Palinpinon II units begin to come on-line in 1994, the installed capacity in the Visayas breaks down as follows:

Plant	Installed Capacity (MW)
Hydro	2
Geothermal	228
Land-based diesel/gas turbine	224
Power barges	62
Coal	105
Total	621

Table 2.9
Peak Demands on Visayas Grids (MW)

Grid	1992 Actual	1997 Estimate Based on NAPOCOR Revised Sales Forecast
Cebu	183	350
Negros-Panay	179	283
Leyte-Samar	93	128
Bohol	17	26
TOTAL	472	787

The PDP for the Visayas is presented in Table 2.10. The PDP essentially relies on the development of the geothermal resources on Leyte and Negros to meet the electricity requirements of the Visayas, supplemented late in the period with hydroelectric development in Panay. Bohol continues to depend on diesel generation until it becomes interconnected.

2.4.2 Visayas Distribution Structure

The basic structure of the industry in the Visayas is like that in Luzon and Mindanao, i.e., NAPOCOR is the primary generator and power supplier and owns and operates transmission. Like Mindanao, the Visayas grids show a greater balance of distribution utilities than does Luzon.

Table 2.11 summarizes the distribution structure of the Visayas grids. A complete listing of NAPOCOR's customers on these grids can be found in Appendix D. From the table, the following observations can be made:

- Utilities are both numerous and small. With the exception of VECO (130 MW peak) in Cebu, CENECO (42 MW peak) in Negros, and PECO (33 MW peak) in Panay, none of the remaining 30 utilities exceeds 30 MW in peak load. In addition, the load factor for many of the smaller utilities is poor.

- With the exception of two large industrial customers (PASAR and PHILPHOS) connected to NAPOCOR on the Leyte-Samar grid, directly connected customers are not significant.

Table 2.10
Visayas Grid Power Development Program
1994 - 2005

Year	Month	Plant Additions	Capacity (MW)
1994	Jan	Palinpinon II Unit 1 Geothermal	20
	June	Palinpinon II Unit 2 Geothermal	20
	Dec	Palinpinon II Unit 3 Geothermal	20
	Dec	Palinpinon II Unit 4 Geothermal	20
	Aug	Mambacal Geothermal	40
1996	Jan	Leyte-Cebu Interconnection	
	Jan	Tongonan Geothermal	200
	Jan	Bohol diesel (or barge)	11
	Jan	Mambacal Geothermal	60
1997	Jan	Tongonan Geothermal	400
	Jan	Mambacal Geothermal	60
	Jan	Bohol diesel	6
1998	Jan	Tongonan Geothermal	275
	Jan	Bohol diesel	11
1999	Jan	Bohol diesel	6
	Jan	Timbahan Hydroelectric	35
2000	Jan	Bohol diesel	6
2001	Jan	Cebu-Bohol Interconnection	
2005	Jan	Villa Siga Hydroelectric	29

Table 2.11
Distribution Structure of Visayas Grids

	Bohol	Cebu	Leyte-Samar	Negros	Panay
Sales (GWh) Utilities	51	835	170	419	328
Industrials	3	2	292	25	--
Load (MW) Utilities	15	172	60	89	75
Industrials	2	--	51	4	--
No. of Utilities	3	5	11	6	8
Industrials	3	7	2	6	--
Load Factor Utilities	39.5	55.4	32.2	53.8	49.9
Industrials	24.7	57.8	65.1	45.6	--

2.5 IMPLICATIONS FOR RESTRUCTURING AND PRIVATIZATION

What are the implications and problems of the current industry structure and power situation with respect to privatizing NAPOCOR and establishing a competitive, responsive and efficient industry? This question can be answered by addressing two issues. First, how well does the current industry structure facilitate the entry of private sector participants into generation and encourage competition as a force to drive efficient investment and operations? Second, what are the special factors and limitations specific to each grid that must be explicitly accounted for in a restructuring and privatization approach?

2.5.1 Industry Entry and Competition

Several conditions affect the nature and degree of competition and participation in the industry:

- number of sellers of generation
- number of buyers of generation
- ease of bilateral trades between buyers and sellers

- ease of entry into generation
- access to transmission
- transparency of pricing
- unbundling of core functions
- existence of level playing fields among participants in each core function
- availability of planning information
- access to the end-user (through retail wheeling).

These are reviewed below:

- Generation is the most capital-intensive part of the business and accounts for a majority of costs. An industry structure that accommodates and encourages a diverse number of developers and sellers of generation to vie for the business of a diverse buying market, at both the wholesale and retail levels, will help promote the development and introduction of efficient technologies and stimulate generation operational efficiency. The current Philippine electric industry structure cannot be so characterized. NAPOCOR is essentially the only seller of generation in the wholesale market. The emerging IPP GenCo industry is in effect controlled by NAPOCOR, which buys its entire output and resells this output to the distribution utilities. Transactions between non-NAPOCOR generators and distribution utilities take the form of the distributor buying from its own subsidiaries, but this practice is currently very limited. Although there are many buyers from NAPOCOR, NAPOCOR is the only buyer of generation from IPPs.

- Ease of bilateral trades between buyers and sellers of generation promotes entry into generation, efficient use of in-place generation capacity and flexible planning by generation buyers. Under the current structure, bilateral trades between sellers and buyers of generation are difficult. DOE is now revising certain rules to partially address this problem. However, in the absence of a comprehensive approach to facilitating bilateral trades, these revised rules are likely to fall short of establishing an effective trading market.

- It is desirable that the industry structure promote and accommodate the entry of participants into generation, based on their technical expertise, financial resources or other competitive advantages. Under the current structure, entry into the generation market is primarily through bidding on solicitations issued by NAPOCOR. Of note, these solicitations typically specify fuel type, unit size, technology and other generation design parameters, as opposed to allowing prospective developers make these determinations (although NAPOCOR may be moving toward more generic solicitations). Other entries into generation are made by exception only, and NAPOCOR, by virtue of its control of transmission, is a key party in affecting the feasibility of any generation project proposed by another party.

- Access to transmission under fair, cost-based, predictable terms is essential to promoting an efficient market between generation buyers and sellers. Access to transmission is gained only by negotiation with NAPOCOR. There are no formal rights of access, established transmission pricing practices or principles, or transmission tariffs.

- Accurate (transparent) prices are also essential to the efficient functioning of the industry. Prices set the benchmarks against which generation participants compete for buyers. Prices also drive investment and usage decisions by end-users. To the extent that prices are inaccurate due to subsidies or are not unbundled to reflect the cost of the underlying services (particularly power supply versus transmission), inefficient competitive advantages and disadvantages are created, and inefficient investment decisions are promoted. Prices throughout the industry for generation, transmission, and distribution are not transparent. There are many subsidies embodied in rates, particularly those of NAPOCOR, but at the distribution level as well. Rates are bundled (i.e., they do not separate generation from transmission, demand from energy, or distribution lines service from sales service).

- It follows from the above that unbundling of the control of core functions, most notably transmission from generation, becomes an important feature of industry structure if an efficient market between generation buyers and sellers is to be established. In the current structure, core functions are bundled. NAPOCOR owns and controls generation and transmission. Generation is not unbundled, either horizontally or vertically. Prices for generation and transmission, and in the case of directly connected customers, distribution services, are also bundled.

- Finally, an industry structure that allows reasonable competition at the retail level, particularly for large customers having the financial, technical and managerial resources to procure their own power requirements, adds yet another avenue for competition and efficiency. There is currently no retail wheeling. The only form of retail competition is direct connection to NAPOCOR (i.e., circumventing the distribution utility), and there are no clear rules applicable to such connections.

For all of the above reasons, a level playing field is precluded in the generation and transmission functions among NAPOCOR, distribution utilities, and potential generators. NAPOCOR also holds a fuel cost advantage by virtue of RP taxation policy, giving it a further competitive advantage over any potential independent producer. Although reasonable planning information is available, it is only useful in promoting competition where the factors enumerated above are in place.

In summary, the current structure does not promote and accommodate diverse entry and participation in the industry or meet the requirements for establishing competition. As a result, it effectively bars the efficiency, responsiveness and customer service that diversity and competition might promise. The recommended restructuring and privatization approach attempts to address each of these barriers to efficiency and competition.

2.5.2 Special Factors and Limitations

Several special factors and limitations also emerge from a review of the current structure of the industry. These considerations must be carefully accounted for in restructuring and privatization. These are discussed below.

1. ***Natural Geographical Divisions***. There are natural geographical divisions of the generation business and island transmission grids.

    - Mindanao, at the southern end of the Philippines, is currently isolated from the other islands in terms of transmission interconnection. The interconnection, planned for 1997 or later, will apparently help provide reliability for all grids and might be used to move hydropower north. Mindanao is rich in indigenous hydroelectric and geothermal resources, and indigenous coal might also play a role in the future power supply. These resources, however, may be relatively expensive to develop and have long lead times and large front-end capital requirements. Therefore, a concerted effort by the utilities will be required to efficiently develop these resources in a timely manner, and strong financial backing will be required.

    - The islands in the Visayas are inextricably bound together for electricity resource development. None of the islands can efficiently and independently develop and consume its indigenous geothermal and hydroelectric resources. Efficient development and utilization calls for exporting part of these resources to other islands in the Visayas. To do so requires that the island interconnections be established, further binding the Visayas together for power supply planning and system operations. Each of the individual Visayas grids is arguably too small to independently develop efficient-size alternative generation during the planning horizon. Again, a portion of any efficient-sized plant would have to be shared among the islands. Close collaboration in planning, investment and operations is therefore called for. Assuming that the economics that underlie the PDP and the reliance on geothermal, hydroelectric and interconnections are sound, then the utilities in the Visayas should plan and operate on a one-system basis as much as practical.

- The Luzon grid is an integrated system with a diversity of indigenous and non-indigenous power sources. The power flows on the north/south backbone transmission system are bi-directional, and the future development of indigenous resources, new thermal plants and the Leyte-Luzon interchange should all be based on meeting the combined power needs of the Luzon utilities.

2. ***Need for unified transmission.*** Keeping the national transmission system intact as an integrated grid has compelling appeal. Much remains to be accomplished in the transmission plan (in particular, the interconnection projects) before the transmission system is truly a unified grid. A national perspective is needed to plan and develop the island interconnections, and this will be greatly facilitated with transmission remaining an integrated organization. Operational requirements, the role that the transmission organization can play in meeting national objectives, and the effect of transmission on the competitiveness of the industry all argue for the retention of transmission as a nationally integrated system.

3. ***Small Scale of Mindanao and Visayas.*** The Mindanao and Visayas electricity industries are relatively small and will remain so for the foreseeable future. This means that some of the key conditions for promoting diversity and establishing competition are less achievable, in particular, creating a generation market with a diversity of buyers and sellers. Moreover, the nature of the power development programs for these regions, which rely heavily on hydro and geothermal, does not easily promote or accommodate a diverse ownership of generation resources. The development of these resources also requires effective central planning and relatively strong financial organizations. For these reasons, a more centralized, and unavoidably monopolistic, industry structure may tend to remain in these regions, and utilities may have less options for power supply.

4. ***Efficient Scale of Luzon.*** In contrast, the Luzon grid's generation is large and diverse enough that there need be no residual generation monopoly after long-term restructuring and privatization are complete.

5. ***Meralco Dominance of Luzon Market.*** The fact that Meralco has an almost 80 percent market share on the Luzon grid poses a special concern in maintaining an independent and competitive generation market. Were Meralco to aggressively enter into generation, the company could eventually in effect control the generation market. The possibility of a distribution utility gaining a dominant control over the generation market is much more remote on the Visayas and Mindanao grids, where the largest distribution utility controls approximately 25 percent and 10 percent of these markets,

respectively. Proper regulatory policies and procedures must be in place to prevent generation market dominance.

6. ***Disparities in Distribution Utility Capabilities.*** There is great disparity in the size, financial strength and management performance of the distribution utilities. Some of the utilities will be able to perform very well in a decentralized and competitive market. Many of the smaller and weaker systems will be significantly challenged. For the distribution utilities to perform effectively and provide their customers with affordable electricity, a considerable amount of reform, including consolidation and financial strengthening, must occur in step with the generation, transmission and other restructuring initiatives. Importantly, for there to be meaningful competition in the generation sector, the distribution utilities must become credible and financeable buyers. The restructuring approach must provide the opportunity and incentives for this necessary reform of distribution utilities. Many utilities will not survive in their current autonomous state.

7. ***Critical Need for Power Supply Plan Execution.*** A very important factor on all grids is that significant expansion of generation and transmission is needed over the planning horizon. Restructuring and privatization must be orchestrated in such a way that attention and resources are not diverted from project execution. There must be enough financial strength on each grid to ensure that the needed capital is attracted to finance expansion. There must also be mechanisms for the RP to ensure that adequate power supplies will be available and to enable the RP to step in and deal with projected or actual shortages of power, should these situations arise.

8. ***Absence of DSM/IRP.*** Demand-side management and integrated resource planning are absent in the industry. To achieve their potential for competitiveness and efficiency, these practices should be fully incorporated into the new industry structure and utility operating and planning responsibilities. This is especially important on the Luzon grid in Meralco's service area and in the industrial sector in Mindanao.

9. ***Expanded Tasks for the Energy Regulatory Board and the Department of Energy.*** The final factor that will influence restructuring and privatization is the significantly expanded tasks of both the Energy Regulatory Board and DOE. In many respects, the planning and operation of the industry on all grids will become more complex. Regulatory oversight and policy development and implementation will become more important and perhaps more difficult. Both organizations will have to respond by increasing their technical and resource capabilities.

The recommended restructuring and privatization approach attempts to address these special factors and limitations. These recommendations are presented in Chapter 3.

CHAPTER 3
RECOMMENDED INDUSTRY STRUCTURE

What direction should the Philippine electricity industry take in terms of structure, ownership and competitive environment, and why? What are the phases the industry must work through to move toward a more efficient structure and privatization? And what are the key activities and issues associated with each phase? This chapter addresses these questions.

The task of privatizing NAPOCOR is particularly challenging. Not only are private sector involvement and ownership key issues, but equally important are the following factors:

- current concentration of market power
- lack of competition
- lack of a strong and assured power supply situation
- management and financial limitations among the various distribution utilities.

Privatizing NAPOCOR, but leaving the current industry structure essentially intact, would not best serve the needs of the Philippines or its electricity consumers. Restructuring must achieve a transition from the current "command and control" structure that operates under centralized decision making. The restructured industry would be a more balanced industry that is market sensitive, driven to efficiency by competitive market forces, and is operated by a robust complement of participants. Making this transition must focus on building the capabilities of all participants to accomplish privatization from a position of strength.

This chapter is organized as follows:

- Section 3.1 presents a brief review of the industry structure options considered for the Philippines. Chapter 4 contains a more detailed discussion of the structures that were not selected.

- Section 3.2 provides an overview of the recommended structure and privatization approach and the three phases involved in moving from the current situation to the desired structure.

- Section 3.3 describes in more detail the activities associated with Phase 1, which involves restructuring and strengthening the industry.

- Sections 3.4 and 3.5 discuss the decisions and issues that must be addressed in Phases 2 and 3, respectively. This discussion is more general because many of the decisions and actions taken during these later phases will depend on the results of Phase 1.

- Section 3.6 briefly reviews the responsiveness of the recommendations to the competitive problems and special factors and limitations discussed at the conclusion of Chapter 2.

3.1 INDUSTRY STRUCTURE OPTIONS

This study initially focused on defining an overall restructuring and privatization approach that would serve as a basis for developing a work plan. As part of our analysis of the industry and to facilitate the many discussions held, we established a framework for depicting structural approaches. This framework has two components:

1. A graphical depiction of structural alternatives showing a breakdown by function (i.e., generation, transmission, distribution, and customer-side activities) and whether each was potentially competitive or a natural monopoly. (This presentational format was described in Chapter 2 and illustrated in Figure 2.1.)

2. A continuum of industry structures classified according to degree of vertical integration, reliance on competition, and focus of regulation. This continuum was used in conjunction with the graphical depiction to assist in evaluating the alternatives with industry participants.

Part of the evaluation process was a two-day workshop, attended by representatives from the Department of Energy (DOE), NAPOCOR, the Energy Regulatory Board (ERB), the Philippine National Oil Company/Energy Development Corporation (EDC), Philippine Rural Electric Cooperative Association, Department of Finance, USAID, and cooperatives and private distribution companies. The workshop participants considered the basic alternatives, and the workshop's results were used to help shape this report's recommendations. Subsequently, discussions were held throughout the industry to review these alternatives and test and refine the recommended approach.[1]

3.1.1 Continuum of Industry Structure Approaches

Figure 3.1 depicts the range of options considered to restructure and privatize the Philippines electricity industry. These options are differentiated by three characteristics:

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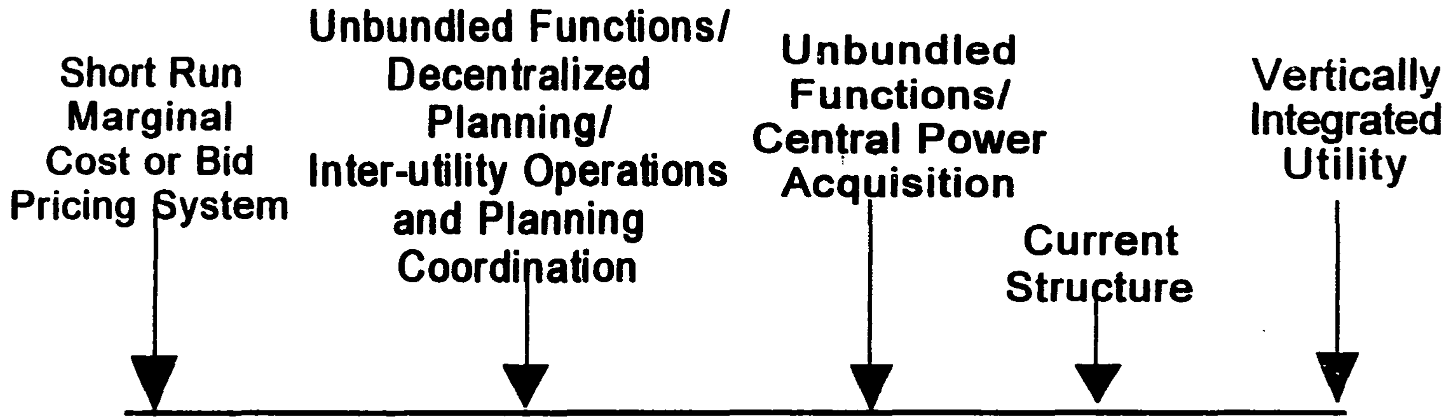
1 The proceedings of the workshop are included as Appendix E.

Figure 3.1
Continuum of Industry Structure Approaches



Degree of Vertical Integration	*Unbundled*	*Bundled*
Reliance on Competitive Forces	*High*	*Low*
Focus of Regulation	*Precluding monopoly power*	*Controlling monopoly power*

- ***The degree of vertical integration in the structure of the industry.*** Structural approaches falling on the left of the continuum exhibit a low degree of integration, where core functions (i.e., generation, transmission, dispatch, distribution lines, and distribution sales) are unbundled and performed by separate entities. In contrast, industry structures falling on the right of the continuum exhibit a high degree of vertical integration, where core functions are bundled in one vertically integrated firm.

- ***Reliance on competitive forces as a primary means of promoting efficient investment and operations.*** Industry structures falling on the left of the continuum rely much more on competition in the generation and sales functions. Structures on the right rely little on competition (the vertically integrated firm virtually precludes competition).

  There are three principal areas where competition is desirable:

  - in the generation sector to serve the power requirements of a diverse market
  - at the retail level to serve the power and other service requirements of end-users
  - between supply- and demand-side resources based on cost-effectiveness and relative risk.

  It is generally acknowledged that the other areas of the electricity business, notably transmission and the distribution "lines" service, are natural monopolies where meaningful competition is not possible or desirable.

- ***Focus of regulation.*** For the unbundled industry structures on the left of the continuum, regulation is more concerned with precluding monopoly power in generation and retail sales, and with maintaining a competitive balance among sector participants. For structures on the right, however, regulation of the vertically integrated utility is focused on controlling monopoly power through price and investment regulations and other regulatory interventions in utility management decisions.

3.1.2 Industry Structure Options

Five structural options are depicted on the continuum of Figure 3.1. The first two approaches listed below are fundamentally different approaches to industry structure. Between them are many variations. Three of these are depicted on the continuum.

- ***Short-Run Marginal Cost (SRMC) or Bid Pricing System.***[2] Anchoring the left of the continuum, this approach exhibits the most unbundling and reliance on competition. It served as the underlying basis for the restructuring and privatization of the electric sectors in England/Wales and Argentina. Under this option, a balanced, competitive generation market would be established to sell power to a central grid (based on a price bidding approach on the England/Wales grid, i.e., hourly blocks at specified prices, or on estimated short-run marginal generation costs on the Argentina grid). Generators would receive the marginal block price during any particular hour. Distribution companies and customers directly connected to the grid would also purchase from the grid at the hourly marginal prices, plus the cost of transmission and losses. Hedging contracts between the sellers to the grid and the buyers from the grid would emerge both to protect against price risks and to enable generators to obtain financing. This option was considered for the Luzon grid and, as discussed later in this chapter, it may have long-term applicability.

- ***Vertically Integrated Utility.*** Anchoring the right of the continuum is the most bundled approach, which relies heavily on cost-based price regulation and other regulatory intervention, and precludes competition. Perhaps the most representative of this industry structure approach is Electricite de France. It is also widely prevalent, although eroding, in the United States.

- ***Unbundled Functions/Decentralized Planning/Inter-Utility Operations Integration.*** This approach, as it would operate in the Philippines, is substantially reliant on competition and is the recommended long-term structure goal. It involves extensive unbundling and places power procurement responsibilities with the distributors, who are those most affected by such decisions. Through coordination agreements, however, it also allows the utilities to capture economies of scale possible with large utility systems and to achieve optimal use of in-place generation.

- ***Unbundled Functions/Central Power Acquisition.*** This approach also involves extensive unbundling, but relies on a central organization to procure and re-sell power to the distribution utilities. Because of the relatively small sizes of the Mindanao and Visayas grids, the industry in these regions may in many respects operate *de facto* under this structural approach. The Luzon grid may

[2] In the Restructuring and Privatization Workshop and the related materials, this approach was referred to as the "Market Clearing Pricing System." This final report uses the term "SRMC or Bid Pricing System" to more accurately reflect the distinguishing characteristics of this approach, which attempts to most closely approximate the classical economic pricing model where there is efficient competition and prices are based on short-run marginal costs.

also operate mostly under this structure during Phase 1, but during that time, should be moving at an accelerating pace to the recommended structure.

- ***Current Structure.*** This approach involves a high degree of bundling and a relatively low degree of reliance on competition. It was discussed in Chapter 2.

The four structural options that were rejected are discussed in more detail in Chapter 4, which includes a discussion of the evolution of the current structure and the applicability of privatizing NAPOCOR along the lines followed by Petron, the refining and marketing subsidiary of PNOC.

3.2 RECOMMENDED STRUCTURE AND PRIVATIZATION APPROACH

Figure 3.2 presents the recommended long-run structural direction for the industry and NAPOCOR: unbundled functions/decentralized planning/inter-utility operations and planning coordination. This structure would move the Philippine electricity industry substantially toward less integration and toward more unbundling and greater competition, with some shifting of regulatory focus toward preserving competitive generation and sales markets and away from controlling monopolies.

3.2.1 Key Features of the Recommended Approach

The key structural features of the recommended approach depicted in Figure 3.2 are:

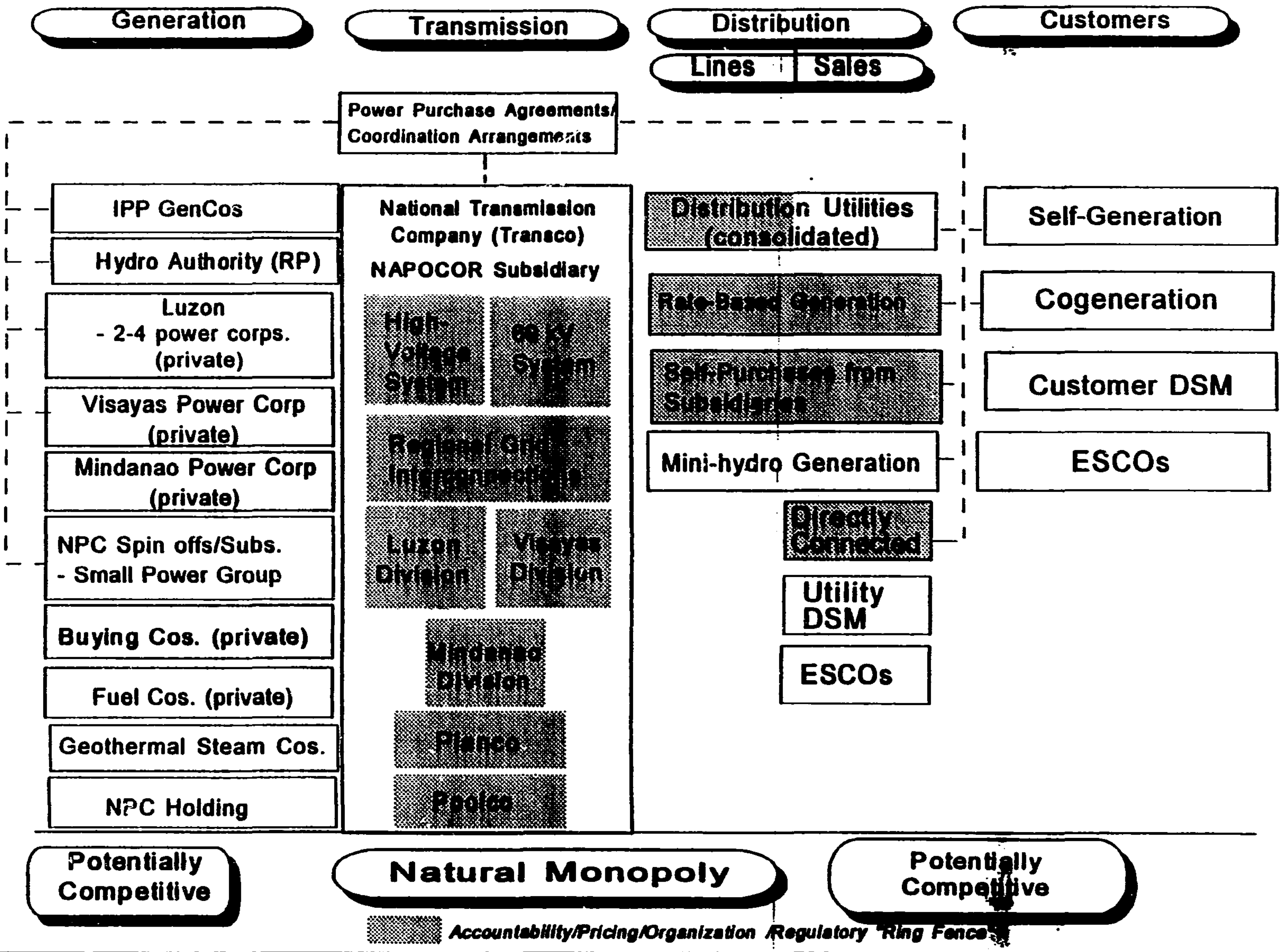
- ***Generation.*** NAPOCOR's generation is unbundled and privatized, both vertically (separated from transmission) and horizontally (regionally and intra-regionally).

  - IPP GenCos are a major factor in power supply, responding to the competitive bidding programs of utilities. Existing NAPOCOR generation is, to the extent practical, also spun off to IPP GenCos during Phase 1 of restructuring. Geothermal generation is also accomplished through independent power producers. NAPOCOR's IPP contracts are subsequently either devolved to the private regional power supply companies established in each region, i.e., Luzon, Visayas and Mindanao, or devolved directly to distribution utilities and large end-users.

  - NAPOCOR's hydroelectric properties (not including pumped storage and small hydro projects) are spun off to an independent Republic of the Philippines (RP)-owned authority, which is responsible for developing

Figure 3.2

Philippine Industry Structure Based on Unbundled Functions, Decentralized Planning and Inter-Utility Operations and Planning Coordination



new major hydro resources on a national basis.

- Organized initially as an autonomous subsidiary, the long-term structure and ownership of NAPOCOR's Luzon generation will be two to four private companies.

- NAPOCOR's remaining generation in Mindanao and Visayas is organized into separate subsidiaries and sold to private operators and investors.

- Other NAPOCOR activities (e.g., the Small Utilities Group) become subsidiaries and are privatized to the extent practical.

- New entrants ("buying companies") will emerge and will serve the role of combining the buying power of a group of utilities, or acting on behalf of a single utility, as agents to secure power supplies. For example, this report recommends a program through which utilities will consolidate and form generation or power acquisition companies to develop or acquire their power needs.

- NAPOCOR remains in the fuel supply business only if there are compelling strategic reasons and not because of taxation policy. Otherwise, NAPOCOR should withdraw to encourage the emergence of a full range of fuel supply providers. Geothermal steam is produced as currently practiced.

- As a result, National Power Company (NPC) Holding emerges as a streamlined and focused entity and in the long term, will be principally concerned with transmission and planning and operating coordination.[3]

▶ ***Transmission.*** The transmission system is established as an autonomous, independently managed subsidiary of NAPOCOR (Transco) and invests in transmission facilities, operates and maintains the high-voltage systems (and also sub-transmission systems, depending on the success of distribution utilities in consolidating and purchasing these facilities), and plans and implements interconnections. Other entities, including utilities and generators, may also develop and own transmission facilities that are consistent with the Transco

[3] The issue of increased overhead associated with multiple entities was raised during the study. However, small increases in the efficiency of generation investment and operation can quickly offset the overhead associated with managing the more numerous (and more focused and accountable) generation entities. Power sector restructuring has in some cases established each generating unit as a separate entity (Argentina).

grid expansion plan; owners of these private facilities must provide access to other users if capacity is available and would earn associated wheeling revenue. However, control and/or operation will reside with Transco. Grid prices are regionally differentiated. Grid operation and generation dispatch (Poolco) and long-term system reliability and capacity planning (Planco) are also performed by Transco. Transco will operate on a commercial basis and establish standard and non-discriminatory grid access policies and wheeling charges.

- ***Distribution.*** The responsibility to plan and provide for power supplies is placed with the distribution utilities, who must prepare integrated resource plans (IRPs) to identify the most cost-effective demand- or supply-side alternatives to meet customer requirements. In preparing IRPs, the utilities would first implement cost-effective DSM and then procure remaining generation requirements through a competitive procedure. Distribution utilities may engage in a mix of self-generation (rate-based), purchases from IPP GenCos (including subsidiaries), purchases from regional power supply companies, and DSM, all as justified by competitive procurement procedures. However, self-generation and purchases from subsidiaries will involve special regulatory oversight and approval.

- The "lines" function is ring fenced[4] to provide transparent retail prices, and retail wheeling tariffs are developed. Initially, only large, direct connected customers meeting threshold size requirements would be permitted to take wheeling service, but these restrictions would be relaxed over time, based on competitive conditions, to embrace a broader definition of consumers to increase competition, check the growth of generation and the market power of distribution utilities, and promote efficiency. NAPOCOR's directly connected customer business is also ring fenced to provide regulatory oversight. The buying companies may develop or acquire power supplies and, utilizing retail wheeling tariffs, compete with distribution utilities for sales to customers within the utilities' franchise areas.

- Although distribution utilities will be allowed to enter into self-generation or purchase directly from subsidiaries, these activities are tightly ring fenced, must be justified through IRP competitive procurement procedures, and are subject to close regulatory oversight.

[4] Ring fencing is a term that applies to alternatives to actual structural unbundling and separation of ownership. For example, ring fencing might be accomplished through establishing divisions or wholly-owned subsidiaries, implementing accounting practices that isolate functions, disaggregating prices for different services, or focusing regulations on key utility activities or decisions. See Section 4.1 for more discussion on ring fencing and its limitations.

- *DSM.* Both utility DSM and independent energy services companies (ESCOs) serving the utility's DSM program needs will grow in importance under the new structure, as integrated resource planning principles demonstrate the validity of demand-side options in the resource acquisition process.

- *Power Purchase Agreements.* Power purchase agreements between generators, distribution utilities and end-users (where retail wheeling is in practice) govern the basic terms of power supply arrangements.

- *Coordination.* An important requirement is the need for comprehensive planning and operations coordination arrangements covering all grid participants with respect to the system-wide "pooling" and coordinated reliability and generation dispatch services to be provided by Transco. An integration agreement entered into by all grid participants, a set of rules established by DOE, or a combination thereof, would be subject to regulatory oversight and would govern all grid use and transactions. It would cover such key areas as the capacity obligations of each utility, centralized unit commitment and economic dispatch (short-term spot market interchanges), coordinated maintenance scheduling, provisions for making short- and long-term capacity sales among utilities, coordinated planning, access rights to new generation, and pricing, billing and shared-savings procedures covering transactions between utilities.

- *Customers.* Customers may also initiate DSM and/or work with ESCOs to develop and sell their DSM potential.

The restructuring and privatization are accompanied and supported by several initiatives to rationalize pricing practices and eliminate subsidies, improve the financial operations and structure of distribution utilities, and build capabilities at ERB and DOE.

This long-run industry structure approach promotes efficiency and competition in several ways. It creates the most buyers and sellers of generation, and it puts in place an operating and integration framework that facilitates bilateral trades among these buyers and sellers. It also facilitates ease of entry into generation, and assures access to transmission. Functions are significantly unbundled, with level playing fields. Coordinated planning is an essential feature, thus making planning information readily available. Transparent pricing is also facilitated. The use of integrated resource planning introduces competition between supply- and demand-side resources and, by formally introducing DSM as a valuable option, opens up a new supply resource. These conditions act to promote efficient investment and end use. Through the coordination agreement and the associated price rules for unit commitment and dispatch, short-term operational efficiency is also promoted and rewarded.

3.2.2 Phases of Restructuring and Privatization

Reaching the long-run target industry structure will realistically take several years. The current dominance of NAPOCOR in the generation market, the financial and management constraints of the distribution utilities, and the other critical issues that the industry must remain focused on -- most notably, restoring the industry to a healthy power supply situation -- are key considerations that argue for a phased approach. A three-phase plan is recommended here. The objectives, estimated time frame, major activities, and expected results for each phase are summarized in Table 3.1. These phases are discussed in more detail in Sections 3.3 through 3.5.

Phase 1. This phase covers the next four to five years. With a special concerted effort, it might be feasible to shorten this period or to accelerate certain activities. However, this phase entails a logical sequence of steps that should be implemented in a comprehensive and quality manner. During this phase, the major focus will be on building the strength of the industry, restructuring the transmission and generation sectors, implementing inter-utility coordination arrangements, decentralizing planning and decision making, consolidating and building the financial and management capabilities of the distribution utilities, and easing the industry into more competitive markets requiring more sophisticated management and technical expertise. During this phase, NAPOCOR will also continue to work with the private sector to refurbish and operate its generation facilities. However, more critically, NAPOCOR will prepare to completely privatize its generation activities on each grid.

Phase 2. This phase covers a shorter but critical period during which a major evaluation and reassessment is conducted before embarking on the final structure and privatization initiatives on each grid. The sale of the power supply subsidiaries in Mindanao and Visayas is anticipated during this phase. The final generation privatization scheme in Luzon is not as straightforward and will require additional restructuring during Phase 2 before NAPOCOR's control over Luzon generation is transferred to the private sector.

Phase 3. During this four- to five-year phase, the industry will move into full implementation and operation under the decentralized, more competitive industry structure.

3.3 PHASE 1: STRENGTHENING, PREPARING, AND RESTRUCTURING THE INDUSTRY

This section describes the major actions to be undertaken during the next five years to implement the recommended industry structure and increase private sector participation. These actions deal with restructuring and strengthening the industry, and preparing it for operation under the new structure. They also lay the groundwork for a significant privatization of generation entities.

Table 3.1 Phases of Restructuring and Privatization

Phase 1: *Strengthen and restructure industry.*	**Phase 2:** *Evaluate results, implement further restructuring, and privatize.*	**Phase 3:** *Move into final structures and competitive environments.*
Time Frame: 1994-1998 (4-5 years)	**Time Frame:** 1998-1999 (2 years)	**Time Frame:** 1999-2004 (4 to 5 years)
Objectives: Strengthen all sectors and participants; restructure generation and transmission; establish coordination arrangements; consolidate distribution utilities and build capabilities; prepare industry for competition, privatization and decentralization.	**Objectives:** Evaluate results and industry performance; set final restructuring goals; adopt policies that accelerate participants' growth into new structure and responsibilities; privatize generation.	**Objectives:** Achieve full restructuring and decentralized planning; establish fully effective competition in generation, retail sales and resource planning; monitor competitiveness and industry performance.
Major Activities: ∘ Unbundle generation horizontally and vertically ∘ Unbundle transmission ∘ Unbundle hydroelectric to Hydro Authority ∘ Decentralize planning responsibility and adopt IRP ∘ Establish operations and planning coordination ∘ Rationalize pricing; introduce retail wheeling ∘ Consolidate and strengthen distribution utilities ∘ Promote private participation in generation (IPP bidding, ROMs, etc.) ∘ Strengthen regulatory and policy agencies ∘ Streamline NAPOCOR through additional subsidiaries, rationalize staffing levels	**Major Activities:** ∘ Conduct key evaluations (e.g., competitive conditions, success of IRP, coordination arrangements, distribution utility consolidation) ∘ Make structural goal adjustments; re-visit workability of alternative competitive models in Luzon; improve coordination arrangements ∘ Privatize generation: sell Mindanao and Visayas subsidiaries; select and implement final Luzon generation privatization plan ∘ Expand retail wheeling ∘ Implement policies to accelerate utilities' adaptation to new structure	**Major Activities:** ∘ Implement programs determined by assessing development of the industry under the restructuring and privatization initiatives ∘ Extend practices such as retail wheeling and retail sales competition ∘ Adopt incentive regulatory schemes proven to be effective ∘ Monitor competitiveness, market behavior and the potential for market dominance
Major Results: ∘ NPC power supply subsidiaries in Mindanao, Visayas and Luzon ∘ NPC national transmission subsidiary responsible for transmission, dispatch and operations coordination, and coordination of planning from national perspective ∘ RP Hydro Development Authority ∘ Integrated resource planning by all utilities ∘ Coordination arrangements to achieve efficient operations and planning ∘ Transparent, unbundled prices ∘ Increased private participation in generation ∘ Consolidated, strengthened and financially viable distribution utilities ∘ Improved regulatory and policy capabilities ∘ Streamlined NAPOCOR	**Major Results:** ∘ Adjustments to structural and ownership goals ∘ Adjustments to regulatory oversight and policy programs ∘ Improved IRP and coordinated utility planning ∘ Enhanced operations coordination; full economic dispatch on all grids ∘ Privatized generation ∘ Increased competition: generation, retail sales, supply-side vs. demand-side resources ∘ Improvements in structure and performance of distribution sector	**Major Results:** ∘ Full functioning of all utilities under decentralized decision making ∘ Competitive generation markets ∘ Competitive retail sales markets ∘ Widely practiced, state-of-the-art IRP ∘ Innovative regulatory incentive programs ∘ Efficient inter- and intra-grid coordinated operations ∘ Stable, efficient size and financially viable distribution utilities

3.3.1 Presidential Decree No. 40, Distribution Utility Responsibilities and IRP

An essential step in establishing a new framework is to repeal Presidential Decree No. 40 (PD 40) and amend NAPOCOR's corporate charter in recognition of the changes in the industry, the evolving role of NAPOCOR, and the greater part that all utilities will play in fostering a competitive, efficient generation market.

Under the provisions of PD 40, NAPOCOR has the responsibility for "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," with the "ultimate objective for NAPOCOR 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 NAPOCOR." PD 40 has been modified to facilitate the development of the independent power project (IPP) market and to enable others (including distribution utilities) to enter generation. However, these entrants are by exception only, and the responsibility for transmission and generation development and for preparing the annual national Power Development Program remain with NAPOCOR.

Developments in the past few years have modified the provisions of PD 40. Most notably, the construction, ownership and operation of generation facilities by private sector participants has been made possible through Executive Order No. 215 (EO 215) and the implementing rules, and NAPOCOR has relied heavily on independent power producers during the "fast track" period for new thermal capacity. Continued reliance on IPPs is NAPOCOR's official strategy, which might be extended to non-thermal plants and possibly to transmission facilities. Some of the larger distribution utilities are also seeking participation in generation development, ownership and operation.

The changes in generation development in the industry have spawned a number of regulatory and private sector activities to establish a workable framework to accommodate wider participation in the generation market. In particular, revisions are being made to the EO 215 implementing rules, Meralco and NAPOCOR are negotiating a long-term power purchase contract which is purported to be the model for all utilities, and Magellan Utilities Development Corporation is seeking a transmission wheeling agreement from NAPOCOR in conjunction with Meralco's generation development plans. The results of these activities are likely to be exceedingly complex, difficult to implement realistically in some cases, and have questionable effectiveness in establishing an efficient, workable framework to facilitate and guide the orderly development of the industry.

Legislation will be required to repeal PD 40. Upon repeal, the amendments introduced by EO 215 become ineffective. The charter of NAPOCOR, as set forth in RA 6395, would require amendment to make NAPOCOR's charter consistent with its new role and the roles of other entities in the industry. The principal thrust of repealing PD 40 and amending NAPOCOR's charter is summarized in Table 3.2.

Table 3.2
Effect of PD 40 Repealing Legislation and Amendment of Corporate Charter on Responsibilities

Area of Decision Making or Operation	Placement of Responsibility	
	Under PD 40	Under Repealing Legislation
Generation investment, operation, and wholesale power sales	NAPOCOR, except by explicit exception	Open entry into generation, subject to compliance with planning and operating coordination arrangements
Transmission investment and operation	NAPOCOR	Transco (or other entities by permission of DOE)
Planning	NAPOCOR	All utilities, including Transco, Poolco and Planco
Small island electrification	NAPOCOR	NAPOCOR subsidiary
Hydroelectric development	NAPOCOR, in coordination with other RP agencies	New RP Hydro Authority
Geothermal generation	NAPOCOR	Open entry into generation, subject to prohibition based on market share
Fuel Taxation	NAPOCOR exempt	All generators treated equally

In step with repealing PD 40 is establishing the responsibility of the distribution utilities to plan and provide for their power supply requirements. During Phase 1 there will be strong regional NAPOCOR-owned power supply companies that will stand ready to meet the power requirements of utilities pursuant to contractual arrangements. However, the obligation to serve and the associated obligation to secure power resources is now shifted to the distribution utilities. Successor owners of the regional power companies will not operate under an obligation to serve. Continued reliance on the regional power companies for total requirements may or may not be a viable long-term option for distribution utilities, nor may it be the most cost-effective.

In this respect, the manner in which the distribution utilities perform their planning and make resource acquisition decisions becomes of central importance. Under the restructured industry and pursuant to the requirements of the legislation that repeals PD 40, utilities will be required to implement integrated resource planning and competitive bidding procedures for resource acquisition. The methodologies for performing IRP and the protocols for conducting competitive resource acquisitions will be prescribed by DOE. Once IRP is in full practice, a utility must show that it has sought out and procured the most efficient resources.

The repealing legislation should address two additional issues. First, it should direct ERB to develop and implement policies that govern the conditions under which distribution utilities may participate in generation, either rate-based or by purchasing from an affiliated entity. For example, ERB can require that utility participation in generation be justified through a competitive procurement duly approved and supervised by ERB. Bid responses should be subject to an independent evaluation. ERB may adopt other cost benchmarks to ensure that utility's plans are cost-competitive. ERB could also institute other criteria or reporting requirements.

Second, the legislation should direct that the restructuring and privatization plan adopted upon the repeal of PD 40 incorporate appropriate measures to reasonably protect NAPOCOR from financial risk stemming from the defection of customers, potentially leaving NAPOCOR with excess generation assets. The approach currently under discussion of entering into long-term (10-year) contracts illustrates one way of addressing this concern. An alternative could be an indefinite term contract, but where each party may unilaterally reduce its commitment with proper notice (e.g., reducing commitments by up to 20 percent a year starting in year 10, as long as a five-year notice is given). Under either approach, however, procedures for engaging in short-term capacity trades should be established to enable utilities to better manage the uncertainties unavoidably associated with contracting long term for generation supplies (see Poolco discussion in Section 3.3.2).

3.3.2 Transmission

Establishing the national transmission company ("Transco") is a key structural change. Transmission is a natural monopoly activity that exerts great control over the workability of transactions between buyers and sellers of generation. Open access to transmission under fair and transparent prices is essential to establish a more competitive market between generation sellers and buyers, and is a key requirement in promoting more self-reliance on the part of the distribution utilities in power procurement.

It is recommended that Transco be a wholly-owned, commercial subsidiary of NAPOCOR. NAPOCOR's ownership of this subsidiary is made acceptable by the successful implementation of the other recommendations that call for NAPOCOR to privatize its generation assets and responsibilities. By accomplishing this, NAPOCOR avoids an inevitable conflict of interest when the owner of the transmission grid is also a competitor in the generation market. However, although the restructuring plan calls for the privatization of NAPOCOR's generation, NAPOCOR will nevertheless remain in the generation business for several years. In this regard, it is critical that the management of Transco be completely independent of the generation business. Transco should also have its own board that does not overlap with the board that deals with the generation business.

Ownership interest in Transco could be sold to private investors. However, given the central role that Transco will play in the industry, this should not necessarily be done. It is also not necessary or important that a decision on the sale of ownership interest in Transco be made at this time. Rather, the key action is to establish an independent, well-managed, commercial company that operates under efficient regulation and that is relatively free of political interference in its operations and profitability. In this respect, it is critical that regulations applied to Transco establish levels of profitability and cash flow sufficient to maintain stand-alone commercial viability. ERB has considerable latitude in this regard. Under existing authorities, ERB may allow Transco to earn as high as a 12 percent return on rate base. If this is not sufficient to provide at least 20 percent of Transco's ongoing capital requirements for expansion and rehabilitation, then ERB should adopt price regulation based on cash requirements similar to the policy for cooperatives. If ERB requires furthering enabling authority to regulate Transco's prices in this manner, this authority should be established through the restructuring and privatization implementing legislation.

Transco will have three principal functions: 1) construction and operation of transmission facilities, including island interconnections; 2) generation and transmission systems dispatch and the coordination of grid operations (Poolco); and 3) coordination of system-wide planning, including the preparation of the national Power Development Program. Each of these functions is discussed below.

Facilities

Transco will plan, construct, finance and operate the high-voltage backbone system on a national basis. It may contract out various facets of its business, including the operation and maintenance of transmission facilities and construction, to carry out its responsibilities at least cost. Although Transco would develop and own most transmission facilities, other parties may also develop transmission. For example, Transco may enter into build-operate-transfer arrangements for the provision of new facilities or may adopt a system of capacity contract rights to promote private sector investment in new transmission. Moreover, distribution utilities may own transmission facilities, e.g., Meralco in the case of its currently owned transmission. However, existing and new transmission facilities developed by non-Transco parties must be fully integrated with the Transco grid, consistent with Transco's grid expansion plan, and made available to other users under standard wheeling tariffs approved by ERB.

Transco will coordinate its planning activities with those of the utilities, generators and the Hydro Authority through its Planco subsidiary. Transco will plan and implement interconnections. The costs of both current and future interconnections will be allocated to each grid based on the use by and benefits to each grid. Depending on the specific generation projects and uses that justify the interconnection, costs may be allocated to specific end-users or utilities.

Transco will provide open access to transmission under transparent and fair prices that are regulated by ERB. Prices will be disaggregated by voltage levels and any special allocations that may be warranted, for example, 69 kV facilities. Unless explicitly directed otherwise by DOE or legislative mandate, Transco will set transmission prices that are free from subsidies and are differentiated by region (i.e., Luzon, Visayas and Mindanao) to reflect differences in costs.

Although Transco will normally have no interest in generation, it should be given emergency authority, subject to DOE approval, to independently contract for generation in the case of projected or actual capacity shortages. The capacity would eventually be sold to utilities that are short on capacity, or costs would be recovered through direct charges to utilities. ERB would regulate the investment and sale of any emergency power acquisition by Transco. This authority would be invoked only in a case where the competitive market and utilities have in some manner failed to meet their obligations to serve the customers' loads.

Transco will also own and operate certain 69 kV facilities that serve a transmission function or that are otherwise deemed to be of strategic importance to the stability and purposes of the grid. However, many of these facilities will be eligible for transfer to consolidated distribution utilities pursuant to the program discussed in Section 3.3.6.

Poolco and Coordination Arrangements

Transco's Poolco operations will be the centerpiece of the industry operations. Poolco will work closely with Planco in generation and transmission system planning. It will also work in concert with DOE, ERB, generators and utilities in developing aspects of the necessary inter-utility coordination arrangements needed to plan and operate transmission and generation on a "one-system" basis as much as practical.

Among Poolco's key functions are the following:

- commitment of units to the grid based on least cost, reflecting system-wide economies and operating requirements
- economic dispatch on a real-time basis to meet energy requirements, provide operating reserves, and maintain voltage and system stability in a system-wide least-cost manner

- determination of methods of setting unit short-run costs for the purposes of dispatch

- coordination of maintenance scheduling on a system-wide basis to minimize costs and maintain system reliability

- in conjunction with DOE, setting of reliability criteria and required reserve levels, load shedding and emergency procedures

- administering other features of inter-utility coordination arrangements and tracking and billing associated transactions among utilities.

A key requirement of the restructured industry is to implement inter-utility operations coordination arrangements to integrate and facilitate efficient power planning, purchases and investment, and to govern the operations of generation facilities across all utilities. In order for utilities to assume an increasing role and responsibility in power supply planning, make investments in generation, enter into contracts with IPPs, and operate their portfolios efficiently, it is desirable to coordinate and integrate these decisions across all utilities to approach "one-system" operation and economies. Otherwise, individual utilities in pursuit of their own objectives will fail to capture these economies.

It is recommended that the restructuring process begin in Phase 1 with DOE issuing the necessary rules for coordination, working in concert with Poolco and the regional subsidiaries, Transco, IPPs and the distribution utilities. As the restructuring progresses, these DOE rules may be amended or replaced by a comprehensive integration agreement among the utilities with the approval of DOE. In this way, integration arrangements are begun in the proper policy direction, and lengthy and potentially contentious negotiations among utilities will not delay restructuring. The DOE rules can be modified as experience is gained.

Among the important provisions that should be developed as part of the coordination arrangements are the following:

- *Procedures for specifying the capacity obligations of each utility.* Setting capacity obligations entails the adoption of reliability standards and the reserve levels required to meet reliability goals. Associated with these procedures should be provisions for penalty payments from capacity-deficient utilities to those that meet their capacity obligations. Capacity obligations can be met through firm power purchases (e.g., from regional power corporations), unit power purchases (e.g., directly from IPPs), and self-generation.

- *Procedures for central unit commitment and economic dispatch.* All generation should be committed to the grid for dispatch by Poolco using cost minimization principles. Not only will Poolco minimize energy generation costs, but it will allocate spinning and other operating reserve requirements and local area voltage generation support in the most efficient manner across the grid. Central economic dispatch will result in short-term, or spot market, transactions among the utilities, depending on the relative efficiencies of generation units.

Procedures for costing and pricing these transactions and sharing the savings must be developed as part of the coordination arrangements. These will be key to promoting efficient maintenance, operation and utilization. The pricing rules can be structured to reward efficient units by allowing them to make energy and/or capacity sales at the avoided costs of other generators. Under this pricing scheme, the most efficient generators will earn additional revenues (which may be shared with the utilities that have otherwise contracted for the capacity of the unit, pursuant to the terms of the power purchase agreement). The least efficient generators or those with poor availability factors will not be able to take advantage of sales opportunities and will see their generation further curtailed by more efficient generation. These less efficient generators will in effect purchase generation from other generators at avoided costs.

Power purchase agreements between generators and utilities or end-users that incorporate minimum offtake provisions may reduce the potential for efficient dispatch, depending on the specific features of the offtake provisions. If the provision is designed more to guarantee a minimum amount of revenue to the generator, then economic dispatch may still be practiced. If, however, the provision reflects the generator's contractual obligations to take or pay for fuel supplies, economic dispatch may not always be possible. For the purposes of optimizing the use of the most efficient units, minimum offtake contracts tied to underlying fuel purchase obligations should be avoided to the extent practicable. It will be important that generators participate in the setting of Poolco's dispatch rules and procedures to properly account for the specific contracts and other limitations of each generating unit.

- *Procedures for scheduling maintenance.* As the diversity of generation ownership increases, so will the importance of coordinating the scheduled maintenance across organizational boundaries. Procedures should be established for accomplishing efficient maintenance scheduling and for compensating utilities that must schedule their maintenance at a time that is optimal for the system overall, but not optimal from their own system's perspective.

- *Procedures that facilitate short-term capacity sales among utilities.* As utilities become responsible and self-sufficient in providing for their own power requirements, an efficient market for trading capacity will become increasingly important. In particular, entering into long-term purchase contracts, e.g., with NAPOCOR, will expose the utilities to ongoing exposure to either capacity surpluses or shortages. Imbalances can be especially expected on a short-term, year-to-year basis. Some utilities will be short and some long, and a capacity trading market is needed to enable the utilities to balance their requirements. The integration arrangements can facilitate these transactions, in particular, short-term trades among utilities to meet capacity obligations and smooth the lumpiness of capacity additions.

- *Procedures that promote coordinated planning and investment.* A generating unit or power purchase that meets overall system plan requirements as documented in the national Power Development Program or the plan of an individual utility approved by DOE should be afforded the benefits possible through the coordination arrangement, including economy energy and operating reserves interchanges, scheduled maintenance energy and capacity services, unscheduled maintenance energy and capacity services, and access to the short-term trading market. The denial of these benefits to a generator that is not consistent with the national plan will serve as a significant incentive to comply with industry policies and plans.

The coordination arrangements would grow in sophistication as the utilities take on a larger role in planning their future and in taking responsibility for meeting their own power requirements.

In effect, the industry is currently working on implementing "first generation" integration arrangements through the following initiatives:

- negotiations to structure a long-term (10-year) power purchase agreement between NAPOCOR and Meralco, which also addresses such issues as joint operations committees and reserves and back-up power

- planned roll-out of a NAPOCOR/Meralco-type agreement to all other utilities, requiring the utilities to identify the power requirements they need from NAPOCOR and enter into a firm contract for these requirements

- transmission agreement negotiations between Magellan and NAPOCOR, which must address and resolve many complex transmission access and pricing issues

- revised rules to implement Executive Order No. 215 dealing with the entry of non-NAPOCOR entities into the generation market.

The longer-term problematic areas in the prospective NAPOCOR/Meralco agreement include the provision for setting capacity obligations, lack of specific provisions on how economic dispatch and economy interchange of energy and operating reserves will be accomplished, no formal provisions for coordinating maintenance and sharing the related costs, and no provisions for facilitating a capacity trading market. Although EO 215 implementing rules attempt to address some of these deficiencies, they lack any prescriptive solutions and rely heavily on bilateral negotiation among the affected utilities, with a regulatory fall back if negotiations fail.

The implementation of the Hagler Bailly operations integration recommendations will replace many of the prospective provisions of the above agreements. Transmission will be provided and priced by Transco, EO 215 will be repealed, and many of the provisions of the long-term contract would be affected. Under the integration arrangements recommended here, the requirement for utilities to enter into long-term contracts for their requirements from NAPOCOR may be retained. However, those contracts would then become more straightforward firm power supply contracts, and the many complexities of integrated planning and operation would be resolved via the industry-wide coordination arrangements. The long-term contracts would simply be a component of the utilities' supply portfolio or supply obligation, as the case may be, under the provisions of the broader coordination arrangement.

In constructing coordination arrangements, it will be instructive for NAPOCOR, DOE and representatives from the distribution utilities to study the contractual integration approaches and experiences of several power pools internationally.

Planco and Preparation of the National Power Development Program

The competitive environment proposed for the electricity industry requires fundamental changes in the current planning process, including the preparation of the industry-wide Power Development Programs (PDPs) for each region on a regular basis. The planning process should:

- incorporate all utilities, reflecting the expanded responsibilities of the distribution companies and a separate Transco and Hydro Authority
- eliminate NAPOCOR's responsibility for developing the national PDP
- make the planning process consistent with the inter-utility coordination arrangements.

Planning in the restructured industry will be more decentralized and in this respect, "national planning" will be more difficult. The national plan is primarily the aggregated plans of the utilities. These individual plans are made more efficient through the coordination arrangements (e.g., adoption of reserve requirements on a system-wide basis). The individual plans are also coordinated through the Transco subsidiaries Poolco and Planco to account for transmission constraints and optimal siting. Through Planco, the utility plans are aggregated and reviewed by DOE. DOE may issue policy directives or ask for revisions or further analysis as a basis for approval of the plans.

NAPOCOR will no longer be responsible for planning and providing for power requirements. In the restructured industry, Transco will be a separate entity that must be fully integrated into the planning function. All utilities will forecast their requirements and develop a plan for meeting these requirements. Planning for the development of geothermal projects, which must compete on an equal footing with other power supplies in the restructured industry, must also be coordinated. Similarly, planning for hydroelectric projects must be coordinated.

One of the key workplan tasks will be to develop the "first generation" planning procedures that will guide the industry during the early phase of restructuring. These procedures must be developed in concert with and reflect the progress of the other structural changes. At the broadest level, the planning procedures will involve several key steps:

1. Planning guidelines will be established for such areas as reliability policy and reserve level goals, transmission constraints and committed transmission projects, siting objectives or constraints, DOE policy goals and government incentives for fuel mix, policy directives on such matters as economic development, and committed generation projects that are available for participation.

   To facilitate siting, Planco will develop simulation models to optimize the siting of new generation. It will also develop costing studies for proposed new sites, and these studies will be a factor in the siting planning, decisions and approvals.

2. Individual utilities will develop supply and demand plans through IRP procedures approved by DOE.

3. Individual plans will be aggregated into grid-wide plans and evaluated by Planco and Poolco, including, for example, assessment of demand forecasts, adequacy of current and planned reserve levels, impact on transmission requirements, siting issues, or consistency with national policy objectives and directives.

4. Utilities or Transco and the Hydro Authority will revise the plans as required to reflect the results of the integrative evaluation.

5. Last, the plans will be integrated into a grid-wide plan by Planco and with approval by DOE. It is important to note that certain national objectives, e.g., development of indigenous geothermal resources, will be met by the IPPs' and utilities' plans, only if these projects are competitive relative to other resource options. It will be incumbent on DOE to address any economic or other development obstacles through appropriate policy initiatives, e.g., taxation or financial incentives, in order to level the playing field for geothermal, for example.

Throughout this process, the utilities will perform most of the planning and evaluation, but procedures, organizational responsibilities and checks will be established to ensure that the utilities meet these expanded responsibilities.

A key requirement to assist utilities in performing effective planning is procedures for facilitating their participation in new generation. With some notable exceptions, utilities in the Philippines are too small and under-capitalized to enter the generation market independently. However, through the coordination arrangements, this problem can be partly overcome. For example, the arrangements can specify that for generation units developed by any utility (including the regional power corporations) above a certain size or for IPP Genco contracts entered into by utilities, that other utilities may participate in these projects up to a specified amount, in small increments. In this way, all utilities can gain access to efficient-size generation. Participation in generation can be accomplished in two basic ways:

- Unit purchase contracts, with a lead utility sponsor for the project who lays off a portion to other utilities through these contracts. Of course, the strength of the utilities entering into the unit contracts will also influence the creditworthiness of the project. In this respect, small or financially weak utilities will find it advantageous to consolidate and also form collaborative organizations to make the purchase (see Section 3.6.6).

- Unit ownership interest, where several utilities or collaborative organizations co-sponsor a project and provide their combined financial muscle.

These two approaches can of course be combined for a project as well.

As part of these coordination arrangements, minimum financial and performance criteria can be set for utilities to qualify for entering into a unit purchase contract. This requirement could provide additional incentive for distribution utilities to consolidate and form strong collaborative approaches to power acquisition. Power purchase opportunities for utilities are market driven, i.e., the developer of the generation project must find the overall strength of each customer an acceptable risk. This is a dimension on which IPPs can also compete.

3.3.3 Generation

NAPOCOR's generation business will undergo significant restructuring during Phase 1. This restructuring is designed to create more diversity of generation, more focused entities, more accountability, and ultimately, more competition. Through these actions, an orderly transition can be orchestrated, wherein NAPOCOR can exit this business but leave behind a competitive, responsive generation sector.

The key steps during Phase 1 are the following:

1. *Establish RP Hydro Authority*

On all three grids, both NAPOCOR's existing hydroelectric projects and those currently under construction and development, as well as planning, operating and support staff, will be transferred to a new independent RP-owned authority that will develop and own major hydro resources. Pumped storage and small hydro projects would not be transferred to the Hydro Authority.

An alternative would be to leave the hydro plants with NAPOCOR as a separate subsidiary. However, there are no compelling advantages in retaining this function within NAPOCOR, and doing so would contradict the objective of removing NAPOCOR from the power generation sector.[3] The planning and operations coordination needed between Transco and Hydro as separate entities pose no insurmountable problems. Separation provides more focused organizations with more transparent operations and performance. Moreover, both business are complex, and there is no need to add further complexity by combining them.

A work plan activity will be to define the basis for allocating and pricing current and future hydroelectric generation. For example, current generation might be allocated according to a system of entitlements reflecting, among other things, past usage; and generation from future projects might be allocated on a contract subscription basis.

2. *Establish Regional Power Companies*

All remaining generation on each grid, including power purchase contracts, will be transferred during Phase 1 to regional power companies (RPCs) as NAPOCOR subsidiaries (Luzon Power, Mindanao Power, and Visayas Power). During this period, the RPCs would be charged with the responsibility of managing these resources to achieve maximum value.

As described more fully in Section 3.4, in Phase 2 the Visayas and Mindanao subsidiaries will be sold and the Luzon subsidiary will be further restructured by grouping and selling its assets to two or more operating companies. A substantial "operating interest" can be sold to an entity experienced in the power business that will bring needed capital and expertise; shares can also be sold to the general public. In this respect, the privatization of the regional subsidiaries would be similar to the sale of interest in Petron.

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[3] The privatization of major hydro projects is not particularly desirable and in most cases not practical because private developers either cannot successfully cope with the complex developmental issues involved and the close coordination required with other governmental agencies in multi-use water projects, or they have no relative advantage. This does not imply, however, that private sector participation of certain kinds should not be sought; e.g., operating contracts and BOTs for specific components of a project can attract private sector capital and expertise.

During Phase 1 NAPOCOR and the RPCs will continue to privatize existing generation through sale to IPPs, repair-operate-maintain (ROMs), and other contract arrangements. The supply portfolios of the RPCs are available to provide general service to current and future customers in much the same way as NAPOCOR does now. Moreover, these companies may continue to serve the needs of their customers by adding future generation to their portfolios and selling at average portfolio prices. Tariffs for service would be separately established by each regional utility based on its actual costs rather than reflecting system-wide costs (and various subsidies) as is the case today. Adjusting prices to this new regime may require a transition period to mitigate the effects of price increases necessary to accomplish this more autonomous organization.

Both utilities and directly connected customers will be able to purchase their entire power needs from the RPC portfolio. However, under the proposed plan, they will also be permitted to freely enter the market to purchase all or any portion of their electricity requirements from other suppliers by entering into bilateral contracts with independent power generators, power collaboratives, or any other entities that may emerge as competition evolves. These supply arrangements may take the form of power contracts that are unit-specific or involve purchases from a combination of plants arranged in custom-designed portfolios by private suppliers.

During Phase 1, customers who purchase a portion of their supply from others also may continue to buy from the RPCs under a partial requirements tariff. ERB would regulate all of these purchase and sales transactions, whether consummated under tariff rates or through contracts. Where effective competition emerges, this regulation should rely on market forces to set prices, reserving the more comprehensive "rate-of-return" approach to market segments where service is still under monopoly control.

An issue that has been consistently raised regarding Mindanao Power is the potential effect on rates. In the August 1993 report *Technical Consultancy to Determine Feasibility of Creating a Mindanao Power Corporation*, sponsored by NAPOCOR, it was estimated that Mindanao rates could increase as much as 30 percent if Mindanao were established as an autonomous subsidiary with rates fully reflective of costs. Although we have seen no similar formal study for the Visayas grid, several industry participants expressed the view that the rate effects would be similar. To derive at an estimate of the rate effect of eliminating subsidies, we obtained from NAPOCOR its estimates of 1998 rates for each grid, which were based on an overall return on rate base (RORB) for NAPOCOR's consolidated operations. These rates were adjusted to remove the subsidies by equalizing the RORB for each grid. The results of the analysis are summarized below:

Percent Change in NAPOCOR 1998 Rates with Elimination of Inter-Grid Subsidies				
	Luzon	Visayas	Mindanao	Small Utilities
At 8 percent RORB	(7)	17	6	102
At 12 percent RORB	(1)	25	18	119

The most severely affected is the Small Power Utilities Group, which would have rates approximately 20 percent higher than Visayas, 40 percent higher than Luzon, and almost double Mindanao rates. Many industry participants agreed that rate adjustments were both necessary and feasible on the primary grids, but that eliminating the small grid subsidies would be more problematic. Managing the phase-in of required rate adjustments will be important, while giving the regions more self-control over their future power supply and cost.

It is noted that the existence of these subsidies and the perceived difficulties associated with their elimination should not stand in the way of needed restructuring and reform. If somehow deemed to be in the national interest, the subsidies could be preserved, e.g., through the government transfer price for generation assets to the respective RPCs or through Transco pricing, although we do not support this approach.

3. Develop IPP GenCo Market

IPP GenCos will grow as key industry participants during Phase 1. With the exception of hydro, these entities should be in a position to capture a large share of new additions in the generation market. Driving the IPP industry will be the competitive procurement of the utilities, working either independently, in collaboration, or through the RPCs. In conjunction with ERB, DOE will monitor the IPP market for undue concentration of market share and the degree of actual competitiveness; it will be authorized to place conditions on qualifying bidders or limits on specific IPP GenCos to preserve or promote competition.

Geothermal generation is also accomplished through independent power producers. EDC and PGI can continue to develop steam resources. It is important to ensure that projects are developed at lowest cost, and this requires that other IPP GenCos be allowed to compete for the power generation component of geothermal projects on a level playing field.

An issue that arises under the new industry structure concerns the definition of "public utility." Under the new structure, an IPP may sell to more than one customer. These customers could be either end-users or distribution utilities, or both. It is important that as long as these sales are made as a result of competitive procurement under rules approved by DOE and that a determination is made by DOE that sufficient competition exists in the IPP market, then the IPPs are not subject to return-of-rate based regulation. In preparing the enabling legislation for restructuring and privatization, the effect of the CA146 Public Services Law on IPPs should be evaluated, and appropriate exceptions and authorities be embodied in the legislation to eliminate economic regulation as a barrier to IPP market development.

4. Levelize Fuel Costs

NAPOCOR is currently in the business of supplying fuel to IPPs as a result of the peculiarities of fuel taxation. Unless it can be demonstrated that there is a compelling strategic advantage to having NAPOCOR in the fuel supply business, which is doubtful, NAPOCOR should exit this business and let the IPPs provide their own fuel supplies. Fuel supply then becomes another dimension of competitive bidding and one of the means through which an IPP might establish a relative competitive advantage. The leveling of fuel costs can be accomplished by taxing NAPOCOR's fuel use. The revenues could be used to help replace subsidies (e.g., low income, rural service) that should be removed from rates as much as possible.

Using NAPOCOR's projection of 1998 rates, the elimination of NAPOCOR's fuel levy exemption would increase rates approximately 6 percent. Due to differences in fuel mix across grids, however, the rate effect would also differ, with Luzon prices rising slightly more than 6 percent, but Visayas and Mindanao rates rising approximately 3.5 percent. Again, the most severely affected would be the Small Utilities Group, which would see nearly an 18 percent rise in subsidized rates (8 percent in unsubsidized rates). Alternatively, all generators could be given the same exemption from fuel levies. Since NAPOCOR is currently supplying fuel to IPPs, extending the exemption to all generators will not have a material incremental affect on government tax revenues.

The sourcing of fuel is likely to become an issue of growing importance. In particular, we understand that local fuel producers cannot consistently produce fuel that meets the quality specifications of NAPOCOR, and that trace metals are especially problematic. As consistent fuel quality grows in importance as a requirement to meet tougher emissions standards, either more imports will be required or the local fuel producers will have to respond to the market requirements. Placing responsibility for fuel supply with the IPPs and other power generators creates a more diversified market to efficiently source fuels. It also shifts this unnecessary risk from NAPOCOR to parties who are just as qualified and able to shoulder it.

5. Establish Small Power Utilities Group as a Subsidiary

The activities of the Small Power Utilities Group, although important in the overall electric sector program, will become peripheral to NAPOCOR's role in the restructured industry. This

Group should be established as a separate subsidiary of NAPOCOR to give it more focused management attention and greater visibility in terms of its costs and performance.

The subsidiary will own current NAPOCOR assets associated with serving small island grids. On an island-by-island and system-by-system basis, the Small Utilities subsidiary should assess the requirements and prospects for bringing each system to commercial viability and where feasible, develop and implement a privatization plan to get as many of these systems as possible into the private sector and from underneath RP. The Small Utilities subsidiary should coordinate with the National Electrification Administration (NEA) to promote self-sufficiency among the small grids. For example, it might be feasible and desirable for NEA to convert some loans to grants to enable certain small grids to achieve self-sufficiency in operating costs.

Rate subsidies to small island grids should be systematically reduced so that as many as possible approach commercial viability, and residual subsidies should be sought through direct congressional appropriations.

As a result of these actions, NPC Holding emerges as a restructured and streamlined successor to NAPOCOR, with its principal long-term asset being the National Transmission Company. NPC Holding might also hold residual passive ownership interests in the privatized regional power companies and might have a more active interest in the Small Utilities Group, depending on the success of that subsidiary.

3.3.4 Energy Efficiency

One of the goals of restructuring is to introduce energy efficiency throughout the electricity industry. Many of these efficiency gains will be realized through the basic unbundling process, and through the introduction of competitive market forces, which will force all viable industry players to become more efficient. However, further efficiency gains are possible through the introduction of demand-side management and integrated resource planning. These two activities enhance conventional energy efficiency by managing the demand side of the electricity industry on a par with supply-side management, and by introducing the integrated planning of resource utilization to make least-cost resource acquisition decisions.

DSM is the planning, implementation, and evaluation of utility activities designed to encourage customers to modify their electricity consumption patterns, both with respect to the timing and level of electricity demand. It is typically achieved through energy efficiency (the reduction of kilowatt hours of energy consumption) or load management (the reduction of kilowatts of power demanded) or through shifting demand to off-peak times. DSM is founded on the principle that the energy saved can be just as cost-effective (or greater in many cases) as the energy generated, and therefore is a potential resource to be managed like generation capacity. For instance, if a utility manages to reduce electricity demand, it can postpone the construction of expensive new power plants and reduce fuel consumption, thus yielding economic and environmental benefits for the nation, the utility, and customers.

IRP is a process whereby utilities identify and acquire the most cost-effective electric resources necessary to meet their customers' needs. It refers to the acquisition of electric resources by utilities with the lowest possible cost to themselves, their customers, and society at large. Resources include traditional supply-side measures and also measures that provide efficiency improvements in generation, transmission, distribution, and end-use consumption. IRP is founded on the principle that costs and benefits must be evaluated for the industry as a whole (from generation to consumption) and must include external benefits to society such as environmental and social impacts.

Both DSM and IRP have widespread applications in the Philippine setting. It is important that these two energy efficiency mechanisms be incorporated into the restructuring plan, and that the country realize energy efficiency gains from restructuring. Both DSM and IRP measures, and a time-based implementation plan, are detailed in the companion USAID report: *Demand-Side Management Action Plan for the Philippines,* which was developed under the same technical assistance program. Under the recommended restructuring approach, utilities will acquire both supply-side and DSM resources as a result of IRP plans developed by the distribution companies.

As power sectors are restructured and privatized, an important issue is how to address the societal benefits provided by energy efficiency improvements. For example, utilities in the United States that are starting to confront deregulation and increased competition are calling into question the role of IRP and DSM management activities. Some utilities see no role for IRP and DSM, since the marketplace would automatically make resource decisions based on price competition that could not accommodate the rate impacts of DSM. Other utilities believe that IRP must still be practiced by electricity suppliers to maximize their profitability, and that DSM would be an important customer service for utilities seeking a competitive edge.

This issue has been addressed in the restructuring recommendations by requiring the distribution companies to take the responsibility for strategic planning and acquiring both supply-side and DSM resources. Cost-effective DSM will be implemented, and remaining power requirements will be procured through competitive schemes. This approach is consistent with the institutional policy development goals of the multilateral development banks that are seeking to ensure the sustainable development of the power sectors in developing countries.

3.3.5 Regulatory and Policy Jurisdiction and Institution Building

It will be important to clarify and delineate regulatory and policy jurisdiction and procedures under the restructured industry, including whether an agency's authority is advisory in nature or the agency has directive or implementation power. ERB and DOE are the primary regulatory and policy agencies most affected by the restructuring recommendations, and their recommended roles and responsibilities are summarized in Table 3.3. Where necessary, these should be codified through the appropriate combination of legislation and executive orders. To illustrate, Table 3.3 assigns to ERB all franchising (NEA currently grants franchises for rural cooperatives) and for resolving issues over assigning directly connected customers to the local distribution utility (this is currently handled by a joint DOE and Department of Trade and Industries task force).

Not only is a careful delineation of responsibility and authority required, but each institution must also build the capability to meet these requirements. This involves, on the part of each agency, a careful analysis of the workload that will evolve, the types of technical skills and other expertise that will be required, and other resource needs. These must then be matched against a critical evaluation of current organizational capability and capacity. The resulting gap must then become the focus of institution building programs to prepare the agency for its responsibilities under the restructured industry.[4]

A basic thrust of the restructuring and privatization recommendations is to increase competition and disperse monopolistic power wherever this is feasible. Where it is not feasible, ring fencing and regulation are employed. One hoped-for effect from these recommendations is that regulation can shift somewhat to monitoring competitive conditions and increase the focus on maintaining competition as opposed to controlling monopolies and regulating cost-based rates. In this respect, DOE should monitor the market dominance and behavior of utilities and generators on all grids, and be prepared to take corrective steps if market power starts to become too concentrated or anti-competitive.

In addition, other policies can be pursued to help maintain a competitive market.

First, by holding utilities to strict competitive procurement rules, self-dealing abuse can be mitigated. As standard practice under the restructured industry, utilities should file their competitive procurement procedures with DOE for approval. If the utility does not self-generate or self-bid, e.g., through subsidiaries, there would be a more limited regulatory oversight of the implementation of the procurement procedures. If the utility does bid, it would be subjected to close scrutiny by DOE for plan approval and by ERB for plan

[4] As an adjunct to this report, Hagler Bailly conducted a preliminary assessment of the optimum role of ERB in the restructured industry and identified certain actions the agency should take to prepare for its expanded responsibilities. This analysis is presented in Appendix C.

Table 3.3
Regulatory and Policy Roles and Responsibilities In the Restructured Industry

Regulatory/Policy Area	Responsible Lead Agency	New or Existing Role
UTILITY RATES		
▸ Wholesale and retail	ERB	Existing
▸ Rate-related efficiency standards	ERB	Part existing
▸ Transmission rates	ERB	New
▸ Backup rates		
-- Methodologies	DOE/ERB	New
-- Approval of utility rates	ERB	New
▸ Long-run marginal costing		
-- Methodologies	ERB	New
-- Rate setting	ERB	Part existing
▸ Avoided costs		
-- Methodologies	EIAB/DOE	New
-- Utility filings	ERB	New
▸ Incentive rates	ERB	New
UTILITY PROCUREMENT		
▸ Integrated resource planning (IRP)		
-- Rules and methodology	DOE	New
-- Review/approval of utility plans	DOE	New
-- Review/approval of Planco national plan	DOE	New
-- Oversee IRP implementation, prudence hearings	ERB	New
▸ demand-side management (DSM)		
-- Rules and incentives	DOE	New
-- Approval of utility plans	DOE	New
-- Oversee implementation/investment	ERB	New
▸ International competitive bidding (ICB)		
-- Certification of private generators	EIAB/DOE	Part existing
-- Rules and methodologies	EIAB/DOE	New
-- Approval of utility RFPs	EIAB/DOE	New
-- Monitoring of utility ICB implementation	EIAB/DOE	New
-- Approval of all PSGF contracts	ERB	Part existing
-- Oversee project implementation/milestones	DOE	Part existing
▸ Major investments--approve rate base increases	ERB	Existing
POWER CONTRACTS		
▸ Directly connected customers	ERB	New
▸ CPCN/franchise powers	ERB	Part existing
▸ Standard power purchase contracts	DOE	New
▸ Review of all PSGF contracts	ERB	Part existing
INTER-UTILITY COORDINATION		
▸ Planning procedures	DOE	New
▸ Operating procedures	DOE	New
▸ Pricing	ERB	New
ANTITRUST MONITORING		
▸ Competitive structure	DOE	New
▸ Pricing and anti-competitive behavior	ERB	New

implementation. Moreover, the utility would have to use independent evaluators in those cases where it is a bidder.

Second, it is recommended that retail wheeling be evaluated, initially for large consumers. To further mitigate distribution utility market control, an evaluation can be conducted of a more extensive and rapid unbundling of "distribution lines" service from "sales" service in a utility's service area to introduce competition and greater incentive for customer service and efficiency. Through this unbundling, the utility's sales activities, and hence the generation supplies that back up these sales, might be dispersed among a number of sales entities, and if successful, would check the utility's market power in generation (it would no longer have monopoly control over important segments of the retail market).

The recommended approach is to conduct this evaluation during the first two years of Phase 1, develop a final policy during the third year, and start implementation in the fourth year. This schedule allows time to correct key problems that would otherwise make retail wheeling less efficient, e.g., existing rate subsidies and structures and high system losses. Retail wheeling would apply initially to large users. The practice would be progressively extended to broader customer groups in the successive phases.

A detailed evaluation of this policy might initially focus on the Meralco service area. In this evaluation, a number of policy and implementation issues must be resolved. For example, it will be necessary to ensure that Meralco retains sufficient incentive to continue electrification and to expand the availability of its distribution lines service. Also, to the extent that power sales become governed by private contracts not subject to economic regulation, are there potential tax avoidance problems that must be resolved? With respect to the pricing of retail wheeling services, how should system technical losses and pilferage be accounted for? The satisfactory resolution of these and other implementation issues will be key to a successful retail wheeling program.

In this regard, the State of California has announced a retail wheeling policy for comment and scheduled implementation later in 1994. The first phase of the policy established retail wheeling for large customers, but would be extended to all customers eventually. Small commercial and residential customers would be afforded the option of retail wheeling and competitive power procurement by 2002. The Philippines can monitor this development for its applicability to the service areas of distribution utilities in the Philippines as a means to increase competition and to limit monopoly power. The enabling legislation for the recommended restructuring should establish and preserve DOE's authority to order distribution unbundling through retail wheeling.

Third, some industry observers, including officials at NAPOCOR, have expressed concern that a single IPP might become a dominant factor in generation. To the extent that this comes about by virtue of superior competitive bidding and performance, it is not necessarily undesirable. However, if it were to occur and were deemed to be undesirable, it could be easily addressed by appropriately specifying the criteria for qualified bidders. For example, a bidding program might disqualify a firm that has a market share on any grid that exceeds some threshold level.

3.3.6 Distribution Utility Industry Structure and Performance

Many of those interviewed for this study stressed the need for the strong implementation of fundamental regulatory reforms as an important element in addressing continuing problems of the industry. Although these issues often are not directly related to restructuring and privatization, the success of the overall industry vision and plan presented here is linked in important ways to successfully coping with these issues.

Many industry observers also stressed the necessity of bringing about reform among the distribution utilities. In particular, high losses, inefficient management, politicized operations, uneconomical size, and lack of financial strength and credibility were consistently enumerated as problems. From the standpoint of the objectives of this study, the critical issue is: *who is willing to take the commercial risks of developing and selling power to distribution utilities?* If a truly competitive generation market is to be developed, it will require that the distribution utilities, the primary market for generation, become qualified and financially sound buyers. As it now stands, few utilities are credible in this respect. This issue is not entirely under the control of the government or the utilities: the requirements of IPPs and financial institutions must be met. Establishing the needed credibility is a significant challenge, but one that must be met to promote the restructuring and privatization envisioned in this report's recommendations.

The adoption of this study's restructuring and privatization recommendations would normally motivate the inefficient utility to the extent that relative cost performance is a catalyst for change. However, the effectiveness of industry peer benchmarking is doubtful, and it is not sufficient to leave distribution utility reform solely to the workings of market forces. More timely reform is needed. In particular, poor performance is due only in part to inefficient structure and inadequate management; politicized operations is a major factor. For this reason, considerable political will and leadership are needed to bring about meaningful reform and establish financial credibility.

This section presents a four-pronged approach to rationalizing the structure and improving the financial strength and performance of the distribution sector, and developing them into viable buyers of power in the restructured industry.

Consolidations and Generation and Transmission Companies

The restructuring recommendations place responsibility for planning and procuring future power supplies with the individual distribution utilities and put in place a planning, investment and operating framework to assist the utilities to meet this new responsibility. We emphasize that the objective is also for the distribution utilities to be accountable for decisions, to stand behind their commercial commitments without government backing, and to take the risks now shouldered by government. These changes will place even more demand on the utilities for management expertise and financial strength. As noted above, this requires that the utilities meet at least the minimum requirements of private power producers and financial institutions. In this respect, the fragmentation of the industry becomes even more problematic than under the current industry regime. Therefore, a program for addressing the consolidation of small utilities into efficient-size entities also becomes more pressing. The goal of consolidation is to eliminate duplicate functions and to establish viable planning, financing and power acquisition entities.

Although we would support a legislatively mandated, centrally directed approach to consolidation, we perceive that this may be extremely difficult or impossible because of political issues. A voluntary program might offer better prospects for success. The features of such a voluntary approach are broadly outlined below. This approach will require detailed evaluation, in particular, its affect on distribution utility rates, financing requirements and sources, and overall costs and benefits. This can be accomplished through a targeted "fast track" pilot implementation to develop the approach in detail, and pending a satisfactory evaluation, demonstrate its workability and benefits to utilities and their customers. Management of the program and the pilot evaluation and implementation will require strong leadership by DOE to develop consolidation policy and the objectives of the pilots, work through NEA as the implementing agency, and ensure that ERB develops appropriate regulations to support the policy objectives and consolidation program.

Step 1: Develop consolidation proposals. To promote consolidation by utilities, a consolidation plan should first be developed based on well defined technical, financial and social criteria. NEA is in the best position to develop such a plan. Once developed, the plan should be offered to the various utilities. The proposals for consolidation embodied in the plan should be augmented: by 1) an evaluation of the consequences of ~~not consolid~~ating under the restructured industry and 2) a package of loan, rate and expansion incentives discussed below. The utilities could adopt the consolidation plan as developed by NEA or propose alternative consolidations. (We note that some utilities might not be candidates for consolidation; on a case-by-case basis, these non-viable systems should be addressed as part of the Small Power Utilities program to commercialize small systems or make their subsidies transparent. See Section 3.3.3.)

As implementing agent, NEA should seek to ensure that proposals for consolidation address key economies of scale in management; general overhead such as office support, legal, personnel and accounting; certain customer service functions, e.g., billing and records; and operations. A professional management staff should also be required as part of any consolidation proposal.

Step 2: Establish performance benchmarks for each consolidated utility and a program to achieve these benchmarks. The benchmarks will reflect the specific constraints and opportunities unique to the utilities and will include operations costs, system losses and financial performance. Performance standards are discussed more fully below. A rate plan will also be established to rationalize over time the rates of a consolidated utility toward a uniform rate. The rates should also be at least stabilized and possibly reduced as a result of the consolidation.

Step 3: Form collaborative "generation and transmission companies" (G&Ts). Ideally, each consolidated utility should approach at least 200 MW and if practical, 400 MW or more in size, establishing credibly-sized buying entities for engaging in the wholesale power market for its owners. To further increase the market power of consolidated utilities, two or more consolidated groups would form a G&T in order to establish a viable bulk power buying entity. The G&T would be chartered to perform a number of services for its owners, including:

- bulk power acquisition, its principal activity
- ownership, development and operation of sub-transmission (69 kV and 128 kV) that collectively serves the local transmission and distribution needs of the owners
- central engineering and similar services, particularly where more skilled and responsive customer services or system design are needed (e.g., for large industrial customers)
- DSM program development and implementation.

The utility owners of the G&T would be required to make a minimum investment in the G&T to establish a reasonable amount of initial equity. The G&T would initially be financed, however, primarily by NEA loans, which we believe are available to support the recommended program. This will require expanding NEA's role to loan to private utilities and the G&Ts, which can be accomplished through DOE policy directives. ERB would allow the G&T a premium return on investment during its formative years to build up its equity position, or returns that would produce sufficient cash to finance 20 percent of expansion and rehabilitation needs, whichever is higher.

Step 4: Expand G&T operations. In particular, two avenues of expansion will be pursued. First, the G&T will acquire from NAPOCOR the 69 kV (and possibly higher) voltage transmission that serves the collective needs of the G&T's owners. The G&T will finance these acquisitions through NEA (and ODA loans through NEA) and charge its owners for use through transmission rates. The G&T will also develop and expand additional sub-transmission facilities to meet the requirements of its owners. The second area of expansion is to take over servicing the sub-transmission/distribution and energy sales needs of directly connected customers. This will provide opportunity for perhaps substantial revenue growth for the consolidated utilities. For risk sharing purposes, especially if the directly connected customers are large in relation to the utilities, the utilities may serve these customers directly from the G&T.

We stress that it is not enough simply to establish these G&Ts; it must be ensured that they are financially credible, and that private power developers will enter into commercial contracts with them. This will require close attention to the requirements of IPPs and financial institutions throughout the development of the details of the consolidation approach, as well as the exploration of risk reduction methods, including performance bonds on the part of the utilities owning the G&T. The timing for establishing G&Ts may be opportune as NAPOCOR approaches the lending exposure limits of many of its key lenders.

There are several additional features that should be part of the consolidation program as described above:

- The directly connected customers that are devolved to the utilities or their G&Ts should be provided the option to retail wheel and purchase their power requirements from the most economical source. ERB would rule on proposed wheeling rates that would adequately compensate the G&T for use of its facilities.

- Both the G&T and its consolidated utility owners should adopt the corporate form of organization. Because such changes are already being encouraged and supported by NEA, this requirement is consistent with current policy in the cooperative sector.

- Even greater incentives should be provided to utilities to participate in the proposed voluntary consolidation and financial strengthening program. The key incentive would be a premium rate of return for the consolidated utility, or cash flow as the case may be, as long as the benchmarks are being met. Performing utilities would be granted the maximum return (12 percent) on revalued assets, or possibly higher if these rates are not sufficient to finance 20 percent of capital expansion requirements. Non-performing utilities and utilities that decline to engage in consolidation would be granted a lower rate of return.

  During the development of the pilots, another incentive should be evaluated for its costs and benefits and political feasibility. Specifically, assuming that the consolidated utility achieves the agreed-upon performance benchmarks, then a portion of the NEA loan to the G&T might be forgiven. In this way, the performing utility would gain an increase in equity ownership in the G&T equal to the amount of forgiven NEA loan. This will also strengthen the G&T's equity component and financial structure. This incentive would require a one-time appropriation for each G&T. While we recognize that forgiving any loan amounts is not without cost to the government, the benefits in strengthening a problematic part of the industry might be worthwhile.

To get the voluntary program off to a quick start and demonstrate its effectiveness, four pilots should be developed and the costs and benefits evaluated, and assuming positive results, the pilots should be promoted and implemented. Again, this will require a collaborative effort by ERB, NEA and DOE, working closely with the respective utilities, to get these pilots underway with the goal of producing visible results in two years. The four pilots would be as follows:

- Bicol utilities
- Cebu cooperatives and VECO (with Panay and Negros utilities later)
- Davao, Cotobato and area utilities
- CEPALCO, MORESCO I and II, and BUSECO utilities (northern Mindanao).

The Cebu cooperatives are currently considering measures to prepare for a pilot along the lines discussed, and a proposal has been received from the northern Mindanao utilities. Again, we believe that funding for G&T transmission acquisition, and possibly for some of the preparatory evaluations and organizational work, will be available to support these projects. The prospects for collaboration, at least in certain cases, are high, and the benefits to the utilities substantial. Early success will provide momentum to the overall consolidation program.

Financial and Management Performance

In parallel with the consolidation program, ERB should pursue distribution sector reform through its regulatory policies and decisions. The performance standards specified in the Hagler Bailly report *Power Sector Cost Structure and Transfer Pricing Study*, prepared in 1990 for the Asian Development Bank and the former Philippine Office of Energy Affairs, should be evaluated for their reasonableness and then implemented. These standards deal with establishing minimum levels of profitability, financial soundness, and good management. The standards proposed in the report are summarized below.

Performance Indicator	Suggested or Preliminary Minimum Standard	Suggested or Preliminary Preferred Standard
Return on revalued fixed assets	at least 5%	at least 10%
Debt service coverage ratio	at least 1.3	at least 2.0
Accounts receivable	at most 12 weeks	at most 10 weeks

These standards are suggestive and preliminary; standards for a specific utility should be reviewed through a hearing process at the ERB, and specific standards adopted for each utility. For example, it may be more appropriate to set a standard based on the cash flow requirements of the utility in those cases where the utility is growing and has substantial needs for investment. In such a case, a return on revalued assets might not generate sufficient cash. The standards, whether based on return on investment or on cash generation requirements, would then be enforced through the rate approval process at ERB.

In discussions, ERB seemed generally amenable to a program along the lines recommended. In particular, we discussed a potential policy under which ERB would revalue the assets of cooperatives when they came in for a rate adjustment, impute a reasonable capital structure (e.g., 40 percent equity, 60 percent debt), and then set rates based on a rate-of-return requirement. Earnings produced for the cooperative as a result of this practice would be restricted and would be devoted to future expansion requirements or retained as capital. If more cash is required to finance a reasonable portion of expansion and rehabilitation needs (e.g., 20 percent) than is produced by this rate of return approach, then rates would have to be adjusted accordingly. Although the ERB presumably espouses this policy, no orders have been handed down that embody it. This should be corrected as soon as practical, and if needed, ERB should recruit additional staff to meet these requirements. (See Appendix F for a detailed discussion of ERB capability building requirements.)

Loss Standards

The loss performance standards specified in the Hagler Bailly report should also be implemented or alternative standards should be established on a utility-specific basis. These standards deal with establishing minimum and target improvement levels for losses. The percentage loss standards proposed in the report are summarized below.

Utility	Suggested Minimum Standard	Suggested Preferred Standard	Suggested Standard of Excellence

Meralco and other companies (private and municipal)	15	9	under 8
Cooperatives			
under 10,000 customers	20	12	under 10
over 10,000 customers	15	10	under 9

As with the financial performance standards, these standards are suggestive and preliminary, and should be reviewed through a hearing process at the ERB to set final standards to reflect the circumstances specific to each utility. The standards specified in the above table will not always be appropriate. In particular, at some level, further reductions in losses may require substantial investment that may not be warranted or there may be higher-priority uses of capital. The final standards for each utility should then be enforced through the rate approval process at ERB.

Again, discussions with ERB indicated that it is pursuing a policy along the line suggested. However, ERB's focus seems to be on the minimum standards, and the ERB minimums are in some case substantially more lenient than those recommended here as reasonable. In particular, small cooperatives can be allowed up to 30 percent losses before they face a potential financial penalty. This allowance should be set at least at the Hagler Bailly recommended minimum standard level unless a hearing at the ERB establishes the reasonableness of an alternative. Again, the minimum standard is being considered here, not even the preferred standard or standard of excellence. Although it might be reasonable to accept a phased program from a cooperative that initially allows losses in excess of the recommended standards, the phases should be short, and ERB should be systematically driving all utilities toward at least the preferred standard.

3.3.7 Policy on Direct-Connected Customers

The historic disputes involving customers directly receiving service from NAPOCOR would be largely resolved by leaving the choice of energy supplier to the customer and providing for tariffs to recover the costs of wholesale and/or retail wheeling services to deliver the energy purchased.

Some industry observers have suggested that direct-connected customers should be turned over to the distribution utilities more aggressively, and that this action is an essential step in establishing financial viability for many of the smaller utilities. This study does not entirely endorse this notion.

In principle, incremental revenues to the distribution utility from the direct-connected customer should be based on the fairly allocated cost of providing the distribution lines and equipment and related customer support activities, with the cost of power, if it is supplied by the distribution utility, similarly allocated based on cost. This will hardly bail out the inefficient distribution utility or overcome inherent small size inefficiencies. Moreover, to the extent that a distributor might price to a direct-connected customer to subsidize other customers or to pay for inefficient management, the industry and public policy are ill served.

Large industrial customer are also inherently more risky than smaller commercial and residential loads. A large industrial load can be much more volatile than commercial and residential loads, and electricity demand and consumption, and therefore utility revenues, are more likely to swing with economic conditions and the fortunes of the customer. If the industrial customer is also large relative to the total size of the distribution utility, great financial risk results for the utility. This risk is compounded if the distribution utility cannot shift the risk of volatility or loss of the load back to NAPOCOR or other power suppliers. Indeed, under the restructured industry where the utility must plan for and secure its power supplies, it will not be automatically assured of this flexibility. The financial consequences of large industrial load loss could be severe for the utility.

To illustrate this risk, some of the ferro-alloy industries in Mindanao represent as much as 50 percent of the load of some utilities. Recently, over 100 MW of this load has been shut down on the Mindanao grid due to competitive conditions. If a distribution utility had entered into long-term power purchase commitments (e.g., the proposed 10-year purchase contract with NAPOCOR) and were unable to put this capacity back to NAPOCOR, it would essentially be bankrupt. Therefore, the ability of the distribution utility to diversify its industrial load and otherwise deal with the risks associated with large industrial loads must be addressed in any decision to shift such customers to the distribution utilities.

Finally, many large customers require more reliable distribution, more skilled engineering services, or more responsive emergency services than many utilities can realistically provide.

In Section 3.3.6, a voluntary program is proposed under which utilities can systematically and rationally take over serving directly connected customers. Under that approach, each of the issues discussed above is resolved. That approach. or some variant of it, is the preferred means of eventually rationalizing the change in service to directly connected customers.

However, for those utilities that elect not to participate in the voluntary consolidation program but still seek to serve directly connected customers, then the restructuring and reforms enumerated in this report should first be implemented. Doing so will establish a level playing field for NAPOCOR (or RPCs), other generating entities, distribution utilities and customers with respect to transmission access and pricing (by Transco) and with respect to the pricing of generation services (by NAPOCOR, regional power companies or IPPs). It will also establish the basic performance standards for distribution utilities.

Then, directly connected customers above a size threshold would be allowed to select the most competitive power supplier; how this selection is made would be left to the customer. The following would be involved:

- Large industrial customers over a size threshold (e.g., 2 MW) will purchase their power requirements from NAPOCOR (or the RPCs once established), another non-utility power supplier, the local distribution company, or some combination of these. The terms of the power purchase contract would depend on the preferences of the contracting parties.

- The distribution utility would establish and publish a retail wheeling rate for each customer in its service area that exceeds the size threshold. Retail wheeling rates would be subject to regulation by ERB.

- In the case of current directly connected customers taken over by the utility, the utility would be required to purchase and service the related interconnection and distribution facilities, including 69 kV sub-transmission facilities where applicable.

- The distribution utility may not make an interconnection or acquire current interconnection facilities and serve the customer unless it can demonstrate to the customer, or to ERB in the event of disputes, that it meets minimum financial, management and loss performance standards and technical criteria to service and maintain the interconnection and the customer adequately.

It is also suggested that the ERB consider setting limits on the size of customer that a distribution utility can serve relative to its total load. In the alternative, ERB is leaving it to the utilities to decide this risk, but some might not be sufficiently prudent.

3.3.8 Reforming Rates

The recommendations contained in the *Power Sector Cost Structure and Transfer Pricing Study* are largely still relevant and should be enacted to further establish conditions that support efficiency and privatization. This involves reforming NAPOCOR's rates and requires that:

- Generation rates include only energy and capacity after the establishment of Transco.

- Rate designs reflect how costs are incurred. In this regard, long-run marginal costs should be developed to help guide rate design decisions.

- Subsidies across grids and between customer classes within grids be eliminated over a reasonable horizon. The elimination of certain current subsidies (i.e., the prohibition on rate increases to residential customers consuming less than 100 kWh per month established under the Power Crisis Act, and the subsidy applicable to residential customers consuming less than 300 kWh per month) will require either repealing legislation or phasing these subsidies out at the expiration of their set terms.

- Rates be differentiated by service characteristic as much as practical, with customers with similar service characteristics paying similar prices.

- Market-driven rates (as opposed to fully allocated cost-based rates) be allowed upon approval by ERB and determination that there is workable competition.

- Appropriate demand, time-of-use, voltage level, and seasonal features be incorporated into rate structures to provide accurate price signals to customers. Time-of-day differentials should be implemented in Luzon and the Visayas, and seasonal differentials in Mindanao. Time-of-day differentials are probably also needed in Mindanao, and this should be verified through an update of the Hagler Bailly study results.

NAPOCOR has filed a restructured rate for the Luzon Grid with the ERB. Of the above rate rationalization goals, the restructured rate only addresses demand charges. Even here, however, the rate redesign falls far short of what is required. In the case of Meralco, the proposed demand charges will collect about 30 percent of the charges to Meralco. However, rates to other NAPOCOR customers have a demand charge as low as 5 percent. No movement was made on correcting any subsidies. For example, small utilities with substantially lower load and power factors than Meralco and served at a lower voltage nevertheless can buy power from NAPOCOR at a rate lower than can Meralco.

It is recommended that the restructuring of NAPOCOR's rates become a priority program at ERB, particularly since changes in rate structure will become necessary as the regional power companies are established as separate entities. NAPOCOR cannot realistically be expected to act aggressively to restructure its rates unless ERB gives it specific directives and schedules.

NAPOCOR's rates should be reformed, and the distribution utilities should follow suit. Once the NAPOCOR rates are reformed, distribution utility rates should be restructured to reflect the new NAPOCOR rate designs.

3.4 PHASE 2: EVALUATION AND ADJUSTMENT OF APPROACH AND PRIVATIZATION

Phase 2 is a period of evaluation and either a reaffirmation of the approach that is being pursued on each grid or a reassessment and adjustment. This section reviews some of the major requirements of this phase.

3.4.1 Evaluation

DOE, in conjunction with ERB, Transco and the utilities, will evaluate the progress of the industry in moving into IRP, decentralized planning and coordinated operations. The areas for investigation are the:

- extent of competition in the generation market, market shares, and robustness of the IPP industry
- success of regulatory programs in rationalizing pricing practices and improving the operations and structure of the distribution industry
- success of the pilot and voluntary utility consolidation programs
- status of grid interconnections and intra- and inter-grid coordination under the coordination arrangements
- status of IRP, market penetration of DSM, and extent of direct transactions between utilities and independent power producers
- experience with retail wheeling and extent of competition for retail sales
- power supply plans, adequacy of power supply and strength of industry on each grid
- strength of regulatory oversight and policy programs at DOE and ERB
- effectiveness of joint participation among utilities in power projects.

The results of these evaluations will enable DOE and ERB to determine where the restructuring is working well and where obstacles have been encountered. Any obstacles then become the target for corrective actions in Phase 2 and carrying forward to Phase 3.

3.4.2 Structural Adjustments

On the basis of the above evaluations, adjustments might be needed in structural goals. It appears that the unbundled functions, decentralized planning, and operations integration structure will remain the structure of choice. However, Phase 2 involves the privatization of generation entities, so it is only prudent that a comprehensive evaluation be completed before the RP embarks on a program that will substantially reduce its future control over power generation and restrict its flexibility to direct further restructuring.

Mindanao and Visayas

In Mindanao and the Visayas, it is likely that the industry, at least in the intermediate term, will tend to operate more like the unbundled functions, central power acquisition model because of the small size of these systems and the nature of the power development projects planned on these grids. This means that there must be greater reliance on regulatory oversight of the operations of the regional power supply companies. Before privatizing these regional companies, the needed regulatory capability must be in place. If the utility consolidation program is successful, the market power of the RPCs will be reduced.

It will also be necessary to verify that the coordination arrangements are in place and working, and that all utilities have a workable framework through which they can develop power supplies from sources other than the regional supply companies.

Luzon

The structural issue in Luzon that should be reassessed is whether it is desirable to adopt a SRMC or bid pricing system on this grid. The emergence of a truly competitive generation market, where there are sufficient sellers and buyers and a reasonably efficient and adequate supply of generation, may justify an alternative structure. These conditions are lacking in Luzon at this point, but might be established over the next several years.

There are four principal differences between a SRMC or bid pricing system and the structure recommended here. They pertain to how units are dispatched, how generators are paid for their generation, the prices that buyers pay for purchases from the grid, and the obligation to serve and related planning responsibilities.

1. ***Dispatching.*** Under a SRMC or bid pricing system, generators would submit quotes to the grid company (Transco), indicating the amount and price of generation they are willing to sell for a period of time, e.g., hourly. The buyers from Transco would either submit estimates of their requirements for the same time periods or Transco would derive these demand estimates itself. Transco would then dispatch generation to meet

load and maintain adequate reserves, voltage support and system stability. The theory behind dispatching on bids is that the generators are in the best position to know their short-run marginal costs on a real-time basis and therefore will provide more accurate information on which to dispatch.

Under this study's recommendations, dispatch will be based on estimates of short-run marginal costs calculated by Transco using engineering calculations, heat rate curves, fuel prices and similar factors provided primarily from each generator. In theory, the two methods should produce the same costs, but if the costs are dynamic, the Transco estimates will not be as timely or accurate as what might be possible if each generator is calculating these costs on a real-time basis.

2. ***Prices for generation.*** Under a SRMC or bid pricing system, generators would be paid a price for their generation during a specific period based on the short-run marginal cost of the marginal generator for that period. In this manner, all generation is sold to Transco at the short-run marginal cost set by the marginal generator, a condition sought in classical economic efficiency models. In comparison, under this study's recommendations, generators will be paid based on bilateral contracts between the generator and distribution utility or other buyers. However, for economy energy sales, generators also are paid based on the short-run costs of the buyer.

3. ***Prices for purchases from grid.*** Under the SRMC or bid pricing system, buyers of electricity from the grid would also pay the grid short-run marginal costs of generation purchases, plus adjustments for losses and charges for transmission. In this sense, the costs of electricity will vary by time according to marginal cost and also meet the condition sought in classical economic efficiency models. Under this study's recommendations, buyers instead pay prices based on their bilateral contracts with generators.

4. ***Obligation to serve and planning.*** Under the SRMC or bid pricing system, the notion of "obligation to serve" is, in theory, supplanted by the behavior of the participants in the market. Generation will be built and provided in anticipation of market demand, and buyers simply rely on the grid spot market for their purchases. In practice, there must be oversight to monitor the development of adequate generation supplies.

At first, there might appear to be major differences in a SRMC or bid pricing system and the unbundled functions, decentralized planning, inter-utility coordination approach. However, these differences are significantly mitigated by the bilateral contracts that also emerge under a SRMC or bid pricing system. These contracts are referred to as "price hedge" contracts, and are entered into for two purposes. First, they provide price protection to the generator or buyer, or both. Second, the contracts reduce the market risk for the generator so that the generation project can be financed. In theory then, if all generators and all buyers fully hedge and if the engineering estimates of short-run costs are accurate, there will be no major differences in the outcome of the two approaches. In practice, not all participants will fully hedge and a true spot market, although perhaps small, will emerge. Moreover, depending on the specific provisions of its hedging contracts and the amount of capacity not hedged, a generator will have greater incentive to maintain high availability and the lowest practical operating costs.

It is not recommended here that the RP adopt a SRMC or bid pricing system as the structural and operational goal in Luzon. But neither can it be precluded at this time. Instead, it is recommended that attention be focused on creating a diverse and competitive generation market as soon as practical, which is also a basic requirement for a successful bidding system. Attention should also be given to promoting many buyers for this generation, with open-access transmission and operations and planning coordination arrangements that facilitate the efficient and competitive matching of buyers with sellers. Movement to a SRMC or bid pricing system as a further refinement of this approach would not be inconsistent, nor is it ruled out. It should be revisited during Phase 2.

A SRMC or bid pricing system approach for Luzon was considered as an option for this grid. This option involved setting a transition period of 10 years during which all of NAPOCOR's generation would be contracted out to the private sector (as it is under this study's recommendations). In addition, at the end of the transition, all generation would be sold to Transco on a bid basis. During the transition, all utilities would be required to enter into bilateral contracts for incremental supplies. At the end of the transition, NAPOCOR's contracts would be administered strictly as price hedge contracts. Distribution utilities' bilateral contracts would also revert to price hedges.

This approach is not recommended for several reasons. Most critically, the Philippines does not currently have the generation diversity, either in an efficient mix of reliable units or in ownership. How this condition will evolve cannot be predicted with certainty, and reliance on the IPP market alone might not produce sufficient diversity. To illustrate, Hopewell has already captured a large share of the IPP projects, and it was the low bidder for the construction and operation of the Sual I and II projects, representing 1,000 MW of coal capacity. To achieve diversity of ownership, the Philippines must either attract more IPP participants or possibly settle for higher-cost bidders in the interest of establishing generation ownership diversity.

The sheer burden the industry will face to ramp up quickly on IRP and develop the system of bilateral contracts is also a concern. This task is almost daunting at this point due to the large number of small utilities and directly connected customers that would face these requirements. Concerns also surfaced over whether power purchase contracting could be orchestrated in a way that would ensure that new power plants are financeable and would be constructed when needed. Last, the privatization of NAPOCOR's existing generation in Luzon would be impeded by forcing a SRMC or bid pricing system as the "end play" on Luzon, which might be perceived as radical and risky by IPPs and utilities alike. Nevertheless, these issues should be revisited during Phase 2.

3.4.3 Privatizing Generation in Luzon

Related to the discussion above on the applicability of a SRMC or bid pricing system in Luzon is the final privatization of NAPOCOR's generation in Luzon, allowing NAPOCOR to exit that business. Upon the successful implementation of Phase 1, the approach recommended for privatizing the Luzon generation is to package Luzon Power's generation into portfolios and sell these portfolios to two or more operating companies. Associated with each new company would be the devolvement of bilateral contracts with utilities for power purchases, either based on the portfolio or on specific units. If successfully executed, the sale of the portfolios to the private sector will allow NAPOCOR to exit the business and leave in its place a balanced group of competitors.

It should be practical and feasible to make these sales, particularly if Luzon is restored to a strong power supply situation, implementing the coordination arrangements, and establishing decentralized IRP and competitive procurement as the planning mode. Although these sales were included as part of implementing the recommended structure based on unbundled functions, decentralized planning, inter-utility coordination and a system of bilateral contracts, establishing several competitive companies in Luzon is equally compatible with a grid pricing system.

During Phase 1 or as part of establishing the groupings of assets to be sold to private operating companies, NAPOCOR might also disaggregate and devolve some of its generation directly to its customers through bilateral contracts. The pursuit of this option is highly dependent on increasing the capabilities of the distribution utilities to plan and administer contracts, rationalizing the size and structure of the smallest and financially weakest utilities, and rationalizing the directly connected customers.

A specific plan to group assets, make the sales to private companies, and possibly devolve some generation to customers would be developed and implemented during Phase 2.

3.4.4 Privatizing Generation in Mindanao and Visayas

Assuming that the Phase 2 evaluations discussed above prove the veracity of the recommended approach in these regions, the NAPOCOR subsidiaries could be privatized through a straight sale of interests to the private sector. A sale similar to Petron might be acceptable, where an investor with expertise in utility management purchases an operating interest. It appears that NAPOCOR must dispose of most of its interest in each subsidiary such that it has no influence over decisions on the selection of management and board members. The total disposition of ownership interest should be NAPOCOR's goal.

3.4.5 Retail Wheeling

It is recommended that retail wheeling be introduced at a measured pace for large customers to promote the competition for these loads and as part of a policy to rationalize direct connection practices. In Phase 2 the effectiveness of this policy should be evaluated with a view toward extending retail wheeling and sales competition to a broader composition of users. Not only does this foster competition and efficiency, it also creates a greater diversity of buyers of generation, especially in Luzon where the large customer base in the Meralco area might attract innovative and efficient sales providers.

3.4.6 Demand-Side Management

Projecting that DSM has an important role to play in meeting the requirements of customers, it will be important to carefully monitor and evaluate the progress of the utilities in diligently performing IRP and seeking out DSM opportunities. In Phase 2 DOE, in conjunction with ERB, should evaluate whether the industry is adequately capturing these opportunities and promulgate new rules or incentives that might be needed to overcome identified barriers.

3.5 PHASE 3: MOVEMENT INTO FINAL COMPETITIVE STRUCTURE

During Phase 3 the industry will move fully into restructuring and decentralized planning. The industry will develop fully effective competition in generation, retail sales and resource acquisition. DOE and ERB's activities during this phase will be determined in large part by the developments in the industry during the previous phases. However, it is reasonable to predict that extending retail wheeling and retail sales competition more broadly will be an active concern. Adopting incentive regulatory schemes and moving away from cost regulation will become more practical and effective. Monitoring competitiveness and market behavior and dominance will also be important.

To reiterate, some of the major results to strive for in Phase 3 include:

- full functioning of all utilities under decentralized decision making
- competitive, privatized generation markets
- competitive retail sales markets
- widely practiced, state-of-the-art IRP with good market penetration of DSM
- innovative regulatory incentive programs
- efficient inter- and intra-grid coordinated operations.

3.6 REVIEW OF COMPETITIVE FACTORS AND SPECIAL CONDITIONS

Chapter 2 reviewed how the current Philippine electricity industry structure fails to meet key requirements for competition. It also reviewed several special factors that should be accounted for in a restructuring and privatization approach. To conclude the discussion of the recommended approach, this section briefly reviews how the recommendations address these concerns.

To reiterate, the industry structure conditions that affect the degree of competition and participation in the industry are:

- number of sellers of generation
- number of buyers of generation
- ease of bilateral trades between buyers and sellers
- ease of entry into generation
- access to transmission
- transparency of pricing
- unbundling of core functions
- existence of level playing fields among participants in each core function
- availability of planning information
- access to the end-user (through retail wheeling).

This chapter has attempted to address each of these. This study's approach is designed to create more sellers at the wholesale power level, in particular by facilitating direct sales between utilities and independent generators on all grids, and further by restructuring NAPOCOR assets to create private wholesale suppliers in Mindanao and the Visayas and competing companies in Luzon. More buyers are created by putting all utilities into the generation market and consolidating and strengthening utilities to become viable buyers. A key purpose of the coordination arrangements, access to transmission, and access to capacity provisions is to promote bilateral trades between buyers and sellers.

Creating access to generation, implementing coordination arrangements, creating many buyers and eliminating NAPOCOR's central control over generation, promotes ease of entry into generation. The establishment of an independent Transco is designed to provide access to transmission.

Through unbundling, eliminating subsidies and rationalizing rates, transparent pricing is established. Functions are extensively unbundled and level playing fields are created, including those for fuel costs. Planning is coordinated and information is widely available. Finally, open access to customers through retail wheeling is provided for at a measured pace, starting with large customers but progressively extending this competition in each phase.

This chapter has also attempted to address the special factors identified in Chapter 2:

1. *Natural geographical divisions.* The recommendations account for this condition by adopting regional restructuring and privatization approaches.

2. *Need for unified transmission.* The national transmission system has been kept intact, but regionally differentiated prices are provided for.

3. *Small scale of Mindanao and Visayas.* These conditions have been accounted for by retaining a regional supply company in each region that can manage the development of power projects and provide effective planning and strong financial credentials. Recognizing that the generation companies in these regions will require greater regulatory oversight, the recommendations nevertheless provide distribution utilities with workable arrangements to develop alternative sources of generation as well as a program through which they can consolidate into more viable entities.

4. *Efficient scale of Luzon.* In contrast, the recommendations reflect that effective competition in generation and retail sales can be established in Luzon, and that there need be no residual generation monopoly.

5. *Potential dominance over generation by distribution utilities.* Dominance over the generation market by distribution utilities with large market share is guarded against through competitive procurement schemes and targeted regulatory policies and procedures.

6. *Disparities in distribution utility capabilities.* This issue has been addressed in several ways, including: regulatory programs to strengthen and improve the performance and structure of distribution companies, a transition period during which utilities can take actions to prepare to meet their responsibilities under the restructured environment, and that facilitates consolidation of smaller utilities into larger, financially stronger entities.

7. *Critical need for power supply plan execution.* Strong power supply subsidiaries have been in place on each grid for a transition period to execute critical projects and prepare for privatization.

8. *Absence of DSM/IRP.* Demand-side management and integrated resource planning with competitive procurement by all utilities is a central feature of the recommended approach.

9. *Expanded tasks for ERB and DOE.* We have accounted for the fact that these organizations in particular will be critical in orchestrating the industry through each phase and in providing regulatory and policy oversight on an ongoing basis. The requirement to build the expertise and resources of each agency in parallel with the evolution of the industry restructuring has also been accounted for.

CHAPTER 4
OTHER INDUSTRY STRUCTURES

This chapter discusses the alternative industry structures considered in this evaluation and introduced in Chapter 3. It begins by reviewing how the Philippine electricity industry might evolve in the absence of any specifically developed strategy to reach a long-term structure and ownership goal. After discussing the alternative structures, the chapter concludes by considering the applicability to NAPOCOR of the privatization approach that was recently pursued for Petron.

Almost all of the material in this chapter was presented and discussed at the restructuring and privatization workshop in Manila (see Appendix E for its proceedings).

4.1 POTENTIAL EVOLUTION OF CURRENT STRUCTURE

Chapter 2 described in considerable detail the existing structure and ownership of the industry. The restructuring and privatization workshop considered what the industry might look like in the future if current policies and trends continued and significant structural change was not pursued, but instead, the industry aggressively seeks to:

- ***Increase private sector participation.*** Participation might be particularly increased in the generation function to build new capacity and rehabilitate and operate existing NAPOCOR generating units. Aggressive EO 215 rules to provide entry into the generation market by distribution utilities and private companies might also promote more private sector participation.

- ***Increase the transparency of operations and pricing.*** "Transparency" means that operations performance, operating policies, and derivation of prices are clearly identified and understandable. For example, if transmission costs and pricing are included in an energy tariff but are not stated separately, then transparency is poor. Similarly, distribution pricing can be made more transparent by separately pricing the "lines" function and the "sales" function.

- ***Increase accountability for performance.*** Accountability can be improved, for example, by increasing the transparency of key operations, clearly assigning responsibility and authority, setting goals, and basing compensation on measured performance.

- ***Improve regulatory effectiveness.*** This could be accomplished, for example, by improving the skills, staffing and resource levels at ERB or implementing regulatory programs to improve the operating performance of distribution utilities.

Figure 4.1 shows a possible evolution of the industry under these assumptions. Key to this figure is the concept of "ring fencing." Ring fencing is an alternative to actual structural unbundling and the separation of ownership. It is accomplished through one or more of the following:

- establishing semi-autonomous organizational units for key functional activities, with clearly defined management responsibility, goals and performance measurement

- implementing accounting practices that isolate and separately account for the costs and performance of key activities

- adopting pricing practices that separately charge users for disaggregated services, e.g., separating transmission from generation

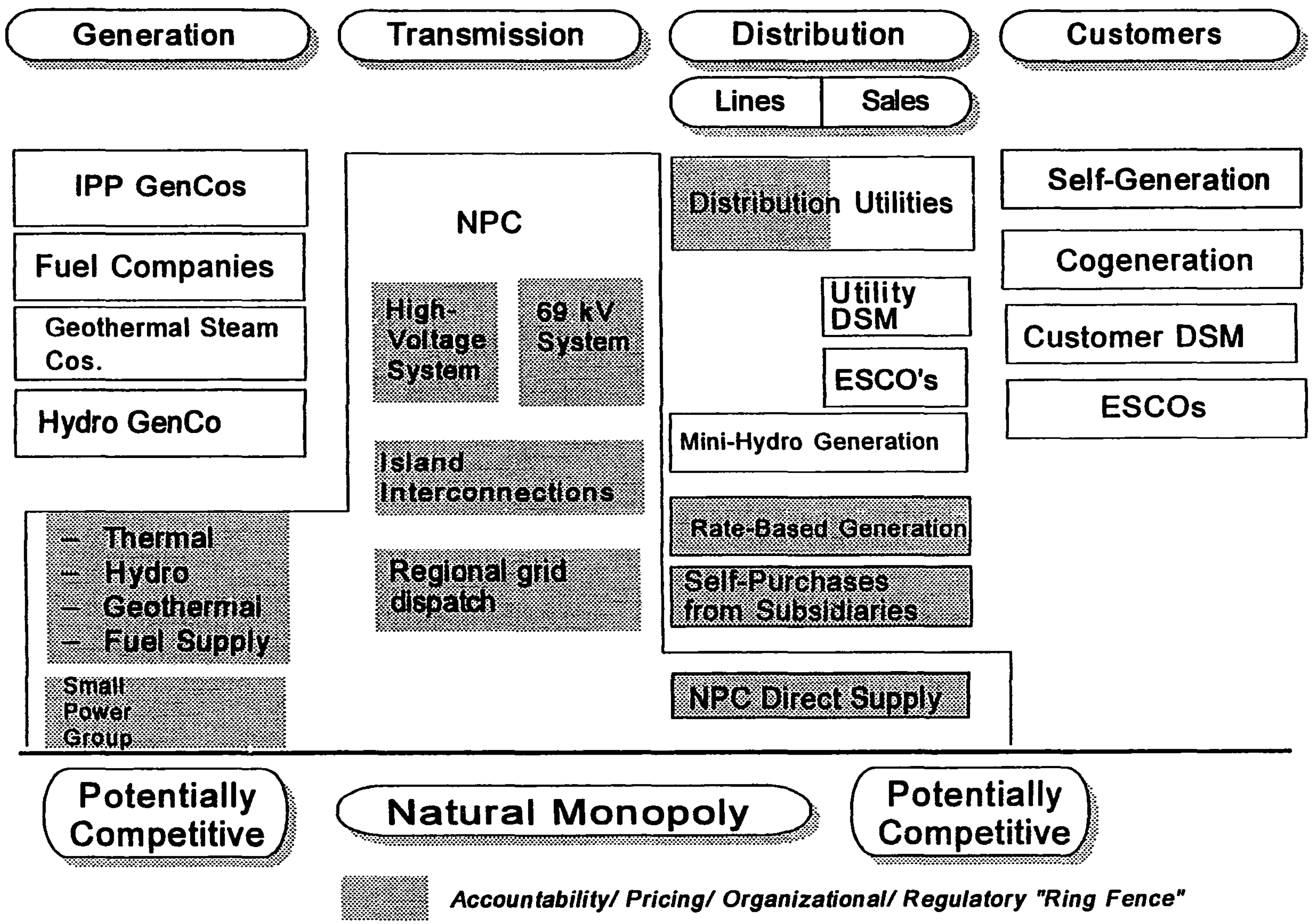
- pursuing regulatory practices that focus on key utility decisions or policies, e.g., utility self-generation or distributor self-purchases from subsidiaries.

In this regard, NAPOCOR is currently engaged in an effort to ring fence its regional operations by decentralizing to its five regional operating centers some of the activities and decisions that normally have been made centrally by Manila headquarters. In addition, NAPOCOR is attempting to account for and report the regional operations as profit centers, which requires that costs and revenues be carefully tracked for each center. Any cost or activity that falls beyond the responsibility of the center should in theory be reallocated. In this manner, more accountability might be established.

The shaded functions or activities in Figure 4.1 indicate the use of ring fencing. *However, we strongly emphasize that ring fencing is substantially inferior to the actual disaggregation of functions into separate organizations and ownership, and is in many cases very difficult or impractical to implement effectively.* For example, the NAPOCOR regional centers cannot be managed by the local managers as true profit centers because the managers have no control over prices. Neither can NAPOCOR effectively operate the regional operations as profit centers because prices are not set based on operating center costs. The limitations of ring fencing should be borne in mind during the discussion below on the possible industry evolution depicted in Figure 4.1.

The generation function might be further "privatized" by relying on private sector IPP GenCos to build and operate new power generation facilities. However, the nature of

Figure 4.1
Possible Evolution of Existing Structure of the Philippines Electric Industry



generation unbundling that is achieved through the current NAPOCOR approach is limited. At present, the very tight purchase power agreements between NAPOCOR and the IPP GenCos make the IPP GenCos essentially constructors and operators of fuel conversion facilities. The GenCos do not operate in an unbundled, competitive environment with many buyers and sellers of generation, and they do not compete for short-term sales based on their efficiency.

In the competitive environment envisioned in this study, generation will be unbundled in a broader sense, placing greater competitive and performance requirements on the IPP GenCos. Nevertheless, under the current structure, NAPOCOR can aggressively pursue other forms of contracting, including contracts with private sector operators to refurbish and operate existing facilities (e.g., repair-operate-maintain -- ROMs). Hydro development might be spun off as a separate activity or subsidiary, although this may be stepping beyond "evolution" into restructuring, as this is one of the structural changes recommended here. Geothermal might be developed through integrated steam/power generation projects with private sector developers, including PGI and EDC. NAPOCOR could exit the fuel supply business for independent power producers: this would require leveling the playing field on fuel taxes, again as recommended here. Other NAPOCOR activities could be spun off into subsidiaries or to the private sector or other state organizations, e.g., small island electrification. The remaining generation activities of NAPOCOR might then be ring fenced to focus regulatory and management oversight.

In the absence of restructuring, transmission and dispatch will remain key NAPOCOR activities. However, four functional activities (high-voltage transmission, 69 kV sub-transmission, island interconnections, and regional grid dispatch) are shown as ring fenced for performance monitoring and in some cases for separate pricing, e.g., transmission services. It is also possible that private sector investment might be attracted to the transmission function through build-operate-transfer (BOT) contracts for selected projects.

Several changes are depicted in the distribution function. First, the "lines" function is ring fenced, with the costs of "lines" service identified separately in the distribution tariff. In addition, customers above a certain size might buy power directly from NAPOCOR or other power producers and use retail wheeling services across the local distribution lines. Self-generation and purchases from IPP GenCos or subsidiaries might grow in importance with certain distribution utilities. These activities are shown as ring fenced and subject to close regulatory oversight. In this evolutionary scenario, NAPOCOR's supply to directly connected customers is also ring fenced and subject to close regulatory oversight. Two new activities could emerge as important factors in the industry: demand-side management by both utilities and end-use customers, and energy service companies (ESCOs) that provide DSM services to either utilities or end-use customers. Finally, cogeneration by customers could become a more important source of electricity supply.

With the exception of increased private sector participation in generation and the possible spinning off of certain NAPOCOR activities into subsidiaries or to third parties, this evolutionary scenario does not entail any significant restructuring to promote competition, capital formation or performance accountability. NAPOCOR remains a national monopoly with potential limitations of performance and efficiency incentives that are attendant to monopolies. The practice of ring fencing is liberally used as a means of addressing the problems of monopoly structure and bundled functions. Reliance on regulation is especially heavy throughout all facets of the industry.

Despite these limitations, some industry participants expressed interest in this scenario, particularly in combination with bringing in a significant private investor/operator firm as an equity owner in NAPOCOR similar to ARAMCO/Petron. However, the so-called "Petron approach" does not address any of the structural problems in the industry. Rather, it is more of an ownership option that could be pursued for various entities under practically any industry structure. The "Petron approach" is discussed in Section 4.5.

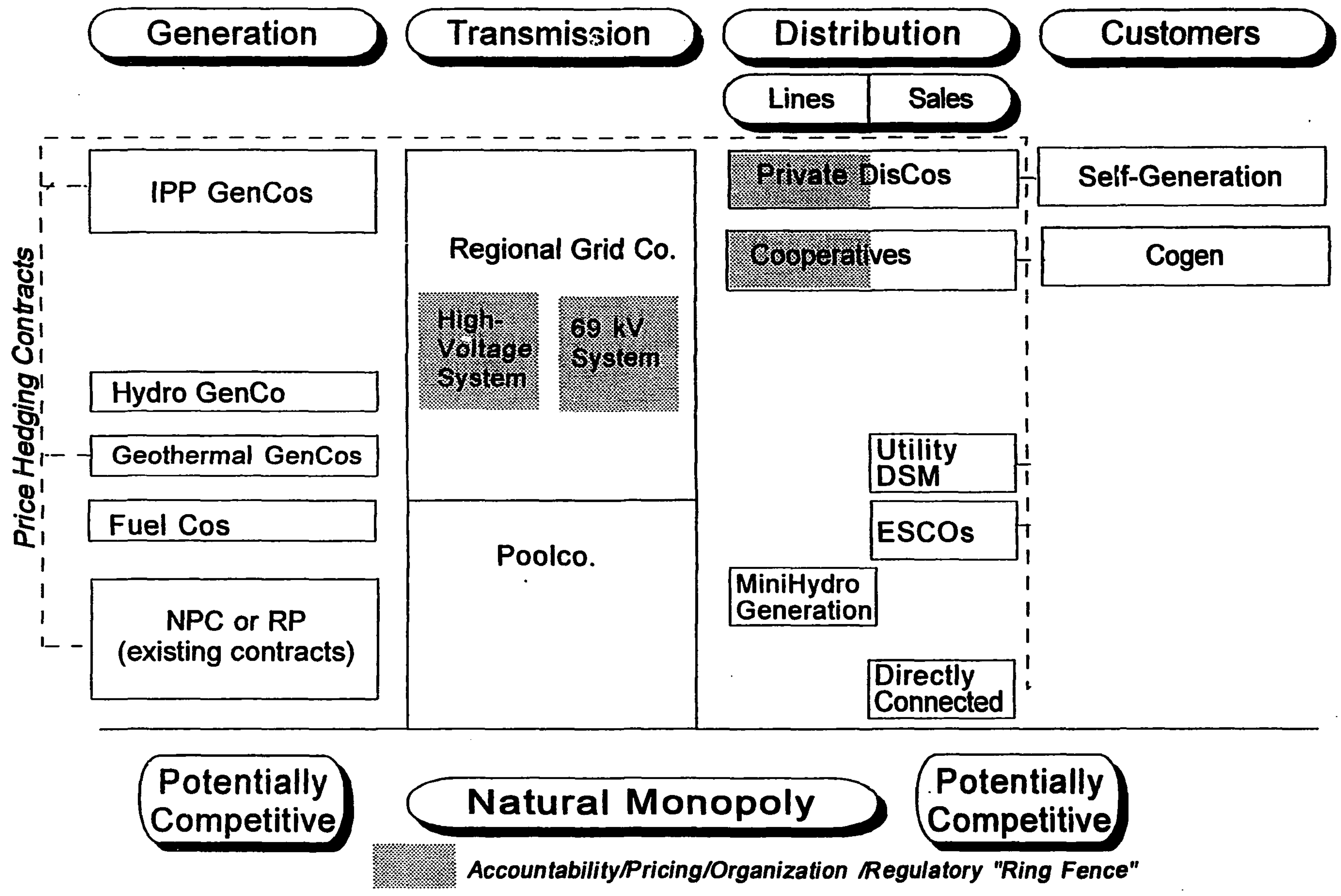
4.2 ELECTRICITY INDUSTRY STRUCTURE BASED ON SHORT-RUN MARGINAL COST OR BID PRICING SYSTEM

Figure 4.2 depicts the SRMC or bid pricing approach (referred to as the "market clearing pricing approach" in the workshop) that was considered for application in the Philippines. Because of its potential long-term application in Luzon, this approach was discussed in some detail in Chapter 3, where it was identified as an important area for re-evaluation during Phase 2 of the recommended restructuring and privatization approach (see Sections 3.4.2 and 3.4.3).

Under this approach, all generation would be spun off to IPP Gencos, Hydro GenCos and Geothermal GenCos. NAPOCOR would exit from the fuel supply business. The generators would provide price quotes for blocks of power by time period (e.g., half hour periods during the following day) that they are willing to provide to the Regional Grid Company (RGC). Distribution utilities would purchase their requirements from the grid. The RGC matches the supply quotes with the requirements of the distribution companies and dispatches generation to match supply and demand in real time. It would also recover its transmission and sub-transmission costs (ring fenced in Figure 4.2). Also ring fenced is the distribution "lines" function, allowing customers above a certain size to purchase directly from the grid and pay local distribution wheeling charges. Perhaps the best publicized adoption of the SRMC or bid pricing system is on the England/Wales grids.

NAPOCOR has several contracts with IPP GenCos that might not be restructured under this approach. These contracts essentially result in price hedges for NAPOCOR and the respective IPP GenCos. That is, the existence of these contracts does not necessarily impede the adoption of the SRMC or bid pricing system as an industry structure. The broken line on Figure 4.2 indicates the existence of these price hedge contracts. In fact, were the SRMC or bid pricing system to be implemented, price hedging contracts would likely be entered into by

Figure 4.2
Electricity Industry Structure Based on Short Run Marginal Cost or Bid Pricing System



most if not all participants in the generation and distribution functions. If the England/Wales experience is any predictor, these contracts between distribution utilities and generators, which will typically have take-or-pay features, also form the basis for capacity expansion projects and are perceived as necessary to make new generation plants financeable. This raises an important issue: in the absence of NAPOCOR, there are few financially strong distribution companies that could independently enter into viable and financeable contracts with IPP GenCos under the SRMC or bid pricing approach. There is a continuing need for NAPOCOR or an alternative financial guarantor to ensure that IPP GenCos are attracted to the industry to construct generation units to meet demand.

Although the SRMC or bid pricing approach is technically feasible, it will not be competitive, at least currently. None of the participants in the workshop or industry representatives with whom we held subsequent discussions considered the approach prudent or workable at this time.

In particular, the approach is not practical on the Visayas or Mindanao grids, where there is clearly too little diversity of generation. On these grids, there are only a few generation units, which does not provide a workable competitive bidding environment on the generation side. Moreover, in Mindanao, most of the generation is hydroelectric with limited dispatchability. Lack of generation diversity could also be a problem on the Luzon grid, and the concentration of IPP generation in a few large facilities and a small number of operators also raises the risks of non-competitive bidding or effective gaming behavior on the Luzon grid (see Section 3.4.2 for a detailed discussion of applicability on the Luzon grid). Industry participants considered the required sophistication and complexity of the SRMC or bid pricing system to be particularly problematic for most utilities in the industry, and might also impede timely and efficient capacity expansion decisions and financing.

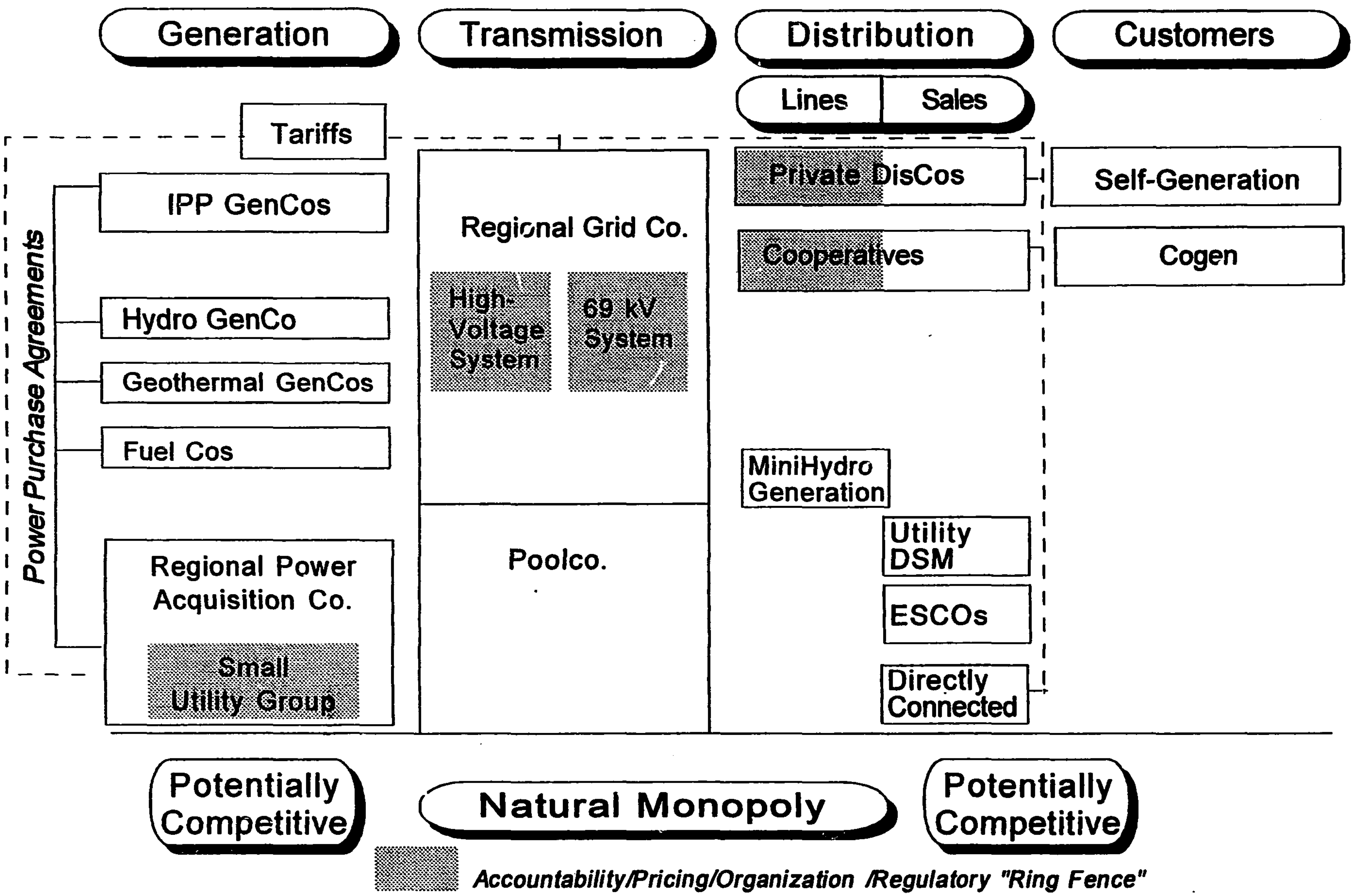
4.3 INDUSTRY STRUCTURE BASED ON FUNCTIONAL UNBUNDLING AND CENTRAL POWER ACQUISITION

This approach, depicted in Figure 4.3, found considerable support among the workshop participants, although key issues were raised. Under this approach, generation is unbundled in a way similar to that described for the SRMC or bid pricing approach. New generation is provided by IPP GenCos, and NAPOCOR's existing generation is, to the extent practical, also spun off to IPP GenCos. Hydro and geothermal generation are also accomplished through independent companies. NAPOCOR exits from the business of supplying fuel to IPPs. Other NAPOCOR activities are spun off, leaving a Regional Power Company with two key functions: 1) perform the power supply planning for the region and 2) acquire the power requirements through administering a competitive bidding program.

The transmission system is established as a separate national company with three regional subsidiaries or divisions. The grid company provides transmission planning and investment,

Figure 4.3

Industry Structure Based on Functional Unbundling and Central Power Acquisition



operates and maintains the high-voltage and sub-transmission systems, and plans and implements interconnections. This figure shows the grid operation and generation dispatch as being performed by a separate Poolco, although this function could also be combined with the grid company.

On the distribution side, the distribution utilities would obtain all of their power requirements from the RPC with the exception of mini-hydro generation. All other generation by distribution utilities or their subsidiaries would be sold to the RPC. The distribution "lines" function is ring fenced to provide transparent retail prices and retail wheeling for customers meeting threshold size requirements. The directly connected customers are also ring fenced to provide regulatory oversight.

The strengths of this structure include its simplicity, the degree of unbundling and transparency, and management focus and accountability by function. Moreover, it retains the RPCs as state-owned enterprises, at least initially, which can provide the financial strength to negotiate with IPPs. If performed expertly, the competitive procurement process of the RPCs should introduce further competition into the capital and operating cost-intensive generation function. The distribution utilities are freed from investment requirements to provide generation and can focus their limited resources on the distribution systems. The grid company is a state-owned enterprise, at least initially. Operated on a commercial basis, it should be able to access diverse funds for expansion. The grid company might be sold in whole or in part to the private sector at a later time if this is deemed to be desirable. Similarly, the regional RPCs might also be sold in whole or in part to private investors.

This approach also has significant disadvantages. In particular, the RPC is the sole buyer of power from generators and the sole seller of power to distribution utilities. This falls far short of the competitive market that might be established if all utilities become effective buyers of generation and a market with many buyers and many sellers is established.

Another critical drawback is that the distribution utilities are not responsible or accountable for their power supply costs. Although planning procedures might be established such that the distribution utilities can participate in developing the regional generation plan, the execution of that plan rests solely with the RPC.

The differences between this unbundled functions/central power acquisition approach and this study's recommendation are several. First, although regional power companies are established under both approaches, under this study's approach the RPC is only one of the options available to utilities for power supply. Second, responsibility for planning and power supply is placed with the distribution utilities, not the RPC, resulting in many more competitors for generation and creating a critical market discipline for the utilities. Third, a structure is put in place to facilitate the utilities performing these added responsibilities. This study's approach capitalizes on the financial strength of all utilities, including NAPOCOR, over a transition period, but sets a window within which all utilities are pressed to become financially self-sufficient. Under the unbundled functions/central power acquisition approach, NAPOCOR/RPCs would continue to be the dominant factor in generation. In contrast, under this study's approach their power would diminish on a relative basis as utilities grew into their added responsibility and developed increasing self-sufficiency.

4.4 INDUSTRY STRUCTURE BASED ON REGIONAL (OR NATIONAL) VERTICAL INTEGRATION

Figure 4.4 illustrates how the Philippine electricity industry would look if total vertical integration were pursued. This approach is the "regulatory model" for the industry, i.e., that the industry is basically a monopoly, competition is ineffective, the most efficient structure is the single firm, and that effective regulation of utility management decisions is needed to control the monopoly power and ensure efficient investment and operation. This approach would require extensive ring fencing of the operations, investments and pricing of the integrated utility, relies the least on competition, and places the heaviest requirement on regulation.

This approach was discussed at the workshop not so much as a viable option, but rather to complete the consideration of the spectrum of approaches. It falls short on virtually all of the areas of concern, in particular in failing to promote competition or to increase responsibility and options for the distribution utilities to plan and provide for their power requirements.

4.5 THE PETRON APPROACH

The so-called "Petron approach" involves three steps:

1. The first step is to establish a commercially viable company (or companies). This would normally require that one of two conditions be established:

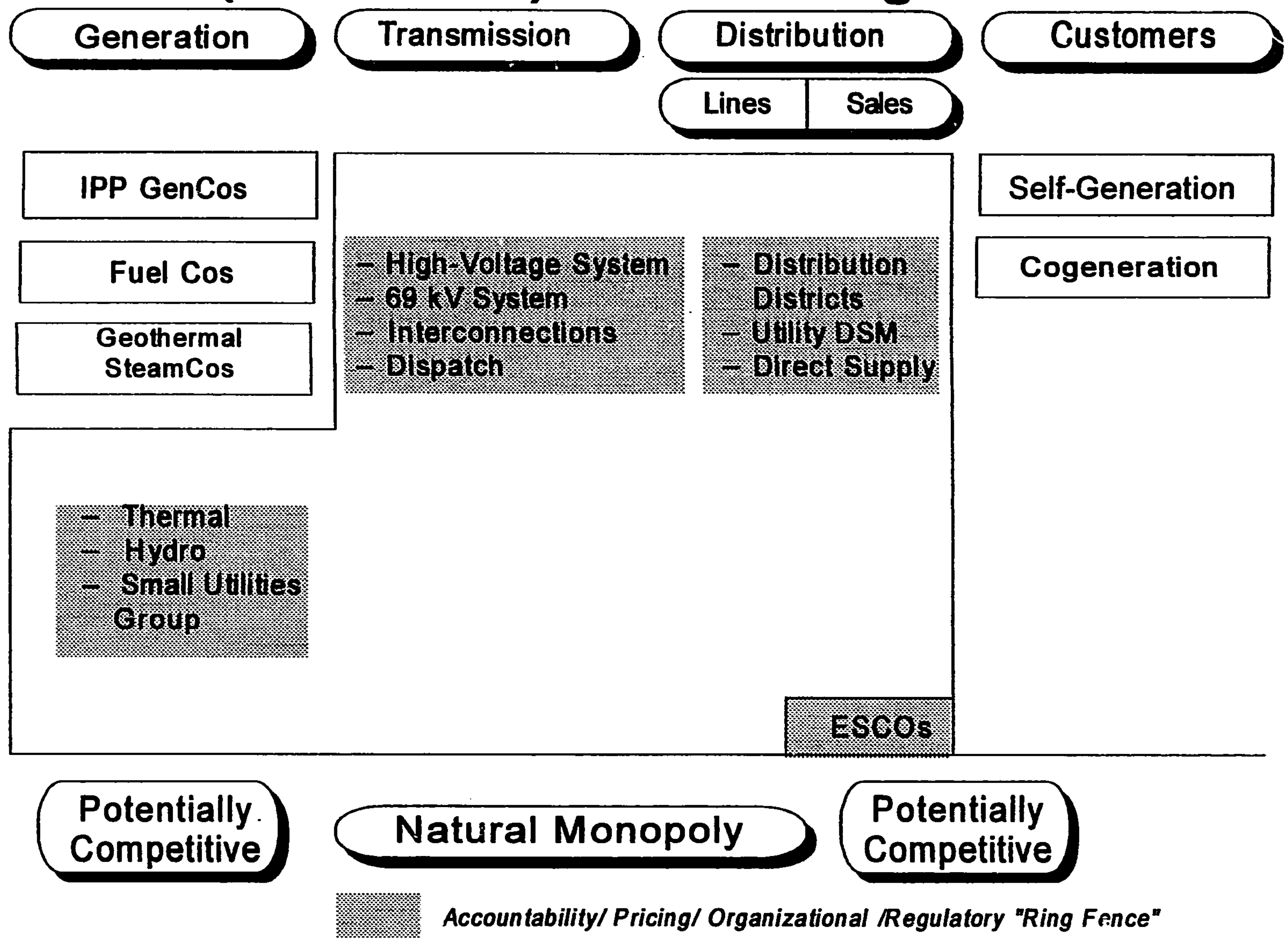
   - the company operates in an essentially unregulated market where it is free to pursue operating, investment and pricing strategies to compete and earn acceptable returns on its investment, or

   - the company operates under competent, transparent, and established regulatory practices that reward the company with reasonable returns on its investment, excepting only those instances where management has been objectively deemed to have been imprudent.

   Neither of these conditions, of course, is likely to hold completely true. Rather, a combination of some degree of market deregulation and competition, along with a system of regulation, will normally characterize a company's environment. The

Figure 4.4

Industry Structure Based on Regional (or National) Vertical Integration



important requirement is that this environment allow management to concern itself primarily with normal business strategy and operations, and to earn an acceptable profit if it performs well at these activities.

A workable combination of market deregulation, competition and regulation has generally been established for Petron. For the most part, Petron operates in a competitive market, with two well-financed and effective private sector competitors. These competitors tend to constrain anti-competitive or monopolistic behavior on the part of Petron. All three companies are required to sell retail products at the same price, thus impeding anti-competitive behavior centered on price, including dumping or price collusion. Moreover, regulations applied to the industry must be relatively even-handed for all practical purposes. For example, regulations that impede the performance, management flexibility or profitability of Petron relative to its competitors will cause Petron to decline in market strength and investment value.

2. The second step is to charter the company under the corporate code. This has two important effects that help the company perform effectively and earn profits. First, it frees the company from government salary and other personnel policies and allows it to pursue, on an equal footing with its competition, salary structures and other employee policies necessary to attract and retain qualified talent. Second, it significantly removes the firm from control by governmental bureaucracies and from interference in management decisions and operations by members of the political body.

3. The third step is to sell a substantial interest in the company to either an investor who will take a significant role in the management of the company (like ARAMCO in the case of Petron), or alternatively sell a stake to the general investing public. Pursuing the first investor strategy does not preclude also pursuing the second at a later time. To sell these stakes, especially to a foreign investor taking a major financial and management role in the company, satisfactory completion of the first two steps is a necessity.

The potential application of the "Petron approach" to the electricity sector and NAPOCOR is discussed below. Table 4.1 contrasts Petron and the oil markets with NAPOCOR and the electricity markets.

The most immediate and important difference is that the fundamental preparatory market or industry environment does not exist in the electricity sector. In particular, NAPOCOR is a monopoly with essentially no competition, which stands in sharp contrast with the competitive conditions that prevail with Petron and the oil markets. In the absence of effective competition that allows a market relatively free of regulation, the alternative is a regulatory regime that promotes acceptable service and cost, but at the same time also reassures private investors that they are relatively free to operate the firm to earn acceptable profits. It is not likely that investors would so assess the current regulatory environment in the Philippines electricity industry.

Table 4.1
Comparison of NAPOCOR and Petron

Market Factor	NAPOCOR	Petron
Competitive market	No (monopoly)	Yes
Faciliatory/stable regulation	Problematic	Workability established
Commercially viable operation	Not established; problematic	Established
Exogenous benefits to investor	No	Yes
Need for regulation	High	Significantly reduced
Exposure to political interference	High	Constricted

The structural and privatization approach recommended here is designed to promote more competition in the industry, to provide more transparent and effective regulation, and, importantly for any potential application of the "Petron approach," to develop commercially viable companies, including NAPOCOR subsidiaries and Transco. To facilitate attracting and retaining the needed expertise and to prepare companies for possible sale to the public, NAPOCOR subsidiaries and Transco would be chartered under the corporate code. This might also restrain counter-productive micro-management or intervention by a political body. These companies could be offered in whole or in part to a large investor, e.g., a foreign electric utility, or more broadly to the investment community.

It is worth noting that there are potentially important strategic and financial benefits to ARAMCO that are exogenous to the financial merits of Petron as an operating entity. Most notably, ARAMCO gains additional vertical integration and an assured market for its crude development and sales activities. At the same time, the Philippines gains a reliable source of crude supply and potential investment stability. It is not clear that such exogenous factors exist for an investment in NAPOCOR.

Finally, when applied to the electric sector and NAPOCOR, the "Petron approach" might entail a large foreign investor taking a significant ownership and management role in a monopoly constrained to the nation's boundaries, bound up with the public interest, of necessity subject to regulation by governmental agencies, and never far away from political interference. It is arguably good public policy not to further complicate and constrain the overall management and development of the industry by introducing significant foreign control over a monopolistic entity as large and centrally important as NAPOCOR currently is.

This study's recommendations embody many of the same elements as the "Petron approach," e.g., establishing commercially viable entities, promoting competition, and achieving balanced and transparent regulation. Within this context, the "Petron approach" is perhaps more appropriately viewed as an *ownership option* that might be applicable to several entities in a restructured electric sector, as opposed to itself providing the basic framework for privatization.

CHAPTER 5
WORK PLAN

This chapter presents the work plan for implementing the recommended restructuring and privatization approach. The work plan focuses on Phase 1, but key activities that bear on Phase 2 issues or decisions are also noted.

The work plan consists of two parts, the Summary Plan, which identifies the major tasks, and the individual Task Plans. The designated responsibility assignments are noted on the specific task plan, as are particularly important or difficult issues.

The Summary Plan for Phase 1 is presented on the next page. During this phase, all restructuring and regulatory programs are scheduled to be in place and operating, with the exception of the further restructuring and sale of the Luzon subsidiary, sale of the Mindanao and Visayas subsidiaries, and the evaluation of further structural change in Luzon (i.e., SRMC or bid pricing system).

Two important points need to be emphasized with respect to the plan and schedule. *First, all of the recommendations can be acted on immediately without waiting for enabling legislation; there is no need to delay any implementation.* Complete implementation will require legislation, including mandates that direct agencies to carry out programs under their now existing authorities, but substantial steps on every recommendation can be taken immediately. *Second, the success of the five-year Phase 1 depends on careful, quality execution of each of the tasks. Although it might be desirable to accelerate the Phase 1 schedule, in so doing, none of the steps should be eliminated and the quality of execution should not be compromised.* A major focus of Phase 1 is to strengthen and restructure the industry to establish the necessary foundation for successful privatization.

Many key events are scheduled over the five-year Phase 1 period. Some of the more important milestones and their schedules include the following:

▸ Poolco and Planco are established	6 months
▸ Transco and generation divisions are fully operational	18 months
▸ Pilot distribution utility consolidations are in place	18 months
▸ Transmission and generation tariffs are unbundled	24 months
▸ Distribution utility regulatory programs are implemented	24 months
▸ Initial operating rules are established	27 months
▸ IRPs are filed by larger distribution utilities	30 months
▸ Transco and regional generation divisions are incorporated	36 months

- Retail wheeling policy is formulated for large customers — 36 months
- First PDP is prepared under the new industry structure — 36 months

Summary Work Plan -- Phase 1 **Philippine Electricity Industry Restructuring and Privatization**	
Task	
1.	Enact Enabling Legislation
2.	Create and Privatize Regional Power Companies in Luzon, Mindanao and the Visayas
3.	Establish Transco and Organize Regional Transmission Grid Satellites
4.	Create Poolco and Establish Utility Coordination Operating Rules
5.	Establish Distribution Utility IRP and Industry Coordinated Planning Process
6.	Organize the Hydroelectric Power Authority
7.	Organize the Small Power Utilities Group
8.	Develop and Implement Retail Wheeling
9.	Implement Consolidation and Regulatory Programs to Strengthen Distribution Utilities
10.	Rationalize Wholesale and Retail Electricity Tariffs
Comments and Issues	
1.	All recommendations can be acted on immediately without waiting for enabling legislation; there is no need to delay any implementation.
2.	All organizations in the sector, but particularly DOE and ERB, must have an ongoing program to build expertise in step with restructuring and privatization responsibilities; this must remain a high priority of management.
3.	Inherent in the work plan and in the ongoing activities of ERB and DOE will be the review and monitoring of competitive conditions, practices and behavior. Special studies or investigations may be required from time to time.

Specific work plans have not been developed for two activities in this report. These activities are an essential part of implementing the restructuring plan, but need to be formulated and implemented by the respective Philippine agencies.

- ***Monitoring competition in the industry, particularly in the generation sector.*** Through the performance of their responsibilities as defined in this report and further delineated in legislation, DOE and ERB will exercise considerable oversight over the industry and its competitive behavior. To illustrate this point, the approval of IRP policies and methods, approval of protocols for competitive bidding, review of utility IRP plans and resource acquisition decisions, and participation in the preparation of the national PDP will each provide DOE and ERB with information on industry conditions and competitiveness. So will other aspects of the recommendations, including for example, the periodic evaluations and further extensions of retail wheeling. To supplement these activities, DOE and ERB, as part of their normal operations, should track market trends and developments (e.g., market shares for each IPP GenCo on each grid) and conduct special studies or investigations on an as-needed basis.

- ***Building the capabilities of RP agencies, particularly DOE and ERB, to function in the restructured industry.*** This will be an ongoing process whose importance cannot be over-emphasized. It will be incumbent on all organizations, public and private alike, to understand the requirements that each faces and put in place programs to develop the skills and acquire the resources needed to do its job. In this respect, DOE and ERB must have an ongoing program to build expertise in step with restructuring and privatization, and this must remain a high priority of the management of these agencies.

The remainder of this chapter discusses the work plans for each task. Following the discussion, the specific work plans are illustrated in comprehensive table format.

5.1 TASK 1: ENACT ENABLING LEGISLATION

The objective of this task is to work with the legislature to develop and enact comprehensive legislation that provides the appropriate authorizations and mandates to the President, DOE, NAPOCOR, ERB, distribution utilities, and other affected organizations and agencies to implement the restructuring and privatization plan. Figure 5.1 defines the critical substantive areas where specific legislative proposals and mandates should be developed and enacted.

In developing this legislation, it will of course be important that certain steps be taken to build a consensus and sound understanding of the requirements and implications of the recommendations. A combination of workshops and task forces charged with analyzing and developing specific components of the legislative package should be established.

In addition to the areas addressed in the Task 1 work plan, an important issue to deal with in the legislation is subsidies. DOE should develop its position on how and over what period existing subsidies should be phased out, including inter-grid subsidies. To ease the transition to the new structure and allay concerns over prices, a phase-out should be adopted. Under this study's schedule, the regional subsidiaries and Transco are fully established and operational and ready for privatization by the end of Phase 1. This would be a logical period also for ending inter-regional subsidies. Ending subsidies for the Small Utilities Group will undoubtedly be more problematic, and eight years are recommended to accomplish this. The legislation should also address how the Small Utilities subsidies will be funded. This will also be an opportune time to review the other legislatively mandated subsidies to determine if they are basically acceptable under the new structure or whether revisions to these should also be proposed in the restructuring legislation.

Two additional observations can be made on the legislation. First, it should be specific with respect to key dates contained in this overall work plan, e.g., the establishment of corporate subsidiaries, the sale of these subsidiaries, the implementation of IRP, or the implementation of regulatory programs. Second, it should require that NAPOCOR, DOE and ERB formally report to the legislature on the progress of implementing the restructuring and privatization and on important issues that arise.

5.2 TASK 2: CREATE AND PRIVATIZE REGIONAL POWER COMPANIES IN LUZON, MINDANAO AND THE VISAYAS

NAPOCOR will take the first steps toward privatizing the generation sector by segregating its thermal generating plants by geographical and grid region, and forming semi-autonomous operating divisions as a precursor to the creation of subsidiaries which will then be sold to the private sector. NAPOCOR should proceed immediately with establishing these divisions.

An essential task NAPOCOR can undertake without waiting for the legislature to address restructuring is to modify its existing tariffs in anticipation of the new industry structure. By preparing and filing unbundled service tariffs now, it will lay the foundation for separate transmission and power tariffs when Transco and the regional power companies are established as separate corporate entities. Further, there are cross-grid subsidies that need to be eliminated and other rate structure reforms are needed. Work toward these objectives should begin as soon as possible to provide a smoother transition.

It is also vitally important that NAPOCOR file a specific plan with DOE to continue and extend its efforts to privatize existing generation through sales to independent power producers or through ROMs and similar arrangements that will revitalize available capacity.

In preparation for the formation of subsidiaries and their sale in Phase 2, asset valuations should be conducted and legal or financial constraints addressed, including obtaining the authorities needed for franchise and other utility operating rights.

The final steps in this task are to take the steps necessary to prepare for the disposition of NAPOCOR assets held in these subsidiaries through sales to private investors.

5.3 TASK 3: ESTABLISH TRANSCO AND ORGANIZE REGIONAL TRANSMISSION GRID SATELLITES

The purpose of this task is to create an independent transmission grid company that will act as the conduit for energy transactions on a national basis between generating companies and their customers. Transco is charged with building, operating and maintaining the national power grid, the operation of a coordinated power pool, and coordinating utility planning from a national perspective to maintain adequate, reliable electricity service. Power pooling issues and planning activities are treated in Task 4 and Task 5, respectively.

NAPOCOR should establish Transco as a separate operating division as soon as possible, but no later than 18 months and without waiting for legislative action, in order to create an immediate focus on the complex issues this organization must address in its key role in the restructured industry. Subsequent to the adoption of legislation defining the new industry structure and the completion of the necessary financial and legal undertakings to complete the transition, Transco should be made a subsidiary of NAPOCOR. Full corporate standing should be established within three years.

During these organizational changes, NAPOCOR should continue and consummate its efforts to establish regional centers for facilities management and power dispatch and control. These measures will strengthen Transco's ability to respond to problems affecting the local grids. In order to provide the access to transmission services that will make a competitive generation market a reality, Transco will need to develop transmission service tariffs which specify both prices and terms of service. The development process should begin early to have tariffs in place in two years, for the issues involved are complex.

5.4 TASK 4: CREATE POOLCO AND ESTABLISH UTILITY COORDINATION OPERATING RULES

The objective of this task is twofold: 1) to establish a dedicated division within Transco to deal with operating the grid and dispatching all significant generation, and 2) to develop, implement and administer operating rules that both capture the economies possible through "one-system" operation and facilitate effective and efficient decentralized planning by distribution utilities. Poolco should be created immediately and be charged with establishing effective central dispatch on all grids, including the installation of required communication, data and control facilities, and procedures. In parallel, Poolco will work with DOE to issue the first and most critical coordination operating rules.

NAPOCOR should be directed to establish Poolco within the next six months and charge Poolco to develop a detailed plan and schedule, including resource requirements, for accomplishing its dispatch and coordination objectives on each grid. DOE would monitor progress against this plan.

The "first generation" operating rules should be established by DOE. However, the critical expertise needed to develop these rules resides with the Poolco staff, and DOE should rely heavily on Poolco in this regard. The spirit of the rules is to facilitate all utilities and generators participating in the generation market and creating competitive pressure for generation efficiency. It is important that DOE and Poolco approach the task of developing operating rules with this objective. In addition, utilities and generators that will operate under the rules should be consulted and made part of the deliberation and development process. In this regard, DOE should take the leadership role to assemble an appropriate task force and coordinate its work. Until such time as the enabling legislation is enacted, the interim framework for operations coordination may be the EO 215 Rules. These rules should be revised and made as prescriptive as practical, and formulated with a view toward facilitating the transition from the current structure and operations to that recommended in this report. The project team has provided several suggested changes to those rules that should be considered in establishing the "first generation" set of operating rules.

Much work has been done by utility systems around the world to address how best to coordinate the operations of different utilities to capture efficiencies, facilitate planning and increase the reliability of electricity supplies. One of the activities of the operating rules working group should be to research and evaluate the experiences of other systems, including selected field investigations.

Operating rules will constantly evolve; they will not be static. We have recommended that DOE take the lead in ensuring that an initial set of rules is established for two reasons: DOE can issue rules soon and avoid lengthy negotiations among utilities, and DOE can ensure that the rules start out with the right policy direction. In the longer run, utilities and generators will become responsible for developing and implementing these rules, and Poolco should establish working committees with utility and generator representation for this purpose.

5.5 TASK 5: ESTABLISH DISTRIBUTION UTILITY IRP AND INDUSTRY COORDINATED PLANNING PROCESS

The objective of this task is to put in place and implement, for one full cycle, the new planning procedures that reflect the realignment of responsibilities in the restructured industry. These planning activities will in many respects be undertaken in parallel with current planning by NAPOCOR until a complete changeover can be made late in Phase 1. The new planning procedures must address the development of planning methodologies and guidelines, the preparation of integrated resource plans by utilities that are consistent with these guidelines and methodologies, and the integration of the utility plans into a national plan for approval.

An important issue for early resolution is the division of the authority, responsibilities and roles of DOE and ERB with respect to planning. Chapter 3 discussed a general allocation of responsibilities. The roles and responsibilities of DOE and ERB must be made as clear as possible. Clarification should be a priority during the next several months, and the resolution should be embodied in the legislation developed in Task 1.

In the planning process, Transco and its Planco and Poolco divisions will be essential participants in establishing planning guidelines, performing evaluations and analyses, and coordinating with DOE, ERB and utilities in preparing the national Power Development Program. This adds even more priority to establish Transco and for Transco to achieve full proficiency as quickly as possible.

5.6 TASK 6: ORGANIZE THE HYDROELECTRIC POWER AUTHORITY

The objective of this task is to reorganize NAPOCOR's hydroelectric business, both existing projects and projects under development (but excluding pumped storage and small projects), into an RP authority dedicated to the timely and efficient development of hydroelectric resources on all grids. This reorganization stems from two considerations. The first is to privatize NAPOCOR's generation and leave it with the key transmission and operations and planning coordination functions. Privatization will be greatly facilitated by removing hydroelectric assets from those to be transferred to the private sector. The second is simply to create focus and accountability for performing a difficult and complicated but highly essential function. A dedicated organization can be made more effective in this regard. The added administrative and coordination burden will be more than offset by these benefits.

The establishment of the Authority will proceed in much the same way as the establishment of the regional generation subsidiaries and Transco. Hydroelectric will first be established as an autonomous division. Subsequently, its staff, operations and assets will be transferred to an entity not affiliated with NAPOCOR.

During the next few months while enabling legislation is being prepared and the charter of the Authority developed, discussions should be held with other agencies involved in hydro development (e.g., the NIA) to ensure that the necessary interfaces between the Authority and these organizations are addressed, as appropriate, in the enabling legislation.

5.7 TASK 7: ORGANIZE THE SMALL POWER UTILITIES GROUP

With the successful execution of the above tasks, NAPOCOR will have organized its generation business in such a way that it can be privatized, leaving only the Small Power Utilities Group responsible for the electrification of small islands not interconnected with a primary grid. The activities of this group should also be established as a subsidiary, and the subsidiary's management charged with privatizing as many of the small island systems as possible and operating the remainder on a commercial basis or with subsidies specifically appropriated by Congress on an annual basis.

The mandate for Small Power Utilities should be embodied in the enabling legislation so that the legislature is supportive of the long-term strategy to either privatize or operate on a commercial basis. Between now and the time the strategy is successful and completely implemented, subsidies will be required. However, these subsidies should be capped at the current level and systematically reduced over an eight-year period.

5.8 TASK 8: DEVELOP AND IMPLEMENT RETAIL WHEELING

The objective of this task is to develop and implement retail wheeling, allowing certain end-users to competitively procure their electricity requirements and prompting the generation market to seek out buyers other than at the wholesale level. Applicable initially to large customers, the effectiveness of the policy will be evaluated with the presumption that retail wheeling will be made progressively available to an expanding group of users. A well-administered retail wheeling policy will also be necessary to rationalize policy on direct connected customers and facilitate the consolidation and financial strengthening programs as more fully discussed in this report. The industry may benefit by studying and following the recent initiative of the California Public Utilities Commission to order retail wheeling for large customers. Many of the issues that must be resolved to implement California's policy will be similar to those of the Philippines.

5.9 TASK 9: IMPLEMENT CONSOLIDATION AND REGULATORY PROGRAMS TO STRENGTHEN DISTRIBUTION UTILITIES

The tasks to this point have dealt primarily with improving the competitiveness and efficiency of generation and demand and supply resource acquisition by all utilities, and in creating autonomous, focused and accountable organizations in the power supply and transmission sectors. The management and operations of the distribution sector must also be addressed: the electricity consumers of the Philippines can ill afford inefficient and ineffective distribution system management. Perhaps more critical, distribution utilities must become financially credible for the restructuring and privatization to achieve its potential. Section 3.3.6 described initiatives that, if diligently pursued, will go a long way in addressing utility industry performance and establishing financial credibility. The task work plan in Figure 5.9 lays out a schedule for implementing these much needed reforms.

The enabling legislation should mandate that DOE, ERB and NEA implement these programs and report back to the legislature on results according to this work plan. The enabling legislation should authorize ERB to place into receivership any distribution utility that fails to meet its management and performance obligations to its customers.

The legislation should also authorize ERB to order consolidations pursuant to DOE policy where it has been determined that a utility is too small to be economically viable or to meet minimum service quality standards. This will become increasingly important as restructuring proceeds, and the requirements for IRP and competitive resource acquisition fall on utilities. Some will not be able to perform these tasks, either because they are too small and lack resources and expertise, or because they simply fail to perform. ERB must act in these cases based on a clear mandate to assure overall distribution utility success in the restructured industry.

5.10 TASK 10: RATIONALIZE WHOLESALE AND RETAIL ELECTRICITY TARIFFS

Rationalizing electricity tariffs is an important supporting initiative that complements the restructuring and privatization effort. By giving accurate price signals, wholesale rates provide a more appropriate basis for performing IRP, evaluating and acquiring DSM resources, and evaluating competitive offers from generators. Distortion in wholesale rates leads to distortions in these critical utility decisions, leading to inefficient choices and the misallocation of scarce resources.

Similarly, the utilities' retail rates should provide accurate price signals to end-users who also make consumption, fuel choice and appliance and capital equipment decisions based in part on electricity prices. Inaccurate retail rates lead to distortions in these end-users' decisions, and to inefficiency and the misallocation of resources.

Finally, cost-based rates and transparency in rate regulation (including the absence of political interference) will promote considerably more confidence on the part of private operators and investors, whose strong interest should be encouraged when privatizing the regional power companies.

To some degree rates will be rationalized through unbundling NAPOCOR's rates and separating transmission services from tariffs for purchased power. However, the regional power supply companies will continue to offer power at the wholesale level and also at the retail level for some customers with the advent of retail wheeling. It is thus important that the rates of these companies be addressed. Little has been done to date to improve distribution utilities' rate structures, and regulatory scrutiny is needed here as well. Distribution utilities themselves may be anxious to revise their rate schedules in response to the competitive pressures introduced by retail wheeling.

Figure 5.1

Task 1. Enact Enabling Legislation

Subtask	Description	1994 (4) 1995 (1 2 3 4) 1996 (1 2 3 4) 1997 (1 2 3 4) 1998 (1 2 3 4) 1999 (1 2)
1.1	Create and charter an autonomous Hydroelectric Power Authority and authorize the direct transfer of NAPOCOR hydro assets to the new Authority.	
1.2	Direct NAPOCOR to establish regional generation subsidiaries, transfer regional thermal generation assets to each subsidiary, set region-specific tariffs and privatize through sale. Autonomous divisions are to be created immediately and become functionally independent within 18 months, fully operational corporate subsidiaries within another 18 months, and privatized within 6 years.	
1.3	Direct NAPOCOR to establish Transco as a wholly-owned subsidiary and to transfer NAPOCOR transmission assets to the new subsidiary. Transco will own and develop the national transmission system, including island interconnections, and will be responsible for coordinated power transactions and reliability planning (Poolco) and coordinating the development of the national Power Development Program through its Planco division. Transco is to be established as an autonomous division of NAPOCOR within 18 months and a fully operational corporate subsidiary within another 18 months. Transco will establish grid connection policies and region-specific transmission prices within 24 months.	
1.4	Direct DOE to establish integrated resource planning procedures and competitive resource acquisition protocols and procedures to be followed by all utilities, and direct that all utilities follow these procedures and submit plans to DOE on a schedule to be developed by DOE. The larger utilities will be required to submit these plans by no later than the end of 1996 and all utilities by the end of 1998.	
1.5	Direct NAPOCOR to establish a subsidiary to provide service to isolated island consumers (Small Utilities Group) and direct NAPOCOR to develop a plan to rationalize the structures of these small systems with a view toward maximizing privatization. Direct and authorize NAPOCOR, as regulated by ERB, to reduce and where practical, eliminate the direct subsidies to these systems over an eight-year period and to operate any systems that have not been privatized either on a commercial basis or with subsidies provided directly through annual congressional appropriations.	

Figure 5.1

Task 1. Enact Enabling Legislation

Subtask	Description	1994: 4 · 1995: 1 2 3 4 · 1996: 1 2 3 4 · 1997: 1 2 3 4 · 1998: 1 2 3 4 · 1999: 1 2
	(Continued)	
1.6	Direct ERB to implement regulatory programs to improve the financial and operational performance of distribution utilities (private companies and cooperatives) and to rationalize inefficient structures. Provide ERB with receivership powers and authority to order consolidations to enforce these regulations. Provide ERB with franchise power over cooperatives. Provide for independent funding of ERB through a levy on electricity sales. Direct DOE, as lead agency working with ERB and NEA, to evaluate and implement small utility consolidation incentive program and to seek additional congressional authorizations if needed.	
1.7	Direct ERB to rationalize the design and structure of electric rates throughout the sector, commencing with NAPOCOR, then distribution utilities. Authorize ERB to set Transco rates to ensure commercial viability and adequate internal financing capability.	
1.8	Direct ERB to develop and implement a retail wheeling policy to promote retail competition and customer choice.	
1.9	Provide both DOE and ERB with the mandate, authority and resources each needs to guide the implementation of the industry restructuring and privatization from the policy and regulatory perspectives.	
1.10	Either discontinue NAPOCOR's fuel taxation exemption or provide exemption to all generators to eliminate current market distortions.	
1.11	Repeal PD No. 40 and modify NAPOCOR's charter to reflect its new role in the industry.	

Comments and issues:

1. Legislative mandates should be sought to eliminate subsidies, in particular inter-grid subsidies, but others as well. DOE and ERB should develop specific phase-out provisions and schedules as part of the legislation.
2. The legislation should incorporate the key dates contained in this work plan and should otherwise authorize DOE and ERB to set specific schedules for performance required by NAPOCOR, utilities and others.
3. All industry participants should be required to provide periodic reports of their progress toward meeting legislative intent and specific mandates.
4. Key responsibilities, especially for DOE and ERB, should be defined and included in the enabling legislation to the extent possible. In particular, responsibilities for developing planning guidelines and coordinating national planning, setting IRP procedures, reviewing and approving utilities' IRPs, and monitoring competitive procurement practices are key areas for which to define roles.
5. DOE should be authorized and directed to adopt appropriate measures to prevent any significant stranded asset risk for NAPOCOR.
6. The effect of CA146 Public Services Law on IPPs should be clarified and appropriate exceptions included in the legislation to eliminate potential economic regulation barriers to the development of the IPP market.

Figure 5.2

Task 2. Create and Privatize Regional Power Companies in Luzon, Mindanao and the Visayas

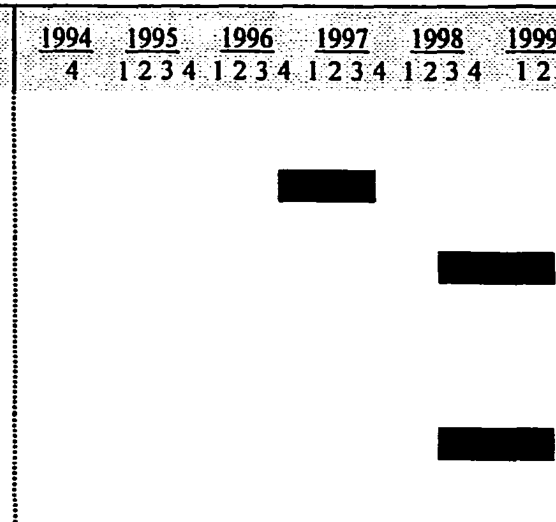
Subtask	Description
2.1	Create immediately by Board resolution autonomous regional divisions within NAPOCOR to assume control over NAPOCOR's thermal generating units, operate them efficiently, and maintain the plants to preserve and enhance their value when sold to private investors. These divisions should become fully operational within 18 months and be operated and managed as much as practical as independent entities.
2.2	NAPOCOR prepares and submits to DOE, within six months, detailed plans, schedules and responsibility assignments for establishing each subsidiary. A critical part of each plan must be a schedule for eliminating inter-grid subsidies by the end of Phase 1 in mid-1999. DOE will monitor progress against each regional plan.
2.3	Prepare and file regional unbundled electricity tariffs with ERB that are designed to recover each operating division's power costs from the customers it serves. These tariffs will be synchronized with Transco's unbundled transmission rates in order to provide the necessary transition from NAPOCOR's bundled rates that include both transmission and power supply services. The rates will be consistent with the plans to phase out subsidies and in compliance with any mandates or directives that might be contained in the enabling restructuring and privatization legislation. The deficiencies in NAPOCOR's current wholesale rate structures documented in this report should be eliminated in the new tariffs from the outset (see Task 10).
2.4	NAPOCOR prepares, within the next six months, grid-specific plans and schedules for additional privatization of existing generation through sales to IPPs, ROMs or other means. DOE will monitor performance against these plans. The objective is to continue to expand programs to rehabilitate and upgrade existing facilities by inviting active participation by private investors. This task is critical to provide capacity that adequately matches power demands, and it must not be deterred or delayed as a result of industry restructuring.
2.5	Conduct asset valuations and obtain any necessary approvals to transfer assets to each subsidiary. Secure necessary franchise or other authorities.

Schedule columns: 1994 (4); 1995 (1 2 3 4); 1996 (1 2 3 4); 1997 (1 2 3 4); 1998 (1 2 3 4); 1999 (1 2)

Figure 5.2

Task 2. Create and Privatize Regional Power Companies in Luzon, Mindanao and the Visayas

Subtask	Description
	(Continued)
2.6	Create wholly-owned, but independently managed and operated, corporate subsidiaries from the regional operating divisions. This should be accomplished within three years.
2.7	Prepare a plan for selling the Mindanao and Visayas subsidiaries, each in its entirety, to the private sector. These companies will continue as power suppliers in each area under ERB-approved tariff rates and will acquire supplies through a competitive procurement process. However, distribution utilities and end-users may choose to receive service from alternative suppliers which would be delivered via wheeling services provided by Transco and/or local distribution utilities.
2.8	Prepare a plan to reconfigure the Luzon subsidiary's assets into two or more reasonably comparable portfolios for sale to private operating companies which would be viable wholesale power suppliers (and competitors).

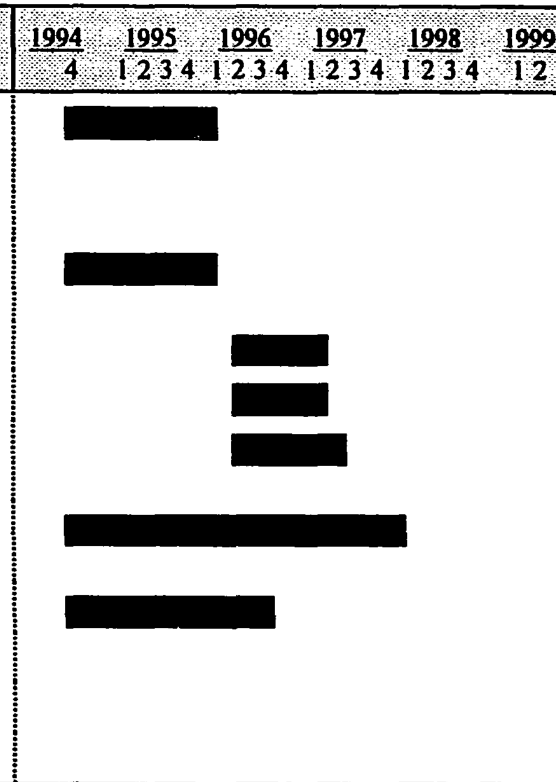


Comments and issues:

1. It is important that the establishment of these subsidiaries proceed quickly through establishing operating divisions first and honing these divisions to operate as independently as possible. This will require the delegation of considerable authority for resource commitment and other decision making.
2. Delays should be avoided in starting the process of phasing out subsidies. This process can start immediately without any additional requirements. The longer this corrective action is delayed, the more problematic it becomes to achieving restructuring and privatization goals.
3. NAPOCOR has prepared an analysis of many of the implementation issues associated with establishing the Mindanao subsidiary, none of which is particularly problematic except the potential rate adjustments associated with the elimination of subsidies. That analysis will be instructive in developing the subsidiary plans on the other grids as well.

Figure 5.3

Task 3. Establish Transco and Organize Regional Transmission Grid Satellites



Subtask	Description
3.1	Establish Transco immediately, through a Board resolution, to become a fully operational division within 18 months. Ring fence Transco as much as possible (accounting, pricing, organization and staffing, regulatory) and implement policies and procedures to make Transco's operations, policies and decisions as arms-length as possible from NAPOCOR's generation business.
3.2	Prepare updated grid expansion plans and interconnection plans along with economic rationale and proposed rate impacts for the use of each regional power division/subsidiary.
3.3	Audit and revalue NAPOCOR's transmission assets as a basis for transferring the assets to Transco.
3.4	Enact legislation granting Transco franchise and other required authorities.
3.5	Incorporate the Transco division as a wholly-owned subsidiary of NAPOCOR. Establish a separate Board of Directors and eliminate any interlocking directorates or management positions.
3.6	Establish regional power management and grid operations centers to facilitate the decentralized management of local grid operations and the economic dispatch of generation.
3.7	File tariffs with ERB specifying interconnection policy and prices for each regional grid.

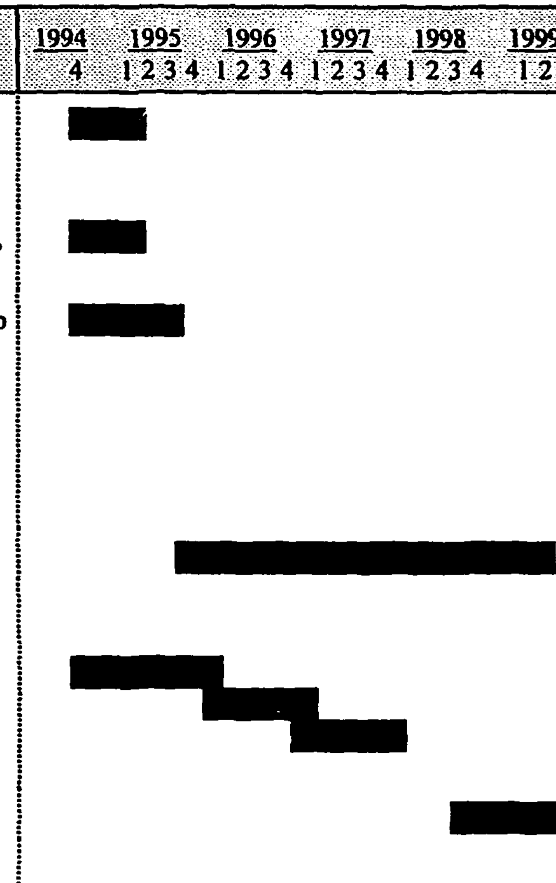
Comments and issues:

1. Establishing Transco as soon as possible is critical since it is a central feature of many aspects of the restructuring and privatization plan, including planning, operations coordination, and transmission access to generation for distribution utilities.
2. The updated transmission expansion and interconnection plans and the regional tariffs are key inputs in evaluating the overall rates that will prevail on each regional grid.

Figure 5.4

Task 4. Create Poolco and Establish Utility Coordination Operating Rules

Subtask	Description
4.1	*NAPOCOR:* Establish Poolco drawing on the expertise and experience of NAPOCOR staff. Establishing Poolco will proceed in parallel with the establishment of the Transco division, but on a shorter schedule. Poolco should be operational within a six-month period.
4.2	*Poolco:* Develop a plan for achieving full economic dispatch on each grid and installing SCADA systems, AGC and other facilities necessary to accomplish this goal.
4.3	*DOE:* Form working group with Poolco and representatives from utilities and generators (IPPs) to develop interim, "first generation" grid operating rules. Specify the priority of operating rules to be developed, evaluate the experiences of other power pools internationally, revise and expand EO 215 Rules, and develop and adopt initial set of rules. At a minimum, the initial rules should address methods for determining unit incremental costs for commitment and dispatch, economic dispatch and related billing, unit commitment procedures, operating reserve responsibility, coordinated maintenance scheduling, and installed capacity responsibility.
4.4	*Poolco:* Establish ongoing working committee to start work on "second generation" operating rules.
4.5	*Poolco:* Implement full economic dispatch: Luzon Grid 1995 Mindanao Grid 1996 Visayas Grid 1997
4.6	*Poolco and DOE:* Issue comprehensive "second generation" rules.



Comments and issues:

1. DOE should ensure that the interim grid operating rules set clear policy objectives by encouraging reasonable grid access and the development of a competitive generation market.
2. Industry standing committees or working groups will be needed over the long run to respond to changing market conditions.

Figure 5.5

Task 5. Establish Distribution Utility IRP and Industry Coordinated Planning Process

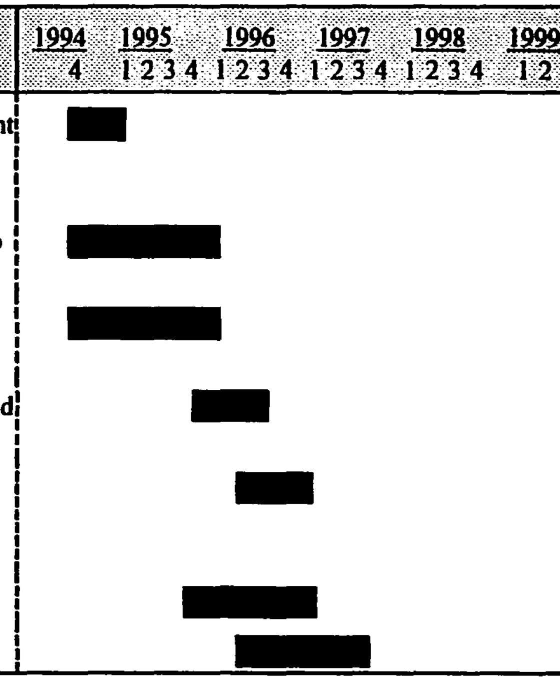
Subtask	Description	1994: 4 · 1995: 1 2 3 4 · 1996: 1 2 3 4 · 1997: 1 2 3 4 · 1998: 1 2 3 4 · 1999: 1 2
5.1	Establish procedures and guidelines for utilities in preparing integrated resource plans and conducting competitive resource acquisition. These procedures and guidelines will also deal with the review process to be followed for plans prepared by the utilities. The IRP and resource acquisition rules should be promulgated and issued by DOE for review and comment. The final rules will provide the requirements for the first IRPs to be prepared. The rules will contain a schedule for the filing of IRPs by utilities. Larger utilities with more resources should be required to be the first to comply with IRP requirements; smaller firms should be permitted, and probably encouraged, to collaborate in meeting IRP requirements.	
5.2	Establish Planco as a separate unit of Transco focused on long-term planning and resource acquisition issues involving the entire power sector.	
5.3	*Planco and ERB:* Develop planning guidelines and information collection and access capabilities to assist distribution utilities in preparing IRPs.	
5.4	Develop a process administered by Planco for the aggregation of individual utility IRPs and other industry data to produce regional and national Power Development Programs for review and approval.	
5.5	*Utilities:* File initial IRPs for review and approval. The first set of IRPs from the larger utilities will be filed by the end of 1996, with the balance of utility plans to follow over the next two years.	
5.6	*Planco, DOE and Utilities:* Prepare first Power Development Plan under the new industry structure.	
5.7	Direct utilities in their first round of competitive solicitations and acquisitions to meet approved resource requirements.	
5.8	Evaluate the effectiveness of the IRP competitive procurement process.	

Comments and issues:

1. The respective roles of DOE and ERB in each of the above subtasks must be clearly delineated; this is a priority during the preparation of legislation.
2. The timely establishment and full operation of Transco and its Poolco and Planco divisions is a key requirement in establishing the new planning procedures and implementing them through the first complete cycle.

Figure 5.6
Task 6. Organize the Hydroelectric Authority

Subtask	Description
6.1	*DOE/NAPOCOR:* Research necessary coordination with other organizations involved in hydro development and account for the proper delineation of responsibilities, authorities and interrelationships in the enabling legislation and charter of the Authority.
6.2	Organize NAPOCOR's hydroelectric business into an autonomous division and ring fence its operations to establish independent operation as much as practical.
6.3	*Hydro Division:* Prepare updated expansion plans, resource requirements, financing plans and expected power rates for planning purposes and for use by regional generation divisions/subsidiaries.
6.4	Conduct evaluation of hydroelectric exports from Mindanao, including economic feasibility, required island interconnections, proposed pricing, financing, and impact on the power industry in Mindanao.
6.5	Establish pricing and/or allocation methods for hydroelectric production applicable to each phase of restructuring, i.e., sales to NAPOCOR during the first part of Phase 1, sales to NAPOCOR subsidiaries in the latter part of Phase 1, and sales to privatized NAPOCOR subsidiaries in Phase 2.
6.6	Obtain any needed authorities from the legislature.
6.7	Transfer NAPOCOR assets to the Authority and establish fully independent operations.



Comments and issues:

1. The Authority will face key decisions on pricing and the allocation of hydroelectric generation as the industry is restructured, requiring it to choose between allocation schemes, open market selling, competitive contracts or some combination of these approaches.

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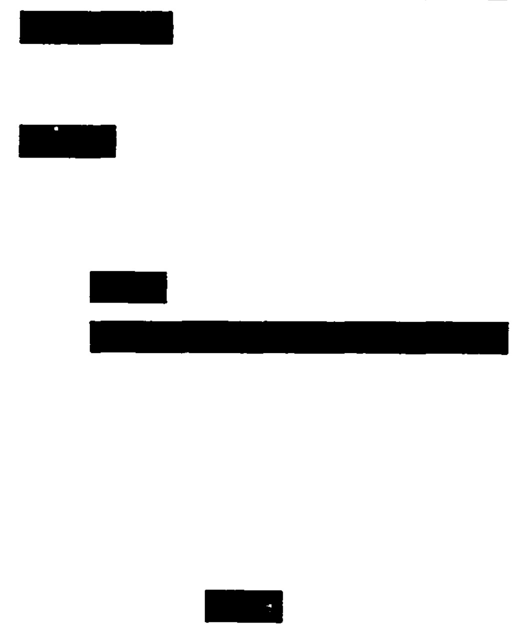
Figure 5.7

Task 7. Organize the Small Power Utilities Group

Subtask	Description	1994: 4 / 1995: 1 2 3 4 / 1996: 1 2 3 4 / 1997: 1 2 3 4 / 1998: 1 2 3 4 / 1999: 1 2
7.1	*NAPOCOR:* Establish the Small Power Utilities Group as an autonomous NAPOCOR division. Tightly ring fence -- organization and staffing, accounting, pricing and regulation -- to operate as much as possible on an independent basis.	
7.2	*Small Power Utilities Group:* Prepare a general strategy and plan for privatizing small island systems, and where it is not clearly feasible to privatize, develop a plan for phasing out subsidies and operating on a commercial basis within eight years. The plan should include appropriate consolidation of NAPOCOR and NEA activities.	
7.3	*Small Power Utilities Group:* Submit plan to Congress and resolve source and amount of subsidies.	
7.4	*Small Power Utilities Group:* Execute plan on a system-specific basis: - Develop and implement privatization strategies where feasible. - Consolidate NAPOCOR and NEA functions, and integrate into vertically organized utilities where practical. - Project costs and adopt rate strategy to phase out subsidies over an eight-year period. Subsidy reduction should start within one year and be applied consistently until rates recover actual costs of providing service.	
7.5	*Napocor:* Incorporate division as wholly-owned NAPOCOR subsidiary and transfer assets.	



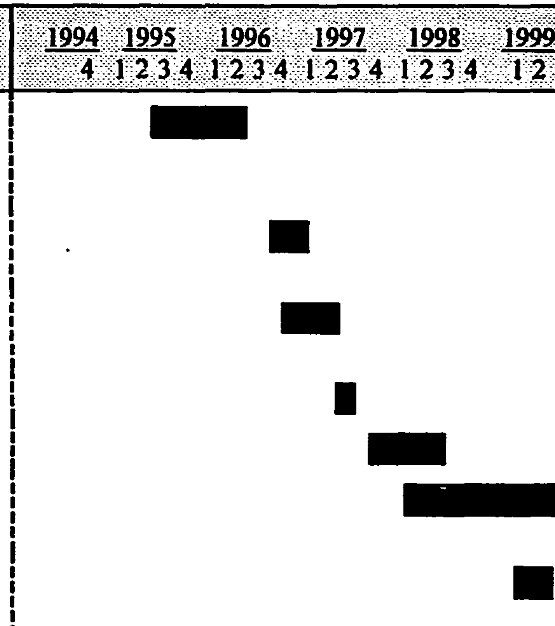
Comments and issues:

1. An issue to be resolved is the source of subsidies during the 8-year period when the Small Utilities Group is privatizing and establishing commercial viability and possibly subsequently for some of the small systems. Subsidies should be appropriated each year in the national budget according to the plan developed by the Small Utilities Group.

Figure 5.8

Task 8. Develop and Implement Retail Wheeling

Subtask	Description
8.1	*ERB:* Issue draft policy mandating retail wheeling for customers exceeding a specified size threshold. The policy shall define applicability, issues and service terms to be addressed in the wheeling tariffs, time frames for filing tariffs, and the schedule of implementation.
8.2	Affected parties in the industry, including utilities, IPPs, end-users and DOE, provide written responses to the proposed ERB policy.
8.3	*ERB:* Either holds public hearings to consider the policy or relies on the written responses to re-evaluate its policy.
8.4	*ERB:* Issues final policy, implementation schedule, guidelines and requirements.
8.5	*Utilities:* File individual retail wheeling policies and wheeling tariffs for review and approval by ERB.
8.6	*ERB:* Monitor market penetration of retail wheeling to ensure fair and unbiased access of end-users to alternative generation suppliers.
8.7	*ERB:* Evaluate wheeling policy and its effectiveness, report to DOE, and order utilities to expand the category of consumers eligible for wheeling service.



Comments and issues:

1. The issue of stranded investment usually associated with competitive access to formerly protected markets is not likely to be a serious problem in the Philippines because the demand for power exceeds near-term supplies.

Figure 5.9

Task 9. Implement Consolidation and Regulatory Programs to Strengthen Distribution Utilities

Subtask	Description	1994: 4 · 1995: 1 2 3 4 · 1996: 1 2 3 4 · 1997: 1 2 3 4 · 1998: 1 2 3 4 · 1999: 1 2
9.1	*ERB:* Set utility-specific financial and management performance standards and define ratemaking policy that will address and enforce the standards. Each utility, as part of its next rate case, will affirmatively demonstrate its compliance with the standards, or, if deficient, lay out a plan and schedule for meeting these standards, subject to ERB's acceptance and approval. Subsequent failure on the part of the utility to meet its approved schedule for improvements will result in revenue penalties or other sanctions, all in accordance with ERB's established regulations.	
9.2	*ERB:* In a similar fashion, determine appropriate standards for "lost and unaccounted for" energy, issue regulations and enforce compliance in the same manner described in 9.1 above.	
9.3	*DOE:* In conjunction with NEA and ERB, develop and implement utility consolidation incentive program. In compliance with policy established by DOE, NEA will conduct a consolidation analysis of the distribution industry on all grids and develop recommendations reflecting the new competencies that will be required of all distributors in the restructured industry. This study will be used to guide the design and implementation of the pilot and industry-wide consolidation program. It will also be instrumental to ERB in implementing rate decisions, evaluations of utility financial and technical performance, and determining the efficacy of IRP and competitive resource acquisition plans, particularly of utilities identified as high-priority candidates for consolidation.	
	-- Develop and implement pilot consolidations	
	-- Submit to Congress enabling legislation if needed, particularly for financial incentives	
	-- Expand program industry-wide	

Comments and issues:

1. Hagler Bailly's 1990 report, *Power Sector Cost Structure and Transfer Pricing Study*, prepared for the Asian Development Bank and the former Philippine Office of Energy Affairs, will be helpful in implementing these regulatory programs.

Figure 5.10

Task 10. Rationalize Wholesale and Retail Electricity Tariffs

Subtask	Description	1994: 4 / 1995: 1 2 3 4 / 1996: 1 2 3 4 / 1997: 1 2 3 4 / 1998: 1 2 3 4 / 1999: 1 2
10.1	*NAPOCOR:* File revised tariffs for each grid, consistent with the rate design and structure goals discussed elsewhere in this report. In these filings NAPOCOR identifies the inter-customer class subsidies on each grid; proposes a time frame of, at most, five years to eliminate these subsidies; and commences the phase-out in the current filing. NAPOCOR also proposes a schedule over which other deficiencies in its rates (e.g., the absence of demand charges) will be corrected.	
10.2	*ERB:* Review and either approve or modify the tariffs and the schedule for correcting subsidies and design deficiencies.	
10.3	*NAPOCOR (or the regional grid companies):* File revised tariffs in compliance with the directives and schedule approved by ERB in its orders. These tariff filings will incorporate subsidy phase-outs, rate design modifications, and key structural changes such as unbundling of transmission and generation.	
10.4	*Utilities:* At the next rate case subsequent to any change in the wholesale rate design, the utility will reflect these changes in its own rate structure. Similarly, the utility will demonstrate there is no inter-class subsidies or, otherwise, will present a plan for ERB approval for phasing out existing subsidies.	

Comments and issues:

1. Hagler Bailly's 1990 report, *Power Sector Cost Structure and Transfer Pricing Study*, will be helpful in implementing these regulatory programs.

Republic of the Philippines
Department of Energy

Restructuring and Privatization of the Electricity Industry in the Philippines

Appendices

31 August 1994

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Bureau for Global Programs, Field Support and Research
United States Agency for International Development

UNITED STATES OF AMERICA

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APPENDIX A
PHILIPPINE POWER SYSTEM DEVELOPMENT MAP

APPENDIX B
NAPOCOR SALES AND PEAK DEMAND BY CUSTOMER: LUZON GRID

B

NAPOCOR Sales and Peak Demands
Rank Ordered by Grid

Customer	Energy (KWH)	Demand (KW)	% Load Factor	Code *	Percent of Total MWH Grid	NAPOCOR
[redacted]						
UTILITIES						
MERALCO	14466750000	2591000	63.56	P	77.8170	60.8640
BATELEC II	132557166	30981	48.71	C	0.7130	0.5577
ANGELES ELECTRIC	117990009	23400	57.4	P	0.6347	0.4964
SFELAPCO	117123275	27938	47.73	P	0.6300	0.4928
BENECO	105261454	25455	47.08	C	0.5662	0.4429
PELCO III	104441770	21356	55.68	C	0.5618	0.4394
PELCO II	104166317	25920	45.75	C	0.5603	0.4382
OLONGAPO CITY	99568292	20404	55.55	O	0.5356	0.4189
TARLAC ENTERPRISES	81336530	19840	46.67	P	0.4375	0.3422
DECORP	81074288	17583	52.89	P	0.4361	0.3411
BATELCO (PENELCO	80768214	20196	45.53	C	0.4345	0.3398
CASURECO II	73281290	17438	47.84	C	0.3942	0.3083
CENPELCO	67396274	19090	40.19	C	0.3625	0.2835
CELCOR (SMI)	66352464	14016	53.89	P	0.3569	0.2792
ISELCO I	64958250	19251	38.41	C	0.3494	0.2733
PANELCO III	61979137	16628	42.43	C	0.3334	0.2608
ALECO II	58461197	12336	53.95	C	0.3145	0.2460
INEC	58078910	18602	35.54	C	0.3124	0.2443
ISECO	57873760	17667	37.29	C	0.3113	0.2435
BATELEC I	55650210	14370	44.09	C	0.2993	0.2341
LUECOM	54394002	14088	43.96	P	0.2926	0.2288
QUEZELCO I	53602466	15118	40.36	C	0.2883	0.2255
NEECO I	50266239	11958	47.85	C	0.2704	0.2115
LUELCO	47399618	13317	40.52	C	0.2550	0.1994
CANORECO	45857704	12600	41.43	C	0.2467	0.1929
NEECO III	42147510	10850	44.22	C	0.2267	0.1773
TARELCO I	39077570	11462	38.81	C	0.2102	0.1644
ISELCO II	37341850	12299	34.56	C	0.2009	0.1571
NEECO II	36779862	9512	44.02	C	0.1978	0.1547
PELCO I	35600541	9480	42.75	C	0.1915	0.1498
CAGELCO I	35288800	9500	42.29	C	0.1898	0.1485
ZAMECO II	33705403	8460	45.36	C	0.1813	0.1418
FLECO	30969779	7410	47.58	C	0.1666	0.1303
TARELCO II	27944467	7800	40.79	C	0.1503	0.1176
ZAMECO I	25124383	6240	45.84	C	0.1351	0.1057
ALECO I	24572497	5760	48.57	C	0.1322	0.1034
CAGELCO II	23745968	7151	37.8	C	0.1277	0.0999
CASURECO I	22922511	7488	34.85	C	0.1233	0.0964
NUVELCO	22818040	6475	40.12	C	0.1227	0.0960
CASURECO III	21877980	6295	39.57	C	0.1177	0.0920
BATANGAS CITY	19873360	12579	17.99	O	0.1069	0.0836
ALECO III	19408543	6228	35.48	C	0.1044	0.0817

*Code: P=private, C=Cooperative, O=Munis/Prov/City

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Appendix B
NAPOCOR Sales and Peak Demands
Rank Ordered by Grid

Customer	Energy	Demand	% Load	Code	Percent of Total MWH	
	(KWH)	(KW)	Factor	*	Grid	NAPOCOR
LUZON						
SAN JOSE CITY	18812732	4050	52.88	C	0.1012	0.0791
SORECO II	17293160	4884	40.31	C	0.0930	0.0728
BAUAN MUN	16468900	3885	48.26	O	0.0886	0.0693
PANELCO I	15554350	4560	38.83	C	0.0837	0.0654
MANSONS CORP	13279778	3642	41.51	P	0.0714	0.0559
SORECO I	10780980	3168	38.74	C	0.0580	0.0454
ABRECO	10425800	3360	35.32	C	0.0561	0.0439
CASURECO IV	10281752	3336	35.09	C	0.0553	0.0433
IBAAN ELECTRIC	6863500	1575	49.61	P	0.0369	0.0289
SAN PASCUAL MUN	6738200	1921	39.93	O	0.0362	0.0283
QUIRELCO	6233500	3278	21.65	C	0.0335	0.0262
MANAOAG UTILITY	5823510	1691	39.21	P	0.0313	0.0245
AURELCO	5591250	1680	37.89	C	0.0301	0.0235
QUEZELCO II	5247900	1313	45.5	C	0.0282	0.0221
KAELCO	4584475	1614	32.34	C	0.0247	0.0193
PRESCO	4521133	1610	31.9	C	0.0243	0.0190
IFELCO	2583560	1014	29.01	C	0.0139	0.0109
MORPRECO	2483600	1194	23.68	C	0.0134	0.0104
SAN NICOLAS	1186150	364	3.1	O	0.0064	0.0050
PAELCO	631400	630	11.41	C	0.0034	0.0027
AURELCO - CASIGUR	330582	0		C	0.0018	0.0014
BATANELCO	287560	203	16.13	C	0.0015	0.0012
NORZAGARAY MUN	176060	52	38.54	O	0.0009	0.0007
KAELCO - LUBUAGAN	10500	0		C	0.0001	0.0000
CAGAYAN II - CALAYAN	2730	0		C	0.0000	0.0000
SUBSUBTOTAL	16971980962	3234565			81.2927	71.4040
INDUSTRIES						
PHILEX MINES	198183300	31800	70.95		1.0660	0.8338
BCI - DIZON MINES	113980845	18600	69.76		0.6131	0.4795
NCC	96694500	17200	64		0.5201	0.4068
BENGUET MINES	92295840	15600	6.35		0.4965	0.3883
TRUST INTL PAPER CO.	81292800	12000	77.12		0.4373	0.3420
LEPANTO	77819700	12873	68.82		0.4186	0.3274
REPUBLIC CEMENT	77760861	13950	63.46		0.4183	0.3272
HI - CEMENT	71971890	15750	52.02		0.3871	0.3028
SAN MIGUEL CORP.	59503101	12000	56.45		0.3201	0.2503
SKK STEEL	51466056	26644	21.99		0.2768	0.2165
EPZA - BAGUIO	44810850	6400	79.71		0.2410	0.1885
FORTUNE CEMENT	42336000	8294	58.11		0.2277	0.1781
BCI- CEMENT	40695200	6400	72.39		0.2189	0.1712
EPZA - BATAAN	39740238	8700	52		0.2138	0.1672
BPPMI	38551834	5700	77		0.2074	0.1622

*Code: P=private, C=Cooperative, O=Munis/Prov/City

Appendix B
NAPOCOR Sales and Peak Demands
Rank Ordered by Grid

Customer	Energy (KWH)	Demand (KW)	% Load Factor	Code *	Percent of Total MWH Grid	Percent of Total MWH NAPOCOR
ZON						
ONTINENTAL CEMENT	34376790	8850	44.22		0.1849	0.1446
PZA - CAVIT	33933900	8400	45.99		0.1825	0.1428
ENTRAL CEMENT	32412940	5100	72.35		0.1743	0.1364
MILWAUKEE	29960368	17400	19.6		0.1612	0.1260
JPPC	27731895	5100	61.9		0.1492	0.1167
CAT	24818886	7560	37.37		0.1335	0.1044
ELEGANT	22361761	12900	19.73		0.1203	0.0941
ANLUBANG SUGAR EST	13729273	2700	57.89		0.0739	0.0578
INGASCO	13006000	1900	77.93		0.0700	0.0547
SOLID EVT CORP	12657553	8200	17.57		0.0681	0.0533
BAGAC NUCLEAR	12018595	3630	37.69		0.0646	0.0506
PILIPINAS SHELL	11812500	4200	32.02		0.0635	0.0497
CCP	10825806	1620	6.08		0.0582	0.0455
ITOGON- SUYOC	10318320	2160	54.38		0.0555	0.0434
FINE CHEM PHILS.	10273267	3276	35.7		0.0553	0.0432
PARAGON-JOHANNESBURG	8882125	2100	48.12		0.0478	0.0374
CALTEC PHILS	8603000	3300	29.68		0.0463	0.0362
PHILSECO	8138115	3800	24.38		0.0438	0.0342
BCI - COTO MINES	8037010	2400	38.12		0.0432	0.0338
MG CHEMICALS	7631400	1470	59.1		0.0410	0.0321
ACIFIC FLOUR MILLS	6629000	1575	47.92		0.0357	0.0279
A G & P	4576665	1950	26.72		0.0246	0.0193
PHIL ASIA FOODS INC	3988380	1932	23.5		0.0215	0.0168
ISAROG PULP & PAPER	3322840	829	45.63		0.0179	0.0140
BRC	3186072	4200	8.64		0.0171	0.0134
PNOC- BAUAN	2814000	1200	26.7		0.0151	0.0118
KEPPEL (PHILS)	2651950	1156	26.12		0.0143	0.0112
CORDERO ICE PLANT	2481500	600	47.08		0.0133	0.0104
DND - ARSENAL	2360778	750	35.83		0.0127	0.0099
PANIQUI SUGAR CORP	1790617	783	26.03		0.0096	0.0075
ITED CHEMICALS	1652000	2218	8.48		0.0089	0.0070
ANTERS PRODUCTS	1567471	648	27.54		0.0084	0.0066
E.E.I.	1382500	525	29.98		0.0074	0.0058
EMPLAR ENTERPRISES	1325110	700	21.55		0.0071	0.0056
TS BAY TERMINAL IN	1281000	328	44.46		0.0069	0.0054
BACOCK-HITACHI PHI	1130500	390	33		0.0061	0.0048
MMRC (GABALDON)	1096000	180	69.32		0.0059	0.0046
CAPITOL HEAVY IND	814231	868	10.68		0.0044	0.0034
PHIL EXPLOSIVE	753160	428	20.03		0.0041	0.0032
LIPA ICE PLANT	695800	117	67.7		0.0037	0.0029
SPAR DEVELOPMENT	676211	435	17.7		0.0036	0.0028
UNION CARBIDE	298934	266	12.79		0.0016	0.0013
LUZON AGGREGATES	272960	230	13.51		0.0015	0.0011

*Code: P=private, C=Cooperative, O=Munis/Prov/City

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NAPOCOR Sales and Peak Demands
Rank Ordered by Grid

Customer	Energy (KWH)	Demand (KW)	% Load Factor	Code *	Percent of Total MWH Grid	NAPOCOR
FPIC (GABALDON)	206400	20	117.49		0.0011	0.0009
BENGUET - TUDING	171000	120	16.22		0.0009	0.0007
IPO LIMESTONE	139282	127	12.49		0.0007	0.0006
PHILSUCOM	66168	41	18.37		0.0004	0.0003
SUBSUBTOTAL	1515963048	340593			8.1544	6.3779
MISCELLANEOUS						
VOA	23824740	5381	50.4		0.1282	0.1002
AFP-CABCOM	20105168	4500	50.86		0.1081	0.0846
INT'L RICE RES INST	16177952	3723	49.47		0.0870	0.0681
UNIV OF PHIL LB	10129280	3966	29.08		0.0545	0.0426
REFUGEE CENTER	5758777	1440	45.53		0.0310	0.0242
BASA AIR BASE	4110199	960	48.74		0.0221	0.0173
PMA	2678040	726	41.99		0.0144	0.0113
FERNANDO AIRBASE	2568600	618	47.32		0.0138	0.0108
NIA - AMRIS	2225640	1060	23.9		0.0120	0.0094
NIA - MAGAPIT	2201500	2275	11.02		0.0118	0.0093
BATS CITY WATER DIST	2083284	320	4.12		0.0112	0.0088
CLSU	1970822	684	32.8		0.0106	0.0083
NIA - GUIMBA	1236588	655	21.49		0.0067	0.0052
MWSS	1002602	907	12.58		0.0054	0.0042
NIA - AMULUNG	970200	1260	8.77		0.0052	0.0041
NIA - PANTABANGAN	929115	630	16.79		0.0050	0.0038
ASIA KONSTRUCT	818120	210	44.35		0.0044	0.0034
BOY SCOUT PHIL	771120	308	28.5		0.0041	0.0032
FOREST PROD RES	699638	332	23.99		0.0038	0.0029
NIA - UPRIIS	533840	195	31.17		0.0029	0.0022
NIA (LAGUNA)	470325	146	36.67		0.0025	0.0020
FOREST RESEARCH INST	411180	252	18.58		0.0022	0.0017
MPBC	226464	54	47.74		0.0012	0.0010
NIA - MRIIS	220505	399	6.29		0.0012	0.0009
NIA - ISABELA	169010	1260	1.53		0.0009	0.0007
PHIL ARMY BRIGADE	150720	0			0.0008	0.0006
NPC PERSONNEL	105617	0			0.0006	0.0004
PNOC - TIWI	78766	0			0.0004	0.0003
PNOC (MAK-BAN)	72384	0			0.0004	0.0003
AFP RADIO STATION	57301	16	40.77		0.0003	0.0002
NIA - DULONGBAYAN	16660	47	4.04		0.0001	0.0001
NIA - AMPUCAO	11466	0			0.0001	0.0000
NIA - SAN FABIAN	9702	31	3.56		0.0001	0.0000
PORTO DEL SOL	1320	17	0.88		0.0000	0.0000
SUBSUBTOTAL	102796645	32372			0.5529	0.4325
SUBTOTAL	18,590,740,655	3607530			100.0000	78.2144

*Code: P=private, C=Cooperative, O=Munis/Prov/City

APPENDIX C
NAPOCOR SALES AND PEAK DEMAND BY CUSTOMER: MINDANAO GRID

Appendix C
NAPOCOR Sales and Peak Demands
Rank Ordered by Grid

Customer	Energy (KWH)	Demand (KW)	% Load Factor	Code *	Percent of Total MWH Grid	NAPOCOR
MINDANAO						
UTILITIES						
EPALCO	316183695	73005	49.31	P	10.7176	1.3302
LPCO	307759535	73968	47.37	P	10.4320	1.2948
SOCOTECO II	156727906	34001	52.48	C	5.3126	0.6594
ZAMCELCO	144851997	31385	52.54	C	4.9100	0.6094
MORESCO I	110472745	34178	36.8	C	3.7447	0.4648
ILPI	105637061	21978	54.72	P	3.5808	0.4444
ANECO	79461437	18503	48.89	C	2.6935	0.3343
DANECO	75626769	19119	45.036	C	2.5635	0.3182
MELCI II	43478462	11588	42.71	C	1.4738	0.1829
COTLIGHT (CLPCO)	41596464	10044	47.15	P	1.4100	0.1750
AMSURECO I	40684731	11740	39.45	C	1.3791	0.1712
DASURECO	40505193	9587	48.1	C	1.3730	0.1704
MORESCO II	31993994	8470	43	C	1.0845	0.1346
SURNECO	30620528	6606	52.77	C	1.0379	0.1288
FIBECO	30524434	7837	44.34	C	1.0347	0.1284
LASURECO	29750350	7083	47.82	C	1.0084	0.1252
SOCOTECO I	28045149	7823	40.81	C	0.9506	0.1180
MAGELCO	27950330	8740	36.41	C	0.9474	0.1176
ZANECO	26826238	8507	35.9	C	0.9093	0.1129
SUKELCO	24392074	6672	41.62	C	0.8268	0.1026
SURSECO I	23661939	5767	46.71	C	0.8021	0.0995
LANECO	22074913	10170	24.71	C	0.7483	0.0929
DORECO	21529776	5422	45.21	C	0.7298	0.0906
COTELCO	21526408	8353	29.34	C	0.7297	0.0906
ASELCO	21345574	9239	26.3	C	0.7235	0.0898
ZAMSURECO II	20246525	6495	35.49	C	0.6863	0.0852
BUSECO	17758100	6053	33.4	C	0.6019	0.0747
MELCI I	11068530	3600	35	C	0.3752	0.0466
SURSECO II	7988225	2670	34.06	C	0.2708	0.0336
CAMELCO	2731397	1473	21.11	C	0.0926	0.0115
SIARELCO	386802	690	6.38	C	0.0131	0.0016
SUBSUBTOTAL	1863407281	470766			63.1634	7.8397
INDUSTRIES						
NSC	332492906	92031	41..3		11.2704	1.3989
PICOP (BISLIG)	134089121	25440	60		4.5452	0.5641
PCS	125690512	23196	61.69		4.2605	0.5288
MCCI	111865368	18000	70.75		3.7919	0.4706
MVC	80024400	16920	53.84		2.7126	0.3367
DUCC	61308969	13020	53.51		2.0782	0.2579
FCC/ACC	41941200	11040	43.25		1.4217	0.1765
ICC	40203670	9699	47.19		1.3628	0.1691

*Code: P=private, C=Cooperative, O=Munis/Prov/City

Appendix C
NAPOCOR Sales and Peak Demands
Rank Ordered by Grid

Customer	Energy (KWH)	Demand (KW)	% Load Factor	Code *	Percent of Total MWH Grid	Percent of Total MWH NAPOCOR
MINDANAO						
MPCC	26104750	4100	72.48		0.8849	0.1098
NDMC	25913899	12585	23.44		0.8784	0.1090
PACEMCO	20963783	4416	54.04		0.7106	0.0882
DOLE PHIL	20517206	5412	43.16		0.6955	0.0863
PILMICO (PFC)	14364327	2920	56		0.4869	0.0604
NALCO	12956596	3772	39.1		0.4392	0.0545
PPC (DMPI)	10676433	2700	45.02		0.3619	0.0449
MCC (PNOC)	8861292	2274	44.36		0.3004	0.0373
SIOM	7793606	2329	38.1		0.2642	0.0328
PICOP (ILIGAN)	4193802	1011	47.22		0.1422	0.0176
MENDECO (MDC)	2656524	772	39.17		0.0900	0.0112
BCC/PNOC	2306764	633	41.49		0.0782	0.0097
SUBSUBTOTAL	1084925128	252270			36.7754	4.5645
MISCELLANEOUS						
FOURTH ID	1274668	301	48.21		0.0432	0.0054
GSDPEA	177339	0			0.0060	0.0007
MENZI AGRI CORP	158908	57	31.74		0.0054	0.0007
COMMEL	90650	23	44.87		0.0031	0.0004
DAVAO HOUSING	41410	0			0.0014	0.0002
NMTC (RMTC)	30996	22	16.04		0.0011	0.0001
GEN SANTOS HOUSING	25710	0			0.0009	0.0001
KIBAWE HOUSING	4064	0			0.0001	0.0000
PAL	254	1	2.89		0.0000	0.0000
SUBSUBTOTAL	1803999	404			0.0611	0.0076
SUBTOTAL	2,950,136,408	723440			100.0000	12.4117

*Code: P=private, C=Cooperative, O=Munis/Prov/City

APPENDIX D
NAPOCOR SALES AND PEAK DEMAND BY CUSTOMER: VISAYAS GRID

Appendix D
NAPOCOR Sales and Peak Demands
Rank Ordered by Grid

Customer	Energy (KWH)	Demand (KW)	% Load Factor	Code *	Percent of Total MWH Grid	NAPOCOR
[redacted]						
UTILITIES						
BOHOL PROVINIAL	24748546	4931	57.14	O	45.4284	0.1041
BOHECO I	13526152	5812	26.49	C	24.8286	0.0569
BOHECO II	12684124	3979	36.29	C	23.2830	0.0534
SUBSUBTOTAL	50958822	14722			93.5400	0.2144
INDUSTRIES						
PHILIPPINE STARCH	2242432	951	26.84		4.1162	0.0094
PHILIPPINE SINTER	809149	546	16.87		1.4853	0.0034
SUBSUBTOTAL	3051581	1497			5.6015	0.0128
[illegible]CELLANEOUS						
[illegible]OL ENTERPRISES	467719	128	41.6		0.8585	0.0020
[illegible]SUBTOTAL	467719	128			0.8585	0.0020
[illegible]TOTAL	54,478,122	16347			100.0000	0.2292
[redacted]						
UTILITIES						
VECO	700943328	129781	61.49	P	74.7210	2.9490
CEBECO II	51024557	23597	24.62	C	5.4392	0.2147
MECO	39625219	7728	58.37	P	4.2241	0.1667
CEBECO I	22964325	6505	40.19	C	2.4480	0.0966
CEBECO III	20464652	4901	47.54	C	2.1815	0.0861
SUBSUBTOTAL	835022081	172512			89.0139	3.5131
INDUSTRIES						
MEPZA	66409658	13644	55.41		7.0793	0.2794
GENERAL MILLING CORP	33105898	6919	54.47		3.5291	0.1393
PRIME WHITE CC	1169465	686	19.41		0.1247	0.0049
ATLAS CMDC	2285	4201	0.01		0.0002	0.0000
SUBSUBTOTAL	100687306	25450			10.7333	0.4236
MISCELLANEOUS						
PHIL AIR FORCE	2335563	469	56.49		0.2490	0.0098
PNOC - LAB	23927	0			0.0026	0.0001
GARCIA CANTEEN	5461	0			0.0006	0.0000
AER CONST	2580	0			0.0003	0.0000
RR CONST	1997	0			0.0002	0.0000
VENUS CANTEEN	1757	0			0.0002	0.0000
ABB/MOBI	79	0			0.0000	0.0000
SUBSUBTOTAL	2371364	469			0.2528	0.0100
SUBTOTAL	938,080,751	198431			100.0000	3.9467

*Code: P=private, C=Cooperative, O=Munis/Prov/City

Appendix D
NAPOCOR Sales and Peak Demands
Rank Ordered by Grid

Customer	Energy (KWH)	Demand (KW)	% Load Factor	Code *	Percent of Total MWH Grid	NAPOCOR
[redacted]						
UTILITIES						
LEYECO II	56285895	17855	35.89	C	12.1685	0.2368
LEYECO V	38244771	9640	45.17	C	8.2682	0.1609
LEYECO I	12372903	7095	19.85	C	2.6749	0.0521
SAMELCO II	12289670	3368	41.54	C	2.6569	0.0517
LEYECO IV	9937436	2842	39.81	C	2.1484	0.0418
SOLECO	9719288	5809	19.05	C	2.1012	0.0409
NORSAMELCO	8219908	2909	32.17	C	1.7771	0.0346
SAMELCO I	7073058	2460	32.73	C	1.5291	0.0298
LEYECO III	6032582	3194	21.5	C	1.3042	0.0254
ESAMELCO	5963687	3894	1.44	C	1.2893	0.0251
BILECO	3986303	1347	33.69	C	0.8618	0.0168
SUBSUBTOTAL	170125501	60413			36.7796	0.7157
INDUSTRIES						
PASAR	177254479	32736	61.64		38.3208	0.7457
PHILPHOS	115173779	18567	70.62		24.8995	0.4846
SUBSUBTOTAL	292428258	51303			63.2204	1.2303
SUBTOTAL	462,553,759	111716			100.0000	1.9460
[redacted]						
UTILITIES						
CENECO	214918349	41533	58.91	C	48.3083	0.9042
VRESCO	79373620	17704	51.04	C	17.8412	0.3339
NOCECO	59636370	14365	4.26	C	13.4048	0.2509
NORECO II	47127588	10151	52.85	C	10.5931	0.1983
NORECO I	16919463	4694	41.03	C	3.8031	0.0712
AMLAN MUN	1507431	467	36.75	O	0.3388	0.0063
SUBSUBTOTAL	419482821	88914			94.2892	1.7648
INDUSTRIES						
NOBEL PHILS	13455618	2418	63.35		3.0245	0.0566
SMC - BACOLOD	11192830	2275	56.01		2.5159	0.0471
DUCOMI	565387	632	10.18		0.1271	0.0024
PHESCO	3181	11	3.29		0.0007	0.0000
SUBSUBTOTAL	25217016	5336			5.6682	0.1061
MISCELLANEOUS						
M L TEVES	149708	45	37.87		0.0337	0.0006
G FLEISCHER	39948	15	30.32		0.0090	0.0002
SUBSUBTOTAL	189656	60			0.0426	0.0008
SUBTOTAL	444,889,493	94310			100.0000	1.8717

*Code: P=private, C=Cooperative, O=Munis/Prov/City

Appendix D
NAPOCOR Sales and Peak Demands
Rank Ordered by Grid

Customer	Energy (KWH)	Demand (KW)	% Load Factor	Code *	Percent of Total MWH Grid	Percent of Total MWH NAPOCOR
[redacted]						
UTILITIES						
PECO	168664549	32568	58.96	P	51.4094	0.7096
CAPELCO	45961508	10446	50.09	C	14.0092	0.1934
ILECO I	40799455	10424	44.56	C	12.4358	0.1717
ILECO II	24965352	7065	40.23	C	7.6095	0.1050
AKELCO	22699170	6781	38.11	C	6.9188	0.0955
ANTECO	11983975	3933	34.69	C	3.6527	0.0504
ILECO II	9770401	2933	37.92	C	2.9780	0.0411
GUIMELCO	3236559	900	40.94	C	0.9865	0.0136
SUBSUBTOTAL	328080969	75050			100.0000	1.3803
SUBTOTAL	328,080,969	68950				
TOTAL	23,768,960,157	4820724				

*Code: P=private, C=Cooperative, O=Munis/Prov/City

APPENDIX E
WORKSHOP ON ELECTRIC SECTOR RESTRUCTURING AND NPC PRIVATIZATION

WORKSHOP

ON

ELECTRIC SECTOR RESTRUCTURING
AND
NPC PRIVATIZATION

Conducted By
RCG/HAGLER, BAILLY, INC.

Sponsored By

The Philippine Department of Energy

and

The U.S. Agency for International Development

February 15-16, 1994
Mandarin Oriental Hotel
Makati, Metro Manila, Philippines

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WORKSHOP ON ELECTRIC SECTOR RESTRUCTURING AND NPC PRIVATIZATION

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WORKSHOP ON ELECTRIC SECTOR RESTRUCTURING AND NPC PRIVATIZATION

1.0 INTRODUCTION

This report capsulizes the outputs of a Workshop on **ELECTRIC SECTOR RESTRUCTURING AND NPC PRIVATIZATION** recently conducted by RCG/Hagler, Bailly, Inc. in coordination with the Philippine Department of Energy (DOE). The workshop was held last February 15-16, 1994 at the Mandarin Oriental Hotel in Makati, Philippines.

The key planners and facilitators of the 2-day workshop sessions were: Michael Ellis, Stan Bowden and Ashley Brown, consultants of RCG/Hagler, Bailly, Inc.

2.0 BACKGROUND

RCG/Hagler, Bailly, Inc. is assisting the Department of Energy of the Philippines to formulate the appropriate policies for the privatization of the National Power Corporation (NPC) under the USAID's ESAP Technical Assistance to the DOE Project. In line with this task, RCG/Hagler, Bailly, Inc. organized a 2-day workshop.

2.1 Objectives of the Workshop

The principal objectives for organizing the workshop were to

- define the specific objectives for restructuring and privatization of the NPC;
- discuss specific restructuring approaches and how they could work in the Philippines; and
- analyze implementation issues from the perspective of those to be involved in the privatization program.

The consensus developed during the workshop was intended to provide direction to the consultants in drawing up the specific work plan for restructuring and privatization.

2.2 Workshop Participants

The selection of the workshop participants was carried out by the DOE. Notably, the intention was to gather inputs from those involved with power generation, transmission and distribution in both the government and private sectors. Annex A shows the listing of those who attended the workshop.

3.0 HIGHLIGHTS OF THE DISCUSSIONS

3.1 Restructuring and Privatization Objectives

It was the consensus that the most critical goals for privatizing NPC are:

- to minimize political considerations in decision making in the sector;
- to motivate each entity in the sector to operate on a commercially viable basis, thereby eliminating government subsidies; and
- to improve efficiency and promote healthy competition within the sector.

3.2 Desirable Industry Structure Characteristics

The following characteristics were presented by the consultants which will promote competition and in general, help achieve gains in efficiency:

- Existence and development of many sellers
- Existence and development of many buyers
- Ease of bilateral trade between buyers and sellers
- Ease of entry into power generation activities
- Access to essential facilities such as transmission
- Transparent marginal cost-based pricing
- Unbundled core functions
- Level playing field among participants in each core function
- Availability of planning information.

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3.3 Existing Structure of the Philippine System

The present structure of the Philippine electricity system is characterized as follows:

- Generation is largely by NPC, with a number of independent power producer generating companies (IPP GenCo's) supplementing NPC generation. These IPP GenCos are new participants in the industry, having been established through the recent "fast track" program to meet generation shortfalls.

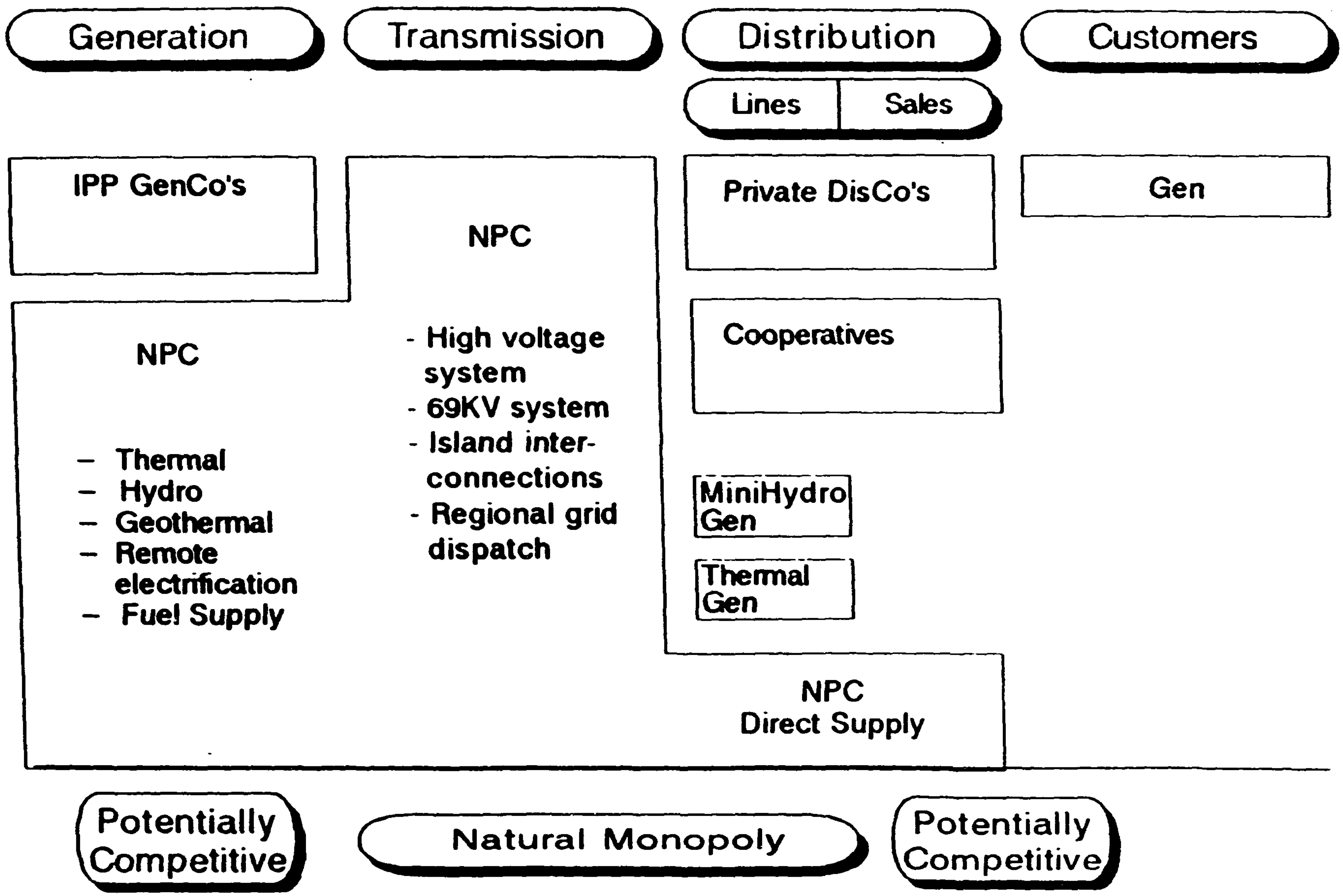
- Transmission and dispatch functions are also performed by NPC, i.e., transmission, dispatch and generation are vertically integrated.

- Distribution lines and sales functions are performed by the private distribution companies and rural electric cooperatives for most customers, although NPC also performs these functions for several customers that are directly connected to the grid at 69KV or higher. For these customers, NPC is a fully vertically integrated utility.

- A limited amount of generation is performed by distribution companies, mostly mini-hydro and small thermal units.

- On the customers' side, considerable amount of generation exists, mostly as emergency units to deal with brown-outs.

Existing Structure of the Philippines Electricity Industry



3.4 Possible Evolution of the Existing Structure of the Philippine Electric Industry

Based on the existing structure, the Philippine electric industry may evolve along the following lines:

3.4.1 *General Assumptions*

- Current policies and trends will remain

- No significant structural change will be pursued

- The present policies shall continue to be aggressively pursued:

  a. Intensified private sector participation, particularly in the generation function to build new capacity and rehabilitate and operate existing NPC generating units;

  b. Increased "transparency" of operations and pricing;

  c. Greater accountability for performance; and

  d. Improved regulatory effectiveness

3.4.2 *"Ring Fencing"*

The concept of "ring fencing" was liberally considered as alternate to actual structural unbundling or separation of functions. Rather than creating a new organization, organizational units can be established within an existing organization (e.g. NPC), which through accounting, pricing and regulatory practices, can be made more visible and more accountable.

3.4.3 *Generation*

In the generation function, the following developments may be expected:

- Independent power producers continue to grow and account for a substantial part of the generating function within the industry.

- There will be diversity in the types of contract arrangements, e.g. build-operate-transfer, build-own-operate, repair-own-and maintain, etc.

- Hydro development could be spun off into a subsidiary or independent company.

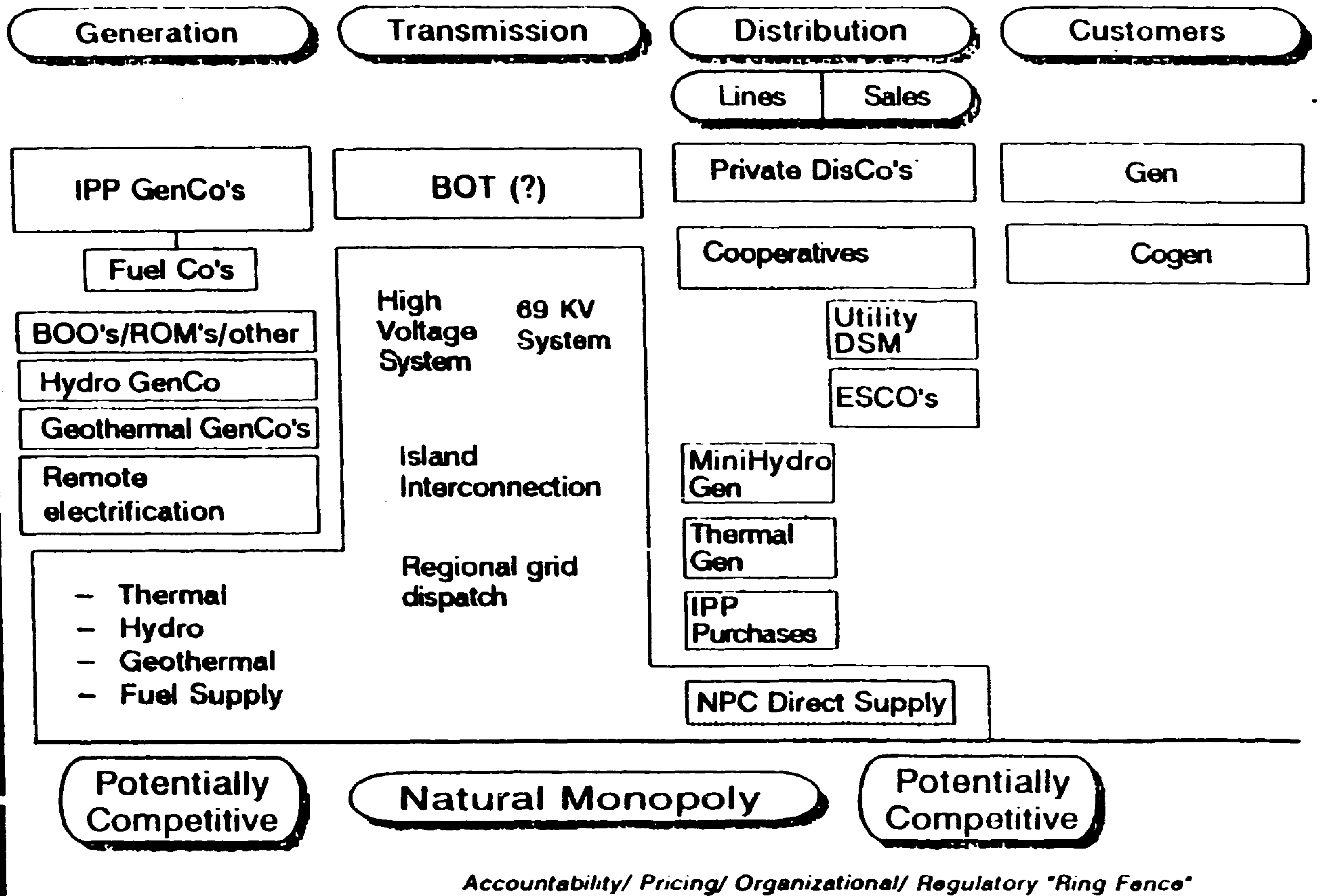
- The private sector may develop geothermal companies.

- NPC may get out of the business of supplying fuel to give way to private companies.

3.4.4 *Transmission*

- The consultant noted no evident substantial change in the current trends but observed that some BOT transmission projects are possible. Four major activities, however lend themselves to ring fencing: high voltage transmission, 69 KV sub-transmission, island interconnections and regional grid dispatch. The result can be more visibility and greater flexibility in preparation for future privatization.

Possible Evolution of Existing Structure of the Philippines Electric Industry



3.5 Approaches and Structural Models for Consideration

Four models for restructuring and privatization were presented for consideration in the Philippine setting.

Options presented by the consultants that may be pursued in restructuring and privatizing the Philippine electricity industry have three main differentiating characteristics:

- Degree of vertical integration in the structure of the industry

- Reliance on competitive forces as a primary means of promoting efficient investment and operations.

- Focus of regulation (i.e. between maintaining competitive balance on one hand and focus on monopolistic and regulatory policies on the other)

3.5.1 *The "Market Clearing Pricing System" Approach*

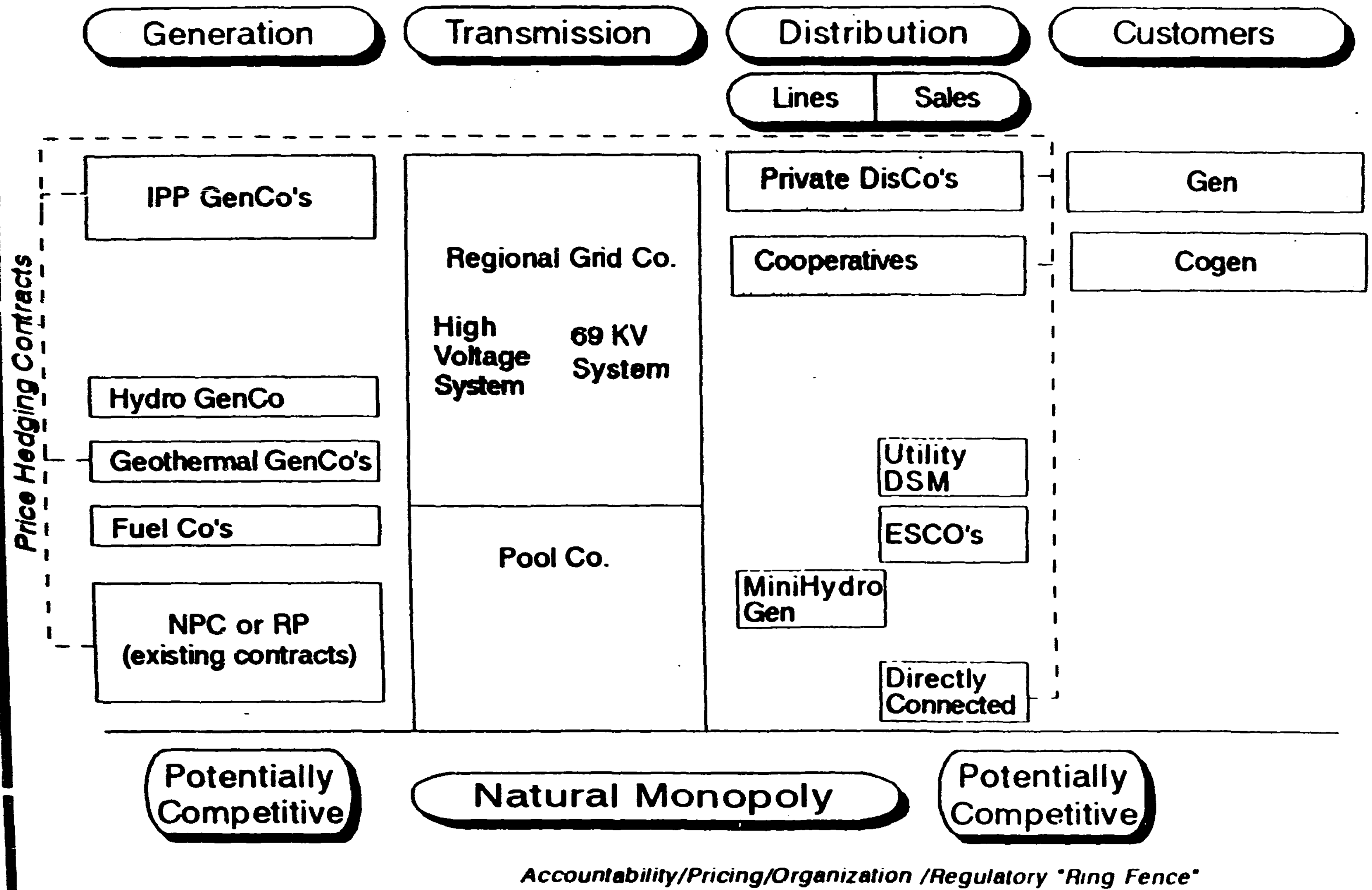
This approach exhibits the most unbundling and reliance on competition. It provided the underlying basis for restructuring and privatization of the power sector in England/Wales, and Argentina.

Under this approach, all generation would be spun off to IPP GenCo's, Hydro Genco and Geothermal Genco's. NPC would get out of the fuel supply business. The generators would provide price quotes for blocks of power by time period that they were willing to provide to the Regional Grid Subsidiary.

On the distribution side, the distribution companies provide their purchase requirements and the price they are willing to pay. The Regional Grid Subsidiary matches the supply quotes with the purchase quotes and dispatches generation accordingly. It also recovers its transmission and sub-transmission costs.

Under this model, customers above a certain size may purchase directly from the grid and pay local distribution wheeling charges.

Electricity Industry Structure Based on Market Clearing Pricing System



3.5.2 *The "Inter-utility Contractual and Operations Integration" Approach*

This approach involves extensive unbundling and places power procurement responsibilities with the distributors.

The generation function is disaggregated, with NPC disposing of its generation to IPP GenCo's or other independent companies. The transmission system consists of a national grid company with three regional subsidiaries.

A significant feature of this approach is the comprehensive planning and integrated operations agreement, especially among the distributors.

In many ways, this approach best meets the criteria for competitiveness. It creates the most number of buyers and sellers and facilitates trade between them. It eases entry into generation and assures access to transmission.

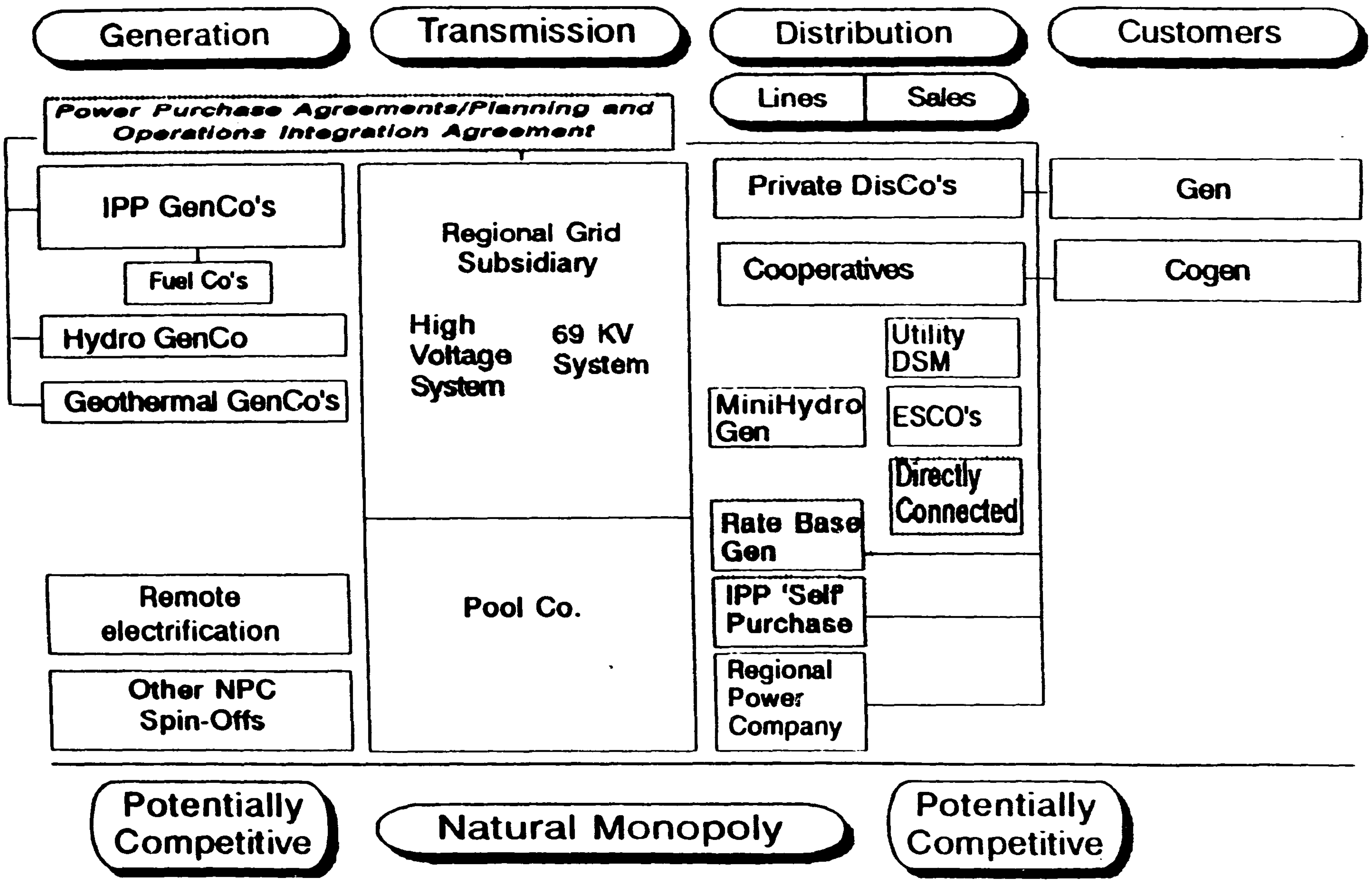
The Regional Power Corporation (RPC), initially a state-owned enterprise, remains a key participant in providing power supply and in overcoming the financial limitations of many of the distribution companies.

A portion of each power generating facility could be offered to distribution companies. Likewise, the RPC would offer to distributors participation in the projects its sponsors. These generation "participation rights" would facilitate the build-up of power supply portfolio by the distributors.

During the transition period of 5 years, the RPC might provide power purchase performance guaranty. In this capacity, it could lend its credit strength to power purchase agreements of small, financially weak distributors and overcome reluctance of IPP GenCos to deal with the small distribution companies. The guaranty would be limited to power purchase liabilities in case of financial failure of the distribution company. In such case, the RPC would be in a position to re-market the power.

The guaranty service of the RPC can be extended over a given time frame. During this period, distribution companies can improve their financial capabilities or consolidate to strengthen their position.

Industry Structure Based on Inter-utility Contractual and Operations Integration



Accountability/Pricing /Organizational /Regulatory "Ring Fence"

3.5.3 *The "Unbundled Functions/Central Power Acquisition" Approach*

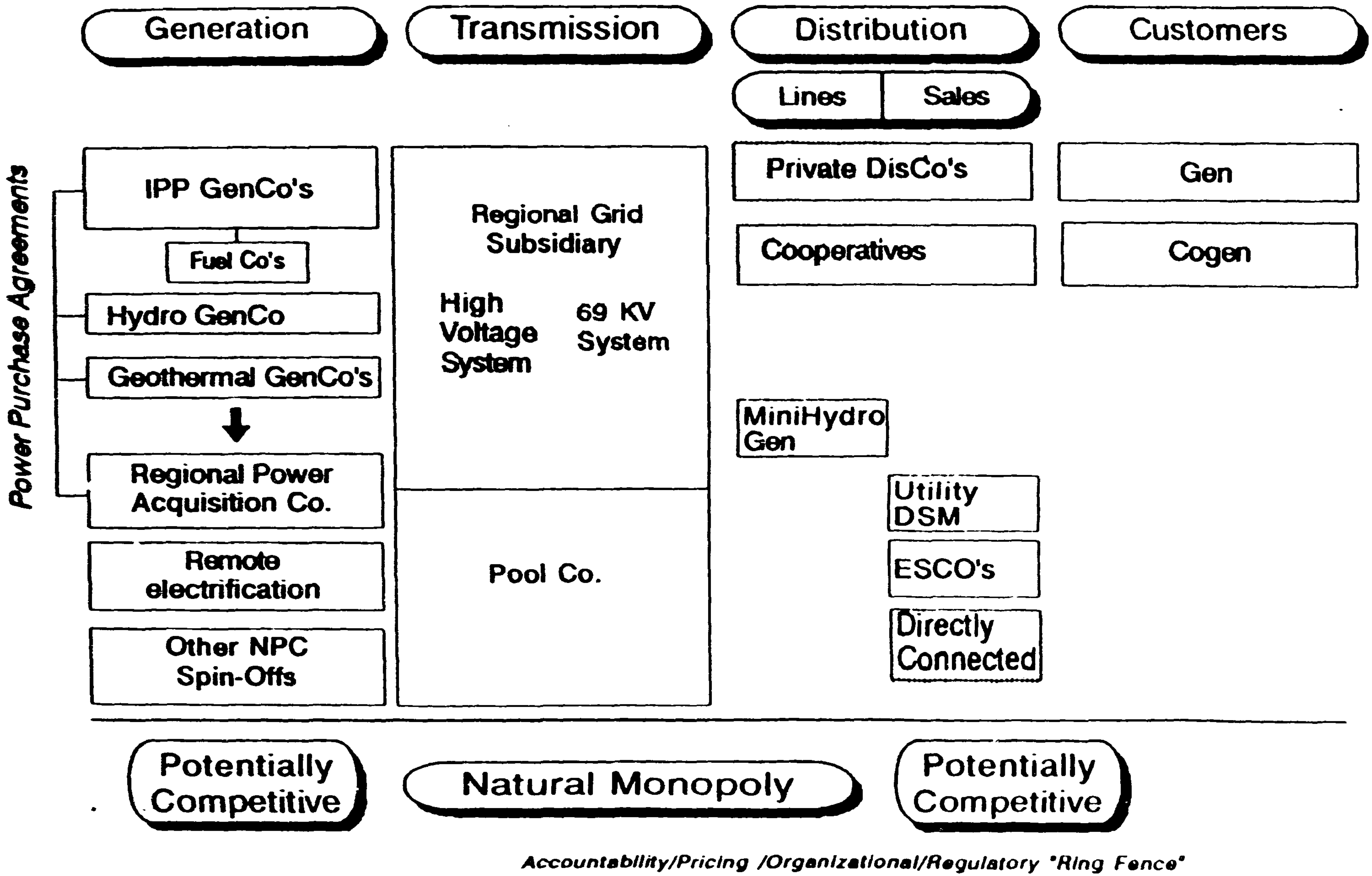
This approach involves extensive unbundling, but relies on a central organization to procure and re-sell power to the distributors.

New generation is provided by IPP GenCo's through competitive bidding as NPC's existing generation is practically spun off to IPP GenCo's. Hydro and geothermal generation are handled by independent companies. NPC is out of the business of supplying fuel to IPP's. Other NPC activities are spun off, leaving a Regional Power Acquisition Company with 2 key functions: 1) to perform power supply planning for the region and 2) to acquire the power requirements of the region through competitive bidding.

The transmission system is established as a separate national company with 3 regional subsidiaries or divisions. The grid company provides transmission planning and investment, operates and maintains the high voltage and sub-transmission systems, and plans and implements interconnections.

On the distribution side, the companies obtain all their power requirements from the Regional Power Acquisition Company with the exception of that generated by mini-hydros. All other generation by distributors or their subsidiaries are sold to the Regional Power Acquisition Company.

Industry Structure Based on Functional Unbundling and Central Power Acquisition



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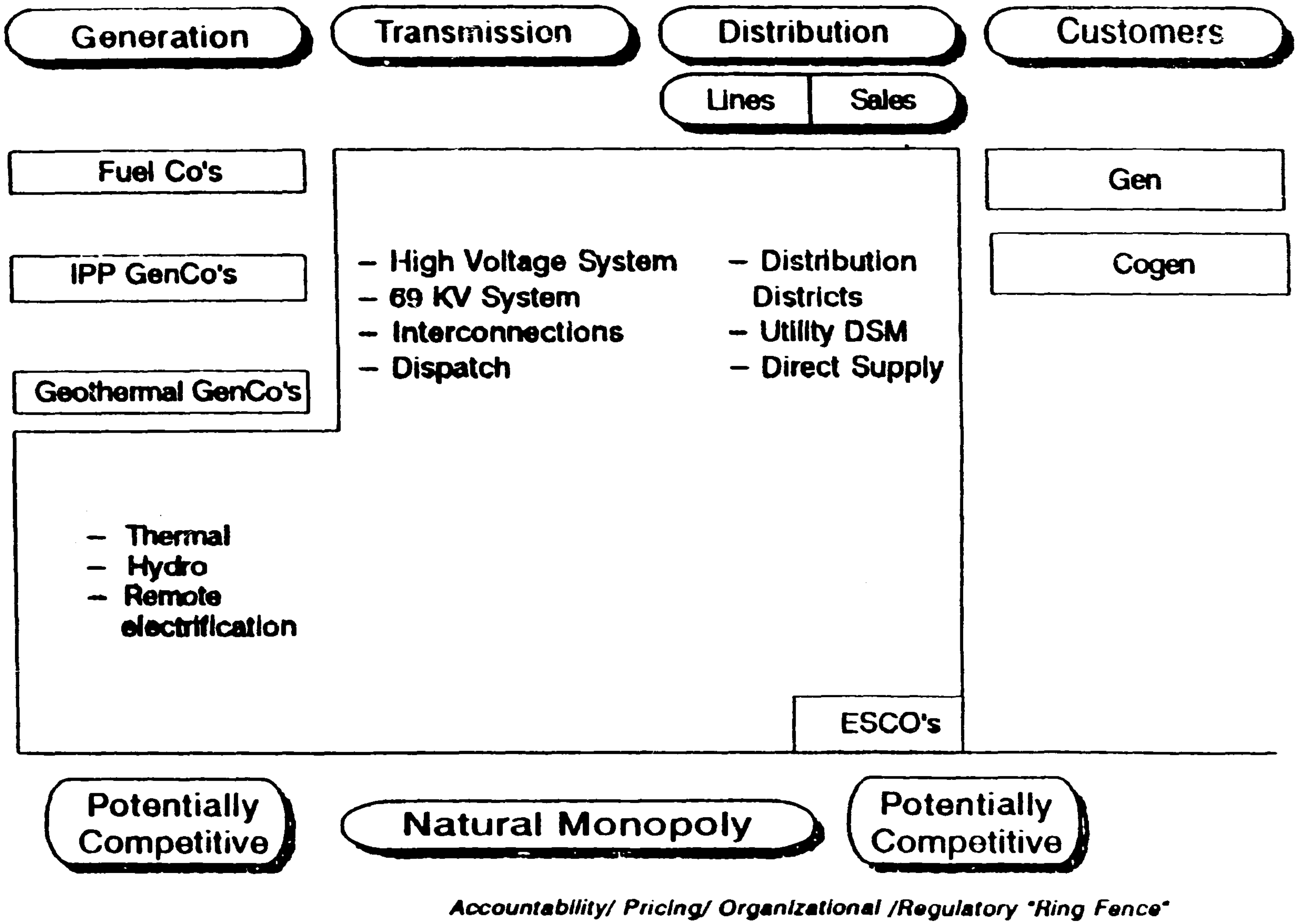
3.5.4 *The "Vertically Integrated Utility" Approach*

This is the most bundled approach, relying on heavy regulation and precluding competition. This is prevalent in the U.S.

This approach was discussed not so much as a viable option, but rather to complete the consideration of the spectrum of approaches. This approach relies the least on competition and places the greatest requirement on regulation.

Industry Structure Based on Regional (or National) Vertical Integration



3.6 Significant Implementation Issues

Significant issues relevant to the operationalization of the models were discussed:

3.6.1 *Political Issues*

- It is difficult to completely detach the electric power industry from a number of social policies and economic development issues.

- With the present structure of the industry, the National Power Corporation (NPC) serves as a convenient vehicle with which to pursue the initiatives of legislators.

- Privatization should lead to de-politization of NPC decision-making.

- The present initiatives to freeze power rates give wrong signals for the development of the industry.

- Decisions on the development of indigenous resources are frequently affected by political considerations.

- Some fundamental change in government policies are needed. Seventy-five per cent of the number of customers are serviced by electric cooperatives. There are mandated areas assigned to them by the National Electrification Administration (NEA). Electric cooperatives are in some cases more political than commercial institutions. This is one of the reasons why a number of cooperatives are incurring financial losses.

- One reason why NPC is not implementing the imposition of increased capacity charge is the pressure it is receiving from the electric cooperatives.

3.6.2 *Subsidy Issues*

Significant issues were discussed in connection with the goal of eliminating government subsidies in the sector:

- Politicians play a role in the development of the energy sector. We need to see their point of view and possibly anticipate them.

Most politicians would argue that developing countries have other objectives higher than profit motives. They would rather subsidize power in certain areas in order to bring development there. Social concerns make utilities part of public obligations rather than a business.

It was argued, however that such socialistic approach will not work. Market forces should be used to lead to these same objectives. An inherently uneconomic project cannot become economic even with government subsidies.

- In the development of power projects, it is believed by many that NPC basically takes all the risks which should be associated with the developer. This leads to distortion of the market.

  On the other hand, it was argued that if such arrangement results in lower capital cost, then it is worthwhile for NPC to assume this role. The reduction in capital cost reduces the cost of electricity for the consumers.

  However, in the final analysis, this is not necessarily the case. For instance, in the case of geothermal power which is being promoted by the government, the country cost is low but the actual cost to NPC is high if we consider that royalties paid for the geothermal scheme go to the government and not to NPC.

- From the point of view of the national government, privatization should eliminate or reduce subsidy to NPC.

- An argument raised was that NPC in fact, is not actually being subsidized but rather, it is undercapitalized. As it gives away subsidies, it has to continue relying on loans.

- It was argued out however that be it equity or subsidy, what is wanted is to eliminate government exposure in NPC.

3.6.3 *Competitiveness in the Industry*

The following significant issues were discussed in line with the goal of improving efficiency and competitiveness within the electric sector:

(a) *Development of Indigenous Resources*

The issue is the choice of who should develop indigenous resources: government or the private sector. This could become quite an emotional issue.

The consensus was that the approach to this decision should be based on the creation of level playing fields on which decisions can be made on economic merits. Within this framework, the development of indigenous resources could be economically competitive. Developers can therefore step forward to produce energy from indigenous resources and avail of the benefits they deserve.

- Geothermal Energy

  Geothermal power plants can stand on their own economic merits. Other issues to be considered affect national security or other government objectives which could prompt government to grant extra support or subsidy to these projects. Such issues should be addressed outside of the power industry.

  If the economic viability is established and government wishes to shift to geothermal sources of energy, this should be addressed through tax incentives and by eliminating barriers.

- Hydropower

  This is an area where there are benefits that can not be captured in the typical power plant decision making process. Some public sector involvement may be required.

(b) *Transmission Facilities*

The present situation provides easy entry into the generation side of the industry. However, access by generating plants to the transmission facility is a central requirement to promote competitiveness. The terms for inter-connection should be carefully studied.

(c) *Pricing*

There should be transparency in pricing. It should be clear to the public how price is derived so they can see what they are paying for. In cases of marginal pricing, the economic goals should be clearly understood.

(d) *Creating Level Playing Fields*

There is need to create level playing fields in each of the following functions: fuel supply, transmission, distribution and sales.

(e) *Demand Outlook*

It is important to look at how well any particular approach to be developed relates to the demand outlook.

(f) *Regional Distribution*

Key questions were:

- Should there be a single system for Luzon, another one for the Visayas and one for Mindanao?

- Should there be only one seller in each franchise area?

(g) *Competitiveness*

Seventy five per cent of electricity consumers depend on rural electric cooperatives for power distribution. Therefore, even if we are able to solve all problems in generation and transmission, if the cooperative system is not improved, the desired result to the consumers may not be possible.

The problem of small distribution companies, aside from some management inefficiencies, arises from the consumer mix in their franchise area. In a number of cases, there is no power demand. These small companies consider themselves lucky if they have a load factor of 45 per cent.

During the discussion on cooperatives, it was also observed that about half of losses incurred are due to pilferage, not technical problems.

NEA had identified a few cooperatives in Central Luzon which are the most inefficient. A number of them, however, have improved operations.

3.6.4 *Financing Issues*

A number of issues concerning financing of power projects were put forward:

- Power demand will increase dramatically in the next decades. Therefore, greater focus should be given to enhancing capital formation not only from the private sector but from other possible sources as well. It was noted that privatization should bring in new resources not presently accessed by government and NPC.

- There are several alternative investment options. To attract the private sector to go into more power projects, how can such projects be made attractive? What is wrong with the present structure which does not seem to attract sufficient investments?

- An NPC representative explained that the main objective of the privatization move is not to generate new capital as their projects for the medium term are already firmed up and in place, mostly to be implemented by the private sector. NPC is shifting its attention from oil, thermal and coal power sources to indigenous sources (steam and hydro) which are much more risky. These sources also require higher cost of civil works. Since NPC is veering away from power generation, what it would like to do is share its experience with other power sectors which are having difficulty in sourcing capital.

- NPC is willing to give way to the electric cooperatives in the generation function. However, coops can not obtain loans without government guarantee. Their management and technical capability as well as credibility have to be strengthened.

- Similarly, IPPs ask for NPC guarantee in order to obtain financing. This function should be transferred to the distributor. Therefore, efforts should be directed to strengthening not only the power generator but the distributor, as well.

- Questions were raised as to whether a subsidiary regional power acquisition company could be as credit-worthy as NPC. One suggestion was for NPC to partly finance the equity of the subsidiary with DBP and some other banks taking some of the guarantees away from the mother company.

3.6.5 ***Administrative Issues***

A number of issues related to the administrative aspects were discussed:

- An important question raised was whether or not Government is aware that by shifting to a policy relying on market forces, prices might radically increase.

- The Emergency Power Act has been effective in bringing about the needed capacities in the short term and in involving the private sector to manage and operate existing plants. Such act should be implemented every 2 or 3 years, especially when faced with government agencies that can not successfully pursue projects.

- Electric cooperatives are mandated to implement electrification. Since most of them are not financially strong, it was suggested that a policy may be necessary to merge them or tie them up with the urban centers to operate a generator, retaining cooperative arrangements.

  A suggestion was put forward to create an NPC finance institution to handle financial problems of the cooperatives at market rates while NEA continues to handle the coops' problems through subsidy.

- The absence of an NEA representative during this particular session was noted, precluding more discussions on the electric cooperatives.

- It was noted that regulatory functions are not within the power of NPC. This should rest with the Energy Regulatory Board (ERB).

- NPC's loan covenants and minimum required returns should be reviewed as they might impede asset sales. For some NPC generation assets, their sale would result in higher costs to NPC, i.e. electricity repurchase cost from the new owner operator would exceed NPC's current short run operating costs.

- Hydro generation was identified as the only generation source that could be split between government ownership (for large scale hydro) and private ownership (for small scale and mini-hydro).

- It was generally agreed that geothermal power generation can be fully privatized and integration of operations (steam production and power generation) is desirable. EDC need not necessarily be privatized, but should compete with private producers on a level playing field.

- Fuel supply to IPPs was viewed as a major area needing reform. Fuel tax is primarily a revenue issue, not a power sector issue, except where fuel taxes are used to provide incentives to alter fuel mix.

- A regional power company was accepted as workable but many institutional issues would need to be resolved.

- DOE is prepared to relinquish IPP accreditation under a market-based system of power procurement. IPP accreditation could primarily become a permitting process.

3.6.6 *Regulatory Perspective*

A number of issues were presented by the consultants which require regulation.

3.6.6.1 *Transmission*

The transmission function is usually considered basically monopolistic. Two important issues were discussed pointing to the need for regulation on the transmission function:

a) If a generator owns the grid, this can preclude his competitors from getting their generation to the market;

b) Even if the grid is independently owned by a non-generator, there is still the danger of charging exorbitant rates.

3.6.6.2 *Distribution*

The distribution function is also basically regarded as monopolistic to the extent that the distribution company can prevent direct connection to the market place. This can be regulated by

- setting rules for business practices and setting the rates; or

- curbing the power of distributors by allowing direct purchases from generators in cases where consumption is above a certain level (e.g. 1 MW and above).

In this connection, it was argued that direct purchases by industry from generators instead of private distributors and especially electric cooperatives should not be allowed, because this prevents the improvement of the load factor of the distribution units. The answer to this question, however would lie in a pragmatic evaluation of what is cheaper for the large consumer and equitable for the distributor.

3.6.6.3 *Regulatory Body*

It is not necessary to separate the regulatory functions for generation and distribution. All that is required would be to maintain a balance between the sensitive and local economic sense and a broad view of the national economy. The ERB can serve to provide this balance.

4.0 SUMMARY OF CONCLUSIONS AND CONCERNS

4.1 Conclusions on the Considered Approaches

4.1.1 *"Market Clearing Pricing System":* We are not ready for this approach in the Philippines.

4.1.2 *"Inter-utility Contractual and Operations Integration" Approach:* In many ways, this approach best meets local demands with favorable effects on:

- Market based system
- Capital Formation
- Less government interference
- Efficiency improvement

4.1.3 *"Unbundled Functions/Central Power Acquisition" Approach:* Probably workable but thinking is required on how to make this model viable in the Philippines.

4.1.4 *"Vertically Integrated Utility" Approach:* Not a viable option.

4.2 Significant Concerns and Consensus

The major issues and consensus brought forward during the workshop were:

- Whether or not to continue to promote the present structure of promoting more generation activities in the present system or in buying directly from IPPs: how to insure effifiency of integration into the grid, so as not to miss any economy of scale.
- NPC loan covenants and minimum required returns have to be reviewed and revised as required.
- Who should be responsible for reserve capacity?
- Most buyers of power are not considered credit worthy by financing institutions. This can slow down implementation of more generating plants.

- In the Visayas and Mindanao grids where there are only few players in the market, the possibility of collusion is great.

- It is difficult to completely detach the electric power industry from social-political policies and economic development issues, although this thrust must be pursued.

- The present situation provides easy entry into the generation side of the industry. However, access to the transmission facility is vital to promoting competitiveness and should be carefully studied.

- Since 75 per cent of electricity consumers depend on rural electric cooperatives for power distribution, even if problems of generation and transmission are resolved, the desired result to the consumers may not be possible unless the cooperative system is improved. Their management and technical capability, as well as credibility, have to be strengthened.

- Some efficiency problems are functions of low population density in the area and are not technical in nature.

4.3 Based on the results of this workshop and other relevant factors, the Consultants will present their recommendations to DOE.

ANNEX A

WORKSHOP PARTICIPANTS

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ANNEX B

WORKSHOP MATERIALS

Agenda

Restructuring and Privatization Objectives

Restructuring and Privatization Approaches

- How they work
- Implementation issues
- Potential efficiency effects

Next Steps

Notes on Workshop Slides

SLIDE: "**Restructuring and Privatization Objectives**"

This slide summarizes the overall objective and lists specific goals that restructuring and privatization should promote. At the workshop, the participants expanded these goals to include:

-- De-politicize decision making in the sector

-- Reduce or eliminate government subsidies.

Participants generally agreed that the most critical goals that restructuring and privatization should help accomplish are:

-- De-politicize decisions in the electric sector as much as practical.

-- Establish each entity in the electric sector to operate on a commercially viable basis (and reduce or eliminate government subsidies).

-- Ensure capital formation.

-- Promote competition and efficiency improvement.

Restructuring and Privatization Objectives

Overall objective:

Establish an industry structure that promotes reliable electricity supplies at competitive levels of efficiency and price.

Restructuring and privatization should:

- Promote efficient planning and investment
- Promote efficient operation and maintenance
- Provide for efficient pricing
- Promote access to diverse captial resources
- Account for needed managerial and technical expertise
- Achieve a workable balance between reliance on competitive forces, market power of utilities, and regulatory requirements
- Respond to national and regional economic development and social policy concerns

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Notes on Workshop Slides

SLIDE: "**Desirable industry structure characteristics .....**"

This slide identifies industry characteristics that, if established, will promote competition and, in general, help achieve gains in efficiency.

Approaches to restructuring and privatization that were substantially deficient in establishing these industry characteristics were considered less desirable by workshop participants.

Desirable industry structure characteristics in competitive models of the electric utility industry include:

- Existence of many sellers
- Existence of many buyers
- Ease of bilateral trades between buyers and sellers
- Ease of entry (generation)
- Access to essential facilities (transmission)
- Transparent, marginal cost based pricing
- Unbundled core functions
- Level playing field among participants in each core function
- Availability of planning information

We will consider these characteristics as we discuss each restructuring and privatization approach.

Notes on Workshop Slides

SLIDE (Revised): "Continuum of Industry Structure Approaches"

Before discussing specific restructuring and privatization approaches, we reviewed the continuum shown on this slide. The continuum illustrates the range of options that might be pursued to restructure and privatize the Philippines electricity industry. Options along this continuum are differentiated by three characteristics:

-- Degree of vertical integration in the structure of the industry. At one end of the continuum, there is a low degree of integration, where core functions (i.e., generation, transmission, dispatch, distribution lines, and sales) are unbundled and performed by separate entities. At the other end, there is a high degree of vertical integration, where core functions are bundled in the one firm.

-- Reliance on competitive forces as a primary means of promoting efficient investment and operations. At one end of the spectrum, there is high reliance on competition, particularly in the generation and sales functions. At the other end, there is low reliance on competition, where, for example, the vertically integrated firm precludes competition.

-- Focus of regulation. At one end of the continuum, regulation is primarily concerned with precluding monopoly power and maintaining a competitive balance among sector participants. At the other end, regulation of the vertical integrated utility is focused on controlling monopoly power through price and investment regulations and other regulatory intervention in utility management decisions and policies.

The two approaches below define each end of the continuum:

-- The "Market Clearing Pricing System" approach exhibits the most unbundling and reliance on competition. This approach is the underlying basis for the restructuring and privatization of the electric sector in England/Wales and Argentina, for example.

-- At the other end of the continuum is the "Vertically Integrated Utility", the most bundled approach, relying on heavy regulation and precluding competition. Perhaps the most representative of this industry structural approach is EDF. It is also widely prevalent in the US.

Between these fundamentally different approaches to industry structure and privatization are three additional approaches:

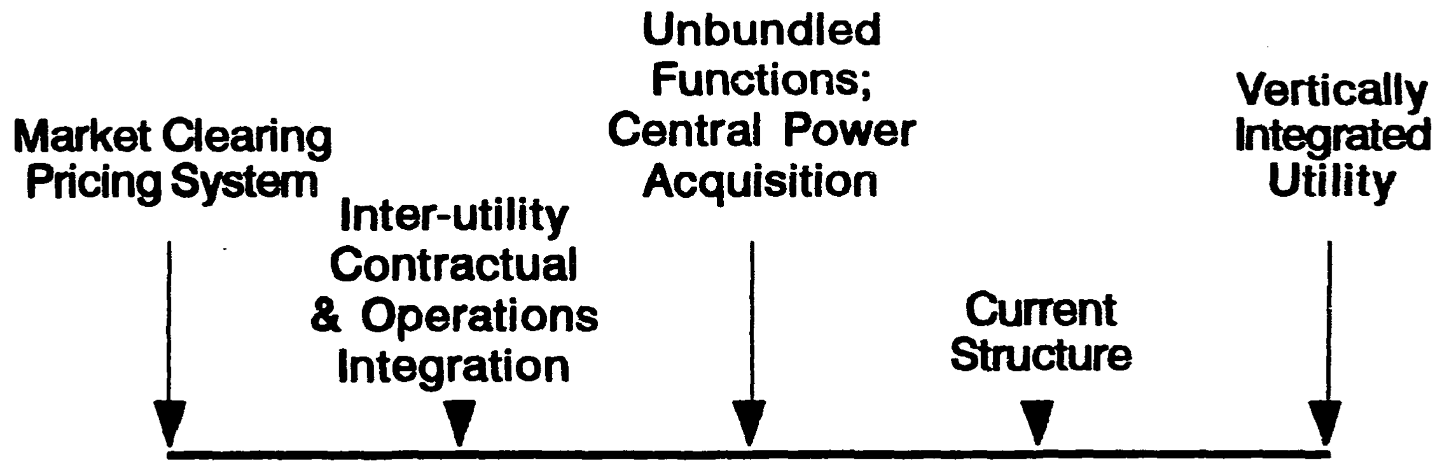
-- The "Inter-utility Contractual and Operations Integration" approach, as it would operate in the Philippines, is the most reliant on competition. It involves extensive unbundling and places power procurement responsibilities with the distributors, who are most effected by these decisions.

-- The "Unbundled Functions/Central Power Acquisition" approach also involves extensive unbundling, but relies on a central organization to procure and re-sell power to the distributors.

-- Finally, the Current Structure is depicted, with a high degree of bundling and relatively low degree of reliance on competition.

The remainder of the workshop focused on the workability and merits of these different approaches.

Continuum of Industry Structure Approaches



Degree of Vertical Integration	Unbundled	Bundled
Reliance on Competitive Forces	High	Low
Focus of Regulation	Precluding monopoly power	Controlling monopoly power

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<u>Notes on Workshop Slides</u>

SLIDE: "Existing Structure of the Philippines Electricity Industry"

This slide graphically depicts the current structure and ownership of the industry. This presentation format was used throughout the workshop to facilitate explanation and discussion of alternative approaches, and we first discussed the format itself.

First, across the top of the slide, the industry is functionally broken down into Generation, Transmission, and Distribution. Distribution is further broken down into the "lines" function, that is, provision of the physical lines needed to deliver power from the transmission grid to the customer's point of use, and the "sales" function, which involves various services to the customer, including sales of Kwhs. In subsequent slides, we adopted a further functional unbundling by disaggregating the operation of the grid and dispatch of generation ("Poolco") from transmission planning and investment.

Second, across the bottom of the slide, we indicate that the functional area is either potentially competitive, or that it is a natural monopoly where meaningful competition is not feasible. The generation and distribution sales functions are potentially competitive, depending on the industry structure approach pursued, whereas transmission, PoolCo and the lines function of distribution are natural monopolies.

On the slide, we show that:

-- Generation under the current structure is largely NPC, with a number of independent power producer generating companies (IPP GenCo's) supplementing NPC generation. These IPP GenCos are new participants in the industry, having been established through the recent "fast track" program to meet generation shortfalls.

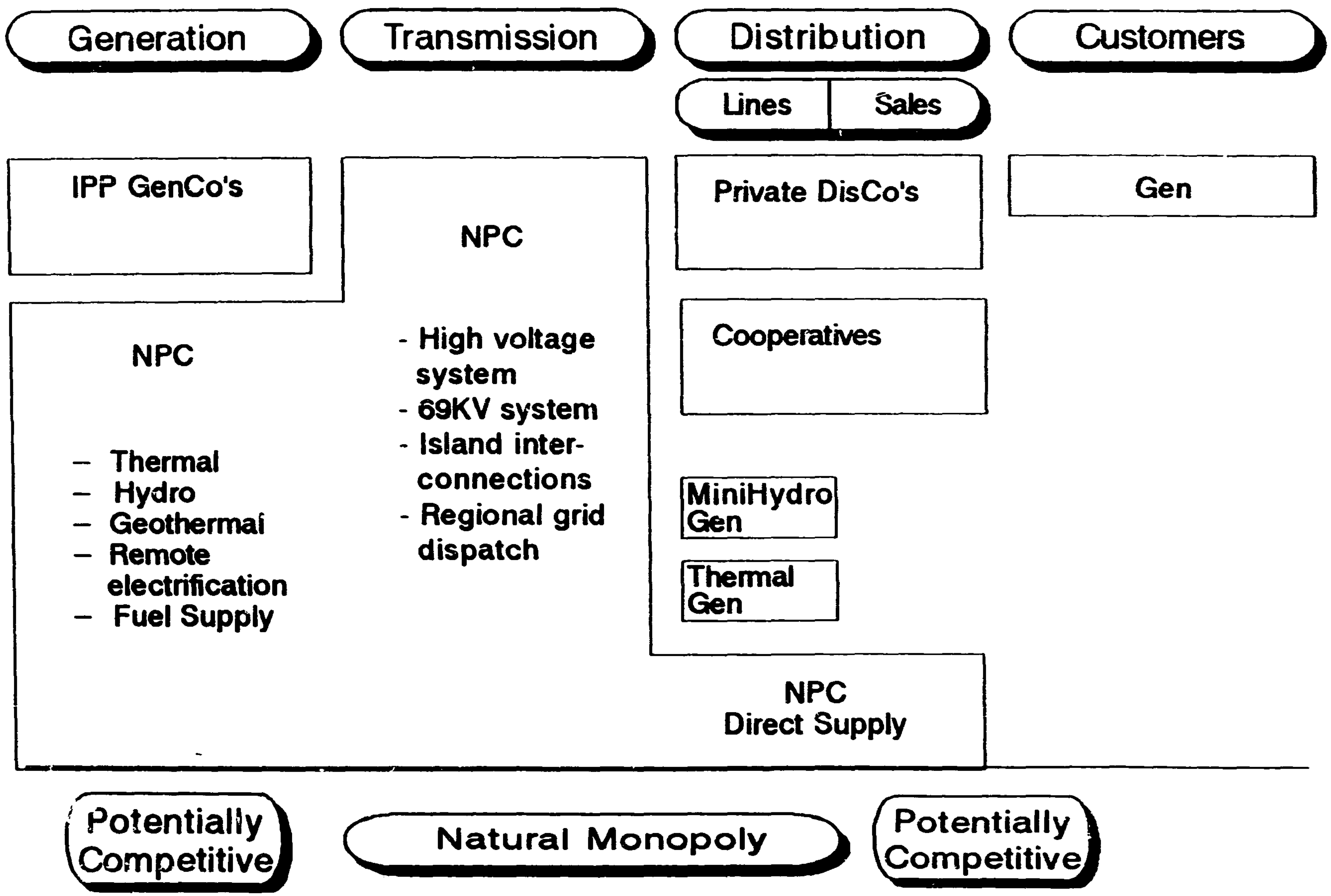
-- Transmission and dispatch functions are also performed by NPC, i.e., transmission, dispatch and generation are vertically integrated.

-- Distribution lines and sales functions are performed by the private distribution companies and rural electric cooperatives for most customers, although NPC also performs these functions for several customers that are directly connected to the grid at 69KV or higher. For these customers, NPC is a fully vertically integrated utility.

-- A limited amount of generation is performed by the distribution companies, mostly mini-hydro and small thermal units.

-- On the customer's side, considerably amount of generation exists, mostly as emergency units to deal with brown-outs.

Existing Structure of the Philippines Electricity Industry



Notes on Workshop Slides

SLIDE (Revised): "Possible Evolution of Existing Structure of the Philippines Electric Industry"

This slide provides the framework for our discussion of what the electricity industry might look like in the future if we stay with current policies and trends, do not pursue significant structural change, but aggressively seek to:

-- Increase private sector participation, particularly in the generation function to build new capacity and rehabilitate and operate existing NPC generating units.

-- Increase "transparency" of operations and pricing. By transparency we mean that operations performance, operating policies, and derivation of prices are clearly identified and understandable. For example, if transmission costs and pricing are included in an energy tariff and not stated separately, then transparency is poor. Similarly, distribution pricing can be made more transparent by separately pricing the lines function from the sales function.

-- Increase accountability for performance. For example, accountability can be improved by increasing the transparency of key operations, clearly assigning responsibility and authority, setting goals, and basing compensation on measured performance.

-- Improve regulatory effectiveness, e.g., by improving the skills and staffing levels at ERB.

In discussing this slide, we introduced the concept of "ring fencing", which is used on this and subsequent slides. Ring fencing is an alternative to actual structural unbundling or separation of functions. Ring fencing is accomplished through one or more of the following:

-- Establishing autonomous organizational units for key functional or sub-functional activities, with clearly defined management responsibility, goals and performance measurement.

-- Implementing accounting practices that isolate and separately account for the costs and performance of key activities.

-- Adopting pricing practices that separately charge users for disaggregated services, e.g., separating transmission from generation.

-- Pursuing regulatory practices that focus on key utility decisions or policies, e.g., utility self generation or distributor purchases from subsidiaries.

However, we note that ring fencing is significantly inferior to actual disaggregation of functions into separate organizations and ownership.

Below we discuss the possible industry evolution as depicted on the slide.

Generation

The generation function could be further disaggregated from the current situation, primarily through continued and increased reliance on private sector IPP GenCo's to build and operate new power generation facilities. Other forms of contracting could also be pursued, including an aggressive push to get the private sector to refurbish and operate existing facilities (e.g., ROM's). Hydro development might be spun off as a separate activity or subsidiary. Geothermal could be developed through integrated steam/power generation projects with private sector developers. NPC could get out of the fuel supply business for independent power producers: this would require leveling the playing field on fuel taxes. Other NPC activities could be spun off into subsidiaries or to the private sector or other state organizations, e.g., remote electrification.

The remaining generation activities of NPC could then be ring fenced to focus proper regulatory and management oversight.

Transmission

In the absence of restructuring, transmission and dispatch would remain key NPC activities. However, we have shown four major functional activities -- high voltage transmission, 69KV sub-transmission, island interconnections, and regional grid dispatch -- as ring fenced for performance monitoring and in some cases for separate pricing, e.g., high voltage transmission and sub-transmission. It is also possible that private sector investment might be attracted to the transmission function through BOT contracts for selected projects.

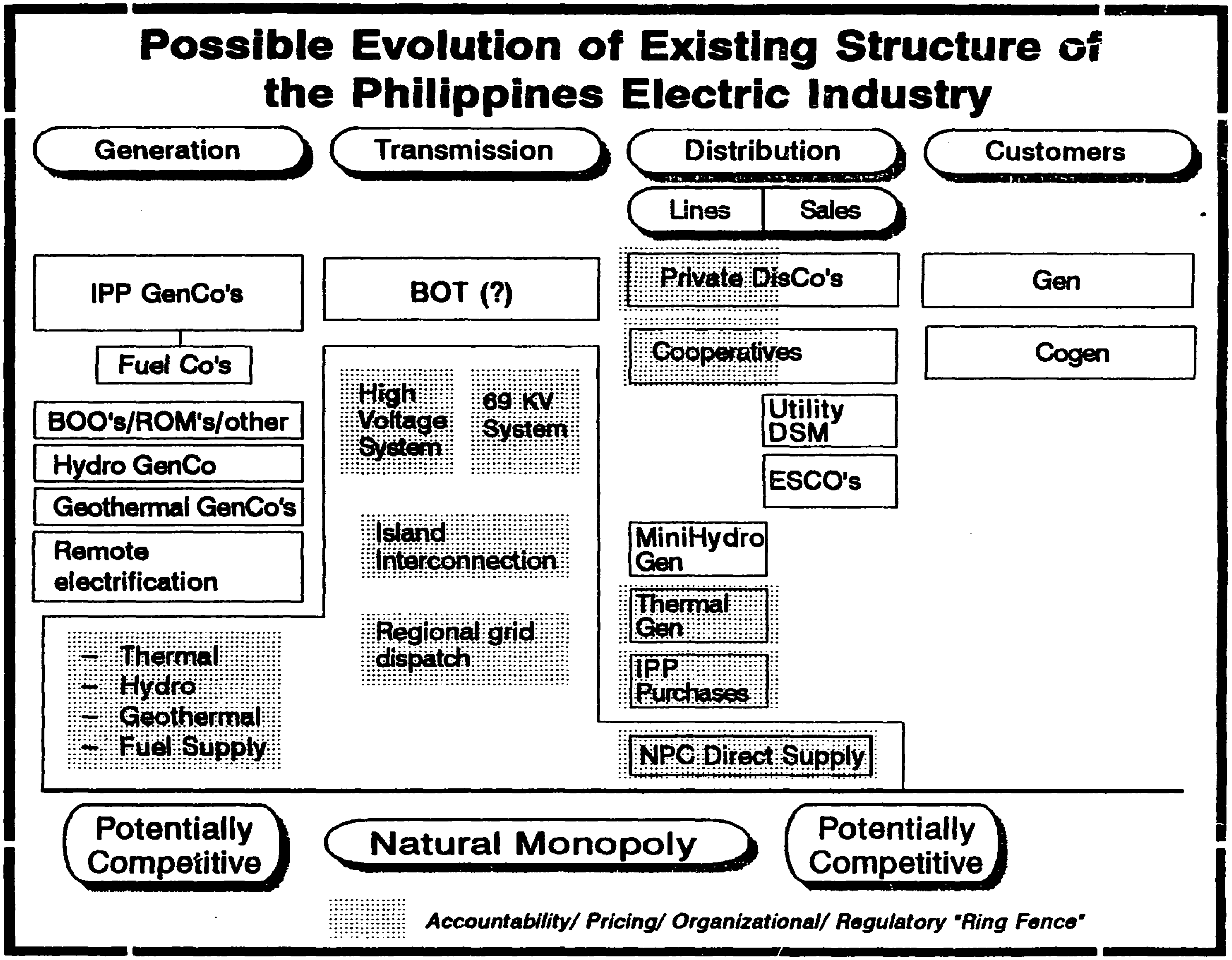
Distribution

Several changes are depicted in the distribution function. First, the lines function is ring fenced, with the costs of line service identified separately in the distribution tariff. In addition, customers above a certain size may buy power direct from NPC and use retail wheeling services across the local distribution lines. Self generation and purchases from IPP GenCo's or from subsidiaries would grow in importance with certain distributors. These activities are shown as ring fenced and subject to heavy regulatory oversight. We discussed in the workshop that in this evolutionary scenario, NPC direct supply should also be ring fenced and subject to heavy regulatory oversight; this change has been made to the slide. Two new activities could emerge as significant factors in the industry: utility demand side management (DSM) and energy service companies (ESCO's) that provide DSM services. Finally, cogeneration by customers could become a more important source of electricity supply.

Observations

With the exception of increased private sector participation in generation and the possible spinning off of certain NPC activities into subsidiaries or to third parties, this evolutionary scenario does not entail any significant restructuring to promote competition, capital formation or performance accountability. NPC remains a national monopoly with potential limitations of performance and efficiency incentive that are generally considered to be attendant to monopolies. The practice of ring fencing is liberally used as a means of addressing the problems of monopoly structure and unbundled functions. Reliance on regulation is especially heavy throughout all facets of the industry.

Despite these limitations, considerable interest in this evolutionary structure was expressed by NPC participants. In particular, pursuit of an industry approach along these lines in combination with bringing in a significant private investor/operator firm as an equity owner, like the Petron privatization, was seen as an approach with possible merit. In the addendum to these notes, we will offer further comments on this idea.


Possible Evolution of Existing Structure of the Philippines Electric Industry
Generation
Transmission
Distribution
Customers
Lines
Sales
IPP GenCo's
Fuel Co's
BOO's/ROM's/other
Hydro GenCo
Geothermal GenCo's
Remote electrification
– Thermal
– Hydro
– Geothermal
– Fuel Supply
BOT (?)
High Voltage System
69 KV System
Island Interconnection
Regional grid dispatch
Private DisCo's
Cooperatives
Utility DSM
ESCO's
MiniHydro Gen
Thermal Gen
IPP Purchases
NPC Direct Supply
Gen
Cogen
Potentially Competitive
Natural Monopoly
Potentially Competitive
Accountability/ Pricing/ Organizational/ Regulatory "Ring Fence"

Notes to Workshop Slides

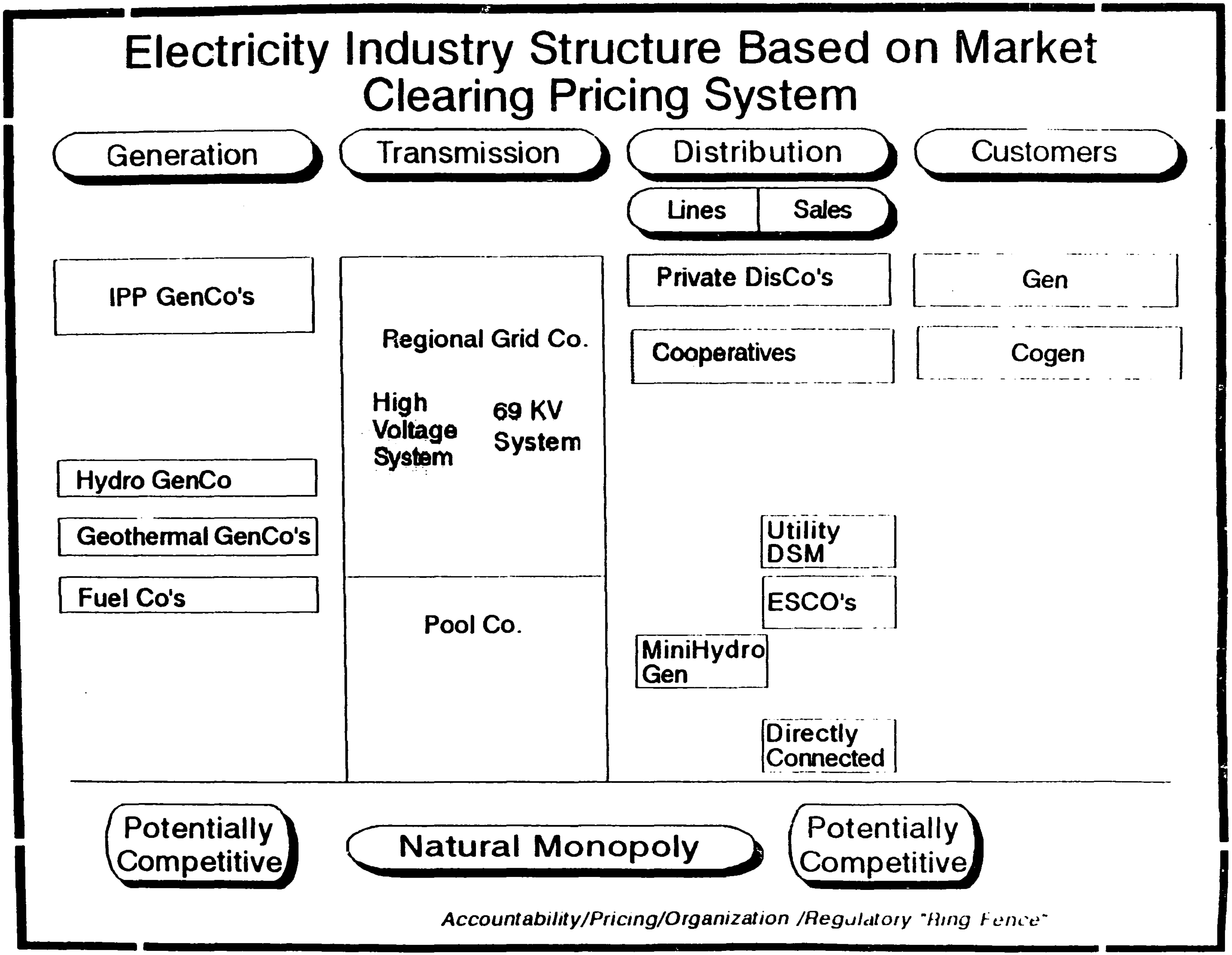
SLIDE: "Electricity Industry Structure Based on Market Clearing Pricing System"

There are three slides that we used to discuss the applicability in the Philippines of an industry structure and associated privatization scheme based on market clearing prices. The first slide illustrates how this approach would work in principle. All generation would be spun off to IPP Genco's, Hydro GenCo and Geothermal GenCo's. NPC would get out of the fuel supply business. The generators would provide price quotes for blocks of power by time period (e.g., half hour periods during the following day) that they are willing to provide to the Regional Grid Subsidiary. On the distribution side, the distribution companies likewise provide their purchase requirements and the prices they are willing to pay. The GridCo Subsidiary matches the supply quotes with the purchase quotes and dispatches generation accordingly. The regional GridCo would also recover its transmission and sub-transmission costs (ring fenced on the slide). Also ring fenced is the distribution lines function, allowing customers above a certain size to purchase directly from the grid and pay local distribution wheeling charges.

The second slide illustrates the point that NPC has several contracts with IPP GenCo's that might not be restructured. In that case, the contracts essentially serve as price hedges for the Regional Power Acquisition Company and the respective IPP GenCo's. That is, the existence of these contracts does not particularly impede the adoption of the market clearing pricing system as an industry structure.

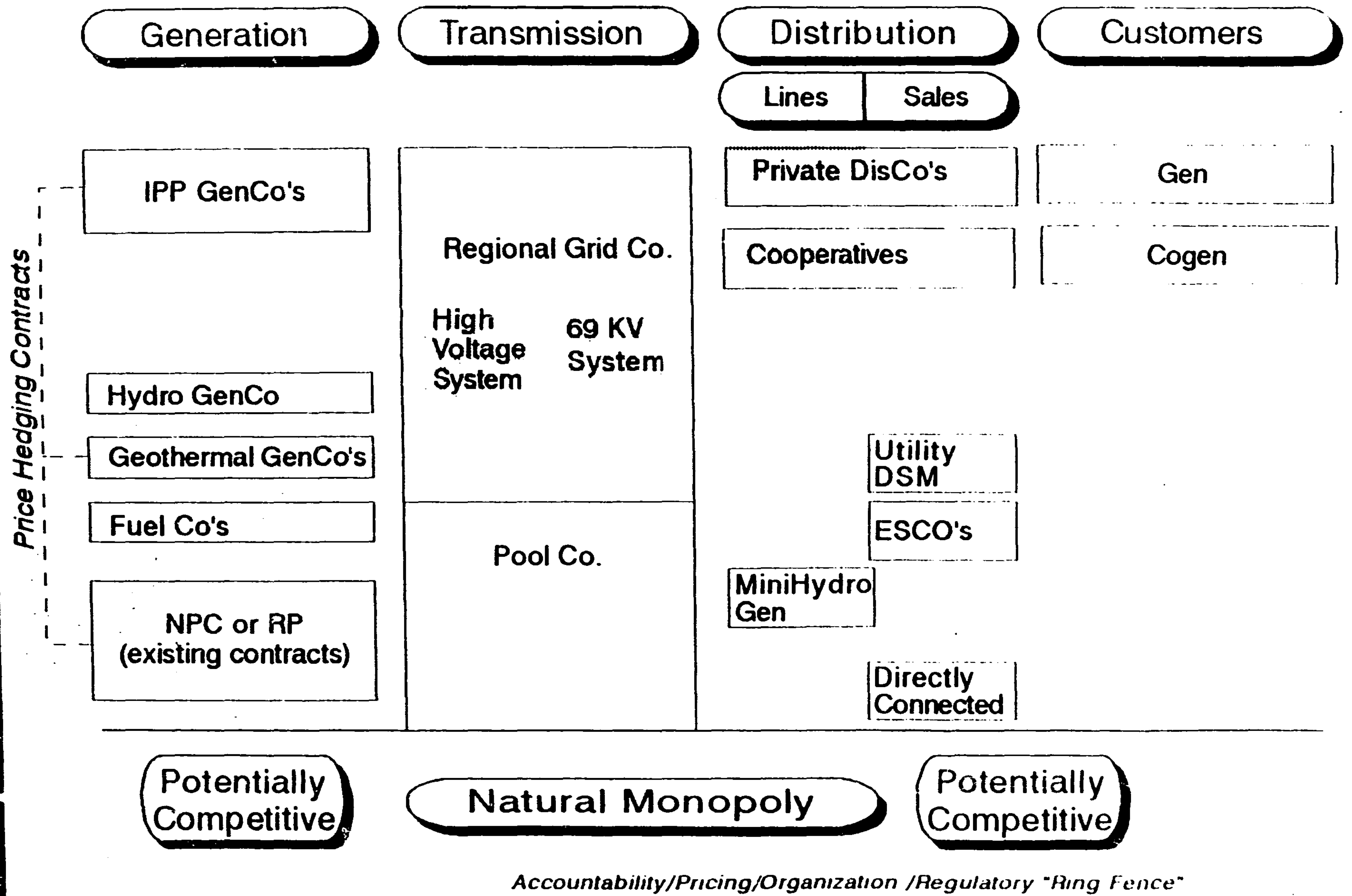
The third slide illustrates the point that, were the market clearing pricing system to be implemented, price hedging contracts would almost assuredly be entered into by all participants in the generation and distribution functions. In particular, the point was made that such contracts would in practice be the basis for capacity expansion projects to make them financeable. This raised an issue deemed to be particularly important: in the absence of NPC, there are few financially strong distribution companies that could independently enter into viable and bankable contracts with major IPP GenCo's. Therefore, a continuing role was seen for NPC to ensure that IPP GenCo's were attracted to the industry to construct generation units to meet demand.

Although the participants considered this approach to be technically feasible, they did not believe that it would be prudent or workable at this time. Several participants thought that this structure might be a long term goal, although it was also recognized that pursuit of alternative approaches in the present might make it difficult or impractical to adopt this structure in the future. In particular, the market clearing price approach is not practical on the Visayas or Mindanao grids, where there is clearly too little diversity of generation. Lack of generation diversity could also be a problem on the Luzon grid. Concentration of IPP generation in a few large facilities and a small number of operators also raises the risks of collusion or non-competitive bidding behavior on the Luzon grid. The workshop participants also raised the issue that the required sophistication and complexity of the system would be problematic for most participants in the industry and might impede timely and efficient capacity expansion decisions and financing.



Electricity Industry Structure Based on Market Clearing Pricing System
Generation
Transmission
Distribution
Customers
Lines
Sales
IPP GenCo's
Regional Grid Co.
High Voltage System
69 KV System
Private DisCo's
Cooperatives
Gen
Cogen
Hydro GenCo
Geothermal GenCo's
Fuel Co's
Utility DSM
ESCO's
MiniHydro Gen
Directly Connected
Pool Co.
Potentially Competitive
Natural Monopoly
Potentially Competitive
Accountability/Pricing/Organization /Regulatory "Ring Fence"

Electricity Industry Structure Based on Market Clearing Pricing System



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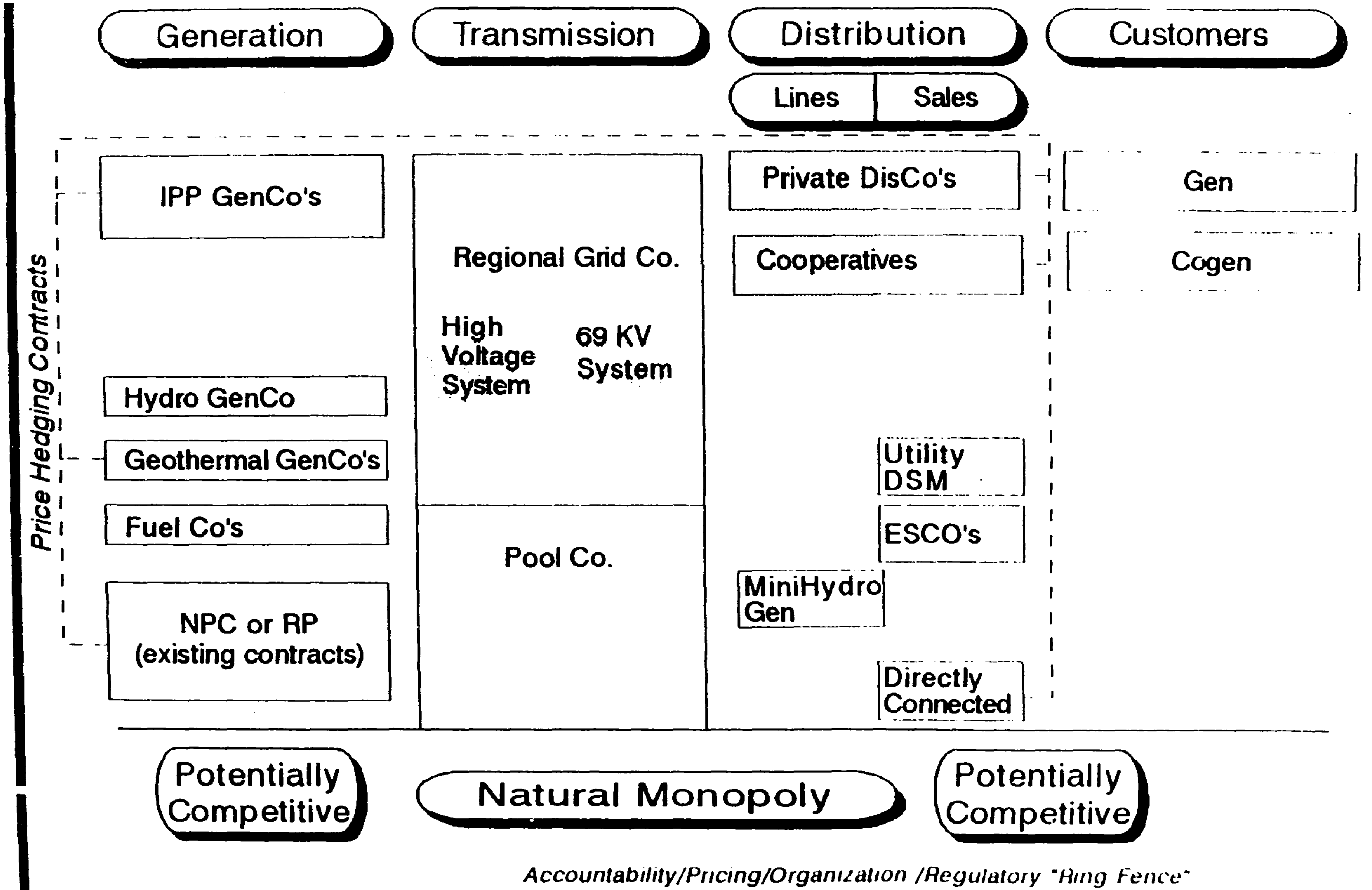
Electricity Industry Structure Based on Market Clearing Pricing System



Notes on Workshop Slides

SLIDE (Revised): Industry Structure Based on Functional Unbundling and Central Power Acquisition

In the workshop we discussed this approach next, and it found considerable support among participants, although certain key issues were raised. Reviewing the slide, we note that generation has been unbundled similar to that described for the market clearing price approach. New generation is provided by IPP GenCo's through competitive bidding, and NPC existing generation is, to the extent practical, also spun off to IPP GenCo's. Hydro and geothermal generation are also accomplished through independent companies. NPC is out of the fuel supply business to IPP's. Other NPC activities are spun off, leaving a Regional Power Acquisition Company with two key functions: 1) perform the power supply planning for the region, and 2) acquire the power requirements through administering a competitive bidding program.

The transmission system is established as a separate national company with three regional subsidiaries or divisions. The grid company provides transmission planning and investment, operates and maintains the hi... voltage and sub-transmission systems, and plans and implements interconnections. We have shown the grid operation and generation dispatch as being performed by a separate PoolCo, although this function could also be combined with the grid company. The national grid company and each regional subsidiary would operate on a commercial basis and would establish standard and non-discriminatory grid access policies and wheeling charges based on costs.

On the distribution side, the companies would obtain all of their power requirements from the Regional Power Acquisition Company (RPC) with the exception of mini-hydro generation. All other generation by distributors or their subsidiaries would be sold to RPC. The distribution lines function is ring fenced to provide transparent retail prices and retail wheeling for customers meeting threshold size requirements. The directly connected customers are also ring fenced to provide regulatory oversight.

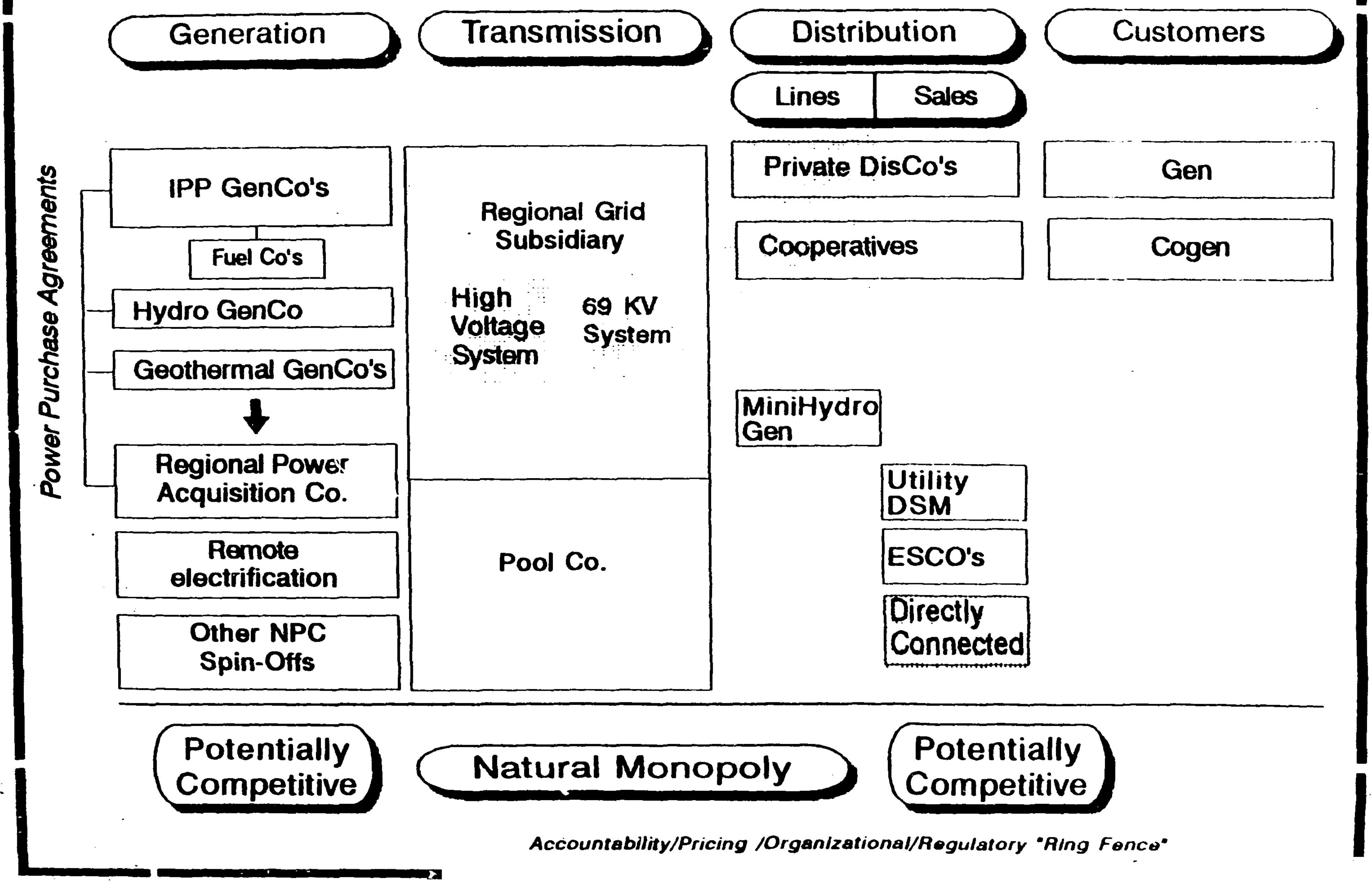
The strengths of this structure include its simplicity, the degree of unbundling and transparency, and the management focus and accountability by function. Moreover, it retains RPC as a state owned enterprise, at least initially, which can provide the financial strength to negotiate with IPP's. If performed expertly, the competitive procurement process should introduce further competition into the capital and operating cost intensive generation function. The distribution companies are freed from investment requirements to provide generation and can focus their limited resources on the distribution systems. The grid company is a state owned enterprise, at least initially. Operated on a commercially viable basis, it should be able to access diverse funds for expansion. The grid company might be sold in whole or in part to either private investors or the distributors at a later time if this is deemed to be desirable. Similarly, the regional RPC's might also be sold in whole or in part to private investors.

Three principal drawbacks or issues were discussed. First, the RPC is the sole buyer of power from generators and the sole seller of power to distributors. The distributors are not directly responsible or accountable for their power supply. However, planning procedures can be established such that the distributors can participate in developing and approving the regional generation plan. But execution of that plan rests solely with the RPC.

The second drawback, at least for a few distributors, is that distributors are precluded from entering into significant self generation or purchasing directly from subsidiaries or IPP's. Although the approach could be modified to allow for distributor generation, it would have to be tightly ring fenced. Even then, regulatory oversight and approval of these projects is likely to be particularly problematic.

The third issue is that regionalization of the grids and establishment of regional power acquisition companies will make current grid cross subsidies very transparent. In this respect, the question was raised as to whether the regions currently being subsidized can or will accept the higher prices that will result if the subsidies are eliminated. One approach to this problem might be to phase out the subsidies over a period of time, e.g., five years. This would avoid a sudden step increase in prices, and it would provide a period of time for building the regional operations to provide supplies at the lowest practical costs.

Industry Structure Based on Functional Unbundling and Central Power Acquisition



Notes to Workshop Slides

SLIDE (Revised): Industry Structure Based on Inter-utility Contractual and Operations Integration

This industry structure, although similar in many respects to the Functionally Unbundled/Central Power Acquisition approach, differs in three significant ways:

-- The burden to plan and provide for power generation supplies is with the distribution companies, not with the Regional Power Corporation (RPC).

-- Distribution companies may engage in a mix of self generation (rate-based), purchases from IPP GenCo's (including subsidiaries), and the RPC. They may also buy their total requirements from the RPC, but in this case must contract for specific capacity and energy requirements.

-- The RPC has a different "charter" in that now its primary purpose is to facilitate the distribution companies in becoming self sufficient in generation and direct IPP contracting. The RPC is the power supplier of last resort for those distributors who are unable to otherwise arrange for power supplies.

Reviewing the slide, we note again that the generation function has been disaggregated, with NPC disposing of its generation to IPP GenCo's or other independent companies. To note the difference in focus of the RPC, it is now depicted in the same role as the distributor's generation and IPP purchases. The transmission function is organized the same as with the Functionally Unbundled/Central Power Acquisition approach, with a national grid company with three regional subsidiaries. The same ring fencing is present: distribution lines, distributor rate-based generation, IPP "self" purchases by distributors, and directly connected customers. Each of these ring fenced areas would be subject to heavy regulation.

A significant requirement of the Inter-utility Integration approach is a comprehensive planning and operations integration agreement, especially among the distributors. This agreement, which would be subject to regulatory oversight, covers such key areas as joint generation planning, generating and contract capacity obligations, participation rights in generation, and interchange of services and related pricing.

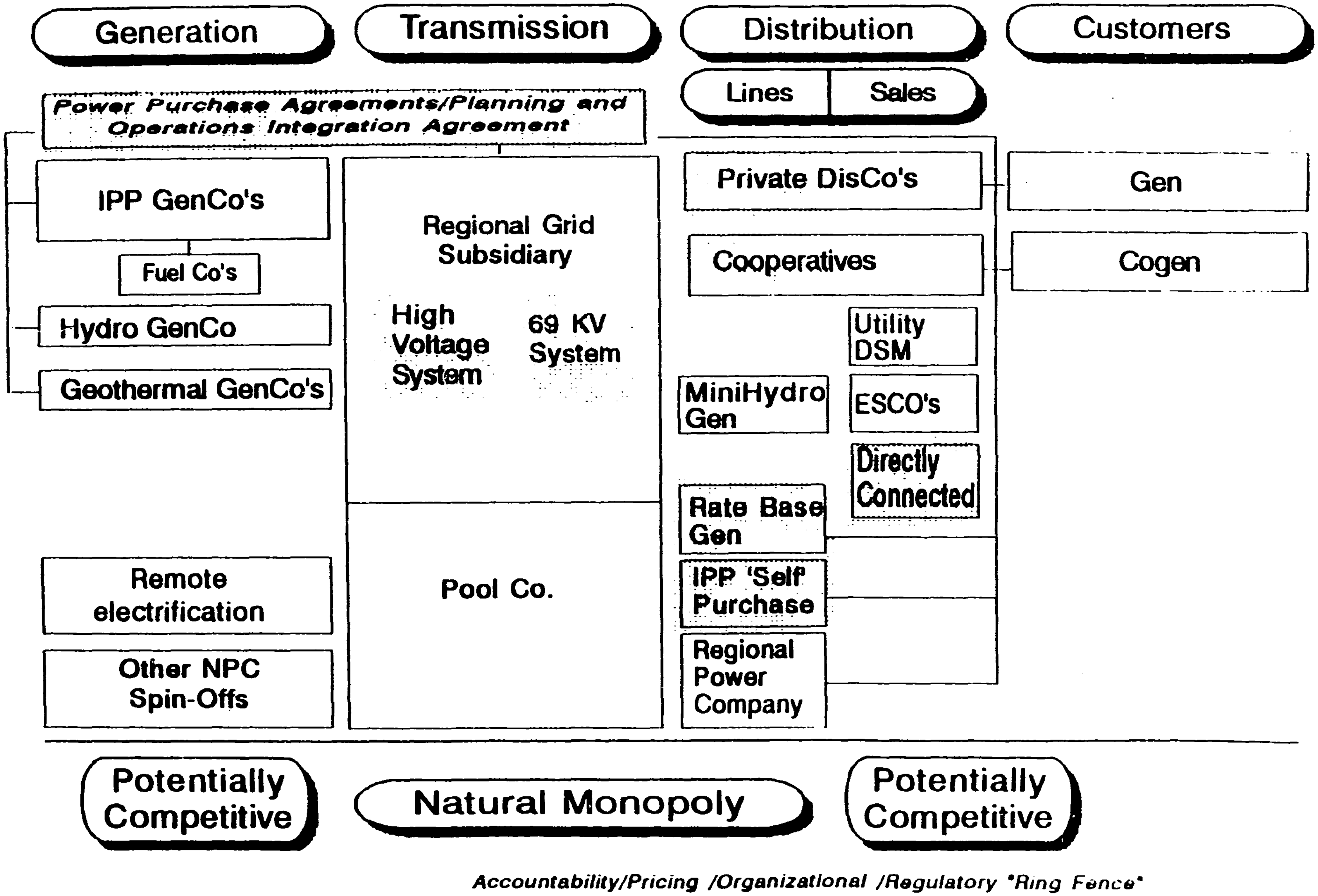
In many ways, this industry approach best meets the competitive industry characteristics discussed earlier. It creates the most buyers and sellers, and it puts in place an operating and contractual framework that facilitates bilateral trades among these buyers and sellers. Ease of entry into generation is also facilitated, and access to transmission is assured. Functions are significantly unbundled, with level playing fields. Planning information is readily available in that joint planning is an essential feature. Transparent pricing is facilitated.

The RPC, initially a state-owned enterprise, remains a key participant to provide power supplies and to overcome the financial limitations of many of the distribution companies. Specifically, the RPC can put its credit power behind projects if necessary to ensure that private developers build the needed power plants. In this respect, two additional features can be incorporated into the Inter-utility Integration approach:

-- A portion of each power generation facility could be offered to distribution companies not otherwise included in the sponsoring group. This would also include RPC, which would offer to distributors participation in the projects it sponsors. These generation "participation rights" would facilitate all distributors in building their power supply portfolios. Participation could be through unit power contracts, ownership shares in the facility itself, or power supply subcontracts (i.e., the primary power purchaser subcontracts a portion to other distributors). Generation access rights would be one of the many provisions of the Planning and Operations Integration Agreement.

-- The RPC could assume a power purchase performance guaranty role for a transition period, e.g., five years. In this capacity, the RPC would put its credit strength behind power purchase agreements of small, financially weak distributors as a means of providing these companies direct access to generation. This would help overcome expected reluctance of IPP GenCo's to deal with the smaller companies. The guaranty would be limited to power purchase liabilities in the case of financial failure of the distribution company. In such case, the RPC would be in the best position to re-market the power. The purpose of the guaranty service is to provide a reasonable time frame for the distribution companies to take steps to either improve their financial capabilities or to consolidate so that they can function in the new industry structure.

Industry Structure Based on Inter-utility Contractual and Operations Integration



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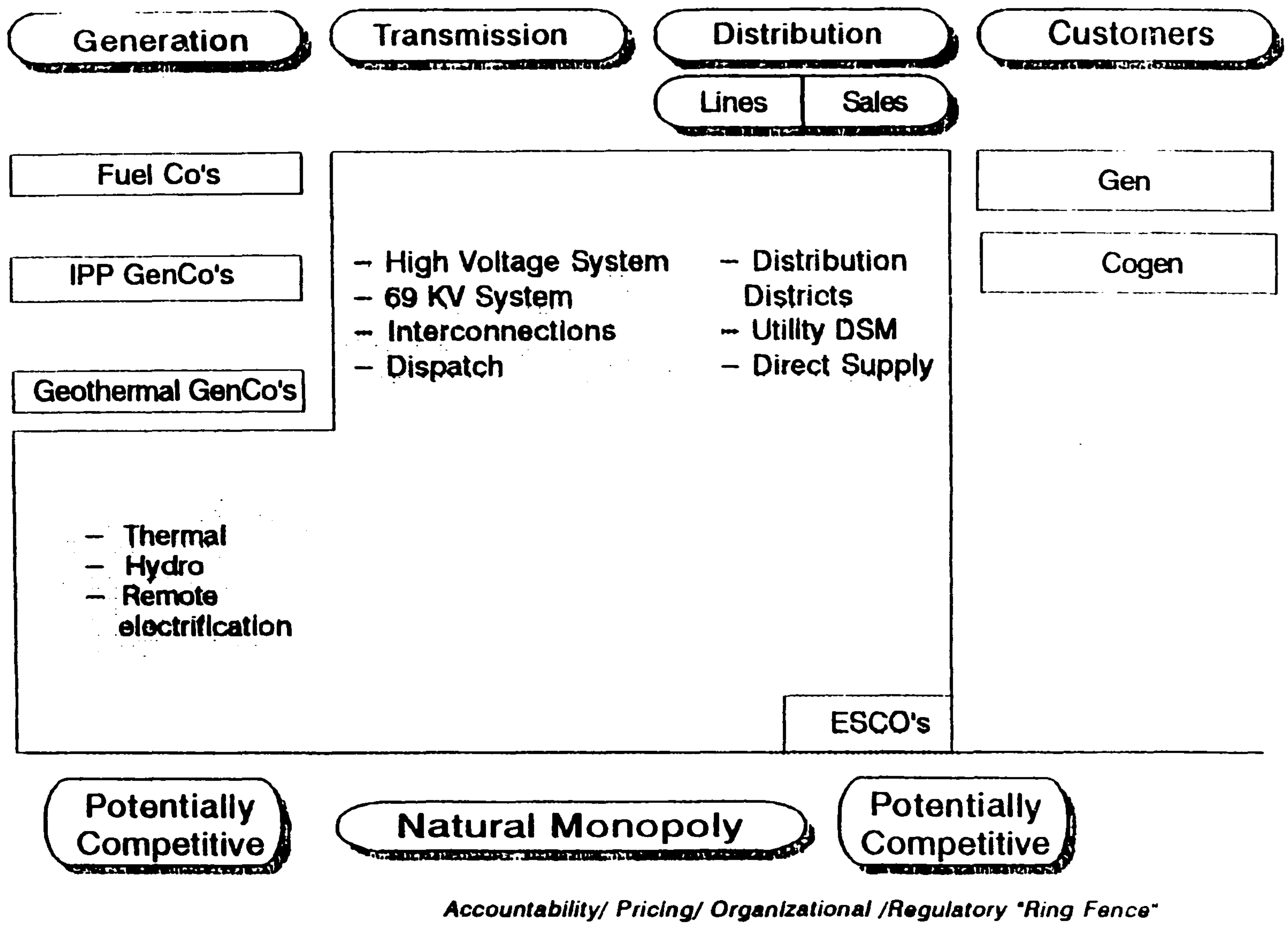
Notes on Workshop Slides

SLIDE (Revised): "Industry Structure Based on Regional (or National) Vertical Integration

This slide illustrates how the Philippines electricity industry would look if we were to pursue total vertical integration. This approach was discussed not so much as a viable option, but rather to complete the consideration of the spectrum of approaches. This approach involves extensive ring fencing of the operations, investments and pricing of the integrated utility. This approach also relies the least on competition, and places the heaviest requirement on regulation.

Industry Structure Based on Regional (or National) Vertical Integration



ADDENDUM

Discussion of the "Petron" Approach

During the individual workshop session with the NPC personnel, and during discussions subsequent to the workshop, interest was expressed in a privatization approach for NPC similar to that adopted for Petron. To address this question, we first define the "Petron" approach as involving three major steps:

1. The first step is to establish a commercially viable company (or companies). This would normally require that one of two conditions be established:

   -- The company operates in an essentially unregulated market where it is free to pursue operating, investment and pricing strategies to compete and earn acceptable returns on its investment, or

   -- The company operates under competent, transparent, and established regulatory practices that reward the company with reasonable returns on its investment, excepting only those instances where management has been objectively deemed to have been imprudent.

   Neither of these conditions, of course, is likely to completely hold true. Rather, a combination of some degree of market deregulation and competition along with a system of regulation will normally characterize a company's environment. The important requirement is that this environment allow management to concern itself with normal business strategy and operations and to earn an acceptable profit if it performs well at these functions.

   A workable combination of market deregulation, competition and regulation has been established for Petron. For the most part, Petron operates in a competitive market, with two well-financed and effective private sector competitors. These competitors effectively constrain anti-competitive or monopolistic behavior on the part of Petron. Moreover, regulations applied to the industry must be relatively even-handed for all practical purposes. In particular, regulations can not impede the performance, management flexibility or profitability of Petron relative to its competitors or Petron will decline in market strength and investment value.

2. The second step is to charter the company (or companies) under the corporate code. This has two important effects that help the company perform effectively and earn profits. First, it frees the company from government salary and other personnel policies and allows the firm to pursue, on an equal footing with its competition, salary structures and other employee policies necessary to attract and retain qualified talent. Secondly, it significantly removes the firm from control by governmental bureaucracies and from interference in management decisions and operations by members of the political body.

3. The third step is to sell a substantial interest in the company (or companies) to either an investor who will take a significant role in the management of the company (like ARAMCO in the case of Petron), or alternatively sell a stake to the general investing public. Pursuing the first investor strategy does not of course preclude also pursuing the second at a later time. To sell these stakes, especially to a foreign investor taking a major financial and management role in the company, highly satisfactory completion of the first two steps is a necessity.

We now turn our attention to the potential application of the "Petron" approach to the electric sector and NPC. In the table below, we contrast Petron and the oil markets with NPC and the electricity market:

Comparison of Petron and NPC

Market Factor	NPC	Petron
Competitive market	No (monopoly)	Yes
Facilitatory/stable regulation	No	Yes
Commercially viable operation	Not established; problematic	Established
Exogenous benefits to investor	No	Yes
Need for regulation	High	Significantly deregulated
Exposure to political interference	High	Constricted

The most immediate and significant difference that we encounter is that the fundamental preparatory market or industry environment does not exist in the electricity sector. In particular, NPC is a monopoly with essentially no competition, which stands in sharp contrast with the competitive conditions that prevail with Petron and the oil markets. In the absence of effective competition that allows a market relatively free of regulation, the alternative is a regulatory structure and stability that promotes acceptable service and cost but at the same time also reassures private investors that they are relatively free to operate the firm to earn acceptable profits. It is not likely that investors would so assess the current regulatory environment in the Philippines electricity industry.

The two industry restructuring options that have produced the most interest -- Unbundled Functions/Central Power Acquisition, and Inter-utility Integration --

are designed to promote more competition in the industry, to provide more transparent and effective regulation, and, importantly for potential application of the "Petron" approach, to develop commercially viable companies. These companies could be offered in whole or in part to a large investor, e.g., a foreign electric utility, or more broadly to the investment community. For example, the Regional Power Corporations and the National GridCo would be commercially viable companies.

However, selling equity stakes in these commercially viable companies might not turn out to be a high priority. In the case of the Regional Power Companies, for example, these should not be capital intensive operations if the overall strategy is successful. Rather, the RPC's will be management, planning and financial expertise intensive. To meet these requirements for expertise, institutional building or management contracting might be more desirable as opposed to bringing in a large investor/manager. Similarly, in the case of the National Gridco, either institutional building or management contracting might also be the most sensible course of action, while simultaneously pursuing a strategy of attracting sources of capital from lower cost suppliers such as the World Bank or ADB, as opposed to relying on an equity investor and higher cost private sector capital.

To facilitate attracting and retaining the needed expertise and to prepare companies for possible sale to the public, companies (e.g., the RPC's) could be re-chartered under the corporate code. This might also restrain counter productive micro-management or intervention by the political body. Adoption of the "Petron" approach for the entire sector is not necessary to accomplish this more limited goal.

An observation worth noting is that there are potentially important strategic and financial benefits to ARAMCO that are exogenous to the financial merits of Petron as an operating entity. Most notably, ARAMCO gains additional vertical integration and an assured market for its crude development and sales activities. At the same time, the Philippines gains a reliable source of crude supply and potential investment stability. It is not clear that such exogenous factors exists for an investment in the electric sector.

Finally, the "Petron" approach, when applied to the electric sector and NPC, might entail a large foreign investor taking a significant ownership and management role in an industry constrained to the nation's boundaries, bound up with the public interest, of necessity subject to regulation by governmental agencies, and never far away from political interference. It is arguably good public policy not to further complicate and constrain the overall management and development of the industry by introducing significant foreign control.

In summary, the Unbundled Function/Central Power Acquisition and the Inter-utility Integration approaches restructuring and privatization suggested for the electric sector embody many of the same elements as the "Petron" approach, e.g., establishing commercially viable entities, promoting competition, and achieving balanced and transparent regulation. Within the context of these approaches, the "Petron" model is perhaps more appropriately viewed as an <u>ownership option</u> that might be applicable to several entities in a restructured electric sector, as opposed to itself providing the basic framework for privatization. Moreover, with successful restructuring, the industry's capital requirements might largely be met by private IPP GenCo's in the generation function and by cost-effective quasi-public financing in the transmission function. The more critical need might be to develop indigenous management talent, and not foreign investors to own and manage the transmission and power acquisition entities. This management talent might better be developed through institutional building, management contracting and modifying organizational charters and compensation limitations rather than through foreign or other investor ownership and management.

APPENDIX F
SUPPLEMENT ON ENERGY REGULATORY BOARD

EXECUTIVE SUMMARY

This document provides a supplemental assessment of the optimum role of the Energy Regulatory Board (ERB) within a restructured electricity industry. It is important to recognize that many of the recommendations of this supplement will hold true regardless of whether the overall industry is restructured along the exact lines of the main report. This is the case because of the important implications for the ERB resulting from the passage of the Act creating the Philippines Department of Energy (RA 7638), Executive Order 215, the regulations implementing EO 215, and other Philippine laws.

The key conclusions of this supplement are that the ERB must undertake new responsibilities (and in most cases, additional staff) to handle its expanded role in three areas:

- setting utility rates
- overseeing utility procurement
- approving power contracts.

In the rates area, we envision that the ERB is largely independent of other Philippine agencies, although the Department of Energy (DOE) can serve in a catalytic role by compelling the utilities to develop methodologies and file rates for new services (e.g, transmission rates). In the other two areas, we recommend that the DOE take the lead in developing policies, methodologies and generic formats, while the ERB would serve to oversee the implementation of those policies.

In sum, we recommend that the ERB accept, and aggressively pursue, several new roles and significantly expand others, including:

- developing wholesale transmission rates, backup rates, avoided costs, and more analysis of long-run marginal costing and incentive regulation for the future

- undertaking substantially more work on all facets of the implementation of utility integrated resource plans (IRPs)

- taking a more active role in the review and approval of all independent power project contracts and major investments by electric utilities, looking towards ERB approval of all franchises in the future.

These new and expanded roles and responsibilities will require more staff, more training and more money than is currently authorized for the ERB. On the whole, the ERB could require at least 50 more people than the 290 currently authorized (of which only 203 are on board), and that the people now on staff will need to upgrade their skills and capabilities to fulfill the ERB's new requirements. In addition, the ERB may need a new funding mechanism to carry out its new role.

Moreover, a number of the new activities should begin within the next few months if the ERB is to be able to implement them in a manner that: 1) keeps up with the many changes taking place in the Philippines electricity industry, 2) does not form a barrier to economic growth due to "regulatory gridlock," and 3) dovetails with other aspects of the restructuring of the electric industry. Time is therefore of the essence in implementing the recommendations discussed in this supplement. In many of these areas, the ERB must make an initial investment in training, personnel and capabilities to get "up to speed," and then over time, to maintain and enhance its newly-developed expertise.

One of the problems with moving quickly to implement these activities is the ERB's difficulty in locating and retaining good people. In conjunction with taking on the many new responsibilities discussed in this supplement, we recommend that the ERB develop a proposed salary structure, and obtain government approval for these changes. This structure could be more competitive with the private sector or NAPOCOR, subject to the constraints of the amounts of new funding ERB receives, and could include incentives to employees for superior performance in carrying out their new duties during this difficult transition period.

The major recommendations for the future role of ERB are as follows:

Setting Utility Rates

- The ERB should continue to review and approve tariffs for all Philippine utilities.
- The ERB should work closely with the DOE (and possibly establish a committee with the utilities and the National Electrification Administration-NEA) to establish financial and technical standards for various categories of utilities that will be enforced through the rate-setting process.
- The ERB should assume responsibility for reviewing and approving wholesale transmission rates for all utilities.
- The ERB should establish a task force with active participation and input from the major utility groups; it would establish an acceptable methodology for the

utilities to implement for backup and maintenance rates. The ERB must assume responsibility for reviewing and approving such rates for all utilities.

- The ERB should adopt a resolution that it will work to implement rates based on long-run marginal cost (LRMC) in all future rate cases. Then, it should require utilities to submit their proposed retail tariffs, and that the tariffs be based on the application of LRMC principles.

- The ERB should not place a high priority on establishing utility avoided costs

- The ERB should not try to shift to a widespread system of incentive rates. Rather, it should concentrate on the initiatives already begun or recommended elsewhere in this supplement (e.g., standards for losses, and other financial and technical standards that are enforced through rate-making and franchising) and on the other major changes that will result from restructuring. The ERB should revisit incentive ratemaking in the 1996 time frame.

Overseeing Utility Procurement

- The ERB should oversee all major utility investments in the context of implementing the utilities' IRPs. The utilities should submit their investment plans to the ERB and receive prior approval through the existing ERB process of investment prudence hearings, before they make large investments to carry out their IRPs. To avoid becoming bogged down, the ERB should set a standard time for processing investment prudence hearings.

- The ERB should determine whether the utilities' major demand-side management (DSM) expenses conform to approved IRPs, and determine how often to review DSM expenditures (it may be sufficient to conduct these reviews at the time of rate cases). The ERB also must decide whether to provide DSM incentives, or at least make DSM investments "revenue-neutral."

- The ERB's role in international competitive bidding (ICB) should be to approve the contracts that developers sign with the winning bidders, because these contracts constitute major financial commitments that may have a significant bearing on the utilities' tariffs. The ERB should participate actively in the proceeding at the EIAB to establish a standard methodology for ICB.

Approving Power Contracts

- The ERB should become the single regulatory body responsible for resolving the issue of directly-connected customers. The direct-connection proceedings could be folded into the CPCN/franchise proceedings.

- Cooperative utilities should also undergo CPCN hearings at the ERB. The EIAB should conduct an open proceeding that would determine whether both franchise and CPCN proceedings should continue to co-exist, and whether the franchising process at the NEA should be consolidated into the CPCN process at the ERB. In the longer term, the franchising function should be transferred to the ERB and combined with the CPCN proceeding.

- The ERB should participate actively in the EIAB's proceeding to establish a standard procedure and contracts for the ICB process.

- The ERB should approve all the contracts (with private sector generating facilities (PSGFs) and others) signed as a result of the competitive bidding process. Thus, the ERB will need to shift its focus in setting tariffs to merge the market-based and rate-based perspectives.

Miscellaneous

- The ERB should hire approximately 50 persons above the current ceiling of 290.

- The ERB should develop an independent source of funding that is not tied to overall Philippine budgetary constraints.

- The ERB should develop a proposed salary structure that matches with the new responsibilities the staff will be required to undertake in the near future, and request government approval for these changes.

Exhibit F-1 summarizes the activities that we foresee for the ERB, the timetable in which these activities should begin, and the likely level of effort required.

Exhibit F-1
Energy Regulatory Board -- Potential Roles and Responsibilities

I. UTILITY RATES	LEAD AGENCY	LIKELY TIMING	NEW OR EXISTING ROLE	LEVEL OF EXPANSION
A. Wholesale NPC and Retail Rates	ERB	Current Activity	Existing	Moderate
B. Rate-Related Efficiency Standards				
Establish standards	DOE/ERB	In early 1995	Part Existing	Moderate
Enforce standards	ERB	In 1995	Part Existing	Moderate
C, D. Transmission Rates				
Understand/evaluate wholesale transmission rates	ERB	In early 1995	New	Moderate
Review/approve utility filings for transmission rates	ERB	In mid-1995	New	Major
Understand/evaluate retail transmission rates	ERB	Consider in 1996	New	Moderate
Review/approve utility filings for retail transmission	ERB	Post 1996	New	Major
E. Backup Rates				
Establish task force to develop methodologies	DOE/ERB	In early 1995	New	Moderate
Review/approve utility filings for backup rates	ERB	In 1995	New	Major
F. Long Run Marginal Costing				
Understand/evaluate LRMC methodologies	ERB	In 1995	New	Moderate
Move all utility rates towards LRMC	ERB	1995-1997	Part Existing	Major
G. Avoided Costs				
Develop methodology	EIAB/DOE	In 1995	New	Moderate
Understand avoided cost methodologies	ERB	In 1996	New	Moderate
Review utility filings	ERB	In 1996	New	Moderate
H. Incentive Rates				
Assess incentive rate methodologies	ERB	In 1996	New	Moderate
Implement incentives as appropriate	ERB	From 1996 on	New	Major
II. UTILITY PROCUREMENT				
A. Integrated Resource Planning (IRP)				
Develop and issue IRP rules/methodology	DOE	By mid-1995	New	Moderate
Review/approve submitted utility IRPs	DOE	Beginning 1996	New	Major
Review national plan from PLANCO	DOE	Beginning 1996	New	Moderate
Oversee IRP implementation - prudence hearings	ERB	Beginning 1996	New	Major

Prepared by RCG/Hagler Bailly for Philippine DOE and USAID — August 1994

Exhibit F-1 (continued)
Energy Regulatory Board -- Potential Roles and Responsibilities

	LEAD AGENCY	LIKELY TIMING	NEW OR EXISTING ROLE	LEVEL OF EXPANSION
B. Demand-Side Management				
Develop and issue rules/potential incentives	DOE	By mid-1995	New	Minor
Review/approve submitted utility plans	DOE	Beginning 1996	New	Moderate
Oversee implementation/investments	ERB	Beginning 1996	New	Moderate
C. International Competitive Bidding (ICB)				
Certify private sector generators	EIAB/DOE	Mid-1995	Part Existing	Moderate
Develop and issue rules/standard methods	EIAB/DOE	Early 1995	New	Minor/moderate
Review/approve all utility RFPs	EIAB/DOE	Beginning 1996	New	Major
Monitor utility implementation of ICB	EIAB/DOE	Beginning 1996	New	Moderate
Approve PSGF contracts -- all utilities	ERB	Early 1995	Part Existing	Moderate
Oversee project implementation	DOE	Beginning 1995	Part Existing	Minor
D. Major Investments				
Review/approve rate base increases - all utilities	ERB	Near-Term	Existing	Major
III. POWER CONTRACTS				
A. Cases of directly-connected customers	ERB	Begin in 1996	New	Major
B.CPCN/Franchise Powers	ERB	Begin in 1996	Part Existing	Major
C. Design standard power purchase contracts	DOE	By mid-1995	New	Moderate
D. Review all PSGF contracts	ERB	Begin in 1996	New	Moderate
IV. MISCELLANEOUS				
A. ERB Staffing Increases	ERB	In 1995	New	Major
B. ERB Funding and Salary Changes	ERB	Begin in 1995	New	Major

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F.1 INTRODUCTION[1]

This supplement expands on the potential role of the ERB in the evolving electric industry structure in the Philippines. However, many of the recommendations contained here should be implemented regardless of whether the overall restructuring ideas in the main report are accepted. This is because the recommendations are an outgrowth of Philippine legislation or regulations that already exist, or are about to be issued, including the Act creating the Philippines Department of Energy (RA 7638), Executive Order 215, and the pending regulations implementing EO 215.

This supplement is based on research conducted over several weeks, including one week of meetings in the Manila area with key government officials and industry participants, including the regulatory agencies (ERB, DOE, NEA) and those subject to regulation (NAPOCOR, Meralco, and Cepalco). All those interviewed were cooperative in sharing their views on the role of the ERB in the evolving industry structure.

This supplement is divided into several main sections that conform to the principal areas in which we believe that the ERB must develop new capabilities or upgrade its existing skills. These areas include:

- setting utility rates
- overseeing utility procurement
- approving power contracts.

Exhibit F-1 in the executive summary summarizes the overall recommendations for the ERB's future responsibilities. In addition, the ERB may need a new funding mechanism in order to carry out its new role. Below, each of these areas is discussed in turn. First, however, this supplement briefly describes the context for these recommendations in terms of the new authority granted to the ERB in recent legislation, and the impending changes in the organization of the Philippines electric power industry.

F.2 THE NEED FOR AN EXPANDED ERB

In the Act creating the DOE approved on December 9, 1992 (Section 18 of RA 7638), all of the "non-price regulatory jurisdiction, powers, and functions of the ERB" were transferred to the DOE. In the same section, the ERB was assigned responsibility to "determine, fix, and

[1] The principal author of this supplement is Elliot J. Roseman, a manager at Hagler Bailly. The author gratefully acknowledges the support of Stan Bowden and Michael Ellis of Hagler Bailly, and of staff at the DOE, ERB, NPC, Meralco, NEA and CEPALCO, with whom the field research was conducted in August 1994.

prescribe rates" for NAPOCOR and the cooperative utilities, in addition to the private utilities that the ERB already regulated. In one sentence, this Act magnified the jurisdiction over pricing alone from a handful of utilities to include the single bulk power generator in the Philippines and 119 cooperatives. Since the Act was passed, the ERB has been working to acquire and build the capabilities necessary to handle these responsibilities.

In addition to its new rate-making authority, many changes are occurring within the Philippines electricity industry that have a direct bearing on the utilities' rate base and other costs, and correspondingly, on the rates that utilities will need to charge. These changes include:

- The emerging need for many, if not all, electric utilities in the Philippines to provide directly for their own power requirements in the future, rather than relying solely on NAPOCOR, as in the past. This need will include the preparation of utility IRPs, which could result in major new investments in supply- and demand-side resources, if the IRP is implemented.

- The potential implementation of competitive bidding by a number of utilities to procure new capacity, which could lead to large financial commitments.

- The potential consolidation of several utilities into one, and the potential transfer of customers currently served directly by NAPOCOR to distribution utilities; both actions could have significant impacts on the rate base, financial commitments, and required rates of the utilities.

- Setting up a separate wholesale transmission and dispatching function under a new entity (called Transco) that will propose wheeling policies and tariffs.

The ERB should be involved in regulating a number of these activities because of their direct implications on power rates, and because of the ERB's well-established adjudicatory procedures. In this era of transition in the Philippine electricity industry, the key regulatory questions vis-a-vis the ERB are:

- Where is the line drawn between the ERB and other agencies? What specific responsibilities should be the province of the ERB, and at what point should the ERB become involved?

- Is the ERB currently in a position to carry out these responsibilities? What new staff or training is required?

- By when should the ERB be prepared to initiate and carry out these roles?

The next sections outline the proposed answers to these and other questions.

F.3 SETTING UTILITY RATES

As mentioned above, the ERB is now responsible for determining the rates of all utilities in the Philippines, including NAPOCOR, private utilities and the cooperatives. There are six additional areas of responsibility over utility rates where the ERB should have jurisdiction. These are:

- fate-related efficiency standards
- transmission rates
- backup rates
- long-run marginal costs
- utility avoided costs
- incentive rates.

In addition to the ERB's traditional rate-making role, each of these areas is discussed below.

Exhibit F-1 indicates the activities that ERB should undertake in these areas, when it should undertake them, whether the role is new or currently being handled by the ERB, and whether the activity represents a major, moderate, or minor level of effort. In this context:

- A "major" level of effort will require the ERB to add the equivalent of at least five full-time new professional staff, or move into an entirely new area of work.

- A "moderate" level of effort requires up to five new professional staff, or involves an area that is a combination of both existing and new areas of responsibility.

- A "minor" level of effort requires few if any new staff (primarily training of existing staff), or involves an area that the ERB is already handling well.

F.3.1 Setting Rates for All Utilities

This area is non-controversial in terms of the ERB's responsibility. Recognizing the major new authority it was granted by RA 7638, the ERB has been adding staff at the Energy Regulatory Branch of the ERB since December 1992. For example, this branch employed just 18 people at the time of the DOE Act, when it primarily evaluated the rate of return for the private utilities only, but it has now tripled to 54 employees (17 in the NAPOCOR/ independent power division, 23 in cooperatives, and 14 in private utilities).

However, the Energy Regulatory Branch is still understaffed and already has authorization to hire more professionals. In total, the ERB is authorized by the government's 1994 budget to hire up to 290 people. As of July 1, 1994, the ERB's had 203 staff, leaving a balance of 87 people (30% of the number authorized) that the ERB could hire. We were told that the ERB planned to add a majority of these 87 to the Energy Regulatory Branch, although not necessarily all of them would be in the electricity area (this branch also handles the technical analysis of petroleum prices, a highly controversial topic in the Philippines).

As the structure of the electricity industry changes along the lines outlined in this main report, the demands on this Branch can be expected to continue to increase. First, the cooperatives are likely to have a number of new rate filings as they take increasing responsibility for their owns supplies. Second, more utilities will be making major investments that will increase their rate base or number of third-party purchases, requiring ERB review. In addition to educating the new staff on existing methodologies for rate-of-return regulation, the staff is becoming familiar with and gaining expertise in 1) the full application of the methodology that the National Electrification Administration (NEA) has used to set rates for cooperatives in the past (a "cash-flow" model), and 2) regulating the rates, not just the rate of return of the utilities over which it has jurisdiction.

Conclusion/Recommendation. On the whole, it is clear that the ERB will require a major level of effort to carry out the responsibilities it already has under the DOE Law. No new legislation or regulation is required for the ERB to exercise its authority in these areas.

F.3.2 Establishing Rate-Related Efficiency Standards

The extent to which utilities effectively control their operations is a major issue in the Philippines. As the Philippines electricity sector moves towards a more competitive, more efficient mode of operation, the ERB could use the current rate-setting process to compel the utilities under its jurisdiction to become more efficient and profitable. In fact, there are already several movements in this direction:

- In a decision dated October 29, 1993 (ERB Case 93-13), the ERB established that NAPOCOR would be encouraged to operate efficiently by only allowing it to pass through fuel costs that were tied to a heat rate standard determined in the previous rate case. Specifically, NAPOCOR is now only allowed to pass through fuel costs based on a "pesos per million Btu" standard, not a "pesos per kWh" standard. Further, NAPOCOR was required to submit to annual fuel audits and all of its contracts with independent power producers before their costs could be included in the utility's fuel cost adjustment.

- In ERB Resolution 91-22, the ERB established standards to be used to help resolve issues of the direct connection of existing NAPOCOR customers to other utilities. These standards included financial indicators such as outstanding debt, debt service capability, operating expenses, average collection period, and technical standards such as percentage losses. Moreover, this resolution contained a transition period (one year to achieve minimum standards, five years to attain preferred standards).

- Both houses in the Congress of the Philippines have passed anti-electricity pilferage bills (House Bill No. 1087, Senate Bill No. 736), which would require the ERB (either on its own or with the NEA) to set standards for computing the amount of current usage that is unmetered within 60 days of the passage of the Act, and for ensuring the implementation of the Act. We were told that the conference committee, which is now in the process of resolving differences between the House and Senate versions, is considering whether to include specific percentage loss standards for different types of utilities in the version that is sent to the President for signing. In fact, the NEA has sent comments to the Congress stating that the standards in the Bill may be too stringent for some cooperatives.

- The NEA has been working with the cooperatives for years on a Performance Improvement Program to develop and formulate strategies for reducing both technical and pilferage losses, and to agree on targets for reduction.

Thus, there is ample precedent for the establishment and imposition of efficiency standards in the Philippines. In fact, it is desirable to give these standards some "teeth" so that the utilities will move quickly to improve their performance where possible, with the objective of all utilities operating like profit-making, private sector entities.

These financial and technical standards could be established and applied to the ***current*** rate-making process (e.g., rate-base regulation for private utilities and NAPOCOR, and cash-flow regulation for cooperatives), so that over time, the utilities would need to become more efficient in order to collect money from their ratepayers. Below, several options are presented for moving the electric utilities to other forms of rate-setting over time.

The standards should not only be used as a stick with which to penalize the utilities for non-compliance, but should also provide an incentive for over-compliance. The incentive should be that if the utilities do better than these standards, they could keep the difference for their shareholders/owners.

Conclusion/Recommendation. RA 7638 establishes the DOE as the entity required to "formulate and implement programs, including a system of providing incentives and penalties, for the judicious and efficient use of energy in all energy-consuming sectors of the economy." Therefore, the ERB should work closely with the DOE (and possibly establish a committee with the utilities and the NEA) to establish financial and technical standards for various categories of utilities, which will be enforced through the rate-setting process. Or, the ERB could publish such standards for comment, conduct a hearing, and then issue a generic rulemaking describing the standards that it will enforce over time.

Whatever process is used, once standards are established, the ERB should only allow the utilities to include costs in their rates to the extent that they meet these standards. The process of setting standards should require no more than 60 days. These standards should directly incorporate the values established in the Anti-Electricity Pilferage Law, when passed. Because there is ample precedent for such standards, the ERB should not require additional legislative or other authority to implement them into the rate-setting process.

F.3.3 Transmission Rates -- Wholesale

EO 215 establishes the basis for private sector participation in power generation in the Philippines. In addition, we envision the development of a market for the utilities in which Philippine utilities purchase power from suppliers other than NAPOCOR. For the distribution utilities to be able to purchase power from a source other than NAPOCOR (including other utilities), it may be necessary for the utilities to utilize the transmission lines owned by others. Thus, it is critical for the utilities to establish, and the ERB to regulate, the wholesale rates at which power should be wheeled from one area to another.

RA 7638 established the DOE as the policy making body for regulations on electricity distribution. It is thus appropriate that the DOE take the lead in establishing the "ground rules" under which rates for wholesale transmission will be set, and require the utilities to submit such rates. In fact, the draft regulations now circulating at the DOE to implement EO 215 would require all utilities to establish standard interconnection policies and wheeling tariffs (Article III, Section 6), to be approved by the ERB. Also, Article V, Section 5 requires NAPOCOR and any host utility to wheel power produced by a PSGF through its transmission and distribution lines of 69 kV or higher.

The understanding of the basis for, and the review of, wholesale transmission rates is not a role the ERB is currently fulfilling; it would be a major expansion of its capabilities. Wheeling rates are complicated and likely to be quite controversial, since their levels can make a project either uneconomic or profitable.

Conclusion/Recommendation. There will be a need for personnel in each power-related division of the Energy Pricing Branch (NAPOCOR/private generation, cooperatives, and private utilities) who understand the basis for and proper level of wholesale transmission tariffs. Some existing ERB personnel could be trained in these areas, but new personnel would also need to be hired. Assuming that the regulations implementing EO 215 are signed by the end of the year, the ERB will need to assume responsibility for reviewing and approving such rates by the second half of 1995 No new authority is required for the ERB to assume responsibility for this task.

F.3.4 Transmission Rates -- Retail

Ultimately, the ERB will need to deal with the issue of whether specific customers can be served best by the utilities in whose territories they are located. The regulators of this issue, known as "retail wheeling" in the United States, are just beginning to develop policies and methodologies to deal with the implications of competition for retail customers. Potentially, distribution utilities' investments in supply-side resources to serve specific customers could be rendered unuseful or "stranded" if these customers can choose their own suppliers. Currently, some customers in the Philippines have the potential to cogenerate, and thus lessen their dependence on the local utility, but they cannot purchase power directly from another distribution utility.

Over time, this policy could change, as the distribution utilities become more used to integrated resource planning, competitive bidding, the possibilities of new franchises, dealing with competition, etc. Also, they are bound to try and extend service to areas not currently served by electric power, which could obligate them to make investments that are not entirely competitive. It could be unfair to encourage the utilities to make uncompetitive investments, and then to subject them to competition for their best customers.

Conclusion/Recommendation. Because there is so much for the distribution utilities to handle in the next several years, it is premature for regulators to promote or require these utilities to develop rates and policies on retail wheeling. The ERB should revisit this issue in the 1996 time frame to assess the progress being made (by both the utilities and the regulators) towards implementing other reforms before determining whether it is appropriate to consider retail wheeling issues.

F.3.5 Backup and Maintenance Rates

For the distribution utilities to utilize PSGFs or sources of power other than NAPOCOR, power must be available from NAPOCOR during times of planned maintenance or forced outages. Also, industrial customers using cogeneration or self-generation will require rates for backup power from the distribution utility. It is critical that the distribution utilities and industrial customers know the rates for such power in order to determine the best demand-and supply-side options for their customers or their corporations.

The draft regulations implementing EO 215 include provisions (Article II, Section 4, and Article VII, Section 3) requiring NAPOCOR and the individual utilities to submit rates for the sale of backup and maintenance power to the ERB for review and approval. We agree that this authority should be vested in the ERB. This provision should also include a required timetable for the utilities to develop a methodology and submit such rates to the ERB.

As with wholesale transmission rates, the ERB will need to utilize personnel qualified to review and approve backup and maintenance rates. It will need to understand the basis for such rates, so that its staff can determine their reasonableness.

Conclusion/Recommendation The ERB should establish a task force with active participation and input from the major utility groups. It would establish an acceptable methodology for the utilities to implement regarding backup and maintenance rates. Then, each utility should be required to submit rates to the ERB that conform to that methodology, and the rates should be updated at each rate case.

The task force should take no more than six months to establish its findings, and the rates should be submitted no later than one year from the date of the passage of the EO215 regulations. The ERB should immediately begin to identify existing staff or new hires that will handle this major increase in responsibilities.

F.3.6 Long-Run Marginal Costs

In 1987, the Approved Policy Reforms of the Cabinet directed NAPOCOR to implement a tariff structure based on LRMC. In 1990, Hagler Bailly completed a study establishing LRMC rates for each major grid and customer type in the Philippines, and a target schedule was established for the implementation of new power rates. Fuel cost adjustments caused the original schedule to be delayed, but in October 1992, the National Power Board approved the implementation of power rate restructuring, and in January 1994, NAPOCOR filed new rates for the Luzon grid that move in the direction of LRMC, which the ERB is still considering.

It is widely acknowledged that cross-subsidies exist in the current utility tariffs charged by NAPOCOR to the distribution utilities. In particular, even under NAPOCOR's recently-filed rate proposal for Luzon, the rates charged to Meralco are 19% higher than the estimated LRMC to serve that utility (existing rate of 1.8435 pesos per kWh versus 1.55 pesos LRMC); Meralco subsidizes the rates for all other utilities and direct NAPOCOR customers. Also, NAPOCOR has just filed proposed rates for the Visayas grid, and these rates are all well below what rates would be under LRMC (NAPOCOR's proposal in the Visayas is to raise rates only for non-utilities, and to **lower** rates for small and other utilities, even though their current rates are just 53-74% of LRMC). These non-LRMC tariffs are passed along to retail customers in the retail tariffs, with distribution company markups.

Moreover, it appears that the LRMC rates being used for comparison are the ones calculated by Hagler Bailly in 1990. These rates would still be the LRMC only by coincidence, given all that has taken place in the Philippines power generation sector in the past four years. This study clearly needs to be updated.

We recognize the sensitivity in the Philippines to the rates for power. However, it is critical for rates to be moved towards LRMC on a definite timetable; otherwise, the tariffs for power send the wrong signals to utilities and their customers about how to allocate resources and develop integrated resource plans (see below). Under such rates, it is entirely feasible that a utility could invest in new supplies that are not in the best interest of the Philippines as a whole or its customers in the long run. Therefore, the ERB must be in the forefront of moving both NAPOCOR and the distribution utilities to implement tariffs that utilize LRMC as quickly as politically feasible.

In the long run, LRMC will benefit all customers, since the distribution utilities will become more financially viable on their own and able to attract capital, and consumers will make about regarding the use of power that match its true cost. However, it is expected that some distribution companies will challenge the tariffs that result from LRMC, which could be higher for many consumers. The achievement of tariffs based on LRMC will require strong political will as well as cogent analysis.

Conclusion/Recommendation. The ERB should adopt a resolution that it will work to implement rates based on LRMC in future rate cases, according to government policy. In this resolution, the ERB should state that in future rate cases, the utilities will be required to submit both their proposed retail tariffs and that the tariffs would be based on the application of LRMC. Then, when each rate case is decided, the ERB should adopt a specific timetable (which could be different for each utility) in which the rates will be required to reach LRMC (including technical and financial standards, as described above). 1997 should be the target for tariffs to reach LRMC for all the utilities.

The achievement of LRMC will require that both the utilities and the ERB be trained in LRMC. Intensive training in LRMC should take place at the ERB over the next six months, and at all the distribution utilities over the next year (ERB could sponsor a series of seminars for each grid to be jointly attended by all the distribution utilities). No additional authority is required for ERB to implement this policy.

F.3.7 Utility Avoided Costs

In other countries (especially the United States), avoided costs have been used to establish the maximum price a utility would pay for ***unsolicited*** offers of capacity, particularly from specialized "qualified facilities." However, with the advent of competitive bidding, the avoided cost is generally considered to be the price at which the winning third party (independent power developer, other utility, or the utility preparing the RFP) offers to provide power to the purchasing utility. Thus, in the context of bidding (which DOE favors), avoided cost rates appear to have little application.

However, there are two other potential uses of avoided costs that may apply to the Philippines

- to establish rates that the utility will pay for power provided by projects that are too small to ask to participate in competitive bidding, due to the high costs associated with submitting a bid

- to select utility DSM programs that are not higher in cost than utility supply-side alternatives.

In the first area, the regulators that design the competitive bidding process will want to address the issue of minimum size for bids, which could be different for each utility, and how to allow for offers of capacity and energy that are below this threshold. Many U.S. utilities have dealt with this issue by establishing a "standard offer" and "standard contract" that such small offerors can utilize. The prices paid for power from these utilities are generally set at the utilities' avoided cost. Often, this avoided cost is simply the utilities' marginal cost of generation (i.e., just energy, and no capacity payments), as determined through production cost modeling.

In the second area, DSM programs may either increase or decrease a utility's tariffs, depending on whether their cost is higher or lower than the utility's other options. To determine whether a DSM program is economically justified, avoided costs is a key component.

Both of these factors point towards having the utilities in the Philippines develop a methodology for avoided costs, and calculate avoided costs on a regular basis. It is also important to recognize that it is difficult to establish what a utility's avoided cost is when tariffs are subsidized (i.e., not set at LRMC), so we recommend that the issue of setting tariffs at LRMC be addressed soon.

Conclusion/Recommendation. Under the restructured industry, avoided costs are not particularly applicable to the recommended competitive procurement procedures, but may still find application in the selection of small power projects and DSM program design. As an alternative to avoided costs under EO 215, ERB should work with DOE to define competitive bidding by which the utilities identify and select alternative power supplies to NAPOCOR. Avoided costs will likely be a minor factor in this competitive bidding as well as in the longer-term IRP process. More detailed calculations of avoided costs can be addressed when utility IRPs are due after 1996 for DSM and other purposes.

F.3.8 Incentive Rates

There are a number of rate-related options for the ERB to consider that would depart from the rate-based model of utility regulation, which provides few incentives to operate efficiently because return on rate base is a "cost-plus" type of compensation.

These alternative options would provide incentives to the utilities to operate more efficiently and competitively. As discussed above, some of these options include controlling losses and fuel expenditures, and establishing other financial and technical standards that would be enforced through the ERB's rate-making process. In addition, however, there are a number of other ways in which utility rates can be designed to encourage efficiency:

- ***Targeted incentives***, which can reward the utility based on specific performance measures such as generating unit availability, construction costs, operation and maintenance expenses, and customer satisfaction

- ***Rate of return bandwidth regulation***, in which no rate adjustments are made as long as the earned rates of return fall within the allowed range

- ***Yardstick regulation***, in which utilities can be rewarded or penalized to the extent that their costs (in total or in specific areas) are less than or exceed the costs for a reference group of utilities

- ***Price cap regulation***, in which an initial price cap for revenue requirements or set of caps in different areas are set. Then, adjustments are required for assumed improvements in productivity, and for cost changes that are presumed to be beyond the control of the utility.

- combinations of the above.

Conclusion/Recommendation. In general, these ideas are intriguing, and some utilities in the United States (e.g., Pacific Gas & Electric, Consumers Power) have requested that their regulators approve the implementation of such incentives.

We believe, however, that the ERB, DOE and utilities have enough to deal with to integrate all the changes proposed here. Furthermore, incentives for improving performance will be built into the utility rate-making and franchising process, as described elsewhere in this supplement. It is thus premature for the Philippines to experiment with additional fundamental changes such as the incentive rate mechanisms summarized above. This topic should be revisited in the 1996 time frame, after some experience has been gained with integrated resource planning, wholesale wheeling, competitive bidding, and other items. In the meantime, the ERB could organize a seminar for the staff of the Energy Pricing Branch sometime late next year to familiarize the staff with these concepts and their ramifications in more detail.

F.4 OVERSEEING UTILITY PROCUREMENT

In the restructured electricity industry in the Philippines, there are four areas in which the ERB should participate in the procurement of power supplies:

- integrated resource planning
- demand-side management
- international competitive bidding
- approval of major investments.

Exhibit F-1 indicates the anticipated responsibilities for regulators in each of these areas.

F.4.1 Integrated Resource Planning

For several decades, NAPOCOR has been responsible for developing a Power Development Program that matched expected demands with available supplies. However, as envisioned in the draft regulations implementing EO 215, this system will change substantially. In the near future, all distribution utilities will become responsible for optimizing their own power supplies based on anticipated demand, and for presenting an IRP that indicates how they will combine both supply- and demand-side resources into a package that is optimal for their service territory. Utilities will no longer be able to rely on NAPOCOR to provide as much power as they require, unless they have demonstrated in their most recent IRP that is the best strategy for their customers, and have made arrangements with NAPOCOR to provide it.

Article II, Section 2 of the draft regulations implementing EO 215 requires that both NAPOCOR and the distribution utilities submit individual power development programs that "reflect an efficient portfolio of generation and demand-side resources." In essence, these are IRPs. Article III, Section 9 sets a timetable on the submission of these programs, requiring all utilities that own and operate generating facilities to submit such plans by January 15, 1996.

Conclusion/Recommendation. We fully support the requirement that utilities develop and submit individual IRPs (or possibly submit joint IRPs, as appropriate). However, the distinction between the roles of the DOE and ERB is important to draw here. The DOE should be responsible for setting the requirements for IRP, developing a generic IRP methodology, and reviewing the IRPs that utilities submit, while the ERB should oversee IRP implementation.

The rationale for this distinction is that in RA 7638, the DOE was granted explicit authority to develop energy policies for the Philippines, and the development of IRPs is a direct expression of each electric utility's policies. However, when the IRP plans are ***implemented***, there are major rate and rate base implications for the utilities, and these areas should therefore be the ERB's responsibility.

We thus recommend that the DOE pass the approved IRPs to the ERB, and that the utilities submit their investment plans to the ERB and receive *prior approval* through the existing ERB process of investment prudence hearings, before they make large investments to carry out those plans. The ERB should not be asked to review investments after-the-fact, as often happens now. The ERB should also establish a threshold level of investment (possibly a different level for different types of utilities, or only investments above a certain percentage of the current rate base), so that the ERB's and the utilities' time is not absorbed in reviewing minor expenditures.

To facilitate the submission of the utility IRPs, the DOE/EIAB should issue regulations in 1995 that describe the expected data, analysis and other content of such documents, and the criteria that may be used to determine the preferred IRP. A number of U.S. regulatory commissions have issued such regulations for their utilities. Because of their extensive IRP experience in other countries, consultants could be used to help the DOE in developing the appropriate criteria. The DOE should also establish the timetable for the utilities to submit their IRPs, since it will not be possible for the DOE to carefully review all the utilities' IRPs in the same year.

When the utility IRPs are submitted, the EIAB must review them to ensure they conform to the regulations. In particular, the first IRPs submitted can be expected to depart further from the "ideal" IRP than subsequent ones. Also, as the utilities submit second- and third-generation IRPs, the DOE will need to determine whether the utility has effectively implemented the conditions that the DOE placed on the previous plan(s). With each IRP, the DOE will have several options:

- decide that the IRP's flaws should prevent the DOE from approving the IRP
- approve the IRP with conditions to guide the utility in the next IRP effort
- approve a modified IRP.

Upon approval, the DOE should pass the IRP to the ERB to oversee its implementation. The ERB will need to be prepared for this task, but not until after the first utilities submit their IRPs. Thus, the review of utility investments is a major, but longer-term effort on the ERB's part, for which resources need not be available until sometime in 1996. At that time, however, the work load should become heavy, as there could be many utilities making investments to implement their IRPs each year that the ERB will need to oversee. ERB staff will need to be trained in each division of the Energy Pricing Branch, and the ERB's existing process to evaluate investment prudence will need to be used to assess the utilities' planned investments. Due to the hearing process required, the ERB's legal staff will have to assume additional burdens as well. To avoid becoming bogged down, the ERB should set a standard time for processing investment prudence hearings.

F.4.2 Demand-Side Management (DSM)

The development of IRPs by each utility will require that much attention be given to DSM programs. Already, several utilities such as Meralco are planning to propose and begin to implement DSM programs within the next six months. The integration of DSM with supply-side resources will be a key element of the DOE's review of each utility's IRP.

As utilities invest capital and personnel time in DSM, it raises the issue of how the utility should incorporate these expenditures in rates. In the United States, many commissions started by only allowing utilities to pass through/expense their DSM costs, much like fuel costs, thus providing little financial incentive for the utilities to undertake these investments. In the past few years, commissions have provided incentives (e.g., inclusion in rate base, allowed rates of return higher than for supply-side investments, payments tied to the achievement of minimum levels of savings), and the result has been much higher levels of DSM efforts than before.

Conclusion/Recommendation. The ERB's role, as with IRP described above, should be to oversee the implementation of DSM programs. The DOE would assess whether the utility had presented a proper mix of DSM and supply-side resources, and then the ERB would determine whether the utilities' major expenditures on DSM conform to the approved IRP.

In practice, however, a utility's investments in individual DSM measures (e.g., incentive payments to residential customers for the purchase of high-efficiency appliances) are generally much smaller than investments in supply-side resources, so the rate implications will be smaller. Also, DSM investments often have a much shorter lead time to put in place than power plants. Therefore, there are two options for the ERB:

- the ERB could decide only to review a utility's planned DSM investments *in the aggregate*, no more than once every IRP cycle, and only if the amount of proposed investment in DSM exceeds the previously-determined threshold level for that type of utility, or

- the ERB could decide that the utilities can bypass the prudence hearings for DSM, and only approach the ERB when they wish to include their expenses for DSM into utility rates. This is the common practice in the United States, and the approach that is recommended for the Philippines, particularly given the small amounts of capital likely to be invested in the first few years. In rate proceedings, the ERB could determine whether the utility invested money in DSM in a prudent manner, or whether to disallow some of the expenditures.

In addition, the ERB will need to decide whether to provide incentives for the utilities to invest in DSM, or at least make them "revenue-neutral" by allowing the same rate of return on demand-side as on supply-side capital investments. Again, there is much experience in other countries that the ERB could draw on to consider this question.

The ERB should make a moderate effort to train its staff in DSM evaluation methods and the incorporation of energy-efficiency expenditures into rates, by taking targeted courses offered by international consultants in 1995. Once it has achieved a minimum internal level of competence in DSM, the ERB should hold a generic proceeding on the role of DSM in rate cases, preferably in the 1996 time frame, when the bulk of the Philippine distribution utilities are beginning to submit their IRPs.

F.4.3 International Competitive Bidding (ICB)

If a utility identifies a need for capacity as a result of the IRP process, then ICB could be used to determine how that need should be filled. NAPOCOR has already used ICB during 1992-1993, in the context of signing energy conversion contracts with "fast track" projects, so there is a substantial precedent and model that could be modified to fit the needs of private and cooperative utilities, or different types of projects.

Over the past seven to eight years, competitive bidding has become *the* preferred means by which utilities worldwide have identified the most cost-effective, environmentally sound, and reliable means of satisfying their capacity and energy requirements. ICB would provide utilities with an opportunity to survey all the available suppliers (including NAPOCOR, independent developers, other utilities, and themselves), and select the one(s) that offer the best match with their unique requirements.

Moreover, *without* competitive bidding, and in particular, without a transparent selection process, the contracts that developers negotiate with utilities are subject to question regarding whether other suppliers could have provided power on a more advantageous basis. When investments are small, this may not be controversial, But when bidders are invited to provide power that will constitute a significant expenditure on the part of the utility, the political process can be devastating to contracts that are purely negotiated. For example, Enron's 1,980 MW Dabhol project in India, Mission Energy's 1,200 MW Paiton project in Indonesia, and the Saudi's 1,800 MW Hab River project in Pakistan have taken many years to negotiate, and none is yet completely certain of coming to fruition. While ICB can be an arduous process for both bidders and utilities, purely negotiated contracts can be even more arduous.

In Article VI, Section 4 of the proposed regulations implementing EO 215, the DOE states that the EIAB shall formulate an acceptable means for conducting competitive solicitations (i.e., bidding) that will identify reasonable rates for which utilities can purchase power. NAPOCOR's previous RFPs provide a starting point, but may have to be substantially modified to fit the needs of the private and cooperative utilities.

Conclusion/Recommendation. The ERB's role in competitive bidding would be to approve the contracts that developers sign with the winning bidders, since these contracts constitute major financial commitments that may have a significant bearing on the utilities' tariffs. It is important that the ERB review all utilities' contracts with winning bidders, not just the contracts that winning bidders sign with private utilities. This will involve a moderate expansion of the ERB's current activities that would most likely begin in late 1996 or 1997, when the utilities begin to issue new solicitations for capacity. In addition, there are many considerations other than just price that enter into these contracts, and the ERB will need to expand its capabilities to review these other matters.

In anticipation of this requirement, the ERB should participate in the proceeding at the EIAB to establish a standard methodology for ICB, and make sure that its staff understand the nature of the contracts and commitments that the utilities will enter into through the ICB process. Perhaps the EIAB process could develop, and the ERB could approve, one or more standard power purchase contracts that would streamline the approval process and allow the ERB to focus only on the exceptions to that format.

Over time, the approval of contracts signed through competitive bidding implies that an increasing share of the revenue that utilities will need to collect from their ratepayers will be the result of market-based transactions, not rate-based utility investments. In the process, the ERB will need to shift its focus to merge these two perspectives.

F.4.4 Approval of Major Investments

As described in Section F.4.1 above, we anticipate that a number of utilities will consider and may undertake significant capital investments in the future that will affect their rate base in a material way. While the ERB has only regulated the prudence of major expenditures for private utilities in the past, that was before the ERB had jurisdiction over the rates for both NAPOCOR and the cooperative utilities. Under its current authority to set rates for these entities, it is logical that the ERB should determine the prudence of proposed major expenditures for NAPOCOR and the cooperatives as well.

Conclusion/Recommendation. The ERB should prepare for an expansion of its prudence hearings as recommended in Section F.4.1.

F.5 APPROVING POWER CONTRACTS

There are four primary areas in which the ERB should participate in the approval of power contracts:

- directly-connected customers
- CPCNs and franchise powers
- standard power purchase contracts
- private sector generating facility (PSGF) contract review.

Exhibit F-1 indicates the responsibilities for regulators in each of these areas.

F.5.1 Directly-Connected Customers

This is a highly controversial topic in the Philippines, and was raised in nearly every meeting conducted during Hagler Bailly's field research for this supplementary report. We understand that currently, a Direct Connection Committee, consisting of two representatives each from the DOE and the Department of Trade and Industry, decides when it is appropriate for a customer that NAPOCOR currently serves to be transferred to the local private or cooperative utility

These cases arise whenever the industry's contracts with NAPOCOR expire (generally every few years), or when there is a large new industrial customer that could be served either by NAPOCOR or one of the distribution utilities. In considering these cases, the Committee conducts a hearing at which it hears testimony on the rate implications of changing suppliers, and the distribution company's financial and technical capability to serve its customers.

We also heard in our meetings about the difficulty that the distribution utilities have in taking over a customer from NAPOCOR due to such issues as NAPOCOR's not having to pay franchise taxes, rate cross-subsidies, and the existence of transmission and distribution lines that are currently owned by NAPOCOR in order to serve specific customers.

Conclusion/Recommendation. The kind of considerations (rate impacts, cross-subsidies, ability to serve) that are considered in the direct connection proceedings are some of the same issues that the ERB considers in rate hearings and CPCN proceedings. Furthermore, under this report's recommendations for restructuring, the distribution companies will be more responsible for resource planning than in the past. In that context, these utilities should be able to consider whether their overall set of customers and shareholders would be well served by adding a major industrial customer. Thus, it makes sense for the ERB to become the single regulatory body responsible for resolving the issue of directly-connected customers.

This work would require a major increase in staff at the ERB, in the 1996-1997 time frame. The agency is not currently conducting these proceedings, and it would have to develop its own method and criteria for hearing such cases. The direct-connection proceedings could be folded into the CPCN/franchise proceeding discussed below, so as to integrate the two and utilize the skills of some staff already at the ERB.

F.5.2 CPCNs and Franchise Powers

Currently, the ERB only approves Certificates of Public Convenience and Necessity (CPCNs) for private utilities. The NEA, on the other hand, approves the franchises for all distribution companies, both public and cooperative. In general, franchises expire approximately every 25 years, and the CPCNs are generally granted to coincide with the period of the utility franchise.

While the NEA has a well-established process for reviewing and approving the utilities' franchises, there are several issues with keeping the franchise powers at the NEA:

- There appears to be an inherent conflict of interest in that the NEA is a primary lender to the cooperatives. In particular, the potential exists for the NEA to allow considerations regarding whether the franchise will be able to repay the NEA's loan to enter into its decision of whether to approve a specific franchise, rather than considering only what is best for the territory as a whole.

- We understand that the franchise and CPCN hearings consider many of the same issues, and that the same witnesses often appear at both.

In addition, the CPCN proceedings consider a number of the same factors that the ERB considers in a rate case, such as prospective rates, and the utilities' financial and technical capabilities to serve customers.

Conclusion/Recommendation. It is inconsistent for the granting of CPCNs to be fragmented: they should either be utilized for all the distribution companies or for none of them. Because we favor the former solution, we believe that cooperative utilities should also be brought under the CPCN umbrella at the ERB. This recommendation alone will require a moderate increase of staff time and resources, since the CPCNs for cooperative utilities will occur more frequently than for private utilities due to their sheer numbers.

Also, given the apparent overlap between franchise and CPCN hearings, we recommend that the EIAB conduct an open proceeding that would determine whether both franchise and CPCN proceedings should continue to co-exist. Given the apparent NEA conflict mentioned above, this proceeding might also consider whether the franchising process at the NEA should be consolidated into the CPCN process at the ERB. We understand the political sensitivity of changing the rules governing cooperatives in the Philippines, and believe that the best way to make a determination is through an impartial proceeding conducted by a third party.

We recommend that 1) there should be just *one* hearing (not both the CPCN and franchise) and it should be the franchise proceeding, and 2) that this proceeding should be conducted at the ERB. With power over the granting of franchises, the ERB will be able to fully exercise its regulatory function by imposing conditions in the granting of a franchise that require the improvement of service that the ERB can then enforce through the rate-making process.

If the ERB were to accept responsibility for all franchising/CPCNs, a major increase in staff would be required, beginning in 1996 (or whenever such authority was transferred from the NEA).

F.5.3 Standard Power Purchase Contracts

As discussed in Section F.4.3 above, the implementation of international competitive bidding (ICB) by all utilities in the Philippines will require that the EIAB develop standard procedures for conducting solicitations. Part of this process should include the development of a standard set of contracts for the utilities to utilize and modify as necessary.

Conclusion/Recommendation. Because the ERB will have to approve the contracts that utilities sign with winning bidders, it should participate actively in the EIAB's proceeding to establish a standard procedure and contracts for the ICB process. This participation will require no increase in ERB staff, but will require the ERB to identify the individuals in the Energy Pricing Branch and the legal staff that are best suited to fulfill this role, and to serve as the staff that will review the contracts that the utilities eventually sign with PSGFs.

F.5.4 Private Sector Generating Facility Contract Review

Currently, the ERB oversees and approves the contracts signed between NAPOCOR and the PSGFs. These contracts have major implications for the tariffs that utilities will need to charge their retail customers in order to recover their wholesale power purchases. As the distribution utilities become responsible for planning their own supplies, one clear option is for them to purchase power from a PSGF, or to consolidate their purchasing power to jointly purchase power from a larger PSGF unit than any one could support.

Conclusion/Recommendation. As described above, we believe that the ERB should approve all contracts (with PSGFs and others) signed as a result of the competitive bidding process.

F.6 MISCELLANEOUS ITEMS

There are two additional areas where we anticipate a need for changing the way in which the ERB operates:

- ERB staffing
- ERB funding and staff salaries.

F.6.1 ERB Staffing

The ERB's 1994 budget is about 43.2 million pesos, based on a staffing level of 290 employees. In fact, the ERB will spend considerably less than this amount, since its staffing level (as of the end of July 1994) was only 203 employees. The 1994 budget is approximately 75% higher than the 1993 budget of 24.6 million pesos, based primarily on authorization for more staff. We were told that the ERB's 1995 provisional budget is not anticipated to be higher than the budget for 1994.

The simple facts are that:

- The ERB will need to hire considerably more staff to fulfill the functions described in this supplement. Some of these staff are already approved, since the ERB is far below its authorized hiring ceiling.

- These staff will have to be trained and become highly skilled in some specialized areas (including specific facets of utility ratemaking, procurement and contracts) in a relatively short period of time.

- The ERB will need to build up a "critical mass" of skills in each of these areas, so that the departure of a single person does not greatly impair the ERB from carrying out its new functions. The ERB's new staff will need to be encouraged to stay at the ERB.

Conclusion/Recommendation. The current budget and staffing allowances take into account some increase in the ERB's pricing responsibilities (although probably not in such areas as transmission pricing and backup rates), but does not take its new duties in the areas of utility procurement and contract approval into account at all. For these purposes, we estimate that the ERB will require another 50 or so staff members to take these functions into account over the 1995-1996 time period.

F.6.2 ERB Funding and Staff Salaries

On several occasions both public and private sector staff told us about the ERB's difficulty in attracting and keeping good people based on the current salary structure. Hagler Bailly did not make a systematic study of salaries in government agencies, and how the ERB fits into this structure.

Conclusion/Recommendation. The ERB should consider developing an independent source of funding that is not tied to overall Philippine budgetary constraints. In the United States, many state regulatory commissions are funded through a very small tax assessed on each kilowatt-hour of utility sales. A similar procedure is recommended for the ERB: a "user fee" type of arrangement.

The ERB should have access to the proceeds from a fund, and those revenues would be allocated to the ERB each year by the Philippine Congress. By requiring that the Congress appropriate these funds, based on criteria that it would establish (perhaps on a peso per kWh basis, or the number of cases expected to be heard), there would be a check on the extent to which the ERB's budget could rise.

In addition, the ERB could establish (and the Congress could approve) certain fees that the utilities would have to pay to the ERB to at least partially cover the ERB's cost for hearing cases that they file on their own initiative

The creation of such funding mechanisms might require an act of Congress. Such legislation would also have to specify that the funds so raised could only be used for the ERB, and that the ERB would not utilize any funds from general revenues of the Philippines.

We also recommend that the ERB develop a proposed salary structure that matches with the significant new responsibilities that its staff will be required to undertake in the near future, and request government approval for these changes. This structure could be more competitive with the private sector or NAPOCOR, subject to the funding constraints discussed above, and could include incentives to employees for superior performance in carrying out their new duties during this difficult transition period.

F.7 OVERALL CONCLUSIONS

ERB's new and expanded roles and responsibilities will require more staff, more training and more money to successfully complete than is currently authorized for the ERB. On the whole, we estimate that the ERB will require at least 50 more people than the 290 currently authorized (of which only 203 are on board), and that the people now on staff will need to upgrade their skills and capabilities to fulfill the ERB's new requirements.

Moreover, a number of the new activities need to begin within the next few months if the ERB is to be able to implement them in a manner that:

- keeps up with the many changes taking place in the Philippines electricity industry
- does not form a barrier to economic growth due to "regulatory gridlock"
- dovetails with other aspects of the restructuring of the electric industry.

Time is of the essence in implementing the recommendations discussed in this supplement. In many of these areas, the ERB must make an initial investment in training, personnel and capabilities to get "up to speed," and then over time, the ERB will need to retain good staff in order to maintain and enhance its newly-developed expertise.

APPENDIX G
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