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Philippines
Rural Electrification Sector Study: An Integrated Program to Revitalize the Sector

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CURRENCY EQUIVALENTS

Currency Unit	=	Philippine Peso (₱)
US$1.00	=	₱ 21.4
₱ 1,000	=	US$46.73
₱ 1	=	100 Centavos (Ctvs.)

WEIGHTS AND MEASURES

Kw	=	Kilowatt (1,000 watts)
MW	=	Megawatt (1,000 kilowatts)
GW	=	Gigawatt (1 million kilowatts)
kWh	=	Kilowatt-hours (1,000 watt-hours)
MWh	=	Megawatt-hours (1,000 kilowatt-hours)
GWh	=	Gigawatt-hours (1 million kilowatt-hours)
kV	=	Kilovolt (1,000 volts)
m	=	Meter (3.2808 feet)
km	=	Kilometer (0.6214 miles)

ABBREVIATIONS AND ACRONYMS

ADB	=	Asian Development Bank
APT	=	Asset Privatization Trust
BAPA	=	Barangay Power Association
BOT	=	Build-Operate-Transfer Program
COA	=	Commission on Audits
DBP	=	Development Bank of the Philippines
DENR	=	Department of Environment and Natural Resources
DOF	=	Department of Finance
ECC	=	Energy Coordinating Council
ERB	=	Energy Regulatory Board
ERR	=	Economic Rate of Return
FECOPHIL	=	Feder. of Electric Cooperatives of the Philippines
IRR	=	Internal Rate of Return
LRMC	=	Long Run Marginal Cost
MERALCO	=	Manila Electric Company
MIS	=	Management Information System
NEA	=	National Electrification Administration
NEDA	=	National Economic Development Authority
NPC	=	National Power Corporation
NPV	=	Net Present Value
NRECA	=	National Rural Electric Cooperative Assn. (U.S.A.)
OEA	=	Office of Energy Affairs
OECF	=	Overseas Economic Development Fund (Japan)
PNOC	=	Philippine National Oil Company
REA	=	Rural Electrification Administration (U.S.A.)
REC	=	Rural Electric Cooperative
REMP	=	Rural Electrification Master Plan
SMCC	=	Synthesized Marginal Cost of Capacity
TOD	=	Time of Day
USAID	=	United States Agency for International Development

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY:

AN INTEGRATED PROGRAM TO REVITALIZE THE SECTOR

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Acknowledgements

This report was prepared by a rural electrification sector mission that visited the Philippines during February 20-March 10, 1989. The mission included:

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EXECUTIVE SUMMARY

A. Introduction

1. In early 1988, the Bank undertook a study of the Philippine energy sector; that study (Report No. 7269-PH; September 15, 1988) recommended a broad strategy for resource allocation and utilization. Since then, the Government indicated concern that some of the important benefits of that strategy might not be realized because of inefficiencies in the electricity distribution system, through which about 15% of total available energy is consumed. The Government was particularly concerned about the impact of rapidly increasing distribution losses, which reached 25% by the end of 1987, on the US$7 billion investment program that was launched for electricity generation and transmission in 1989-96. In June 1989, the Bank approved a US$65.5 million loan to finance distribution system improvements in Metro Manila and the surrounding area. In addition, it conducted a study of the rural electrification sector in February 1989. This report details the findings of that study.

2. The study confirmed that the rural electrification sector has major problems. Until about 1983, substantial investments were made for system expansion without due regard for cost or quality of service. Since 1983, with funding for further expansion becoming increasingly constrained, repayment of earlier loans coming due, and the physical deterioration of core systems steadily increasing, the financial distress of the sector's institutions has become acute. The problems are so pervasive that they cannot be addressed by simple solutions; rather, the Government will need to implement an integrated program to revitalize the sector. That program should have three essential components: (i) a comprehensive restructuring of the sector's core institution, the National Electrification Administration; (ii) a broad program of institutional reform, featuring some financial restructuring, of the 117 Rural Electric Cooperatives that are responsible for distributing electricity to smaller urban centers, towns, villages and rural areas nationwide; and (iii) a thorough refocussing of operational practices and investment priorities.

B. Background

The Economic Setting

3. The Philippine economy has undergone a dramatic turnaround since the mid-1980s. The economic reorientation since 1986 has stressed the primacy of efficiency, prudent macroeconomic management, a transition to market mechanisms, a reform of public enterprises, and a streamlining of public sector investment. The next steps in the transition to efficiency-oriented management will include (i) tailoring a public sector investment program to provide the prerequisites for sustained economic growth; (ii) upgrading the implementation capacity of public sector agencies; (iii) accelerating rural development investments; and (iv) removing infra-

structure bottlenecks. In this context, a revitalization of the rural electrification sector is critically needed if issues of investment efficiency, rural development, and infrastructure improvement are to be addressed vigorously.

Energy Sector Institutions

4. The main energy sector Government institutions include: (i) the National Power Corporation (NPC), which is responsible for power generation and transmission; (ii) the Philippine National Oil Company (PNOC), which is responsible for maintaining adequate oil supplies and developing indigenous energy resources; and (iii) the National Electrification Administration (NEA), which is responsible for formulating and implementing rural electrification policies. Following the change in Government in 1986, the Office of Energy Affairs (OEA) was given responsibility for planning and coordinating energy sector policies and programs. OEA, NPC and PNOC are under the formal control of the Office of the President while NEA reports to the Department of Environment and Natural Resources (DENR). Recently, to develop formal linkages between the energy sector participants, the Government formed an Energy Coordinating Council (ECC).

5. Within the power sector, NPC is responsible for all but very modest generation facilities nationwide and most transmission systems. The Manila Electric Company (MERALCO), an investor-owned company, is responsible for electricity distribution in Metro Manila and surrounding areas. Six investor-owned power utilities provide distribution to urban centers outside Manila. Distribution for the smaller urban centers and the rural areas is provided by 117 Rural Electric Cooperatives (REC). NEA is responsible for coordinating the activities of the RECs.

Historical Context

6. The rural electrification program began formally in June 1969, when Republic Act 5038 (i) declared total electrification of the countryside on an area coverage basis to be a national policy; (ii) provided for the creation of NEA as the primary agency responsible for executing the rural electrification policy; and (iii) provided for the organization of RECs to implement the electrification targets and operate the resultant networks. At that time, only 18% of the country's population was enjoying electric service. NEA was supposed to fulfill its statutory responsibility by (i) providing technical support to the RECs; and (ii) financing their expansion programs with grants and long-term loans. Later, it acquired the additional responsibilities of (i) supervising the RECs' technical and managerial activities; (ii) regulating their electricity rates; and (iii) promoting the development of alternative generating schemes and certain other special projects, which were concerned with integrated rural development programs but not per se with rural electrification.

7. In the program's early years, official and Government funding for rural electrification was so plentiful that the cooperative system expanded extremely rapidly. This expansion was realized through both the

construction of new networks and the assumption of responsibility for existing systems following the failure of locally-based, investor-owned power companies. During this early period, RECs were formed following a thorough feasibility study, with service areas that afforded reasonable chances for technical and financial viability. But, as the pace of expansion accelerated, the feasibility studies became more superficial; and RECs were formed to meet political objectives, REC managements suffered from the same politicization, and the quality of operations suffered as a result.

C. State of the Sector

8. Currently, 117 RECs have franchises covering the entire country outside of the areas served by MERALCO and six smaller investor-owned distribution companies. From an initial base of about 170,000 connections in 1971, they now provide electricity to about 2.8 million consumer members. A large proportion of RECs face serious operational and financial problems. Only 22 RECs are considered to be well managed and financially viable; for another 24, financial viability is within reach if they make some operational and commercial adjustments. The remaining 71 either have a pronounced need for substantial remedial action or are considered beyond rescue. REC distribution losses average 25%, but are in some cases as high as 45-50%. Theft of electricity is common, and maintenance is inadequate throughout the REC system. Annual loan releases, which had averaged more that US$28 million in 1971-83, have dropped precipitously, reaching only US$3.3 million in 1988. With the decline in funding, the annual growth rate of new connections has slowed from 30% or more before 1980 to under 4% since 1983, and even declined in 1988.

9. The sector's operational and financial weaknesses are critical. The RECs' poor standards of maintenance have led to a widespread physical deterioration of their networks; as a result, with technical losses averaging 17% (non-technical losses are averaging 8%), most REC distribution systems are operated at well below their design standards, leading to low reliability of service. The Government's past emphasis on growth of coverage without sufficient regard for cost, combined with its use of the RECs to implement costly and economically unjustifiable alternative generation and rural development programs, has saddled most of the RECs with debts they cannot pay, despite the heavy concessional element built into the instruments that were used to finance the sector's expansion. Generally, the RECs lack the skilled staff and equipment needed to improve their operational performance, and the burdens of past mistakes have weakened their prospects for improving their financial health. In many instances, the RECs' financial problems are directly related to managerial weaknesses that have resulted from the interference in their internal affairs by highly politicized Boards or individual Directors. Even if the RECs as a group would be provided with financial relief, some 25-30 among them face limited future prospects on account of franchise areas that are inherently too costly to serve.

10. NEA has performed poorly as both a lender and a provider of technical support to the RECs. Although it collects monthly data to docu-

ment the RECs' performance, it has been unable to implement programs for operational and financial improvement, largely because its already scanty technical staff is spread too thin to perform its functions well. NEA's financial condition is poor; and in 1987 and 1988, it realized a collection efficiency of only 36%. This, in part, reflected the weakened financial condition of the RECs as a result of the recession of 1983-86, and, in other part, the inherent inability of the RECs to repay loans for uneconomic investments that were promoted by the Government and NEA. Too often, the Government has used NEA to promote costly alternative generation schemes or rural development programs of dubious economic value; and, as a result, NEA has on its books some ₱ 2.6 billion in loans for alternative generation and an undetermined amount of loans for social programs for which it has negligible prospects for repayment. Overall, NEA has questionable prospects for meeting some ₱ 7 billion of loans raised from foreign lenders and from the Government.

11. NEA's weaknesses result largely from a lack of clarity regarding its role in the sector, and its consequent lack of direction. While its revenues accrue entirely from its lending operations, it has viewed itself primarily as an electrification company. In that regard, it has acted as the sector's policy maker, investment planner, regulator, and utility manager of last resort; however, it has not developed the primary functions of a financial intermediary, namely loan programming and credit evaluation. Its lack of a clear focus has inhibited it from acting as an effective core agency for the sector.

12. Perhaps the sector's biggest problem is the participating institutions' chronic lack of technical accountability. NEA has neither had (i) a mechanism to coordinate its activities with the rest of the energy sector, even though the RECs taken together form a substantial block of energy consumers, nor (ii) the outlook and accountability of a financial institution, even though lending and credit are essential elements of its own financial health. Instead, NEA has either been accountable to political agencies, as it was during 1979-86 to the former Ministry of Human Settlements, or to rural development agencies, as it is currently to DENR. In that context, its staff has dispensed substantial capital without regard for the technical or financial requirements for cost recovery.

13. The politicization of NEA created an environment that enabled the RECs to become politicized. Although NEA has sound rules governing the conduct and remuneration of REC Boards and individual directors, those rules are flaunted more often than not. Available data suggest a high correlation between interference by Board members in the day-to-day activities of the RECs and poor management of those institutions. While the RECs are in principle accountable to their consumer members, most RECs whose weak performance may be attributed to poor management show little effort to develop member involvement. In effect, these Boards (and in turn their RECs) are accountable primarily to the political interests that sponsored their elections.

D. A Revitalization Program

14. Major reforms in the sector are urgently needed. To address problems that are so pervasive, an integrated program should be developed that will simultaneously (i) introduce proper operational practices, appropriate investment strategies, and sound pricing principles and (ii) strengthen the sector's weak institutions. The first focus of the program should be on operations and investment, so as to determine the requirements for restoring the networks to their original design standards and the parameters of an affordable investment program. Concurrently, appropriate pricing principles should be introduced to optimize the RECs' recovery of their costs from revenues. Programs to restructure and strengthen the RECs and NEA should follow after the requirements of operational and investment reform have been established. Because neither the RECs nor NEA can concentrate effectively on their future responsibilities as long as they are burdened with unmeetable obligations accruing from past uneconomic policies, the institutional strengthening components of the program should include measures for the financial restructuring of these organizations. To ensure that the benefits of restructuring remain effective in the long term, NEA will need to develop and implement a financing strategy that (i) encourages the RECs to invest in high-return projects and adopt proper operational practices and pricing principles, and (ii) discourages them from failing to meet obligations to their creditors and their consumers. Finally, any reform of the RECs and NEA should include provisions for developing functional accountability within each of the organizations while also taking account of the realistic constraints they face.

15. This report makes many recommendations for improved operations, investment planning, and pricing for the rural electrification sector. While the study addresses these issues in the aggregate, to ensure that these diverse activities are properly coordinated and to translate this extensive program into a management plan for each REC, an comprehensive Rural Electrification Master Plan (REMP) is needed to provide a detailed framework within which (i) specific improvement measures can be formulated, taking into account realistic constraints on available financing, and (ii) operational performance can be measured against realistic technical and financial targets. The REMP should be prepared by NEA in consultation with the RECs, with the assistance of consultants. It should plan the integrated long-term development of rural electrification, with special emphasis on the next ten years. It should include as its main elements: (i) establishment of a methodology for investment planning and evaluation; (ii) preparation of indicative investment and lending programs; (iii) development of an appropriate pricing system; (iv) establishment of operational performance criteria; and (v) formulation of a manpower development plan.

E. Operations, Investment and Pricing

16. The condition of the rural electric distribution system has gradually deteriorated so that supply standards and the quality of service have diminished markedly. Now, NEA and the RECs are facing the need for substantial investment in rehabilitation, system improvements, and major maintenance as well as investments that may be justified in system expansion. To ensure that capital is not wasted, proper operation and maintenance should take precedence over any investment in new systems. Funds that are allocated for new investment should be used to support projects that are economically justifiable. Currently, because of the generally poor condition of many core systems, the relative priority of rehabilitation within the context of all possible investments needs to be established. To the degree that investments in rehabilitation and system improvements can be justified on economic grounds, NEA and the RECs should refocus away from extending area coverage and toward improving the quality of existing service. Finally, pricing of electricity should be reformulated so as to encourage efficient operation and maintenance by the utilities as well as efficient utilization of electricity by the consumer, and not merely the recovery of average costs.

Operational Efficiency

17. Basic System Design. The basic design of the distribution networks is sound and appropriate. Until the early 1980s, electricity service and supply continuity standards were generally good, and continue to be satisfactory in a majority of RECs. The system's main flaws result from (i) beginning construction prior to obtaining proper rights-of-way; (ii) improper maintenance; and (iii) use of ad-hoc approaches for construction, operations and maintenance in the face of financial constraints.

18. Improved Operation and Maintenance. Network maintenance is currently performed by the RECs on an ad hoc basis, with poorly-trained staff using inadequate materials, tools and transport. Field inspections of more than half of the RECs, conducted by consultants in 1986-89, found that about 10% of the networks were well maintained, 25% satisfactorily maintained, 35% unsatisfactorily maintained, and the remainder showing no sign of maintenance. NEA should therefore develop a national program for planned and operational maintenance. Based on that program, NEA would help the RECs prepare their own budgets and work programs for major maintenance, and ensure through conditionality on future loans that each REC had formulated and would implement its own maintenance program. Programs for planned maintenance should only cover core systems operating at or near design standards; otherwise, rehabilitation must be done first. At a minimum, maintenance activities should include the following three components: (i) clearance of trees; (ii) treatment of poles to prevent rotting; and (iii) repair of damaged equipment and tools that are now lying idle.

19. Rehabilitation of Core Systems. The rural distribution core system consists of about 250 69-kV substations and about 600 13.2-kV feeders that supply the distribution transformers, low-voltage networks and

consumer service drops. About 20% of the rural network requires extensive rehabilitation or replacement to restore the system to the original design standards. A pilot program for rehabilitating core systems is included under the proposed Bank-financed Energy Sector Loan; if successful, that program could form the basis for the design and implementation of future rehabilitation projects.

20. Reduction of Nontechnical Losses. Nontechnical losses are unacceptably high and should be reduced through a program that includes the following measures: (i) continuous surveillance of lines; (ii) replacement of all "A" base type meters; (iii) sealing of all socket-type meters; (iv) on-site meter testing, replacement and recalibration; (v) rewiring of all substandard major industrial and commercial meters, with regular checks of these meters; (vi) installation of check meters on distribution transformers; and (vii) replacement of low-grade service connections with concentric cable. These technical improvements should be complemented by (i) stronger laws to enable utilities and RECs to pursue pilferers and to impose stiffer penalties on those pilferers who are convicted (several proposed bills are currently pending before Congress); and (ii) increased consumer involvement through the promotion of group accounts, known as Barangay Power Associations (BAPA), that would shift responsibility for losses in the secondary system to the BAPA and reduce billing costs.

21. Commercial Practices. Over the years, the RECs have become slack in implementing proper commercial procedures; now, only about 10% of the RECs run their commercial activities effectively. The causes of this deterioration include: (i) management's failure to accord priority to billing, collection and related activities; (ii) insufficient funds to provide and maintain the equipment needed for commercial efficiency; (iii) shortages of functioning meters; and (iv) local political and social pressures to forgive delinquent consumers. To restore the RECs to a sound commercial footing, NEA should update its commercial guidelines and encourage the RECs to implement them. Each REC should be provided with a mini-computer to manage its billings and collections, and training in the procedures as well as the hardware and software supplied. These improvements should be complemented with investments to rehabilitate service loops, metering installations and meters. The experience in those RECs that have been performing well indicates a high correlation between effective collections and heightened member involvement; therefore, the formation of BAPAs and implementation of member outreach programs should be encouraged. Finally, NEA and NPC should develop technically-based policy guidelines concerning supplies to large industrial and commercial consumers; those guidelines would specify conditions under which the RECs could enjoy exclusive franchises within their service areas.

22. Manpower Development. The most critical manpower development requirement facing the sector is to increase the effectiveness of managers, particularly the RECs' General Managers and NEA's senior functional managers. The REMP could provide the framework for a management development program consisting of: (i) annual seminars for small groups of managers to discuss action planning, prioritization of operational and investment activities, and constraints on implementation of operational and investment plans; and (ii) training courses, including situational management, human resources management, investment planning and financial management, and

distribution planning, to upgrade managerial skills. NEA will need to provide the facilities and absorb the cost of managing this program; the ensure that the related costs are recovered, NEA will need to charge appropriate fees to participating RECs.

Investment Strategy

23. In its early years, the rural electrification program was oriented towards expanding the distribution network outside the urban centers. The dominant issues in investment planning were the appropriate geographical spread of network expansion and the pace for connecting villages and households. This approach, which was driven by (i) technical considerations, (ii) availability of finance, and (iii) implementation capacity, lent itself to quantitative planning methods primarily aimed at ensuring that the financial performance of the newly established RECs kept pace with investment. Over time, this planning approach gradually overlooked such increasingly important system requirements as maintenance and upgrading, intensification of connection density along existing lines, and service to non-residential consumers.

24. NEA changed its investment priorities in 1988 and embarked on a crash program of identifying the previously neglected rehabilitation and upgrading needs. However, this salutary effort can be sustained only if an investment evaluation and programming method based on economic criteria is put into place. Using such an approach confirms the intuitive view that rehabilitation is the highest investment priority, as indicated by rigorous analysis of alternative investment options which compete for scarce resources. As only marginal savings could be realized from changing design standards, the investment options are determined by the relative weight given to system improvement and expansion in the investment program. The results of sample feasibility studies conducted by NEA indicate that the highest priority should be accorded to rehabilitation/upgrading with simultaneous addition of new connections in the rehabilitated parts of the network. Expansion is economically justified only when a large part of demand is provided by non-residential consumers such as medium and small industry.

25. These indicative priorities need to be translated into a consistent rural electrification investment plan and NEA lending program. Since establishing such a comprehensive planning and programming process in NEA and the RECs will take some time, indicative investment scenarios were developed to get this process started. Based on the priority for system improvement derived in the sample studies, two scenarios involving variations in the pace of investment were examined: (i) a scenario based on a gradual increase in rehabilitation expenditure, and (ii) a second scenario based on a massive early rehabilitation effort. The first scenario eventually rises to a higher level of annual expenditure as delayed rehabilitation overlaps with increasing investment for expansion. Under both scenarios, (i) system upgrading will take up most of the sector's funding and implementing capacity for the medium term, and (ii) considerable investment in expansion will have to be postponed to allow the distribution system to regain efficiency. In the early 1990s, when annual investment levels reach about ₱ 1 billion, substantial new funds will have to be mobilized. In any

case, the most important constraint affecting the level of future investment appears to be the absorption capacity of NEA and the RECs. The most likely scenario, which involves aggregate investments of about ₱ 3.8 billion during 1989-93, represents a best guess of NEA's absorption capacity.

26. During the early 1990s, assuming a redirection of NEA's investment strategy, the proportion of rural population receiving electricity supply could rise from the present level of about 50% to about 65% by 1993/94. About half of the newly connected 700,000 to 800,000 consumers would be within easy reach of the existing grid, and would receive their connections through add-on investments; the remainder would receive electricity as a result of judicious expansion into economically justifiable areas. From the mid-1990s onward, connecting the remaining 250,000 to 300,000 consumers that could be supplied economically through add-on investments would increase coverage to about 70% of the rural population. However, given that the share of unconnected productive consumers must necessarily decline and the areas remaining to be electrified would become increasingly remote, the expansion investments that might increase penetration significantly are likely to become more difficult to justify in economic terms. Even in the long term, penetration beyond about 75% of the rural population would appear difficult to justify economically, and would have to rely instead on social priorities (in which case, the economic cost would have to be absorbed).

27. The past proliferation of rural electrification in the Philippines occurred because of the emphasis that had been given to the social aspects of expanding the service. However, during the next five to ten years, the sector will be undergoing substantial restructuring (paras. 36 and 41-44). During this period, emphasis needs to be placed on addressing issues surrounding the needed restructuring while supporting investments that have prospects for an imminent favorable financial outcome and direct economic potential. Investments that are justified primarily on social grounds can be considered only sparingly before the late 1990s or early 2000s, and should be postponed until the current institutional problems have been remedied and the RECs have regained financial strength.

Pricing Policy

28. NEA guides and monitors the RECs' rate setting activities. Rates are established according to a simple formula that includes the cost of power purchases (or own generation), REC operating costs, and debt service requirements. Current NPC bulk rates for REC purchases from the major grids are about ₱ 0.5-1.0/kWh, resulting in an average retail rate for REC customers of about ₱ 1-2/kWh. In isolated island RECs, where local generation costs ₱ 2.0-2.5/kWh, retail rates have averaged about ₱ 4-5/kWh. Recently, NPC has agreed to take control of the generating facilities serving those islands and charge those RECs a subsidized rate of ₱ 1.30/kWh; in turn, the RECs would observe a retail rate ceiling of ₱ 2.5/kWh.

29. In general, the existing formula does not encourage efficiency in consumption patterns, and does not provide for future investment. A move towards rates based on long-run marginal cost (LRMC) principles would

address both deficiencies. In 1987, the Government instructed NPC to develop LRMC-based bulk rates, and NPC is in the process of designing an appropriate pricing structure. As the power purchase price forms a large element of the final REC retail price, the outcome of the NPC pricing analysis will be an essential input into REC rate setting. The key issue in the structure of NPC rates is the differential in marginal cost between peak and off-peak periods of daily demand. To give clear signals to wholesale consumers, NPC should introduce time-of-day pricing gradually, thus encouraging the shifting of price-elastic demand to off-peak periods.

30. The application of marginal-cost principles to REC pricing is a logical extension of the improved NPC rate structure. During the evening hours, when NPC and REC peak periods overlap, the supply cost imposed by retail consumers is highest, amounting to about ₱ 3/kWh in Luzon RECs with acceptable system loss levels; however, the corresponding off-peak costs would only be ₱ 0.60-1.80/kWh. Large REC consumers such as industries could be billed on a time-of-day basis, according to this cost structure. Residential consumers, for whom average pricing is more suitable, would face a single rate, which would reflect the weighted costs imposed on the system by their pattern of consumption. On average, the RECs' revenue per kWh is likely to remain below the current ceiling of ₱ 2.50 (assuming that they can keep their system losses at or below 20%), while the demand pattern would adjust to optimize the cost of supply. The report develops a rate formula which follows these principles. While the rate formula indicates substantial changes in the structure of rates to encourage more efficient utilization of electricity, efficient RECs would be realizing average revenues near their current rates. In many cases, industrial consumers would be paying less than or the same as current rates, while residential consumers might be paying as much as 10%-15% more than they are currently. While the concept of time-of-day pricing is beneficial in the long run, it should be introduced cautiously, observing consumer reactions at each gradual implementation step. If the concept yields efficiency benefits and is easy to administer, it should be implemented in full.

31. Electricity appears affordable to typical rural residential consumers. A simple cross-sectional analysis of price elasticity (ignoring income effects), as well as the responses to an NEA-conducted survey, indicate that consumer resistance to price increases only becomes strong at about ₱ 2.50/kWh. The current share of expenditure for electricity amounts to about 10% of household income, while that for kerosene lighting is closer to 15%. Survey responses indicated that households would use electricity to expand their lighting hours provided it cost no more than kerosene. In the minority of RECs that depend on high-cost isolated diesel generation, any subsidization should be granted to the REC in a highly transparent manner, showing the cost differential between retail rate ceilings and true supply costs.

G. The Rural Electric Cooperatives

32. The RECs' problems do not result from their structure as cooperatives. This conclusion is supported by (i) the mass failure in the early 1970s of investor owned utilities that served provincial cities and towns; (ii) the disinterest of investor-owned utilities or utility management companies in taking control of failing REC franchises; and (iii) the concentration of these failing REC franchises in areas where core systems are in severe disrepair and institutional problems are pervasive (as in central and southern Luzon), or where high self-generation and administrative costs undermine financial viability (as in the small, remote islar s of the Visayas). The RECs' operational and financial performance is more likely to be improved by launching programs to address the problems crippling the system rather than by creating a new organizational arrangement.

33. The major institutional problem shared by the most of the poorly performing RECs is the high degree of politicization of their Boards. Too often, those Boards and their members have become excessively involved in the REC's day-to-day affairs. This has resulted in abuse of perquisites and indications of corruption. While an elected Board representing the interests of consumer members is the fundamental characteristic of a cooperative, the politicization of REC Boards and the resulting abuses indicate that, in those instances, the Board members are not accountable to their consumer members but rather to the political interests that supported their elections. To restore some accountability, existing legislation should be amended to provide that (i) a majority of REC Boards be composed of non-elected members, chosen either on an ex-officio basis or by appointment of the NEA Administrator, and (ii) elected Board members serve a fixed term of two to four years, and thereafter be ineligible to serve the REC as a top officer. NEA's currently sound guidelines governing the conduct of REC Boards and their members need to be enforced through the use of conditionality on future NEA loans to the RECs.

34. The subdivision of RECs, usually for reasons of political patronage, has created clusters of RECs with franchise areas that cannot be served economically. Currently, some 25-30 RECs appear to have severely limited chances of ever becoming financially viable. Geography appears to be the most important constraint limiting their prospects for attaining viability. Virtually all of these RECs serve either remote, small islands, or sparsely populated mountainous areas with insurgency problems in Luzon, Mindanao, or Samar. The Government needs to consider adopting special policies for supporting those RECs. Such policies could include excusing past loans that these RECs have virtually no chance of repaying, and using grants to finance economically-viable investments.

35. In conjunction with a program to restructure NPC, NEA received ₱ 500 million in equity in August 1988; in turn, the funds were used to enable 21 RECs to refinance their significant arrearages to NPC. Under this Relending Program, 10 of the RECs retained their existing General Managers and Boards; for the other 11 RECs, NEA appointed new General Managers after the Boards agreed to be reduced to advisory bodies. Operations have improved significantly in the first group, but have continued to deterio-

rate in the latter group. If NEA must exercise its authority to supplant a General Manager and/or disembody a Board, it should take that action as a receiver and not as a utility manager. In that capacity, NEA should actively solicit proposals from all potentially interested parties - including adjacent RECs, investor owned utility management companies, and new groups from within the bankrupt REC's franchise area - for the future viable operation of that franchise.

36. While solutions to the RECs' financial constraints can best be developed on a case-by-case basis, the following system-wide measures, which would have the effect of restructuring the RECs, would be generally beneficial and should be implemented as soon as practicable:

(a) Even the most financially viable RECs are unable to generate sufficient revenues from operations to finance needed investments. The RECs as a group are seriously undercapitalized and their scope for recapitalization is extremely limited. New consumers are required by law to pay only ₱ 5 to join a REC, far below the cost to the REC of providing each consumer with service. As a result, membership-contributed capital in 1987 represented just 0.2% of total REC assets. The Government needs to amend existing legislation to increase the membership fee to at least ₱ 200 for all consumers. While this could increase the RECs' paid-in capital by an aggregate of about ₱ 320 million by 1995, still other approaches to increasing the RECs' capital should be considered. Specifically, the Government should provide the RECs with relief from (i) loans for extensions of service to uneconomic areas, alternative generation schemes, or social programs; and (ii) damage caused by natural disasters such as typhoons.

(b) NEA should contain the proliferation of RECs by (i) curtailing the establishment of new RECs, (ii) reviewing the feasibility of consolidating adjacent RECs now participating in NEA's Relending Program, and (iii) developing incentives for well-functioning RECs to absorb adjacent REC franchises in receivership. Such incentives could take the form of providing (i) special working capital loans, or (ii) grants to support needed economically justifiable investments aimed at revitalizing the failing franchise. A broader consolidation program was considered and dropped for the time being out of concern that NEA could not enforce the dissolution of a REC that was not in receivership. A further factor now deterring consolidation is that the main criterion for an effective consolidation is geographical contiguity of service areas, and very few poor performers are contiguous to good ones.

(c) NEA should encourage needed institutional reforms through the use of conditionality in connection with future NEA loans to poorly performing RECs. NEA should consider supporting additional investments for RECs that meet their targets for operational and financial improvement, and might consider lending cash to RECs with a record of several years of good performance. Alternatively, NEA should deny funding to poor perform-

ers that make insufficient effort to improve their operations, regardless of the priority of those RECs' planned investments.

37. An attempt by NEA to quantify the degree of managerial depth available to the cooperative system indicated that managerial ranks are thin, largely because of the low pay scales in effect at most RECs. These pay scales should be adjusted to enable the cooperatives to attract and retain sufficient numbers of qualified managers.

H. The National Electrification Administration

38. Following the change of Government in 1986, many government agencies received special assistance to restructure their operations, but no such assistance was extended to NEA. Despite this lack of Government support, in 1987-88, NEA's Board recruited an energetic new leadership team that appears capable and interested in providing the agency with an appropriate focus. That team has already taken bold steps to streamline the staff and introduce efficiency measures. However, these measures by themselves are not enough to make NEA function effectively as the sector's core agency. The organization needs a reorientation of its role and its operating perspectives, accompanied by a financial restructuring to put it on a "clean books" basis.

NEA's Role

39. Given its weak performance during the last ten years, NEA's continued existence cannot be justified on the basis of its electrification activities alone. NPC can provide many, though not all, of the same services. However, NEA's lending activities are so specialized as to make compelling its continued functioning in that capacity. Its borrowers, the RECs, provide a service that is critical to the economic development of the areas within which they operate, yet few of them are financially viable and even fewer are credit worthy. Highly specialized technical support is needed to ensure that the formulated loans support feasible and appropriate projects, and the RECs develop into institutions that operate well enough to repay their loans. Thus, a core agency coordinating rural electrification through lending and technical support activities is essential to any institutional structure serving this sector.

40. NEA's difficulties have stemmed mainly from a lack of focus in its activities, and the previous Government's bent for asking NEA to exceed its institutional capabilities. Previously, however, when its direction was clear and its available resources were adequate, NEA performed effectively. Now, its Board and top management should reorient NEA to act primarily as an interested lender that provides support services aimed at assisting its borrowers on the path to credit worthiness. NEA currently has a staff of about 900 people who are providing many of those support services. These activities need to be supplemented with more focussed loan programming, credit analysis, and loan administration functions. Because NEA needs only to reorient its focus and supplement its existing staff, the

most effective approach to developing the needed core agency activities is to address NEA's weaknesses.

41. Over the years, NEA has acquired a number of side activities that were only peripherally related to rural electrification, or aimed at developing for the RECs supply alternatives to connection to the NPC grid. In its 1988 reorganization, NEA discontinued some of the more arcane of these activities; however, it continues to be involved in alternative generation investments. NEA needs to restrict its business to providing finance and technical support for the distribution utilities serving rural areas, and should divest itself of its other activities.

42. Despite its involvement in the energy sector, NEA is currently formally accountable to DENR, which cannot provide the technical support that NEA needs. To coordinate NEA's activities and investments with the rest of the energy sector, NEA has a seat on the ECC. Even so, a stronger interaction with the energy sector is needed. NEA should have the same reporting relationships as NPC, PNOC and OEA, the energy sector's main participants; this would mean bringing NEA directly under the Office of the President, and having it report to the Executive Secretary.

43. NEA also urgently needs to develop functional accountability over its activities. Although operating in both the electrification and the lending businesses with constrained resources, NEA has not previously had either formal ties to NPC or the outlook and accountability of a financial institution. NPC can provide technical support for many of NEA's electrification planning and implementation functions. NEA should formalize its relationship with NPC by having the NPC president serve ex-officio as the NEA chairman, with the NEA Administrator assuming an ex-officio seat on NPC's Board. To ensure that NEA follows the policies of a financial intermediary, one seat on NEA's Board should be reserved for a senior banker, and a second for a senior official of the Department of Finance. Because NEA currently lacks the staff needed to discharge its lending operations and has only limited prospects for acquiring such expertise given its current pay scales, it should acquire the expertise through a consulting arrangement with a major bank or financial institution.

Financial Restructuring

44. NEA can hardly address the problems of the RECs while it is burdened with problems of its own that threaten to overwhelm the organization. Viewed as a commercial enterprise, NEA is insolvent. Accrued interest income, which is essentially NEA's only source of revenue, grew at an annual rate of about 15% during 1984-88; but interest expenses, which generally account for about 75% of operating expenses, grew at an annual rate of 17% during the same period. Overall, NEA collects only about half of the amortization due from the RECs, and the default rate for its alternative energy loans is nearly 100%. Since 1986, current liabilities (mainly advances from the Government) have exceeded current assets, and the gap is growing. A relevant restructuring program, which would put NEA on a "clean-books" basis, would include the major measures enumerated below. The program to implement these measures will need to be framed in the con-

text of when the Government, with its limited resources, can feasibly take responsibility for the liabilities from which NEA should be relieved.

(a) Advances from the Government, aggregating ₱ 3.3 billion, should be converted to equity. These obligations were accrued as the Government made debt service payments to foreign lenders that NEA could not otherwise have met during the past few years.

(b) The Government should assume the impact of foreign exchange losses, aggregating about ₱ 1.9 billion, on NEA's existing foreign loan obligations.

(c) Construction loans receivable due NEA from about 25 remote and/or self-generating RECs, amounting to about ₱ 1.1 billion, should be written off; a corresponding amount of Government loans to NEA should be converted to equity.

(d) NEA should divest itself of all assets and liabilities associated with dendro thermal and mini-hydro generation. This includes divestiture of substantial uninstalled inventory and removal of about ₱ 791 million of dendro thermal loans and ₱ 1.8 billion of mini-hydro loans from NEA's books.

(e) NEA should divest itself of assets and liabilities associated with all social programs and other activities unrelated to electricity distribution (value to be determined).

(f) NEA should reschedule all delinquent REC debts (principal and interest aggregating ₱ 1 billion), based on feasible repayment terms. NEA should arrange a major loan monitoring and collection effort.

(g) ₱ 150 million in deferred development costs, Government project costs and salaries and allowances of NEA staff posted to manage RECs should be expensed against current operations and the accounts used for their deferral should be closed.

(h) NEA should turn its non-performing assets over to the Asset Privatization Trust, which should try to return to the Government whatever value can be realized from those assets.

NEA's stronger balance sheet as a result of the proposed restructuring would enable it to be a magnet for increased official financial assistance; without restructuring, official sources of funds could only be attracted by the social appeal of rural electrification. Because many the loans from which NEA would be relieved under this restructuring program were raised in support of either (i) Government promoted system extensions into uneconomic areas, or (ii) Government sponsored social programs that were only marginally related to rural electrification, they should rightly be transferred to the Government for disposition.

45. This restructuring program involves a substantial outlay of public funds; in order that this be a one-time event that succeeds in revitalizing the sector, the Government needs assurances that the RECs will

discontinue the practices that gave rise to their serious financial problems. The effectiveness of the recommended measures presumes that the RECs will (i) curb their technical losses; (ii) take actions to identify and punish pilferers, and thereby reduce non-technical losses; (iii) improve their collection efficiency; (iv) revise their prices to cover the full cost of providing service; and (v) pay on time for their power purchases and debt service.

46. The primary beneficiaries of the program will be the 25 poorly performing RECs with inherently poor financial prospects, which will benefit greatly by having past construction loans cancelled. The other major beneficiaries will be the 46 poorly performing RECs whose current distress results largely from mismanagement. Most of these latter RECs are clustered in central and southern Luzon, and have franchise areas that provide favorable financial and economic prospects. To enable these prospects to be realized in the future, many of their delinquent loans will need to be rescheduled. All the poorly performing RECs should be required to earn their relief by formulating and agreeing to implement operational and financial improvement programs. Their progress in realizing agreed performance targets should be monitored closely, and these RECs' eligibility for future loans from NEA should depend on their showing clear evidence of sustainable improvements in performance.

Financing Strategy

47. The proposed restructuring is essentially a one-time measure with an immediate impact. To prevent a recurrence of its past problems, NEA will need to develop a financing strategy that, at once (i) provides finance on appropriate terms for economically justifiable projects, (ii) penalizes RECs that make insufficient effort to improve performance, and (iii) considers the special needs of RECs with structural constraints that limit their prospects for financial viability.

48. To keep its lending activities manageable, NEA should simplify its categories for lending and standardize its lending terms. In the future, it should limit its lending to support rehabilitation of rural networks, add-on connections, economically justified system extensions, and working capital. While the bulk of its loans should be for the cash value of materials and equipment it provides to the RECs, it might consider lending cash under special circumstances.

49. NEA should develop a basic interest rate pegged to its average cost of money plus a sufficient premium to cover its normal operations and the foreign exchange risk it expects to bear on future loans. A premium of about 2-3% should cover NEA's normal operations, while a premium of about 6-7% should cover the expected foreign exchange risk. The basic rate would guide NEA's pricing of all its loans. Also, the provisioning against the anticipated foreign exchange losses should be based on all NEA loans made under this financing strategy, not simply those with related foreign exposure, at least until an ample fund has been accumulated. Recently, in connection with a rural electrification project that it is financing, the United States Agency for International Development asked NEA to onlend at

12%. In the current environment, that rate satisfies the criteria for the basic interest rate while being positive with respect to inflation and consistent with the opportunity cost of capital in the Philippines; therefore, it could serve as NEA's initial basic rate. The basic rate should be reviewed annually, and the new rate fixed for all loans generated after completion of the review.

50. NEA can provide incentives to the RECs through variations in the maturity and grace periods applied to individual loans. NEA's standard loans should carry grace periods of two years and maturities of ten years (these terms correspond to the construction period and depreciable lives of most distribution investments). However, maturities of more than ten years (perhaps as much as 20-25 years) could be applied to loans that support, directly or otherwise, (i) investments with higher than normal rates of return, (ii) agreed institutional improvement programs adopted by poor performers, or (iii) the sustained good performance by the better RECs.

51. To accommodate the justifiable investment requirements of RECs without reasonable prospects for financial viability due to geographic constraints, the Government should create a pool of grant funds that can be on-lent for 25-30 years at no interest but with a service charge of 1-2% (to cover NEA's costs). NEA could provide interest rate relief by blending loan and grant financings. Funding from this facility should be treated similarly to NEA's other loans. To qualify for financing from this pool, an REC would have to undertake a program to improve its operational and financial performance. To receive funds from this facility, the REC would need to agree to conditionality to (i) implement the performance enhancement program, and (ii) realize agreed periodic performance targets.

52. NEA should use its leverage as a lender to discourage chronic unsatisfactory performance in certain RECs. Performance targets could be included in loan conditionality. In the extreme, NEA could decide not to finance a particular poor performer, regardless of the priority of that REC's investment program.

53. Based on this financing strategy and financial projections developed for NEA based on the alternative investment scenarios, NEA will need to finance some ₱ 3.8 billion of investments between 1989-93. Of that amount, about ₱ 1.6 billion will come from official financing that is either committed or at advanced stages of negotiations. Another ₱ 1.7 billion is expected to be provided through as yet unidentified official finance. In addition, about ₱ 0.5 billion will need to be provided by the Government as equity. This corresponds to the amount expected to be required for (i) justifiable investments by RECs with limited prospects for commercial viability, and (ii) repair of networks damaged by typhoons.

Organizational Improvements

54. Some of NEA's spotty performance can be attributed to organizational weaknesses, including: (i) a lack of central coordination; (ii) inadequate managerial compensation, making the retention of well-qualified managers very difficult; and (iii) a propensity to become involved in the day-to-day management of the RECs, thereby spreading thin its managerial and technical cadre. NEA should make three major organizational changes:

(a) To coordinate the activities of its disparate units more effectively, it should establish a multi-disciplinary unit reporting directly to the Administrator that would be charged with applying sound banking principles in the formulation and implementation of a consistent medium-term lending program. While NEA has staff with some of the skills required by this unit, it lacks the requisite banking expertise; therefore, NEA will need to obtain this loan programming function on a consulting basis from a large bank or major financial institution.

(b) Since NEA's pay scales follow directly from its classification as an infrastructure agency by the Department of Budget and Management, NEA should establish and fulfill the requirements for reclassification as a Government Financial Institution, a category with higher pay scales.

(c) NEA should seek to minimize the time during which it must second its own staff to manage RECs by starting immediately after a takeover the process of identifying and transferring control of a REC to the group with the best long term plan for operating it viably.

1. RURAL ELECTRIFICATION SECTOR OVERVIEW

A. Introduction

1.1 In early 1988, the Bank undertook a study of the Philippine energy sector; that study (Report No. 7269-PH; September 15, 1988) recommended a broad strategy for resource allocation and utilization. Since then, the Government has indicated concern that some of the important benefits of that strategy might not be realized because of inefficiencies in the electricity distribution system, through which about 15% of total domestic available energy is consumed. The Government was particularly concerned about the impact of rapidly increasing distribution losses, which reached 25% by the end of 1987, on the US$7 billion investment program that was then being launched in electricity generation and transmission for 1989-96. The Bank has responded to the Government's concern by making a loan to finance a project to improve power distribution in and around Metro Manila (Loan 3084-PH, 1989). It also studied the condition of the rural electrification sector in February 1989. This report details the findings of that study.

1.2 In brief, the study confirmed that the rural electrification sector has major problems, including (i) poor operational performance, (ii) physical deterioration of core systems, and (iii) acute financial distress among all the sector's institutions. The problems are so pervasive that they cannot be addressed by simple solutions. Rather, the Government will need to implement an integrated program to revitalize the sector, with the aim of (i) restructuring of the sector's core institution, the National Electrification Administration (NEA); (ii) considerably reorienting the organization, operations, and financial structure of the 117 Rural Electric Cooperatives (REC) that are responsible for distributing electricity to smaller urban centers, towns, villages and rural areas nationwide; and (iv) thoroughly refocussing the sector institutions' operational practices, investment priorities and pricing policy.

1.3 The recommended program for strengthening the rural electrification sector would provide an important stimulus for the continued economic revitalization of the Philippines economy, which has undergone a dramatic turnaround since the mid-1980s. Following an economic decline during the early years of this decade, the reorientation since 1986 has stressed the primacy of efficiency, prudent macroeconomic management, a transition to market mechanisms, a reform of public enterprises, and a streamlining of public sector investment. While much already has been done to move forward in these areas, a large part of the reform agenda remains to be addressed. The next steps in the transition to efficiency-oriented management will include (i) improving the level and composition of the public sector investment program, focusing on appropriate priorities to sustain economic growth; (ii) upgrading the implementation capacity of public sector agencies; (iii) accelerating investment in rural development to encourage income growth outside of urban areas; and (iv) removing infrastructure bot-

tlenecks to encourage productive investment and improve the delivery of services such as power supply. Such a reorientation is critically needed in the rural electrification sector, where strengthening the sector's weak institutions will enable issues of investment efficiency, rural development, and infrastructure improvement to be addressed vigorously.

B. Energy Sector Institutions

1.4 Before the change in Government in 1986, the Ministry of Energy coordinated all policies, plans and programs for the energy sector. The ministry served as the parent organization for two of the largest Government owned corporations: (i) the National Power Corporation (NPC), which had responsibility for power generation and transmission; and (ii) the Philippine National Oil Company (PNOC), which was responsible for assuring the adequacy of oil supplies and for development of indigenous energy resources. The National Electrification Administration (NEA), the organization responsible for formulating and implementing the Government's rural electrification policies, was under the control of the Ministry of Human Settlements, and not under the Ministry of Energy.

1.5 Following the change in Government in 1986, both the Ministry of Energy and the Ministry of Human Settlements were dissolved; all energy agencies as well as NEA were brought temporarily under the Office of the President. In mid-1987, the Office of Energy Affairs (OEA), which was given responsibility for planning and coordinating policies and programs for the energy sector, was formally placed under the Office of the President. At the same time, NPC and PNOC were brought under the formal control of the Office of the President while NEA was placed under the jurisdiction of the Department of Environment and Natural Resources (DENR). Recently, to develop formal linkages between the energy sector participants, the Government formed an Energy Coordinating Council (ECC) that would (i) be chaired by the Executive Secretary; (ii) have as members NPC, PNOC, and NEA; and (iii) have OEA acting as its Secretariat.

1.6 In its early stages, NPC was responsible only for hydropower development. The Manila Electric Company (MERALCO) generated most of the power for the Manila metropolitan area; power was supplied to provincial towns and rural areas by other privately-owned power companies and small municipal utilities. In 1971, NPC was given total responsibility for all power generation facilities nationwide as well as for the establishment of island power grids. This restructuring led to NPC's acquisition in 1979 of most of MERALCO's generating facilities. Electricity distribution in rural areas is handled by Rural Electric Cooperatives (REC).

1.7 Currently, NPC is responsible for all but very modest generation facilities and most transmission systems nationwide. MERALCO is responsible for distribution in Metro Manila and surrounding suburbs and rural areas. Six privately-owned power companies provide distribution to the larger urban centers outside Manila. Distribution for the smaller urban centers and the rural areas is provided by 117 RECs. NEA is responsible for coordinating the activities of the RECs.

C. The Rural Electrification Program

The Program's Origins

1.8 In June 1960, the Electrification Administration was created (Republic Act [RA] 2717) to carry out the Government's policy of providing cheap and dependable electric power for the country's agro-industrial development. Rural electrification of previously unenergized areas proceeded at a slow pace for the next seven years. In February 1967, using funds provided by the United States Agency for International Development (USAID) feasibility studies were conducted for two pilot rural electrification programs: (i) to electrify eight towns in Misamis Oriental, and (ii) to electrify three towns in Negros Occidental. In June 1969 total electrification of the countryside on an area coverage basis was declared a national policy (RA 6038). At that time, only about 18% of the country's population was enjoying electric service. This Act also provided for the organization of Rural Electric Cooperatives to implement the electrification targets and operate the resultant networks, and converted the Electrification Administration into the National Electrification Administration.

1.9 NEA's charter gives it the twofold responsibilities of (i) coordinating implementation of the Government's total electrification policy, and (ii) supporting the RECs' efforts to achieve that total electrification objective. NEA is supposed to fulfill this latter responsibility by (i) providing technical support to the RECs; and (ii) financing their expansion programs with grants and long term loans. Later Presidential Directives gave NEA the additional responsibilities of (i) supervising the RECs' technical and managerial activities; (ii) regulating their electricity rates; and (iii) promoting implementation by the RECs of mini-hydro and dendrothermal generating schemes. The Government also created within NEA various Special Project Offices that are responsible for integrated rural development programs unrelated to rural electrification. These programs included housing, water supply and livelihood projects.

1.10 In September 1971, the first REC, Misamis Oriental Electric Cooperative, Inc. (MORESCO) was energized. In August 1973, NEA became a corporation (Presidential Directive [PD] 269) and was provided initial capital stock of ₱ 1 billion. Subsequent capital increases in 1978 (PD 1370) and 1979 (PD 1645) raised the authorized equity capital to ₱ 5 billion. NEA orchestrated the growth of the system by functioning as a financial intermediary channeling the Government contributions or funds provided by donors to the RECs. Almost all the loans provided by NEA to any particular REC were for the peso value of materials procured by NEA on behalf of that REC. As such, the REC received goods and was credited with a loan liability; cash seldom flowed from NEA to an REC. Few, if any, sources of private sector finance were willing to lend to the RECs; as a result, they were required to self generate the working capital needed for operations. As donor and Government funding for rural electrification appeared to be plentiful, the cooperative system expanded rapidly both through the construction of new distribution networks and the assumption of responsibility for

existing facilities. The RECs acquired these existing core systems (mostly small, aging networks with 2400 volt primary distribution lines) from locally-based, investor-owned power companies.

1.11 The cooperative system was closely modeled on the U.S. experience. NEA itself was modeled, both in form and operation, on the Rural Electrification Administration. The RECs were organized and were supposed to be administered in much the same fashion as those in the United States. Also consistent with the U.S. model, the Philippine RECs established (in July 1979) the Federation of Electric Cooperatives of the Philippines (FECOPHIL) to serve as the umbrella organization representing their interests. FECOPHIL's charter was closely based on that of the National Rural Electric Cooperative Association (NRECA), which had functioned as the lead consultant providing technical assistance under USAID financed projects.

1.12 The movement to use cooperatives to supply electricity to small urban centers and rural communities developed momentum in the early 1970s. During this early period, the RECs' service areas were defined to afford reasonable chances for technical and financial viability, and the decision to form an REC was generally preceded by a thorough feasibility study. However, as the pace of expansion accelerated, the feasibility studies became more superficial. NEA did not focus significant attention on the day-to-day concerns of managing a rapidly expanding commercial organization; and, because of the long grace periods included in the terms of most NEA loans to the RECs, the financial implications of what was too ambitious an expansion program and the poor financial performance of the RECs were masked until the early 1980s. Annex 1.01 shows the number of consumers served by the RECs each year since 1974, and Annex 1.02 shows the year-by year formation of RECs.

Current State of the Sector

1.13 Currently, 117 RECs are providing electricity throughout the entire country, except for franchise areas served by the investor-owned companies. About 22 of these RECs are considered to be well managed as well as financially viable; for another 24, financial viability is considered within reach if they make some operational and commercial adjustments. The remaining 71 either have a pronounced need for substantial remedial action, or are considered beyond rescue.

1.14 The RECs' problems are both operational and financial. Chronic operational problems include excessive distribution losses, theft of electricity, and inadequate maintenance. The RECs' poor standards of maintenance have led to a widespread physical deterioration of their networks; as a result, with technical losses averaging 17%, most REC distribution systems are operated at well below their design standards. The Government's past emphasis on growth of coverage without sufficient regard for cost, combined with its use of the RECs to implement costly and economically unjustifiable alternative generation and rural development programs, has saddled most of the RECs with debts they cannot pay, despite the heavy concessional element built into the instruments that were used to finance the sector's expansion. Generally, the RECs lack the skilled staff and equip-

ment needed to improve their operational performance, and the burdens of past mistakes have weakened their prospects for improving their financial health. In many instances, the RECs' financial problems are directly related to managerial weaknesses that have resulted from the interference in their internal affairs by highly politicized Boards of Directors. Even if the RECs as a group would be provided with financial relief, some 25-30 among them face limited future prospects owing to franchise areas that are inherently too costly to serve.

1.15 NEA has performed poorly as both a lender and a provider of technical support to the RECs. Although it has documented the RECs' operational weaknesses, NEA has been unable to implement programs for improving their performance, partly because its already scanty technical staff has been spread too thin to perform its functions well.

1.16 The RECs are rural institutions that reflect the economic condition and financial health of their members; the economic constraints experienced during last several years by the rural population has had an adverse impact on them. Given that its primary business is to act as financier for the sector, NEA's financial condition must necessarily reflect the state of the RECs. The recession of 1983-86 weakened the RECs financially; in turn, that weakness resulted in NEA's realizing a collection efficiency of only 36% in both 1987 and 1988. In many instances, NEA promoted the measures that led to the RECs' uneconomic growth; therefore, not surprisingly, when the RECs are unable to meet their obligations on loans from NEA, NEA cannot meet its related obligations on the originating loans. In all, NEA has questionable prospects for meeting some ₱ 7 billion of loans raised from foreign lenders and from the Government. Too often, NEA has lacked clear direction regarding the nature of its business. While its revenues accrue entirely from its lending operations, it has viewed itself primarily as an electrification company. It has fulfilled a wide variety of roles, but it has not developed the primary functions of a financial intermediary, namely loan programming and credit evaluation. The organization's lack of a clear focus has inhibited it from acting as an effective core agency for the sector.

1.17 Perhaps the sector's biggest problem is the participating institutions' chronic lack of functional accountability. In the past, NEA has neither had (i) a mechanism to coordinate its activities with the rest of the energy sector, even though the RECs taken together form a substantial block of energy consumers, nor (ii) the outlook and accountability of a financial institution, even though lending and credit are essential elements of its own financial health. Instead, NEA has either been accountable to political agencies, such as it was during 1979-86 to the former Ministry of Human Settlements, or to rural development agencies, such as it is currently to DENR. In that context, its staff has dispensed substantial capital without regard for the technical or financial requirements for cost recovery. The politicization of NEA created an environment that enabled the RECs to become politicized. Although NEA has sound rules governing the conduct and remuneration of REC Boards and individual directors, those rules are flaunted with equanimity. Available data suggest a high correlation between interference by Board members in the day-to-day activities of the RECs and poor management of those institutions. While the RECs are

in principle accountable to their consumer members, most RECs whose weak performance may be attributed to poor management show (i) little effort to develop member involvement and (ii) weak consumer relations. In effect, those Boards (and in turn their RECs) are accountable primarily to the political interests that sponsored their elections.

D. Issues Facing the Sector

1.18 To resolve the sector's problems, the issues enumerated in the following paragraphs must be addressed. The issues have been grouped according to whether their primary impact is on (i) sector operations, (ii) the RECs as institutions, or (iii) NEA's capacity to fulfill its responsibilities as the sector's core agency.

Operations, Investment and Pricing

1.19 Poor Operational Performance. As a result of the low priority accorded to operational matters, most RECs provide inefficient and unreliable service; furthermore, they frequently provide electricity to rural consumers at excessive cost. Even the financially viable RECs have high rates of forced outages; however, operational problems are much more acute in the poorly performing RECs, where constrained cash flow for the proper maintenance of physical and human resources has resulted in the severe physical deterioration of their networks.

1.20 Of the poorly performing RECs, some 25-30 have only marginal chances of ever attaining the financial viability needed to ensure implementation of proper operational practices. Most of these RECs serve small remote islands in the Visayas; the remainder serve rugged mountainous areas with insurgency problems in Luzon, Mindanao, or Samar. Their inimical geography and population sparsity, combined with their high cost of supply, limits their prospects. Another 41-46 RECs could become viable by taking substantial remedial action. Most of them are located in central and southern Luzon, and are characterized by (i) franchise areas with potentially favorable financial prospects, (ii) rapidly deteriorating core systems, and (iii) politicized Boards and managements.

1.21 System Losses. With system losses averaging 25% nationwide, substantial amounts of expensive electricity are being wasted. System losses represent the second greatest "use" of available energy. Specific Regions show different patterns of efficient operations and loss control. For example, the twelve RECs in Region 3 (Central Luzon) have system losses that averaged about 36% in 1987, making losses the predominant "use" of available electricity in those service areas.

1.22 Area Coverage Targets. The objective of the rural electrification program was to achieve total area coverage as rapidly as possible. Often, the RECs expanded their systems at the expense of major maintenance or the renewal of obsolescent core networks. Currently, the RECs serve somewhat more than 2.8 million consumers. Although the number of consumer

connections grew by more than 30% per year until 1980, this was not enough to meet the Government's original target of 90% area coverage by 1987. With the growth rate dropping since 1981, the target for achieving 90% electrification has had to be extended on several occasions. Currently, the Government's policy is to electrify 90% of rural areas by 1995.

1.23 This emphasis on area coverage has led NEA to support substantial investments in system expansion that were not economically justifiable. The RECs met the cost of these investments either with cross-subsidies from productive loads in the same franchise areas, or by ignoring their related debt service payments to NEA. Despite the wide spread evidence of uneconomic investment and the resulting sector wide financial constraints, NEA has still not developed appropriate criteria for investment decision-making.

1.24 Prioritization of Investments. NEA does not have a systematic strategy for programming investments by the RECs. Although a determined effort was made in 1988 to identify and prepare high-priority investments, this exercise was conducted in response to a perceived need to formulate a short-term investment strategy quickly. NEA still lacks a consistent strategy and a sound methodology to establish national investment priorities.

1.25 Alternative Generation Programs. One striking example of the impact of inadequate investment screening is the substantial losses being incurred on account of uneconomic investments in alternative generation facilities. In October 1979, PD 1645 authorized NEA to develop indigenous and renewable energy sources, including specifically (i) mini-hydro generating facilities of under 5 MW, and (ii) dendro thermal generation plants. Overall, 19 mini-hydro sites and 9 dendro thermal plants were either completed or are still under construction. None of the completed dendro thermal plants are in operation today[1/]. Moreover, a large number of mini-hydro units, with an aggregate value of almost ₱ 1 billion, and nine dendro thermal units have not been installed and are in storage. Although, in 1988, NPC assumed responsibility for these facilities, the RECs are still obligated for the loans that financed these investments. At present, they are virtually in complete default to NEA in regard to these loan. In turn, NEA has been unable to service its debt related to these programs (para. 6.13). Annex 1.03 provides a brief summary of the operational aspects of the mini-hydro and dendro thermal programs.

1/ The mini-hydro program's major problems included (i) inadequate technical planning, (ii) insufficient site investigation and (iii) unsatisfactory hydrology. In addition, many of the sites chosen were aimed at serving areas already receiving electricity from the NPC grid. The dendro-thermal program envisaged growing trees on 1,000 acre sites over a five-year cycle. The mature trees, when felled, were to be crushed into wood chips for burning in the boiler of a nearby power plant. The planting program did not produce the expected number and quality of trees; the poor results were due to inadequate site preparation, lack of fertilizer, and generally careless farming. In addition, the wood processing equipment was poorly operated and maintained, and the boilers were unable to burn the resultant output of chips.

1.26 Pricing of Electricity. Rural electric tariffs neither reflect the cost of supply nor influence consumers to optimize their utilization of electricity. NEA has developed and distributed a rate setting guideline that is based upon a simple average costing methodology. The resultant retail rates do not provide the RECs with sufficient cash for even routine maintenance and equipment overhauls, much less for the self financing of even minor amounts of system expansion.

1.27 Subsidies for Financially Weak RECs. RECs in remote areas, that must rely for their supplies on expensive self-generation, charge high rates (often in excess of ₱ 4.00/kWh) that exceed the threshold of consumer affordability. Recently, the Government has decided to limit retail electric tariffs to a maximum of ₱ 2.50/kWh. To implement this policy, NPC is taking control of all generating facilities and lines energized at 69 kV and above, and will sell electricity to those RECs at a subsidized rate of ₱ 1.30/kWh. In addition, a number of RECs will require direct subsidies to maintain their operations. NEA has computed the cost of this direct subsidy, which will be shared by NPC and NEA, at about ₱ 50 million over the next five years. Fourteen self generating RECs are the beneficiaries of the direct subsidy program.

The Rural Electric Cooperatives

1.28 Appropriateness of the Cooperative System. In 1988, as the outgrowth of a program to restructure NPC, NEA took control of the management of eleven RECs whose arrearages to NPC had reached intolerable levels so that the cutoff of electric service was imminent. In connection with the takeovers, the RECs' Boards of Directors were disembodied and the General Managers were replaced. The failure of these cooperatives, the majority of which are located in some of the most prosperous rural areas of Central Luzon, raises questions about whether using cooperatives for providing electricity to rural areas of the Philippines is appropriate. If so, a major reorientation of the RECs appears urgently needed.

1.29 The RECs' Weak Financial Prospects. The RECs typically serve residential and small commercial consumers, most of whom take small amounts of electricity (often less than the amount covered by the minimum monthly charge) at low voltage. These consumers are expensive to serve and account for low revenues. Yet, even this modest revenue base has proven difficult to collect. At the same time, the RECs taken together account only for about 15% of NPC's sales. Thus, whether jointly or severally, the RECs have only limited leverage in their dealings with NPC, their principal supplier. In effect, the RECs are inherently weak institutions engaged in a business with weak financial prospects; and realizing even those weak prospects depends on the RECs (i) managing their operational, commercial, and financial affairs efficiently, and (ii) avoiding costly or non-optimal investments that have only limited potential for acceptable economic returns.

1.30 The RECs Poor Financial Performance. The RECs financial performance has been extremely poor. In 1987, the cooperative system as a whole recorded a negative net margin of ₱ 22 million. Certain REC accounting policies are not consistent with generally accepted commercial prac-

tices; therefore, this figure most likely understates the RECs' financial losses. This poor performance has been recorded even though the RECs as a group are realizing very high mark-ups. In 1987, the average revenue for all the RECs was ₱ 1.66/kWh, compared with an average cost of ₱ 0.87/kWh for power purchases from NPC.

1.31 Proliferation and Politicization of the RECs. Following the first oil price shock in 1973, a spate of new RECs were formed to replace small private companies that had become non-viable because of their inability to recover the burgeoning cost of fuel. By 1976, the RECs became viewed as organizations that provided political outreach to their leaders; and, the regime used REC directorships and management positions as patronage for political support. Until recently, RECs were repeatedly subdivided, thereby ballooning the number of these patronage opportunities. As the RECs became more politicized, financial viability and quality of service became less important.

The National Electrification Administration

1.32 NEA's Role. NEA has a spotty record as the sector's core agency. Since its inception, NEA has lacked clear direction regarding its role. The relevant statutes cast NEA in the diverse and occasionally mutually exclusive roles of (i) policy maker, (ii) borrower of hard loans, (iii) lender to a marginal clientele, (iv) implementor of network expansion programs, (v) executor of alternative generation programs, (vi) promoter of rural development social programs, (vii) investment planner, (viii) procurement agency, (ix) electrification consultant, capable of providing expertise regarding investment, construction, operations, maintenance, pricing, and finance, (x) regulator of a fragmented industry, and (xi) utility manager. Moreover, while NEA has always been accountable to political agencies, it has never been functionally accountable.

1.33 NEA's Financial Weakness. Although NEA is charged with earning a profit, the organization currently has an cumulative deficit and is projecting to continue operating at a loss or at break even through 1991. NEA has experienced or is forecasting that its loan collection efficiency of only 36% for 1987 and 1988 will improve only to 52% in 1989. As a result, NEA's cash flow is not adequate to meet its operating requirements; unless NEA is restructured, it will need continuing Government financial commitments to enable repayment of outstanding foreign loans.

1.34 Financing Strategy for the Sector. During the period 1989-92, NEA plans to channel up to about US$200 million to the RECs for investment. Currently, the Government and NEA lack a clear financing strategy for the sector. That strategy needs to resolve the following existing gaps: (i) measures for restructuring the sector's institutions; (ii) criteria and instruments for lending; (iii) lending terms; (iv) use of conditionality; (v) measures for addressing foreign exchange risk; and (vi) special policies to accommodate the investment needs of inherently weak RECs.

1.35 Loan Programming. NEA currently lacks an effective loan programming function; and, as a result, its management lacks the tools for

coordinating NEA's diverse activities. NEA's approach to loan programming has involved (i) using money that could be obtained from the Government to make sizeable purchases of materials and equipment, and then (ii) apportioning those purchases to the RECs, either to meet an agreed new connection target or to reward Boards and managers for political support. Only rudimentary credit analyses were performed. NEA has neither placed emphasis on developing and implementing a medium-term lending program, nor on applying sound banking principles in formulating loans. Even if NEA would wish to upgrade its loan programming activity, its staff lacks the needed banking and credit expertise; and it cannot attract the requisite number of suitably qualified people given its current pay scales.

E. A Revitalization Program

1.36 Major reforms in the sector are urgently needed. Addressing problems that are so pervasive requires an integrated program that will at once (i) introduce proper operational practices and appropriate investment strategies, and (ii) develop strong sector institutions. The development of such a program is the focus of the remainder of this report.

1.37 The first focus of the program must be on operations and investment, so as to determine (i) the requirements for restoring the networks to their original design standards and (ii) the parameters of an affordable investment program. These parts of the program must be complemented by the development and adoption of sound pricing principles, so that the RECs may optimize recovery of their costs from revenues. Programs to restructure and strengthen the RECs and NEA must necessarily follow after the requirements of operational and investment reform have been established. Because neither the RECs nor NEA can concentrate effectively on their future responsibilities as long as they are burdened with unmeetable obligations accruing from past uneconomic policies, the institutional strengthening components of the program must necessarily include measures for the financial restructuring of these organizations. To ensure that the benefits of restructuring remain effective in the long term, NEA will need to develop and implement a financing strategy that (i) encourages the RECs to invest in high-return projects and adopt proper operational practices and pricing principles, and (ii) discourages them from failing to meet obligations to their creditors and their consumers. Finally, any reform of the RECs and NEA must necessarily include provisions for developing functional accountability within each of the organizations while also taking account of the realistic constraints they face.

1.38 The ensuing chapters of this report follow this sequence in developing the logical underpinnings for recommendations that, when taken together, provide the needed integrated program. The program is necessarily comprehensive, and the Government may have difficulties implementing its features simultaneously. For that reason, allowance was made in developing the recommendations for their gradual implementation. Even if implemented gradually, this program should provide substantial economic benefits and financial savings in the process of revitalizing a highly troubled sector.

2. OPERATIONAL EFFICIENCY

A. Introduction

2.1 Originally, the Government intended that RECs would be formed to provide service in previously non-electrified areas; in those cases, which were mostly in the Visayas and Mindanao, core supply networks were usually technically sound and the operating systems were usually well designed and implemented. After the first oil price shock in the mid-1970s, however, a number of RECs were created to take over the franchises of numerous operators (mostly serving small urban centers in central and southern Luzon) that had failed, and extend their service to outlying areas. These inherited networks were often old, with substandard core systems. NEA was responsible for financing the return of those core systems to design standards and ensuring that these RECs had adequate qualified staff to operate and maintain properly the assets being absorbed. This mandate to rehabilitate decaying core systems was inconsistent with NEA's primary objective of mobilizing all available resources to extend area coverage, and thus was largely ignored. As a result, many core systems, especially older ones that had belonged to failed franchisees, fell deeper into disrepair.

2.2 Beginning in the early 1980s and becoming more pronounced after 1983, as funds for expansion became more scarce and the political pressure to add new connections remained strong, the technical standards were increasingly compromised in the construction of additions to networks. Contemporaneously, as political pressure mounted to hold down tariffs in the face of mounting constituent costs for electricity, maintenance standards were also increasingly compromised. Major repairs, such as are often needed following typhoons, were usually flimsy patchworks that made best use of available materials and equipment; as newly received materials had to be channeled to expansion projects, the patchworks were seldom replaced by permanent installations.

2.3 Since 1983, the quality of rural electric service has declined sharply. Technical losses have increased, as have instances of downed or obstructed lines and outages related to overloading of substations. With a few notable exceptions, the performance of the individual RECs has also declined sharply. This decline has affected all aspects of their operations, including, inter alia, construction standards, supply continuity, network maintenance, control of operating costs, revenue collection, technical losses, and pilferage of electricity. However, because the basic systems and the extensions that were built in the 1970s were well designed and structurally sound, NEA and the RECs can still arrest this decline if assistance is made available and the problem is addressed urgently.

2.4 This report makes many recommendations. This chapter develops recommendations aimed at improving operational performance[1/]; the next two chapters focus on resolving issues concerned with investment planning and pricing. Taken together, these recommendations provide the operational component of a revitalization program for the sector. While this study addresses these issues in the aggregate, to ensure that these diverse activities are properly coordinated and to translate this extensive program into a management plan for each REC, a comprehensive Rural Electrification Master Plan (REMP) is needed to provide a detailed framework within which (i) specific improvement measures can be formulated, taking into account realistic constraints on available financing, and (ii) operational performance can be measured against realistic technical and financial targets.

B. The Rural Electric System

Technical Characteristics of the System

2.5 The rural distribution network follows a 60 cycle, 4-wire, multi-grounded WYE design that is almost identical to the standard developed for the rural electrification system in the United States by the Rural Electrification Administration (REA); the major differences are that the Philippines uses 7,620/13,200-volt primary voltage levels (compared to 7,200/12,470 volts in the U.S.) and 240 volt/2-wire secondary systems (compared to the 120-240 volt/3-wire system in the U.S.). The basic design of the networks is sound and appropriate, with the major systemic flaw being an underestimation of the need for lightning arresters and voltage regulators. U.S. consultants provided good construction and operations manuals and supervised the correct implementation of the recommended techniques in the early years. Until the early 1980s, electricity service and supply continuity standards were generally good, and continue to be satisfactory in a majority of RECs.

2.6 Except for RECs in remote locations, the rural network is supplied by NPC at about 250 69-kV grid substations. NPC constructed the substations, which are owned and operated by the RECs. Meters at the substations are placed on the primary side of the transformers. The distribution

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1/ The measures being recommended fall into categories identified as (i) major maintenance, (ii) system improvement, and (iii) rehabilitation. Major maintenance involves activities to keep systems that are operating at design standard in good repair. Expenditures for major maintenance should be budgeted and financed from on-going revenues. System improvement is performed on systems currently operating at or near design standard, to enable them to meet expected increases in demand from existing consumers, or growth in the number of connections. Expenditures for system improvement require capital allocations, but the cost should be quickly recoverable from the resultant incremental revenues. Rehabilitation is needed to restore a system to design standard. Those expenditures will need capital allocations and external financing, and the costs can only be recovered from the total consumer base over five to ten years.

networks consist of about 65,000 km of lines, including about 46,000 km of primary lines and about 19,000 km of secondary lines. The RECs also own and operate about 900 km of 69-kV lines (the standard NPC subtransmission voltage). A summary of line lengths is given in Table 2.1 and an analysis of line lengths by Region is provided in Annex 2.01. The RECs in central and southern Luzon that assumed control over the operations of failed predecessors acquired extensive non-standard networks. While some rewiring has taken place, the system still includes some 1,900 km of non-standard line. This remnant can and should be replaced.

Table 2.1: LENGTH OF LINE BY DESIGN PARAMETER
(000 km)

	3 Phase 4-Wire	3 Phase 3-Wire	1 Phase 2-Wire	Secondary	Total
Standard RE lines	19.1	5.9	19.8	18.4	63.2
Non-standard RE lines (2.4, 4.16 and 4.8 kV)	.6	.2	.4	.6	1.8
TOTAL	19.7	6.1	20.2	19.0	65.0

2.7 Each of the RECs supplies an average of 24,000 consumer members, with an average of 40 consumers for each distribution transformer. Annex 2.02 summarizes Regional differences in consumer density. Each substation serves an average of two to three feeder lines. The design parameters for system protection are basic and inexpensive, and consist of reclosers on feeders and fuses on all branches. This low cost approach results in some problems of coordination of rural network protection with protection measures used in the NPC transmission system. The design standard provides for the use of self-protected, single-phase distribution transformers that range in size from 5 to 100 kVa. Wooden poles are used throughout the system and the standard for conductor is steel-reinforced aluminum. As the Philippines does not have any indigenous manufacturing or repair capacity, virtually all this material is imported.

Technical Losses

2.8 The original rural electrification system in the Philippines was designed for a 12-13% range of technical losses based on a 5-year load forecast (Annex 2.03); this closely followed the REA design. The level of technical losses should decrease as the load increases, assuming implementation of effective maintenance and planned system improvements. In the U.S., where the system is generally operated and maintained as designed, technical losses declined from 12% to 8%; however, in the Philippines they increased to an average of 17% - and, in some RECs, technical losses exceed 20%. These high technical losses result from overloaded lines and transformers, poor line connections, cracked insulators, poorly maintained elec-

trical and mechanical equipment and poor service connections. In addition, because necessary rights-of-way were not obtained during construction of lines, the RECs cannot cut and prune trees to the degree required; as a result, inadequate clearance of trees is a major cause of technical losses.

Recommendation

2.9 Considerable gains can be realized from a program to reduce technical losses, principally because much of the system was well conceived, designed, and constructed; years of neglect can therefore still be reversed. Reduction of technical losses will require a combination of measures including, among other things, (i) system improvements, including upgrading power supply or increasing the capacity of line transformers where technical losses are high due to overloaded networks; (ii) improved maintenance that focusses on clearing trees (para. 2.16) from lines (alternatively, poles might be reconfigured where existing rights of way do not permit adequate clearance of trees)[2/]; and (iii) rehabilitation of non-standard core systems or poorly maintained networks (paras. 2.33-2.35). Technical losses due to design factors are discussed further in Annex 2.03.

2.10 With such measures, technical losses could be reduced by 4.5%. This would imply an annual cost saving of about ₱ 1.4 million per REC, or about ₱ 0.62 million per substation and feeder network. Reducing technical losses would also result in derivative benefits for the RECs, including: (i) increased local system capacity, and (ii) improved supply continuity; both of these benefits would lead to improved quality of service. The financial impact of these derivative benefits cannot be computed directly; however, if the average REC manages to sell the increments of energy that are saved, it could realize additional revenues of about ₱ 1 million per year (based on current rates), or about ₱ 0.4 million per year per substation and feeder network. Alternatively, it would save the cost of purchasing from NPC unsold amount of the energy that was saved. The cost of the system improvement measures (para. 2.9) is not likely to exceed about ₱ 3 million per substation and feeder network (in most cases, the cost would be notably less). The cost of improved maintenance measures should not be incremental, but rather should be borne through improved efficiency. Where rehabilitation is required, the cost should be related to added revenues from incremental demand, and not to savings from reduced losses. Therefore the incremental cost of reducing technical losses should be covered by savings in recurrent costs or enhanced revenues from existing demand within two years.

2/ As necessary, tree clearing programs should take account of environmental considerations.

C. Operation and Maintenance

2.11 As with construction, operation and maintenance standards for rural networks were based on REA practices, and training courses were provided during the 1970s to demonstrate correct procedures to REC staff. Over the years, these procedures gradually fell into disuse in the majority of RECs. Currently, network operation and maintenance is performed by the RECs on an ad hoc basis, with inadequately trained staff using inadequate materials, tools and transport. Less than 50% of the original staff who attended the early training courses on operation and maintenance still remain with the RECs. The original supply of operation and maintenance tools has also been depleted. Test equipment was left unrepaired, safety equipment became unworkable, and when the original vehicles finally stopped working, they were never replaced. The RECs must now rely on public transport to move crews and materials, which is expensive and inefficient.

2.12 The years of neglect and poor maintenance have left the network in poor working order. Field inspections conducted at over 50% of the RECs during a 1986-89 survey by USAID-financed consultants found that about 10% of the distribution system was well maintained, 25% was satisfactorily maintained, 35% was unsatisfactorily maintained, and the remaining 30% showed no sign of having received maintenance (Annex 2.04). The causes cited for poor maintenance included (i) lack of finance, (ii) shortages of materials, and (iii) managerial inattention to maintenance. The most common problems are rotting poles, broken crossarms, conductor sagging, bad connections, broken insulators, missing hardware, broken reclosers, fuses, lightning arresters, and other safety equipment, cut or missing ground wires, unsafe service drops, and defective meters.

2.13 In general, distribution systems require a combination of operational and planned maintenance. Operational maintenance includes such ongoing activities as semi-annual line patrols and monthly inspection of all meter installations in the course of routine meter-reading and check-reading. Planned maintenance programs are normally developed from: (i) operation and maintenance reports, (ii) guidelines for priority plant maintenance, and for equipment such as reclosers, transformers, lightning arresters, and (iii) the physical condition of the network.

2.14 Table 2.2 compares the maintenance requirements of U.S. RECs[3/], which are generally well-managed and operate systems similar to those in the Philippines, with those of their Philippine counterparts. The performance of the U.S. RECs indicates that the expected trend in well-managed distribution systems is for planned maintenance to increase gradually relative to forced maintenance and the total cost of operations per unit sold to decrease gradually. In the Philippines, the trend is in the opposite

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3/ As the U.S. RECs are generally efficient, well operated and profitable, this comparison may appear unfair to the Philippine RECs; however, since the Philippine rural electrification systems were designed according to the U.S. model, the comparison essentially relates the performance of the Philippine systems to their design standards.

direction and will continue to worsen unless improved operation and maintenance procedures are adopted.

Table 2.2: COMPARISON OF MAINTENANCE REQUIREMENTS (U.S. and Philippine RECs)

	U.S. RECs After 5 Years	U.S. RECs After 10 Years	Phil. RECs After 5 Years	Phil. RECs After 10 Years
	(Percent of Operation and Maintenance Expenses)			
Operations	70%	50%	-	30%
Planned Maintenance	20%	35%	-	20%
Forced Maintenance	10%	15%	-	50%
O&M Cost as % of Revenue	5.8%	4.4%	5.2%	6.2%

Recommendation

2.15 Three critical maintenance needs have been identified for the Philippines: (i) clearance of trees, (ii) treatment of poles, and (iii) repair of damaged equipment and tools. Remedies for these problems, which are common to many rural electrification systems, could account for about 50% to 70% of the cost of a planned maintenance program.

2.16 Tree clearing and pole treatment programs (Annex 2.05) are central to a sound annual maintenance plan. These programs are likely to cost about US$7.5 million annually for the system as a whole (although only about US$5 million are incremental costs for the RECs), and should include specific work plans and budgets for each REC. A failure to implement these programs will lead to further serious deterioration of the network and continuing unacceptably low supply continuity and service standards.

2.17 A recent survey indicates that equipment and tools with a replacement value of over US$5 million are lying idle in REC stores, and that inoperable network equipment of even greater value is awaiting repair. NEA is acutely aware of this problem and is arranging to establish seven strategically located zonal repair centers to serve the repair, major maintenance, and spare parts needs of the RECs (Annex 2.06).

2.18 As the sector's core agency, NEA urgently needs to develop and implement national policies, standards and planning systems for planned and operational maintenance. In that context, NEA will need to help the RECs prepare budgets and work programs for major maintenance. NEA would then need to ensure, possibly as a condition of lending to an REC, that it (i) has developed a sound program of major maintenance, (ii) has arranged to make available from revenues funds sufficient to implement the program (in the near term, when substantial major maintenance is needed to reverse years of neglect, NEA may wish to make some loans for this purpose to RECs

that cannot raise sufficient tariff revenues to cover these requirements), and (iii) is implementing properly and consistently the agreed major maintenance program. Programs for planned maintenance should cover only core systems that are operating at or close to design standards; otherwise, rehabilitation must be done first. Since NEA may not have sufficient numbers of qualified staff to plan and supervise the RECs' implementation of such a comprehensive maintenance program, NPC, which has a direct interest in minimizing the RECs' inefficiency, should assist NEA by seconding staff to supplement NEA's capabilities, and taking responsibility for the field monitoring of the RECs' maintenance efforts.

D. Commercial Practices

2.19 In the early 1970s, with assistance from U.S. consultants, NEA provided all RECs with operational and training manuals outlining the commercial policies, guidelines and procedures that were to be followed. Specific guidelines were provided for meter reading and billing, collection, disconnection, penalties for reconnection, membership in a REC, and rights-of-way. The policy also specified the basis for pricing. Over the years, the RECs have become slack about implementing the commercial procedures so that, currently, only about 10% of the RECs run their commercial activities effectively. The causes of this deterioration in commercial performance include: (i) weak REC management which failed to accord necessary priority to billing, collection and related activities; (ii) insufficient funds to provide and maintain the equipment needed for commercial efficiency; (iii) shortages of functioning meters, resulting in substandard metering, looping of services and unmetered supplies; (iv) local political and social pressures to forgive the delinquency of consumers capable of mustering external support; and (v) seasonality of incomes, particularly among farmers, who fall into arrears during the lean months on the promise that they will repay after they sell their wares. At present, financial losses from inefficient commercial practices could be as high in value as 8% of energy sold.

Arrearage Levels

2.20 The total annual revenue from rural consumers is ₱ 4.0 billion, which averages about ₱ 34 million per REC. The average percentage allocation of revenues among consumer categories is shown in Table 2.3; these percentages vary significantly among RECs, especially for those in remote islands and in central and southern Luzon.

Table 2.3: ALLOCATION OF REC REVENUES AMONG CONSUMER CATEGORIES (%)

Consumer Categories	Residential	Industrial	Commercial	Miscellaneous Public Lighting, etc
Contribution to Aggregate REC Revenues (%)	40	30	18	12

2.21 The average level of accounts receivable is about 27% of total revenue (averaging about 3.2 months, or 100 days sales). While residential consumers are responsible for nearly 70% of outstanding bills, the monetary value of residential arrears is only about 35% of the total. For the balance: (i) local and national government bodies account for about 28% of the monetary value of arrears; (ii) large commercial and industrial consumers account for about 30%, and (iii) other consumers for the remaining 7%. While this mix varies among the RECs, a relatively small number of government and business establishments account for the bulk of arrearages.

Industrial Consumption

2.22 Currently, a number of large industrial consumers that take power at high voltage are supplied directly by NPC. These consumers prefer this arrangement because of (i) a desire to pay for electricity at the lower rates charged by NPC, (ii) a concern that NPC's service is more reliable than that offered by the RECs; and (iii) a reluctance of some among them to face bills that they still have outstanding with the local REC, going back to the period prior to their direct connection with NPC. As indicated in Table 2.4, NPC now directly provides about 40% of the total energy supplied to industrial consumers.

Table 2.4: SUPPLIERS OF ENERGY TO INDUSTRIAL CONSUMERS (MWh by Area)

Area	RECs	Private Utilities	NPC
Luzon	80,312	15,703	78,023
Visayas	29,040	26,600	30,244
Mindanao	62,955	48,000	127,651
TOTALS	172,307	100,303	235,918

2.23 In most other countries, the usual practice is that all consumers are supplied by the distribution authorities except those requiring supplies at voltage levels higher than the highest distribution voltage. Some technical factors that would influence this choice are: (i) size of load; (ii) nature of load (e.g., continuous process manufacture); (iii) quality of supply requirements (e.g., the need for supplies to be free of harmonics); (iv) security considerations; and (v) the capital cost requirements of alternative arrangements.

Recommendations

2.24 For large consumers, NEA and NPC should develop technically-based policy guidelines concerning the supply of large consumers[4/]. Such guidelines would need to balance the critical importance of protecting the integrity of the RECs' franchise areas against the capability of the RECs to provide industrial consumers with reliable supply at reasonable cost. Where industrial consumers who are directly connected to NPC have arrears outstanding to their local RECs, NPC should arrange to collect a surcharge that would be used to settle those consumers' accounts with the RECs.

2.25 More generally, since the basic commercial systems that the RECs originally implemented are sound, NEA should now arrange to update these guidelines, particularly their coverage of procedures for revenue collection, including meter reading, billing, disconnection, penalties for reconnection, and electricity theft. Each REC should be provided with a mini-computer to process the data developed through the new systems, and with training in the procedures, hardware and software provided[5/]. At the same time, the biases that undermine the ability and desire of REC managers to strengthen their commercial operations will also need to be addressed, presumably through conditionality to be attached to future NEA loans to the RECs. The experience of those RECs that have been performing well has indicated a close correlation between effective collections and heightened member involvement. In effect, the members police themselves and bring peer pressure to bear on the larger consumers. Therefore, special arrangements might be made to foster the growth of group accounts such as Barangay Power Associations (BAPA) (Annex 2.07). Moreover, member outreach programs are also needed to demonstrate the interrelationship between effective revenue collection and service standards, operating costs, electricity prices and employment conditions. In this regard, programs such as pre-paid stamps

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4/ The Government approved Policy Reforms in the Power Sector already provides that direct connections for industry shall continue until such time as "the appropriate regulatory board determines that the direct connection of industry to NPC is no longer necessary in the franchise area of the specific utility or cooperative." Therefore, the Government's inter-agency committee on technical and financial indicators and standards of performance, where both NEA and NPC are represented, can develop the needed policy guidelines.

5/ In cases where an REC has a very small market, the benefits of computerizing billing and collections should be weighed against the likely cost of the equipment, software and training.

and raffles with prizes could be used as part of a national communication effort to raise the level of public awareness of these issues.

E. Non-Technical Losses

Levels of Non-Technical Losses

2.26 The average level of losses per REC is 25% (Annex 2.08), or about 700 GWh/year in the aggregate. For the average REC, technical losses are estimated at about 17% with non-technical losses accounting for the balance of 8%; however, non-technical losses of as much as 20% have been recorded in the worst cases, most of which are located in Luzon.

2.27 A detailed analysis of the causes of non-technical losses is provided in Annex 2.09, and can be summarized as: (i) utility staff collusion with consumers, (ii) consumer interference with meters, (iii) direct tapping of lines, (iv) faulty metering, and (v) unmetered supplies. Because consumer meters are in short supply, a large number of consumers have unmetered supplies and others have been permitted to provide their own meters. Furthermore, the standard followed for metering of large industrial and commercial consumers (those who use current-transformers) is not of sufficiently high. These practices all result in unrecorded consumption; although the resultant non-technical losses caused by these practices are difficult to estimate accurately, the magnitude is significant.

Recommendation

2.28 Experience in other countries shows that the most effective strategy for reducing non-technical losses is a combination of management action, customer awareness and technical changes. The major elements of a non-technical loss-reduction program would include: (i) effective national legislation providing for the prosecution of pilferers based on circumstantial evidence and prescribing stiff penalties, judicial and financial, for offenders; (ii) continuous surveillance of lines by special monitoring units composed of full-time staff with their own transport; (iii) replacement of all "A" base type meters; (iv) sealing of all socket-type meters; (v) programs for on-site meter testing, replacement and recalibration to be implemented on an ongoing basis, (vi) rewiring of all sub-standard major industrial and commercial meters, with regular semi-annual and spot checks of all such installations, (vii) installing of check meters on distribution transformers, and (viii) replacing of low-grade service connections with concentric cable.

2.29 Existing laws concerning pilferage of electricity are extremely weak. They place an excessive burden of proof on the utility or REC seeking redress; and, even when applied successfully, face the miscreant with only minor penalties. Currently, the Congress is considering several proposed bills to enhance the capability of utilities and RECs to pursue pilferers and to increase the penalties for those who are convicted. NEA should support strongly the rapid adoption of the strongest of these bills.

2.30 Generally, the cooperative approach has been found to be the most effective institutional arrangement for reducing electricity theft; in some RECs in the Philippines, consumer involvement, resulting in a combination of a group climate and peer pressure, has been effective in supporting efforts to minimize pilferage. The RECs should place a much higher priority on consumer involvement to encourage their consumer-members to police themselves. Consumer awareness of the problem could be improved by greater REC outreach through the use of newsletters, newspaper articles and advertisements, radio programs, and local television appearances and advertisements. These measures cost very little and have the capacity to provide substantial savings. They also provide the basis for deeper accountability of the RECs to their consumer-members.

2.31 Some RECs have made effective use of group accounts, with meters installed on individual transformers. Drives to form these group accounts, known as Barangay Power Associations (BAPA) (Annex 2.07), have been well received especially in the farming areas. Where the BAPA movement has been successful, non-technical losses have been more effectively controlled. The approach has a number of important advantages, including (i) providing single-point connections for many consumers, thereby reducing billing costs; (ii) shifting responsibility for all losses in the secondary system to the BAPA; (iii) monitoring the transformer load; (iv) providing a social grouping in the BAPA; and (v) providing the BAPA with a small income for use on community projects. The estimated cost of a more widespread program of transformer metering is estimated at about US$100,000 per REC or US$40,000 per substation and feeder network; potential savings per feeder per year could exceed US$40,000 from the recovery of non-technical losses (Annex 2.06) and US$20,000-30,000 from recovery
2.03). This high potential for savings could induce the RECs to provide internal funding for this program as well as accelerated formation of BAPAs in areas where the concept has taken root.

2.32 In general, NEA should place a much higher priority on the reduction of non-technical losses. The system improvement measures to be employed cost much less and could potentially produce a far greater immediate financial impact than even the program to reduce technical losses. NEA should therefore arrange for the RECs to prepare a statistical analysis of the level of losses within their franchises; based on these analyses, some pilot loss reduction projects could be developed around the implementation of a number of the measures discussed above. In addition, annual targets for losses could be developed for each REC, and NEA could support efforts to achieve these targets through conditionality attached to future loans to the RECs.

F. Core Systems

Current Condition

2.33 Due to poor core systems of some networks taken over from the private sector, increasingly poor planning of the new systems developed, and the allocation of resources for system expansion at the expense of planned maintenance, system improvement and rehabilitation, about 20% of the rural distribution network now requires extensive rehabilitation or replacement. The remaining 80% of the system can readily be restored to the original design standards through system improvement type measures.

Recommendation

2.34 Recent studies suggest that restoration of the system to the original design standards would, among other things, involve: (i) about 50 new 69 kV substations; (ii) additional transformer capacity in as many as 40 existing substations; (iii) additional voltage regulation and protection equipment, including reclosers and lightning arresters; and (iv) rehabilitation of the 13.2 kV feeder systems. Implementation of such a program would require (i) strengthening of NEA's distribution planning process and the capabilities of its staff to carry out the related planning, (ii) better coordination of project formulation between NEA and the RECs, (iii) better supervision by NEA of the RECs' project implementation activities, and (iv) closer coordination of NEA and the RECs with NPC, particularly in relation to the development of the 69-kV network and possible introduction of an intermediate 34.5 kV voltage. As NPC has a direct interest in optimizing the efficiency of rural networks, it should provide NEA with assistance in project design and implementation.

2.35 Under the proposed Bank-financed Energy Sector Loan, the Bank plans to support a pilot program (Annex 2.10) for rehabilitating core systems. The program includes (i) clearly defined projects to rehabilitate one substation and all the feeders, branches, secondaries, and service drops emanating therefrom in nine carefully selected RECs; (ii) the provision to 32 RECs of one new 69-kV substation each; and (iii) upgrades to one existing 69-kV substation in nine RECs. This rehabilitation program is expected to cost about US$17 million. In particular, the feeder rehabilitation component emphasizes preparation of detailed project designs by NEA, close coordination between NEA and the selected RECs concerning the focus of the projects, and strict project supervision procedures for NEA. If successfully implemented, the pilot project would form the basis of a future program to restore the rural distribution system to its original design standards.

G. Rural Electrification Master Plan

Improvements on Operations and Planning

2.36 As indicated hereabove, a large number of remedial activities need to be conducted to relieve the operational problems now constraining delivery of electricity service in the rural areas. Some are inexpensive, high-impact measures that the RECs should be able to implement with their existing staffs and revenues, or with limited external assistance. Some will require NEA's financial and technical assistance. To ensure that these diverse activities are properly coordinated and to translate the general aggregate program into a management plan for each REC, a comprehensive Rural Electrification Master Plan (REMP) is needed; the REMP should provide the details of an overall national program, within which (i) specific improvement measures for each REC can be formulated, taking into account realistic constraints on available financing, and (ii) the performance of each REC can be measured against realistic technical and financial targets.

2.37 Although the REMP is meant to translate a general program for the country into an action plan for each REC, it should be formulated on a top down basis, with the objective of planning the integrated long-term development of rural electrification in the Philippines, with special emphasis on the next ten years. It should take the form of a management plan with particular emphasis on the technical requirements for running the business. The REMP would include as its main elements:

(a) Establishment and implementation of a methodology for investment planning and evaluation;

(b) Preparation of an indicative nationwide investment and lending program, on the basis of which a draft investment program could be developed for each REC;

(c) Development of a sound pricing system, together with suggested tariffs for each REC;

(d) Establishment of operational performance criteria, together with performance targets for each REC; and

(e) Formulation of a broad-based manpower development plan, on the basis of which a draft training program could be prepared for each REC.

On a nationwide basis, the plan would identify gaps in all major functions and develop strategies to close them; priority measures for resolving operational and investment issues would be defined, allowing the development of detailed, integrated remedies for the system's major problems. In conjunction with the REMP, an REC Planning Manual would be prepared, which the RECs would use in developing initial integrated five-year rolling technical and financial plans to cover their operations, maintenance, special service improvement programs, and investments. In turn, the indicative investment plans, the suggested tariffs, and the performance criteria that will

already have been developed for each REC can be adjusted to take account of the information being provided by the RECs.

2.38 The REMP should also include the development of procedures for compiling management information and performance reviews so that the performance of each REC would be measured against (i) its work plans and budgets, and (ii) national indices for key parameters (paras. 4.25-4.29 and Annex 4.08). Thus, the REMP would provide a clear framework within which NEA could perform its planning, supervisory and controlling functions and the RECs' Boards and management could assess their own performance.

Formulation of the Plan

2.39 The rural electrification institut. ırrently lack the know-how, experience and capacity to develop the REMP by themselves. They will consequently need assistance from consultants to design and implement the necessary planning processes and procedures, the pricing system, and the information and review systems. Consulting assistance will also be needed for specification of suitable hardware and software to computerize (i) distribution planning and design, (ii) consumer records, (iii) billing and collection, (iv) stores manageme t, and (v) payroll systems. Once the REMP is developed, consulting assistance would be needed for dissemination among NEA and the RECs of the Plan's ey findings and the programs, systems and procedures that comprise the l art of the REMP.

2.40 NPC will also need to become involved in the formulation of those parts of the REMP that concern investment planning and pricing. The effectiveness of NPC's planning of its generation and transmission requirements depends on the preparation of a coordinated distribution plan. Moreover, NPC's financial health rests in part on the RECs' making timely payment for their power purchases. In short, NPC needs a stronger involvement in the planning, implementation and operations of rural electrification.

Manpower Development

2.41 Implementation of the REMP should be supported by an enlarged manpower development program for both management and staff at NEA and the RECs. At the staff level, the main training requirements include: (i) skills upgrading for electricians, linesmen, and other operating staff; (ii) skills upgrading for supervisors; (iii) administrative and management techniques; and (iv) effective management practices. The first three subject areas were adequately covered by training courses developed in the early days of the rural electrification program. Since the system includes an ample cadre of adequately skilled or trained staff, particularly since some who had left for lucrative assignments in the Middle East have now returned, NEA should provide refresher courses in these areas. NEA has two regional training centers, which are currently used for training personnel from abroad. These centers would better be used for training NEA and REC staff.

2.42 The most critical manpower development requirement facing the rural electrification institutions is to increase the effectiveness of managers. In particular, a special effort must be focused on improving the performance of the general managers in the RECs and the senior functional managers in NEA. The REMP could provide the framework for a management development program consisting of two major elements:

(a) Annual seminars for groups of up to 20 NEA and REC top managers, to discuss (i) planning; (ii) prioritization of operational and investment activities; and (iii) constraints on the implementation of operational and investment plans. The seminars would be based on the REMP and the REC Planning Manual.

(b) Training courses that focus on upgrading the core skills of managers, where mixed groups of managers would come together for about one week every six months for a period of about four years to consider (i) the role of the REC Board and its management, (ii) situational management, (iii) human resources management, (iv) investment planning and financial management, (v) distribution planning, and (vi) improved performance through staff training and manpower development.

2.43 NEA does not currently have staff with the necessary know-how to design and implement effective training programs for senior managers; it would need assistance to develop this latter category of required training. The performance review component of the REMP should serve as the logical starting point for the management development program, so that the consultants assisting with preparation of the REMP should also assist with preparation of the training programs. One of the regional training centers should be fully dedicated to the senior management development programs, which would occupy the facility virtually year round. The other regional training center would be used for the courses to upgrade skills and to train REC supervisors. Hands-on training programs would mainly be implemented on-site at the RECs, and would use the updated technical and financial procedure manuals. NEA will need to cover the substantial cost (in terms of both money and staff time) of managing such a training program. To ensure that these costs are recovered, NEA will need to charge appropriate fees to the participating RECs.

2.44 The following chapters provide the framework for two strategic issues that the REMP would translate into detailed action plans for each REC. These include (i) the development of an investment strategy and lending program for rural electric distribution, and (ii) the establishment of clear and sound pricing principles for the sector.

3. INVESTMENT STRATEGY

A. Current Planning Strategy

3.1 Since the early days of rural electrification in the Philippines, the philosophy applied to the sector was one of extending electricity supply to the maximum number of rural households, in order to provide basic infrastructure to rural areas. This concept of "total area coverage" required only a relatively simple planning process: subject to the availability of funds, lines were extended from the existing electricity supply grid to villages and areas within relatively easy reach, and with a reasonable prospect of consumption growth. A socio-economic screening test selected areas that appeared desirable, and an intensive promotion campaign created the momentum for the establishment of a local REC. Once an REC was established, its aim was to maximize the number of consumers within the franchise area so as to attain the critical consumption level needed for the REC to achieve commercial viability.

3.2 This approach to investment planning was optimal for a time of pioneering expansion. The program's early successes confirmed the validity of the approach, and during 1974-81, the number of consumers served by RECs increased by about 38% per year, from 178,000 to 1.7 million (Annex 1.01).

3.3 However, following the phase of rapid expansion driven by social targets, the rate of expansion slowed considerably. During the 1980s, household connections have grown by an annual average of only about 7%; in the last few years, the rate of growth fell to about 3%. At the same time, the dominant issues in planning for the rural electric sector have changed: (i) the requirements of non-residential consumers, who now account for almost 60% of total REC sales, must be met; (ii) increasingly, investments are needed for upgrading, reinforcement, and rehabilitation of the distribution systems as a result of consumption growth, aging core systems and damage caused by natural disasters; and (iii) in view of prevailing economic constraints, NEA needs to guide the RECs toward efficiency-oriented operations and investments.

3.4 Despite the changing sectoral needs, the current Public Investment Program (PIP), updated in 1988, still focuses primarily on the increased coverage of rural areas and households, with the aim of serving 4 million households by 1992. Investments in rehabilitation, although included, are dwarfed by expansion investment. Later in 1988, NEA's new leadership (para. 6.1) decided to refocus the investment program to address the pervasive declines in quality of service. After a crash program to develop data from the RECs, NEA formulated a new, highly ambitious investment program for 1988/89 that places greater emphasis on the need for rehabilitation. This program was later superseded by a proposal covering 1989 alone, that maintained the same priorities but that was reduced in scope to only about 30% of the original request. Both the original and revised programs are summarized in Annex 3.01. In any case, the experience of the last year indicates that, while NEA is changing its investment priorities,

it still lacks a consistent investment strategy and a coherent methodology for prioritizing and selecting investments.

3.5 This chapter derives an indicative investment strategy through the conduct of an economic analysis of the various investment options. Based on the findings of the analysis, which indicates the justification of concentrating on (i) system rehabilitation together with the provision of additional consumer connections within the vicinity of upgraded lines and (ii) system extensions designed to capture productive loads, sample investment scenarios are developed to test the pace at which the new investment objectives could be realized. Since the suggested change in investment strategy will require a new methodology for screening investments, the chapter continues by outlining an approach for evaluating and ranking proposed projects. The chapter concludes by noting the various non-economic factors that should be addressed or considered in conjunction with the adoption of the new planning methodology.

B. Investment Priorities

3.6 NEA's current methods of evaluating investment proposals are not suitable for the ranking of different types of projects, when those projects are competing for limited resources. The existing methodology reflects the earlier emphasis on expansion, where the main concern was to maintain financial viability of the REC while the construction program was oriented to meeting quantitative targets. The existing feasibility study format employed by NEA is heavily descriptive in technical and costing terms, and evaluates the impact of the proposed investment on the REC's total financial performance. This ensures that any particular investment will not damage the REC's financial health; but it does not yield information on the underlying feasibility of the project itself, or on the comparative merits of different investment options. While the analysis of financial performance should continue to be included as part of any investment evaluation, the missing element of economic feasibility analysis needs to be introduced and become the main criterion for investment decisions. The analysis of investment priorities that follows was conducted by NEA according to a methodology that relies heavily on these economic principles.

3.7 The electricity distribution system in rural areas is currently characterized by evident medium-term needs for rehabilitation, and established long-term goals of further expansion. This conflict is typical of rural distribution systems in a transition phase. To determine the most cost-effective investment strategy for the RECs, the following representative alternative investment options were chosen for economic cost/benefit analysis:[1/]

1/ This analysis does not assume any major adjustments to the system's design standards; the current standards are already relatively low-cost.

(a) System rehabilitation[2/] with concurrent addition of new connections along existing lines (add-ons), taking advantage of supply capacity released by the upgrading;

(b) System rehabilitation only, without any new consumption in the rehabilitated area;

(c) System expansion primarily to satisfy incremental residential demand;

(d) System expansion based mainly on incremental industrial demand; and

(e) Combined system rehabilitation and expansion.

3.8 Each option was defined as a specific project within the franchise area of an appropriate REC, using actual investment proposals as the basis. Capital and operating costs of each option were adjusted to approximate economic costs, and the cost of power purchased by the REC was valued both in financial (NPC sales price) and economic terms (LRMC of NPC supply). The benefits were defined as incremental sales, unless the savings from loss reduction investment exceed the additional consumption (relevant for the "rehabilitation only" option). Incremental sales benefits were valued according to a demand function ranging between the cost of alternative energy (kerosene for lighting) and the tariff level, thus capturing the consumer's surplus. Where rehabilitation/upgrading investment was likely to yield system loss reductions in the distribution network, losses were assumed to decline at a realistic rate. The cost of mounting a campaign for the reduction of non-technical losses was included in the calculations. The five representative options were tested for the Pampanga I, Capiz, Tarlac II, and Leyte V cooperatives (Annex 3.02).

3.9 The results of the sample feasibility studies (Annex 3.03) indicate that the highest priority in forthcoming investments should be placed on rehabilitation combined with an intensification of consumer density along the rehabilitated lines. This type of investment combination, yielding an internal rate of return of about 40-50% in economic terms, has the advantage of achieving at low cost both system loss reduction and the freeing of additional capacity for incremental consumption. The superiority of this option as compared to rehabilitation without significant growth in consumption is evident from the poor rate of return (about 2% in economic terms) yielded by concentrating on loss reduction and upgrading alone;

2/ "Rehabilitation" covers reconductoring, transformer replacement, other reinforcement investments, and replacement of failed or dilapidated equipment. "Add-on" investments cover both the connection of additional consumers along existing feeder and branch lines, and the construction of short new branch lines to reach groups of consumers in the vicinity of the feeder who do not yet have access to electric power. Such consumers had not previously been connected because of (i) lack of materials, and (ii) the emphasis on extending the backbone system. "Expansion" refers to (i) construction of new feeders and substations, or (ii) extension, by some considerable distance, of existing feeders, to connect new consumers.

the benefits of reduced bulk purchases to meet an almost unchanged consumption level would not justify the massive investment in system improvement. Although rehabilitation is the essential first step toward increasing consumption in already electrified areas, it needs the follow up of infill connections and growth in demand from existing connections to become economically justifiable. In many RECs, the deterioration of networks and lack of funds for materials has given rise to substantial suppressed demand within a small distance from existing lines[3/]. This suppressed demand should be tapped by increasing the connection density after rehabilitation, and thus triggering the realization of incremental economic benefits.

3.10 The typical pattern of expansion, namely that based on scattered residential connections, shows a low rate of return of about 3-4%; the substantial investment in extending the grid cannot be recovered easily from low-volume consumers. The only clearly feasible expansion option is the extension of feeders to areas dominated by new industrial consumers, where the volume is sufficient to carry the cost of investment. Predictably, a combination of rehabilitation and expansion investment as a package yields a modest internal rate of return between the two extremes. Table 3.1 summarizes the results.

Table 3.1: REPRESENTATIVE FEASIBILITY STUDY RESULTS

Type of Investment	Economic Rate of Return
Rehabilitation with Add-ons	48%
Rehabilitation only	2%
Expansion (residential)	4%
Expansion (industrial)	35%
Rehabilitation and expansion	8%

3.11 The general trend of these results is confirmed by a less sophisticated ranking analysis conducted by NEA within the framework of sample REC consolidation studies. A financial cost/benefit analysis was carried out for alternative investment options (rehabilitation, add-ons, and expansion) in the RECs of Albay I, II, and III, Camarines Sur II and IV, and Pampanga I, II, and III (Annex 3.03). While the rehabilitation investments (albeit with a somewhat optimistic loss reduction assumption) show reasonable internal rates of return, none of the expansion investments meets the criterion of a positive IRR.

3.12 The clear message of the sample exercises is that, in the medium term, the primacy for the allocation of investment funds must lie with system improvement combined with the increase of consumer density per km of line. The extension of feeders to unserved areas should be at the bottom of the priority list, unless clear evidence indicates that productive uses

3/ NEA's own projections indicate that as many as 700,000 potential new consumers are within easy reach of existing feeders.

of power would enable speedy cost recovery. Equity considerations may dictate that some expansion continue, even during the years of heavy emphasis on rehabilitation: the terms for granting a franchise currently mandate that the chosen operator expand the distribution system to low-density areas, based on the principle of cross subsidization within the service area (the pace of that expansion is conditioned on maintaining the financial health of the REC). This could be accommodated optimally at the regional level, where even with the implementation of high-priority upgrading works, the allocation of some remaining available funds for economically justified expansion might still be considered. Areas with relatively adequate distribution networks would be in a position to continue expansion. However, on a national level, the investment program of the next few years should reflect the priority of system improvement.

3.13 The investment strategy adopted should also consider how to realize possible cost savings in implementing rehabilitation and expansion investments. As major savings from design standard adjustments are unlikely to materialize, the benefits will have to come from improving efficiency through such measures as reducing conductor size, increasing pole span, reducing transformer protection, and saving meters through other payment systems (Annex 3.04). Such improvements will not likely have a major system-wide impact but may be significant at the local level. In some instances, the simultaneous application of these measures could save as much as 10% from the total cost per km of line, albeit with some reduction in service reliability. A thorough cost/benefit analysis would determine where the benefits of the potential savings outweigh the loss in quality of service.

C. Investment Scenarios

3.14 As the development of a full-fledged investment program will take some time, NEA and Bank staff constructed a preliminary five-year investment needs projection[4/] that illustrated the possible options and investment patterns (Table 3.2). The initial years of the projection were based on the detailed survey of requirements conducted by NEA in 1988. However, since the survey captures only a portion of rehabilitation requirements, as NEA asked the RECs to limit their requests to fit within the constraint of available funds, appropriate multipliers were applied to rehabilitation investment, derived from sample analysis and NEA experience. The total investment requirements were phased over 5-7 years, giving priority to system improvement, and bringing in expansion only gradually in later years. The high returns of a "rehabilitation plus add-on" program make a compelling argument on behalf of this component of investment in rural systems receiving the very highest priority. Although the optimal approach would include a complete package that includes efficiency improvements, the system improvement investments are so essential that they need to proceed

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4/ The investment projections include investments in rural distribution networks only, and do not include any alternative generation programs.

as soon as funding can be secured, and thereby lay the foundation for later expansion accompanied by efficiency gains.

3.15 While the system improvement element is determined primarily by (i) the current level of demand, (ii) technical needs, and (iii) the immediate potential to connect new consumers along existing lines, the future expansion of the system depends on the pace of penetration into unserved areas. The overall potential is, of course, very large, given that the Government's aggregate electrification target still is beyond easy reach. A demand forecast for rural electrification, therefore, must be guided by the economic justification of individual projects, and by the implementation capacity of the sector. Based on (i) the known short-term potential available through system upgrading and add-ons, and (ii) a gradual progression toward expansion investment in later years, NEA developed a tentative projection of electricity consumption for the early 1990s. This forecast, driven by system needs and capabilities, assumes a demand growth of about 8% per year through 1995 (Annex 3.05).

3.16 Within the core program of investments in rural distribution networks, the scenarios considered were tailored to reflect three important parameters: (i) the primacy of a combination of rehabilitation and add-on investments in the early years, (ii) the projected availability of funds in the short term, and (iii) the likely implementation capacity of NEA and the RECs. Judgments for weighing these parameters are based on the findings of sample feasibility studies and on the institutional and financial constraints that limit the capabilities of the sector's institutions. The analysis yielded two scenarios that are possible, depending on whether NEA and the RECs can accelerate the current sluggish pace of investment:

(a) Scenario 1 assumes that the modest rehabilitation investment needs already formulated for 1989 are representative of the implementation capacity at this point, and that the remaining rehabilitation and add-on investment will be phased over the next four years.

(b) Scenario 2 places the bulk of rehabilitation and add-on investment in the first two years of the program, assuming that the institutions will gear up rapidly for a massive system upgrading drive.

3.17 In both scenarios, expansion investment does not start to be phased in until 1991. Annex 3.05 provides details of the investment program of Scenario 1 by Region and by type of investment, then compares the results of both Scenarios to existing plans. Table 3.2 summarizes these findings. Both scenarios are illustrative of the general pattern and mix of expected investments in rural electrification; neither is a carefully developed accurate projection of annual investment in the sector. In apposition, NEA's latest draft plan calls for a steep increase in investment to about ₱ 1.3 billion in 1990 (with about 67% apportioned for rehabilitation and 33% for expansion), declining gradually to about ₱ 600-700 million per year by 1994 (with a mix of about 55% for expansion and about 45% for rehabilitation.

Table 3.2: INVESTMENT SCENARIOS
(₱ million)

	1989	1990	1991	1992	1993
Scenario 1					
Rehabilitation plus Add-on	315	538	538	538	538
Expansion	0	0	154	530	509
Total	315	538	692	1,068	1,047
Scenario 2					
Rehabilitation plus Add-on	600	850	700	300	0
Expansion	0	0	150	550	500
Total	600	850	850	850	500

Since actual new investment loans for RECs approved by NEA in 1988 amounted to only about ₱ 200 million, Scenario 1 starts with 1989 investment of ₱ 315 million, and increases to an annual figure of about ₱ 1 billion in 1992 and 1993. Having completed the bulk of system improvement investments by 1993, total investments thereafter would drop and would then include routine rehabilitation and modest expansion. Under Scenario 2, system improvement is concentrated heavily in 1989-90, driving the total annual investment level quickly up to ₱ 850 million in 1990; thereafter investment levels stay constant as rehabilitation gradually gives way to expansion over time. After the first five years, the total benefits from consumption growth and loss reduction are likely to be similar for both scenarios. Finally, the most important constraint affecting the level of future investments seems to be the absorption capacity of NEA and the RECs. Scenario 1, which indicates aggregate investments of about ₱ 3.8 billion during the period, represents a best guess at NEA's absorption capacity, and not a level that was considered optimal on other grounds.

3.18 Given the prevalence of rehabilitation and add-on investment in the program's first five years, the total investment sequence yields an IRR similar to that of the highest-priority sample investment. Scenario 1, for which detailed incremental consumption data are available, shows a return of 40-50%. In effect, considerable scope exists for economically sound investments in rural electric networks. The first push of investments for rehabilitation plus add-ons, involving expenditures of about ₱ 2,500 million between 1989 and 1993, would yield high benefits. Investments in system expansion, which are projected to run at about ₱ 500 million per year from 1992/93 onward, would have to be selected carefully to ensure that productive demand becomes the driving criterion. Since the RECs currently sell about 60% of their aggregate volume to industrial and commercial consumers, a good proportion of the expansion program, if selected judiciously, can be designed to yield positive net present values at realistic discount rates.

3.19 The above Scenarios represent a first estimate of the scope of a realistic investment and lending program. NEA should begin by refining these estimates and match them to the detailed requirements and implementation capacity of the RECs. As the plans endorsed in 1988 and early 1989 (Annex 3.05) do not reflect adequately the change in investment strategy away from expansion to rehabilitation and add-ons, NEA will need to present formally to NEDA a revised program that reflects its changed priorities. By serving as a rational and realistic action plan, the formulation of a revised investment program will itself facilitate the discussions with central agencies regarding project approval and fund allocation. Under either Scenario, substantial new injections of finance by 1991/92 appear needed merely to maintain the pace of system improvement, regardless of whether investment for expansion returns to the program in strength at that time or later. The total additional requirement for 1991-93, which is not reflected in the financial projections for NEA (Annex 6.06) would amount to about ₱ 2,200-2,800 million, including a foreign exchange component of about US$80 million.

D. Coverage Targets

3.20 If, during the early 1990s, NEA pursues a system improvement oriented strategy developed according to the indicative investment Scenarios, the proportion of rural population receiving electricity supply could rise from the present level of about 50% to about 65% by 1993/94. About half of the newly connected 700,000 to 800,000 consumers would be within easy reach of the existing grid, and would receive their connections through add-on investments; the remainder would receive electricity as a result of judicious expansion into economically justifiable areas. From the mid-1990s onward, connecting the remaining 250,000 to 300,000 consumers that could be supplied economically through add-on investments would increase coverage to about 70% of the rural population. However, since the share of unconnected productive consumers must necessarily decline and the areas remaining to be electrified would become increasingly remote, the expansion investments that might increase penetration significantly are likely to become more difficult to justify in economic terms. Investment proposals would then have to be evaluated carefully and the Government's broadly encompassing area coverage target would need to be adjusted to reflect the economic, financial, social and political realities derived from several years of investment analysis. Even in the long term, penetration beyond about 75% of the rural population would appear difficult to justify economically.

3.21 In many countries, rural electrification is considered to have a substantial social value, so that investments may well exceed the level to be justified solely on the basis of commercial criteria. The proliferation of rural electrification in the Philippines occurred precisely because the Government and NEA had put great emphasis on those social considerations. Currently, many RECs are struggling with serious operational and financial problems that resulted in large part from uncontrolled growth. Therefore, during the next five to ten years, NEA as well as a large number of RECs will need to be restructured (paras. 5.26 and 6.26). During this

period, the Government's emphasis should be to address the issues surrounding the needed restructurings while supporting investments with prospects of an imminent favorable financial outcome and direct economic potential. Although investments that are justified primarily on social grounds can be considered on a case-by-case basis even before the late 1990s or early 2000s, the bulk of such investments should be postponed until the RECs' current institutional and financial problems have been remedied.

E. Investment Criteria and Planning

3.22 The recommended priorities and investment scenarios indicate a general direction for a future NEA investment strategy. Translation of the priorities into a consistent, detailed investment plan and an NEA lending program will require the introduction of an appraisal and planning methodology that can rank projects by using economic criteria. Establishing the analytical framework includes the following steps:

(a) An initial screening of investment proposals on the basis of simple infrastructure, demographic, and priority parameters;

(b) A rigorous cost/benefit analysis of the pre-screened proposals, utilizing economic methodology;

(c) On a regional or sub-regional level, a ranking of proposals according to economic internal rate of return;

(d) On a national and regional level, the development of an integrated investment program, based on macro parameters and overall targets for efficiency;

(e) Consolidation of steps (c) and (d) to arrive at a realistic list of priority investments;

(f) Application of constraints, including, inter alia, the availability of funds and the capacity to implement projects;

(g) Development and implementation of a consistent NEA lending program based on the adjusted investment plan; and

(h) Annual revision of the plan and lending program, and continuous appraisal of investment proposals.

3.23 The screening process can employ several different methodologies. Traditionally, the NRECA approach of weighting expected benefits and costs has been used, which results in a rough benefit/cost ratio of scores for a specific project. This approach requires a large amount of judgement by experienced practitioners, and detailed survey data. An improvement over the judgmental method would be the detailed ex-post analysis of past projects, from which certain characteristics of successful projects could be derived. A regression analysis of a large sample of completed projects can yield statistically significant correlations between the features of

the area and the project, and the rate of return. All new projects with similar characteristics (population, incomes, price of electricity and other energy, agricultural output, access to credit, terrain difficulty, current levels of electricity use, etc.) can be expected to yield certain rates of return, prequalifying them for more rigorous analysis. Alternatively, the regression method can be replaced by discriminate analysis where the characteristics derived from ex-post analysis divide investment candidates into feasible and non-feasible groups. A thorough study of past REC investments, aimed at developing such screening parameters, would be highly beneficial at this point.

3.24 The methodology for economic cost/benefit analysis needs to be straightforward enough so that it can be applied by REC staffs in preparing their investment proposals for NEA scrutiny. As a minimum, it needs to include (i) adjustment formulae for cost data that transform financial costs into border-price-equivalent economic costs, using appropriate conversion factors; (ii) realistic rules for the estimation of consumption growth and the reduction of systems losses, to avoid overly optimistic projections; (iii) the valuation of benefits at the true value of energy to consumers, as demonstrated by the willingness to pay for both electricity and alternative energy sources (Annex 3.02); (iv) the valuation of power purchases at estimated levels of long-run marginal cost of supply at the substation; and (v) the use of discounted cash flow methodology to derive internal rates of return and net present values, which in turn can be used as decision-making criteria.

3.25 The use of economic cost/benefit analysis as the main investment decision criterion would involve testing the calculated economic rate of return against the benchmark of the opportunity cost of capital, which in the Philippines ranges from about 10% to 15%. On purely economic grounds, investment proposals with a lower rate of return should be rejected as unjustifiable. The analysis of the revised investment strategy, based on rehabilitation plus add-on investments, implies that the bulk of projects included in the early years would be economically sound. As the emphasis in later years shifts to prudent expansion, projects with significant productive loads (small industry, large commercial ventures, etc.) would be economically attractive while those aimed at serving low-volume residential demand would not. All investment proposals, regardless of the commercial viability of the franchise area or the financial health of the REC, should be measured against this same economic yardstick; however, investment decisions per se could well be determined on the basis of other considerations such as (i) social or regional equity, or (ii) strategic or political constraints. When financing such projects, a case would have to be made as to why other considerations should override the economic judgment. The burden of demonstrating that an investment falling short of economic criteria and benchmarks should be financed and implemented would belong to NEA as the financing agency. Rigorous standards of scrutiny would need to be applied to the justification of deviations from economic priorities. Finally, when NEA decides to finance a marginally justifiable project, it will need to safeguard the financial health of the implementing REC through the use of appropriate pricing agreements, financing instruments, and (as needed) transparent subsidies, which are clearly separated from the RECs' commercial operations.

3.26 The development of a national rural electrification investment plan and NEA lending program in parallel with the appraisal of individual investment proposals should proceed according to the following steps:

(a) Conduct an inventory of the status of the distribution systems;

(b) Adjust the overall priorities of the program to reflect the new requirements for system upgrading;

(c) Project national and regional demand development for rural electricity supply, taking into account macroeconomic and demographic variables;

(d) Apply standard physical and cost guidelines for rehabilitation/add-on and expansion investment, to determine broad construction and funding scenarios;

(e) Evaluate possible cost-saving and loss-reducing measures such as the increase of distribution voltage, and more economical service standards, where applicable;

(f) Integrate the results of the ranking of local investment proposals into the indicative plan by adjusting priorities and focusing on investments that provide high rates of return to the economy;

(g) Test the impact of the investment expenditure on marginal cost and tariffs, and determine whether a more modest investment scenario should be contemplated to ensure cost recovery;

(h) Project the outlook for foreign exchange and domestic funding limits, based on the broadly identified program over 5-10 years, and make repeated adjustments to the program to ensure its consistency with available resources;

(i) Design a year-by-year lending program for NEA based on the final adjusted indicative plan, and provide the appropriate manpower resources, analytical skills, procurement procedures and timing, processing procedures, cash flow projections, etc.

3.27 The principal aim of such an exercise will be to gain a longer planning horizon than in the recent past, and to provide a framework within which changes in investment priorities can be accommodated. The indicative national plan should cover 5-10 years, and is likely to be dominated by system improvement investment in the early years. In the outer years, the emphasis is likely to change to a lower level of overall investment, with a balance between steady expansion and the maintenance of the existing system. The NEA lending program would cover about 5 years, indicating the numbers and types of loans to RECs anticipated each year, with tentative loan amounts identified.

F. Planning Constraints

3.28 Even with a more appropriate investment strategy and methodology, a number of constraints and considerations exist which will complicate the planning process, including (i) a scarcity of funds, both foreign and local, (ii) a shortage of staff with the required skills, both at NEA and at the RECs, (iii) strong local and political pressure for expansion of the distribution system and new household connections, (iv) an explicit socio-political mandate to integrate many rural development activities in the electrification program, and (v) the poor operational and financial record of many RECs.

3.29 Funding remains one of the major binding constraints on the investment program. After the deterioration of many RECs' operating performance, little new resources were mobilized. In 1988, only limited funds were available. Of the total of ₱ 700 million, the bulk (₱ 500 million) was devoted to covering the recipient RECs' arrears to NPC (para. 5.16). Of the remaining ₱ 200 million, about ₱ 150 million was used to provide loans for expansion, and only ₱ 50 million for rehabilitation. Although additional finance has been indicated by USAID and the Bank to support investments during 1989-92, these resources are unlikely to accommodate both the rehabilitation and the expansion programs simultaneously. Careful husbanding of the funds is needed, and priorities have to be defined clearly and rigorously. Current financial projections indicate that NEA will need to borrow an additional US$80 million during 1991-93.

3.30 The skills mix of staff in NEA and the RECs is not appropriate for rigorous investment prioritization. Sound engineering, accounting, and administrative professional skills are available in house, and are being put to good use in the evaluation of investment proposals. The crucial economic analytical skill, however, is in short supply. The small NEA project appraisal unit, which until recently was charged with reviewing and evaluating the RECs' investment proposals, consisted of engineers and financial analysts. The new corporate planning division is only slowly adding and thereby giving voice to economists. Finally, in their staffing, the RECs have emphasized operational competence rather than analytical skills. The logical next step in improving the sector's skills mix would be for NEA to accelerate its recruitment of economists and planners, while also developing its own core function of formulating and implementing a consistent lending program. In parallel, the RECs (or regional groups of RECs) should establish suitable counterpart units that can conduct an ongoing dialogue on investment programming with NEA's corporate planning staff. Until NEA and the RECs acquire the necessary expertise, simpler prioritization guidelines will be needed to enable the sector to implement high-priority investments quickly.

3.31 The legitimate socio-political goal of assimilating larger population groups into the basic infrastructure network needs to be implemented circumspectly, avoiding the sub-optimal use of scarce resources. The 1970s and 1980s were characterized by expansion-oriented investment; the coming decade will require a careful balance between competing investment components. The strong demand for new connections, voiced by potential

consumers, will not be satisfied if the existing core of the distribution system deteriorates. In fact, the most economical way to release capacity for additional consumption is the upgrading and reinforcement of overloaded or aging equipment. If system improvement investments are neglected, the benefits accruing to new consumers along extended lines will be nullified by incremental costs imposed on existing consumers by the deterioration of service. A neutral ranking methodology based on economic costs and benefits will facilitate the delicate balancing of needs.

3.32 Rural electrification cannot easily be separated from rural development as a whole. This has been the underlying rationale for NEA's direct involvement with other rural programs including, inter alia, livelihood projects, rural telephone systems, alternative energy, and rural credit. This approach, however, can be appropriate only for a more mature system with a strong central electrification agency, which could expand its planning horizon beyond network investment to encompass ancillary investments. Indeed, at this time, the Government should emphasize the efficient coordination of related rural development activities rather than asking NEA to assume single responsibility for the process. NEA's concern should be limited to ensuring that rural electric investments can have a productive impact. At this stage of rural electrification, NEA's role in that coordinative process could include:

(a) In the course of appraisal, providing a mandate for NEA's project evaluation staff to assess the adequacy of other rural development facilities, the absence of which would obstruct the full impact of electrification on the area. These assessments would focus on the availability of credit for productive equipment and for housewiring; the ease of obtaining and maintaining electric motors, pumps and appliances; the availability of additional fertilizer and other inputs for pump-irrigated agriculture; the existence of a working rural extension service; and an adequate transport infrastructure. A standard checklist for NEA and REC staffs would be a useful tool for this assessment;

(b) A permanent consultation procedure between NEA, the RECs, and other local and national agencies engaged in rural development. Using its regular project proposal evaluations, NEA could make known requirements for supporting investments and policies in a forum that could take action in time for achieving synergy. The Regional Development Councils could become the significant medium for this development coordination process. However, only a consultation medium closer to the locale of the investment project can determine effectively how to coordinate various activities; developing such a medium at the barangay level or one local administration level above could be considered.

3.33 Finally, the distressed financial and institutional situation facing many RECs detracts from the development of a sound planning capability. Short-term considerations dominate the RECs' day-to-day business, as scarce resources must be devoted to anti-pilferage campaigns, the search for line materials, administrative problems, and solutions to financial crises. The introduction of a clear methodology to set investment priori-

ties will enable the RECs to follow a straightforward procedure in making proposals to NEA, while minimizing the time and staff resources that need to be allocated to this exercise.

G. Summary of Recommendations

3.34 The development of an investment strategy and a lending program for rural electric distribution systems will require the following:

(a) In the medium term, investment priority should be shifted primarily to system improvement, consisting of (i) rehabilitation, (ii) upgrading, and (iii) additions of new connections to existing lines. Expansion of the network to unserved areas should be delayed, unless productive use of electricity would ensure a high return. On the basis of available information, increasing coverage from the current level of 50% of potential consumers to about 65% by 1993/94 appears economically justifiable and financially feasible; however, even in the long run, penetration beyond about 75% of the rural population would appear difficult to justify economically.

(b) NEA needs to be relieved of direct responsibilities for investments and programs that are only marginally related to the core function of financing electric distribution systems; and, instead, it needs to focus on its investment and loan programming activities to increase the efficiency of electricity distribution in rural areas. To the extent that the availability of electricity is central to economic activity in the rural areas, NEA should continue to coordinate plans for electrification with other rural development activities.

(c) NEA needs to develop and introduce an improved method for screening, evaluating, and ranking proposed investment projects according to economic criteria.

(d) NEA should develop an indicative investment plan and translate it into a consistent and feasible lending program. This lending program should (i) be based on macroeconomic parameters and constraints, (ii) reflect the relative priorities of individual projects, and (iii) to the extent feasible, be within the framework of the Public Investment Program.

(e) From about 1991 onwards, additional funds needed to finance the ongoing rehabilitation program and to enable economically justified further expansion will need to be mobilized.

(f) NEA and the RECs should start an intensive staff development program that encompasses (i) training of existing staff and (ii) recruitment of economists and planners.

4. PRICING POLICY

A. Introduction

4.1 Each REC determines its tariff levels and structure based on the cost of purchasing power from NPC and its own internal cost structure. The NPC wholesale rate accounts for about half the total cost included in the retail rate for REC consumers, thus exerting a significant influence on REC rate-setting.

4.2 Each REC sets its rates under the supervision of NEA, according to a simple formula that allows for recovery of (i) power supply costs, (ii) an allowance for system losses up to 25%, (iii) other cash operating expenses, and (iv) debt service. This cost-plus formula is computed on the basis of ₱/kWh, and yields the average retail rate to be realized by the REC. By reviewing and approving the calculations that underlie rate adjustment requests received from the RECs, NEA is fulfilling a regulatory function. The current formula has the advantage of being simple to administer, but fails to provide (i) incentives to control internal operating costs, (ii) internal funding of future investment requirements, and (iii) incentives for efficient patterns of consumption. While a crude average cost recovery approach was appropriate for the early period of expansion, the increasingly varied consumer mix requires a more sophisticated method of demand management and cost control.

4.3 The pricing system includes one major element of subsidization, namely, the relief granted to small, remote island RECs that must rely for their supplies on high cost, local, small-scale diesel generators. An application of the current NEA-approved pricing formula for these 14 RECs yields average retail rates of ₱ 4-9/kWh, compared to ₱ 1-2/kWh in most others. The overall subsidy consists of (i) a below-cost power purchase price from NPC (the current owner of the small generating sets) limited to ₱ 1.30/kWh, and (ii) a direct subsidy shared between NPC and NEA in the ratio 84/16. The total subsidy requirement is defined as the difference between the theoretical formula-based average retail rate and the recently imposed rate ceiling of ₱ 2.50/kWh.

4.4 The following paragraphs provide comprehensive suggestions for a thorough reform of the pricing system. In view of the importance of the NPC selling price for the level and structure of REC retail rates, recommendations for the ongoing transition of NPC to marginal-cost-based bulk rates are developed. Subsequently, a pricing philosophy for RECs is suggested, based on the forthcoming change in NPC rates. While the recommendations form a consistent system, some elements of reform are more urgent than others; therefore, the components of the proposed policies can be implemented gradually. However, the ultimate target remains a rational pricing structure that promotes efficiency of both supply and use.

B. NPC Costs

4.5 During recent years, a consensus developed within the Government that NPC should redesign its tariff to reflect long-run marginal cost (LRMC). Currently, NPC's rates are not sufficiently differentiated to accommodate the large differences in costs that consumers with substantially differing demand patterns (such as MERALCO, the RECs, and directly connected industries) impose on its supply system. Clearer cost-based differentiation is needed.

4.6 In 1985, Electricite De France International completed a marginal cost study of electric tariffs. In performing the study, the consultants used a computer model that assumed the least-cost composition and sequencing of generating capacity to meet projected peak demand. Recently, NPC developed calculations using the "peaker" methodology, in which peak marginal cost is based on the costs of capacity specifically designated for meeting the peak. Off-peak marginal cost is based only on the costs of base-load equipment, which would meet off-peak demand. Using this methodology, the calculations for Luzon indicate that a pure LRMC-based tariff would yield a range of rates between ₱ 0.97-1.86/kWh (Annex 4.01), compared with a current average price range of ₱ 0.96-1.08/kWh. The greater breadth of the range reflects the differences in cost of serving the varied consumption patterns of NPC's consumers. According to these calculations, the Luzon RECs would be subject to rates ranging from ₱ 1.02/kWh to ₱ 1.46 kWh.

4.7 An analysis of NPC's LRMC, taking into account peak and off-peak costs of supply, is presented in Annex 4.02. Based on using gas turbines to provide peaking capacity for the Luzon grid, this analysis results in the costs shown in Table 4.1:

Table 4.1: NPC's CALCULATION OF LRMC FOR THE LUZON GRID

	Capacity Cost (₱/KW/year)	Energy Cost (₱/kWh)		
		Peak	Off-peak	Average
At generation	1,285	1.00	0.53	0.60
At extra-high voltage	1,570	1.00	0.53	0.60
At very high voltage	1,960	1.02	0.54	0.61
At high voltage	2,190	1.07	0.57	0.61
At medium voltage	2,440	1.14	0.60	0.68

4.8 Electricity demand in the Philippines does not appear to be subject to significant seasonal fluctuations, except for Luzon. In the Luzon Grid, seasonal peaking does occur during the hot season, and probably reflects the growing air-conditioning load. This seasonal peaking in Luzon would likely lead, with the calculation and use of loss-of-load probabilities, to a higher marginal cost for summer day peaks (7:00 to 23:00 hours)

than for the winter daily peak periods (same time range). However, for simplicity, this refinement was not considered and all peak periods are assessed as having the same marginal cost of supply.

C. LRMC-Based Wholesale Pricing

4.9 Based on the LRMC structure derived for the Luzon grid, the theoretical bulk electricity price to the RECs is calculated in detail in Annex 4.03 and summarized in Table 4.2:

Table 4.2: THEORETICAL ELECTRICITY COST TO THE RECs

	Peak Period (₱/kWh)	Off-Peak (₱/kWh)	Average (₱/kWh)
At 8% discount rate	1.56	0.52	1.05
At 12% discount rate	1.72	0.52	1.12

These estimates lie within the range of the cost-based rate previously calculated by NPC. The main difference results from the proposed introduction of differentiation by time of day.

4.10 NPC should move cautiously to introduce time-of-day (TOD) rates as soon as possible. In terms of hardware, such a move requires only that NPC introduce TOD metering for its major customers. However, since the principle of TOD pricing has not yet been accepted by Philippine consumers, NPC should move in this direction by introducing much smaller peak/off-peak price differentials than what would be justified purely on the basis of marginal cost considerations. After one to two years experience with this smaller differential, assessments and further adjustments could be made.

4.11 In addition to TOD differentials, electric rates should clearly reflect differential supply costs. This means that cost differences for supplying different voltage levels should be reflected in NPC's rate structure. In the case of the RECs, their bulk rate would need to reflect the additional costs of (i) the downward steps from 230 kV (NPC's transmission voltage) to 69 kV (the level at which the RECs take their supplies); and (ii) transmission at 115 kV and 69 kV to the substations where the RECs take their power.

4.12 TOD rates that are based on daily peaking in demand and the cost of supplying the peak should encourage customers - especially industrial and commercial customers - to shift electricity usage to off-peak times where feasible. As a result, a firm peak that cannot be shifted through inducements will be established. Of equal importance, TOD rates could provide incentive for developing technology to enable consumers to shift their electricity usage for certain productive activities to off-peak periods.

4.13 The application of marginal cost principles for rate setting in the grids outside Luzon is possible by using similar calculations. The sources of additional capacity needed to meet marginal requirements in the other grids are similar to those contemplated for the Luzon grid. At the margin, therefore, supply costs are likely to be similar nationwide, although average costs may differ.

D. REC Cost of Supply

4.14 The average price paid in 1987 for REC-supplied electricity varied from as little as ₱ 0.87/kWh to as much as ₱ 5.31/kWh. Some of this variation was due to differences in the cost of electric generation. Most RECs purchased power from NPC at rates that varied from a low of about ₱ 0.57/kWh in the Mindanao grid to somewhat over ₱ 1.00 kWh in most other grids. Some RECs generated their own power at reported costs as high as ₱ 2.30 to ₱ 2.40/kWh. While some questions regarding whether the RECs operated their generating facilities efficiently have arisen, the issue became moot when NPC agreed to take responsibility for power generation nationwide. Under the new arrangement, if the inefficiencies in power supply cannot be reduced, they should at least be standardized. Once the average price paid for electricity by each REC has been rationalized through the application of LRMC-based NPC tariffs, the remaining spread to cover other costs still exhibits very large variations among different RECs. For some RECs, the current mark-up to cover distribution and customer costs is as low as ₱ 0.49-₱ 0.51/kWh. For others, the current spread is as high as ₱ 2.66-₱ 2.91/kWh. Admittedly, some RECs face costs that others do not; however, the breadth of the variations in these spreads is not justifiable within a system of efficiently operating RECs.

4.15 Case studies were conducted for the Tarlac II, Pelco I, Leyte V and Capiz I RECs to test inter alia the economic viability of their rehabilitation and expansion investment programs. In all of these cases, load forecasts projected increased peak loads. Rehabilitation by itself does not stimulate increased peak demand, and so its costs are removed from investment expenditures in computing an REC's cost of supply. Investments for expansion include some cost for actually connecting additional customers and therefore these costs should also be excluded from investment expenditure when computing an REC's cost of supply. For each of the case studies, appropriate adjustments were made.

4.16 Table 4.3, which is based on the more detailed calculations shown in Annex 4.04, summarizes the marginal cost calculations applicable to the four case studies. Column 3 gives the off-peak marginal cost of electricity, which is basically the NPC rate adjusted for system losses in the range of 15%. Column 4 shows the synthesized marginal cost of new REC distribution capacity (SMCC) for the peak period and column 5 gives the total peak period marginal cost (derived by adding the energy cost from column 3 to the SMCC in column 4). Column 6 shows the average cost of capacity per kWh sold. Finally in column 7, total average cost is the sum of the average capacity cost and the off-peak marginal cost (column 3).

Table 4.3: MARGINAL AND AVERAGE COSTS FOR CASE STUDY RECs
(Based on NPC Using Average Cost Pricing)

NO.	(1) UTILITY	(2) CAPACITY (₱/KW)	(3) ENERGY COST (₱/KWh)	(4) SMCC[1/] (₱/KWh)	(5) TOTAL PEAK MC[2/] (₱/KWh)	(6) CAPACITY AVG. COST[3/] (₱/KWh)	(7) TOTAL AVG. COST[3/] (₱/KWh)
1.	TARLAC II[4/]	2148.7	1.29	1.68	2.97	.8795	2.17
	Excluding Rehabilitation			.84	2.13	.4397	1.73
2.	PELCO I	708.27	1.32	.55	1.87	.187	1.51
3.	LEYTE V[4/]	2503.6	1.29	1.96	3.25	.813	2.10
	Excluding Rehabilitation			.98	2.27	.406	1.70
4.	CAPIZ I	496.07	1.25	.39	1.64	.161	1.42

1/ SMCC - Synthesized Marginal Capacity Cost
2/ MC - Marginal Cost
3/ AVG. COST - Average Cost
4/ For Tarlac II and Leyte V, the second line of figures represents the capacity costs after removal of costs unrelated to marginal capacity increases.

4.17 If NPC adopts full marginal cost pricing, the cost of energy to the REC will differ markedly from present rates. To illustrate the implications for a REC, complete marginal costs were calculated for Tarlac II. Table 4.4 shows the results of this exercise. The actual rates charged by Tarlac II in March 1988 were in the range ₱ 1.74-₱ 1.81/kWh. These actual rates are within the range of the average cost rates calculated in Table 4.3; however, they are well below marginal cost when the peak period for NPC and the REC coincide, and well above marginal cost when the off-peak periods of the two entities coincide.

Table 4.4: MARGINAL COST PRICES FOR TARLAC II (₱/kWh)
(Based on NPC Charging Marginal Cost)

Time Period	Energy Price from NPC	Adj. for 15% Losses	SMCC[1/] Tarlac II	Total MC[2/]
NPC Peak Period 7:00-17:00 Daily	1.56	1.83	0.0	1.83
NPC & REC Peak Period 17:00-23:00 Daily	1.56	1.83	1.68 to .84	3.51 to 2.67
Off-Peak 23:00-7:00 Daily	.52	.61	0	.61

1/ SMCC - Synthesized Marginal Capacity Cost
2/ MC - Marginal Cost

NOTE: As of March 1988, the electric rates charged by Tarlac II were: (i) Residential, ₱ 1.78/kWh; (ii) Commercial, ₱ 1.81/kWh; and Industrial, ₱ 1.74/kWh

E. A Possible Rate Formula

4.18 The major weaknesses of the current pricing guidelines being followed by the RECs include:

(a) The guidelines do not contain an explicit provision to enable the RECs to generate revenues sufficient to recover their investment in distribution system assets.

(b) Prices, particularly for large consumers, do not reflect the variations in marginal cost of supplying electricity at differing voltage levels, times-of-day, and (in Luzon) seasons.

(c) The guidelines do not address the administrative efficiency issues that have led to substantial differences in internal costs per kWh among the RECs.

(d) The guidelines do not address problems of pilferage, politicization, and poor management that have fostered system losses in excess of 20% in about 70 RECs.

4.19 Efficient guidelines require that the following data be collected and calculated for each REC:

(a) All system investments need to be segregated into two categories: (i) those that are sensitive to peak demand, and (ii) those that are unrelated to peak demand. The latter category clearly includes inter alia such distribution system components as (i) meters, (ii) drop lines to consumer premises, and (iii) the smallest sized power lines and transformers. The remaining investment should be categorized as investments that are sensitive to peak demand.

(b) System investments that are sensitive to peak demand should be valued on a replacement or current value basis.

(c) A real cost of capital [r] needs to be identified for the REC.

(d) A carrying charge rate [CCR] must then be calculated based on the cost of capital and the life expectancy of the investments that are sensitive to peak demand. This carrying charge rate is then used to convert the investment [I] to an annualized amount, which is then divided by the increased peak capacity made possible by the investment [MC_{KW}]. Next, a coincident load factor [LF_c] for the customer category under consideration needs to be determined, and the number of peak hours during the year [H_{PK}] is calculated. A synthesized marginal cost of capacity [SMCC] can then be calculated.

$$CCR = (r_n - infl)\left\{\frac{1}{1 - ((1+infl)/(1+r_n))^T}\right\}$$

$$(r_r)\left\{\frac{1}{1 - 1/(1+r_r)^T}\right\} \quad \text{(approximation)}$$

$$MC_{KW} = CCR * I$$

$$8{,}760 \text{ hours} = H_{PK} + H_{OPK}$$

$$SMCC = MC_{KW}/(LF_C * H_{PK})$$

where infl = the rate of inflation
r_n = the nominal rate of interest or cost of capital
r_r = the real cost of capital
T = life of the investment

(e) Then, the marginal prices for energy [P_E] from NPC can be adjusted to reflect REC system losses [L] and a set of marginal energy prices developed for use in defining TOD marginal cost-based rates.

$$MP_E = P_E/(1+L)$$

$$\left.\begin{aligned} MP_{PK} &= MP_E + SMCC \\ MP_{OPK} &= MP_E \end{aligned}\right\}$$

Marginal Cost Electric Rates at Peak (PK) and Off-Peak (OPK)

(f) For residential and other small consumers for whom metering costs do not justify TOD marginal cost rates, an average price for electric power needs to be developed. The easiest approach would be to complete the above steps and calculations, using the appropriate coincident load factor for the new consumer group (e.g., residential consumers). The percentage of kWh consumption pertaining to the consumer group that falls in the various costing periods could then be computed and used to weight the different marginal prices in deriving a cost-based average price [AP].

$$AP = \frac{MP_{PK} * H_{PK}}{8,760} + \frac{MP_{OPK} * H_{OPK}}{8,760}$$

(g) The existing guidelines for pricing include a provision to recover the cost of interest on loans. The proposed approach makes this provision unnecessary as it focusses on the collection of revenues sufficient to recover the REC's investment in its distribution system, thus providing for future investment including financing costs. A numerical example is provided in Annex 4.05.

4.20 The application of the proposed pricing formula in setting REC rates will involve rate changes that would be determined on a case-by-case basis. Some RECs may retain their rates at present levels, while others may need to make adjustments upwards or downwards. Whether NPC actually introduces marginal cost-based rates - and if so, at what pace - will have an important impact on the future level of retail rates.

4.21 The case of Tarlac II provides an example for the Luzon grid of the relationship between the approach NPC takes in applying marginal cost pricing and an REC's application of the proposed pricing formula to derive residential rates (para. 4.17). If NPC implements average-cost pricing with appropriate adjustments from the present price (to about ₱ 1.30/kWh), and the REC applies the proposed pricing formula, then the average of the various REC charges would be roughly compatible with the current average calculated cost. However, the rate for a residential consumer with the bulk of consumption at system peak would be close to ₱ 2.00/kWh, as compared to the present rate of ₱ 1.78/kWh. Assuming that NPC implements full marginal cost pricing with TOD differentiation immediately and also that the REC applies the proposed formula, the average of the various REC charges is still about equivalent to current average rates. However, in this scenario, the residential consumer would pay closer to ₱ 2.50/kWh, as he would bear both the NPC and REC peak costs. A third scenario, which assumes that NPC does not change its bulk rate to the REC but that the REC applies the proposed formula, would result in a decrease in the average REC rate; but the residential consumer would continue to pay at the current rate level and bear the REC's peak cost. The smoothest transition to more efficient rate structures, therefore, would appear to be a gradual move of NPC to marginal cost-based rates, combined with an adoption of the proposed formula by the RECs.

F. Operating and Customer-Related Costs

4.22 Apart from consumption-related costs, the RECs incur costs attributable to the connection and administration of individual consumer accounts. Some of these costs are captured by the existing indicators for assessing the financial performance of the RECs, which are presented in Table 4.5:

Table 4.5: PERFORMANCE INDICATORS FOR THE RECs

Financial Indicator	Standard	Actual Calculation Method
(a) Cost of Power / Operating Revenue	50% - 65%	Average Power Cost / Average Price
(b) Operating Expense / Operating Revenue	5% - 7%	Average Operating Cost / Average Price
(c) Maintenance Expense / Operating Revenue	5% - 8%	Average Maintenance Cost / Average Price
(d) Cons. Acct. Expense / Operating Revenue	3% - 5%	Average Customer Expense / Average Price
(e) Adm. & Gen. Expense / Operating Revenue	10% - 15%	Average Adm & Gen Expense / Average Price
(f) Total Operating Exp / Operating Revenue	90% - 95%	Average Operating Exp / Average Price
(g) Net Margin	5% - 10%	1.0 - (f)

4.23 These indicators may yield somewhat misleading results because of the effect of scaling cost information by the average selling price of electricity. Whereas the average cost per kWh for an item would reveal any abnormal differences from a standard, the ratio of this cost to the selling price may not. For example, where the average price is high, the ratio of average administrative and general expenses per kWh to average price may not be large. Annex 4.06 presents comparisons indicating precisely this result. In the extreme case of Masbate, administrative expenses per kWh are ₱ 0.90 kWh, well above the average; in contrast, scaled according to average price, the ratio is 0.19, or only somewhat higher than the desirable range. This latter ratio is in fact lower than the corresponding figure for Camarines Sur I; even though the administrative expenses per kWh for Camarines Sur I (₱ 0.375/kWh) is almost one third of that for Masbate.

4.24 Clearly, customer account expenses should be compared on a per customer basis, and operations and maintenance expenses should be considered per km of line. At the same time, NEA should try to identify the pro-

portion of administrative and general expenses that varies with number of customers and the proportions that might vary with kWh sales and other characteristics of REC operations. Appropriate scaling of these costs would lead to an improved basis for cost comparison. Customer costs and administrative expenses that are related to the number of customers served by the system should not be included in pricing on a per kWh basis; rather, they should be covered as part of a fixed charge on customer's bills.

4.25 The following paragraphs attempt to evaluate cost components not directly attributable to sales volume. For purposes of analysis, and to eliminate the direct effect of system losses on efficiency, a sample of 47 RECs were identified based on the single criterion that energy losses were less than 20% in 1987 (Annex 4.07).

4.26 Comparison of administrative expenses on a per customer basis shows that a reasonable number of RECs are keeping these expenses within a narrow range. In a number of cases, administrative costs per customer are low when, at the same time, those same costs per kWh are high. In these cases, the RECs' price of electricity is also high, and the consequent kWh usage per customer is low; this leads to a high ratio of administrative costs per kWh, even though these expenses would be modest on a per customer basis. To avoid misleading judgments, performance indicators should measure administrative costs on a per consumer basis.

4.27 The current variation in the difference between the price paid by consumers and the sum of (i) energy and (ii) operation and maintenance expenses per kWh appears unjustifiably large. Only in some cases does the difference reflect the extent of the customer and administrative costs; in many other cases, that difference is not related to identifiable overhead expenditures. Preliminary estimates indicate that, for an efficient REC with about 20,000 consumers, the spread over the cost of purchasing energy from NPC (adjusted for cooperative losses) needed by the REC should be about ₱ 0.50. A spread on that order should be sufficient to provide the REC with revenue to cover all of its expenses, including an allowance for recovering the cost of its investment in the distribution system. In a number of RECs, the members are already paying a price that approximates the cost of purchasing power from NPC plus ₱ 0.50. Other RECs, however, show an unexplained spread that is much larger, and may be attributable to either special circumstances or inefficiency (Annex 4.07).

4.28 NEA has proposed (November 27, 1987) some standards for REC expenses, which are shown in Table 4.6:

Table 4.6: STANDARDS FOR REC EXPENSES

Category of Expense	Proposed Standard
Distribution Expenses:	₱ 112 - ₱ 168 per km. of line
Customer Account Expenses	₱ 4.80 to ₱ 7.20 per customer
Administrative and General Expenses	₱ 0.089 kWh to ₱ 0.276 per kWh, depending on sales range

4.29 Annex 4.07 indicates that, in many cases, the RECs' costs are outside the standards shown in Table 4.6. In 30 of 47 cases, actual customer account expenses exceed ₱ 7.20 per customer; and, in 10 of the 47 RECs, those expenses are below the range given in the standards. In addition, administrative and general expenses per kWh in 15 of the 47 RECs exceed the upper end of the range given in the standards. NEA should (i) focus carefully on a thorough evaluation of the RECs' customer-related and other administrative costs, and establish clearly monitorable benchmarks for costs per consumer and costs per km of line; and (ii) introduce a fixed charge per consumer to recover costs not directly attributable to sales volume.

G. Other Pricing Issues

Affordability and Price Elasticity

4.30 A pricing policy cannot be developed without considering the likely response of consumers to pricing decisions. When the pricing policy involves reflecting in the rate structure the higher cost of serving peak usage, the response of large consumers comprising the peak needs to be considered. Peak-load pricing based on marginal costs could, if implemented at the projected prices, lead to a reduction in peak demand; in some cases, peak-load pricing could lead to some shifting of the peak. The same sample of 47 RECs was used to investigate these issues. Annex 4.08 presents the information collected for these RECs on (i) number of customers, (ii) kWh consumption, (iii) per customer kWh consumption, and (iv) price paid. In addition, system peak data were also collected for the 40 RECs (out of the 47) for which such data were available.

4.31 The relationships between (i) price and per customer kWh consumption and (ii) price and peak demand, indicate that peak demand is more price elastic than average kWh usage. This result implies that cost-based TOD rates should initially be implemented only gradually. Customer responses should be monitored and the marginal cost analysis repeated. Several iterations of this process might be needed before stabilization is reached.

4.32 The analysis here did not include data on income levels, which would explain some of the variation in electricity consumption. However, a rough estimate of price elasticity indicates that electricity demand appears to be related to price levels. The rate levels at which customer usage begins to increase significantly can be observed easily from the results of the analysis illustrated in Annex 4.08. This level appears to lie at around ₱ 2.50/kWh. At prices below this range, consumption increases strongly. Therefore, at current REC rate levels, electricity appears to be affordable to the average rural consumer.

4.33 In a sample consumer survey conducted by NEA, households without electricity were found to spend typically about ₱ 60 per month for kerosene for lighting, and a further ₱ 30 per month for purchases and repairs of kerosene lighting equipment. In comparison, the typical monthly elec-

tricity bill for a rural household is about ₱ 20-60. Only higher-income households with electric appliances incur bills of more than ₱ 100 per month. If the annuitized cost of housewiring is added to the cost of electricity, the total cost of power use amounts to about ₱ 50-90, somewhat below the cost of kerosene lighting. Both forms of lighting cost a Luzon farmer about 9-14% of average annual income, with electricity at the cheaper end of the range. Respondents in the survey indicated longer lighting hours with electricity as compared to kerosene, a reflection of the cost incurred. On the whole, affordability of electricity supply appears to be an issue only at the lower margin of the income range of current consumers, as long as the inefficiencies of poorly performing RECs do not push rates beyond levels where consumer resistance begins to be felt.

Pilferage

4.34 Penalties that would induce consumers to help the REC police losses due to pilferage should be included in the tariff. Two alternative approaches to this problem might be considered. Both involve installing meters at the transformer to record actual electricity supply to each section of the REC's service area. If metered electric supply, adjusted for expected line losses, were to exceed reported electric usage by all consumers down the line, the REC might introduce a fixed charge (identified as a temporary rate adjustment) to recover from all customers in that section the cost of lost power. The customers in the section would be advised that if they could police or otherwise identify the pilferers - thereby significantly reducing the pilferage - the fixed charge would disappear. Alternatively, rates (fixed charge or marginal price) could be adjusted automatically to recover expected pilferage; if pilferage were reduced below the recovered level, the consumers could receive a discount or rebate on subsequent bills.

Regulation

4.35 The implementation, monitoring, and regulation of the proposed pricing principles for the RECs require, even more so than the current guidelines, specialized knowledge and administrative methods that are substantially different from those used in the regulation of orthodox private sector rate setting. The non-profit nature of the RECs combined with the marginalist approach to pricing call for regulation by an authority which is intimately involved in rural electrification, such as NEA. This contravenes the current proposal to transfer all regulatory responsibility for the RECs from NEA to ERB. A full transfer of the regulation over REC pricing would burden ERB with a large number of small and frequent rate cases, and would require that ERB adopt a "two-track" approach to rate regulation; one methodology would be applicable to the private utilities, while a second different methodology would be applied to REC pricing. Instead, NEA should retain the responsibility for day-to-day REC regulation and ERB should audit and supervise NEA's regulatory activities. This combined approach would ensure the consistent application of energy sector regulatory principles, while the detailed evaluation of REC rates would be performed by NEA, the authority with the comparative advantage.

4.36 From NEA's perspective, intensive supervision of the principles and practice of REC rate setting is an essential element of its core function as an "interested lender" for rural distribution systems. This function implies that NEA should have an ongoing interaction regarding the full scope of REC activities, including operations, investment planning, cost recovery, and financing requirements. The monitoring of retail pricing and the guiding of REC price levels and structures are integral parts of NEA's role as the agency responsible for ensuring that scarce investment funds are channelled into economically viable rural electric investments.

H. Summary of Pricing Principles

4.37 Based on the cost and price analyses conducted, a number of pricing principles that would encourage efficiency can be developed. For wholesale pricing by NPC, the following principles should be considered:

(a) Implement LRMC pricing on a TOD basis nationwide.

(b) For Luzon, consider seasonal pricing using loss-of-load probabilities to associate marginal costs with pricing periods.

(c) Move in stages to marginal cost prices. Evaluate a partial adjustment to such prices after receiving the results of a year's experience. Rework the marginal cost analysis to project the target for marginal cost prices. If full marginal cost prices cannot be implemented fully, prices should at least reflect differences in marginal costs - such as differentiating between pricing periods and service voltage levels.

(d) Avoid subsidized prices where possible. If subsidies are needed, they should be transparent transfers and not tied to pricing. If prices must be subsidized, the real price should be quoted and the subsidized price should be treated as a temporary adjustment to the real price. In the case of currently subsidized island RECs, any temporary subsidy of this kind could involve a form of inverted bulk rate schedule (the lifeline rate concept). Specifically, the price per kWh for a basic block of consumption should be reduced. The price for all additional consumption should then be set at the marginal cost or full price. Optimally, however, the subsidy should be in the form of a lump sum transfer to the REC to cover the gap between the true cost of supply and the retail rate ceiling.

4.38 The RECs should observe the following pricing principles:

(a) Marginal cost-based prices should be developed for commercial and industrial consumers. A capacity charge (related to kW) and a consumption charge (related to kWh) should be developed to recover sales volume related costs, while customer related costs should be recovered through a fixed charge. The RECs appear to have a demand peak from around 5 p.m. until 11 p.m. each day. This demand peak establishes and drives each REC's distribution capacity. Since distribution capacity must be designed to meet the peak demand, investment costs should be associated with the peak period - leading to a capacity charge and a marginal price for the peak period that is higher than for other costing periods. At the same time, NPC's marginal cost pricing of electricity to the RECs should lead to prices that are different based on the time-of-day and, in Luzon, on the season. REC prices should reflect these rate differences where possible, especially for large commercial and industrial customers where the benefits of TOD metering justify the costs. In Luzon, seasonal rate differences could be reflected in rates for all customers, as no additional metering would be required.

(b) Adjustment toward marginal cost pricing should take place in stages. A first step might involve the use of simple temporary formulae, introducing price differences of about 20-40% to reflect the higher costs of providing supplies at lower service voltage levels or during peak periods. The extent to which customers would respond to rate changes and peak switching would occur needs to be ascertained before rate differentials become too substantial. The experience of each tariff adjustment needs to be monitored and evaluated after a reasonable period of time. After the evaluation, marginal costs should be recalculated and pricing targets reviewed. Throughout this process, whatever formulae are used should be kept as simple as possible to enable the RECs to apply them effectively.

(c) As LRMC prices are unlikely to be economically implemented for residential consumers, an appropriate strategy of average cost pricing should be designed. This involves (i) developing a fair value for the REC's investment in its distribution system, (ii) selecting an appropriate discount rate, (iii) calculating a carrying charge, (iv) annualizing distribution system investment costs, and (v) spreading these costs together with other operating and power purchase costs over kWh usage. Selecting a discount rate and determining an appropriate, annualized distribution system investment costs introduce a cost component for enabling the REC to recover the cost of its investments.

(d) Customer account costs and administrative and general expenses should be delinked from kWh sales. Customer account costs and some administrative and general expenses do not vary with kWh sales. These costs and any investment expenditures for consumer connections, such as metering and drop lines to meters, should be recovered through a fixed monthly or bi-monthly consumer charge.

(e) REC consumers should not be penalized because the REC is being run inefficiently. The available data for the sample of RECs that have low system losses indicates that their costs per kWh or per customer vary widely from one REC to the next. A serious review is needed to determine acceptable ranges for these costs and remedial procedures to correct sizeable deviations from those acceptable ranges.

(f) Pilferage should be discouraged by introducing group metering with penalties for exceeding reasonable loss levels.

(g) The day-to-day activities of regulating the RECs should remain with NEA, and ERB could exercise general supervision over the process.

5. THE RURAL ELECTRIC COOPERATIVES

A. Introduction

5.1 The RECs cannot be viewed as an electricity distribution monolith. The character and performance of the RECs differ greatly from region to region; even within a region, the individual RECs differ markedly from one another. In addition, the performance of RECs in the three major geographic areas - Luzon, the Visayas, and Mindanao - show clear differences.

5.2 Many RECs face financial constraints that have given rise to or exacerbated a host of operational and institutional problems. On the operational side, system losses currently account for 25% of power available for distribution in rural areas and are the second largest "consumer" of REC-supplied electricity (Annex 5.01). The institutional problems include: (i) politicization of REC Board members and general managers; (ii) a shortage of skilled, motivated REC general and line managers; (iii) inadequate will to enforce collection of bills or to disconnect non-paying customers; and (iv) pressure to tolerate pilferage of electricity. Past studies conducted by NEA suggest that these institutional problems are most pervasive among the Luzon RECs; this conclusion was confirmed by field studies undertaken by consultants for USAID. RECs in certain areas also suffer some serious environmental problems, most notably periodic, devastating typhoons. The havoc they wreak is exacerbated by the lack of funds to rebuild damaged systems. This is particularly true among the RECs in southern Luzon and in the Visayas.

5.3 Although efforts were made in the early years to provide the RECs with rational franchise areas that had similar prospects for growth, economic development favored certain locales; moreover, the subdivision of RECs for reasons of political patronage created clusters of irrationally defined RECs from what had previously been rational franchises. Thus, the RECs range in size from the Central Pangasinan Electric Cooperative in Luzon, with 77,000 consumers, to the Siargao Electric Cooperative in Mindanao, with just 414 consumers. Annex 5.02 ranks the 25 largest and smallest RECs, classified according to the number of customers. Where the RECs either serve customer bases that are too small or franchise areas that were not developed according to rational financial or economic criteria, prospects for profitable operations are poor.

B. Financial Condition

Aggregate Financial Results

5.4 In the aggregate, the RECs are in a highly precarious financial condition. For the year ended December 31, 1987, the RECs recorded aggregate net financial losses totalling ₱ 21.6 million (Annex 5.03) and cumulative deficits ₱ 472 million. If the RECs had used certain accepted commercial accounting practices[1/], their performance would have been worse. When considered in the aggregate, the problem of financial losses appears pervasive; however, an analysis of data for individual RECs indicates that a minority of RECs with excessively poor financial performance contribute disproportionately to the combined financial losses. Annex 5.04 provides a complete listing of the 1987 net results, shown in inverse order of performance for those 114 RECs that reported their 1987 operating results to NEA. As the annex shows, the instances of significantly poor performance are concentrated among (i) a few, relatively large RECs in Luzon and (ii) those smaller RECs operating in remote areas.

5.5 Even the most viable RECs do not generate sufficient revenues from operations to enable self-financing of some investment for rehabilitation of existing systems or for expansion. Because of the weak operating results of the RECs, planned maintenance has largely been deferred. In addition, the depressed economy of the early to mid 1980s constrained NEA from providing the RECs with financing needed to maintain, restore, or expand their systems. Domestic private credit institutions have not been active participants in the sector, and their involvement has been limited to short term working capital advances to very few RECs. As a result, many REC systems are deteriorating for lack of funding.

5.6 An outline of the RECs' consolidated balance sheet for the years 1985-87 is presented in Annex 5.05, and summarized in Table 5.1. While a detailed analysis of the aggregate results must be qualified to take account of the important differences between the RECs, these highlights indicate the fundamental weakness, common to all RECs, that limits their prospects of becoming financially viable - namely, their nearly complete lack of equity capital. Membership-contributed capital, which in 1987 represented just 0.2% of aggregate REC assets, is limited by law to a token contribution of ₱ 5 per member. Thus, the RECs are condemned by law to being capitalized entirely with borrowed funds.

1/ Including: (i) making adequate provision for uncollectible consumer accounts; (ii) making timely close outs of completed construction work in process, thereby increasing the annual provision for depreciation, and (iii) taking write offs for unusable generating equipment.

Table 5.1: CONSOLIDATED BALANCE SHEET FOR THE RECs, 1985-87
(₱ Million)

Years Ended December 31	1985	1986	1987
Assets:			
Net Utility Plant	3,094	3,229	3,650
Other Fixed Assets	49	52	69
Current Assets	1,573	1,647	1,760
Deferred Charges	954	966	1,004
Total Assets	5,669	5,894	6,483
Liabilities and Equity:			
Membership Contributions	13	14	15
Cum. Deficit & Other	(308)	(347)	(449)
Total Equity	(295)	(333)	(434)
Long Term Liabilities	4,493	4,550	4,873
Current Liabilities	1,362	1,530	1,863
Deferred Credits	109	147	181
Total Liabilities and Equity	5,669	5,894	6,483

5.7 The low paid-in capital combined in many instances with cumulative deficits leaves many RECs with negative equity. Even in those regions where the RECs have been able to amass modest retained earnings, the debt/equity ratios are much higher than normal distribution utility practice; in Region 12, where the RECs collectively are the best financial performers, the recorded combined debt/equity ratio is 4.2, with all other Regions reporting significantly worse ratios. If the RECs were to recognize as debt payable the loan amounts carried on NEA's books, these capitalization ratios would be significantly worse. Furthermore, the gap between what NEA reports as having been lent to the RECs and what the RECs record as having been borrowed from NEA, which was ₱ 2.2 billion as of December 31, 1987, is large and growing year by year (Annex 5.06).

5.8 Cash represents just 5% of the RECs' total current assets for 1987. On an aggregate basis, the RECs' current ratio has declined from 1.15 in 1985 to 0.94 in 1987. Their reported cumulative deficit is large, and growing. Asset values assigned to alternative generation equipment have questionable validity; and, based on past experience, the liabilities associated with them are not likely to be honored (para. 6.15). Many of the poorly performing RECs have displayed a notable reluctance to collect overdue consumer bills; and, in the absence of a comprehensive collection effort, substantial write-offs of consumer balances seem warranted. Given the extent of these problems, the RECs' generally dreary financial condi-

tion is not likely to be reversed by independent action; a comprehensive, Government-supported restructuring effort will be necessary.

Comparison of REC Performance by Area and Region

5.9 NEA has developed a rating system for the RECs, which includes the assignment of weighted points for, inter alia, such factors as (i) prompt payment of NPC charges, (ii) prompt payment of amortization to NEA, (iii) collection efficiency, (iv) control of line losses, (v) number of consumer connections and (vi) cost control. The points are compiled annually, based on the REC's performance during the year just completed. The total of points awarded determines whether the REC is classified as A, B, C, or D, with A denoting the best category of performance[2/]. Of the 114 RECs that submitted results for 1987 to NEA, 27% were classed in the worst (D) category, while only 19% received "A" ratings. Of the 31 "D" rated RECs, 25 (or 80%) were from Luzon; in contrast, of the 46 RECs that were rated "A" or "B", 11 (or 24%) were from Luzon. While only two (3.7%) of Luzon's 54 RECs were rated "A", eight (26%) of the 31 Visayas' RECs and 12 (41%) of Mindanao's 29 RECs received the best ratings. Table 5.2 summarizes the classification of RECs by area; Annex 5.07 shows these regional differences in performance graphically.

Table 5.2: CLASSIFICATION OF RECs BY AREA
(as of December 31, 1987)

Area	A	B	C	D	Total
Luzon	2	9	18	25	54
Visayas	8	6	14	3	31
Mindanao	12	9	5	3	29
Total	22	24	37	31	114

5.10 The RECs' cost profiles also differ markedly from one geographic region to the next. Annex 5.08 shows the aggregate cost profiles for the RECs operating in the three primary geographic areas; in addition, that Annex compares the cost structures of the RECs operating within a geographic region with the other distribution utilities operating in the same area. This analysis indicates that the Mindanao RECs should have the best prospects for profitability given that the rate they pay for their power purchases from NPC is only ₱ 0.57/kWh and that their other constituent costs are at or below the costs recorded in the other regions. While the cost structures of the Luzon and Visayas RECs appear roughly comparable, the high self-generation and administrative costs faced by the small remote island RECs in the Visayas distorts the aggregate cost profile for the

2/ Among other uses, NEA bases its guidelines for compensation of REC Board Members on this classification.

group. Adjusting for those two factors, the Luzon and Visayas RECs have similar cost constituents, with the difference in their cost structures being the price they pay for purchasing power from NPC.

5.11 From a Region perspective, the vast majority of RECs' in poor financial straits are in Regions 3, 4, 5, 8 and 9. Regions 3, 4, and 5, which take in large areas of central and southern Luzon, contain some of the most prosperous, densely populated rural areas in the Philippines. The financially troubled RECs that provide service to these areas generally show system losses that are higher than the average of 25%, and high interest expenses. These apparently inconsistent results denote high investments in low-return projects combined with deteriorating core systems. In addition, the high level of administrative costs despite the sizeable numbers of consumers indicates that their managements are not controlling costs effectively. In general, these RECs have managerial problems, and not inherently uneconomic franchise areas. In contrast, some of the financially troubled RECs in Regions 4 and 5, as well as most of the poor performers in Regions 8 and 9 serve small, remote islands with sparse populations. In general, they are characterized by low losses and high power costs. This indicates that these RECs have franchise areas that are inherently expensive to serve; the high cost of service so overwhelms other cost data that no judgement can be made as to the effectiveness of these RECs' management. In general, about 25-30 RECs appear to be in financial difficulty because they have franchise areas that are too costly to serve; they appear to be serving small Visayan islands or mountainous, sparsely populated areas in Luzon, Mindanao, and Samar. In turn, about 40-45 RECs appear to be in financial difficulty because of weak management; those RECs are concentrated mostly in central and southern Luzon.

Comparison of RECs with Investor-Owned Utilities

5.12 Comparing the RECs' cost structures on a ₱/Kwh basis with those of other distribution utilities in their geographic regions, indicates that the RECs compare unfavorably with the investor-owned utilities. In general, this is because the investor owned utilities enjoy service areas with a more lucrative economic base and greater population density than those served by the RECs; as a result, they have a greater sales volume over which to spread their fixed costs. In Luzon, MERALCO's distribution cost is about 67%, while its administrative costs are about 58% those of being realized by the RECs. In addition, the RECs' systems losses are proportionally much worse than MERALCO's. Distribution costs of the other investor-owned utilities in Luzon are only about 42% of those of the RECs. Comparisons of the cost structures of the Visayas and Mindanao RECs with investor owned utilities in those areas indicate results similar to those recorded for Luzon. Surprisingly, in the one area where a REC and an investor-owned utility compete directly on similar footing (La Union Province in northern Luzon), the REC sells its energy at lower cost and provides more reliable service.

5.13 Despite the more favorable cost structures of the investor owned utilities and the statistical evidence that they are more efficient than the RECs in the aggregate, the cooperative system continues to be an

appropriate medium for providing electricity distribution services in the rural areas of the Philippines. The only failing REC franchise that has been attractive to an investor-owned utility management company has been the Benguet Electric Cooperative (BENECO), which serves the important resort city of Baguio and some significant outlying industrial users (mining companies). Otherwise, investor-owned utility management companies have not been willing, even when invited to do so on a contractual basis, to assume control over the operations of more characteristically rural networks. Despite their weak financial and operational performance as a group, many RECs have served successfully as engines for considerable economic development in rural areas, often in the face of daunting constraints. The RECs have taken responsibility for and extended the service of investor-owned utilities that virtually abandoned their franchises in the early 1970s, and RECs have extended service to previously non-electrified large areas. In the process, the RECs have brought service to about 50% of rural households.

C. Institutional Structure and Management

5.14 While the cooperative system as a group has not performed well, nearly 40% of the RECs have been successful in developing and operating their systems. Moreover, the concentration of poor performers among the RECs of central and southern Luzon and the small remote islands of the Visayas indicates that some of the problems are more institutional than systemic. Therefore, institutional improvement in the sector is more likely to flow from (i) generalizing the factors that have contributed to the success of the well managed RECs and (ii) replicating these factors in the less effective RECs. In addition, special programs can be developed to address special conditions that contribute to the weak performance of blocks of RECs with unusual common characteristics. The NPC-NEA subsidy program that addresses substantially the structural weakness of remote island RECs is just such a program.

Role of NEA

5.15 NEA's performance as the sector's core institution and its impact on the RECs is discussed at length in Chapter 6. Over the years, NEA's initial collegial relationship with the RECs has been severely strained. The RECs' poor financial performance has resulted in widespread defaults on their loans to NEA; in turn, NEA has at times taken over the management of some poorly-performing RECs, but without producing salutary results. This latter concern has been highlighted in the course of a recent program to refinance the most substantial of REC arrears to NPC.

5.16 In August 1988, under a Relending Program implemented in conjunction with a larger program to restructure NPC, NEA received ₱ 500 million in equity to provide 21 RECs with 7% medium-term loans to refinance their significant arrearages to NPC. While the transactions were structured so that the cash would flow to NPC and not to NEA or the RECs, the RECs' remittances of principal and interest associated with these loans

would ultimately provide NEA with a source of funds. NEA selected ten RECs to participate under Part 1 of the Program and 11 other RECs to participate under Part 2. The two Parts to the Program differed significantly in one respect: the General Managers and Boards of the ten Part 1 RECs retained their jobs and received only advisory assistance from an NEA appointee, but the General Managers and Boards of the Part 2 RECs were effectively disenfranchised -- the General Manager was discharged and replaced by an NEA appointee and the Boards were retained only in an advisory capacity. As regards both Parts of the Program, NEA committed that it would not participate in the day-to-day management of the RECs for more than two years.

5.17 Since the outset of the Relending Program, the operations of the 10 Part 1 cooperatives have improved significantly while those of the Part 2 participants have not improved and in some cases have even deteriorated. As clear evidence of this anomaly, the Part 1 RECs currently are realizing a loan repayment rate of about 80% while the loan repayment rate of the Part 2 RECs is only 27%. As of February 1989, the General Managers of 43 RECs (including those in Part 2 of the Relending Program) were NEA appointees (Annex 5.09). Too often, these appointees have had inadequate training or prior experience in managing troubled organizations and as a result they have largely not succeeded in bringing about the promised performance improvements. These experiences indicate that NEA's involvement in the RECs' day-to-day affairs will not automatically lead to improved performance.

5.18 NEA is not in the utility management business but rather in the lending business. Instead of assuming management responsibilities, NEA can and should regulate the practices that have contributed to the weakness of poorly performing RECs by tying the financing of their investments directly to the adoption of reforms. When a failing REC will not reform and continually fails to meet its obligations either to NPC for wholesale power or to NEA for debt service, NEA should assume control over the franchise in the manner of a receiver and seek proposals for the future operation of the system from all potentially interested parties - including adjacent RECs, investor-owned utility management companies, and new groups from within the bankrupt REC's franchise area - and not simply attempt to regenerate the same REC with potentially the same Board and management. This process should begin as soon as NEA takes control of a REC. The Board members and General Manager of any REC that submits to this form of receivership should be disqualified from future participation in the affairs of the franchise.

5.19 Political considerations have, in the past, had a distortionary effect on NEA's lending operations. Annex 5.10, which was prepared from NEA's records, shows annual loan releases to the RECs from inception through 1988. If the ₱ 500 million Relending Program is excluded from consideration, the graph shows a dramatic burst of loan releases in 1986. The politicization indicated by this pattern of lending remains a dominant factor in investment decision-making. While the restructuring of some RECs' loans, particularly those that were advanced for politically motivated non-economic activities, would provide some financial relief, the impact would be immediate and non-continuous. The best approach to limiting the deleterious impact of politicization on investment decision-making in the future would be for NEA to reorient its support only to economically justified investments.

Role of REC Boards of Directors

5.20 As provided in PD 269, the business of a REC is managed by a Board of not less than five directors, each of whom is a member of the REC. Directors are elected by the consumer members and serve terms as specified in the REC's by-laws. The officers of a REC - its president, vice-president, secretary and treasurer - are elected annually from among the Board members; however, also according to PD 269, the officers and Board members serve as a policy making body while day-to-day operations and management is vested in the REC's General Manager and staff. This organization structure follows closely the U.S. model for RECs.

5.21 In certain of the poorer performing RECs, particularly those of central and southern Luzon, the boards and their members are heavily immersed in the day-to-day affairs of the cooperative. In some cases, this has served to undermine the authority of the General Manager; in other instances, it has led to open squabbling between the General Managers and the Board members. As a result of the confusion at the top of the organization structure and the multiple lines of authority implied by that confusion, necessary discipline within the REC's organization and among its members has broken down. In most cases, the excessive involvement of Board members in the REC's affairs has led to widespread abuse of perquisites and strong indications of corruption. All too frequently, Board seats have been used as opportunities to expand personal influence through patronage. As a result, Board elections have been marked by excessively lavish campaigns and violence at the polls. In general, in the Philippines, the RECs that function effectively have strong General Managers who enjoy the respect of their Boards. In contrast, RECs with General Managers who are dominated by activist Boards often suffer from politicization, which creates major distractions and drains scarce REC resources.

5.22 Two of the major problems confronting many RECs are past due consumer receivables and the proliferation of illegal connections. Each REC has established a policy of prompt disconnection for non-payment, as well as procedures for the detection, disconnection and prosecution of pilferers of electricity. These two problems are not, in theory, difficult to address under the existing policy framework. However, the impact of these problems on the performance of financially-troubled RECs, where the abuses have become widespread and the perpetrators are influential in the community, has been highly deleterious. In certain RECs, the Boards themselves have apparently succumbed to pressures to tolerate these abuses and have blocked the implementation of necessary remedial action. As the RECs operate within narrow financial margins under even the best of circumstances, financial viability cannot be attained if basic commercial practices, such as collection of sales revenue for all power consumed, are not fully supported by the RECs' Boards of Directors.

5.23 An elected Board representing the interests of consumer members is the fundamental characteristic that distinguishes cooperatives from other types of enterprises. Therefore, any deviation from the primacy of the freely-elected Board would imply a disenfranchisement of the REC's members,

and must be approached carefully. Still, because of the host of instances where politicization at the Board level has led to blatant patterns of abuse that have been harmful to the operational effectiveness of the RECs, any program for their institutional rehabilitation must include careful consideration of the appropriate role for the Board and checks on the activities of its members. A proposed change to the NEA charter that would give the NEA Administrator the right to appoint all REC Board members has potential to address this issue of politicization at the local level; however, it would effectively disenfranchise the cooperatives' members and thereby alter the fundamental character of the RECs. Instead, the Government should consider an amendment to PD 269 that restructures REC Boards so that a majority of members would be non-elected. These members, some of whom would acquire their seats either by appointment or by virtue of their positions in the community, could be expected to be responsive to the needs of the public. In addition, elected Board members would serve a fixed term of between two and four years (to be fixed in the REC's by-laws) and thereafter be ineligible to serve that REC either as a Board member or as General Manager. NEA has developed sound and adequate guidelines to govern the conduct of REC Boards and their members. These guidelines currently are not being enforced; NEA should consequently attach conditionality on future loans to the RECs to enforce the guidelines.

Role of REC Managers

5.24 The successful operation of an REC demands not only a competent, experienced General Manager but often also a strong individual with character and courage. Intrusive Board members, consumers long accustomed to REC tolerance of non-payment and pilferage, and an uncertain peace and order situation in many areas present difficult challenges to even seasoned managers. While the General Managers have the pivotal jobs, each REC also needs adequately skilled line managers; however, an informal management inventory performed by NEA in connection with this study indicates that their ranks are spread thin. Compounding this perceived dearth of management talent is the low pay scales in effect at most RECs. Considering how little they can offer and their remoteness from the larger centers of economic activity, the RECs have difficulty in attracting capable managers and still greater difficulty in retaining them. Many managers and technical personnel who were attracted to the rural electrification program during the period of rapid expansion have left to pursue more rewarding opportunities. The pay scales of the RECs should therefore be adjusted to enable them to attract and retain the necessary quantity and quality of managers.

D. Guidelines for Restructuring the RECs

5.25 The RECs' problems are not intrinsic to their organization as cooperatives. This conclusion is supported by (i) the mass failure in the early 1970s of investor-owned utilities that served provincial cities and towns, directly accelerating the growth of the cooperative system; (ii) the disinterest of investor-owned utility management companies in taking over the operations of failing REC franchises; and (iii) the concentration of

financially-troubled RECs in areas where the core systems are in severe disrepair and institutional problems are pervasive (as in central and southern Luzon), or where high self-generation and administrative costs undermine financial viability (as in the small, remote islands of the Visayas). The RECs' operational and financial performance is therefore more likely to be improved by launching programs to address the problems crippling the system rather than by developing new organizational arrangements. The action programs suggested under the REMP to correct operational constraints and the revised pricing policy proposed in Chapter 4 should both contribute to improvements to the RECs' financial performance. These initiatives should be complemented by institutional reforms.

5.26 As indicated above, the RECs are experiencing serious financial difficulties. They are (i) severely undercapitalized; (ii) lacking in prospects for good financial returns; (iii) over-burdened with responsibilities ancillary to their main function of providing electricity distribution services; (iv) distracted by politicization of their Boards and top managements; and (v) critically short of capable managers and skilled staff. While specific solutions for these problems can only be developed on a case-by-case basis, the following restructuring guidelines focus on measures that would have a system-wide beneficial impact.

Increase the RECs' Equity

(a) Increase Members' Equity Contributions. The RECs are uniformly undercapitalized. New consumers are required by law to pay only ₱ 5 to join the REC. This token payment is not only substantially below the cost to the REC of providing the member with service, but it is also so insignificant that the member perceives himself merely as a "customer" and not as an "owner" of the REC. The law that stipulates the RECs' membership fee needs to be amended so that the RECs can recover an equity contribution from consumers that (i) gives the members a greater stake in the REC's success, and (ii) better reflects the cost they impose on the system. One way of infusing new equity into the RECs would be to increase the membership fee substantially for all consumers. For example, raising the membership fee to ₱ 200 for all members (old as well as new) would provide the RECs with about ₱ 320 million in additional paid-in capital by 1995 (still not be enough to bring all Luzon and Visayas RECs back to positive net worth). In the long run, legislation that would also permit RECs to impose annual dues on their members is needed. In return for the additional fees, the RECs should be obliged to circulate an annual report to their members.

(b) Make Available Government Grants. As the RECs are not capable of raising the additional equity they need only through increasing membership fees, the Government needs to consider making available to the RECs some grants, especially to support (i) Government-sponsored extension of service to uneconomic areas, and (ii) relief from typhoon, earthquake, or other environmental damage. In effect, through widespread default on

amortization due to NEA, a number of RECs have de facto been helping themselves to "grants."

(c) Support for Non-Economic RECs. Certain remote and self-generating RECs have no hope of becoming financially viable. The Government and NEA will need to develop a program for providing financial relief to marginal RECs by (i) converting existing construction loans to equity, (ii) providing grant-financing for justifiable system expansion (para. 6.39), and (iii) supporting the NPC-NEA subsidy program for the fourteen RECs that cannot contain their costs below the ₱ 2.50/kWh retail price ceiling (para. 4.3). The debt to equity conversions imply the forgiveness of loans valued at about ₱ 1.1 billion.

Relief from Non-Performing Assets and Delinquent Loans

(d) Transfer of Alternative Generation Facilities. The RECs need relief from the burden of mini-hydro and dendro thermal generation facilities that either do not work or are superfluous to their day to day operations. In general, the RECs are not capable of bearing the cost for such facilities. The facilities that work, together with the corresponding liabilities, are slated to be transferred in the near future to NPC. As the Government spearheaded these alternative generation programs, it should absorb the responsibility for those liabilities that exceed the net asset value of facilities being transferred to NPC. This measure implies forgiving about ₱ 1.8 billion in loans to the RECs (para 6.26 (d)).

(e) Relief from Loans Pertaining to Social Programs. Similarly, the RECs need relief from the burden imposed by social programs that are not related to electricity distribution. In general, the RECs are not capable of supporting these programs. The extent of such loans to be forgiven has yet to be determined (para. 6.26 (e)).

(f) Rescheduling of Delinquent Construction Loans. RECs with substantial arrearages have clearly limited prospects of meeting their debt service obligations on time. NEA should develop and implement a program to reschedule previous, delinquent construction loans (para. 6.26 (f)). The arrears in principal and interest in question have an aggregate value of about ₱ 1 billion. NEA will need to determine, on a case-by-case basis, a schedule for each delinquent loan that takes account of each REC's financial prospects.

Improve the Manageability of the RECs

(g) Amend PD 269 to Depoliticize the REC Boards. The amended law should provide that (i) a majority of Board members be non-elected, chosen either on an ex-officio basis or by appointment of the NEA Administrator, and (ii) elected Board members serve a fixed term of two to four years, and thereafter be ineligible to serve the REC as a Board member or top level officer. NEA's current guidelines governing the conduct of REC Boards and their members are sound and need to be enforced through the use of conditionality on future NEA loans to the RECs.

(h) Consolidation of RECs. Shrinking the number of RECs can yield substantial savings in administrative and payroll costs. NEA should contain the proliferation of RECs by (i) curtailing the establishment of new RECs, (ii) reviewing the feasibility of consolidating adjacent RECs now participating in NEA's Relending Program, and (iii) developing incentives for well-functioning RECs to absorb adjacent REC franchises in receivership. Such incentives, which are meant to prevent the acquisition of a failing REC from becoming a resource drain on a successful REC's existing membership, could take the form of providing (i) special working capital loans, or (ii) grants to support needed economically-justifiable investments aimed at revitalizing the failing franchise. A broader consolidation program was considered and dropped for the time being out of concern that NEA could not enforce the dissolution of a REC that was not in receivership[3/]. As importantly, the main criterion for an effective consolidation is geographical contiguity of service areas, and very few poor performers are contiguous to good ones.

(i) Encourage Regionalization. NEA has initiated a program to develop field offices and appoint managers to oversee the combined operations of the RECs in an administrative Region. Although this effort is currently modest, it has potential for realizing some of the benefits of consolidation. Regionalization can be used to centralize services so that some increases in efficiency or reductions in overhead can be realized. Regionalization should therefore be supported as a salutary intermediate step toward a longer-term program of consolidations.

(j) Raise REC Pay Scales. This action is critically necessary to enable the RECs to attract and retain sufficient numbers of qualified managers.

3/ In one instance, NPC had cut the power to a REC for about two weeks and threatened a second cut in service for the next month before the REC reluctantly agreed to participate in Part 2 of the program.

Reorient the RECs' Investment Practices

(k) Redirect the RECs' Investments. For most of their history, the RECs have been encouraged to invest in extending their networks to reach more residential loads. In general, these investments yield marginal to unsatisfactory returns. The RECs should refocus their investments on projects that include (i) rehabilitation with add-on connections, and (ii) system expansion designed to capture productive loads. Moreover, the RECs should be provided with clear and transparent subsidies when pressed to implement marginal investments that are justifiable only on social or law and order grounds.

(l) Tighten NEA Supervision of Project Implementation. The RECs must accept that, as a financier concerned with the RECs' long-term financial welfare, NEA has a fiduciary responsibility to ensure that (i) the projects it finances are constructed efficiently, and (ii) the RECs are taking needed steps to improve their operating efficiency and financial performance. NEA needs to tighten its supervision procedures, and the RECs will need to agree to those procedures as a condition of borrowing. Moreover, the RECs may need to agree to conditionality concerning their operating and financial performance.

5.27 This restructuring program involves a substantial outlay of public funds; in order that this be a one-time event that succeeds in revitalizing the sector, the Government needs assurances that the RECs will discontinue the practices that gave rise to their serious financial problems. In particular, the effectiveness of the recommended measures (as well as the financial and economic prospects of the investment program developed in Chapter 3) presumes that the RECs will (i) curb their technical losses; (ii) take actions to identify and punish pilferers, and thereby reduce non-technical losses; (iii) improve their collection efficiency; (iv) revise their prices to cover the full cost of providing service; and (v) pay on time for their power purchases and debt service.

5.28 The primary beneficiaries of the program will be the 25 poorly performing RECs with inherently poor financial prospects (paras. 5.26 (c) and 6.26 (c), and Table 6.5), which will benefit greatly by having past construction loans cancelled; before the Government cancels these loans, each of these RECs should formulate and agree to implement measures to optimize their operational and financial performance. They should establish monitorable performance targets, and their eligibility for future borrowings from NEA should be predicated on meeting these targets.

5.29 The other major beneficiaries will be the 46 poorly performing RECs whose current distress results largely from mismanagement. Most of these RECs are clustered in central and southern Luzon (page 6 of Annex 5.03, and Annex 5.04), and have franchise areas that provide favorable financial and economic prospects. To enable these prospects to be realized in the future, many of their delinquent loans will need to be rescheduled (paras. 5.26 (f) and 6.26 (f)). They too must earn their relief by formulating and agreeing to implement operational and financial improvement pro-

grams. Their progress in realizing agreed performance targets should be monitored closely, and a chronic failure to realize those targets should result in the REC defaulting on its rescheduled loans. These RECs should be eligible for future loans from NEA only after showing clear evidence of sustainable improvements in performance.

5.30 Other RECs will benefit from the cancellation of loans for alternative generation (paras. 5.26 (d) and 6.26 (d)) and social programs (paras. 5.26 (e) and 6.26 (e)). However, since the related problems results from faulty Government policy and not from poor management, these RECs should not need to earn their relief by adopting specific institutional development programs.

5.31 The RECs that are performing poorly and will not agree to implement improvement measures should not be provided with relief under the restructuring program. They should be disconnected if they fail to make timely payments for power purchases; similarly, they should be declared in default if they fail to meet their debt service obligations to NEA on time. At that point, NEA's objective should be to transfer control of the failed REC's assets to the group proposing the best long-term plan for the future operation of the franchise.

6. THE NATIONAL ELECTRIFICATION ADMINISTRATION

A. Introduction

6.1 Following the change of Government in 1986, many Government agencies received special assistance to restructure their operations while NEA did not. Despite this lack of overt Government support, in 1987-88, NEA's Board recruited an energetic new leadership team that appears capable and interested in providing the agency with an appropriate focus. That team has already taken some bold steps to streamline the staff and introduce efficiency measures. However, these measures by themselves are not enough to make NEA function effectively as the sector's core agency. The organization needs a reorientation of its role and its operating perspectives, accompanied by a financial restructuring to put it on a "clean books" basis and a new financing strategy designed to meet the sector's future needs. This chapter discusses NEA's role, its institutional relationships, and its past and current financial position. Against this background, recommendations are made for (i) a financial restructuring of NEA, and (ii) a financing strategy for the sector, and (iii) organizational adjustments needed to enable NEA to refocus on its lending activities.

B. NEA's Role

6.2 NEA's existence as the core agency to direct the rural electrification this sector cannot be justified solely on the basis of its providing electrification support to the RECs. NPC, supplemented by the private sector, can provide many (though not all) of the required services. However, the uniquely specialized financial requirements of the RECs provide a compelling reason for NEA's continued existence as the sector's core agency, functioning primarily as an interested lender.

6.3 The RECs provide a service that is critical to the economic development of the areas within which they operate. By nature, their businesses are characterized by a need for heavy capital investment and lengthy cost recovery periods. Yet, few of them are financially viable and even fewer are credit worthy. Because of the thin economic base of most of their franchise areas, many RECs need to borrow at concessional rates and hope that the resultant economic development will be sufficient to enable them to afford market rates for financing subsequent increments of expansion. In the early stages of the rural electrification program, demand for service overwhelmed the funds available for investment; as electrification has increased, so has the need to optimize investment expenditures, thereby creating a need to base investment decisions on load forecasting and cost/benefit analyses. Moreover, the RECs must now refocus their investments away from system expansion and toward rehabilitation and add-ons, but they lack the expertise and orientation for developing and programming such investments. Although the technology of electricity distribution is rela-

tively prosaic, most RECs pay too little to afford an ample cadre of fully qualified managerial and technical staff; they therefore need to supplement their thin capabilities with external expertise. In short, the sector needs a core agency capable of financing weak borrowers with an extensive need for highly specialized technical support, to ensure that (i) the projects being financed are feasible and appropriate, and (ii) the RECs develop into institutions that operate well enough to repay their loans.

6.4 Since the late 1970s, NEA has not performed effectively as the sector's core agency. However, its difficulties stemmed mainly from (i) a lack of focus in its activities, (ii) the absence of functional accountability, and (iii) the previous Government's bent for requiring that NEA exceed its institutional capabilities. However, when NEA's direction was clear and available resources were adequate, it performed quite effectively. NEA has led a movement that succeeded in providing electricity, and therefore raising the standard of living, for about 2.7 million new consumers in less than 20 years; Government policy and not organizational weakness caused NEA to disregard the cost of that program. The organization itself has the structural units to perform most of the functions that would be needed of the core agency; if those functions were to be reassigned, most of NEA's staff of about 900 would still be needed by NEA's successor. NEA needs primarily to reorient its focus toward loan programming, credit analysis, and loan administration, and supplement its existing staff to perform these functions. Thus, the most effective approach to developing the needed core agency activities is to address NEA's weaknesses.

6.5 Over the years, NEA has acquired a number of side activities that were (i) only peripherally related to rural electrification, or (ii) aimed at developing for the RECs' supply alternatives to connection to the NPC grid. In its 1988 reorganization, NEA discontinued some of the more arcane of these activities; however, it continues to be involved in alternative generation. NEA needs to restrict its business to providing finance and technical support for the distribution utilities serving rural areas, and divest itself of its other activities.

6.6 In the past, NEA was shunted between a number of Government agencies before finally settling under the Ministry of Human Settlements. Currently, NEA reports to DENR, which can neither provide the technical support nor require the functional accountability that NEA needs. To coordinate NEA's activities and investments with the rest of the energy sector, NEA has a seat on the ECC. Even so, a stronger interaction with the energy sector is needed. NEA should have the same reporting relationships as NPC, PNOC and OEA, the energy sector's main participants; this would mean bringing NEA directly under the Office of the President and having it report to the Executive Secretary.

6.7 NEA needs urgently to develop functional accountability over its activities. Although operating in both the electrification and the lending businesses with constrained resources, NEA has not previously had either formal ties to NPC or the outlook and accountability of a financial institution. NPC can provide technical support for many of NEA's electrification planning and implementation functions. NEA should formalize its relationship with NPC by having the NPC President serve ex-officio as the NEA Chairman and the NEA Administrator assume an ex-officio seat on NPC's

Board. To ensure that NEA follows the policies of a financial intermediary, one seat on NEA's Board should be reserved for a senior banker, and a second for a senior official of the Department of Finance. Because NEA currently lacks the staff needed to discharge its lending operations, and has only limited prospects for acquiring such expertise given its current pay scales, it should acquire this expertise through a consulting arrangement with a major bank or financial institution.

C. Institutional and Financial Context

6.8 In the rural electrification program's early days, NEA and the fledgling cooperative system received extensive financial support from USAID. Beginning with the formation of two cooperatives under a pilot project that began in 1970 (para. 1.7) and continuing for the rest of that decade, USAID provided concessional loans totalling nearly US$86 million for rural electrification, making it the leading financial supporter of the program. The Overseas Economic Cooperation Fund (OECF) of the Government of Japan, which has provided nearly US$84 million since the program's inception, also participated enthusiastically in the early days and is the sector's second largest financier. The Bank has lent US$60 million for rural electrification (Loans 1120-PH and 1547-PH), and is NEA's third largest creditor. These primary lenders, together with other multi- and bilateral agencies, have provided a total of US$419 million of loans for rural electrification through December 31, 1988 (Annex 6.01).

6.9 During 1971-83, loan releases to NEA from all sources averaged US$28.4 million per year. After 1983, however, the rate of borrowing dropped precipitously, reaching a low of US$3.3 million in 1988 (Annex 6.02). As financing for rural electrification slackened, so did the rapid growth of new consumer connections, dropping to under 4% during 1983-87, and actually declining slightly in 1988 (Annex 1.02).

6.10 Rural electrification quickly became one of the most effective of the Government's rural outreach programs, and NEA was increasingly perceived as one of the leading rural development agencies. The early surge of electric service was hailed as evidence of the Government's commitment to the rural community, and NEA was asked to build upon these early successes by accelerating even more the pace of electrification. Increasingly, the Government's emphasis on adding new connections exceeded the absorptive capacity of NEA and the newly formed RECs. Institution building was subordinated to the objectives of stringing lines and connecting new consumers. NEA's feasibility studies of investments in expansion became increasingly perfunctory, and actual investments under the program often differed markedly from the approved plan. As of December 31, 1988, 38 RECs had availed themselves of loan releases that exceeded approved amounts. The total of these overdrafts is about ₱ 713 million, or 27% more than the total of approved loans for these RECs (Annex 6.03).

6.11 Increasingly, NEA was given responsibility for implementing ambitious social programs that were intended to improve the quality of life for rural dwellers. These programs, some not even remotely linked to elec-

trification, drained scarce financial and manpower resources from both NEA and the RECs. Most of these social programs were either sponsored or promoted by the Ministry of Human Settlements, which became NEA's parent organization in 1978. These programs are summarized in Table 6.1:

Table 6.1: NEA's RURAL OUTREACH PROGRAMS

PROJECTS	DESCRIPTION
Small Scale Industries (BLISS Project)	Small scale industry projects (embroidery, handicrafts, rice mills, ice plants, etc.) financed and supported by the RECs to provide economic development in rural communities.
Water Impounding	Water development through the construction of dams.
BLISS - Level I	Construction of dwelling units in rural areas.
School Reforestation	Tree plantation loans to schools and universities to develop natural energy resources and support the Government's reforestation programs.
Charcoal Livelihood Project	Construction of charcoal kilns.
Power Use	Promotional projects in support of the small-scale industry program.
People's Forest Program	Supporting the national tree planting program through the Family Tree Farms Association.
Rural Water Systems	Providing rural areas with potable water by drilling of deep wells.
School Lighting	Electrification of school rooms throughout the country.

6.12 These programs received funding from a variety of sources, including foreign lenders and other Government agencies. As of December 31, 1988, NEA continued to hold a number of trust funds and recognize trust liabilities associated with these programs. Because of the strong emphasis on physical progress in attaining rural development targets, NEA paid scant attention to whether the programs being supported would provide the RECs with revenues sufficient to meet the related debt service requirements. In

turn, the Government did not provide NEA with adequate capital and operating subsidies to support the cash flow requirements of these and other politically motivated programs. Foreign donor support, often featuring substantial grant elements and long grace periods, provided sufficient finance to defer until the early 1980s the cash flow constraints that inevitably would result from supporting social programs with poor prospects for financial returns.

6.13 NEA was also made responsible for implementing the Government's program to develop alternative forms of electricity generation. This involved supporting the RECs' developing mini-hydro and dendro thermal generating plants of 5 MW or less. These ill-fated ventures were financed by foreign hard currency loans. Table 6.2 gives the status of these programs.

Table 6.2: STATUS OF ALTERNATIVE GENERATION PROGRAMS
(As of December 31, 1988)

	Mini-hydro		No. in Op.	Dendro Thermal		No. in Op.
	# Sites	# Units		# Sites	# Units	
Installed	13	35	N/A	7	7	0
Under Construction	6	17	-	0	0	-
Constr. terminated	10	25	-	7	7	-
In Storage:						
at NEA	29	78	-	3	3	-
at Source Country	17	53	-	0	0	-
TOTAL	75	209	N/A	17	17	0

6.14 Less than 17% of the mini-hydro units acquired by NEA had been installed as of December 31, 1988. Of the 17 dendro thermal units procured by NEA, seven had been installed, although none are in operation. To provide fuel supplies for the dendro thermal units, the program was linked to largely unsuccessful tree planting programs that were financed by NEA and sponsored by the RECs. NPC, which is taking control of the RECs' self-generating facilities, will conduct a study to determine whether the dendro thermal units can be converted to diesel and restored to service; otherwise, the units will be scrapped.

6.15 Financially, the alternative generation program has been a major failure. As shown in Annex 6.04, the RECs have been unable to service the debts related to the program; as of December 31, 1988, they had repaid less than 8% and 0.2 respectively of the amortization due on their mini-hydro and dendro thermal loans. As NPC takes control of the units that have already been installed, it will only absorb liabilities corresponding to the depreciated value of units to be kept in operation. The alternative generation loans will provide cash flow to NEA only to that small extent; the RECs are not expected to remit to NEA debt service related to the remainder of loans raised to finance plants that they no longer own.

D. Current Financial Performance

6.16 NEA's central business is lending to the rural electrification system. NEA obtains funding from foreign and domestic sources, procures goods and services for approved projects on behalf of the RECs, and collects the resulting loan principal and interest from the RECs as these become due. In short, it is a financial intermediary. As a Government corporation, NEA is responsible for generating funds from ongoing operations sufficient to (i) support its internal operations and (ii) service its own debts. To provide an adequate foundation in support of NEA's expected activities, the Government pledged to invest up to ₱ 5 billion in NEA equity; about ₱ 3 billion which was actually paid into NEA as of December 31, 1988. As a financial intermediary, NEA's financial viability is inextricably linked to that of the RECs, since NEA depended upon the cash flow from principal and interest payments from the RECs to meet its obligations. Therefore, from the outset, since the RECs were weak operationally and commercially, NEA was intended to act as an active lender, providing various outreach and technical support services to help the RECs evolve into viable, self-supporting organizations.

6.17 When viewed from the perspective of a commercial enterprise, NEA is insolvent. In the aggregate, NEA is collecting only about half of the amortization due from the RECs; and for most of the alternative energy loans, the default rate is nearly 100%. Since 1986, current liabilities (composed primarily of advances from the Government) have exceeded current assets, and the gap is growing. NEA's debt obligations to its foreign and domestic creditors exceeds its total loans receivable from the RECs. These results suggest that NEA has done a poor job as a lender; and, without a restructuring, its future prospects as a lender are highly limited. NEA's current financial woes are primarily due to: (i) its lack of focus on its lending business; (ii) the Government's underestimation of the substantial capital and operating subsidies needed by the RECs, particularly those operating in remote and/or distressed areas, during their formative period; and (iii) the Government's overestimation of the RECs' and NEA's ability to manage non-commercial and social development projects unrelated to distribution of electricity.

6.18 Highlights of NEA's Balance Sheet for the period 1984-88 (Table 6.3) indicate a significant deterioration in NEA's financial position over that period. If NEA's accounts were adjusted to reflect commercial practices (e.g., by establishing provisions for prospectively uncollectible debts and expensing arrears considered uncollectible), its financial performance would have been significantly worse than was reported.

Table 6.3: BALANCE SHEET HIGHLIGHTS
(₱ millions)

Years Ended December 31	1984	1985	1986	1987	1988
ASSETS					
Current Assets					
Inventories	817	959	1,242	1,263	1,247
Interest receivable-RECs	313	280	392	476	589
Loans receivable-RECs	198	265	369	472	609
Other	71	214	177	268	269
Subtotal	1,399	1,718	2,180	2,479	2,714
Long Term Assets					
Loans receivable-RECs	4,909	5,243	5,858	7,105	7,755
Other	2,758	170	161	1,999	374
Subtotal	7,667	5,413	6,019	9,104	8,130
TOTAL ASSETS	9,066	7,131	8,199	11,583	10,844
LIABILITIES & EQUITY					
Current Liabilities					
Advances from Govt.	N/A	1,334	1,990	2,507	3,307
Other	N/A	352	327	561	481
Subtotal	1,095	1,686	2,317	3,068	3,788
Long Term Liabilities					
Foreign Loans Payable	5,604	2,981	3,447	5,607	6,104
TOTAL LIABILITIES	6,699	4,667	5,764	8,675	9,892
Capital and Surplus					
Paid in capital	2,151	2,241	2,261	2,961	3,084
Cum. (Deficit)/Earning	44	51	2	(231)	(2,310)
Other	172	172	172	178	178
TOTAL CAPITAL	2,367	2,464	2,435	2,908	952
TOTAL LIAB. & EQUITY	9,066	7,131	8,199	11,583	10,844

6.19 NEA's current assets have questionable value.

(a) Nearly 45% of NEA's inventory consists of uninstalled mini-hydro and dendro thermal units. Although NPC may acquire some of the units (para. 6.14), it is unlikely to relieve NEA of much of this inventory, since it refused to take responsibility for the program in its initial stages on economic grounds. Moreover, the suppliers of these units have not indicated interest in retrieving them. Therefore, from a commercial perspective, these assets are worthless (despite NEA's continuing obligation for the related debt).

(b) Interest receivable from the RECs includes both current amounts and arrears. Currently, this account shows that NEA has about two years of interest income due and still owing from the RECs; thus, an ample portion of that account represents arrears.

(c) Loans receivable from the RECs shows a similar accumulation of arrearages in amortization payments. NEA currently makes no provision for uncollectible accounts, so these current assets are clearly overstated in light of actual remittances. Long-term assets as of December 31, 1988 consist almost entirely of loans due from the RECs. As with the current assets, no provision for uncollectible accounts is made and the reported balance is almost certainly overstated.

6.20 NEA's liabilities, on the other hand, represent bona fide claims arising from its borrowings. Advances from the Government, which are growing at an increasing rate, represent the value of principal and interest payments that NEA owed but was unable to pay to its foreign creditors. Foreign loans payable at December 31, 1988 include adjustment for foreign currency fluctuations. For the majority of these foreign loans, NEA bears the exchange risk between the peso and the original currency. In no instance has NEA passed this exchange risk to the RECs; and, when NEA has applied an interest rate spread, the extent of the spread was inadequate to cover the related exchange rate losses. As of December 31, 1988, NEA's cumulative exchange rate exposure amounted to about ₱ 2 billion.

6.21 NEA's paid in capital increased in 1987 primarily because of a Government equity infusion of about ₱ 500 million, the proceeds of which were to finance a Relending Program wherein NEA was to make loans to 21 troubled RECs so that they could pay down their NPC power account arrearages. The proceeds of this equity infusion was never disbursed to the RECs in question, but rather was paid immediately to NPC; and NEA opened new loan accounts, equal in amount to their NPC liability, for each of the participating RECs. NEA will receive the benefit of this equity contribution as these loans are repaid.

6.22 NEA's retained earnings have gone from a small positive balance to a significant accumulated deficit as a result of a change in the accounting treatment for foreign exchange losses. In the past, the impact of the devaluation of the peso on the foreign loan liability was not reflected in NEA's books; now, however, borrowings are adjusted at the end of the year according to the exchange rate prevailing at the time.

6.23 Table 6.4 shows NEA's Income Statement highlights for the period 1984-88. Although the reported figures, as audited by the Commission on Audit (COA), indicate a marginally profitable operation, income from operations is overstated since interest income is recognized when accrued and not when the cash payments are actually received. The recording of interest income on the accrual basis is an acceptable accounting procedure; however, in light of NEA's poor collection experience, the absence of a reserve for bad debts results in overstatement of the year's true income.

Table 6.4: INCOME STATEMENT HIGHLIGHTS
(₱ millions)

Years Ended December 31	1984	1985	1986	1987	1988
Operating Income:					
Interest on loans	173	193	263	284	305
Operating Expenses:					
Interest expense	119	109	184	248	224
Personal services	28	32	33	38	47
Other	12	14	14	23	30
Subtotal	159	155	231	309	301
Income from Operations	14	38	32	(25)	4
Other Income	0	11	5	13	34
Foreign exchange losses	0	0	0	(231)	(234)
NET INCOME (LOSS)	14	49	37	(243)	(196)

6.24 Accrued interest income, which is essentially NEA's only source of revenue, grew at an annual compound rate of about 15% during the period. Interest expense, which generally accounts for about 75% of operating expenses, grew at a compound rate of 17%. From NEA records, the extent to which interest income recognized in each of these years was actually collected cannot be deduced; however, the growth in the interest receivable balance suggests that the collection rate was about 50%. Foreign exchange losses were only recognized in NEA's accounts as of 1987. Because the amount expensed relative to these losses was virtually equivalent to interest expense, this change in accounting procedure had the effect of transforming NEA from a break-even performer into a significant money loser.

6.25 The problems confronting NEA today are due partly to past managerial failings, and (i)partly to the heavy influence of politics in the rural electrification program. For the most part, NEA tried (perhaps too willingly) to do everything that was asked of it. Perceived political needs of the moment drove the organization, often to its detriment. The

recently installed NEA administration has approached the need for a new beginning with substantial energy; however, it is faced with inherited problems of such magnitude that "growing out" of the bad situation may not be feasible. When problems of similar magnitude confronted the Government Financial Institutions (GFI) during the past several years, the Government developed the Asset Privatization Trust (APT) to take over the GFIs' non-performing assets and thereby enable that sector to get a new start on a "clean books" basis. Similarly, NPC was relieved of the ponderous financial burden posed by the politically motivated decision to build the Philippine Nuclear Power Plant when the Government agreed to assume responsibility for those assets and the corresponding liabilities. So far, NEA has been denied access to similar mechanisms for relief from past mistakes.

E. Proposal for a Financial Restructuring of NEA

6.26 NEA cannot address the RECs' problems while it is burdened with problems of its own that threaten to overwhelm the organization. The growing burden of unpayable advances from the Government, the poor payment history of RECs located in distressed or unsecured areas, and the debts overhanging the organization from past, ill advised, activities unrelated to electricity distribution must be addressed as the first stage of the recovery of the sector. Delays in implementing remedial actions will only compound the problems; however, any program to implement this restructuring will have to take account of when the Government, with its limited resources, can feasibly take responsibilities for the liabilities from which NEA should be relieved. The recommended remedial actions, the amounts of which are based on NEA's financial position as of December 31, 1988, are essentially short-term, one time measures that would alter materially NEA's financial situation. A restated Balance Sheet, shown in Table 6.6, indicates the effects of this restructuring program recommended below:

(a) Advances from the Government, aggregating ₱ 3.3 billion, should be converted to equity. This amount represents past payment by the Government of principal and interest related to NEA loan obligations. NEA has no reasonable prospect of repaying this obligation as its cash inflows are not even adequate to cover current operations and debt service. While the Government would absorb the impact of this measure, it represents a non-cash, "book" transaction for both the Government and NEA; however, by substantially improving NEA's capital structure, it also improves NEA's prospects for credit worthiness[1/].

(b) The Government should assume the impact of foreign exchange losses on NEA's existing foreign loan obligations. This amount, aggregating ₱ 1.9 billion, represents the difference between the original peso equivalent valued at the time of availment of the foreign obligations outstanding as of December

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1/ The Government has already provided for conversion of some of these advances to equity, and is weighing approaches for converting the remainder.

31, 1988 and their present peso equivalent value. NEA has made no provision for the RECs to assume all or part of the foreign exchange risk pertaining to these loans; moreover, it cannot expect to recover this cost element retroactively. Recent USAID loans require the Government to assume the foreign exchange risk. Because NEA lacks cash inflows that correspond to these obligations, the Government will have to meet them; thus, while this measure implies no change from the status quo in terms of cash flow, it does substantially improve NEA's Balance Sheet and therefore its prospects for being effective in the future. For the future, the Government and NEA need to develop a system for managing the foreign exchange risk (para. 6.39)[2/].

(c) Construction loans receivable due NEA from remote and/or self generating RECs should be written off; a corresponding amount of Government loans to NEA should be converted to equity. Twenty-five RECs have unpaid construction loans totalling ₱ 1.1 billion (Table 6.5) that should be assumed by the Government in recognition that these loans were justified more on social than on economic grounds. The final amount to be converted to equity would be computed after deducting from the outstanding balances the small amounts that correspond to the undepreciated value of the self generating facilities that NPC is acquiring.

2/ NEA has already applied to have the Government absorb some of the foreign exchange losses applicable to existing loans.

Table 6.5: STATUS OF CONSTRUCTION LOANS TO REMOTE/SELF-GENERATING RECs (₱ million)

Region	REC	Releases	Amortization Due	Amortization Paid	Outstanding Balance
4	Marinduque	35.2	11.6	0.3	34.9
4	Occ. Mindoro	37.8	15.8	6.3	31.4
4	Lubang	10.4	4.2	0.0	10.4
4	Or. Mindoro	101.7	23.5	7.0	94.7
4	Palawan	61.5	3.9	0.6	60.9
4	Busuanga	39.5	0.4	0.0	39.5
4	Tablas Island	69.6	0.2	0.1	69.5
5	Catanduanes	32.9	9.5	0.7	32.2
5	Masbate	49.3	5.3	0.1	49.2
6	Guimaras Is.	47.2	0.4	0.2	47.0
7	Bantayan	49.1	0.0	0.0	49.1
7	Camotes Is.	15.6	0.0	0.0	15.6
7	Siquijor	54.8	0.1	0.0	54.8
8	Samar I	26.1	6.6	1.4	24.7
8	Samar II	92.5	28.2	1.1	91.4
8	E. Samar	49.5	3.4	0.0	49.5
8	N. Samar	28.9	1.8	0.0	28.9
8	Biliran Is.	25.9	0.2	0.1	25.8
9	Sulu	16.7	3.6	0.1	16.6
9	Tawi Tawi	5.6	1.6	0.0	5.6
9	Basilan	18.7	5.9	0.1	18.6
9	Cag. de Sulu	2.5	0.9	0.0	2.5
10	Siargao	112.2	0.0	0.0	112.2
10	Camiguin	73.4	0.1	0.0	73.4
10	Surigao Sur	35.7	1.8	0.4	35.3
		1,092.3	128.7	18.5	1,075.8

(d) Assets and liabilities associated with dendro thermal and mini-hydro, both installed and uninstalled, should be divested. To the extent that NPC acquires the depreciated value of some of these assets, it should assume the corresponding liabilities. NEA's inventory as of December 31, 1988, includes ₱ 565 million of mini-hydro and dendro thermal equipment. The RECs participating in the alternative energy program owe an aggregate of about ₱ 1.8 billion for the mini-hydro and dendro thermal facilities provided to them. As of December 31, 1988, NEA's remaining liability to foreign lenders was ₱ 791 million (based on the exchange rate originally in effect at the time of loan availment). These obligations should be removed from the books of both the RECs and NEA.

(e) Assets and liabilities of all social programs and other activities unrelated to electricity distribution (value to be deter-

mined) should be divested. For the most part, these social projects were economically unsuccessful and have drained scarce resources. Funds held in trust should be returned to the Government. No NEA personnel should be assigned to the monitoring of these activities.

(f) NEA should restructure all delinquent REC debts (principal and interest aggregating ₱ 1 billion), based on feasible repayment terms. Much of the arrearages may be collectible if NEA and its borrowers approach the issue on a case-by-case basis. NEA should arrange a major loan monitoring and collection effort.

(g) ₱ 150 million in deferred development costs, Government project costs and salaries and allowances of NEA staff posted to REC management positions should be expensed against current operations, and the accounts used for their deferral should be closed. These amounts relate to past activities of NEA and no continuing benefits are being realized. The cost of NEA's interim management of the RECs can be borne by the RECs through fees that the RECs would pay as incurred.

(h) NEA should turn its non-performing assets over to the APT, which should try to return to the Government whatever value can be realized from those assets.

To ensure that this effort indeed serves as a one time measure to return NEA (and through it, the troubled RECs) to sustainable financial health, NEA will need to implement stricter credit and financial prudence practices (para. 6.32) and tighter loan administration procedures (para. 6.28). In addition, NEA will need to become more involved in supervising the activities of the RECs. In that context, it will need to take a sterner view of the RECs' failure to comply with their loan agreement obligations. In addition, the individual RECs will need to take steps to improve their operational and financial performance in order to earn their eligibility for relief under this proposed restructuring (paras. 5.27-5.31).

Table 6.6: EFFECTS OF RESTRUCTURING ON NEA BALANCE SHEET */
(₱ million)

Year Ended Dec. 31	Actual 1988	debit	credit	Restated (est)
ASSETS				
Current Assets				
Inventories	1,247		(d) (565)	682
Interest rec.-RECs	589			589
Loans rec.-RECs	609		(c) (110)	
			(d) (281)	218
Other	269			269
Subtotal	2,714	0	(956)	1,758
Long Term				
Loans rec.-RECs	7,756		(c) (964)	5,242
			(d)(1,550)	5,242
Other	374		(g) (150)	224
subtotal	8,130	0	(2,664)	5,466
TOTAL ASSETS	10,844	0	(3,620)	7,224
LIABILITIES & EQUITY				
Current Liabilities				
Advances from Govt	3,307	(a) 3,307		0
Other	481			481
Subtotal	3,788	3,307	0	481
Long Term				
Foreign Borrowings	6,104	(b) 1,907		
		(c) 1,074		
		(d) 719		2,332
TOTAL LIABILITIES	9,892	7,079	0	2,813
Capital and Surplus				
Paid in capital	3,084		(a)(3,307)	6,391
Cum. Surplus/(Def.)	(2,310)	(g) 150	(b)(1,907)	
		(d) 1,605		(2,158)
Other	178			178
Subtotal	952	1,755	(5,214)	4,411
TOTAL LIAB & EQUITY	10,844	8,834	(5,214)	7,224

*/ The letter in parenthesis denotes the component of the restructuring that accounts for the indicated account adjustment.

6.27 Because many loans from which NEA would be relieved under this restructuring program were raised in support of either (i) Government-promoted expansion of distribution systems into uneconomic areas, or (ii) Government-sponsored programs that were only marginally related (if at all) to rural electrification, they should be transferred to the Government for disposition. The beneficiaries of the uneconomic expansion of the distribution systems as well as the social programs were the rural poor, who cannot bear the true cost of those investments. The beneficiaries of the investments in self-generation facilities were the foreign suppliers; since the Government pursued this program even after NPC rejected it on economic grounds, the Government should bear the cost of these mistakes. Since Government policy proscribed NEA from (i) passing to the RECs the exchange risk on foreign borrowings, or (ii) charging the RECs an interest rate spread designed to cover that risk, the Government must bear responsibility for losses that resulted from the deep devaluation of the peso during the 1983-86 recession. While the Government is admittedly facing severe cash flow constraints, no other entity can reasonably be asked to bear the cost of the politically-motivated profligacy of the previous administration.

6.28 In many instances, the recommended adjustments to NEA's Balance Sheet (Table 6.6) were based on estimates, since NEA's accounts contained (i) internal discrepancies and (ii) loan amounts that could not be reconciled with corresponding accounts in the books of the RECs. For example, NEA's subsidiary loan records show the total of mini-hydro and dendro thermal loans receivable from the RECs was ₱ 1.76 billion. These records, which are used for monitoring releases to, collections from, and arrearages of the RECs, are maintained to support NEA's general ledger; however, the general ledger indicates that mini-hydro and dendro thermal loans receivable from the RECs total ₱ 2.31 billion. Also, in none of the twenty cases, examined in depth by USAID's consultants during 1986-87, did the loan amounts carried in either NEA's general ledger or its subsidiary loan records reconcile with the corresponding loan amounts carried in the RECs' books of accounts. In effect, NEA's loan records are not maintained satisfactorily. A comprehensive effort aimed at (i) reconciling the amounts and terms of outstanding loans and (ii) adjusting the books of NEA and the RECs accordingly, is thus urgently needed. Once existing obligations to NEA are established definitively, releases of undisbursed amounts of future loans can be tied to the timely remittance of current payments.

6.29 NEA's accounting practices substantially overstate its commercial condition and, therefore, need to be revised. These practices include: (i) not making provision for uncollectible interest and principal payments due from troubled RECs, although the collection history would suggest that a substantial allowance for uncollectibles is needed, and (ii) capitalizing development costs, Government project costs and salaries and allowances of NEA employees posted to REC management positions. These practices have been specified by the Commission on Audits (COA), which for accounting purposes considers NEA to be a social organization and not a "Government Financial Institution". To improve its ability to monitor its portfolio, NEA should obtain COA's permission to use accounting practices, including making provisions for uncollectible interest and principal payments and expensing many period expenditures that are currently capitalized, that are normal to Government Financial Institutions.

F. Financing Strategy

6.30 The proposed restructuring is essentially a one time measure with an immediate impact. To prevent a recurrence of its past problems, NEA will need to develop a financing strategy that, at once (i) provides finance on appropriate terms for economically justifiable projects, (ii) penalizes RECs that make insufficient effort to improve performance, and (iii) considers the special needs of RECs with structural constraints that limit their prospects for financial viability.

6.31 In the past, NEA has not observed reasonable financial prudence practices in the course of its lending activities. Often, investment decisions were based on political pressures to energize specific areas and technical considerations related to service expansion, but without proper feasibility studies. As a result, some loans were made in support of projects for which cost recovery was impossible. Had proper investment analysis and loan programming been performed, and if NEA's loan recording procedures were adequate, NEA might not have been susceptible to overdrafts to the extent indicated in Annex 6.03. Because ample funds with soft terms and long grace periods were available to the sector in the program's early years, problems resulting from NEA's failure to observe financial prudence were deferred until about 1983.

6.32 In the future, NEA must comply more closely with financial prudence practices. It must base its justification for making loans on proper credit analysis. When lending, NEA should apply conditionality aimed at improved financial performance and institutional development, and it should deny funding on the grounds of a borrower's poor past performance if an REC is unable to provide credible evidence that it would comply with reasonable conditionality. Where the Government wants NEA to support marginal projects for either social or peace and order purposes, transparent subsidies need to be provided. Given the link between NEA's financial health and that of the RECs, NEA must improve the quality of its loan portfolio.

6.33 As shown in Annex 6.05, NEA currently administers at least 38 different types of loans. These include, inter alia, "regular" rural electrification loans, alternative energy loans, and a broad array of loans for social projects unrelated to rural electrification. To keep its lending activities manageable, NEA should simplify its categories for lending and its lending terms. In the future, it should limit its lending to support rehabilitation of rural networks, add-on connections, economically justified system extensions, and working capital. While the bulk of its loans should be for the cash value of materials and equipment it provides to the RECs, it might consider lending cash under special circumstances.

6.34 Annex 6.05 summarizes the terms of both NEA's borrowings as well as its loans. Currently, NEA's charges for its loans are based on the cost of the underlying funds. This approach has proven unsatisfactory because (i) NEA could not price its loans predictably, or even reflect in the interest rate its own underlying cost of operation; (ii) the donors' conflicting onlending preferences were not necessarily consistent with overall

sector development; and (iii) RECs vied with each other to participate in programs supported by the softest, least restrictive financing packages.

6.35 To enable NEA to solicit financial support from a broad range of donors, it should continue to focus on its overall cost of funds in developing its interest rate policy. NEA should develop a basic interest rate pegged to its average cost of capital plus a spread that allows for recovery of its administrative and operating costs and reflects adequately the foreign exchange risk. A premium of about 2-3% should cover NEA's overhead and loan generation costs, while a premium of about 6-7%[3/] should cover the expected foreign exchange risk. The basic rate would guide NEA's pricing of all of its loans. Also, the provisioning against anticipated foreign exchange losses should be based on all NEA loans made this financing strategy, not simply those with foreign exchange exposure, at least until an ample fund has been accumulated. The basic rate should be reviewed annually, and the new rate fixed for the duration of all loans generated after completion of the review. In conjunction with a rural electrification project approved in 1988, USAID asked that NEA apply an onlending rate of 12%; that rate was justified because it was (i) positive relative to inflation, (ii) approximately equal to the opportunity cost of capital in the Philippines, and (iii) broadly reflective of the exchange rate risk that NEA would face on a portfolio composed in equal parts of soft loans from bilateral lenders, harder loans from multilaterals, and low-cost domestic funds. Because the 12% rate currently covers NEA's cost of capital and provides the requisite spreads, it could become NEA's initial basic rate and be valid until the first annual review is conducted, presumably in August/September 1990.

6.36 Once the basic rate has been established, NEA can use preferential pricing to encourage specific types of investment. For example, loans to support rehabilitation with add-on connections or system expansion designed to capture an unconnected productive load could be priced at 1% below the basic rate; loans to support system expansion aimed at only capturing residential loads could be priced at 2% over the basic rate. However, because variations in the repayment period have a greater impact on an REC's cash flow than interest rate variations, NEA should keep all its rates within a range defined by a floor that is 1% below and a ceiling that is 2% above the basic rate.

6.37 The best incentive NEA can use to encourage the RECs to (i) invest in justifiable projects, (ii) stay current in meeting their debt service obligations, and (iii) meet reasonable operational and financial performance targets, is to vary the maturity and grace periods applied to each loans. NEA should have a standard loan that carries a grace period of two years and a maturity of ten years (these terms correspond to the construction period and depreciable lives of most distribution investments). However, maturities of more than ten years (perhaps as much as 20-25 years) could be applied to loans that support, directly or otherwise, (i) invest-

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3/ For the Bank-financed Manila Power Distribution Project, an onlending rate, which was about 6.5% below the current market rate for similar local funds, was accepted on the basis that the differential was an adequate reflection of the foreign exchange risk being borne by MERALCO.

ments with higher than normal rates of return, (ii) agreed institutional improvement programs adopted by poor performers, or (iii) the sustained good performance by the better RECs. NEA should adopt no more than three alternative combinations of maturities and grace periods (i.e., 15 years-30 months; 20 years-36 months; and 25 years-42 months), and develop a point system (i.e., that assigns points for the project's expected rate of return; the REC's credit record; and the REC's operational and financial performance) to determine the specific terms of any particular loan.

6.38 As noted earlier (para. 6.26 (b)), for the future, the Government and NEA need to develop a system for managing the foreign exchange risk. Elsewhere in the Philippine power sector, the foreign exchange risk is borne by the borrowing utility (i.e., NPC or MERALCO) and automatically passed on to the consumer through the electricity tariff. However, NEA cannot realistically on-lend foreign exchange to the RECs; to do so would not only require an unwieldy exchange rate tariff adjustment provision that the RECs would have difficulty administering, but would also expose the financially fragile RECs to the unpredictable risk of devaluation.

6.39 Instead, the risk should be borne by NEA. In the future, NEA will continue to be responsible for (i) the RECs' investment planning and project development, as well as (ii) the selection of investments to be financed by loans and (iii) the credit analysis of the borrowing RECs. In effect, by taking the foreign exchange risk, NEA would become accountable for its mistakes. However, NEA cannot assume the full future foreign exchange burden without making provision for the possibility that the risk might materialize. It should, therefore, develop an Exchange Risk Fund that it would maintain with the Central Bank. Annually, NEA would deposit into the Fund a provision equal to about 6.5% of the principal value of its outstanding repayable foreign credit.

6.40 To accommodate the justifiable investment requirements of RECs without reasonable prospects for financial viability, the Government should create a pool of grant funds that can be onlent for 25-30 years at no interest, but with an annual service charge of 1-2% (to cover NEA's administrative costs). NEA could use the pool either to provide soft finance for a small number of justifiable projects, or to provide interest rate relief for a larger number of projects through the blending of hard and soft loans. To be eligible to tap the soft loan facility, a REC would either have to be receiving power from NPC at the subsidized rate of ₱ 1.30/kWh or participating in the NPC-NEA subsidy program for RECs unable to reduce their costs below the retail ceiling of ₱ 2.50/kWh. The Government should provide NEA with an annual equity investment of ₱ 125 million to fund this pool. As the weak RECs' investment needs are expected to be modest, and as most of them are located in the typhoon belt, the pool could also be used to provide them with relief from typhoon damage. Funding from this facility should be treated similarly to NEA's other loans. To qualify for financing from this pool, a REC would have to undertake a program to improve its operational and financial performance. In connection with a "soft" loan, the REC would need to agree to conditionality to (i) implement the performance enhancement program, and (ii) realize agreed periodic performance targets.

6.41 To prevent the recurrence of past abuses, NEA must make better use of its leverage as a lender. To discourage chronic unsatisfactory performance in certain RECs, NEA could restrict the availability or delay the processing of loans. Performance targets, or even action plans to improve performance, could be covered by loan conditionality. In the extreme, NEA could decide not to finance a particular poor performer, regardless of the priority of that REC's investment program.

6.42 NEA must also avoid a recurrence of its own past financial distress. It is providing the RECs with a vast array of services and needs to develop the operating cash flow to cover the expenses related thereto. It should expect to cover the cost of its lending operations and its overhead from the spread on its loans; however, it needs to provide the bulk of its electrification services to the RECs on a fee basis. A fee schedule, which incorporates rates comparable to those of a consulting firm, needs to be devised to cover the costs of investment planning, project development, procurement, warehousing, and project supervision; the amounts involved should be estimated in advance and be withdrawn immediately from the principal amount of each loan, in the manner of a front end fee. The fee for maintenance services should be payable in cash according to credit terms normal to the Philippines. The cost of NEA staff seconded to the RECs should also be borne fully by the RECs as incurred.

G. NEA's Financial Prospects

6.43 In connection with this study, five year financial projections for NEA were prepared on the basis of the following scenarios:

Scenario I	NEA would finance an investment program for the RECs consistent with Investment Scenario 1 (para. 3.34), without NEA being restructured.
Scenario I-A	NEA would finance an investment program for the RECs consistent with Investment Scenario 1 (para. 3.34), and would be restructured according to the recommended program (para. 6.26) .
Scenario II	NEA would finance an investment program for the RECs consistent with Investment Scenario 2 (para. 3.34), without NEA being restructured.
Scenario II-A	NEA would finance an investment program for the RECs consistent with Investment Scenario 2 (para. 3.34), and would be restructured according to the recommended program (para. 6.26).

All scenarios assume that, (i) the collection rate will improve gradually to about 65% by 1993; (ii) external financing for investment that is shown as committed includes only the US$40 million USAID financing package, the US$22 million rural electrification component of the proposed Bank-financed Energy Sector Loan, and about US$15 million of loans or grants from other

sources[4/] that are either ongoing or strongly indicated; (iii) the Government provides an average of ₱ 125 million annually to support justifiable investments in non-viable RECs and typhoon relief; and (iv) current accounting practices will continue to be used. The projections for Scenarios I-A and II-A are presented in Annex 6.06.

6.44 These projections indicate that the proposed restructuring is the critical financial factor facing NEA. Under all scenarios, the Government would be investing about ₱ 280 million per year in NEA equity to cover the foreign exchange losses on its past loans. Under the restructuring proposal, this commitment would be acknowledged officially; without the restructuring, these investments would still be needed because NEA would lack the wherewithal to meet the corresponding obligations. However, without the restructuring, the Government would be providing NEA with additional advances of about ₱ 500 million per year to meet debt service on loans that, under the restructuring proposal, would be converted to equity. With restructuring, NEA's debt/equity ratio moves from about 40:60 as of the end of 1989 to about 25:75 as of the end of 1993. In contrast, without restructuring, the debt/equity ratio goes from 87:13 as of 1989 to 65:35 as of end 1993; and the improvement would be directly attributable to the very same assumptions of Government support that would be acknowledged officially under the restructuring. With the expression of Government support and the improved capitalization resulting from the restructuring, NEA would be able to obtain credit from the financial markets, and could be held accountable for its financial management; without the restructuring, NEA would continue struggling while the Government would need to make the same cash commitments over a protracted period. In effect, the restructuring proposal recognizes the reality that NEA cannot meet many of the past obligations that the Government had guaranteed and needs to be put on a "clean books" basis to meet the challenges of the future effectively.

6.45 Even with the restructuring, NEA's operating results are extremely sensitive to its collection rate. The projections assume that collections will improve from about 52% in 1989 to about 65% in 1993 (since NEA's collection rate was about 36% in 1987 and 1988, further improvement would be difficult to justify). While NEA is expected to be comfortably profitable on an accrual basis in each of those years, its operating cash flow is projected to be somewhat constrained. Although the restructuring will afford NEA some capacity to borrow, it should be encouraged instead to improve its collection performance. In addition, NEA needs to pay particular attention to ensuring the continued adequacy of its relending rate. Under the four scenarios considered, its profitability improves as existing lower-rate loans are retired and replaced in its portfolio by newer higher-interest loans.

6.46 After completing the restructuring, the pace of the investment in the sector is limited more by the availability of finance and NEA's organizational capability to (i) plan and develop investments, (ii) formulate loans, (iii) procure the needed materials and equipment, and (iv) supervise

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4/ These include about US$9 million from the Asian Development Bank, US$5 million from the Government of Norway, and US$1 million from the Government of the United Kingdom.

the investment activity, than by issues related to its credit worthiness. Indeed, the more NEA can lend, the better become its financial prospects.

6.47 The financial projections for Scenario I-A, the one which best reflects the absorptive capabilities of the sector's institutions, indicate that NEA will need to finance some ₱ 3.8 billion of investments during 1989-93. Of that amount, about ₱ 1.6 billion will come from official financings that are either committed or at advanced stages of negotiations. Another ₱ 1.7 billion is expected to be provided through as yet unidentified official finance. In addition, about ₱ 0.5 billion will need to be provided by the Government as equity. This latter figure corresponds to the amount expected to be required for (i) justifiable investments by RECs with limited prospects for commercial viability and (ii) a reasonable estimate for repairs of typhoon damage.

H. Organizational Issues

6.48 The NEA organization consists of about 900 employees engaged in a variety of technical and supporting functions (Annex 6.07). Part of NEA's spotty performance can be traced to organizational weaknesses, including: (i) a pay scale that provides severe disincentives to managers who may otherwise desire to remain with the organization; (ii) a history of spreading thin its own managerial and technical cadre by frequently becoming heavily (and often ineffectually) involved in the day-to-day management of troubled RECs; and (iii) the lack of a multi-disciplinary central group to coordinate the activities of its disparate units.

6.49 For pay purposes, the Department of Budget and Management classifies NEA as an infrastructure organization. When the NEA pay scales are compared with NPC's, rank and file workers appear to be receiving similar pay rates; however at supervisory and managerial levels the rates diverge quickly, with NPC paying twice as much to its mid and upper level managers (Annex 6.08). NEA's nearly "flat" pay scale is a disincentive to retaining manager; and most of NEA's capable managers and staff who have left in recent years have cited the opportunity for better pay elsewhere as a prime reason for their departure. The Government therefore needs to reclassify NEA as a financial institution and adjust its pay scales to evels that enable attracting and retaining capable managers and supervisors.

6.50 Under the Relending Program (paras. 5.16-5.17), NEA seconded its own staff to take responsibility for the day-to-day management of 11 RECs, on the assumption that the NEA manager would succeed in reversing the poor fortunes of those RECs. Under the same Program, 10 RECs retained their original management. While NEA has good technical staff, few of them have hands-on experience in managing troubled organizations. This became clear as the RECs being managed by NEA appointees recorded a repayment rate of 27%, while the RECs that retained their own managements recorded an 80% repayment rate (Annex 6.09). This suggests that NEA is not effective as a utility manager. Therefore, NEA should take control of a REC in the manner of a receiver; and, immediately after a takeover, it should start the process of identifying and transferring control of the REC to the group with

the best long-term plan for operating the REC viably in the future. NEA's activities in managing troubled RECs should serve as an adjunct to its core lending function and not an end in itself.

6.51 Finally, and most importantly, NEA needs to improve the coordination of its various activities, so that it can fulfill its primary role as an "interested" lender for rural electric systems. This can be done most effectively by developing a loan programming capability which will allow NEA not only to develop and implement a consistent medium-term lending program but also to use the program as a means of coordinating and integrating its own banking, technical and institutional development activities under one all-encompassing umbrella.

6.52 Currently, NEA's loan programming function is diffused throughout the organization, creating the image of a "hollow" institution where peripheral expertise services a non-existent core. The current collegial approach to reviewing project proposals, formulating a lending strategy, and managing lending is not conducive to establishing a strong lender's link to the REC borrowers. The lack of this central function is exacerbated by a dearth of banking competence.

6.53 Final decision-making authority concerning the lending program is now vested in the Administrator and the Executive Committee. However, the decisions need to be driven by clear recommendations originating in a multi-disciplinary unit at the heart of NEA which reports directly to the Administrator and is charged with:

(a) Development of an indicative rational strategy for rural electrification investment;

(b) Formulation of an internally consistent lending program based on this strategy;

(c) Responsibility for assessing specific REC investment proposals;

(d) Formulation of appropriate lending operations based on these proposals; and

(e) Supervision of the implementation of REC investments financed by NEA.

6.54 To discharge this function, the central multi-disciplinary staff (consisting of planners, economists, engineers, financial and institutional specialists) would draw on the specialized skills available in the supporting departments, including those concerned with the development and application of lending instruments. This unit's mandate should be defined to ensure that it functions a coordinative line body, and not as an additional bureaucratic adjunct to NEA's top management. In fact, because of its lack of lending expertise, NEA will most likely have to contract with a large bank or major financial institution to provide this loan programming function on a consulting basis. Such an arrangement may last for as much as ten years while NEA develops the necessary in-house knowledge. Still, NEA's own staff assigned to loan programming would retain responsibility for managing the lending program.

6.55 While NEA would need to hire some new staff for this function, its low pay scales preclude hiring more than a few senior level people. As a result, it will need to rely on bringing in a cadre of bright young people either fresh out of school or with minimal experience. NEA can expect that, over time, some of those people will develop the necessary expertise and will decide to stay and become lending officers and managers in their own right.

I. Summary of Recommendations

6.56 NEA's continued existence as the core agency serving the sector is justified primarily by the specialized requirements of lending to 117 financially weak enterprises that provide a service that is critical to the economic development of the rural areas. For this purpose, NEA needs the capacity to provide technical support to ensure that (i) the formulated loans support feasible and appropriate projects, and (ii) the RECs develop into institutions that operate well enough to repay their loans. Currently, NEA's staff of about 900 people are providing many of those support services. These activities need to be supplemented with more focussed loan programming, credit analysis, and loan administration functions. To perform its core functions effectively, NEA needs to restrict its business to providing finance and technical support for the distribution utilities serving rural areas, and should divest itself of those other activities that were only peripherally related to rural electric distribution. To coordinate its activities more closely with the energy sector, NEA should have the same reporting relationships as NPC, PNOC and OEA; it should be brought directly under the Office of the President, and report to the Executive Secretary. Finally, to begin the development of functional accountability that it urgently needs, (i) NEA should formalize its relationship with NPC by having the NPC president serve ex-officio as the NEA chairman, and the NEA Administrator assume an ex-officio seat on NPC's Board, and (ii) NEA should reserve one seat on its Board for a senior banker, and a second for a senior official of the Department of Finance.

6.57 Despite the strong impetus provided by its new management team, NEA is insolvent financially and unfocused in its lending function. NEA needs to (i) undergo a major financial restructuring in order to purge its balance sheet; (ii) adopt clearer lending policies; (iii) institute more precise loan administration procedures; and (iv) reorient its focus and its activities so that it serves primarily as an "interested" lender for rural electric systems.

6.58 Under the proposed financial restructuring, the Government would relieve NEA of responsibility for (i) ₱ 3.3 billion of advances that were provided to cover debt service obligations to foreign lenders that NEA could not meet from operations during the last few years; (ii) ₱ 1.9 billion of expected losses resulting from exchange rate variations related to NEA's foreign borrowings; (iii) ₱ 1.1 billion in loans that financed expensive self-generation facilities for small remote-island RECs; and (iv) assets and liabilities related to Government-sponsored alternative generation

and social programs. These measures would be realized by converting corresponding loans to equity. To complete the restructuring, NEA would reschedule its remaining delinquent loans to RECs. The stronger balance sheet ensuing from the proposed restructuring would enable NEA to be a magnet for increased official financial assistance for rural electrification.

6.59 To clarify its lending policies, NEA should (i) select investments according to economic criteria to ensure that projects that are funded have the highest potential returns; (ii) lend only for rehabilitation projects, add-on projects, system extensions and working capital support; (iii) develop standard lending instruments, with a basic interest rate pegged to NEA's average cost of capital plus a spread of 2-3% to cover NEA's loan generation expenses and overhead, and a second spread of 6-7% to cover the expected foreign exchange risk; (iv) maintain an interest rate structure, with rates kept within 1-2% of the basic rate; (v) develop a standard maturity of ten years and a standard grace period of two years, to be applied to all categories of loans; (vi) provide incentive for the RECs to pursue good quality investments, pay their debt service on time, and improve their operational and financial performance, through variations in the maturity and grace periods of loans; (vii) develop an Exchange Risk Fund into which NEA would make annual provisions based on 6.5% of its outstanding portfolio of foreign loans; and (viii) develop a pool, that the Government would fund with equity contributions of about ₱ 125 million per year, to support justifiable investments and provide typhoon relief to the financially non-viable RECs. In general, NEA should observe financial prudence practices, extending loans only after having conducted a proper credit analysis and applying to loans conditionality aimed at improving REC financial performance and institutional development. Transparent subsidies should be provided by the Government when NEA is required to support marginal projects for social or peace-and-order purposes.

6.60 To tighten its loan administration practices, NEA should improve its procedures for supervising loans. In particular, it should (i) reach agreement with each REC regarding the amount and terms of each outstanding existing loan; (ii) develop procedures, which include provision for realistic penalties, to improve its collection rate to at least 65% by 1993; and (iii) for future loans, tie releases of undisbursed amounts to the timely payment of existing obligations. To improve its ability to monitor its portfolio, NEA should obtain COA's permission to use accounting practices, including making provisions for uncollectible interest and principal payments and expensing many period expenditures that are currently capitalized, that are normal to Government financial institutions.

6.61 To reorient itself as an "interested" lender, NEA needs to establish a multi-disciplinary unit reporting directly to the Administrator that would be charged with applying sound banking principles in the formulation and implementation of a consistent medium-term lending program. This unit would be charged with (i) development of an indicative rational investment strategy; (ii) based on that strategy, formulation of an internally consistent lending program; (iii) assessment of specific REC investment proposals; (iv) based on those proposals, formulation of appropriate lending operations; and (v) supervision of the implementation of investments being financed by NEA. While NEA has staff with some of the skills required by this unit, it neither has currently in-house nor can attract during the medium term the requisite banking expertise; therefore, NEA will need to obtain this loan programming function on a consulting basis from a large Government bank. Such an arrangement could last for as long as ten years while NEA develops the necessary in house body of knowledge. Still, NEA's own staff assigned to loan programming should retain the responsibility for managing the lending program.

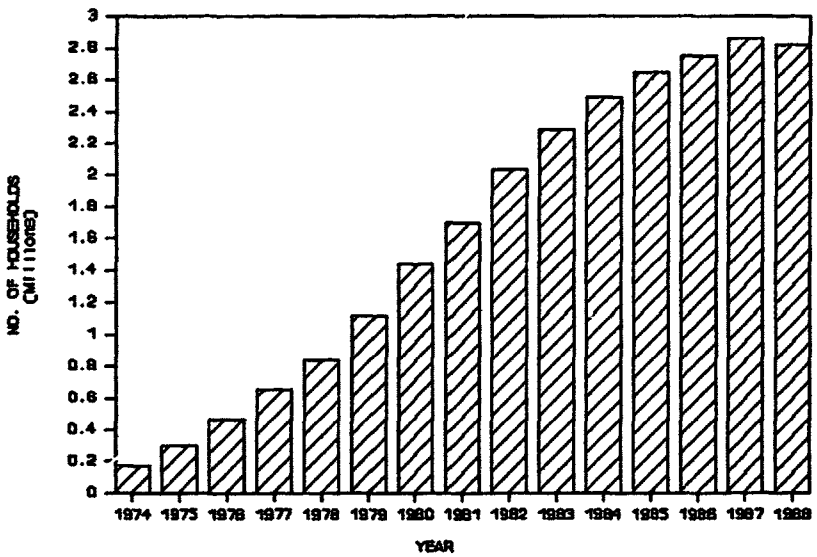
PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Consumers Served by the RECs

Year	No. of Consumers	Increase
1974	176,000	--
1975	299,000	70%
1976	465,000	56%
1977	653,000	29%
1978	845,000	29%
1979	1,118,000	32%
1980	1,441,000	29%
1981	1,700,000	18%
1982	2,034,000	20%
1983	2,284,000	12%
1984	2,492,000	9%
1985	2,648,000	6%
1986	2,752,000	4%
1987	2,857,000	4%
1988	2,825,000	-1%

CONSUMER CONNECTIONS



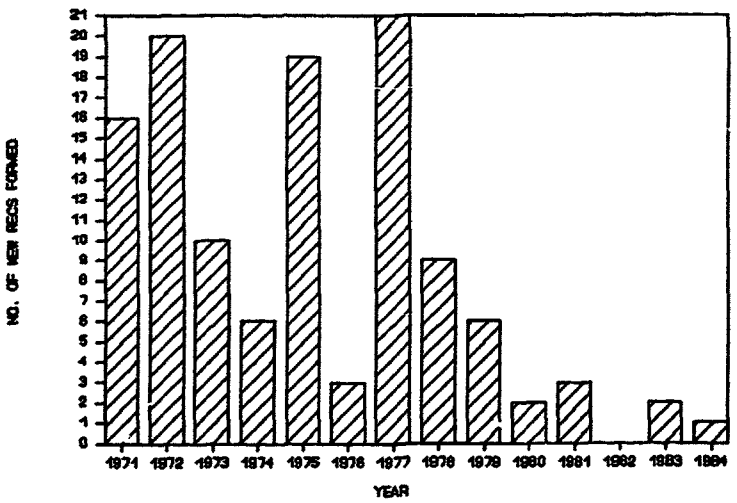
PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Annual Formation of RECs
(1971-88)

Year	No. of RECs Established
1971	16
1972	20
1973	10
1974	6
1975	19
1976	3
1977	21
1978	9
1979	6
1980	2
1981	3
1982	0
1983	2
1984	1
1985	1
1986	1
1987	-2
1988	-1
TOTAL	117

RECS ESTABLISHED BY YEAR



ANNEX 1.03

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Current Status of Mini-Hydro and Dendro-Thermal Programs

1. As of 1980, a development of a total of 75 mini-hydro sites were planned, including some 209 generating units with an aggregate capacity of 99 MW. Of the planned sites, 13 have been completed, six are still under construction, ten have been suspended while under construction, 24 were suspended after the equipment was delivered to NEA's main warehouse in the Philippines, 17 were suspended after the equipment had been purchased but not yet delivered to the Philippines (the equipment is being stored in the source country), and five were suspended in the planning stage. Nearly 70% of the units were supplied by People's Republic of China, with the balance being mainly of French and British origin. The program's major problems included (i) inadequate technical planning, (ii) insufficient site investigation and (iii) unsatisfactory hydrology. Only four of the installations are operating satisfactorily; the remaining nine are facing either insufficient water or site stability problems. NPC has now taken responsibility for this mini-hydro program and is investigating the feasibility of the implementing the remaining projects.

2. Beginning in 1980, a total of 12 Dendro-thermal projects were planned, including 13 of 3.2 MW each and four of 1 MW each. The total capacity of the plants was to be nearly 46 MW. Of the 17 planned projects, six were completed, three were suspended while under construction, five were suspended after the equipment was delivered but before the start of construction, and three were suspended while still in the planning stage. Balfour Beatty Engineering Ltd. of the U.K. was to have supplied six of the plants; Alsthom Atlantique of France was to have supplied nine of the plants; Mintours Duvent Diesel of France was to have supplied the remaining two plants. Technical details of the plants are attached.

3. The Dendro-thermal program envisaged growing trees on 1,000 acre sites over a five-year cycle. The mature trees, when felled, were to be cut into logs and crushed into wood chips for burning in the wood fired boiler of a nearby power plant. The first phase of the planting program was not successful in producing the expected number and quality of trees. The results from second cycle of planting were even poorer than the first due inadequate site preparation, lack of fertilizer, and generally careless farming. The wood processing equipment was poorly operated and maintained, so that the quality of timber chips was uneven. In turn, the boilers were unable to burn the timber chips so that none of them ever produced the rated output of steam. The manufacturers/suppliers have now stopped supporting the equipment they provided (originally supplied under bilateral aid programs). Finally, NEA lacked the in-house capacity to provide the RECs with adequate technical support in designing, planning, implementing, and operating generation plants of this type. NPC has now assumed responsibility for the program, and is investigating the possible use of local coal in the boilers.

ANNEX 2.01

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Kilometers of Line per Region by Design Parameter
(As of December 1987)

			13.2/7.6 kv			240 V	
Region	69 KV	DC	3-PHASE	V-PHASE	1-PHASE	SEC	CKT.KM.
Region I	0	24	1,998	662	3,498	5,753	16,713
Region II	44	35	1,676	377	1,444	1,819	9,387
Region III	27	7	1,412	700	1,178	1,770	8,707
Region IV	4	14	1,933	530	1,761	2,827	11,545
Region V	2	13	1,664	498	1,450	2,252	9,773
Region VI	261	35	2,021	371	3,086	3,144	14,030
Region VII	1	13	1,604	457	1,154	2,172	9,133
Region VIII	271	10	1,493	153	862	1,699	8,220
Region IX	10	14	846	504	686	1,103	5,449
Region X	104	14	1,675	794	1,897	2,573	11,477
Region XI	6	10	1,559	351	1,321	1,727	8,505
Region XII	154	40	1,131	502	1,332	1,052	7,484
SYSTEM TOTAL	884	229	19,012	5,900	19,669	27,891	120,423

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Consumers per km. of Line per Region

Region	HH/Consumers	CKT Km. as of 1988	Consumers/km.
Region I	395,939	15,965	24.8
Region II	177,857	9,455	18.8
Region III	390,892	8,173	47.8
Region IV	332,059	11,125	29.8
Region V	282,602	10,043	28.1
Region VI	275,396	14,457	19.0
Region VII	174,614	9,106	19.2
Region VIII	153,145	8,529	18.0
Region IX	119,783	5,223	22.9
Region X	229,310	11,575	19.8
Region XI	185,957	8,075	23.0
Region XII	102,153	7,484	13.7
SYSTEM TOTAL	2,819,707	119,210	23.7

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Distribution System Design Aspects of Technical Losses

1. Because of the direct relationship between voltage drop and system-losses in an electricity distribution system, this annex will discuss how design and system losses are related by distribution-line segments.

2. The electricity distribution systems are designed in relation to voltage drop: sub-station output is configured based on the number and location of consumers being served, and to the demand they place on the system. Generally, the system is designed so that the percent drop over peak load should not exceed 7%. The systems design are usually designed with a five year time horizon; at the conclusion of the period, expected demand for the next five year increment is recomputed and system-improvement requirements (e.g., voltage regulator additions, conversion of single-phase lines to 3-phase lines, etc.) are planned based on the new expectations for load growth.

3. The typical design standards for a 7620/13200 volt electricity distribution system in rural Philippines allowed for technical system losses of 12%-13% (not including substation transformer losses) for the five-year load-forecast cycle. This standard closely parallels the REA design standard for 7200/12470 volt rural lines in the U.S. Historically, the actual technical losses recorded in early years of REC operations in the U.S. were in the 11%-14% range. In the instance of Philippine RECs that built their systems to provide service in previously unserved area, the actual losses recorded in the early years of operation was in the 12%-15% range, comparing favorably with their U.S. counterparts.

4. Currently, at RECs in the U.S., where load growth has been substantial but distribution system improvements are keeping pace with that growth, total system losses have decreased to the 7%-10% range. In the Philippines, the RECs have shown the opposite trend.

5. The original design work, as performed by local architecture and engineering firms, was in line with the standard. Unfortunately, the REC systems have been operating for an average of 13 years, but the five year update of demand projections has not been developed and the corresponding distribution system improvements required have neither been designed nor implemented at the vast majority of RECs.

6. Although technical losses cannot be pinpointed exactly, they are estimated at about 17% for a typical REC system. This assumes the REC operates a 7620/13200 volt primary system and without any 2,400 volt primary lines remaining from predecessor operators. The range of technical losses for RECs without take-over lines could be as high as 20% in some of the high-loss Luzon RECs and as low as 14% in the best of the RECs. Losses attributable to primary lines may be about 3.5%, resulting inter alia from undersized conductors, poor conductor connections, improper right-of-way clearing, and cracked or defective insulators. Losses attributable to line-transformers may also be about 3.5%, due

mostly to improperly sized transformers and the use of poorly rewound transformers. Secondary line losses are estimated at about 4%, and result from (i) the excessive length of some of these lines, and (ii) factors similar to those causing primary line losses. Technical losses resulting from service drop lines, service entrances, and kWh metering could be as high as 6%, and result from (i) unmetered and undermetered consumer loads, and (ii) service-drop installations and connections that do not meet standards. Table 1 shows how the results realized compare with the design standards.

Table 1: Comparison of Realized Losses with Design Standards

	Design Standard	Probable Actual Losses
Primary Lines	3%	3.5%
Line-Transformers	3%	3.5%
Secondary Lines	3.5%	4%
Service Lines	2%	2.5%
Kwh Meters/Entrances	1%	3.5%
Total	12.5%	17%

7. The system should be designed to keep losses within maximum allowable tolerances; consequently, a realistic target for a rehabilitation project could be to reduce losses from an average of 17% to 12.5%, or a net reduction of 4.5%. The total energy sold to all the RECs is estimated at about 3,500 GWh; in turn, the RECs sell about 2,800 GWh to their consumers and the balance of about 700 GWh (about 25% of total REC sales) is estimated to be dissipated as losses. The energy supplied to the average REC is approximately 30 GWh. This could vary between about 10 to 100 GWh, depending on the size and load-density of the particular REC. A reduction in technical losses by about 4.5% would result in a saving of about 1.35 GWh per REC; valued at an average wholesale price of 1.05 pesos/kWh, the saving would be about ₱ 1.4 million per year for the average REC. Each REC has an average of about 2-3 substations and associated feeder networks; therefore, the saving per feeder system would be about ₱ 0.6 million, or US$30,000, per year.

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Current Condition of the Rural Distribution System

1. Field inspections of segments of electricity distribution lines at nearly 50 RECs, conducted during 1986-89 by USAID financed consultants, assessed the condition of the distribution systems nationwide as follows:

- 10% of the distribution systems are well maintained
- 25% of the distribution systems are maintained satisfactorily
- 35% of the distribution systems are maintained unsatisfactorily
- 30% of the distribution systems show no sign of maintenance

2. A partial list of the distribution systems' problems includes:

- uncleared rights-of-way
- rotting poles, with decay at and just below groundline
- leaning poles
- twisted and broken crossarms
- excessively sagging conductor
- spliced conductor, connected with guy clamps and loop dead-end clamps
- wrapped conductor connections, with no connectors
- no hot line clamps on equipment connections
- broken insulators
- loose and missing hardware
- pulled anchors, with guys that are slack or disconnected
- broken pole ground wires
- improper sized or no equipment fuse protection
- lightning arresters broken, missing, or gap too wide
- service-drops too low - hanging over roofs
- loose service entrance cable
- tilted kWh meters
- broken service entrance ground-wires or with rods missing

3. The most important electrical problem of the distribution systems is improper sectionalizing and fault-current control. The original sectionalizing studies are, for the majority of the RECs, outdated. The reasons include: (i) distribution systems that have been expanded or altered significantly since the study; (ii) OCRs that are not available in the sizes required; (iii) OCRs that were removed from lines years ago the source of power was self-generation; and (iv) OCRs that no longer function because of inadequate maintenance.

4. While fused cutouts have been installed (15 kV, 100 amp rated) on about one-half of tap-lines on the primary distribution system, 80% of the RECs have no records of fuse sizes in the cutouts and co-ordination with OCRs (if any) is non-existent.

5. About 35% of primary lines have serious drops in voltage during peak periods; and another 30% show drops that exceed design parameters. Line-type voltage regulators are used in about 20% of the RECs and would be used at another 20% if proper sizes of regulators were available. However, the preferred approach is to use capacitors because they offer the added benefit of voltage improvement.

6. Because so many capacitors have been installed, power-factor is not a serious problem at the majority of the RECs. Primary metering installations normally include power factor meters, which only register total kVAR; thus, power-factor for peak and off-peak periods is not known. From field checks, 24-hour power factor changes in the 10%-15% range were commonly observed in these low load-factor systems. Additional benefits could be realized by installing proper sized capacitors, to be located by actual load-study. Some of the larger-size banks should be switched in relation to load or time.

7. Sufficient numbers of lighting arresters are installed in 80% of the distribution systems. However, during the heavy construction period of the late 1970s, gaps were not set properly (on gap-type arresters); therefore about 15% of the arresters are improperly installed.

8. The voltage drop is excessive in about 40% of the secondary line due to: (i) absence of transformers for "splitting" the secondary; (ii) absence of larger-size conductors; (iii) high-resistance conductor-connections along the secondary; and, (iv) the addition of unmetered electric loads at night at some RECs (hooking-on to open secondaries for illegal house service or to "kill-rats" in rice fields).

9. Substation operating conditions vary. At about 5% of the substations, the original power transformers have failed. In most instances, they are still at the station, sitting idly on the side, with no prospect of being repaired. About 3% of the substations are missing one or more 69 kV lightning arresters. 40% of the substations have station-type voltage regulators installed, but one-third of these are not functioning. In most instances, the problem is in the control circuit of one of the three single-phase regulators, and the REC has removed all three regulators from service to avoid phase voltage imbalance.

10. About 70% of the substations had three-phase OCRs installed for individual feeder protection at the time of construction. Now, about 30% of these three-phase OCRs have malfunctioned and are out of service. The reasons include: (i) lightning damage; (ii) flashover at the bushings; (iii) loose terminal connection overheating; (iv) mechanical failure; or (v) lack of maintenance.

11. Single-phase OCRs and fused cutouts have been used unsatisfactorily to replace three-phase OCRs. Single-phasing on three-phase circuits results. Also, fault-current interruption capabilities are inadequate.

12. About 30% of RECs have made make-shift installations of meters, using unsuitable materials, on individual feeders. The safety and accuracy of these meters is doubtful.

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Recommendations for Improved Tree Clearing and Pole Treatment

Tree Clearing

1. Trees growing into and through rural electrification networks are a major problem in Philippines. Many of the trees are fruit-bearing. Because rights-of-way were not obtained during the construction phase and the trees are considered of value by their owners, the RECs nationwide have a problem of clearing branches from lines. The problem gets worse each year as the owners are increasingly resistive to attempts to cut or prune the trees.

2. The obstruction of distribution lines by trees causes many problems, including inter alia: (i) conductor breakages, (ii) technical losses, (iii) poor supply quality and continuity, (iv) flickering, and (v) posing a safety hazard to people and property. A regular annual program of tree-cutting to clear lines must be initiated and implemented on a continuous basis; this would only be possible if the RECs reach agreement with the landowners; such agreement could involve compensation. The costs of the program would primarily be for labor, with minimal additional expenditures on tools and equipment; based on average line lengths and unit prices and assuming a five year cycle for network configurations, this program is estimated to cost about US$2.5 million per year. As existing REC staff would be redeployed to perform this work, most of the cost of the program would not be incremental to the RECs but rather would be absorbed within existing cost structures.

Pole Treatment

3. All wooden poles require regular maintenance and cyclical treatment to reduce or prevent rotting; due to the public safety considerations, the periodic treatment of wood poles is mandated by regulation in some countries. The 1974 REA Bulletin on Pole Inspection and Maintenance outlines procedures to be followed in the U.S.

4. The usual maintenance and treatment cycle for poles is from 8 to 12 years; for most of the rural network in the Philippines the elapsed time for most poles since they were last treated has now exceeded this range. The average number of poles per REC is exceeds 8,000 and total for the country is likely to exceed 1 million. Between 10-15% of these poles are estimated to need replacement; about 30-35% need special treatment for rot; and the remainder need standard treatment. To develop an accurate cost estimate for a pole maintenance program, each REC would need to develop detailed on-the-ground inspections; however, based on the number of poles involves and unit costs and using a ten year cycle for maintenance and treatment, the needed pole maintenance program is estimated to cost about US$5 million. As much of this money would be spent for goods and materials, the cost of the program would be incremental to the RECs.

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Zonal Repair Facilities to Service the RECs

1. Millions of dollars worth of electrical equipment, operational and maintenance apparatus, and tools were purchased and distributed to the RECs during the 1970s and early 1980s; however, little consideration was given to the maintenance or upkeep of what was distributed. Little attention was paid to assessing the capabilities of the RECs to provide for their own maintenance or determining how to provide the RECs with those aspects of maintenance that exceeded their capacity. No system or plan was developed for the procurement and distribution of spare parts. Because of insufficient training of equipment operators with regard to maintenance procedures, assets became inoperative and were removed from service much sooner than expected. For the most part, many assets that could be repaired and restored to service remain idle and inoperative at REC storage.

2. The following are the major categories of idle equipment:

(a) Distribution System Equipment

(i) Line-type transformers
(ii) OCRs (3-phase and single-phase)
(iii) Voltage regulators
(iv) Sectionalizers and oil switches
(v) Lighting control-equipment
(vi) Metering transformers (including potential, and current transformers)
(vii) Specialized kW/kWh/kVAR meters
(viii) Mini-max indicating ampere meters

(b) Test Equipment

(i) Recording volt-amp meters and watt meters
(ii) Indicating volt-amp meters and watt meters
(iii) kWh meter rest sets
(iv) Insulation testers and meggers
(v) Rubber-glove test sets
(vi) Communication equipment and test sets
(vii) Oil test sets

(c) Tools and Related Equipment

(i) Hydraulic compression tools
(ii) Hand operated compression tools
(iii) Coffin hoists (wire pullers)
(iv) Climbing equipment for linemen

(d) Safety Equipment

(i) Hot-sticks
(ii) Rubber gloves (Untested)

3. A review of the problem conducted during 1986 indicated that an estimated average of US$30,000-35,000 per REC of equipment, apparatus, and tools were laying idle. A second review, conducted during 1988-89 concluded that, on average, the estimate of machinery laying idle had risen to about US$45,000-50,000 per REC. The same review concluded that the replacement value of idle equipment nationwide exceeded US$5 million, and the quantity of idle equipment is increasing steadily.

4. The RECs can do little by themselves to remedy this problem. They lack the skills and the resources to address most of their repairs requirements. The only action that some have initiated was to attend to the rewinding of small-size transformers, in some cases at their own premises using their own staff, and in other cases by sending the transformers to local shops for rewinding. With few exceptions, the results of these efforts was not satisfactory; because the rewinding was done by hand without proper test instruments to insure quality control, rewinding costs were high and core-coil losses of rewound transformers were usually excessive.

5. Service Centers to serve the RECs are badly needed. Consultants for USAID had recommended that six to eight such centers should be strategically located throughout the Philippines. All of the centers should be equipped to provide the "normal range of services" described in para. 6 below; two of the centers (possibly located in Manila and Cebu) should be fully equipped to provide not only "the normal services" but also to repair and rewind power transformers (the type used in substations).

6. Normal services to be provided by these centers could include:

(a) Stocking Supplies to be made available for the RECs to purchase. These stores would include spare parts (A) and complete units (B):

"A"
- Transformer bushings and other parts
- OCR bushings and other parts
- Voltage regulator bushings and other parts
- Replacement parts for other line equipment and apparatus
- Replacement parts for test equipment
- Replacement parts for lighting equipment
- Replacement parts for multi-phase kW/kWh metering equipment
- Replacement parts for tools and related equipment
- Replacement parts for communication equipment
- Other replacement parts

"B"
- Complete units - transformers, OCRs, and regulators
- Complete units - test equipment
- Complete units - tools and related equipment
- Complete units - safety equipment (hot sticks, gloves)
- Complete units - lighting controls

(b) Repairs and Other Services. These would include special services (A), regular services (B), and mapping (C):

"A"
- Rewinding, repair and testing of line-type transformers.
- Rewinding, repair and testing of OCR Equipment
- Rewinding, repair and testing of voltage regulators
- Repair and testing of other line type equipment
- Repair and adjusting of electrical test equipment
- Repair and testing of lighting control equipment
- Repair and adjusting of tools
- Repair and testing of communication equipment

"B"
- Periodic frequency checks of communication equipment
- Bi-monthly testing of rubber gloves
- Semi-annual testing of hot-sticks

"C"
- Assistance in the preparation of system maps
- Reproduction of key maps and detail maps

7. The RECs would arrange to leave equipment needing repair at the centers while, at the same time, collecting identical new or reconditioned replacements. Alternatively, when appropriate, center personnel would provide services to the RECs on location.

8. In all likelihood, the centers will be owned and managed by NEA. Under its current project, USAID is providing technical assistance to NEA; that consultancy will include a component to study (i) where the centers should be located, how they should be managed, the extent of service they should provide, and the cost of making them operational. In turn, under the proposed Energy Sector Loan, the Bank is providing NEA with nearly US$1 million to establish and equip the centers and train the centers' prospective staff. On this basis, the centers should be ready to provide service to the RECs by mid 1991. The Regional Associations of RECs that NEA is developing may be given a role in operating and managing these service centers.

ANNEX 2.07

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Transformer Circuit Metering - The BAPA Model

1. The average REC in the Philippines uses about 600 line-type transformers to serve about 23,000 consumer-connections. Except in small-island RECs, a single-phase transformer serves an average of 35 to 45 consumers.

2. In the mid-1980s, NEA began promoting the formation of Barangay Power Associations (BAPA) to act on behalf of consumers served by particular transformers (one or more). The BAPA becomes a single consumer-connection for REC billing purposes; it then is responsible for billing and collecting from its membership. Three important objectives of BAPA formation include: (i) to reduce the RECs' expenses for meter reading and billing; (ii) to reduce non-technical losses on secondary and service lines1/; and (iii) to provide a modest income to the BAPA through the differential between the energy rate billed by the REC to the BAPA and the regular retail rates applicable to the BAPA's eventual consumers. At RECs with a consumer base made up primarily of farmers and with only a small commercial load, the BAPA concept is working effectively. However, at RECs formed to take control of systems left by failed predecessors, the consumer members seem to have much less interest in the affairs of their REC. In these cases, the BAPA program has not been well received.

3. Installing kW/kWh meters on the transformer pole at all single-phase line-type transformer locations has benefits that transcend the BAPA program. These benefits include: (i) relating kW demand to the load on the transformer to determine whether the transformer is under or overloaded; and (ii) energy consumption recorded on this master-meter can be compared with the energy consumption billed to all the consumers served from that particular transformer, and thereby identify pockets of non-technical losses. Installing master-meters high on the transformer pole is an inexpensive way to minimize tampering. Self-contained kW/kWh meters can be used with 10 kVA and 15 kVA transformers, and transformer-rated meters can be used together with one current-transformer on larger size transformers. The cost of one typical kW/kWh meter installation is about US$150. Their benefits, including (i) detecting transformer overload and preventing burnout; (ii) detecting oversized transformers that contribute to technical losses; and (iii) pin-pointing non-technical losses to a particular circuit, are much greater than the cost of installing the master-meter. To achieve maximum benefits, transformer locations would need to be numbered. In turn, consumer account numbers would need to contain additional numbers to identify the transformer from which electric service is received. The master-meter would be read monthly on the same date that the consumer meters along that secondary are read.

4. Any program of distribution system rehabilitation should include a provision for "transformer-circuit metering". The cost of this provision is likely to average about US$100,000 average per REC.

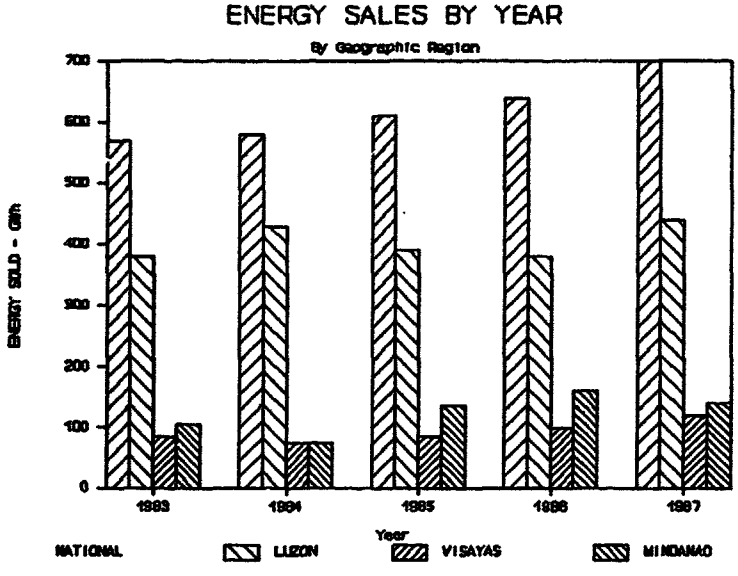
1/ Because the REC's meter is placed at the transformer, the BAPA would bear responsibility for losses beyond the transformer.

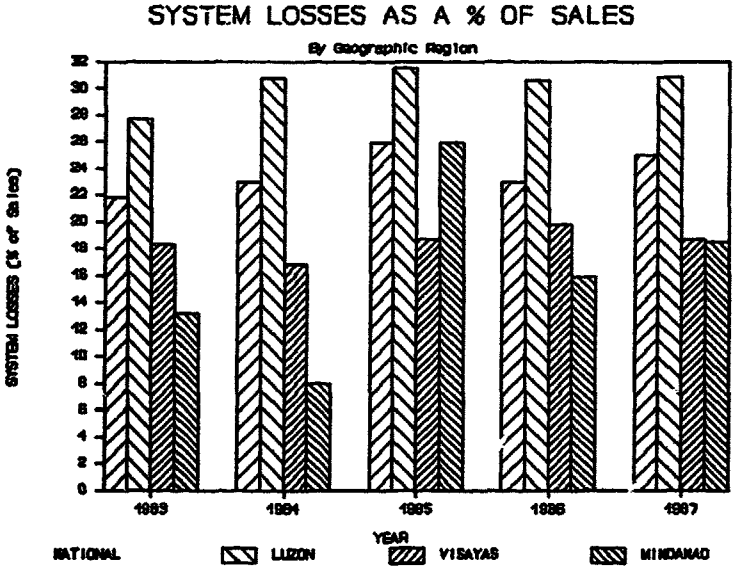
ANNEX 2.08

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Annual Energy Sold and Losses
(By Geographic Region)





PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Program to Reduce Non-Technical Losses

Causes of Losses

1. For this Annex, non-technical losses are categorized as follows:

"A" - Losses created by, or with assistance from, REC employee(s).

"B" - Losses created by innovative consumer actions, with or without assistance from an REC employee or an outside electric energy "theft-artist."

"C" - Losses that are strictly pilferage by wire tapping.

2. In group "A" (REC-employee involvement), the activities which result in energy losses are:

(a) Falsifying billing records to show a consumer as having been disconnected.

(b) Recording lower than actual meter readings.

(c) Tampering with meters to record less than actual consumption.

(d) Place a wire jumper in the socket of socket-type meters; once reset, the meter will record only about half of actual consumption.

(e) Seal the meters improperly during installation to enable undetected tampering by the consumer.

3. Group "B" (Consumer action) includes these various "tricks" that distort recorded consumption:

(a) On "A" Base, bottom-connected meters, tilt the meter so that the bearings controlling the disk bind and the disk slows or stops.

(b) Place permanent magnets on the outside of the meter glass to influence the rotational speed of the meter disk.

(c) Drill a small hole in meter-glass and insert an object to stop or slow the disk's rotation.

(d) Connect a reversing transformer on the internal wiring circuit and thereby slow dramatically the rotational speed of the disk.

4. Group "C" (direct pilferage of electric energy) methods of theft usually involve the following:

(a) Directly connecting wires to open secondary lines.

(b) Directly connecting wires from the service drop to the service entrance connection at the consumer's premises.

(c) Directly connecting wires to the conductors in the kWh-meter service entrance cable (usually by using pins or nails).

(d) Reversing or altering the conductors at the bottom-terminals of "A" Base, bottom connected meters.

(e) Interchange connections at the service drop to service entrance cable connection at the consumer's premises, so that the ground is the conductor to which the 2-W kWh meter, single current coil, is connected in series. By using a makeshift ground at the load, the meter records much less than full consumption.

5. The foregoing presents the methods of pilfering electricity commonly used by residential and small commercial consumers in rural areas of the Philippines. Pilferage at large commercial or industrial consumer premises (where the meter is transformer-rated using current transformers) are more likely to rely on the following methods:

(a) In collusion with REC staff, compute the meter-reading multiplier incorrectly so that false information is provided to the REC billing department and billed consumption is less than actual.

(b) Shunt the current transformer output so that much of the current flow does not pass through the meter.

(c) When consumers are required to supply their own three-phase meters, purchase a meter (either from a big-city market or a theft-expert) in which the gear chain has been replaced with one of a higher ratio. REC metermen have difficulty detecting the error since, even though the register was changed, the speed of the disk in relation to load is still correct.

Loss Reduction

6. At many of the RECs, employee morale is low due largely to: (i) too frequent changes in REC management; (ii) inadequate opportunities for advancement; (iii) relatively low salaries; and (iv) absence of a good wage and benefits plan. These factors provide an inducement for employees to collude with consumers to pilfer electricity. However, morale-building alone is not a sufficient remedy for this problem. REC management must become directly involved in curbing losses where REC staff is in collusion with consumers.

7. The RECs have an internal audit department charged with policing cash-flow. A unit within internal audit should be created for monitoring non-cash commercial activities, including the activities of meter readers, metermen, and linemen. The main function of this proposed unit would be meter control. The RECs have a clear weakness in controlling the handling of meters. Since meters are handled by meter-testing personnel, warehousemen, linemen, installers, and readers, too many opportunities exist for manipulation.

8. The collusion of consumers with professional electricity thieves who are not REC employees is more difficult for REC management to control. Tough enforcement of laws, which are stricter and carry greater penalties than those currently on the books, is needed to address this particular crime.

9. The following actions reduce significantly pilferage among residential and small commercial consumers:

(a) In areas where tapping of secondary lines is a problem, change the secondary phase-conductor to insulated conductor. Tape or otherwise cover all connection points to this phase-conductor so that no open wire connector point exists.

(b) Replace all service-entrance cable (average of three meters length per house) with concentric neutral cable to eliminate the possibility of direct nail-pin tapping.

(c) Use compression connectors at all service-drop wire to service entrance cable connection points. Tape or cover these securely.

(d) Replace large numbers of "A" Base, bottom connected meters, and install new meters so that they cannot be tilted. Test and adjust the meters taken from service. Repeat this process until all "A" Base, bottom connected meters have been changed.

(e) Remove and inspect all socket type meters for jumpers.

(f) Reseal all meters at the time of inspection or replacement.

10. A thorough inspection of meter circuitry should be conducted at all commercial and industrial consumer premises. Primary amp readings should be taken and compared with secondary amp readings to verify the current transformer ratios. The RECs should provide locked compartments in which current transformers would be enclosed to prevent shunting. Meter multipliers should be verified. Three-phase meters should be tested, at least on site, to verify their accuracy. The ratio of meter registers should be checked to determine if it is correct for the particular meter. Three-phase metering installations should be checked semi-annually for commercial and industrial consumers.

11. The work programs outlined above can be undertaken in the context of a program to rehabilitate substations and associated feeders. The potential benefits of a program to reduce non-technical losses is very high, as these losses represent more than 30% of the total distribution system losses. The average loss per REC is estimated at 25% of sales; of this, about 17% is the estimate for technical losses and the balance of 8% is the estimate for non-technical losses. The management actions described above, if effectively and consistently applied, could quickly reduce non-technical losses in the average REC from 8% to 2%. The elimination of non-technical losses altogether would take longer to achieve. As outlined in Annex 4.03, a reduction of 6% for non-technical losses would represent an annual saving of ₱ 1.9 million per year for an average REC (and more than double that for many RECs in Luzon). The saving per substation and associated feeder network, calculated on a similar basis, would be about ₱ 0.8 million, or approximately US$40,000, per year.

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Pilot Program for Rehabilitating Substations and Feeders

Substation Component

Objectives:

1. (a) To provide all of the major electrical equipment for the installation of additional 69/13.2 kV substation capacity at participating RECs; (b) to provide automatic voltage regulating equipment at participating RECs where voltage levels on the 69 kV source dictate a need; (c) to supplement the RECs' existing stock of three-phase oil circuit reclosers to provide proper distribution-feeder fault-current protection and sectionalizing on substation feeders; (d) to provide 69 kV metering equipment to supplement the existing equipment at the RECs to provide high-side 69 kV metering installations for all the substations being provided; (e) to provide 13.2 kV metering to supplement the existing equipment at the RECs and thereby enable 13.2 kV primary metering on all substation feeders; and (f) to provide substation accessories, fuses, switches, lightning arresters.

Scope of Work

2. New Substations. The RECs and NEA have selected the site for the new substations. These have been agreed with NPC.

(a) Land acquisition for substations will be the responsibility of the REC. The material and labor for substation erection will be provided by the REC, with NEA assistance.

(b) The major equipment items for the substations include: power-transformers, voltage regulators, oil circuit reclosers, and substation auxiliary equipment. Installation of this equipment in the respective substations shall be the responsibility of the RECs, with NEA supervision.

(c) NPC shall provide the 69 kV tap-lines to the substations, and will assist the REC in the installation of 69 kV metering equipment.

3. Individual Power Transformers. NEA shall be responsible for delivery of these items to the RECs. Installation of the transformers at the existing substations shall be the responsibility of the RECs.

4. Voltage Regulators, OCRs, Other Auxiliary Substation Equipment. NEA shall be responsible for delivery of these goods to the RECs. The RECs shall install this equipment with NEA guidance.

Distribution System Component

Objectives:

5. (a) To restore to original operating condition 69/13.2 kV substations and all associated electrical distribution lines and apparatus, for commercial use in electricity distribution; (b) to provide a durable system, with increased distribution system capacity, proper voltage levels, adequate system protection, and a minimum of system energy losses.

Scope of Work

6. Substations. Where required: (a) increase substation transformer capacity; (i) install automatic voltage regulators; (b) install three-phase OCRs on individual feeders; (c) install primary 13.2 kV/kWh/kVAR metering on individual feeders (d) add substation auxiliary equipment to supplement existing equipment; and (e) completing installation of equipment-requirements in the affected substations.

7. Tighten all hardware: (a) ground-line treatment of wood poles in substation structure; (b) inspection of substation grounding network; and (c) general improvement of substation area.

8. Primary Distribution Lines. Rebuild all lines that are still operated at non-standard voltage to a 7,620/13,200 kV system.

(a) Poles: (i) Groundline (1/2 meter below ground) and above ground inspection of all poles in the primary lines; (ii) groundline-treat all poles which still appear to be sound; (iii) replace all poles that show signs of uncontrollable decay; (iv) straighten or re-tamp poles as required.

(b) Crossarms and Hardware: (i) Straighten or recant crossarms that are still sound and replace damaged, broken crossarms; (ii) replace or add hardware items and tighten all hardware.

(c) Insulators: (i) Replace all cracked or broken insulators; (ii) clean all insulators along coastal areas.

(d) Guys and Anchors: (i) Add additional line-support as required; (ii) pull guys to proper tension and proper "Rake" on poles; (iii) add guy-guards as necessary: (iv) connect or reconnect grounds to guy wires as required.

(e) Pole-grounds: (i) Reinstall pole-grounds where missing or broken; (ii) check ground rods and clamps; (iii) restaple ground wires; (iv) check connections, pole-ground to system neutral; (v) check for proper clearance, ground wire to pole hardware.

(f) Rights-of-way: (i) Clear all trees, shrubs, branches to proper distance from conductors; (ii) remove or relocate antennas and other man-made hazards near conductors.

(g) Conductors: (i) Reconductor sections of the primary line near substations where present or projected load would result in excessive voltage drop using existing conductors; (ii) re-sag, retie, and re-deadend existing conductor as required; (iii) replace temporary, incorrect splices and sleeves with proper compression connectors.

(h) Conductor Connections: (i) Replace temporary connectors in use at conductor deadends, tapping points with proper compression connectors; (ii) at points where electrical apparatus is connected to conductors, install proper hot-line clamps.

(i) Line-Type Transformers: (i) Increase or decrease transformer sizes by replacement as necessary; (ii) add additional transformers where secondary-line loads are split; (iii) inspect and correct as needed fuse protection on conventional transformers; (iv) and tighten all conductor-transformer connections.

(j) Protective Devices: (i) Maintain existing OCRs; (ii) relocate OCRs as necessary; (iii) add additional OCRs as required; (iv) Relocate or add fused cutouts on all taplines, properly fused to coordinate with OCRs; (v) tighten all conductor-OCR connections.

(k) Voltage Regulation: (i) Add line-type voltage regulators and capacitors as required; (ii) tighten all conductor-regulator connections.

(l) Lightning Protection: (i) Connect all lightning arresters on newly installed combination fused-cutouts and arresters; (ii) inspect connections and gap settings on all existing arresters.

9. Secondary Lines:

(a) Poles: (same as for primary lines)

(b) Hardware/insulators: (same as for primary lines)

(c) Guys and Anchors and Pole-Grounds: (same as for primary lines)

(d) Rights-of-Way: Clear all trees, shrubs, branches to proper distance from conductors.

(e) Conductors: (i) Replace bare open-secondary phase wire with insulated conductor along lines designated in illegal-connection areas; (ii) "Split" secondaries to reduce load on individual transformers and to reduce energy losses; (iii) Re-sag, re-tie and re-deadend as required; (iv) Replace temporary, incorrect splices and sleeves with proper compression connectors.

(f) Conductor Connections: Replace temporary, improper connectors in use at conductor deadends, junctions, tapping points, (including connections service drop wire to secondary conductor) with compression connectors.

(g) Apparatus Connections: (i) Inspect and tighten all conductor connections at transformers and/or other apparatus; (ii) replace any aluminum-copper connections.

10. Service Lines.

(a) Lift Poles: (i) Maintain in the same manner as primary and secondary lines; (ii) install additional lift-poles to establish proper clearances above ground.

(b) Pole-Deadend: Install proper bracket clevis or spool insulator at points where service-drop conductors are attached to poles.

(c) Conductors: (i) Install larger-size duplex for large-residential and small commercial loads as warranted; (ii) Re-sag or rearrange duplex service drop wire in congested areas to eliminate wire contact with roofs or buildings and other obstructions; (iii) re-sag, re-deadend as required.

(d) House-Deadend: (i) Install screw-type insulated wire holder (or clevis type insulated wire holder) where presently missing, and deadend properly; (ii) connect the duplex conductors to the service entrance conductors with compression connectors; (iii) install insulated sleeve or tape protection over connectors (after the service entrance cable has been replaced).

11. Service Entrances.

(a) Cables: (i) Replace all 2-W #10-CU NM entrance cable with conductor of the concentric-neutral type; (ii) staple properly and connect to service-drop conductors with taped or covered compression connectors.

(b) Grounds: (i) Inspect, reconnect, or replace grounds at consumers metering locations to assure proper-solid grounding of neutral conductor, socket and meter.

12. kWh-Meter Installations.

(a) Remove all socket type, "S" Base, meters from their sockets temporarily. Check for jumpers in the meter sockets. Assure that sockets are properly attached to prevent turning. Assure that socket-hubs are sealed (or seal them) to prevent moisture and insects from entering. Tighten connections in sockets. Inspect kWh meters. Replace and reseal kWh meters.

(b) Replace large quantities of "A" Base, meters. Re-install new or newly tested kWh meters assuring that: (i) connections are correct; (ii) terminal connectors are tight; (iii) double mounting-screws are installed to prevent meter turning; (iv) meter-cover tighten to prevent entrance of moisture; and (v) seal properly all kWh meters. Test kWh meters which were removed from service. Repeat the process until all "A" base meters have been tested.

(c) Commercial and Industrial Metering Installations: (i) Test all three-phase kWh meters; (ii) determine applicability of meter to load; and (iii) check register-ratios on all meters.

(d) Current transformer installation: (i) Verify size and ratio of current transformer; (ii) verify kWh-reading multiplier; (iii) protect current transformers and wiring by placing them in locked, properly installed REC-owned compartments. (Inspect and measure voltage output on power transformers if in use.)

Technical Criteria for Assigning Priority to Rehabilitation Prospects

13. Criteria for selecting among prospects for projects to rehabilitate distribution systems would include:

(a) Existence of non-standard voltage distribution lines on substation feeders (benefit to be realized by rebuilding to standard design is substantial).

(b) Physical condition--extent of typhoon damage.

(c) Physical condition of distribution lines--extent of wood pole decay (a serious problem at most RECs).

(d) Electrical condition--extent of overload, voltage drop, technical system-losses.

(e) Extent of non-technical system-losses.

(f) Importance of the substation service area by comparison to other REC-owned substations--presence of commercial or industrial loads.

(g) Potential for additional consumer-connections.

(h) Condition of distribution system electrical apparatus--transformers; OCRs, regulators, capacitors, lightning arresters, and cutouts.

(i) Electrical condition--phase imbalance, low power factor, sectionalizing problems.

(j) Physical condition--condition of guy-anchors; leaning poles; conductor sag.

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

NEA Investment Requirements Survey 1988

Original Funding Requirements 1988/89
(Pesos 000)

Region	Add-Ons	Expansion	Rehab	Total
I	9,890	19,251	47,771	76,912
II	16,480	12,359	53,559	82,398
III	10,671	79,446	96,459	186,576
IV	28,243	103,901	66,888	199,032
V	16,186	114,221	47,146	177,553
VI	40,000	30,000	130,000	200,000
VII	12,646	9.486	41,100	63,232
VIII	26,209	19,658	85,181	131,048
IX	12,449	54,065	14,851	81,865
X	24,506	18,380	79,645	122,531
XI	40,610	107,508	30,581	178,699
XII	3,126	8,376	10,682	22,184
TOTALS	241,016	576,651	703,863	1,521,530

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

NEA Investment Requirements Survey 1988

Revised Funding Requirements - 1989
(Pesos 000)

Region	Add-Ons	Expansion	Rehab	Total
I	3,501	2,502	27,665	33,668
II	4,455	8,487	17,758	30,700
III	5,900	7,001	31,099	44,000
IV	7,380	5,535	23,985	36,900
V	6,389	5,051	25,164	36,604
VI	12,446	5,000	18,440	35,886
VII	5,235	3,816	15,232	24,283
VIII	6,077	4,685	17,680	28,442
IX	4,856	17,336	15,302	37,494
X	8,477	5,205	16,220	29,902
XI	13,280	21,310	23,963	58,553
XII	3,490	2,500	10,700	16,690
TOTALS	81,486	88,428	243,208	413,122

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

PHYSICAL TARGETS

PROJECT	INDICATOR		1989 I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	AVE/TOT
REHABILITATION	SERVICE VOLTAGE (V)	ACTUAL	220	220	204	218	215	200	220	200	217	270	220	214	216
		TARGET	230	225	222	229	200	216	230	230	239	253	230	222	220
	LENGTH OF LINES (CKT KMS)		231	206	362	864	633	75	386	110	320	90	109	312	3,886
	SYSTEM LOSS (%)	ACTUAL	20	26	37	24	25	20	17	24	22	16	15	20	25
		TARGET	24	22	27	23	20	18	11	17	21	13	14	17	19
ADD-ON	NO. OF CONNECTIONS		3683	4,989	5,000	7,600	7,127	10,770	8,948	13,550	8,186	9,000	11,681	3,286	90,000
EXPANSION	LENGTH OF LINES (CKT KMS)		98	166	97	107	32	98	90	86	220	59	207	26	1,280
	NO. OF CONNECTIONS		1,709	3,902	3,000	791	3,377	828	948	2,335	6.152	996	3,302	1.092	28,392

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Sample Feasibility Studies

Benefit Calculation for Residential Consumers

I. USE OF ALTERNATE ENERGY

Kerosene:

Initial Cost = ₱ 800.00
Fuel Cost = ₱ 60.00/month
Repair = ₱ 20.00/month

Assumption:
Life = 10 years
i = 7%

Annuity/month = ₱ 9.287

Monthly Expenses = ₱ 9.287 + ₱ 60 + ₱ 20
= ₱ 89.29

Cost per Kwh = $\frac{₱\ 89.29}{24}$
= ₱ 3.72

Assumption: typical kerosene use time about two thirds of electric lighting time.

II. USE OF ELECTRICITY

Cost of Housewiring = ₱ 1,300

Assumption:
Life = 30 years
i = 7%

Annuity/month = ₱ 8.60

Cost per Kwh = $\frac{₱\ 8.60}{36}$ = ₱ 0.24

Adjusted cost/Kwh = ₱ 1.98 + ₱ 0.24
= ₱ 2.22

III. INTEGRATION

Adjusted cost of Electricity/Kwh = $\frac{₱\ 3.72 - ₱\ 2.22}{2}$ + ₱ 2.22
= ₱ 2.97

Assumption:
Linear sloping demand function

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Sample Feasibility Study - Expansion (Mainly Industrial) (Capiz)

(P'000)

	Year 1	2	3	4	5	6	7	8	9	10	11-25
Incremental Sales (MWh)	-	1456	5093	7499	7941	8394	8852	9121	9348	9888	10811
Incremental purchase (15% loss)	-	1713	5992	8822	9342	9875	10414	10731	10998	11630	12719
Incremental Benefit (tariff)	-	2596	9055	15442	17594	20058	21128	21759	23241	25641	29520
Invest. cost (P'000)	3131	5842	3106	107	183	190	195	198	100	106	-
O&M at 5%		157	438	594	599	608	618	638	638	643	648
Consumer Admin. Cost	-	400	400	400	400	400	400	400	400	400	400
Cost of purchase (0.72/Kwh)	-	1233	4314	6352	6726	7110	7498	7726	7919	8374	9158
LRMC of purchase (1.31/Kwh)	-	2244	7850	11557	12238	12936	13642	14058	14407	15235	16662
Total cost (fin.)	3131	7432	8258	7453	7908	8308	8711	8952	9057	9523	10206
Total cost (econ.)	3131	8443	11794	12658	13420	14134	14855	15284	15545	16384	17710

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Sample Feasibility Study - Rehabilitation & Add-on (Pelco I)

(P'000)

	Year 1	2	3	4	5	6	7	8	9	10	11-25
Increm. sales (MWh)	-	2916	5304	8076	10788	10968	11172	11640	11856	12084	12396
System loss (%)	24	22	22	21	20	19	18	17	16	15	15
Increm. purchase (MWh)	-	3837	6800	10223	13485	13540	13624	14024	14114	14216	14584
Increm. revenue (P'000)	-	5770	10533	16035	21391	21755	22149	23072	23531	23974	24589
Increm. econ. benefit	-	7828	14262	21839	29020	29525	30703	31960	31960	32559	33332
Invest. cost (P'000)	7352	2830	2415	2825	36	44	37	38	39	46	-
O&M of 8%	-	588	815	1008	1234	1[illegible]	1240	1243	1246	1249	1253
Consumer Admin. Cost	-	160	160	160	160	160	160	160	160	160	160
System Loss Reduction Cost	493	493	493	493	493	493	493	493	493	493	493
Cost of purchase (P 1.145/Kwh)	-	4393	7786	11705	15440	15503	15599	16057	16160	16277	16699
LRMC of purchase (1.31/Kwh)	-	5026	8908	13392	17665	17737	17847	18371	18489	18623	19105
Total cost (fin.)	7845	8464	11669	16191	17363	17437	17529	17991	18098	18225	18112
Total cost (econ.)	7845	9097	12791	17878	19588	19671	19777	20305	20427	20571	20518

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Sample Feasibility Study - Rehabilitation Only (Pelco I)

(P.'000)

	Year 1	2	3	4	5	6	7	8	9	10-25
Volume (MWh)										
Sales without rehab. (MWh)	3156	3240	3336	3432	3528	3624	3720	3828	3936	4044
Sales with rehab. (MWh)	3156	3372	3588	3804	4020	4236	4452	4668	4884	5100
Increm. - Sales	-	132	252	372	492	612	732	840	948	1056
Syst. losses w/o rehab. (%)	24	24	24	24	24	25	25	25	25	25
Syst. losses with rehab. (%)	24	23	22	20	18	16	15	14	13	12
Purchase w/o rehab. (MWh)	4153	4263	4389	4516	4642	4832	4960	5104	5248	5392
Purchase with rehab. (MWh)	4153	4379	4600	4755	4902	5043	5237	5478	5614	5795
Increm. purchase	-	116	116	211	239	263	211	277	374	366
Cost (P'000)										
Capital cost	6853	2462	1979	2315	14	14	14	14	14	-
Non-tech. loss reduction cost	493	493	493	493	493	493	493	493	493	-
O&M at 8% of cap. costs	-	546	745	904	1089	1090	1091	1092	1093	1094
Increm. cons. admin. cost	-	149	149	149	149	149	149	149	149	149
Cost of increm. purchase (P 1.145/Kwh)	-	133	133	242	274	298	242	317	419	461
Total cost	7346	3785	3785	3608	4135	2043	1988	2176	2168	1704
LRMC of increm. purchase (P1.31/Kwh)	-	152	276	313	345	276	636	490	479	528
Total cost	7346	3804	3642	4174	2090	2022	2110	2238	2228	1771
Benefit (P'000)										
Tariff based (P1.98/Kwh)	-	261	499	737	974	1212	1449	1663	1877	2091
Econ. benefit (P.2.97/Kwh)	-	392	778	1104	1461	1818	2174	2495	2816	3136
No sales growth: MWh purch. saved	-	54	107	208	304	396	440	483	525	566
Cost saving benefit	-	71	140	272	399	519	576	633	688	742

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RURAL ELECTRIFICATION SECTOR STUDY

Sample Feasibility Study - Expansion (Mainly Residential) (Leyte V)

(P'000)

	Year 1	2	3	4	5	6	7	8	9	10	11-25
Increm. sales (MWh)	-	120	341	615	1020	1506	1841	2198	2586	2953	3390
Increm. purchase (15% loss)	-	141	401	724	1200	1772	2166	2586	3042	3474	3988
Increm. revenue (tariff)	-	139	395	713	1186	1753	2149	2569	3024	3454	3966
Increm. econ. ben. (Res: 2.61/kWh)	-	284	807	1435	2310	3376	4041	4752	5521	6289	7183
Invest. cost	2742	4753	4607	5014	5043	590	590	610	594	63	-
O&M of 5%	-	137	375	605	856	1103	1137	1167	1197	1227	1230
Consumer Admin.	-	25	25	25	25	25	25	25	25	25	25
Cost of purchase (P 0.94)	-	133	377	680	1128	1665	2036	2431	2860	3266	3749
LRMC of purchase (P 1.12)	-	158	449	811	1344	1985	2426	2893	3407	3891	4467
Total cost (fin.)	2742	5048	5384	6324	7052	3383	3788	4233	4676	4581	5004
Total cost (econ.)	2742	5073	5456	6455	7268	3703	4178	4698	5223	5206	5722

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Sample Feasibility Study - Rehabilitation & Expansion (Tarlac II)

(P'000)

	Year 1	2	3	4	5	6	7	8	9	10	11-25
Increm. sales (MWh)	-	1452	6006	7403	8694	9127	9672	10221	10737	11411	12080
Increm loss (%)	22	22	20	18	16	14	12	12	12	12	12
Increm. purchase (MWh)	-	1862	7508	9028	10352	10612	10991	11615	12201	12967	13727
Increm. fin budget (tariff)	-	3365	11382	14490	17427	18202	19174	20165	21093	22292	23502
Increm. econ. ben. (res: 2.29/Kwh)	-	4217	13237	16532	19599	20485	21584	22694	23754	25167	26559
Invest. cost (P'000)	9148	22048	9827	8988	276	308	322	304	379	463	-
O&M of 5%	-	457	1560	2051	2501	2514	2530	2546	2561	2580	2603
Consumer Admin. Cost	-	190	190	190	190	190	190	190	190	190	190
Cost of purchase (fin) (0.97/Kwh)	-	1806	8757	8757	10041	10294	10661	11267	11835	12578	13315
LRMC of purchase (1.31/Kwh)	-	2439	11827	11827	13561	13902	14398	15216	15983	16987	17982
Total cost (fin.)	9148	24501	19986	1986	13008	13306	13703	14307	14965	15811	16108
Total cost (econ.)	9148	25134	23056	23056	16528	16914	17440	18256	19113	20220	20775

ANNEX 3.03

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Sample Feasibility Studies - Results

	IRR (%)	NPV at 12% (Pesos 000)
Rehabilitation only (Pelco I)		
Financial	-7.5	-16,080
Economic	1.8	-11,145
Rehabilitation with Add-ons (Pelco I)		
Financial	24.0	18,557
Economic	48.0	57,583
Extension based on residential (Leyte V)		
Financial	0.13	-13,634
Economic	3.7	-10,519
Extension based on industrial (Capiz)		
Financial	65	82,757
Economic	35	39,020
Rehabilitation with Extension (Tarlac II)		
Financial	11.0	-3,912
Economic	8.0	-12,987

Sample Financial Cost/Benefit Studies

	Financial IRR (%)		
	Rehab	Add-On	Extension
Albay I, II and III	12-15	-	-
Camarines II and IV	25	8	-
Pelco I, II and III	95	-	-

ANNEX 3.04

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RURAL ELECTRIFICATION SECTOR STUDY

Potential Savings from Construction Efficiency Improvements

(a) The raising of distribution voltage wherever possible will contribute to loss reduction;

(b) A smaller size of conductor for distribution lines would lead to the following approximate savings, with little loss of reliability - Using ACSR No.2 instead of ACSR No.2/0 saves about ₱ 5,200 per km., and using ACSR No.2/0 instead of ACSR No.4/0 saves ₱ 3,400 per km. of line;

(c) Increasing the normal pole span from 100 m. to 111 m. saves one pole per km. at about ₱ 1,000 per pole;

(d) Using a lower class wood pole provides a saving of about ₱ 1,350 per km. of line;

(e) A shift from horizontal to vertical alignment of conductor on the pole would address the prevalent problem of insufficient right-of-way to clear branches and foliage. Supply quality would improve while maintenance costs would not rise significantly;

(f) The installation of unprotected transformers may lead to more outages, but perceived cost of an outage in rural areas is likely to be low;

(g) A reduction in non-technical losses can be achieved by installing insulated wire on low-voltage lines, or by changing the current metering and billing system to prepaid card meters, or to an unmetered flat-rate charge where the risk of waste is low. On average, the cost of meters per km of line is about ₱ 2,300; and

(h) Significant efficiency gains could be achieved by introducing computer-assisted network design and planning. Appropriate and economical software and hardware is now readily available, and could be used by both NEA and the RECs in planning investments.

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Rural Distribution Investment 1989-95 (Scenario 1)

(P million)

		1988	1989	1990	1991	1992	1993	1994	1995
Total Consumption (GWh)		2630	2798	3000	3239	3505	3803	4134	4508
Region 1:	Rehab & Add-on		30.9	63.5	63.5	63.9	63.9	-	-
--------	Expansion		-	-	8.6	51.2	52.6	62.8	-
	Total		30.9	63.5	72.3	115.1	116.5	62.8	31.4
Region 2:	Rehab & Add-on		21.7	47.4	47.4	47.4	47.4	-	-
--------	Expansion		-	-	16.7	32.9	33.3	31.6	15.8
	Total		21.7	47.4	64.1	80.3	80.7	31.6	15.8
Region 3:	Rehab & Add-on		37.1	78.2	78.2	78.2	78.2	-	-
--------	Expansion		-	-	13.8	46.0	45.4	33.0	16.3
	Total		37.1	78.2	92.0	124.2	123.6	33.0	16.3
Region 4:	Rehab & Add-on		30.0	23.4	23.4	23.4	23.4	-	-
--------	Expansion		-	-	13.8	46.0	45.4	33.0	25.9
	Total		30.0	23.4	37.2	69.4	68.8	33.0	25.9
Region 5:	Rehab & Add-on		31.5	121.8	121.8	121.8	121.8	-	-
--------	Expansion		-	-	13.0	116.4	112.4	18.1	9.1
	Total		31.5	121.8	134.5	238.2	234.2	18.1	9.1
Region 6:	Rehab & Add-on		24.4	48.1	48.1	48.1	48.1	-	-
--------	Expansion		-	-	13.8	46.0	45.4	33.1	16.5
	Total		24.4	48.1	61.9	94.1	93.5	33.1	16.5
Region 7:	Rehab & Add-on		20.4	24.6	24.6	24.6	24.6	-	-
--------	Expansion		-	-	4.4	40.5	36.1	34.8	26.1
	Total		20.4	24.6	29.0	85.1	60.7	34.8	26.1
Region 8:	Rehab & Add-on		29.3	55.7	55.7	55.7	55.7	-	-
--------	Expansion		-	-	9.5	32.1	29.8	24.1	12.0
	Total		29.3	55.7	65.2	87.8	85.5	24.1	12.0
Region 9:	Rehab & Add-on		19.8	11.1	11.1	11.1	11.1	-	-
--------	Expansion		-	-	27.9	26.4	28.3	22.6	12.1
	Total		19.8	11.1	39.0	37.5	39.4	22.6	12.1
Region 10:	Rehab & Add-on		22.2	35.7	35.7	35.7	35.7	-	-
---------	Expansion		-	-	13.8	46.0	45.4	62.9	16.5
	Total		22.2	35.7	49.5	81.7	81.1	62.9	16.5
Region 11:	Rehab & Add-on		34.1	22.2	22.2	22.2	22.2	-	-
---------	Expansion		-	-	15.7	28.7	21.9	24.6	12.3
	Total		34.1	22.2	37.9	50.9	44.1	24.6	12.3
Region 12:	Rehab & Add-on		13.5	5.8	5.8	5.8	5.8	-	-
---------	Expansion		-	-	3.3	17.7	48.0	44.4	22.2
	Total		13.5	5.8	9.1	23.5	53.8	44.4	22.2

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RURAL ELECTRIFICATION SECTOR STUDY

Rural Distribution Investment 1989-94

(P million)

	1988 Actual	1989	1990	1991	1992	1993	1994
Projected Borrowing							
Ongoing projects (US$)		8.8	7.3				
Committed or expected (US$)		24.4	24.7	21.1	1.6	1.9	
Total (US$)		33.2	22	21.1	1.6	1.9	
Total (P) [1]		710	471	452	34	41	
Investment Scenario 1 [2]							
Rehabilitation & Add-on		315	538	503	538	538	
Expansion		-	-	154	530	509	
Total		315	538	692	1068	1047	
of which FX		265	443	564	860	848	
Local		50	95	128	208	199	
Investment Scenario 2 [3]							
Rehabilitation & Add-on		600	850	700	300	-	
Expansion		-	-	150	550	500	
Total		600	850	850	850	500	
of which FX		500	700	700	700	400	
Local		-	19	250	666	360	
NEDA Plan (1988)							
Relending Program	500						
Rehabilitation	55	624	228				
Expansion	150	713	841	1102	1663		
Total	705	1337	1069	1102	1663		
Mini-hydro	815	356	386	314	168		
Multi-fuel	534	64	59	44	4		
FX funding		1153	808	629	915		
NEA Plan (January 89)							
Rehabilitation & Add-on		667	403	598	687		
Expansion		88	355	740	1052		
Alt. Energy		405	313	343	330		
Total FX requirement		766	824	1172	1491		
NEA Plan (draft Oct. 89)							
Rehabilitation/Upgrading			861	508	247	182	151
Expansion			325	398	319	362	367
Other			82	123	125	55	145
Total			1268	1029	691	599	663

[1] US$1 = P 21.4
[2] Scenario 1: Rehabilitation and Add-on as per latest requests by coops, 90-93 estimated true requirements over 4 years. Expansion not before 91.
[3] Scenario 2: Rehabilition & Add-on strongly concentrated in 89/90, remainder 91/92. Expansion not before 91.

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Comparative Rate Levels for NPC's Luzon Grid
Existing vs Revenue Neutral LRMC-Gas Turbine
(₱/kWh)

				Increase (Decrease) in Rates		
				NPC		Retail /2
	Extng /1	Theor. LRMC Cur Tar	Adj. LRMC Gas Turb. Rev Neut	Theor LRMC vs Extng	Adj LRMC vs Extng	
Utilities	0.98	1.01	0.96	0.03	(0.02)	(0.03)
Small	0.97	1.45	1.38	0.48	0.41	0.56
Private U	0.97	1.43	1.36	0.46	0.39	0.53
RECs	0.97	1.46	1.39	0.49	0.42	0.57
Medium	0.97	1.27	1.21	0.30	0.24	0.32
Private U	0.96	1.15	1.10	0.19	0.14	0.18
RECs	0.97	1.31	1.25	0.34	0.28	0.38
Large RECs /3	0.96	1.15	1.10	0.19	0.14	0.18
Angeles	0.96	1.02	0.97	0.06	0.01	0.02
Batelec II	0.97	1.35	1.29	0.38	0.32	0.43
Beneco	0.96	1.20	1.14	0.24	0.18	0.25
Olongapo	0.96	1.08	1.03	0.12	0.07	0.09
Pelco II	0.96	1.23	1 17	0.27	0.21	0.29
Meralco	0.98	0.97	(0.01)	(0.06)	(0.08)	
Non-Utilities	1.01	1.18	1.12	0.17	0.11	
Industries	1.01	1.17	1.11	0.16	0.10	
Miscellaneous	1.08	1.86	1.77	0.78	0.69	
U.S. Gov't	1.01	1.10	1.05	0.09	0.04	
Total Luzon	0.98	1.03	0.98	0.05	0.00	

/1 Effective November 8, 1988 billing month.
/2 Multiplier: Cooperatives: 1.35; Meralco: 1.4. Subject to changes in retail rate structures.
/3 Above 20,000 KW Demand.

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Marginal Cost Analysis

Costing Periods

1. While some of the grids show the beginnings of seasonal fluctuations involving a summer peak, the Luzon Grid is the only one with a pronounced summer peak. This is clearly apparent in both the plots of monthly generation and monthly sales. Based on these data, the peak season for the Luzon grid runs from April through November.

2. Based on preliminary estimates of load curves, Table 1 reports time periods and load variations for daily peaks. Table 2 then summarizes the lengths of these periods measured in hours.

Capacity Costs

3. The generation and transmission capacity considered is the same as that employed in the Energy Sector Study (Report 7269-PH; September 15, 1988), where the field work was conducted in February of 1988. Peaking capacity was identified as a proposed GT (gas turbine) unit and baseload capacity was represented by two proposed plants CALACA 2 and BACMAN 1. While the basic data for (i) these plants, (ii) the transmission system and (iii) the associated transmission losses are used, the handling of plant outages is given alternative treatment.

Plant Outage

4. The generation capacity calculations are adjusted upwards to allow for planned and forced outages: for the GT peaking unit, the estimate for outages is 25.48% and for the, baseload units, the estimated outage rates are 13.59 % and 24.34%, respectively. The total of these outage rates is in the 25% range, which seem high. Also these adjustments as well as station energy use may more appropriately be handled by simply making a reserve margin adjustment. This approach has the effect of assuming a particular reserve margin in generating capacity as being needed to offset forced and unforced outages. This approach is used here; after the subtotal of capacity costs is computed, operation and maintenance expenses for the unit are added and then, arbitrarily, a reserve margin of 15% is added. In practice, the actual reserve margin available should be computed after some research to determine what the target should be.

Marginal Capacity Costs

5. Tables 1 and 2 report the capacity cost results assuming a 12% and then an 8% real discount rate, and using the reserve margin adjustment.

Table 1: IDENTIFICATION OF COSTING PERIODS 1/

Power Grid	Daily Peak Time/Days MW Variation	Seasonal Peak Months
1. Luzon	7:00-23:00 Week Days 2100MW-2650MW	April through November
ETS Study 2/	6:00-23:00 All Days	February through August
2. Cebu	7:00-23:00 All Days 75MW-95MW	Not significant
ETS Study 2/	No Seasonal or time-of-day structure	
3. Negros	18:00-23:00 All Days 45MW-60MW	Not significant
ETS Study 2/	18:00-22:00 All Days	Not significant
4. Panay	18:00-23:00 All Days 30MW-50MW	Not significant
ETS Study 2/	18:00-22:00 All Days	Not significant
5. Leyte-Samar	18:00-23:00 All Days 45MW-70MW	Not significant
ETS Study 2/	18:00-22:00 All Days	Not significant
6. Bohol	18:00-23:00 All Days 5MW-10MW	Not significant
ETS Study 2/	18:00-22:00 All Days	Not significant
7. Mindanao	18:00-23:00 Wkday Only 450MW-560MW	Not significant
ETS Study 2/	no time of day	Jan through March & Aug. through Dec.

1/ 1988: 365 Days: 105 weekend days, 260 weekdays; holidays were ignored.

2/ ETS study was the Electricity Tariff Study compiled for NPC by Electric de France in 1985-1986

Table 2: LENGTH OF COSTING PERIODS IN 1988 1/

Power Grid Total	Seasonal Periods: Offpeak		Peak
1. Luzon			
Months:	Dec-March/4 mo	April-Nov/8 mo	
Weekdays:			
Number (Days)	86	174	260
Hours: Peak (17)	1462	2958	4420
Off-Peak (7)	602	1218	1820
Total	2064	4176	6240
Weekends:			
Number (Days)	35	70	105
Hours: Peak	0	0	0
Off-Peak(24)	840	1680	2520
2. Cebu			
Months:	No significant seasonal peak		
Weekdays:			
Number (Days)			260
Hours: Peak (17)			4420
Off-Peak (7)			1820
Total			6240
Weekends:			
Number (Days)			105
Hours: Peak (16)			1680
Off-Peak(8)			840
Total			2520
3. Negros, Panay, Leyte-Samar, Bohol			
Months:	No significant seasonal peak		
Weekdays:			
Number (Days)			260
Hours: Peak (6)			1560
Off-Peak(18)			4680
Total			6240
Weekends:			
Number (Days)			105
Hours: Peak (6)			630
Off-Peak(18)			1890
Total			2520
4. Mindanao			
Months:	No significant seasonal peak		
Weekdays:			
Number (Days)			260
Hours: Peak (6)			1560
Off-Peak(18)			4680
Total			6240
Weekends:			
Number (Days)			105
Hours: Peak			0
Off-Peak(24)			2520

1/ No allowance is made for holidays and 1988 is treated as if there were only 365 days. Therefore there are 8,760 hrs in year, 105 weekends and 260 weekdays.

Table 3: CAPACITY COSTS OF GENERATION

No.	Item	Units	Power Loss (%)	Generating Station		
				GT	BACMAN 1	CALACA 2
1.	Capital cost	$/kW		350	690	900
2.	Plant life	yrs		15	25	25
3.	Discount Rate	%		12%	12%	12%
	Carrying Charge Rate	%		14.68	12.75	12.75
4.	Annual Cost	$/kW/yr		51.39	87.97	114.75
5.	Fixed O&M	$/kW/yr		.80	.63	.65
6.	Subtotal	$/kW/yr		52.19	88.60	115.40
7.	Reserve Margin	%		15%	15%	15%
8.	Capacity Cost at Gen	$/kW/yr		60.02	101.89	132.71
9.	Capacity Cost at EHV	"	.5	60.32	102.40	133.38
10.	Capacity Cost at VHV	"	1.4	61.18	103.85	135.27
11.	Capacity Cost at HV	"	5.0	64.40	109.31	142.39
12.	Capacity Cost at MV	"	6.0	68.51	116.30	151.48

Table 4: CAPACITY COSTS OF TRANSMISSION 1/

No.	Item		Units	Voltage Level			
				ehv	vhv	hv	mv
1.	NPV of Investments		$M	187.60	71.70	16.30	4.40
2.	NPV of MW at Peak		MW	1695.00	517.70	325.00	102.80
3.	AIC		$/kW	110.68	138.50	50.15	42.80
4.	AIC/yr		$/kW/yr	13.36	16.72	6.06	5.17
Including Losses:							
		losses	$/kW/yr				
5.	At EHV	.5%	13.36	13.36			
6.	At VHV	1.4%	30.27	13.55	16.72		
7.	At HV	5.0%	37.92	14.27	17.60	6.06	
8.	At MV	6.0%	45.51	15.18	18.73	6.44	5.17

1/ Discount Rate: 12% Life: 45 years Period: 1987-1996

Table 5: TOTAL CAPACITY COST

(Real Cost of Capital at 12%)

No.	Item	Units	Generating Station		
			GT	BACMAN 1	CALACA 2
1.	At generation	$/kW/yr	60.02	101.89	132.71
2.	At EHV	"	73.38	115.25	146.07
3.	At VHV	"	91.45	134.12	165.54
4.	At HV	"	102.32	147.23	180.31
5.	At MV	"	114.02	161.81	196.99

Marginal Energy Costs

6. Marginal energy cost calculations are taken directly from the earlier exercise attached. They are summarized in Table 9.

Table 9: MARGINAL ENERGY COSTS

Voltage at which Electricity Taken	Units	Power Losses	Pricing Period		
			Peak	Offpeak	Average
At Generation	UScts/KWH		4.67	2.46	2.80
At EHV	UScts/KWH	.5%	4.69	2.48	2.81
At VHV	UScts/KWH	1.4%	4.75	2.51	2.85
At HV	UScts/KWH	5.0%	5.00	2.64	2.85
At MV	UScts/KWH	6.0%	5.32	2.81	3.19

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RURAL ELECTRIFICATION SECTOR STUDY

LRMC-Based Wholesale Pricing

1. Since the billing period is one month, the annual capacity costs must be divided by 12 to convert them to monthly costs. These capacity costs have been calculated per kW of demand falling exactly at the system peak, or alternatively stated, per kW of coincident demand on the system. But, during the peak period for the Luzon Grid (7:00-23:00), not all customer groups or individual customers place their maximum loads on the system at the exact time of the system peak. Therefore the measured or metered maximum load that the REC places on the system during the peak period may not be that REC's total contribution to the system peak unless it occurs at the system peak itself. Thus capacity costs per kW are not appropriate for establishing, rates as they may not indicate the costs imposed on the system by the particular customer (REC, private utility, industrial customer, etc). Therefore a class coincidence factor (equal to 1/diversity factor) must be calculated for the customer in question. The formula for calculating demand charges is therefore:

Demand Charge/KW = coincidence factor x monthly capacity cost/kW
= (1/diversity factor) x monthly cap. cost/kW

2. An alternative approach might be to make the rate simpler by developing a single kilowatt hour charge that incorporates both capacity costs and energy costs while allowing for the issues raised above. One commonly used formula for calculating the per kWh marginal capacity charge component is:

$$SMCC = MC_{KW}/(LF_C \times H)$$

where SMCC = the synthesized marginal capacity charge on a per kWh basis
MC_{KW} = marginal cost of capacity in the billing period
LF_C = the coincident load factor for the customer in the period
H = the number of hours in the period (Annex 3.03, Table 2)

Data do not appear to exist for the coincident load factors for different NPC customers or customer groups. Therefore, the load factors given for the various customer groups are assumed to be approximately coincident.

Table 1: LOAD FACTORS

Customer Group	Load Factor
Cooperatives	.463
Industry	.631
Private Utilities	.668

Finally, completing the SMCC calculations and employing the information on marginal energy prices, Table 2 reports marginal cost TOD rates with synthesized marginal capacity costs for the RECs in the Luzon grid:

Table 2: MARGINAL COST-BASED ELECTRIC RATES (per kWh)

Customer Group	Prices		
	Peak Period (7:00-23:00) (SMCC + marginal energy price)	Off Peak (marginal energy price)	Average[1/]
Cooperatives:			
a. 8% real rate of interest	₱ .0276 + .0469 = ₱ .0744 (₱ 1.56/kWh)	₱ .0248 (₱ .52/kWh)	₱ .05 (₱ 1.05/kWh)
b. 12% real rate of interest	₱ .035 + .0469 = ₱ .0819 (₱ 1.72/kWh)	₱ .0248 (₱ .52/kWh)	₱ .053 (₱ 1.12/kWh)

1/ Assumes constant consumption flow

As a basis for comparison, if the Luzon Grid had no peaking pattern, then baseload capacity would be the marginal capacity; and in that case the marginal cost of supplying electricity on a per kwh basis would be as follows:

Table 3: MARGINAL COST RATES WITHOUT SYSTEM PEAKS

		Capacity Cost		Energy Price		Marginal Cost	Generating Plant
mc/kWh	=	₱ 107.33/8760	+	₱ .0281	=	₱ .04/kWh (₱ .84/kWh)	(CALACA2)
mc/kWh	=	₱ 84.58/8760	+	₱ .0248	=	₱ .034/kWh (₱ .714/kWh)	(BACMAN1)

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RURAL ELECTRIFICATION SECTOR STUDY

REC Cost of Supply: Four Case Studies

TARLAC II

The case study for Tarlac II considers both rehabilitation and an investment program for expansion. Data from NEA's Project Appraisal Division regarding distribution costs show that in 1988, approximately one half of the investment was spent on expansion and one half on rehabilitation. In addition, of the investment going to expansion, 16% was for meters and street lights. Of the rehabilitation investment, 23% was spent for those same items; and, in 1989, as much as 34% of rehabilitation investment will be spent on meters and street lights.

Table 1 summarizes the calculations in reaching marginal cost rates and an alternative average price for the Tarlac II Electric Cooperative.

Table 1: MARGINAL COST CALCULATIONS AND RATES FOR TARLAC II

1.	Present value of investment cost (₱ 000's) (assume real discount rate of 8%)		₱ 85,627.4
2.	Carrying charge rate		9.3679%
3.	Annualized investment cost 9.3679*85627.4 =		₱ 8,021.49
4.	Annual O & M expenses (₱ 000's)		₱ 2,603
5.	Original Peak kW		590 kW
6.	Peak KW after investments		4,249 kW
7.	Increase in peak kW		3,659 kW
8.	Annual Cost/kW (3+4/7)		₱ 2.9036
9.	Cost attributable to expanding Peak kW (74%) (remove investment in meters & street lights)		₱ 2.1487
10.	Peak Period:(17:00 to 23:00 daily)	Peak Hrs	2,555 hours
		Off-Peak Hrs	6,205 hours
11.	Assumed coincident Load Factor:	residential	.5
		commercial	.6
		industrial	.7
12.	Marginal Cost of Distribution Capacity: ₱ 2,148.7/(.5*2555) = ₱ 1.68/kWh		
13.	Energy Price/kWh sold with 15% power loss and ₱ 1.12/kWh wholesale price from NPC assumed:		₱ 1.29/kWh
14.	Marginal Cost Rates:	Peak	₱ 2.97/kWh
		Off-Peak	₱ 1.29/kWh

15. Adjustments for Rehab calculations:
assume 1/2 of investment is for expansion then
item 12 should be reduced by 1/2: SMCC = .5 * 1.68 = ₱ .84/kWh
Marginal Cost Rates are then: Peak ₱2.13/kWh Off-Peak ₱ 1.29/kWh

16. Average Cost Rate calculation:
(Investment Cost + O&M)/total kWh = ₱ 10,624,490/12,080,000 kWh
= ₱ .8795/kWh

Reduce by 1/2 to eliminate Rehab: ₱ .43975/kWh

Total Cost/kWh = ₱ .43975/kWh + energy price
= ₱ .43975/kWh + ₱ 1.29/kWh = ₱ 1.73/kWh

PELCO I

The case study for PELCO I considers only an investment program for expansion. Data from NEA's Project Appraisal Division regarding distribution costs, show that in 1989, that approximately 7% of the investment expense was spent on meters and street lights. In 1991 expenditures for these items was expected to drop to 4%.

Table 2 summarizes the calculations in reaching marginal cost rates and an alternative average price for the Pampanga I Electric Cooperative.

Table 2: MARGINAL COST CALCULATIONS AND RATES FOR PELCO I

1.	Present value of investment cost (₱ 000's) (assume real discount rate of 8%)	₱ 14,479.9
2.	Carrying charge rate	9.3679%
3.	Annualized investment cost 9.3679*14479.9 =	₱ 1,356.46
4.	Annual O & M expenses (₱ 000's)	₱ 1,253
5.	Original Peak kW	1,261 kW
6.	Peak kW after investments	4,742 kW
7.	Increase in peak kW	3,481 kW
8.	Annual Cost/kW (3+4/7)	₱ .749497/kW
9.	Cost attributable to expanding Peak kW (74%) (remove investment in meters & street lights)	₱ .70827/kW
10.	Peak Period:(17:00 to 23:00 daily) Peak Hrs	2,555 hours
	Off-Peak Hrs	6,205 hours
11.	Assumed coincident Load Factor: residential	.5
	commercial	.6
	industrial	.7
12.	Marginal Cost of Distribution Capacity: 708.27(.5 * 2555) =	₱ .554/kWh
13.	Energy Price/kWh sold with 15% power loss and ₱ 1.145/kWh wholesale price from NPC assumed:	₱ 1.32/kWh
14.	Marginal Cost Rates: Peak	₱ 1.87/kWh
	Off-Peak	₱ 1.32/kWh
15.	Adjustments for Rehab calculations: (none)	
16.	Average Cost Rate calculation: (Investment Cost + O&M)/total kWh = ₱ 2,609,460/13,931,496 kWh = ₱ 0.187/kWh	

Total Cost/kWh = ₱ .187/kWh + energy price
= ₱ .187/kWh + ₱ 1.32/kWh = ₱ 1.51/kWh

LEYTE V

The case study for Leyte V considers an investment program for both expansion and rehabilitation investment program. Table 3 summarizes the calculations in reaching marginal cost rates and an alternative average price for Leyte V Electric Cooperative.

Table 3: MARGINAL COST CALCULATIONS AND RATES FOR LEYTE V

1.	Present value of investment cost (₱ 000's) (assume real discount rate of 8%)		₱ 16,282.5
2.	Carrying charge rate		9.3679%
3.	Annualized investment cost 9.3679 * 14479.9 =		₱ 1,525.33
4.	Annual O & M expenses (₱ 000's)		₱ 1,230
5.	Original Peak kW		68 kW
6.	Peak kW after investments		1,108 kW
7.	Increase in peak kW		1,040 kW
8.	Annual Cost/kW (3+4/7)		₱ 2.64935/kW
9.	Cost attributable to expanding Peak kW (94.5%) (remove investment in meters & street lights)		₱ 2.5036/kW
10.	Peak Period:(17:00 to 23:00 daily)	Peak Hrs Off-Peak Hrs	2,555 hours 6,205 hours
11.	Assumed coincident Load Factor	residential commercial industrial	.5 .6 .7
12.	Marginal Cost of Distribution Capacity: 2503.6 (.5 * 2555) =		₱ 1.9598/kWh
13.	Energy Price/kWh sold with 15% power loss and ₱ 1.12/kWh wholesale price from NPC assumed:		₱ 1.29/kWh
14.	Marginal Cost Rates:	Peak Off-Peak	₱ 3.25/kWh ₱ 1.29/kWh
15.	Adjustments for Rehab calculations: (none) assume 1/2 of investment is for expansion then reduce item 12 by 1/2 to ₱ .9799/kWh and the marginal cost rates are	Peak Off-Peak	₱ 2.27/kWh ₱ 1.29/kWh
16.	Average Cost Rate calculation: (Investment Cost + O&M)/total kWh = ₱ 2,755,330/3,390,000 kWh = ₱.81/kWh		

Total Cost/kWh = ₱ .81/kWh + energy price
= ₱ .81/kWh + ₱ 1.29/kWh = ₱ 2.10/kWh

CAPIZ I

The case study for Capiz I considers only an investment program for expansion only. Table 4 summarizes the calculations in reaching marginal cost rates and an alternative average price.

Table 4: MARGINAL COST CALCULATIONS AND RATES FOR CAPIZ I

1.	Present value of investment cost (₱ 000's) (assume real discount rate of 8%)		₱ 11,712.19
2.	Carrying charge rate		9.3679%
3.	Annualized investment cost 9.3679 * 85627.4 =		₱ 1,097.18
4.	Annual O & M expenses (₱ 000's)		₱ 648
5.	Original Peak kW		570 kW
6.	Peak kW after investments		4,088 kW
7.	Increase in peak kW		3,518 kW
8.	Annual Cost/kW (3+4/7)		₱ .49607
9.	Cost attributable to expanding Peak kW (remove investment in meters & street lights)		
10.	Peak Period:(17:00 to 23:00 daily)	Peak Hrs	2,555 hours
		Off-Peak Hrs	6,205 hours
11.	Assumed coincident Load Factor:	residential	.5
		commercial	.6
		industrial	.7
12.	Marginal Cost of Distribution Capacity: 496.07/(.5 * 2555) =		₱ 0.388/kWh
13.	Energy Price/kWh sold with 12% power loss and ₱ 1.12/kWh wholesale price from NPC assumed:		₱ 1.25/kWh
14.	Marginal Cost Rates:	Peak	₱ 1.642/kWh
		Off-Peak	₱ 1.25/kWh
15.	Adjustments for Rehab calculations:		
16.	Average Cost Rate calculation: (Investment Cost + O&M)/total kWh = ₱ 1,745,180/10,811,448 kWh = ₱ .1614/kWh		

Total Cost/kWh = ₱ .1614/kWh + energy price
= ₱ .1614/kWh + ₱ 1.25/kWh = ₱ 1.41/kWh

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RURAL ELECTRIFICATION SECTOR STUDY

Hypothetical Cases: Calculation of Marginal Cost Rates for REC Customers

A. Entire Plant Investment Considered

1. Current Cost of Investment in System: ₱ 35,000,000
2. Investment attributed to Minimum System and Customer hook-up ₱ 10,000,000
3. Investment Associated with capacity necessary for peak demand ₱ 25,000,000
4. Calculation of CCR:

   Assume: r_r = 8% and T = life of investment = 25 years
   Then: CCR = 9.3679%

5. Annualized Investment cost: CCR * Item (3) = ₱ 2,341,975
6. Annual O&M [10% of item (3)]: ₱ 2,500,000
7. Peak kW without item (3): 500 kW
8. Peak kW with item (3): 5600 kW
9. Increase in Peak kW: (8-7) 5000 kW
10. Annual Cost/kW: [(5+6)/9] ₱ 968/kW
11. Costing periods and hours:

Period	Time	Hours in Year
i) Peak	Daily: 1700 thru 2300 or 7 hours	2555 hrs
ii) Off-peak	Daily: all other hours or 17 hours	6205 hrs
	TOTAL	8760 hrs

12. Coincident load factor for Customer classes:

   i) Residential .5
   ii) Commercial .6
   iii) Industrial .7

13. Marginal Cost of Capacity

i) Residential: ₱ 968/(.5*2555) = ₱ .758/kWh
ii) Commercial: ₱ 968/(.6*2555) = ₱ .631/kWh
iii) Industrial: ₱ 968/(.7*2555) = ₱ .541/kWh

14. Energy Price/kWh sold with 15% power loss for all customer classes (it may be that power losses are different for the different classes--if so this needs to be taken into account)

Assume flat wholesale rate: ₱ 1.00/kWh
Energy price/kWh sold: ₱ 1.15/kWh

15. Marginal Cost Rates assuming flat rate pricing by NPC at ₱ 1.00/kWh. If NPC adopts Marginal Cost Prices, then all calculations below would have to be adjusted accordingly:

i) Residential: Marginal Costs: Peak 1.15 + 7.58 = ₱ 1.908/kWh
Off-peak = ₱ 1.15/kWh

Since the benefits do not justify costs for time-of-day pricing for residential customers, a flat rate price should be set equal to a weighted average of Peak and Off-peak marginal costs. The weights could be the percentage of residential electricity consumption occurring in the periods or, without this information, the percentage of hours in each period could be used as a rough approximation.

Assume 50% or Residential electricity usage occurs in peak period

Residential price: 5*1.908 + .5*1.15 = ₱ 1.529/kWh

ii) Commercial: Marginal Costs: Peak 1.15 + .631 = ₱ 1.781/kWh
Off-peak = ₱ 1.15/kWh

If benefits do not justify metering costs then a calculation similar to the one above would be made for these customers to obtain a flat rate. If the benefits do justify metering costs, then the marginal costs would be the prices in the costing periods.

iii) Industrial: Marginal Costs: Peak 1.15 + .541 = P 1.691/kWh
Off-peak = P 1.15/kWh

The analysis and rates for this case are determined along the same lines that were used for the Commercial case above.

B. Incremental Investment in Plant

The analysis for this case would proceed along the same lines as were used in the case above, except that items 1 and 2 would be interpreted as current value of all investment and current value of previous investment.

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RURAL ELECTRIFICATION SECTOR STUDY

REC Performance Indicators

Table 1: ALTERNATIVE FINANCIAL INDICATORS

REC	MP2 1/	OP	MAINT	CUST 2/	ADMIN	AVC
1. Ilcos Norte	1.246	0.031	0.097	0.199	0.199	1.773
2. Ifugao	1.350	0.068	0.307	0.182	0.581	2.489
3. Quirino	1.157	0.034	0.123	0.225	0.429	1.968
4. Zambales I	1.190	0.023	0.028	0.076	0.090	1.408
5. Aurora	1.112	0.107	0.125	0.173	0.440	1.956
6. Mindoro Or. II	2.388	0.123	0.327	0.388	0.634	3.860
7. Quezon I	1.096	0.043	0.072	0.096	0.135	1.442
8. Camarines Sur I	1.212	0.083	0.058	0.115	0.375	1.843
9. Camarines Norte	1.327	0.031	0.105	0.115	0.159	1.739
10. Masbate	2.964	0.327	0.518	0.345	0.907	5.061
11. Sorsogon II	0.672	0.088	0.080	0.149	0.268	1.035
12. Capiz	0.863	0.049	0.062	0.261	0.153	1.389
13. Central Negros	1.396	0.066	0.028	0.056	0.124	1.670
14. Guimaras	1.895	0.000	0.033	0.049	0.977	2.954
15. Iloilo I	0.922	0.032	0.072	0.180	0.167	1.373
16. Negros Occ.	1.280	0.050	0.058	0.128	0.151	1.667
17. Bantayan	2.699	0.043	0.119	0.273	0.371	3.505
18. Bohol I	0.824	0.055	0.102	0.128	0.175	1.285
19. Camotes	2.757	0.194	0.155	0.320	0.583	4.010
20. Cebu I	1.046	0.035	0.088	0.127	0.216	1.513
21. Cebu II	1.013	0.033	0.065	0.090	0.221	1.423
22. Cebu III	0.965	0.047	0.074	0.131	0.186	1.402
23. Negros Or. I	1.269	0.027	0.035	0.061	0.120	1.512
24. Negros Or. II	1.399	0.027	0.088	0.111	0.178	1.803
25. Biliran	1.263	0.220	0.182	0.239	0.591	2.495
26. Eastern Samar	2.749	0.182	0.143	0.273	0.580	4.028
27. Leyte IV	1.382	0.114	0.040	0.135	0.391	2.062
28. Leyte V	1.127	0.050	0.044	0.096	0.111	1.428
29. Northern Samar	2.519	0.089	1.504	0.775	2.581	7.469
30. Samar I	1.575	0.128	0.271	0.214	0.445	2.633
31. Zamboanga Norte	0.689	0.068	0.065	0.094	0.260	1.176
32. Zamboanga Sur II	0.637	0.066	0.134	0.138	0.220	1.195
33. Augusan Norte	0.715	0.038	0.056	0.099	0.114	1.022
34. Augusan Sur	0.699	0.037	0.055	0.135	0.259	1.184
35. Bukidnon II	0.700	0.049	0.055	0.090	0.151	1.045
36. Misamis Occ. II	0.665	0.028	0.111	0.130	0.102	1.035
37. Misamis Or. II	0.681	0.013	0.061	0.105	0.165	1.025
38. Siarga Is.	2.867	0.047	0.148	0.625	1.781	5.469
39. Surigao Norte	0.632	0.013	0.015	0.045	0.045	0.749
40. Davao Norte	0.685	0.021	0.119	0.092	0.173	1.089
41. Davao Sur	0.679	0.039	0.056	0.093	0.144	1.011
42. So. Cotobato I	0.685	0.047	0.117	0.116	0.183	1.150
43. So. Cotobato II	0.707	0.009	0.058	0.068	0.076	0.918
44. Surigao I	0.627	0.047	0.055	0.122	0.186	1.038
45. Lanao Sur	0.682	0.012	0.111	0.044	0.063	0.913
46. Maguindanao	0.669	0.015	0.046	0.101	0.176	1.024
47. No. Cotabato	0.692	0.063	0.083	0.141	0.235	1.231

1/ MP2 NPC price adjusted for losses
2/ CUST Customer Account Expenditures

Table 2: NEA FINANCIAL INDICATORS

REC	MP2/P	OP/P	MAINT/P	CUST/P	ADMIN/P	AVC/P
1. Ilcos Norte	0.617	0.015	0.048	0.099	0.099	0.878
2. Ifugao	0.582	0.029	0.132	0.079	0.251	1.073
3. Quirino	0.480	0.014	0.051	0.094	0.178	0.817
4. Zambales I	0.696	0.014	0.017	0.045	0.053	0.823
5. Aurora	0.501	0.048	0.056	0.078	0.198	0.881
6. Mindoro Or. II	0.647	0.033	0.089	0.105	0.172	1.046
7. Queson I	0.672	0.027	0.044	0.059	0.083	0.884
8. Camarines Sur I	0.635	0.044	0.031	0.060	0.196	0.965
9. Camarines Norte	0.710	0.017	0.056	0.061	0.085	0.930
10. Masbate	0.621	0.068	0.109	0.072	0.190	1.061
11. Sorsogon II	0.328	0.043	0.039	0.073	0.131	0.505
12. Capiz	0.464	0.027	0.033	0.140	0.082	0.747
13. Central Negros	0.763	0.036	0.015	0.031	0.068	0.913
14. Guimaras	0.569	0.000	0.010	0.015	0.293	0.887
15. Iloilo I	0.555	0.020	0.043	0.109	0.101	0.827
16. Negros Occ.	0.688	0.027	0.031	0.069	0.081	0.896
17. Bantayan	0.680	0.011	0.030	0.069	0.093	0.883
18. Bohol I	0.487	0.033	0.061	0.076	0.104	0.760
19. Camotes	0.548	0.039	0.031	0.064	0.116	0.797
20. Cebu I	0.612	0.021	0.051	0.075	0.126	0.885
21. Cebu II	0.596	0.020	0.038	0.053	0.130	0.837
22. Cebu III	0.568	0.028	0.043	0.077	0.109	0.825
23. Negros Or. I	0.788	0.017	0.022	0.038	0.075	0.939
24. Negros Or. II	0.714	0.014	0.045	0.057	0.091	0.920
25. Biliran	0.544	0.095	0.078	0.103	0.255	1.076
26. Eastern Samar	0.770	0.051	0.040	0.077	0.162	1.128
27. Leyte IV	0.578	0.048	0.017	0.056	0.164	0.863
28. Leyte V	0.727	0.032	0.028	0.062	0.072	0.921
29. Northern Samar	0.648	0.023	0.387	0.199	0.664	1.920
30. Samar I	0.553	0.045	0.095	0.075	0.156	0.924
31. Zamboanga Norte	0.482	0.048	0.046	0.066	0.182	0.822
32. Zamboanga Sur II	0.468	0.048	0.098	0.102	0.162	0.878
33. Augusan Norte	0.656	0.035	0.052	0.091	0.104	0.938
34. Augusan Sur	0.510	0.027	0.040	0.099	0.189	0.864
35. Bukidnon II	0.584	0.041	0.045	0.075	0.126	0.871
36. Misamis Occ. II	0.593	0.025	0.099	0.116	0.091	0.924
37. Misamis Or. II	0.508	0.010	0.045	0.078	0.123	0.765
38. Siarga Is.	0.540	0.009	0.028	0.118	0.335	1.030
39. Surigao Norte	0.735	0.015	0.017	0.052	0.053	0.871
40. Davao Norte	0.561	0.017	0.097	0.075	0.142	0.892
41. Davao Sur	0.580	0.033	0.048	0.079	0.123	0.864
42. So. Cotobato I	0.523	0.036	0.089	0.089	0.140	0.878
43. So. Cotobato II	0.693	0.009	0.057	0.067	0.074	0.900
44. Surigao I	0.575	0.043	0.051	0.112	0.171	0.952
45. Lanao Sur	0.725	0.012	0.118	0.046	0.067	0.972
46. Maguindanao	0.539	0.012	0.037	0.082	0.142	0.826
47. No. Cotabato	0.467	0.042	0.056	0.096	0.159	0.832

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Sample Cooperatives: Price and Cost Comparisons among RECs
(Pesos/kWh)

REC	Price/Cost Information (₱/kWh)							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	MP1 1/	MP2 2/	O&M 3/	CUST1 4/	MP&OM 5/	TOTC 6/	PRICE 7/	CUST2 8/
1. Ilcos Norte	0.98	1.25	0.13	0.40	1.37	1.77	2.02	16.99
2. Ifugao	1.07	1.35	0.38	0.76	1.73	2.49	2.32	17.68
3. Quirino	0.96	1.16	0.16	0.65	1.31	1.97	2.41	27.07
4. Zambales I	0.97	1.19	0.05	0.17	1.24	1.41	1.71	23.77
5. Aurora	0.93	1.11	0.23	0.61	1.34	1.96	2.22	28.69
6. Mindoro Or. II	1.52	2.39	0.45	1.02	2.84	3.86	3.69	7.91
7. Quezon I	0.92	1.10	0.11	0.23	1.21	1.44	1.63	12.99
8. Camarines Sur I	1.21	1.21	0.14	0.49	1.35	1.84	1.91	26.61
9. Camarines Norte	1.12	1.33	0.14	0.27	1.47	1.74	1.87	32.83
10. Masbate	2.43	2.96	0.84	1.25	3.81	5.06	4.77	19.35
11. Sorsogon II	0.93	1.11	0.17	0.42	1.28	1.70	2.05	20.29
12. Capiz	0.74	0.86	0.11	0.41	0.97	1.39	1.86	28.80
13. Central Negros	1.12	1.40	0.09	0.18	1.49	1.67	1.83	28.62
14. Guimaras	1.63	1.90	0.03	1.03	1.93	2.95	3.33	34.00
15. Iloilo I	0.74	0.92	0.10	0.35	1.03	1.37	1.66	19.68
16. Negros Occ.	1.13	1.28	0.11	0.28	1.39	1.67	1.86	24.57
17. Bantayan	2.21	2.70	0.16	0.64	2.86	3.51	3.97	17.97
18. Bohol I	0.67	0.82	0.16	0.30	0.98	1.29	1.69	7.77
19. Camotes	2.37	2.76	0.35	0.90	3.11	4.01	5.03	5.60
20. Cebu I	0.89	1.05	0.12	0.34	1.17	1.51	1.71	16.48
21. Cebu II	0.88	1.01	0.10	0.31	1.11	1.42	1.70	16.06
22. Cebu III	0.85	0.96	0.12	0.32	1.09	1.40	1.70	15.36
23. Negros Or. I	1.12	1.27	0.06	0.18	1.33	1.51	1.61	27.13
24. Negros Or. II	1.12	1.40	0.12	0.29	1.51	1.80	1.96	18.85
25. Biliran	1.02	1.26	0.40	0.83	1.66	2.50	2.32	15.81
26. Eastern Samar	2.16	2.75	0.43	0.85	3.18	4.03	3.57	8.33
27. Leyte IV	1.12	1.38	0.15	0.53	1.54	2.06	2.39	7.45
28. Leyte V	0.94	1.13	0.09	0.21	1.22	1.43	1.55	57.46
29. Northern Samar	2.30	2.52	1.59	3.36	4.11	7.47	3.89	13.13
30. Samar I	1.32	1.57	0.40	0.66	1.97	2.63	2.85	80.79
31. Zamboanga Norte	0.56	0.69	0.13	0.35	0.82	1.18	1.43	21.72
32. Zamboanga Sur II	0.56	0.64	0.20	0.36	0.84	1.19	1.36	21.39
33. Augusan Norte	0.58	0.72	0.09	0.21	0.81	1.02	1.09	22.94
34. Augusan Sur	0.58	0.70	0.09	0.39	0.79	1.18	1.37	27.11
35. Bukidnon II	0.63	0.70	0.10	0.24	0.80	1.05	1.20	23.35
36. Misamis Occ. II	0.56	0.66	0.14	0.23	0.80	1.04	1.12	18.92
37. Misamis Or. II	0.56	0.68	0.07	0.27	0.76	1.03	1.34	25.03
38. Siarga Is.	2.40	2.87	0.20	2.41	3.06	5.47	5.31	19.05
39. Surigao Norte	0.57	0.63	0.03	0.09	0.66	0.75	0.86	17.21
40. Davao Norte	0.57	0.68	0.14	0.26	0.82	1.09	1.22	29.10
41. Davao Sur	0.57	0.68	0.10	0.24	0.77	1.01	1.17	19.92
42. So. Cotobato I	0.57	0.68	0.17	0.30	0.85	1.15	1.31	21.97
43. So. Cotobato II	0.57	0.71	0.07	0.14	0.77	0.92	1.02	25.11
44. Surigao I	0.57	0.63	0.10	0.31	0.73	1.04	1.09	24.94
45. Lanao Sur	0.56	0.68	0.12	0.11	0.81	0.91	0.94	20.34
46. Maguindanao	0.54	0.67	0.08	0.28	0.75	1.02	1.24	42.03
47. No. Cotabato	0.55	0.69	0.16	0.38	0.85	1.23	1.48	25.50

1/ MP1 — NPC price to REC
2/ MP2 — NPC price adjusted for losses
3/ O&M — REC O&M expenses per kWh
4/ CUST1 — Customer and administrative expenses
5/ MP&OM — MPS=O&M Item (2) + Item (3)
6/ TOTC — Total operating expenses (per kWh)
7/ PRICE — Average price to consumers
8/ CUST2 — Customer and administrative expenses (per consumer)

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Price Elasticity of Demand

FIGURE 1

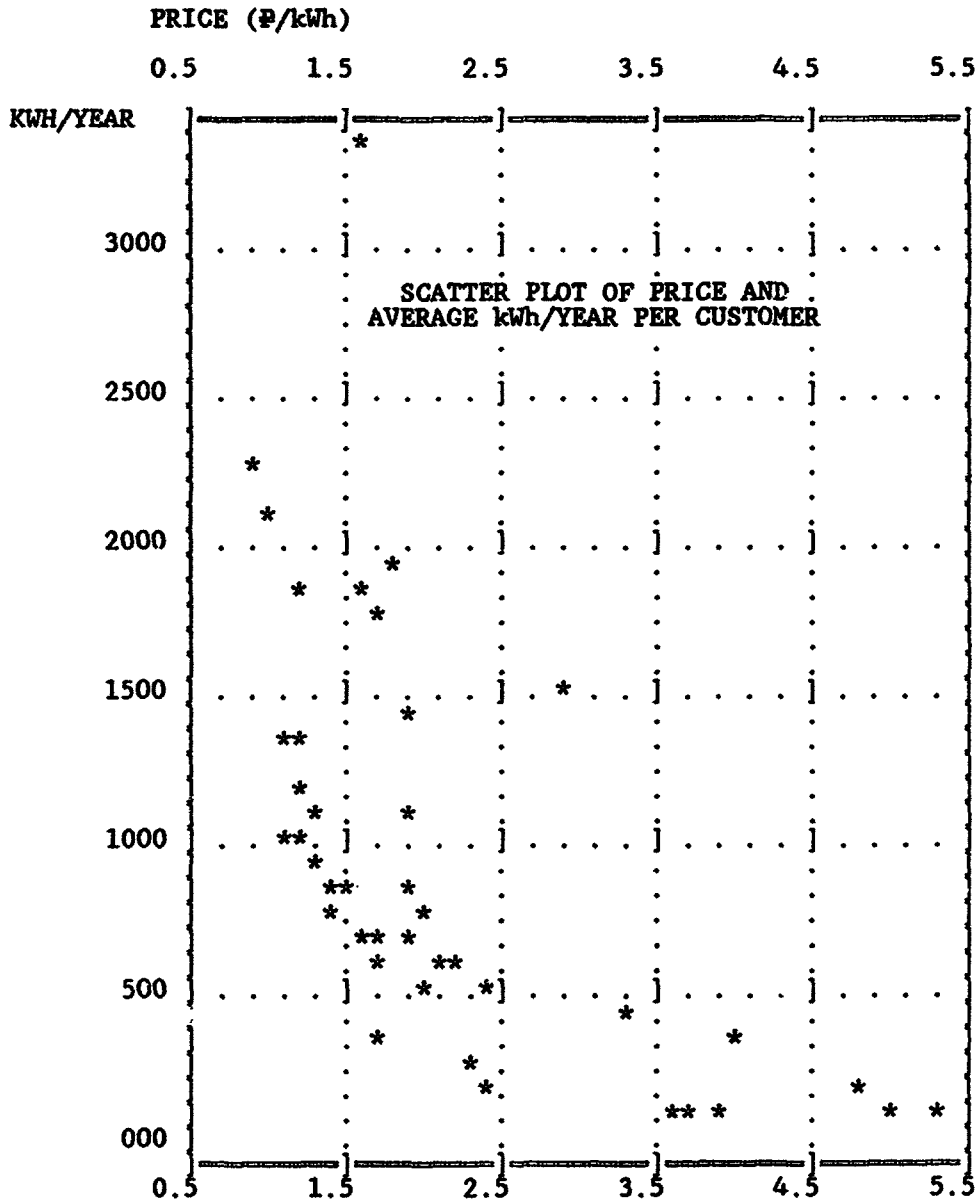
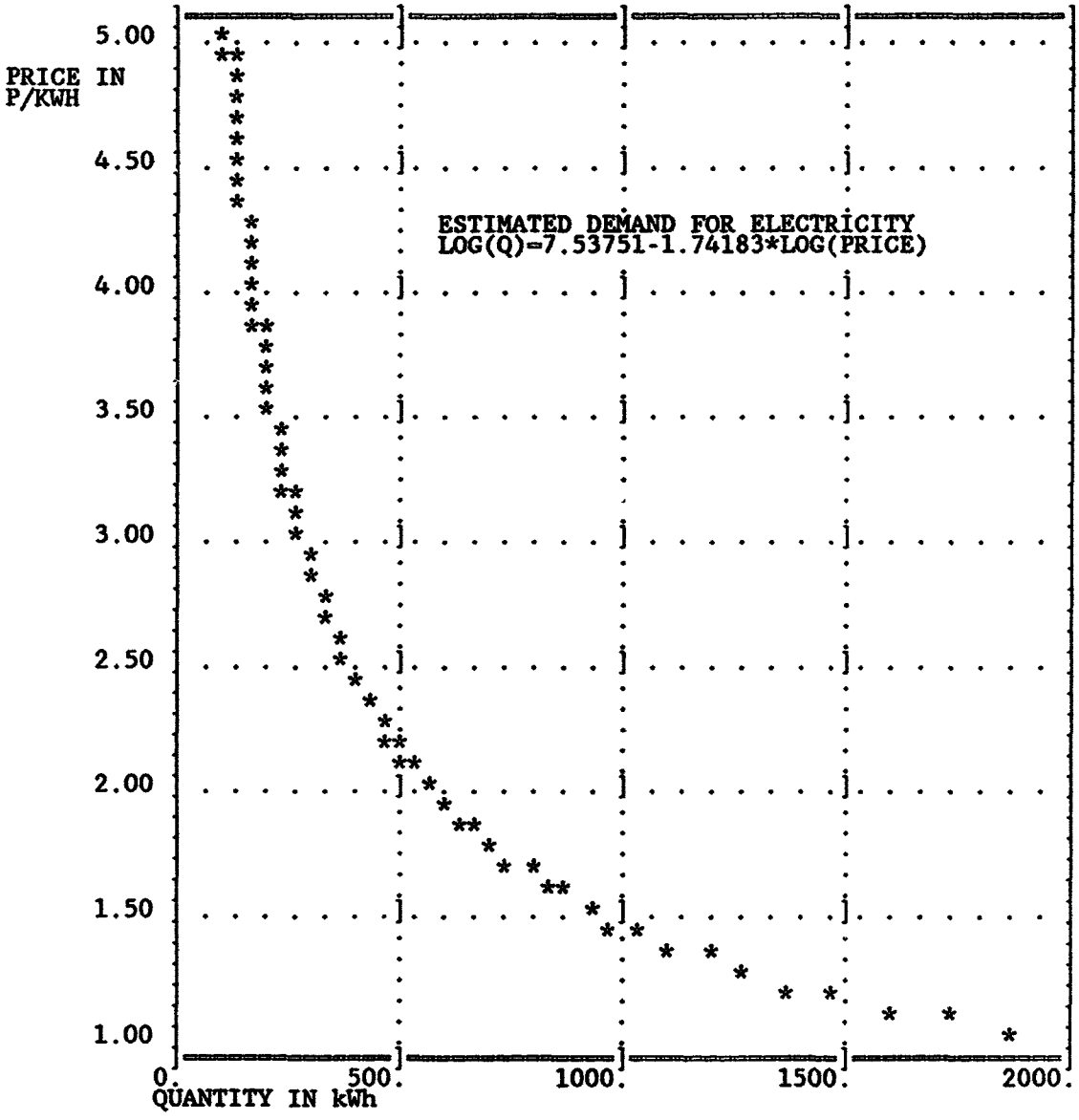


FIGURE 2


PRICE IN
P/KWH
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
ESTIMATED DEMAND FOR ELECTRICITY
LOG(Q)=7.53751-1.74183*LOG(PRICE)
0.
500.
1000.
1500.
2000.
QUANTITY IN kWh

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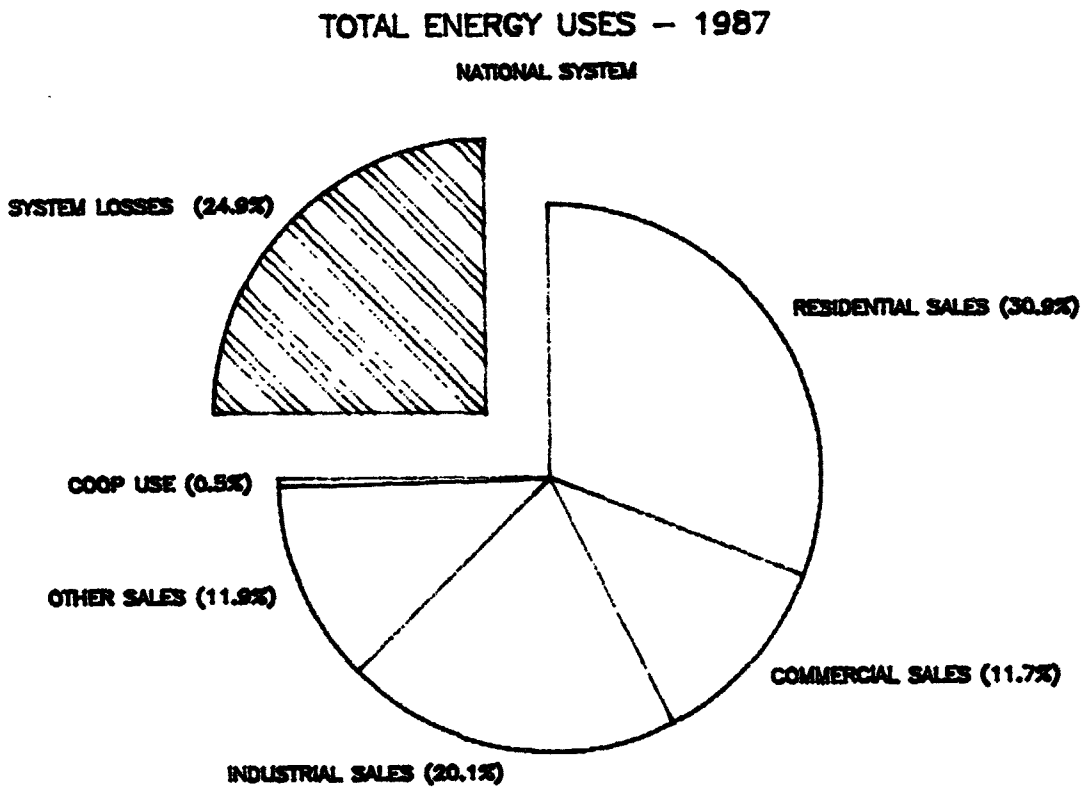
RURAL ELECTRIFICATION SECTOR STUDY

REC Energy Usage



PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

25 Largest Rural Electric Cooperatives
(by Number of Consumers)

	REC	Location	# Consumers	Category
1	Central Pangasinan Electric Coop	Luzon	77,192	C
2	Ilocos Norte Electric Coop	Luzon	68,503	A
3	Pampanga II Electric Coop	Luzon	64,067	D
4	Ilocos Sur Electric Coop	Luzon	58,707	D
5	Batangas II Electric Coop	Luzon	55,513	C
6	Batangas I Electric Coop	Luzon	51,892	D
7	Central Negros Electric Coop	Visayas	51,752	C
8	Quezon I Electric Coop	Luzon	48,683	A
9	Bataan Electric Coop	Luzon	48,446	D
10	La Union Electric Coop	Luzon	46,780	C
11	Isabela I Electric Coop	Luzon	41,185	C
12	Pangasinan III Electric Coop	Luzon	40,601	D
13	Agusan del Norte Electric Coop	Mindanao	38,743	B
14	Zamboanga City Electric Coop	Mindanao	38,590	B
15	Benguet Electric Coop	Luzon	36,503	D
16	South Cotabato II Electric Coop	Mindanao	33,296	A
17	Davao del Norte Electric Coop	Mindanao	31,713	B
18	Iloilo I Electric Coop	Visayas	31,541	A
19	Nueva Ecija III Electric Coop	Luzon	31,334	D
20	Nueva Ecija I Electric Coop	Luzon	30,845	D
21	Nueva Ecija II Electric Coop	Luzon	30,766	D
22	Pampanga III Electric Coop	Luzon	30,077	D
23	Bohol I Electric Coop	Visayas	30,055	A
24	Negros Oriental II Electric Coop	Visayas	29,751	B
25	Davao del Sur Electric Coop	Mindanao	29,102	A
			1,075,637	

25 Smallest Rural Electric Cooperatives
(by Number of Consumers)

	REC	Location	# Consumers	Category
89	Samar I Electric Coop	Visayas	8,199	C
90	Occidental Mindoro Electric Coop	Luzon	8,114	C
91	Marinduque Electric Coop	Luzon	7,707	D
92	Iloilo III Electric Coop	Visayas	7,282	C
93	Aurora Electric Coop	Luzon	6,671	B
94	Quirino Electric Coop	Luzon	6,147	B
95	Pampanga Rural Electric Coop	Luzon	5,748	D
96	Kalinga Apayao Electric Coop	Luzon	5,325	C
97	Basilan Electric Coop	Mindanao	5,015	D
98	Quezon II Electric Coop	Luzon	4,900	C
99	Eastern Samar Electric Coop	Visayas	4,665	C
100	Mountain Province Electric coop	Luzon	4,328	D
101	Sulu Electric Coop	Mindanao	4,249	D
102	Ifugao Electric Coop	Luzon	4,224	C
103	Tablas Island Electric Coop	Luzon	3,551	C
104	Province of Siquijor Electric Coop	Visayas	2,979	C
105	Masbate Electric Coop	Luzon	2,976	C
106	Camiguin Electric Coop	Mindanao	2,454	C
107	Northern Samar Electric Coop	Visayas	2,162	D
108	Guimaras Island Electric Coop	Visayas	2,066	B
109	Bantayan Island Electric Coop	Visayas	2,000	C
110	Camotes Island Electric Coop	Visayas	1,331	D
111	Biliran Island Electric Coop	Visayas	997	B
112	Tawi-Tawi Electric Coop	Mindanao	615	
113	Siargao Electric Coop	Mindanao	414	C
			104,119	

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Rural Electric Cooperatives

National Summary Statement of Operations
(₱ Million)

Year Ended December 31	1987	1986	1985
Operating Revenues:	3,536.9	3,118.8	3,196.5
Operating Expenses:			
Power	2,467.4	2,170.4	2,423.7
Transmission	2.4	1.6	1.3
Distribution-Operation	90.5	79.8	74.8
Distribution-Maintenance	145.0	114.2	102.5
Consumers Account	244.9	211.2	198.4
Administrative and General	298.5	259.8	234.9
Total	3,248.7	2,836.8	3,035.6
Operating Margin	288.2	282.0	160.9
Depreciation Expenses	160.0	141.1	133.5
Interest on Long-Term Debt	132.2	129.1	115.9
Net Operating Margin	(4.0)	11.8	(88.5)
Non-Operating Revenue	56.0	59.2	60.3
Non-Operating Expenses	(73.7)	(60.2)	(46.8)
Net Margin	(21.7)	10.7	(75.0)

Rural Electric Cooperatives

Regional Summary Statement of Operations
(₱ Million)

Year Ended December 31, 1987	Luzon	Visayas	Mindanao
Operating Revenues:	1,856.7	872.0	808.1
Operating Expenses:			
Power	1,354.3	604.4	508.7
Transmission	.2	1.3	.9
Distribution-Operation	46.3	22.9	21.2
Distribution-Maintenance	68.8	29.5	46.7
Consumers Account	132.2	50.1	62.6
Administrative and General	138.2	73.7	86.7
T o t a l	1,740.0	781.9	726.8
Operating Margin	116.7	90.1	81.3
Depreciation Expenses	66.9	43.4	49.6
Interest on Long-Term Debt	67.9	38.0	26.3
Net Operating Margin	(18.1)	8.7	5.4
Non-Operating Revenue	26.8	16.8	12.4
Non-Operating Expenses	(57.8)	(8.3)	(7.6)
Net Margin	(49.1)	17.2	10.2

Luzon - Rural Electric Cooperatives

Regional Summary Statement of Operations
(₱ Milion)

Year Ended December 31, 1987	I	II	III	IV	V	Luzon
Operating Revenues:	453.6	232.5	525.9	330.4	314.2	1,856.7
Operating Expenses:						
Power	323.2	143.3	436.4	233.3	218.1	1,354.3
Transmission	-	.1	-	-	.1	.2
Distribution-Operation	11.5	6.1	10.4	7.6	10.7	46.3
Distribution-Maintenance	16.0	10.7	12.8	16.1	13.2	68.8
Consumers Account	33.7	16.6	30.1	26.9	24.9	132.2
Administrative and General	34.9	17.6	27.9	25.2	32.6	138.2
T o t a l	419.3	194.4	517.6	309.1	299.6	1,740.0
Operating Margin	34.3	38.1	8.3	21.3	14.6	116.7
Depreciation Expenses	15.6	11.7	12.5	15.9	11.3	66.9
Interest on Long-Term Debt	17.1	16.3	11.0	12.9	10.5	67.9
Net Operating Margin	1.6	10.1	(15.2)	(7.5)	(7.2)	(18.1)
Non-Operating Revenue	8.4	5.6	5.0	5.0	2.8	26.8
Non-Operating Expenses	(4.5)	(1.7)	(38.6)	(2.5)	(10.4)	(57.8)
Net Margin	5.6	14.1	(48.9)	(5.1)	(14.8)	(49.1)

OPERATING STATISTICS					
Municipalities Served	143	107	91	125	108
Barangays Energized	3126	1425	1747	2062	1987
Houses Connected	385724	174293	393635	267453	277760
MWh Purchased/Generated	340196	149934	446786	213673	229297
MWh Sold	225871	101879	286875	157030	165148
Coop Consumption (MWh)	1282	566	970	2452	841
Systems Loss (In Percent)	33.22	31.67	35.57	25.36	27.61
Average Systems Rate (₱)	2.01	2.28	1.84	2.10	1.90
Average Power Cost per kWh (₱)	0.95	0.96	0.98	1.09	0.95

*Excludes non-operational electric cooperatives

Visayas - Rural Electric Cooperatives

Regional Summary Statement of Operations
(₱ Million)

Year Ended December 31, 1987	VI	VII	VIII	Visayas
Operating Revenues:	458.1	174.9	238.9	872.0
Operating Expenses:				
Power	303.9	112.9	187.6	604.4
Transmission	.4	-	.9	1.3
Distribution-Operation	14.2	3.6	5.1	22.9
Distribution-Maintenance	15.2	7.5	6.7	29.5
Consumers Account	28.3	10.4	11.4	50.1
Administrative and General	40.2	17.9	15.6	73.7
T o t a l	402.2	152.3	227.3	781.9
Operating Margin	55.9	22.6	11.6	90.1
Depreciation Expenses	21.5	10.2	11.7	43.4
Interest on Long-Term Debt	14.2	7.6	16.3	38.0
Net Operating Margin	20.2	4.9	(16.4)	8.7
Non-Operating Revenue	9.3	3.9	3.5	16.8
Non-Operating Expenses	(5.7)	(.5)	(2.1)	(8.3)
Net Margin	23.8	8.3	(15.0)	17.2

OPERATING STATISTICS

Municipalities Served	128	120	112
Barangays Energized	1895	1605	1623
Houses Connected	265532	163604	150279
MWH Purchased/Generated	303367	115224	178939
MWH Sold	240865	96657	144601
Coop Consumption (MWH)	1757	773	1352
Systems Loss (In Percent)	20.02	15.44	18.43
Average Systems Rate (P)	1.90	1.81	1.65
Average Power Cost per KWH (P)	1.00	0.98	1.05

*Excludes non-operational electric cooperatives

Mindanao - Rural Electric Cooperatives

Regional Summary Statement of Operations
(₱ Million)

Year Ended December 31, 1987	IX	X	XI	XII	Mindanao
Operating Revenues:	189.6	278.4	227.0	113.1	808.1
Operating Expenses:					
Power	127.6	178.6	138.5	63.9	508.7
Transmission	-	.1	.1	.8	.9
Distribution-Operation	5.5	7.2	5.6	3.0	21.2
Distribution-Maintenance	9.0	14.2	16.4	7.1	46.7
Consumers Account	14.6	20.8	17.6	9.6	62.6
Administrative and General	16.5	28.8	28.0	13.2	86.7
Total	173.2	249.7	206.2	97.6	726.8
Operating Margin	16.4	28.7	20.8	15.5	81.3
Depreciation Expenses	13.2	17.0	12.8	6.7	49.6
Interest on Long-Term Debt	5.5	8.9	5.6	6.3	26.3
Net Operating Margin	(2.4)	2.9	2.4	2.5	5.4
Non-Operating Revenue	1.3	3.6	6.1	1.4	12.4
Non-Operating Expenses	(.6)	(4.8)	(1.8)	(.4)	(7.6)
Net Margin	(1.7)	1.6	6.7	3.6	10.2

OPERATING STATISTICS				
Municipalities Served	65*	112	76	94
Barangays Energized	761*	1344	678	1332
Houses Connected	122460*	217123	180184	99361
MWH Purchased/Generated	207437	310346	241538	113885
MWH Sold	147391	269280	202582	90697
Coop Consumption (MWH)	809	941	948	383
Systems Loss (In Percent)	28.55	12.93	15.74	20.02
Average Systems Rate (P)	1.29	1.03	1.12	1.25
Average Power Cost per KWH (P)	0.62	0.58	0.57	0.56

*Excludes non-operational electric cooperatives

Regions With Aggregate REC Losses - 1987

Luzon Cooperatives:

Net Income/(Loss)-1987 Region III (Peso '000)	
Zambales II	8,208
Zambales I	3,611
Tarlac I	596
Pampanga Rural	(160)
Pampanga III	(297)
Tarlac II	(524)
Nueva Ecija II	(5,641)
Nueva Ecija III	(8,355)
Pampanga II	(10,654)
Pampanga I	(10,790)
Bataan	(11,264)
Nueva Ecija I	(13,591)
Total	(48,861)

Net Income/(Loss) - 1987 Region IV (Peso '000)	
Palawan	3,328
Quezon II	274
Quezon I	(45)
Occ. Mindoro	(100)
Aurora	(159)
Batangas I	(330)
Oriental Min. I	(381)
Oriental Min. II	(773)
Marinduque	(833)
Busuanga Island	(907)
Batangas II	(1,105)
Tablas Island	(1,235)
First Laguna	(2,837)
[illegible]bang	N/A
Total	(5,103)

Net Income/(Loss) - 1987 Region V (Peso '000)	
Albay II	2,141
Albay I	903
Cam. Sur I	179
Sorsogon I	(331)
Cam. Norte	(626)
Masbate	(936)
Sorsogon II	(1,397)
First Catan	(1,590)
Cam. Sur III	(1,964)
Cam. Sur IV	(3,288)
Cam. Sur II	(3,474)
Albay III	(4,432)
Total	(14,815)

Visayas Cooperatives:

Net Income/(Loss)) - 1987 Region VIII (Peso '000)	
Leyte I	2,332
Leyte V	1,282
Leyte IV	779
Leyte II	(338)
Northern Samar	(78[illegible])
Biliran Island	(805)
Eastern Samar	(1,213)
Leyte II	(3,084)
Samar I	(3,749)
Samar II	(4,538)
Southern Leyte	(4,831)
Total	(14,954)

Mindanao Cooperatives:

Net Income/(Loss) - 1987 Region IX (Peso '000)	
Zamboanga City	1,901
Zamboanga Sur I	1,027
Zamboanga Sur II	477
Zamboanga Norte	(108)
Basilan	(2,112)
Sulu	(2,864)
Tawi-Tawi	N/A
Total	(1,679)

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Rural Electric Cooperatives

Net Operating Income (Losses)

Year Ended December 31, 1987
(₱ '000)

	Region	Location	REC	Net Income (Loss)
1	III	Luzon	Nueva Ecija I	(13,591)
2	III	Luzon	Bataan	(11,264)
3	III	Luzon	Pampanga I	(10,790)
4	III	Luzon	Pampanga II	(10,654)
5	III	Luzon	Nueva Ecija III	(8,355)
6	III	Luzon	Nueva Ecija II	(5,641)
7	VIII	Visayas	Southern Leyte	(4,831)
8	VIII	Visayas	Samar II	(4,538)
9	V	Luzon	Albay III	(4,432)
10	VIII	Visayas	Samar I	(3,749)
11	V	Luzon	Cam. Sur II	(3,474)
12	V	Luzon	Cam. Sur IV	(3,288)
13	VIII	Visayas	Leyte II	(3,084)
14	XII	Mindanao	Lanao Sur	(2,965)
15	X	Mindanao	Misamis Or. I	(2,936)
16	IX	Mindanao	Sulu	(2,864)
17	IV	Luzon	First Laguna	(2,837)
18	IX	Mindanao	Basilan	(2,112)
19	V	Luzon	Cam. Sur III	(1,964)
20	V	Luzon	First Catanduanes	(1,590)
21	I	Luzon	Abra	(1,508)
22	V	Luzon	Sorsogon II	(1,397)
23	IV	Luzon	Tablas Island	(1,235)
24	VIII	Visayas	Eastern Samar	(1,213)
25	II	Luzon	Ifugao	(1,116)
26	IV	Luzon	Batangas II	(1,105)
27	V	Luzon	Masbate	(936)
28	IV	Luzon	Busuanga Island	(907)
29	IV	Luzon	Marinduque	(833)
30	VIII	Visayas	Biliran Island	(805)
31	VIII	Visayas	Northern Samar	(789)
32	X	Mindanao	Misamis Occ. I	(777)
33	IV	Luzon	Or. Mindoro II	(773)
34	II	Luzon	Kalinga Apayao	(656)
35	V	Luzon	Cam. Norte	(626)
36	VI	Visayas	Central Negros	(555)
37	XI	Mindanao	Surigao Sur II	(544)
38	III	Luzon	Tarlac II	(524)
39	X	Mindanao	Sairgao Island	(513)
40	IV	Luzon	Or. Mindoro I	(381)
32	X	Mindanao	Misamis Occ. I	(777)
33	IV	Luzon	Or. Mindoro II	(773)
34	II	Luzon	Kalinga Apayao	(656)
35	V	Luzon	Cam. Norte	(626)
36	VI	Visayas	Central Negros	(555)
37	XI	Mindanao	Surigao Sur II	(544)
38	III	Luzon	Tarlac II	(524)
39	X	Mindanao	Sairgao Island	(513)
40	IV	Luzon	Or. Mindoro I	(381)

Rural Electric Cooperatives

Net Operating Income (Losses)

Year Ended December 31, 1987
(₱ '000)

	Region	Location	REC	Net Income (Loss)
41	VIII	Visayas	Leyte III	(338)
42	V	Luzon	Sorsogon I	(331)
43	IV	Luzon	Batangas I	(330)
44	III	Luzon	Pampanga III	(297)
45	XII	Mindanao	Lanao Norte	(293)
46	X	Mindanao	Camiguin Island	(254)
47	I	Luzon	Sur	(245)
48	VII	Visayas	Prov. of Siquijor	(230)
49	III	Luzon	Pampanga Rural	(160)
50	IV	Luzon	Aurora	(159)
51	XI	Mindanao	Surigao Sur I	(129)
52	IX	Mindanao	Zambo Norte	(108)
53	IV	Luzon	Occ. Mindoro	(100)
54	IV	Luzon	Quezon I	(45)
55	I	Luzon	Pangasinan III	(31)
56	I	Luzon	Pangasinan I	(15)
57	II	Luzon	Cagayan II	(9)
58	VII	Visayas	Bantayan Island	(6)
59	I	Luzon	Mt. Province	(2)
60	VII	Visayas	Camotes	65
61	I	Luzon	Pangasinan II	96
62	V	Luzon	Cam. Sur I	179
63	X	Mindanao	Surigao Norte	196
64	VI	Visayas	Guimaras Island	232
65	VII	Visayas	Negros Or. I	237
66	IV	Luzon	Quezon	274
67	VI	Visayas	Iloilo II	306
68	VII	Visayas	Bohol II	346
69	II	Luzon	Quirino	418
70	VII	Visayas	Cebu I	438
71	X	Mindanao	First Bukidnon	462
72	I	Luzon	Ilocos Sur	477
73	IX	Mindanao	Zambo Sur II	477
74	X	Mindanao	Agusan Norte	528
75	XI	Mindanao	Davao Oriental	568
76	III	Luzon	Tarlac I	596
77	VIII	Visayas	Leyte IV	779
78	X	Mindanao	Misamis Occ. II	873
79	V	Luzon	Albay I	903
80	VII	Visayas	Cebu IIII	907

Rural Electric Cooperatives

Net Operating Income (Losses)

Year Ended December 31, 1987
(₱ '000)

	Region	Location	REC	Net Income (Loss)
81	IX	Mindanao	Zambo Sur I	1,027
82	XI	Mindanao	South Cota I	1,032
83	VII	Visayas	Negros Or. II	1,089
84	X	Mindanao	Agusan Sur	1,234
85	XI	Mindanao	Davao Norte]	1,263
86	VIII	Visayas	Leyte V	1,282
87	VI	Visayas	Iloilo III	1,293
88	X	Mindanao	Misamis II	1,328
89	XI	Mindanao	South Cota II	1,453
90	X	Mindanao	Bukidnon II	1,460
91	XII	Mindanao	North Cotabato	1,488
92	II	Luzon	Nueva Vizcaya	1,557
93	IX	Mindanao	Zambo City	1,901
94	VI	Visayas	Vresco	1,958
95	I	Luzon	Benguet	2,122
96	V	Luzon	Albay II	2,141
97	II	Luzon	Cagayan I	2,202
98	VIII	Visayas	Leyte I	2,332
99	VII	Visayas	Bohol I	2,393
100	XII	Mindanao	Sultan Kudaarat	2,509
101	II	Luzon	Isabela II	2,798
102	XII	Mindanao	Maguindanao	2,837
103	VI	Visayas	Capiz	3,003
104	XI	Mindanao	Davao Sur	3,066
105	VII	Visayas	Cebu II	3,109
106	IV	Luzon	Palawan	3,328
107	III	Luzon	Zambales I	3,611
108	VI	Visayas	Iloilo I	3,644
109	I	Luzon	Ilocos Norte	4,673
110	VI	Visayas	Negros Occ	5,333
111	III	Luzon	Zambales II	8,208
112	II	Luzon	Isabela I	8,908
113	IV	Luzon	Lubang	N/A
114	IX	Mindanao	Tawi-Tawi	N/A

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Rural Electric Cooperative

National Summary Balance Sheet
(₱ Million)

As of December 31	1987	1986	1985
A S S E T S			
Gross Utility in Service	3,919.2	3,409.0	3,097.4
Accumulated Depreciation	(1,051.2)	(895.1)	(761.7)
Net Utility Plant in Service	2,868.1	2,513.9	2,335.8
Construction Work in Progress	781.5	714.7	758.2
T o t a l	3,649.6	3,228.6	3,093.9
Other Property and Investment	69.1	52.1	48.8
Current and Accrued Assets:			
Cash	107.8	105.4	63.5
Accounts Receivable:			
Energy Sales	725.2	696.4	726.7
Others	303.8	254.8	227.1
	1,029.0	951.1	953.8
Materials and Supplies:			
Distribution Lines	502.4	469.8	454.8
Housewiring	9.9	11.9	11.4
Others	57.7	53.6	48.1
	570.0	535.2	514.4
Fuel Stock Inventory	8.2	10.0	8.1
Other Current and Accrued Assets	45.3	45.2	32.8
Total Current & Accrued Assets	1,760.4	1,647.0	1,572.6
Deferred Charges	1,003.9	966.2	954.1
Total Assets	6,483.0	5,893.9	5,669.4
LIABILITIES AND EQUITIES			
Equities and Margin			
Membership	14.5	13.8	13.4
Accumulated Margins	(472.1)	(366.0)	(333.7)
Other Equities and Margins	23.0	19.0	25.7
Total Equities and Margins	(434.6)	(333.2)	(294.6)
Long Term Liabilities:			
NEA Construction	4,378.3	4,286.1	4,232.6
Mini-Hydro	235.4	-	-
Dendro Thermal	105.8	-	-
Others	154.5	263.7	260.4
Total Long Term Liabilities	4,873.9	4,549.8	4,493.0
Current and Accrued Liabilities:			
Accounts Payable			
Power/Fuel and Oil	795.8	704.4	750.4
Others	233.1	208.5	183.0
Consumers Deposit	48.5	35.5	28.1
Other Current and Accrued Liabilities	783.1	581.5	400.1
Total Current and Accrued Liabilities	1,862.5	1,530.0	1,361.6
Deferred Credits	181.2	147.3	109.4
Total Liabilities and Equities	6,483.0	5,893.9	5,669.4

Rural Electric Cooperatives

Regional Summary Balance Sheet
(₱ Million)

As of December 31, 1987	Luzon	Visayas	Mindanao	Total System
A S S E T S				
Gross Utility in Service	1,767.3	1,076.3	1,075.6	3,919.2
Accumulated Depreciation	(477.7)	(298.9)	(274.6)	(1,051.2)
Net Utility Plant in Service	1,289.6	777.5	801.1	2,868.1
Construction Work in Progress	451.3	199.6	130.5	781.5
T o t a l	1,740.9	977.1	931.6	3,649.6
Other Property and Investment	30.1	18.7	20.3	69.1
Current and Accrued Assets:				
Cash	57.8	35.6	14.4	107.8
Accounts Receivable:				
Energy Sales	436.0	155.1	134.1	725.2
Others	144.4	94.6	64.9	303.8
	580.3	249.6	199.0	1,029.0
Materials and Supplies:				
Distribution Lines	269.8	133.5	99.2	502.4
Housewiring	5.0	2.3	2.7	9.9
Others	28.2	21.3	8.2	57.7
	303.0	157.0	110.1	570.0
Fuel Stock Inventory	3.2	4.6	.4	8.2
Other Current and Accrued Assets	22.4	12.4	10.5	45.3
Total Current & Accrued Assets	966.8	459.3	334.4	1,760.4
Deferred Charges	619.6	318.2	66.1	1,003.9
Total Assets	3,357.4	1,773.3	1,352.3	6,483.0
LIABILITIES AND EQUITIES				
Equities and Margin				
Membership	7.7	3.3	3.3	14.5
Accumulated Margins	(455.7)	(93.2)	76.8	(472.1)
Other Equities and Margins	10.3	17.7	(4.9)	23.0
Total Equities and Margins	(437.8)	(71.9)	75.1	(434.6)
Long Term Liabilities:				
NEA Construction	2,128.2	1,276.9	973.1	4,378.3
Mini-Hydro	161.1	74.3	0	235.4
Dendro-Thermal	100.6	5.2	0	105.8
Others	82.5	40.1	31.9	154.5
Total Long Term Liabilities	2,472.5	1,396.5	1,005.0	4,873.9
Current and Accrued Liabilities:				
Accounts Payable				
Power/Fuel and Oil	613.1	112.7	69.9	795.8
Others	103.5	60.5	69.1	233.1
Consumers Deposit	18.2	20.0	10.3	48.5
Other Current and Accrued Liabilities	472.4	207.2	105.4	785.1
Total Current and Accrued Liabilities	1,207.2	400.5	254.8	1,862.5
Deferred Credits	115.4	48.3	17.5	181.2
Total Liabilities and Equities	3,357.4	1,773.3	1,352.3	6,483.0

Luzon - Rural Electric Cooperative

Regional Summary Balance Sheet
(₱ Million)

As of December 31, 1987	I	II	III	IV	V	Luzon
A S S E T S						
Gross Utility in Service	402.6	368.0	290.0	437.0	269.6	1,767.3
Accumulated Depreciation	(107.6)	(67.3)	(97.9)	(119.0)	(85.9)	(477.7)
Net Utility Plant in Service	295.0	300.7	192.1	318.1	183.7	1,289.6
Construction Work in Progress	94.1	60.5	81.1	70.0	145.6	451.3
T o t a l	389.2	361.2	273.2	388.0	329.3	1,740.9
Other Property and Investment	17.5	2.6	2.0	4.7	3.3	30.1
Current and Accrued Assets:						
Cash	15.9	6.5	3.8	19.8	11.8	57.8
Accounts Receivable:						
Energy Sales	106.9	48.0	130.4	45.5	105.2	436.0
Others	25.2	34.6	29.2	23.3	32.0	144.4
	132.1	82.6	159.6	68.9	137.2	580.4
Materials and Supplies:						
Distribution Lines	59.4	56.7	25.5	66.1	62.1	269.8
Housewiring	2.3	.6	.4	.7	1.0	5.0
Others	3.4	4.6	4.0	12.7	3.6	28.2
	65.1	61.9	29.8	79.5	66.7	303.0
Fuel Stock Inventory	.9	-	.1	1.7	.4	3.2
Other Current and Accrued Assets	1.2	10.6	1.2	.7	8.6	22.4
Total Current & Accrued Assets	215.2	161.6	194.6	170.6	224.7	966.8
Deferred Charges	116.3	100.6	108.2	140.6	153.8	619.6
Total Assets	738.2	626.0	578.1	703.9	711.1	3,357.4
LIABILITIES AND EQUITIES						
Equities and Margin						
Membership	1.9	1.0	2.1	1.4	1.4	7.7
Accumulated Margins	(24.2)	(27.0)	(236.2)	(99.4)	(68.9)	(455.7)
Other Equities and Margins	2.2	.9	2.0	4.4	.7	10.3
Total Equities and Margins	(20.1)	(25.1)	(232.1)	(93.6)	(66.8)	(437.8)
Long Term Liabilities:						
NEA Construction	459.6	446.4	353.6	501.1	367.5	2,128.2
Mini-Hydro	42.8	-	-	50.5	67.8	161.1
Dendro-Thermal	4.4	4.7	-	.5	91.1	100.6
Others	18.3	.9	8.5	40.7	14.1	82.5
Total Long Term Liabilities	525.1	452.0	362.1	592.8	540.4	2,472.5
Current and Accrued Liabilities:						
Accounts Payable						
Power/Fuel and Oil	82.8	11.3	336.6	60.2	122.2	613.1
Others	37.8	12.7	20.5	13.2	19.2	103.5
Consumers Deposit	6.0	3.2	4.2	3.2	1.6	18.2
Other Current and Accrued Liabilities	84.1	136.3	68.4	104.5	79.0	472.4
Total Current and Accrued Liabilities	210.7	163.5	429.6	181.2	222.1	1,207.2
Deferred Credits	22.5	35.6	18.5	23.5	15.4	115.4
Total Liabilities and Equities	738.2	626.0	578.1	703.9	711.1	3,357.4

Visayas - Rural Electric Cooperatives

Regional Summary Balance Sheet
(₱ Million)

As of December 31, 1987	VI	VII	VIII	Visayas
A S S E T S				
Gross Utility in Service	477.9	285.8	312.6	1,076.3
Accumulated Depreciation	(144.3)	(59.2)	(95.3)	(298.9)
Net Utility Plant in Service	333.6	226.6	217.3	777.5
Construction Work in Progress	105.5	25.4	68.8	199.6
T o t a l	439.1	252.0	286.1	977.1
Other Property and Investment	10.6	3.7	4.4	18.7
Current and Accrued Assets:				
Cash	15.7	11.5	8.4	35.6
Accounts Receivable:				
Energy Sales	83.2	26.1	45.8	155.1
Others	57.8	16.8	20.0	94.6
	141.0	42.9	65.8	249.6
Materials and Supplies:				
Distribution Lines	46.9	40.7	45.9	133.5
Housewiring	1.4	.3	.5	2.3
Others	12.5	1.7	7.0	21.3
	60.8	42.8	53.4	157.0
Fuel Stock Inventory	3.5	.7	.4	4.6
Other Current and Accrued Assets	1.4	9.2	1.9	12.4
Total Current & Accrued Assets	222.3	107.0	129.9	459.3
Deferred Charges	139.7	77.1	101.4	318.2
Total Assets	811.7	439.9	521.8	1,773.3
LIABILITIES AND EQUITIES				
Equities and Margin				
Membership	2.0	.8	.8	3.6
Accumulated Margins	11.5	7.0	(111.7)	(93.2)
Other Equities and Margins	6.6	7.0	4.0	17.7
Total Equities and Margins	20.1	14.9	(106.8)	(71.9)
Long Term Liabilities:				
NEA Construction	539.5	347.5	389.9	1,276.9
Mini-Hydro	21.0	17.1	36.2	74.3
Dendro-Thermal	-	5.2	-	5.2
Others	15.4	2.8	21.9	40.1
Total Long Term Liabilities	575.8	372.6	448.0	1,396.5
Current and Accrued Liabilities:				
Accounts Payable				
Power/Fuel and Oil	60.7	16.4	35.7	112.7
Others	33.0	12.7	14.8	60.5
Consumers Deposit	12.3	3.6	4.1	20.0
Other Current and Accrued Liabilities	89.3	7.5	110.4	207.2
Total Current and Accrued Liabilities	195.3	40.2	165.0	400.5
Deferred Credits	20.4	12.2	15.6	48.3
Total Liabilities and Equities	811.7	439.9	521.8	1,773.3

Mindanao - Rural Electric Cooperatives

Regional Summary Balance Sheet
(₱ Million)

As of December 31, 1987	IX	X	XI	XII	Mindanao
A S S E T S					
Gross Utility in Service	286.8	355.8	262.1	171.0	1,075.6
Accumulated Depreciation	(83.1)	(86.5)	(67.2)	(37.8)	(274.6)
Net Utility Plant in Service	203.6	269.3	194.9	133.2	801.1
Construction Work in Progress	23.8	43.1	34.2	29.4	130.5
T o t a l	227.4	312.5	229.1	162.6	931.6
Other Property and Investment	6.1	6.7	6.6	1.0	20.3
Current and Accrued Assets:					
Cash	(.8)	4.2	6.1	4.9	14.4
Accounts Receivable:					
Energy Sales	26.1	42.7	33.6	31.7	134.1
Others	11.6	20.2	15.6	17.4	64.9
	37.7	62.8	49.3	49.2	199.0
Materials and Supplies:					
Distribution Lines	20.0	30.3	29.5	19.5	99.2
Housewiring	1.0	.4	.8	.5	2.7
Others	3.0	2.6	1.7	.9	8.2
	23.9	33.3	32.0	20.9	110.1
Fuel Stock Inventory	(.1)	.2	.3	-	.4
Other Current and Accrued Assets	1.0	2.8	6.0	.6	10.5
Total Current & Accrued Assets	61.7	103.4	93.6	75.6	334.4
Deferred Charges	(5.3)	9.6	25.6	36.2	66.1
Total Assets	290.0	432.1	354.9	275.4	1,352.3
LIABILITIES AND EQUITIES					
Equities and Margin					
Membership	.6	1.1	1.0	.5	3.3
Accumulated Margins	6.6	(9.1)	31.8	47.4	76.9
Other Equities and Margins	(10.4)	3.5	1.4	.5	(4.9)
Total Equities and Margins	(3.1)	(4.4)	34.1	48.5	75.1
Long Term Liabilities:					
NEA Construction	215.2	317.4	240.7	199.8	973.1
Mini-Hydro	-	-	-	-	0
Dendro-Thermal	-	-	-	-	0
Others	6.0	18.2	4.1	3.6	31.9
Total Long Term Liabilities	221.2	335.5	244.8	203.4	1,005.0
Current and Accrued Liabilities:					
Accounts Payable					
Power/Fuel and Oil	18.3	22.1	23.4	6.3	69.9
Others	12.5	28.4	20.4	7.9	69.1
Consumers Deposit	.5	3.2	5.8	.7	10.3
Other Current and Accrued Liabilities	36.0	42.2	19.6	7.7	105.4
Total Current and Accrued Liabilities	67.2	95.8	69.2	22.5	254.8
Deferred Credits	4.6	5.2	6.7	.9	17.5
Total Liabilities and Equities	290.0	432.1	354.9	275.4	1,352.3

ANNEX 5.06

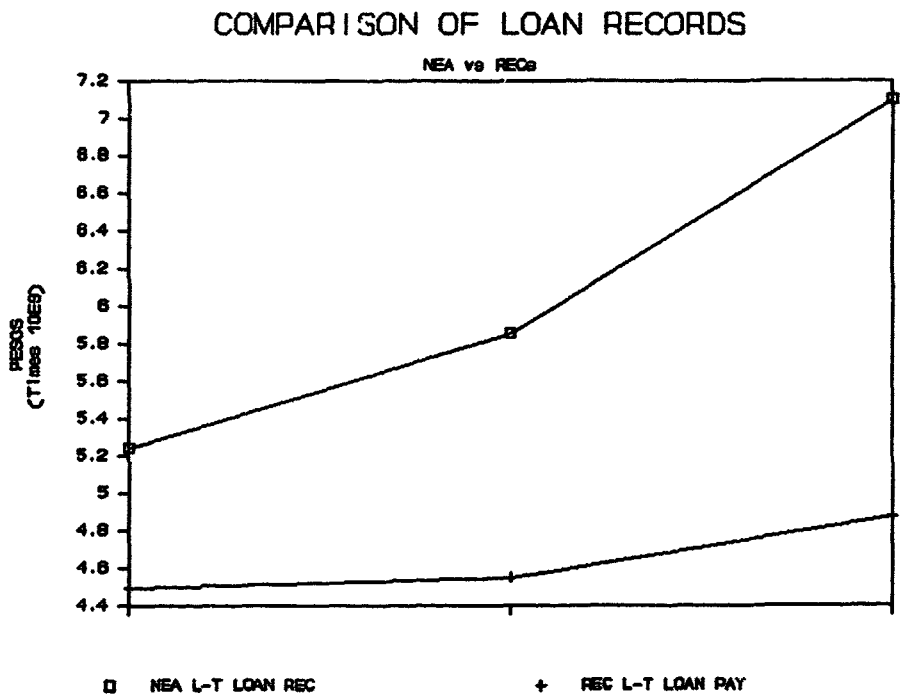
PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Comparison of Loan Records

NEA vs RECs
(₱ Million)

	1985	1986	1987
NEA Long Term Loans Receivable	5,243	5,858	7,105
REC Long Term Loans Payable	4,493	4,550	4,874
Difference (NEA exceeds RECs)	750	1,308	2,231



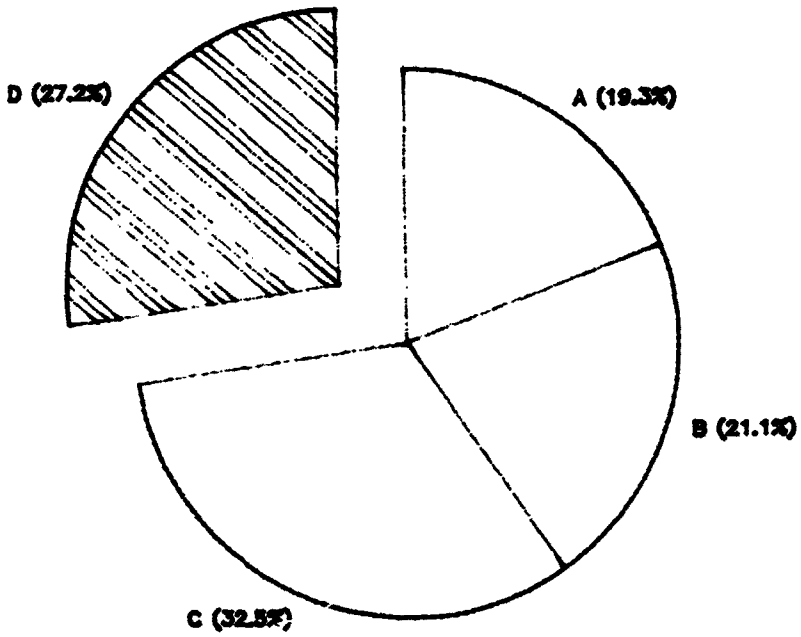
PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Distribution of RECs Among Performance Categories

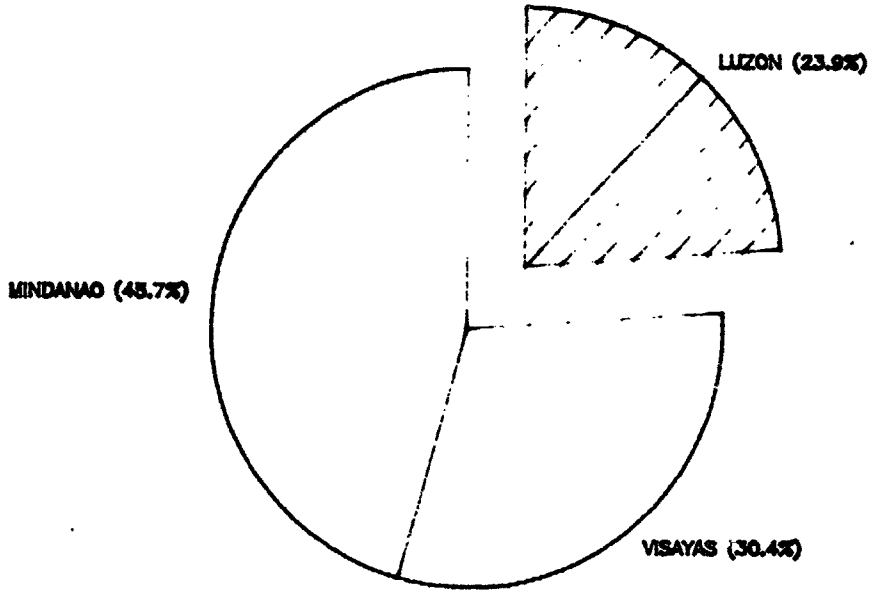
NATIONWIDE SUMMARY OF REC PERFORMANCE

as of DECEMBER 31, 1987



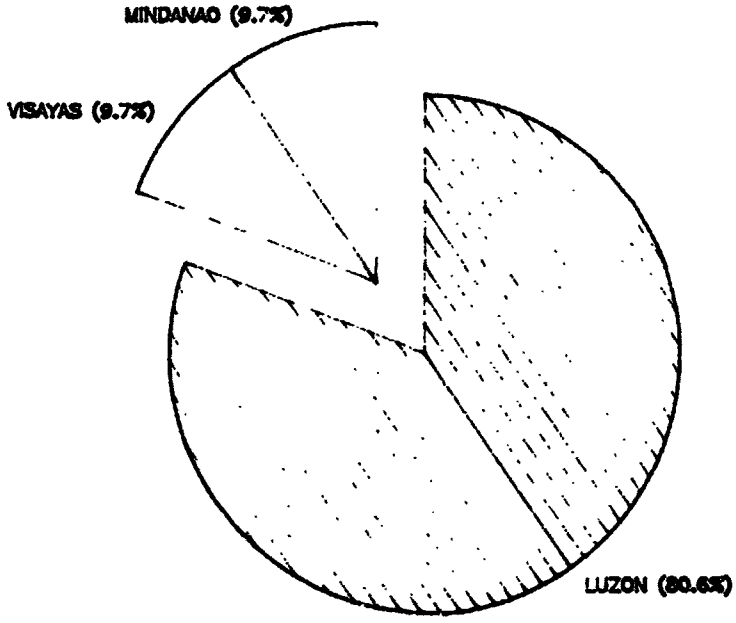
46 A & B RATED RECs BY GEOGRAPHIC AREA

AS OF DECEMBER 31, 1987



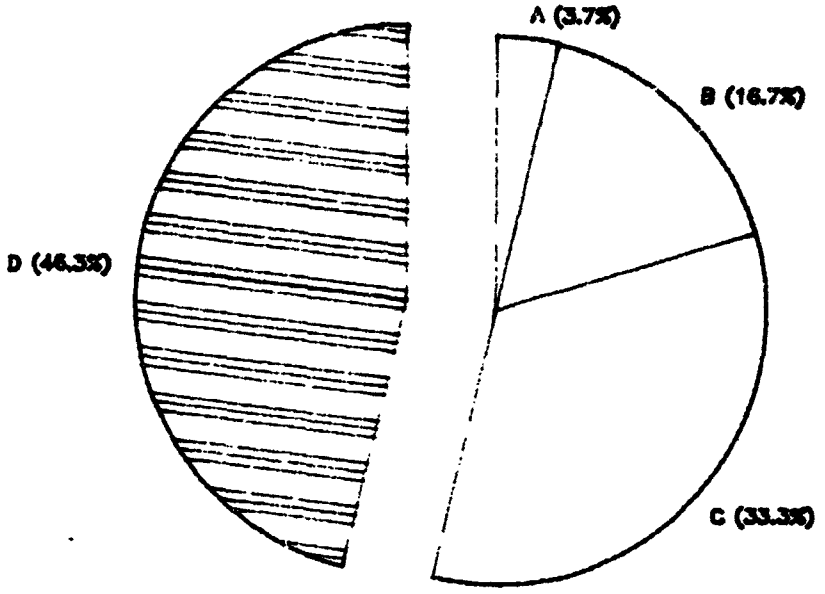
31 D RATED RECs BY GEOGRAPHIC AREA

as of DECEMBER 31, 1987



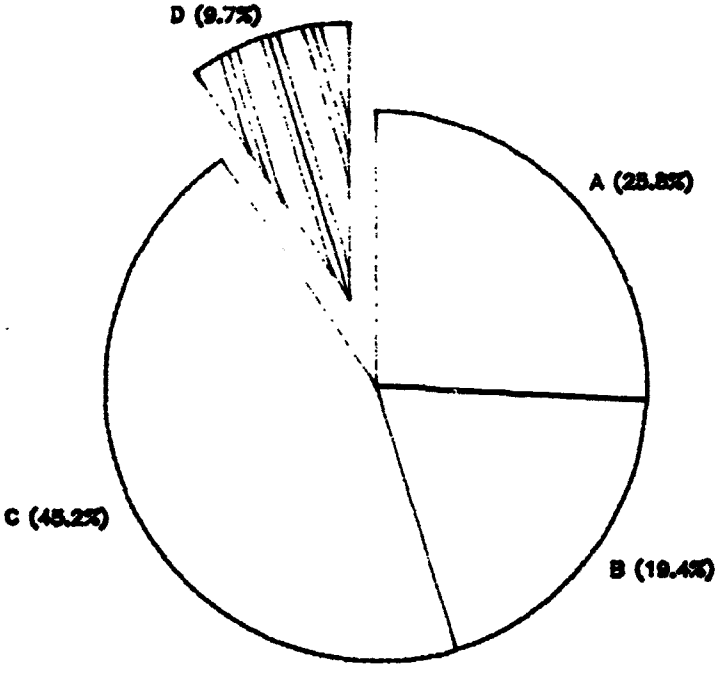
54 LUZON RECs – SUMMARY OF PERFORMANCE

as of DECEMBER 31, 1987



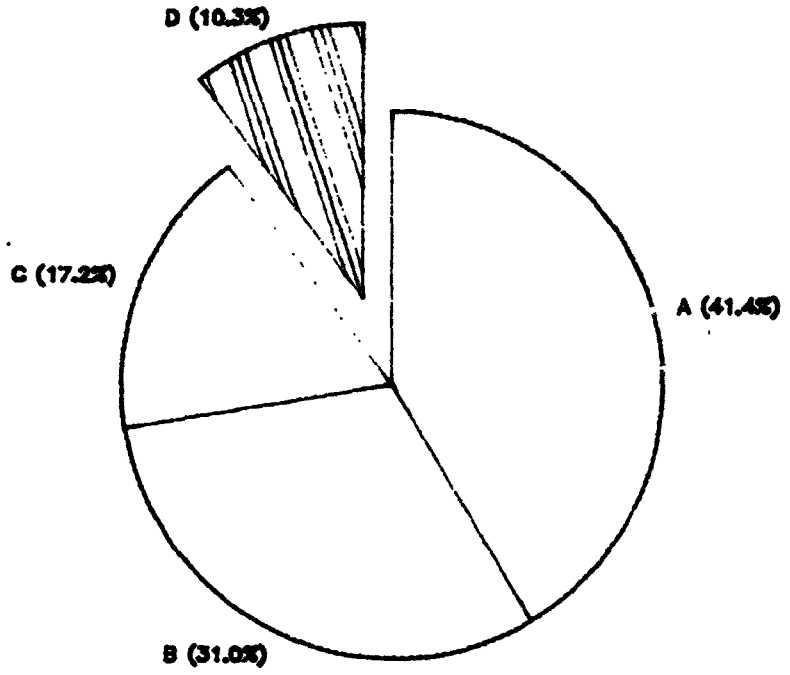
31 VISAYAS RECs–SUMMARY OF PERFORMANCE

as of DECEMBER 31, 1987



29 MINDANAO RECs—SUMMARY OF PERFORMANCE

as of DECEMBER 31, 1987



PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Cost Profile Summary
(₱/kWh)

Year Ended December 31, 1987	Luzon	Visayas	Mindanao	Philippines
Distribution				
Purchased Power from NPC	0.9793	0.8671	0.5657	0.9038
Trans/Distribution	0.1564	0.1717	0.1755	0.1593
Other Prodn. Cost	0.0006	0.0733	0.0270	0.0068
Administration	0.0633	0.1199	0.1007	0.0706
System Losses	0.3339	0.2981	0.1608	0.3107
Total	1.5336	1.5301	1.0298	1.4512
Interest Expense	0.0787	0.0489	0.0214	0.0706
Total Cost	1.6123	1.5790	1.0511	1.5218
Profit	0.0642	0.0566	(0.0018)	0.0839
Selling Rate to End Users	1.6765	1.6356	1.0493	1.6058
GWh Sales	10,043	768	1,318	12,129
% of Total	82.8	6.3	10.9	100.0
% losses (kWh Sold vs. Supplies)	21.8	18.9	15.7	21.0

Cost Profile Summary - Luzon
(₱/kWh)

Year Ended December 31, 1987	MERALCO	RECs	Private Utilities	RECs & Utilities	Total
Distribution					
Purchased Power from NPC	0.9793	0.9793	0.9793	0.9793	0.9793
Trans/Distribution	0.1502	0.2228	0.0948	0.1966	0.1564
Other Prodn. Cost	0.0000	0.0000	0.0239	0.0048	0.0006
Administration	0.0567	0.0980	0.1381	0.1062	0.0633
System Losses	0.3184	0.6198	0.3042	0.5441	0.3339
Total	1.5046	1.9199	1.5403	1.8310	1.5336
Interest Expense	0.0818	0.0712	0.0070	0.0563	0.0787
Total Cost	1.5864	1.9911	1.5473	1.8873	1.6123
Profit	0.0618	(0.0191)	0.0404	(0.0047)	0.0642
Selling Rate to Eend User	1.6482	1.9720	1.5877	1.8826	1.6765
GWh Sales	8,828	932	283	1,215	10,043
% of Total	87.9	9.3	2.8	12.1	100.0
% losses (kWh sold vs. Supplies)	20.6	32.1	19.9	29.6	21.8

Cost Profile - Visayas
(₱/kWh)

Year Ended December 31, 1987	RECs	Private Utilities	Total
Distribution			
Purchased Power from NPC	0.8671	0.8671	0.8671
Trans/Distribution	0.2592	0.0931	0.1717
Other Prodn. Cost	0.0000	0.1492	0.0733
Administration	0.1317	0.1093	0.1199
System Losses	0.3265	0.2734	0.2981
Total	1.5845	1.4920	1.5301
Interest Expense	0.0639	0.0356	0.0489
Total Cost	1.6484	1.5276	1.5790
Profit	0.1884	(0.0714)	0.0566
Selling Rate to End Users	1.8368	1.4562	1.6356
GWh Sales	362	406	768
% of Total	47.1	52.9	100.0
% losses (kWh Sold vs. Supplies)	19.2	18.6	18.9

Cost Profile Summary - Mindanao
(₱/kWh)

Year Ended December 31,1987	RECs	Private Utilties	Total
Distribution			
Purchased Power from NPC	0.5657	0.5657	0.5657
Trans/Distribution	0.2023	0.1421	0.1755
Other Prodn. Cost	0.0000	0.0612	0.0270
Administration	0.0976	0.1047	0.1007
System Losses	0.1999	0.1166	0.1608
Total	1.0656	0.9903	1.0298
Interest Expense	0.0339	0.0069	0.0214
Total Cost	1.0994	0.9973	1.0511
Profit	0.0273	(0.0372)	(0.0018)
Selling Rate to End Users	1.1267	0.9600	1.0493
GWh Sales	706	612	1,318
% of Total	53.6	46.4	100.0
% losses (kWh Sold vs. Supplies)	18.6	12.0	15.7

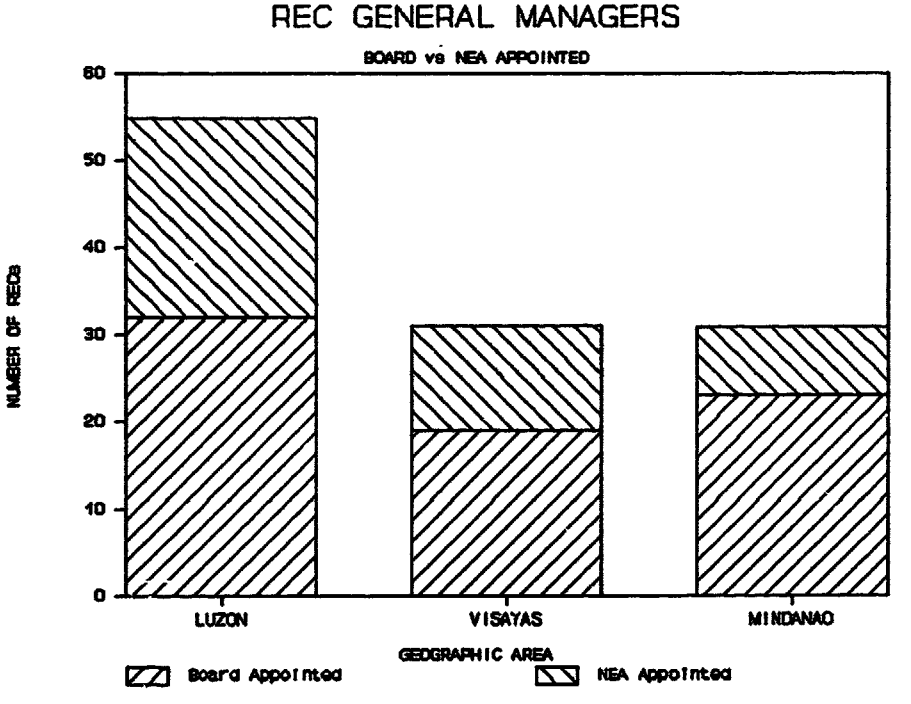
ANNEX 5.09

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

REC General Managers - Board vs. NEA Appointments
(as of February 1989)

	Luzon	Visayas	Mindanao	Total
Board Appointments	32	19	23	74
NEA Appointments	23	12	8	43
Total	55	31	31	117



PHILIPPINES

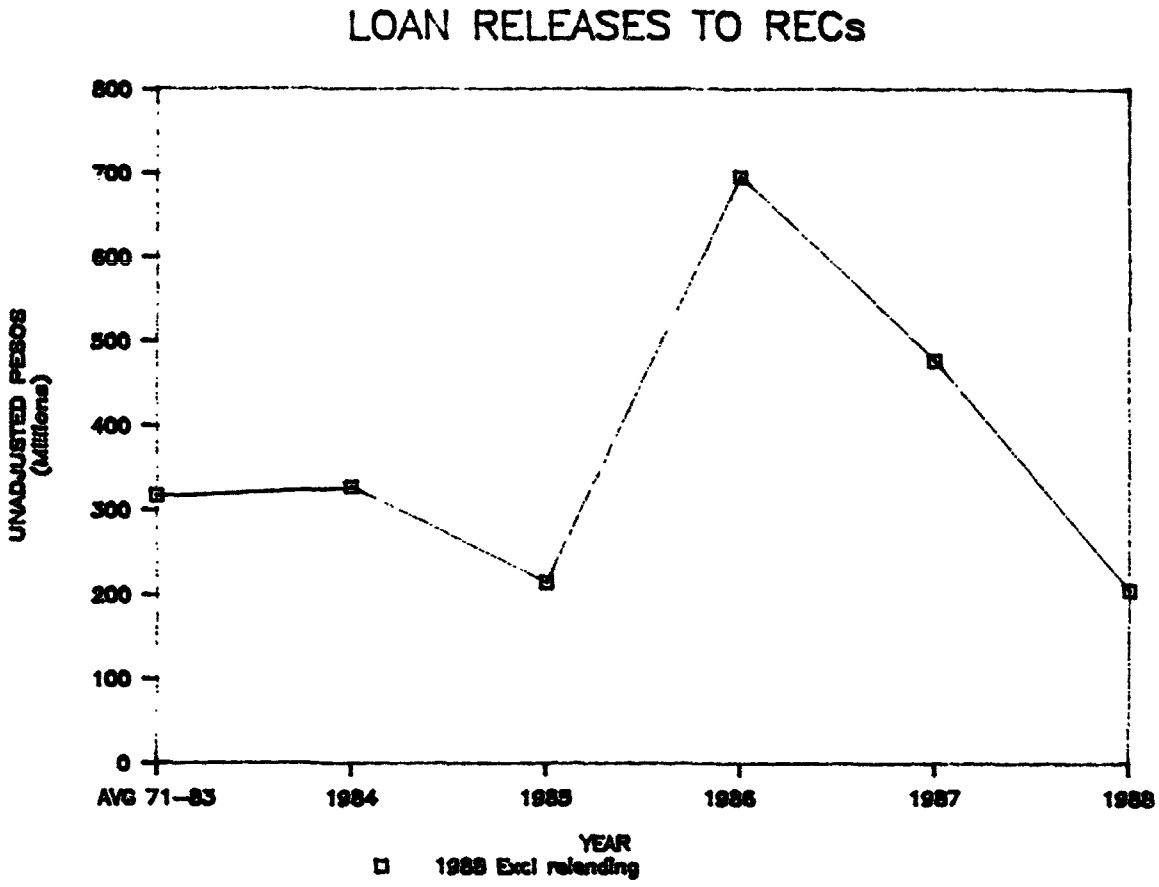
RURAL ELECTRIFICATION SECTOR STUDY

Loan Releases to RECs (Per NEA Records)
(₱ Million)

Region		1971-83	1984	1985	1986	1987	1988	Total
	1	351.7	43.9	79.8	21.5	6.8	49.6	553.3
	2	369.8	37.7	4.4	46.6	4.3	8.6	471.5
	3	317.8	34.8	29.2	81.6	14.6	356.1	834.3
	4	424.4	41.1	18.9	154.3	15.7	55.6	710.0
	5	318.9	23.1	11.7	76.6	7.1	148.1	585.5
Luzon		1,782.8	180.5	144.1	380.8	48.4	618.1	3,154.6
	6	424.5	28.9	5.2	55.3	56.9	23.8	594.7
	7	201.7	16.9	25.2	124.5	32.4	17.9	418.7
	8	331.0	24.0	9.0	64.4	24.1	(2.1)	450.5
Visayas		957.1	69.9	39.5	244.3	113.4	39.7	1,463.8
	9	184.1	17.9	6.3	39.1	4.2	8.9	260.5
	10	223.0	29.6	10.0	11.5	226.2	13.0	513.3
	11	191.7	15.3	9.8	11.5	54.2	9.7	292.3
	12	152.3	14.6	5.3	8.9	31.7	16.3	229.0
Mindanao		751.2	77.4	31.3	71.0	316.3	47.9	1,295.0
Total		3,491.1	327.7	214.9	696.0	478.1	705.7 1/	5,913.5
Annual Releases		317.4	327.7	214.9	696.0	478.1	705.7	
Excluding Relending Program							205.7	

1/ Peso 500 million was disbursed as part of the REC relending program

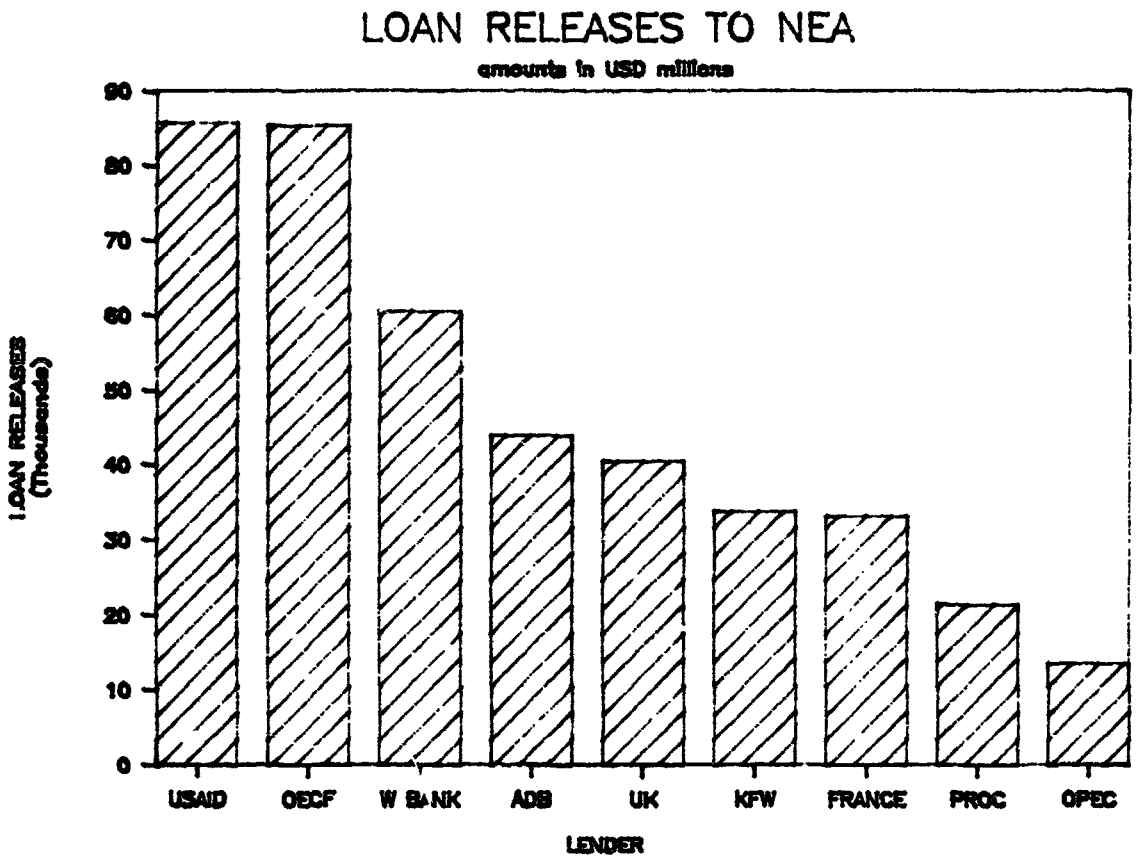
Annual Lending to the RECs
(₱ Million)



PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Foreign Lending to NEA - By Source



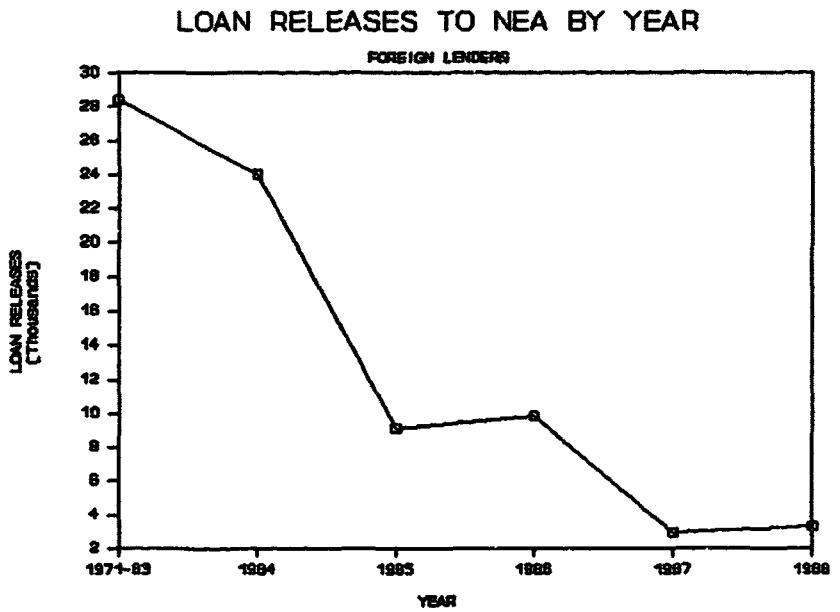
ANNEX 6.02

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Foreign Lending to NEA by Year
(Amounts in US$ '000)

LENDER	1971-83	1984	1985	1986	1987	1988	Total
USAID	85,845	0	0	0	0	0	85,845
OECF	83,769	1,621	0	0	0	0	85,390
W BANK	60,550	0	0	0	0	0	60,550
ADB	25,723	13,553	2,785	983	134	835	44,013
UK	39,517	673	391	0	0	0	40,581
KFW	15,161	3,101	1,773	8,540	2,828	2,466	33,869
FRANCE	31,568	432	977	314	0	0	33,291
PROC	15,067	3,262	3,184	0	0	0	21,513
OPEC	12,136	1,401	20	0	0	0	13,557
Totals	369,336	24,043	9,130	9,837	2,962	3,301	418,609
Average	28,410	24,043	9,130	9,837	2,962	3,301	23,256



ANNEX 6.03

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Summary of Overdrawn Loans to RECs

As of December 31, 1988
(₱ Million)

Region	REC	Total Granted	Total Released	Net Overdraft	% Overdraft
I	1 Ilocos Norte	266	316	50	19%
	2 Abra	123	130	7	6%
	3 Ilocos Sur	156	158	2	1%
	4 Mountain Province	57	59	2	4%
	5 W. Pangasinan	102	137	35	34%
II	6 Isabela I	254	307	53	21%
	7 Isabela II	178	230	52	29%
	8 Nueva Vizcaya	136	164	28	21%
III	9 Nueva Ecija II	83	94	11	13%
IV	10 Batangas I	41	49	8	20%
	11 Marinduque	81	89	8	10%
	12 Lubang	9	10	1	12%
	13 Busuanga	19	39	20	105%
	14 Tablas	21	70	49	233%
	15 Camarines Sur IV	172	175	3	2%
	16 Sorsogon I	29	30	1	3%
	17 Masbate	32	49	17	53%
VI	18 Aklan	92	116	24	26%
	19 Capiz	87	91	4	4%
	20 Iloilo II	88	97	9	10%
	21 Guimaras	15	47	32	213%
VII	22 Bantayan	11	49	38	345%
	23 Siquijor	12	55	43	358%
VIII	24 Leyte V	86	92	6	7%
	25 Biliran	32	54	22	69%
	26 Samar I	77	87	10	13%
	27 Eastern Samar	52	70	18	35%
IX	28 Zamboanga Sur I	40	44	4	10%
	29 Alicia	3	4	1	33%
X	30 Siargao	13	111	98	754%
	31 Agusan Norte	37	43	6	16%
	32 Misamis Oriental II	27	28	1	4%
	33 Bukidnon II	44	45	1	2%
	34 Misamis Occidental II	25	26	1	4%
	35 Camiguin	38	69	31	83%
XI	36 Surigao Sur I	34	36	2	6%
	37 Davao Oriental	29	34	5	17%
	38 So. Cotabato II	46	56	10	22%
	T o t a l	2,648	3,361	713	27%

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Status of NEA's Mini-Hydro Loans - By Region

As of December 31, 1988
(₱ Million)

Region	Loan Releases	Payments Due to Date	Payments Received	Arrearages
1	238.0	101.8	0.9	100.9
2	242.0	47.7	2.3	45.4
3	111.0	0.0	0.0	0.0
4	57.0	0.0	0.0	0.0
5	164.0	23.4	0.5	22.9
Luzon	812.0	172.9	3.7	169.2
6	76.0	0.0	0.0	0.0
7	138.0	7.8	6.2	1.6
8	189.0	47.9	8.8	39.1
Visayas	403.0	55.7	15.0	40.7
9	38.0	13.4	0.1	13.3
10	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0
Mindanao	38.0	13.4	0.1	13.3
Total	1,253.0	242.0	18.9	223.2

Status of NEA's Dendro-Thermal Loans - By Region

As of December 31, 1988
(₱ Million)

Region	Loan Releases	Payments Due to Date	Payments Received	Arrearages
1	187.0	20.3	0.0	20.3
2	131.0	4.5	0.0	4.5
3	65.0	10.2	0.0	10.2
4	63.0	7.6	0.1	7.5
5	57.0	4.5	0.0	4.5
Luzon	503.0	47.0	0.1	46.9
6	93.0	10.1	0.0	10.1
7	1.0	0.7	0.0	0.7
8	0.0	0.0	0.0	0.0
Visayas	94.0	10.8	0.0	10.8
9	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0
Mindanao	0.0	0.0	0.0	0.0
Total	597.0	57.8	0.1	57.7

ANNEX 6.05

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Summary of NEA's Relending Terms

Foreign Loans			Lending by NEA to RECs		
Foreign Lenders	Maturity/ Grace Period	Interest Rates		Maturity/ Grace Period	Interest Rates
I. Rural Electrification			I. Construction Loans		
USAID	40/10	2%-First 10 yrs 3%-Thereafter	Initial loan 1 Self gen RECs 2 Grid connect	 35/5 30/5	 2% 3%
KFW I-1st Portion KFW I-2nd Portion	30/10 8	2% 7.5% (1/4% comm fee)	Additional loan 3 Self gen RECs 4 Grid connect	 25-30/1 25/1	 3-6% 4-7%
KFW II	30/10	2% (1/4% comm fee)	Current terms	25/1	7%
ADB	21/4	10.1% (3/4% comm fee)			
OPEC	15/5	10.1% (1/2% comm fee)			
OECF	25/7	3.25%			
II. Dendro Thermal/Mini Hydro			II.1 Dendro Thermal		
OECF	30/10	3%	5 France-Govt 6 France-Com'l	25.5/5.5 10.5/.5	4.25% 8.25%
PROC	14/3	7.5%	7 France-Local	25/1	3% Yrs 1-3 9.5% Yrs 4-25
FRENCH	25/5 10	3.5% 7.5%	8 UK-Govt 9 UK-Com'l	25.5/6.5 10.5/.5	.75% 8.25%
UK I-1st Portion UK I-2nd Portion	25/7 10/3	2% 7.5% (1/2% comm fee)	10 UK-Local	25/1	3% Yrs 1-3 9.5% Yrs 4-25
			II.2 Mini Hydro		
UK II-1st Portion UK II-2nd Portion	25/7 10/3	Grant 7.5% (1/4% comm fee)	11 France-Govt 12 France-Com'l 13 France-Local	15-25/.5 15-25/.5 15-25/.5	4.25% 8.25% 12%
			14 UK-Govt 15 UK-Com'l 16 UK-Local	15-25/.5 15-25/.5 15-25/.5	2.75% 8.25% 12%
III. Others			III. Others		
World Bank 1120 PH World Bank 1547 PH	16/4 15/5	8.5% 7.45% (3/4% comm fee)	17 RUR Water Supply 18 Power Use 19 Power Use 20 Power Use-BLISS 21 Short Term 22 School Tree 23 BLISS-Gen-Bldg 24 BLISS-Generators 25 BLISS-Gen-Gasifier 26 BLISS-Gen-Diesel 27 BLISS-Gen-Charcoal 28 BLISS-Distribution 29 BLISS-Tree Plant 30 Gasifier-Jeepney 31 Gasifier-Bancas 32 Wiring/Waterworks	20/.5 5/1 10/2 10/2 varies 15/5 20/5 10/2 10/2 5/1 5/1 30/5 10/4 5/2mos. 5/3mos. 5-10/1	3.5% 5% 11% 11% 7.5% 4% 8% 8% 8% 8% 8% 2% 11% 11% 11% 6%

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

NEA's Financial Projections for 1989-93

Table of Contents

Assumptions - Scenario I.A & II.A

A. Revenues

1. Interest income represents interest earned on loans granted to the RECs. A 12% rate is estimated on loans funded by official foreign lenders borrowings and the Government, while a 7% rate is charged on loans funded by NEA's own internal resources. Interest on old loans vary between 2% and 12%.

2. Other income is estimated to be P5 million per annum.

3. Foreign grants represent amounts to be provided by USAID, the Government of Norway, and IBRD. The USAID and Norwegian grants are as arranged in the grant agreements between their respective governments and the Government of the Philippines. The IBRD related grant (US$22 million equivalent) represents the proceeds of the proposed Energy Sector Loan, which the Government has agreed to pass on to NEA as an equity investment.

B. Expenses

1. Interest expense is computed based on amortization schedules for various existing loans payable to foreign creditors. Interest rates charged on new loans are estimated to be as follows:

Creditor	Interest Rate
Asian Development Bank	10.1%
Government of United Kingdom	7.5%
Other Sources	12.0%

2. Personnel services represent costs of salaries and wages, employee benefits, and other personnel related expenses. These are estimated to increase by 20% per annum.

3. Transportation and travel are estimated at ₱8 million, increasing at the rate of 5% annually.

4. Costs of rent, light and water is estimated to be ₱6 million, increasing at the rate of 20% annually.

5. Other administrative costs represent office supplies; gas and oil; publications, books and subscriptions; representation, advertising, etc. These costs are estimated to increse by 10% per year.

6. Depreciation rate is 4% for buildings and 10% for transport and other fixed assets. For newly acquired fixed assets (computers), depreciation is assumed at 15%.

7. Development costs are amortized over 30 years.

8. Other costs are estimated to be 1% of total revenues.

C. Others

1. The collection rate for loans receivables (matured portion) is estimated as follows:

Year	% of Collection
1989	55
1990	57
1991	60
1992	63
1993	65

2. Expected foreign exchange financing is assumed to be received as follows:

Year	Amount in US$
1989	30.2
1990	22.0
1991	21.1
1992	5.6
1993	1.9

3. A portion of existing inventories will be released with the corresponding value being recorded as loans to the cooperatives. Yearly releases of this form are estimated to be 5% of the previous year's balance.

4. Collection of accrued interest receivable are assumed to follow the pattern shown for loans receivables in item C.1 above. Accrued interest receivable are lodged in the "Other Receivables" account.

5. Current maturities of long-term receivables are transferred to the "Loans Receivables" account under Current Assets. The estimated amount of the current maturities is based on the amortization schedule.

6. Fifty percent (50%) of cost incurred for institutional development is estimated to be for computers and another 50% for training. Training expenditures are considered to be development cost.

National Electrification Administration

Financial Projections for Scenario I.A

Projected Income Statement

1989to 1989
(₱ Million)

Year Ended December 31	1989	1990	1991	1992	1993
Revenues					
Interest Income	265	344	439	585	742
Other Income	5	5	5	5	5
Foreign Grants	397	149	666	185	57
Total Revenues	**667**	**498**	**1,111**	**775**	**784**
Expenses					
Interest on Foreign Loans	297	342	327	311	315
Personal Services	63	76	91	109	131
Transportation & Travel	8	9	9	10	10
Rent, Light & Water	6	7	9	10	12
Other Administrative Cost	11	12	13	15	16
Depreciation & Amortization	10	14	17	21	24
Other Costs	7	5	11	8	8
Total Expenses	**402**	**464**	**477**	**483**	**517**
Income Before Extra Ordinary Losses	0	0	0	0	0
Other Income (Losses)					
Forex Losses on Existing Loans	0	0	0	0	0
Net Other Income(Loses)	0	0	0	0	0
Net Income (Loss)	**265**	**34**	**633**	**291**	**267**

National Electrification Administration

Financial Projections for Scenario I A

Projected Balance Sheet

1988 to 1993
(₱ Million)

As of December 31	1988 (Actual)	1989	1990	1991	1992	1993
A S S E T S						
Current Assets						
Cash	218	389	212	89	756	(1,609)
Trust Funds	16	16	16	16	16	16
Loans Receivable (Matured Portion)	218	317	415	512	608	706
Inventories	683	629	576	523	470	417
Other Receivables	624	797	1,028	1,307	1,672	2,094
Total Current Assets	1,758	2,148	2,247	2,488	2,010	1, 624
Investment and Fixed Assets						
Long-Term Loans Receivable	5,242	5,390	5,753	6,255	7,116	7,938
Other Investments	1	1	1	1	1	1
Fixed Assets (Net of Accum. Depn)	8	18	29	41	46	50
Total Investment & Fixed Assets	5,251	5,410	5,784	6,297	7,163	7,989
Other Assets	215	221	231	244	253	262
Total Assets	**7,224**	**7,779**	**8,263**	**8,989**	**9,427**	**9,857**
LIABILITIES AND CAPITAL & SURPLUS						
Current Liabilities						
Payables	405	422	491	561	630	704
Trust Liabilities	67	67	67	67	67	67
Other Current Liabilities	9	9	9	9	9	9
Total Current Liabilities	408	498	567	636	706	776
Long-Term Liabilities						
Loans Payable - Foreign	2,332	2,344	2,370	2,047	1,732	1,458
Total Liabilities	**2,813**	**2,842**	**2,937**	**2,683**	**2,438**	**2,238**
Capital and Surplus						
Paid-in Capital	6,391	6,652	7,007	7,354	7,745	8,127
Donated Capital	177	177	177	177	177	177
Retained Earnings	(2,159)	(1,894)	(1,860)	(1,227)	(935)	(668)
Contigent Surplus	2	2	2	2	2	2
Total Capital and Surplus	**4,411**	**4,937**	**5,326**	**6,306**	**6,989**	**7,638**
Total Liabilities & Equity	**7,224**	**7,779**	**8,263**	**8,989**	**9,427**	**9,875**

National Electrification Administration

Financial Projections for Scenario 1 A

Projected Cash Flow Statement

1989 to 1993
(₱ Million)

Year Ended December 31	1989	1990	1991	1992	1993
Cash Inflow					
Collection of Receivables	212	244	306	385	500
Equity Contribution					
National Government	261	355	347	391	382
Subsidy	0	0	0	0	0
Advances from the Bureau of Treasury	0	0	0	0	0
Foreign Grants	397	149	666	185	37
Foreign Borrowings	340	357	0	0	41
Others	5	5	5	5	5
Total Cash Inflow	1,215	1,110	1,324	966	965
Cash Outflow					
Loan Releases to RECs	315	538	692	1,068	1,047
Loan Repayments to Foreign Borrowers	608	604	581	566	556
Cost of Inhouse Operations	95	109	133	151	177
Cost of Technical Assistance	27	35	41	35	37
Payment of Advances to Bureau of Treasury	0	0	0	0	0
Total Cash Outflow	1,044	1,286	1,447	1,811	1,818
Net Cash Inflow (Outflow)	171	(176)	(123)	(845)	(853)
Add: Cash Balance, Beginning	218	389	212	89	(756)
Net Cash Balance, Ending	389	212	89	(756)	(1,609)

National Electrification Administration

Financial Projections for Scenario II A

Projected Income Statement

1989 to 1993
(₱ Million)

Year Ended December 31	1989	1990	1991	1992	1993
Revenues					
Interest Income	282	427	554	679	761
Other Income	5	5	5	5	5
Foreign Grants	397	149	666	185	37
Total Revenues	**684**	**581**	**1,225**	**869**	**803**
Expenses					
Interest on Foreign Loans	297	342	327	311	315
Personal Services	63	76	91	109	131
Transportation & Travel	8	9	9	10	10
Rent, Light & Water	6	7	9	10	12
Other Administrative Cost	11	12	13	15	16
Depreciation & Amortization	10	14	17	21	24
Other Costs	7	6	12	9	8
Total Expenses	**402**	**465**	**479**	**484**	**517**
Income Before Extra Ordinary Losses	282	116	746	385	286
Other Income (Losses)					
Forex Losses on Existing Loans	0	0	0	0	0
Net Other Income(Loses)	0	0	0	0	0
Net Income (Loss)	**282**	**116**	**746**	**385**	**286**

National Electrification Administration

Financial Projections for Scenario II A

Projected Balance Sheet

1988 to 1983
(₱ Million)

As of December 31	1988 (Actual)	1989	1990	1991	1992	1993
A S S E T S						
Current Assets						
Cash	218	103	(364)	(595)	(1,156)	(1,414)
Trust Funds	16	16	16	16	16	16
Loans Receivable (Matured Portion)	218	317	416	515	614	714
Inventories	683	629	576	523	470	17
Other Receivables	624	815	1,107	1,454	1,850	2,247
Total Current Assets	1,758	1,880	1,751	1,913	1,794	1,980
Investment & Fixed Assets						
Long-Term Loans Receivable	5,242	5,675	6,348	7,002	7,638	7,960
Other Investments	1	1	1	1	1	1
Fixed Assets (Net of Accum. Depn)	8	18	29	41	46	50
Total Investment & Fixed Assets	5,251	5,695	6,379	7,044	7,685	7,958
Other Assets	215	221	231	244	253	262
Total Assets	7,224	7,796	8,362	9,202	9,732	10,200
LIABILITIES & CAPITAL AND SURPLUS						
Current Liabilities						
Payables	405	422	491	516	630	740
Trust Liabilities	67	67	67	67	67	67
Other Current Liabilities	9	9	9	9	9	9
Total Current Liabilities	480	498	567	636	706	779
Long-Term Liabilities						
Loans Payable - Foreign	2,332	2,344	2,370	2,047	1,732	1,458
Total Liabilities	2,813	2,842	2,937	2,683	2,438	2,238
Capital and Surplus						
Paid-in Capital	6,391	6,652	7,007	7,354	7,745	8,127
Donated Capital	177	177	177	177	177	177
Retained Earnings	(2,159)	(1.877)	(1,761)	(1,014)	(630)	(343)
Contigent Surplus	2	2	2	2	2	2
Total Capital and Surplus	4,411	4,954	5,425	6,519	7,294	7,963
Total Liabilities & Equity	7,224	7,796	8,362	9,202	9,732	10,200

National Electrification Administration

Financial Projections for Scenario II A

Projected Cash Flow Statement

1989 to 1993
(₱ Million)

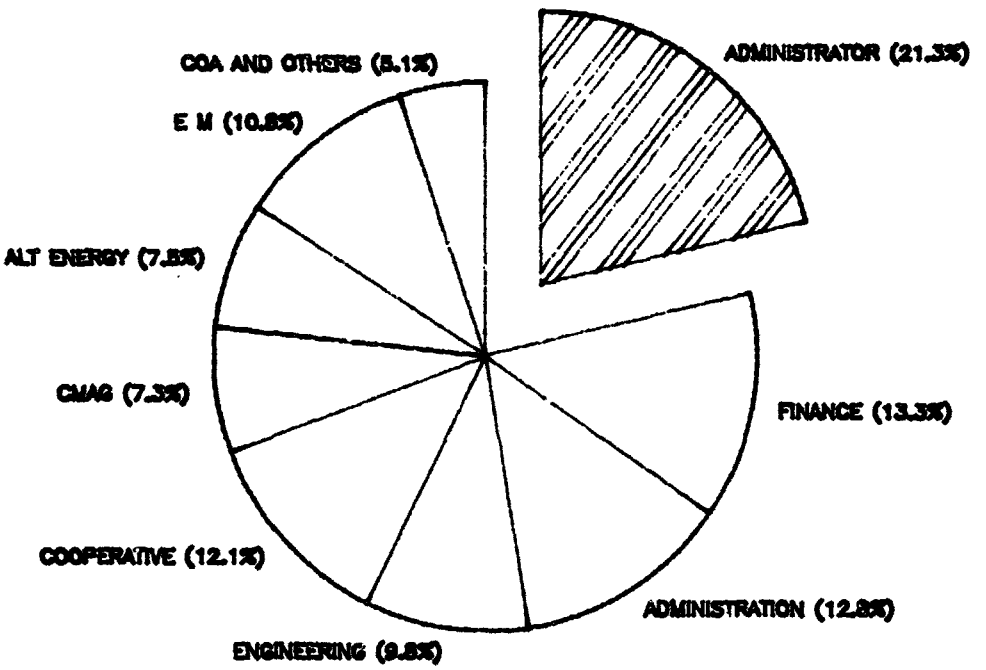
Year Ended December 31	1989	1990	1991	1992	1993
Cash Inflow					
Collection of Receivables	212	266	356	452	549
Equity Contribution					
National Government	261	355	347	391	382
Subsidy	0	0	0	0	0
Advances from the Bureau of Treasury	0	0	0	0	0
Foreign Grants	397	149	666	185	37
Foreign Borrowings	340	357	0	0	41
Others	5	5	5	5	5
Total Cash Flow	1,215	1,132	1,374	1,033	1,013
Cash Outflow					
Loan Releases to RECs	600	850	850	850	500
Loan Repayments to Foreign Borrowers	608	604	581	556	556
Cost of Inhouse Operations	95	110	134	152	177
Cost of Technical Assistance	27	35	41	35	37
Payment of Advances to Bureau of Treasury	0	0	0	0	0
Total Cash Outflow	1,330	1,599	1,606	1,594	1,271
Net Cash Inflow (Outflow)	(114)	(467)	(232)	(561)	(758)
Add: Cash Balance, Beginning	218	103	(364)	(595)	(1,156)
Net Cash Balance, Ending	103	(364)	(595)	(1,156)	(1,414)

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

NEA Staff - By Department

NEA PERSONNEL DISTRIBUTION -- 1988



PHILIPPINES

RURAL ELECTRIFICATION

Comparison of NEA & NPC Salary Structure

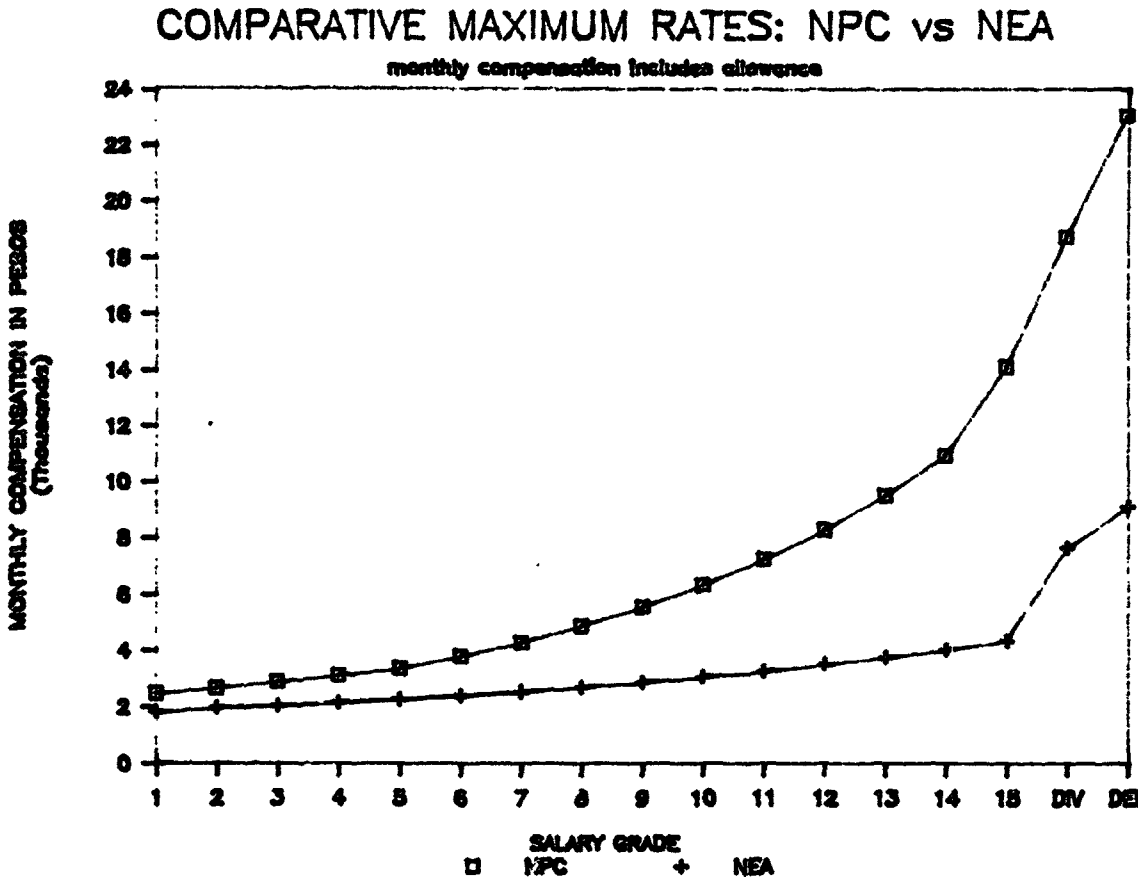
Maximum Rates
(Amounts in Pesos)

	RANK AND FILE											SUPERVISORY			MANAGERIAL		
NPC	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	DIV	DEP
Basic pay	1,247	1,377	1,520	1,680	1,855	2,153	2,501	2,902	3,371	3,912	4,538	5,266	6,112	7,093	8,233	10,046	12,262
COLA/SSA	561	620	684	756	835	969	1,125	1,306	1,517	1,760	2,042	2,370	2,750	3,192	3,705	4,521	5,518
RDA																1,000	1,500
RTA															1,500	2,500	3,100
Emer allow	255	255	255	255	255	255	255	255	255	255	255	255	255	255	255	255	255
Rice sub.	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
Clothing	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
Total	2,497	2,686	2,893	3,125	3,379	3,811	4,315	4,897	5,577	6,361	7,269	8,325	9,551	10,974	14,127	18,756	23,069
NEA																	
Basic pay	500	608	656	736	813	898	992	1,096	1,211	1,337	1,477	1,632	1,807	1,991	2,199	4,404	5,373
COLA/SSA	200	243	262	294	325	359	397	438	484	535	591	653	723	796	880	1,762	2,149
RDA																	
RTA																	
Emer allow	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Rice sub.	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Clothing	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
AMEL	50	61	66	74	81	90	99	110	121	134	148	163	181	199	220	440	537
Meals	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
Charcoal	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Total	1,828	1,990	2,062	2,182	2,298	2,425	2,566	2,722	2,895	3,084	3,294	3,526	3,789	4,065	4,377	7,684	9,138
Difference	669	696	831	943	1,081	1,386	1,749	2,175	2,682	3,278	3,976	4,799	5,763	6,909	9,750	11,072	13,931

Comparison of NEA & NPC Salary Structure

Hiring Rates
(Amounts in Pesos)

	RANK AND FILE											SUPERVISORY			MANAGERIAL		
NPC	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	DIV	DEP
Basic pay	619	684	755	834	922	1,070	1,242	1,442	1,674	1,943	2,254	2,616	3,036	3,523	4,090	4,090	6,091
COLA/SSA	279	308	340	375	415	482	559	649	753	874	1,014	1,177	1,366	1,585	1,841	1,841	2,741
RDA																1,000	1,500
RTA															1,500	2,500	3,100
Emer allow	255	255	255	255	255	255	255	255	255	255	255	255	255	255	255	255	255
Rice sub.	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
Clothing	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
Total	1,587	1,681	1,784	1,898	2,026	2,241	2,490	2,780	3,116	3,506	3,957	4,482	5,091	5,797	8,120	10,120	14,121
NEA																	
Basic pay	405	448	494	546	603	666	736	813	898	992	1,096	1,211	1,337	1,477	1,632	3,270	3,988
COLA/SSA	162	179	198	218	241	266	294	325	359	397	438	484	535	591	653	1,308	1,595
RDA																	
RTA																	
Emer allow	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Rice sub.	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Clothing	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
AMEL	41	45	49	55	60	67	74	81	90	99	110	121	134	148	163	327	399
Meals	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
Charcoal	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Total	1,686	1,750	1,819	1,897	1,983	2,077	2,182	2,298	2,425	2,566	2,722	2,895	3,084	3,294	3,526	5,983	7,060
Difference	(99)	(69)	(35)	1	43	164	308	482	691	940	1,235	1,588	2,008	2,504	4,594	4,137	7,061


COMPARATIVE MAXIMUM RATES: NPC vs NEA
monthly compensation includes allowance
MONTHLY COMPENSATION IN PESOS
(Thousands)
24
22
20
18
16
14
12
10
8
6
4
2
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
DIV
DEP
SALARY GRADE
NPC
NEA

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

Relending Program - Status of Loan Repayments
As of February 28, 1989

Group 1 - RECs Mainteing Existing Management Structure

Name	1st Payment Date	Total Amount Due	Payments	Arrear	% Paid
CASURECO IV	8-31-88	1,044.1	1,043.8	.3	100%
PRESCO	8-31-88	351.8	149.2	202.6	42%
TARELCO I	8-31-88	2,044.9	2,044.8	.0	100%
TARELCO II	8-31-88	1,226.3	1,050.3	176.1	86%
CENPELCO	10-31-88	1,376.1	273.1	1,103.0	20%
PANELCO III	10-31-88	899.7	538.2	361.5	60%
LUELCO	10-31-88	742.0	742.0	0	100%
DORECO	1-31-89	208.2	207.7	.5	100%
BATELEC I	1-31-89	289.8	462.9	(173.1)	160%
ALECO I	1-31-89	290.9	290.6	.3	100%
Subtotal - Group 1		8,473.7	6,802.5	1,671.2	80%

Group 2 - RECs Under NEA Management - No Board of Directors

Name	1st Payment Date	Total Amount Due	Payments	Arrear	% Paid
BATAAN	11-30-88	3,957.5	0	3,957.5	0%
NEECO I	1-31-89	1,508.9	0	1,508.9	0%
NEECO II	10-31-88	2,442.3	1,145.7	1,296.6	47%
NEECO III	11-30-88	1,767.2	0	1,767.2	0%
PELCO I	8-31-88	5,712.7	1,007.0	4,705.7	18%
PELCO II	11-30-88	4,512.5	100.0	4,412.5	2%
PELCO III	11-30-88	1,414.1	1,060.6	353.5	75%
ALECO II	10-31-88	3,468.2	2,774.1	694.1	80%
ALECO III	11-30-88	1,218.2	303.2	915.0	25%
CASURECO II	11-30-88	1,864.5	1,397.7	466.8	75%
FLECO	12-31-88	1,003.0	0	1,003.0	0%
Subtotal - Group 2		28,869.2	7,788.4	21,080.8	27%
Grand Total		37,342.9	14,590.9	22,752.0	39%

PHILIPPINES

RURAL ELECTRIFICATION SECTOR STUDY

List of RECs and Their Acronyms

Region I

Ilocos Norte (INEC)
La Union (LUELCO)
Benguet (BENECO)
Abra (ABRECO)
Ilocos Sur (ISECO)
Mt. Province (MOPRECO)
Pangasinan I (PANELCO I)
Pangasinan II (PANELCO II)
Pangasinan III (PANELCO III)

Region II

Cagayan I (CAGELCO I)
Cagayan II (CAGELCO II)
Isabela I (ISELCO I)
Isabela II (ISELCO II)
Ifugao (IFELCO)
Kalinga-Apayao (KAELCO)
Nueva Vizcaya (NUVELCO)
Quirino (QUIRELCO)

Region III

Bataan (BATELCO)
Bulacan
Nueva Ecija I (NEECO I)
Nueva Ecija II (NEECO II)
Nueva Ecija III (NEECO III)
San Jose City (SAJELCO)
Pampanga I (PELCO I)
Pampanga Rural Elec. (PRESCO)
Pampanga II (PELCO II)
Pampanga III (PELCO III)
Tarlac I (TARELCO I)
Tarlac II (TARELCO II)
Zambales I (ZAMECO I)
Zambales II (ZAMECO II)

Region IV

Batangas I (BATELEC I)
Batangas II (BATELEC II)
Cavite
Laguna (FLECO)
Marinduque (MARELCO)
Occidental Mindoro (OMECO)
Lubang Island (LUBELCO)
Oriental Mindoro (ORMECO)
Palawan (PALECO)
Busunga Island (BISELCO)
Quezon I (QUEZELCO I)
Quezon II (QUEZELCO II)
Aurora (AURELCO)
Rizal
Tablas Island (TIELCO)

Region V

Albay I (ALECO I)
Albay II (ALECO II)
Albay III (ALECO III)
Camarines Norte (CANORECO)
Camarines Sur I (CASURECO I)
Camarines Sur II (CASURECO II)
Camarines Sur III (CASURECO III)
Camarines Sur IV (SAXURECO IV)
Catanduanes (FICELCO)
Sorsogon I (SORECO I)
Sorsogon II (SORECO II)
Masbate (MASELCO)
Ticao Island (TISELCO)

Region VI

Aklan (AKELCO)
Antique (ANTECO)
Capiz (CAPELCO)
Iloilo I (ILECO I)
Iloilo II (ILECO II)
Iloilo III (ILECO III)
Guimaras Island (GUIMELCO)
V-M-C Rural Elect. (VRESCO)
Central Negros (CENECO)
Negros Occidental (NOCECO)

Region VII

Bohol I (BOHECO I)
Bohol II (BOHECO II)
Cebu I (CEBECO I)
Cebu II (CEBECO II)
Cebu III (CEBECO III)
Bantayan Island (BANELCO)
Camotes Island (CELCO)
Negros Oriental I (NORECO I)
Negros Oriental II (NORECO II)
Siquijor Island (PROSIELCO)

Region VIII

Leyte I (DORELCO)
Leyte II (LEYECO II)
Leyte III (LEYECO III)
Leyte IV (LEYECO IV)
Leyte V (LEYECO V)
Biliran Island (BILECO)
Southern Leyte (SOLECO)
Samar I (SAMELCO I)
Samar II (SAMELCO II)
Eastern Samar (ESAMELCO)
Norther Samar (NORSAMELCO)

Region IX

Zamboanga Norte (ZANECO)
Zamboanga Sur I (ZAMSURECO I)
Zamboanga Sur II (ZAMSURECO II)
Zamboanga City (ZAMCELCO)
Sulu (SULECO)
Basilan (BASELCO)
Tawi-Tawi (TAWELCO)
Cagayan de Sulu (CASELCO)

Region X

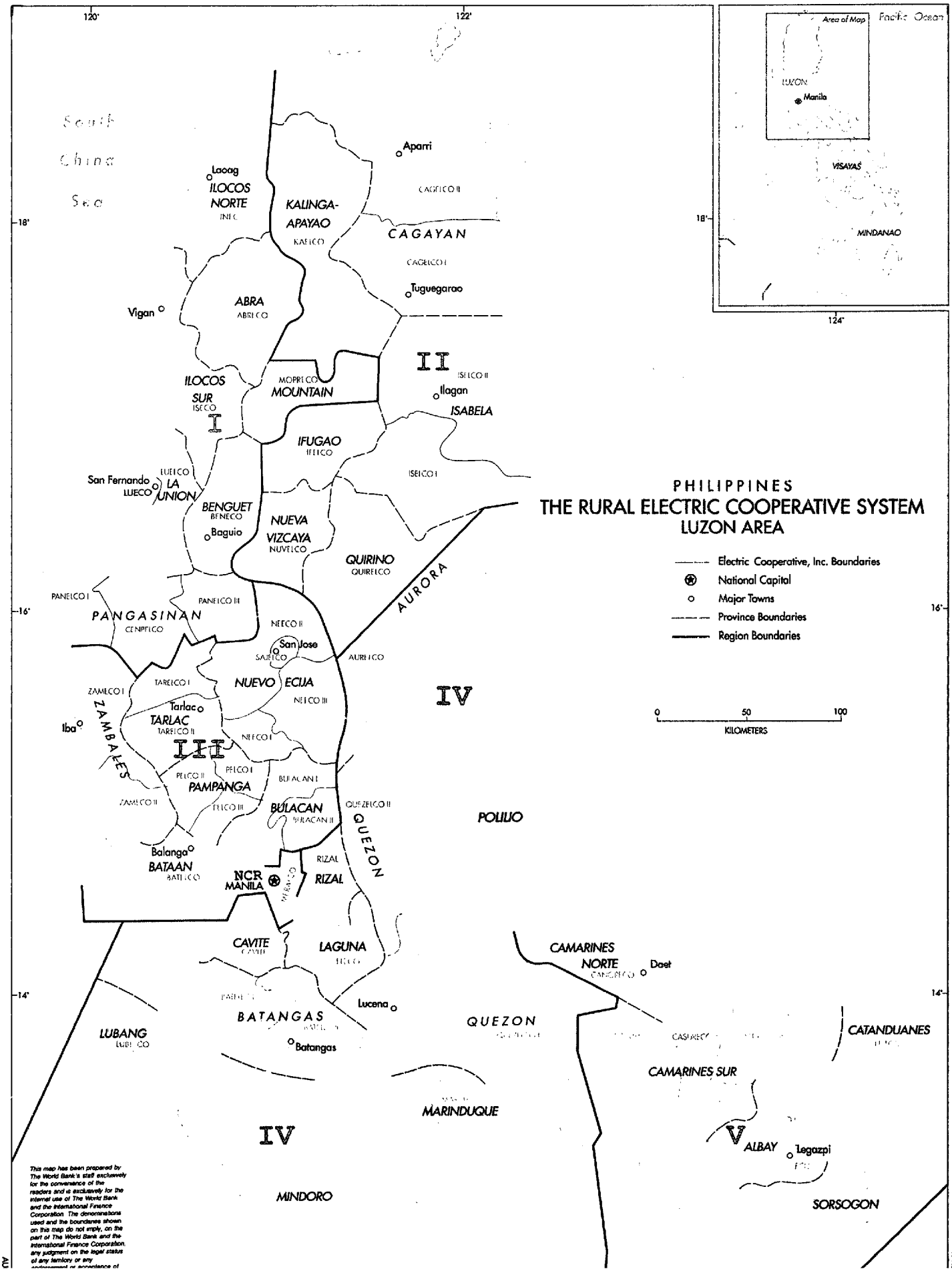
Surigao Norte (SURNECO)
Surigao Island (SIARELCO)
Agusan Norte (ANECO)
Agusan Sur (ASELCO)
Misamis Oriental I (MORESCO I)
Misamis Oriental II (MORESCO II)
Bukidnon I (FIBESCO)
Bukidnon II (BUSECO)
Misamis Occidental (MOELCI I)
Misamis Occidental (MOELCI II)
Camiguin Island (CAMELCO)

Region XI

Surigao Sur I (SURSECO I)
Surigao Sur II (SURSECO II)
Davao Oriental (DORECO)
Davao Norte (DANECO)
Davao Sur (DASURECO)
So. Cotabato I (SOCOTECO I)
So. Cotabato II (SOCOTECO II)

Region XII

Lanao Norte (LANECO)
Lanao Sur (LASURECO)
Maguindanao (MAGELCO)
North Cotabato (COTELCO)
Sultan Kudarat (SUKELCO)


PHILIPPINES
THE RURAL ELECTRIC COOPERATIVE SYSTEM
LUZON AREA
Electric Cooperative, Inc. Boundaries
National Capital
Major Towns
Province Boundaries
Region Boundaries
0 50 100
KILOMETERS
Area of Map
Pacific Ocean
LUZON
Manila
VISAYAS
MINDANAO
South China Sea
Laoag
ILOCOS NORTE
INEC
KALINGA-APAYAO
KAELCO
Aparri
CAGELCO II
CAGAYAN
CAGELCO I
Tuguegarao
ABRA
ABRECO
Vigan
ILOCOS SUR
ISECO
I
MOPRECO
MOUNTAIN
II
ISELCO II
Ilagan
ISABELA
ISELCO I
IFUGAO
IFELCO
LUELCO
San Fernando
LUECO
LA UNION
BENGUET
BENECO
Baguio
NUEVA VIZCAYA
NUVELCO
QUIRINO
QUIRELCO
AURORA
PANELCO I
PANELCO III
PANGASINAN
CENPELCO
NEECO II
San Jose
SAJELCO
AURELCO
TARELCO I
NUEVO ECIJA
NEECO III
IV
ZAMELCO I
ZAMBALES
Tarlac
TARLAC
TARELCO II
Iba
III
NEECO I
PELCO II
PELCO I
PAMPANGA
BULACAN I
ZAMELCO II
PELCO III
BULACAN
BULACAN II
QUEZELCO II
QUEZON
POLILLO
Balanga
BATAAN
BATELCO
RIZAL
NCR
MANILA
MERALCO
RIZAL
CAVITE
LAGUNA
CAMARINES NORTE
Daet
Lucena
BATANGAS
Batangas
QUEZON
LUBANG
CATANDUANES
CASELCO
CAMARINES SUR
MARINDUQUE
IV
V
ALBAY
Legazpi
MINDORO
SORSOGON
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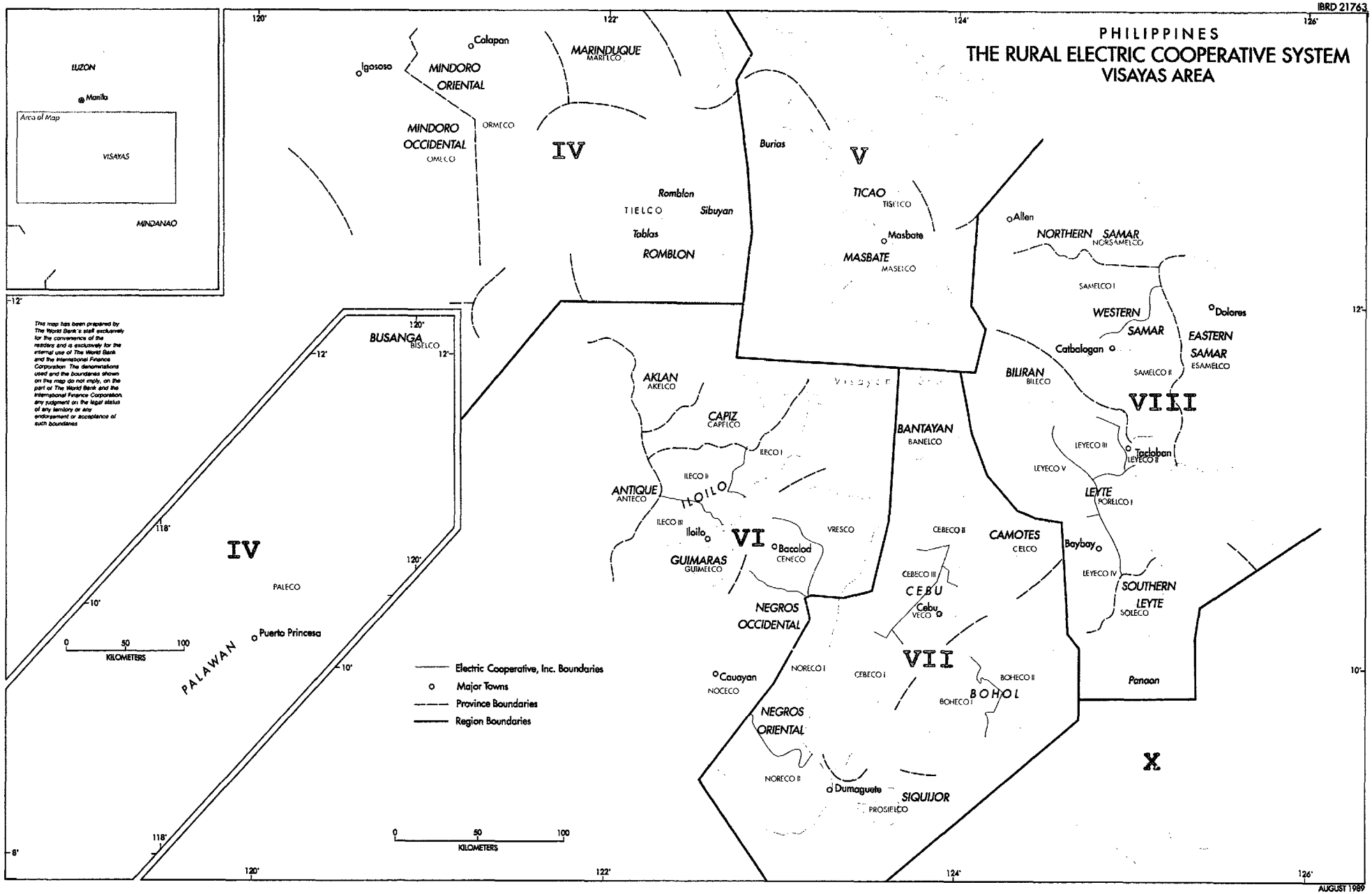
PHILIPPINES
THE RURAL ELECTRIC COOPERATIVE SYSTEM
VISAYAS AREA



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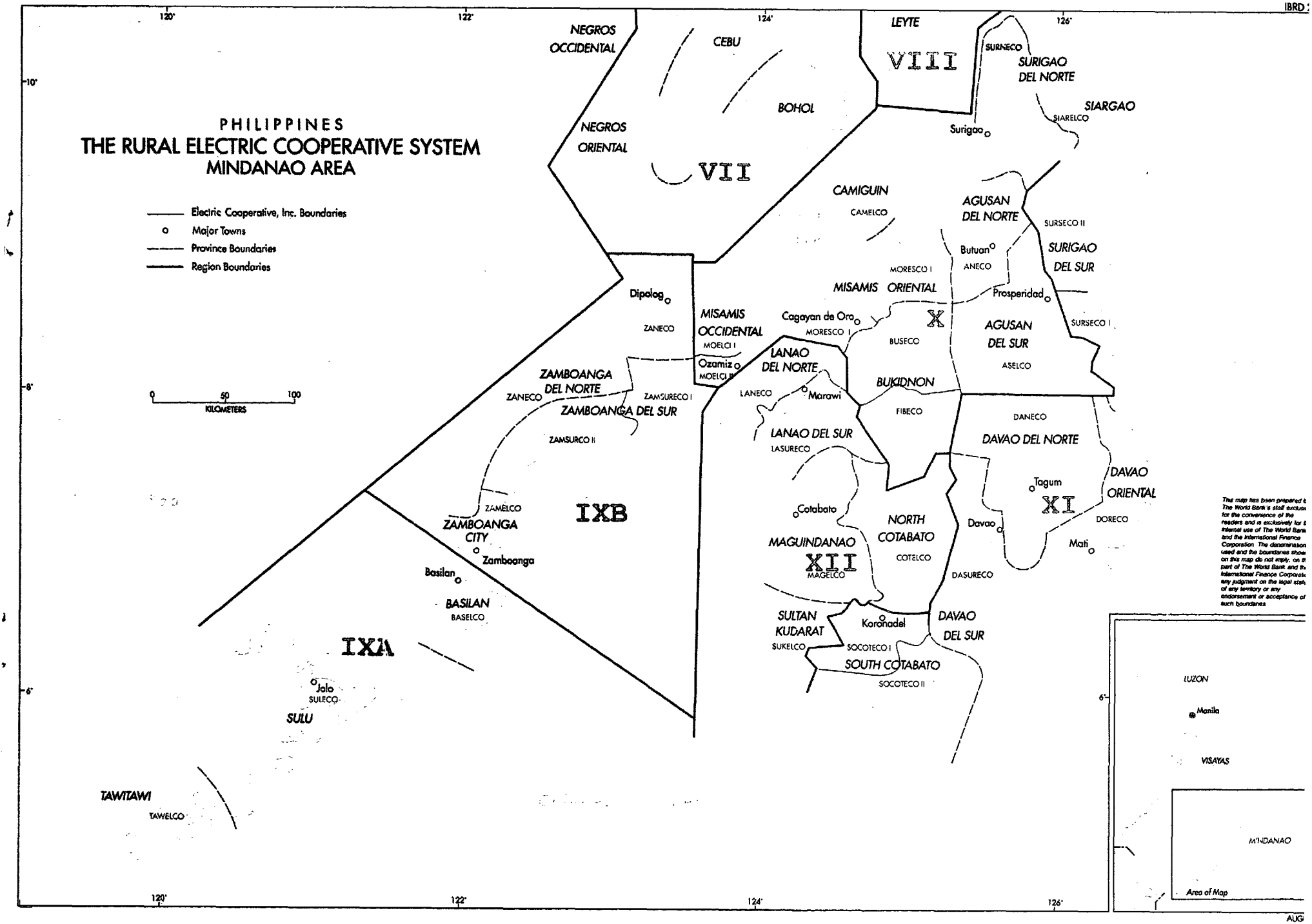
AUGUST 1989


PHILIPPINES
THE RURAL ELECTRIC COOPERATIVE SYSTEM
MINDANAO AREA
Electric Cooperative, Inc. Boundaries
Major Towns
Province Boundaries
Region Boundaries
0 50 100
KILOMETERS
120°
122°
124°
126°
10°
8°
6°
NEGROS OCCIDENTAL
CEBU
BOHOL
NEGROS ORIENTAL
VII
LEYTE
VIII
SURNECO
SURIGAO DEL NORTE
SIARGAO
SIARELCO
Surigao
CAMIGUIN
CAMELCO
AGUSAN DEL NORTE
SURSECO II
Butuan
ANECO
SURIGAO DEL SUR
MORESCO I
MISAMIS ORIENTAL
Prosperidad
Dipolog
ZANECO
MISAMIS OCCIDENTAL
MOELCI I
Cagayan de Oro
MORESCO I
X
BUSECO
AGUSAN DEL SUR
SURSECO I
ASELCO
Ozamiz
MOELCI II
LANAO DEL NORTE
ZAMBOANGA DEL NORTE
ZANECO
ZAMSURECO I
ZAMBOANGA DEL SUR
LANECO
Marawi
BUKIDNON
FIBECO
ZAMSURCO II
LANAO DEL SUR
LASURECO
DANECO
DAVAO DEL NORTE
DAVAO ORIENTAL
Tagum
XI
DORECO
Mati
ZAMELCO
IXB
ZAMBOANGA CITY
Zamboanga
Cotabato
NORTH COTABATO
COTELCO
Davao
MAGUINDANAO
XII
MAGELCO
DASURECO
Basilan
BASILAN
BASELCO
SULTAN KUDARAT
SUKELCO
Koronadel
DAVAO DEL SUR
SOCOTECO I
SOUTH COTABATO
SOCOTECO II
IXA
Jolo
SULECO
SULU
TAWITAWI
TAWELCO
LUZON
Manila
VISAYAS
MINDANAO
Area of Map