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Power Sector Issues and Options

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LIST OF ACRONYMS

ACDI	Canadian International Development Agency
AFTEG	Africa Energy Unit
Bbl	Barrel
BOT	Build-own-transfer
CCGT	Combined cycle gas turbine
CEHDES	*Consejo Empresarial Hondureño para el Desarrollo Sostenible*
CFLs	Compact fluorescent lamps
CIMEQH	*Colegio de Ingenieros Mecánicos, Electricistas y Químicos*
CNE	*Comisión Nacional de Energía*
CNG	Compressed natural gas
COHEP	*Consejo Hondureño de la Empresa Privada*
CO_2	Carbon dioxide
CPI	Consumer Price Index
CPME	*Comisión Presidencial de Modernización del Estado*
CRIE	*Comisión Regional de Interconexión Eléctrica*
DSM	Demand-side management programs
EBITDA	Earnings Before Interests, Taxes, Depreciation and Amortization
ELCATEX	*Elásticos Centroamericanos y Textiles, S. A.*
EMCE	*Empresa de Mantenimiento, Construcción y Electricidad*
ENEE	*Empresa Nacional de Energía Eléctrica*
ENERSA	*Energía Renovable S. A.*
EOR	*Ente Operador Regional*, Regional System Operator
ERP	Enterprise Resource Planning
FBC	Fluidized bed combustion
FCN	*Fondo Cafetero Nacional*
FOSODE	Social Fund for Electricity Development, *Fondo Social de Desarrollo Eléctrico*
GAUREE	*Generación Autónoma y Uso Racional de la Energía Eléctrica*
GDP	Gross domestic product
GEF	Global Environment Facility
GHG	Greenhouse gases
GIS	Geographic Information System
GIURE	Inter-Institutional Group for the Efficient Use of Energy
GOH	Government of Honduras
GT	Gas turbine
GWh	Gigawatt hour
HFO	Heavy fuel oil
HV-MV	High Voltage to Medium Voltage
IBU	Independent business unit
ICE	*Instituto Costarricense de Electricidad*
IDA	International Development Association
IDB	Inter-American Development Bank

IFI	International Finance Institutions
INE	*Instituto Nacional de Estadística*
ISA	*Interconexión Eléctrica S.A.*
kV	Kilovolt
kWh	Kilowatt-hour
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LUFUSSA	*Luz y Fuerza de San Lorenzo, S. A.*
MBTU	Million British Thermal Unit
MHP	Microhydro Power
MSD	Medium speed diesel
MVA	Mega Volt-Ampere
MW	Megawatt
MWh	Megawatt-hour
NGO	Nongovernmental organization
NO_x	Nitrogen oxide
NPV	Net present value
OES	*Oficina de Electrificación Social*
PESIC	*Proyecto de Eficiencia Energética en los Sectores Industrial y Comercial de Honduras*
PLANES	National Social Electification Plan, *Plan Nacional de Electrificación Social*
PM	Particulate matter
PPA	Power Purchase Agreement
PPP	Public/private partnership
PREEICA	*Proyecto de Energía Eléctrica de Istmo Centroamericano*
PV	Photovoltaic
RE	Renewable energy
ROM	Rehabilitate, operate, maintain
SASEI	South Asia Energy and Infrastructure Unit
SDDP	Stochastic Dual Dynamic Programming
SEMEH	*Servicio de Medición Eléctrica de Honduras*
SERNA	Ministry of Natural Resources and Environment, *Secretaria de Recursos Naturales y Ambiente*
SHS	Solar Home Systems
SIEPAC	*Sistema de Interconexión Eléctrica para América Central*
SOE	State-owned enterprise
SO_x	Sulfur oxide
SSM	Supply-side management programs
UNAH	*Universidad Nacional Autónoma de Honduras*
WP	Windpower
WTI	West Texas Intermediate

Acknowledgments

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EXECUTIVE SUMMARY

INTRODUCTION

1. This report was prepared in response to a request by the Government of Honduras to assist in the preparation of a power sector strategy for the country. Specifically, the Government asked for help in identifying the main issues in the power sector, and in addressing them through formulation of a clearly defined, achievable strategy. Left unresolved, these issues risk derailing the country's macroeconomic framework, potentially damaging the competitiveness of the country and its prospects for poverty reduction.

2. The main issues to be analyzed in the study were identified at a workshop held on September 19, 2006, in Tegucigalpa, jointly with the *Secretaría de Recursos Naturales y Ambiente* (SERNA) and the *Comisión Presidencial de Modernización del Estado* (CPME), and with the participation of representatives from the *Empresa Nacional de Energía Eléctrica* (ENEE), civil society, the private sector, Congress, public sector agencies, donors, utilities, and ministries. It was decided that the study would be divided into two components: (a) the first would identify and evaluate options on institutional reforms, particularly ENEE's restructuring and management, and securing electricity supply; and (b) the second would formulate a power sector strategy. Two reports will be prepared, with the second report to be finalized according to the timing of the Government's decision.

3. This first report analyzes the institutional and policy issues; financial and fiscal concerns; social aspects, such as tariffs and subsidies, and access to electricity; and investment requirements—including the development of renewable resources. The report is divided into two parts. Part A presents a diagnostic of the electricity sector, including ENEE's financial performance, fiscal impacts, reliability of supply, institutional and legal framework, pricing policy, and electricity coverage. Part B evaluates the options available to improve sector efficiency, ensure financial sustainability, promote the diversification of energy sources, and increase electrification coverage.

DIAGNOSTIC OF THE SECTOR

4. In the early 1990s, the electricity sector in Honduras experienced a severe financial crisis when electricity tariffs were not adjusted to cover the debt service of the El Cajón hydroelectric project commissioned in the mid-1980s, and ENEE's performance was poor (electricity losses of about 28 percent, overstaffing, and poor maintenance of thermal plants). The financial crisis led to the energy crisis of 1993 when a severe drought coincided with a lack of generation reserve capacity. There was an urgent need to mobilize private financing to expand generation capacity and to improve ENEE's performance.

5. The response to this crisis was the sector reform of 1994, based on a new Electricity Law that established a competitive power market (vertical unbundling, freedom of entry to all sector activities, open access to transmission and distribution networks, and freedom of choice for large users); the separation of the roles of policymaking, regulation, and provision of electricity

services; application of cost-recovery tariffs and targeted subsidies; and private provision of electricity services.

6. The new market model, and the underlying assumptions made by the reformers, proved to be too ambitious for Honduras, with a small power system, a tradition of political clientelism, and weak institutions. First, the competitive market envisioned in the law was not implemented because the distribution networks were not unbundled and privatized, and ENEE continued operating as a vertically integrated state-owned enterprise and a de facto single buyer, responsible for procuring all the new energy required to meet demand. Second, the separation of the government roles was not effective: SERNA and the new Energy Cabinet lacked the technical support and expertise to conduct energy planning and policymaking, and ENEE continued to play a major role in these activities. The new regulator, the *Comisión Nacional de Energía* (CNE), had a marginal role due both to a lack of political support to implement the new regulations, and to its lack of resources and ENEE's dominant role in the sector. Third, the principles of cost-covering tariffs and targeted subsidies have not been implemented due to inadequate political commitment, but also because of the dependency on imported oil for power generation, which resulted in high and volatile generation prices that were not passed on to retail tariffs.

7. The de facto single-buyer model has been successful in attracting private investment to expand generation capacity based on long-term Power Purchase Agreements (PPAs) with thermal generators and small renewable projects. The combination of PPAs, backed by payment guarantees of the Government, and the selection of diesel plants, with low capital costs and short construction periods, reduced the market and project risks for private investors. Since 1994, private developers have invested some US$600 million in about 800 megawatts (MW) of medium speed diesel and gas turbine capacity. In addition, they have invested some US$70 million in 110 MW of small hydro and bagasse-fired capacity that benefited from fiscal and price incentives. Reliance on the private sector has thus become the norm for generation capacity expansion.

8. ENEE's performance is still poor. Electricity losses increased during 2001–06 from about 20 percent to 25 percent, mostly related to theft, fraud, and illegal connections. The expectation of a future restructuring and privatization postponed needed actions to improve ENEE's corporate governance and modernize its information systems and commercial practices.

9. The hydro-dominated generation system of the mid-1990s was converted to a thermo-dominated system, and Honduras now depends on imported fuels for about 70 percent of its power generation (almost all thermal generation under PPAs). The cost of energy purchases and fuel expenses doubled from 2001 to 2006, due to a higher share of thermal generation and the steep increase in heavy fuel oil prices. ENEE's revenues, eroded by high non-technical losses, could not cover the increases in costs.

10. ENEE had to rely on emergency generation to meet demand during 2001–04 due to delays in procuring new generation capacity. About 180 MW in skid-mounted diesel generators were leased in 2002–04 to meet an energy shortfall in the period before 410 MW in new PPAs were commissioned. In 2007 the supply/demand balance has again been tight, with a capacity reserve of about 5 percent.

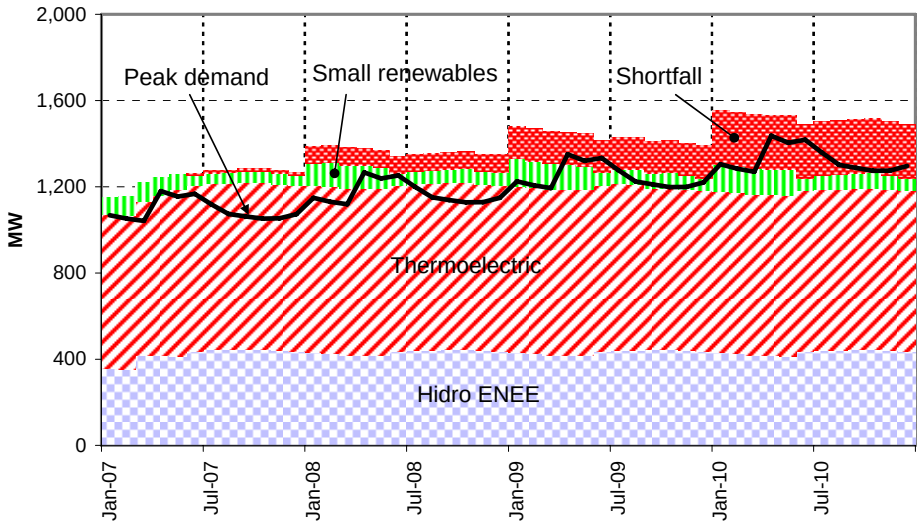
11. The visible results of this situation are: (a) the financial crisis of ENEE, and (b) the looming energy crisis that could affect Honduras over the next two years.

The Emerging Energy Crisis

12. The new generation capacity, which is planned to be commissioned in 2007–10 (about 150 MW, mainly in renewable power) is not sufficient to meet demand growth. A capacity shortfall of about 70 MW is estimated for 2008, which would increase to 275 MW by 2010 (see Figure 1). Considering that no new power has been contracted, and that development of new generation projects would take about three years, it is likely that Honduras would have to rely again on expensive emergency generation to meet demand during 2007–10. Although the need for new generation capacity by 2009 was anticipated two years ago, the development of the required generation projects has been delayed due to a slow decision process.

Figure 1

Supply/demand balance 2007-2010



13. There is a large backlog of transmission and sub-transmission investments that could not be implemented as planned due to financial constraints. ENEE had to install expensive diesel generation in some congested industrial areas in the north and downgrade the transmission planning reliability criteria. Further delays in strengthening the transmission networks will increase the probability of blackouts, operating costs, and electricity losses, and worsen the quality of service.

ENEE's Financial Crisis

14. ENEE has been incurring annual financial losses of about Lps.2.5 billion (equivalent to almost 2 percent of Honduras's gross domestic product). Its internal cash generation has been negative, and ENEE has had to postpone needed investment in distribution and transmission and to finance the shortfall with expensive revolving loans from local banks and credits from thermal generators on the payment of energy purchases that amounted to Lps.2.3 billion in 2003–05.

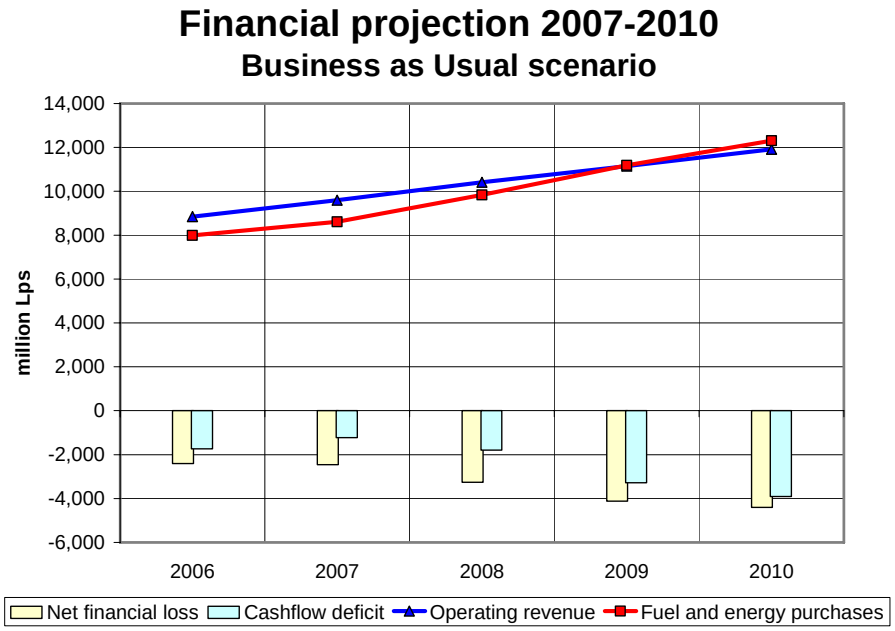
Debt service coverage and contribution to investments have been negative during the past five years.

15. The financial crisis can be explained by a combination of factors: (a) poor performance (high electricity system losses); (b) the vulnerability of generation costs of a thermo-based power system to high and volatile international oil prices; (c) high costs of the long-term PPAs contracted in the 1990s, which reflect high market risks and expensive emergency solutions; and (d) the average electricity tariff covers only about 80 percent of the efficient supply costs.

16. Government direct contribution to alleviate ENEE's financial crisis during 2001–05 was moderate. The net direct contribution, estimated at about Lps.1 billion, was mostly for rural electrification projects. In addition, the Government has paid about Lps.1.4 billion in direct tariff subsidies to residential consumers. However, ENEE's annual financial losses during 2002–06 are a more appropriate reflection of the economic cost, because they reveal the huge need for investments in the sector, the alarming cash-flow position, and the structural imbalances between costs and revenues.

17. A business-as-usual scenario—no actions taken to reduce commercial losses and to reduce electricity subsidies—is not sustainable in the short term. The operating revenues will not be sufficient to cover the fuel and power purchases, and by 2010 the financial loss will increase to Lps.4.4 billion and the cash-flow deficit to Lps.3.9 billion (see Figure 2). There is no fiscal space to finance the deficit, and Honduras could face a severe energy crisis.

Figure 2



THE CHALLENGES

18. The Government of Honduras must meet its main goal of ensuring a reliable, efficient, and sustainable energy supply under difficult circumstances. The power sector is in crisis: high electricity losses, lack of cost-recovery tariffs, negative cash generation, loss of ENEE's net worth, high dependency on imported liquid fuels for power generation, tight supply/demand balance, and a backlog of transmission investments. The crisis will deepen in the short term if substantial and immediate corrective measures are not taken: electricity demand is expected to grow at a high rate, above 7 percent per year; about 250 MW in new generation capacity will be needed by 2010; high international oil prices are likely to persist and generation costs may remain high and volatile; and there is no fiscal space to finance the electricity sector or increase electricity subsidies.

19. In the short term (2007–10), the main challenges are to improve ENEE's critical financial situation and avoid the emerging energy crisis. Keeping the lights on is essential for the political survival of any government. For the medium and long term, the report identifies four major challenges: (a) ensuring the financial sustainability of the sector, (b) mobilizing private finance to ensure a sustainable and reliable supply, (c) diversifying the energy sources, and (d) increasing access to electricity services by the poor. The report identifies and discusses several options to address these challenges.

SHORT-TERM CHALLENGES AND OPTIONS

Improving the Financial Performance of ENEE

20. The main factors, under the control of ENEE and the Government, which have a substantial impact on ENEE's financial performance in the short term (2007–10) are electricity losses and electricity prices. Any reduction in commercial losses is converted into more sales and less generation, which means higher revenues and lower energy purchase costs. Any increase in average retail prices is converted into higher revenues and energy savings.

21. Substantial improvements in electricity losses and electricity tariffs are required to reverse ENEE financial losses during 2007–10. The analysis of ENEE's financial projections under different scenarios shows that reducing electricity losses to about 16 percent in four years and aligning average tariffs with economic costs in about three years would produce a cumulative cash-flow surplus during this period. A gradual improvement in losses and tariffs would result in a cumulative cash-flow deficit of about US$200 million and would not be sustainable, taking into account fiscal constraints. A substantial improvement in losses with no tariff adjustments would also result in a deficit of US$239 million (see Table 1).

Table 1

ENEE´s financial projections
2007-2010

		Moderate corrective measures	Major corrective measures	No tariff adjustment
System losses				
2006	%	25.2%	25.2%	25.2%
2008	%	23.8%	20.7%	20.7%
2010	%	22.6%	16.2%	16.2%
Average retail tariff				
2006	Lp/kWh	2.00	2.00	2.00
2008	Lp/kWh	2.15	2.37	2.00
2010	Lp/kWh	2.28	2.40	2.00
Additional generation capacity requirement	MW	275	170	170
Cumulative cash flow	US$MM	-200	168	-239

22. Most of the electricity losses are commercial losses that can be reduced in the short term with substantial corrective measures. A recent study estimated that technical losses are about 10 percent, implying that current commercial losses are about 15 percent, of which about 39 percent corresponds to fraud, 29 percent to illegal settlements, and 29 percent to billing errors (see Table 2).

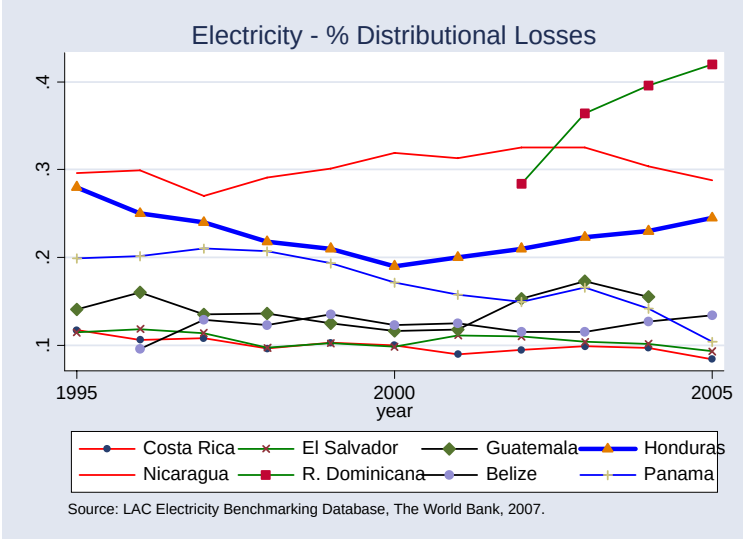
Table 2 - Breakdown of Commercial Losses, in Percent

Cause	Breakdown of Commercial Losses, in Percent				
	Residential	Commercial	Industrial	Other	Total
Fraud	15.0	8.4	12.0	3.2	**38.6**
Billing errors	11.4	6.4	9.2	2.4	**29.4**
Marginal settlements	11.1	6.2	8.9	2.4	**28.6**
Meter calibration	0.6	0.3	0.5	0.2	**1.6**
Other causes	0.7	0.4	0.6	0.2	**1.8**
Totals	**38.8**	**21.8**	**31.2**	**8.3**	**100.0**

Source: Consultoría Colombiana, Loss study.

23. A comparison with regional countries indicates that electricity losses in Honduras are high and that all countries in the region (except Nicaragua) have been able to keep losses near or below 15 percent, an indication that this target can be achieved by good management and better commercial practices (Figure 3).

Figure 3



24. ENEE is currently implementing a loss-reduction program as a key element of a short-term financial recovery plan. The program includes a high-profile and publicized operation (*Operación Tijera*) that has motivated consumers in arrears or in irregular situations to pay their bills or request regularization of their connections in order to avoid the announced service cuts. The program includes a US$30 million investment in prepaid meters, tamper-proof connections, and other equipment. The operation shows the importance of direct involvement in the loss-reduction program by the top levels of management, as was already done when ENEE managed to bring losses down to 18 percent in 2000 from a high of 28 percent in 1995.

25. As a complement to the loss-reduction program, the Government may consider in the short term other options (management contracts) to attract experienced private operators and improve ENEE's performance (see para 35).

26. On electricity prices, the report concludes that there are substantial distortions in the tariff structure and that the average electricity tariff covers about 81 percent of the economic costs of supply. There is a generalized cross-subsidy that exceeds the limits established in the Electricity Law and benefits mainly non-poor residential consumers with monthly consumption above 150 kWh/month. The analysis shows that the generalized subsidy and a direct subsidy paid by the Government are poorly targeted and regressive.

27. All options to align tariffs with economic costs and target subsidies to protect low-income consumers have a relatively high political cost. The Government would have to consider substantial tariff adjustments in this presidential period to about 370,000 non-poor residential consumers, who currently pay between 50 percent and 80 percent of economic costs and have one of the lowest residential tariffs in the region. Average tariffs for industrial and commercial consumers already cover economic costs and are one of the highest in the region. Two options are discussed in the report: one would involve increasing tariffs for non-residential categories by about 5.1 percent, and the other considers an 11 percent increase for other categories to mitigate the tariff impact on residential consumers with consumption below 150 kWh/month, as shown in the Table 3.

Table 3.

	Average Cost of Supply $/kWh	Current Final Price (after direct subsidy) $/kWh	Option 1 Final Price (after direct subsidy) $/kWh	Option 2 Final Price (after direct subsidy) $/kWh	Number of Users
Residential Block kWh/month					
0–50	0.224	0.039	0.056	0.039	174,338
51–100	0.158	0.040	0.063	0.041	132,804
101–150	0.147	0.047	0.091	0.048	128,361
151–300	0.141	0.066	0.134	0.125	242,723
301–500	0.137	0.089	0.139	0.139	83,368
501–	0.134	0.109	0.143	0.143	43,747
Industrial medium-voltage	0.107	0.105	0.112	0.119	134
Commercial	0.130	0.133	0.137	0.145	59,700

28. The argument that increasing tariffs is counterproductive and is a bad option, because electricity fraud will also increase in response to higher tariffs, is weak in this case. Well-targeted subsidies can protect low-income consumers that may not be able to afford to pay a large tariff increase. Other residential consumers have relatively low electricity tariffs and most likely can afford to pay a large tariff increase distributed in monthly adjustments over two or three years. What is important is to show that tariff increases and reduction of commercial losses are necessary actions to avoid energy shortages, the option with the highest economic cost for consumers and the biggest political cost for the government.

29. The renegotiation of PPAs, included in ENEE's short-term recovery plan, may marginally reduce the financial burden of energy purchases and should be used with care. The annual capacity charges of existing PPAs now amount to about US$110 million, or 25 percent of the cost of energy purchases. A survey of PPA prices in Central America completed in 2001 shows that only the prices of Lufussa I and Elcosa contracts are clear outliers, which may reflect high project risks perceived by the pioneer investors in the generation and use of expensive emergency solutions. The new contracts with Lufussa III and Enersa have very competitive prices. It has been reported that a preliminary agreement was reached to reduce the annual payments for 2007–09 by US$20 million, but presumably Lufussa and Elcosa are asking for an extension of the expensive contracts expiring in 2010, and its financial impact should be assessed with care.

Avoiding the Emerging Energy Crisis

30. The analysis of the generation expansion plans shows that, in the short term, there is a deficit of firm power in 2007–10 of between 170 MW and 380 MW, depending on the scenario (business as usual, moderate actions, and major actions), which can be addressed only by leasing skid-mounted diesel generation, which can be deployed in the short term, and the implementation of load management programs. The supply/demand balances of the neighboring countries appear to be too tight to provide firm capacity support in this period.

31. Progress made in taking effective measures to reduce electricity losses and to introduce cost-recovery tariffs and energy efficiency programs would have a substantial impact on avoiding an energy crisis by reducing additional generation capacity requirements. This would also

produce large financial benefits to ENEE by avoiding contracting expensive emergency generation for 2007–10. The difference between the electricity demand of the "business-as-usual" scenario and the "major actions" scenario is such that about 180 MW of expensive generation could be saved.

MEDIUM- AND LONG-TERM OPTIONS

Ensuring the Financial Sustainability of the Sector

32. The loss-reduction program and tariff adjustments are necessary short-term options to improve ENEE's financial situation. However, it is unlikely that substantial and sustainable improvements in the performance of ENEE can be achieved if its corporate governance is not strengthened. Good performance is a necessary condition to ensure financial sustainability, because passing on to tariffs ENEE's inefficiencies or providing fiscal support are not valid options in this case. Credible and competent price regulation is another necessary condition. The report discusses medium-term institutional options to improve ENEE's performance, including the creation of independent business units, management contracts, corporatization and partial private control, and alternatives to use competition as a further pressure for better performance.

33. The restructuring of ENEE and the creation of independent business units (IBUs) for distribution, transmission/dispatch, and generation, with separate accounts and transfer prices, will provide incentives to improve efficiency (performance of individual units can be monitored and rewarded), facilitate regulation of distribution and transmission (separate regulatory accounts, transparent pricing, and benchmarking), and help develop competition (reduce barriers to open access and increase autonomy of dispatch). This is a medium-term option that will be initiated with the restructuring study that the Government is expected to contract shortly.

34. However, the creation of IBUs is not sufficient to improve the weak corporate governance of ENEE. The transformation of these units into separate companies subject to private sector corporate law, with an independent board of directors and professional management and with the participation of minority shareholders, is an option that should be considered for the longer term.

35. In the meantime, it is essential to reduce commercial losses and improve the management of ENEE. The recent ad hoc government interventions in the management of ENEE (four changes in about one year) have not been effective and are not sustainable. A management contract (transfer full or partial responsibility for day-to-day operations to an outside operator) is a low-risk public/private partnership that can be used as an interim arrangement to attract experienced private operators and improve performance. However, the international experience with management contracts in electricity shows that they usually fail if the operator does not have full autonomy to make key decisions and implement its proposed measures to improve performance, and does not have a financial stake in the operation of the utility (payments linked to specific and measurable performance improvements).

36. The contract with the *Servicio de Medición Eléctrica de Honduras* (SEMEH) for reading, billing, and collections is not an appropriate management contract to reduce losses, because it is limited in scope and creates weak incentives for performance. Several options are suggested, such as soliciting international competitive bids for a new management contract, renegotiating the

existing SEMEH contract, or contracting private operators with full responsibility for reducing losses in clusters of distribution feeders with high losses.

37. A gradual transition from a single-buyer model to a competitive wholesale power market is an option to improve efficiency in the power sector of Honduras. In the short term, it is possible to increase the benefits of competition for long-term contracts under the single-buyer model by using public/private partnerships to facilitate private development of the capital-intensive projects required by 2013, by strengthening the financial position of the buyer, and by establishing transparent competitive bidding procedures to procure new power.

38. In the medium term, once ENEE is restructured and corporatized, the PPAs with competitive prices can be transferred to the distribution companies, which will be responsible for competitive procurement of new power under long-term supply contracts to meet projected demand. Additional competition can be introduced by promoting the development of the market for large consumers (open access to transmission and distribution grids).

39. Finally, in the long term, once the *Sistema de Interconexión Eléctrica para América Central* (SIEPAC) project is commissioned in 2009 and the market of large consumers is expanded with the creation of new industrial parks, a spot market can be established to complement the market for long-term energy supply contracts, facilitate regional trade, and promote competition for the market of large consumers. Changes in the law will be required to create the institutions and trading arrangements necessary to operate a competitive market.

40. The improvements of corporate governance and the development of a competitive market will require capable policymaking and regulation. A short-term solution to improve policymaking is to strengthen the energy group of SERNA and eliminate the Energy Cabinet. Improvements in regulation require, first, political support and government commitment to implement the rules. Improving CNE's credibility is a longer-term process that requires changes in the law to increase its autonomy, transparency, and technical competence.

41. Table 4 shows the timing and linkages between the options for a gradual development of a competitive market and the options for improving the corporate governance of ENEE.

Table 4

HONDURAS
Power market development

Restructuring and corporate governance	Unbundling / privatization				Long term
	Unbundling / minority shareholders				Long term
	Unbundling / corporatization			Medium term	
	Separation of accounts (IBUs)		2009 - ?		
	Vertical integration / renegotiated SEMEH or management contract	2008 - 2009			
	Vertical integration / SEMEH contract	2007			
Trading and pricing arrangements	Long term contracts	PPAs with ENEE Improvements in competitive bidding procedures	PPAs with ENEE Transfer prices between G and D units	PPAs are transfered to distcos Long term contracts with distcos	Flexible physical/financial contracts Obligation to meet demand with contracts
	Large consumers participation	Promote participation in contract market with transparent transmission charges			Participation in spot and contract markets
	Energy balance and auxiliary services	Provided by ENEE			Creation of market administrator and spot market
	Regional market	Transactions to optimize operation and meet energy shortfall		Distcos and large consumers trade in contract market	Active trading in contract and spot market
	Generation price	Average of marginal cost		Average cost of long term contracts	Average of contracts and spot
Market model		**Single-buyer**		**Wholesale competition**	

Ensuring a Sustainable and Reliable Power Supply

42. The report analyzes the generation expansion requirements and the financial results of ENEE under three demand scenarios for 2007–15, which consider different assumptions on the corrective measures taken to reduce electricity losses and adjust electricity tariffs. In a business-as-usual scenario (high case), no measures are taken (electricity prices are frozen in nominal terms and electricity losses continue to increase gradually). In a base case scenario, moderate corrective measures are taken (electricity prices keep up with inflation, and electricity losses are reduced at a moderate rate). In a low case scenario, substantial corrective measures are taken (electricity prices are increased to reach a cost level equivalent to economic cost, and electricity losses are reduced to 12 percent).

43. In the medium term, capacity additions of about 600 MW in large hydroelectric and thermoelectric projects will be necessary at the earliest commissioning date, estimated for 2013, in order to meet demand growth and replace costly emergency generation to reduce generation costs. Attracting the private sector for the development of these capital-intensive projects with long construction periods by 2013 poses a major challenge. It will be necessary to complete technical and economic feasibility studies and environmental impact assessments, find and select project sponsors, and implement an adequate financing structure (public/private partnership) to manage market and project risks.

44. The planning and procurement process for the development of new generation plants has to be improved. ENEE had to rely on costly emergency generation to meet demand during 2001–04, and will have to do the same during 2008–10, due to delays and deficiencies in this process. The planning process should guide future government actions (policies, investment incentives) and provide a signal to investors to induce an efficient allocation of resources. CNE should establish rules and procedures for energy procurement that promote competition and least-cost generation expansion, providing sufficient lead time for the preparation of proposals, ensuring project financing and construction of competitive projects.

45. Timely implementation of the least-cost indicative generation plan is essential to reduce generation costs. The report shows that the average energy purchase price would be reduced from about US$95/MWh in 2007–10 to about US$87/MWh by 2011 and to US$75/MWh by 2013, with the retirement of expensive PPAs and emergency generation and with the commissioning of lower-cost generation plants beginning in 2011.

Diversifying Energy Sources

46. Honduras has the opportunity to implement a diversification policy to reduce the volatility of energy prices, decrease generation costs, and improve energy security. There is a substantial potential of untapped indigenous renewable resources that can be developed at competitive prices, because a long-term trend of high oil prices is likely. Furthermore, the commissioning of the SIEPAC project will expand the potential for regional energy trade and the development of large regional generation projects. Large and economic coal-fired and gas-fired thermal projects will not reduce the dependency on imported fuels but can contribute to reducing the volatility of generation prices (coal projects) or to the development of clean energy (gas projects).

47. To implement an effective diversification policy, it is recommended to:

a) Promote public/private partnerships to develop medium and large hydroelectric projects and large coal-fired thermoelectric projects, where the public sector supports the completion of feasibility and environmental studies; secures timely granting of licenses and permits, and the implementation of environmental mitigation plans and settlement programs; provides financial support mechanisms to ensure long-term financing; and implements the projects necessary to strengthen the 230 kV transmission grid.

b) Eliminate the barriers to expanding regional energy trade, mainly the lack of a spot energy market in Honduras, the operation of ENEE as a vertically integrated monopoly, the lack of clarity of ENEE's exclusive rights for importing and exporting electricity, and the preferential rights of local demand on local generation.

48. **Renewables.** The development of renewable sources is an important element of the strategy to diversify energy supply, reduce vulnerability to external shocks, and mitigate the environmental impacts of energy production. Recent progress in implementing this strategy has been made largely as a result of fiscal and tariff incentives sanctioned in a 1998 law. The current focus is on the development of large hydropower projects and on providing additional incentives for the grid-connected renewable projects. The potential for the development of off-grid and small renewable sources appears to be largely untapped, though a resource base assessment is not available. Little has been done to promote micro- and pico-hydro power and the use of

photovoltaic capacity due to the lack of specific incentives and policies for off-grid rural electrification programs. Even the new Renewable Energy Bill, which is now before the Congress, fails to emphasize specific incentives and mechanisms for off-grid solutions.

49. **Energy efficiency.** Energy efficiency measures at both supply and demand are the most economical options to reduce the need for additional generation capacity and to improve security of supply. In the case of Honduras, as discussed above, the implementation of a well-structured loss-reduction program could effectively reduce the short-term need for emergency generation and/or power rationing. Furthermore, energy efficiency measures on the demand side could be used in conjunction with rural electrification programs to improve access and reduce the impact of higher electricity tariffs.

50. Despite some recent progress under the *Generación Autónoma y Uso Racional de Energía Eléctrica* (GAUREE) project, financed by the European Union between 2000 and 2007, Honduras is still lagging behind other countries in the region in terms of design and implementation of energy efficiency programs. Large efficiency improvements could be made in the areas of air conditioning for both the residential and commercial sectors. The electricity tariff structure for residential consumers with tariffs for low consumption that do not cover marginal generation cost is also an impediment to the success of energy efficiency programs.

51. A good opportunity to start a comprehensive program for energy efficiency in the country is the recently established Inter-Institutional Group for the Efficient Use of Energy (GIURE), with the participation of SERNA, the *Consejo Hondureño de la Empresa Privada* (COHEP), the Ministry of Education, ENEE, the *Universidad Nacional Autónoma de Honduras* (UNAH), the *Consejo Empresarial Hondureño para el Desarrollo Sostenible/Proyecto de Eficiencia Energética en los Sectores Industrial y Comercial de Honduras* (CEHDES/PESIC), CNE, and the *Colegio de Ingenieros Mecánicos, Electricistas y Químicos* (CIMEQH). The group has formulated a plan to reduce the national energy demand by 100 MW in 2008, equivalent to an 8 percent reduction of the peak demand forecasted by ENEE. The plan includes a number of activities and projects to be carried out by the individual agencies.

Improving Electricity Coverage

52. Social electrification is an important part of the Government's poverty reduction strategy, particularly in rural areas where the electricity coverage reaches only 45 percent compared to 94 percent in urban areas in 2006. Electrification was programmed under the 1994 Electricity Law for the Electricity Sector with the creation of the Social Fund for Electricity Development (FOSODE). The early outcome has been positive, increasing the national coverage from 43 percent in 1994 to 69 percent in 2006.

53. The government set a target to increase national electricity coverage to 80 percent by 2015, giving equal priority to urban and rural areas. The unit connection cost by grid extension is projected to further increase because more remote and less densely populated areas are to be connected. The annual investment needs are estimated by FOSODE to be around US$16million. However, this cost estimate covers only the direct costs of extending the existing grid to the users, and does not include the investment costs for subtransmission networks and running costs for the needed new generation capacity. Moreover, since the current tariff to new users is much

below the cost-recovery level of providing electric services, there will be profound fiscal impacts on cross- and direct subsidies associated with achieving the government's electrification targets. At the current tariff level and current consumption level for the newly connected customers, the tariff deficit and the direct subsidy resulting from new connections are estimated to be US$4.1 million in 2007 and to increase to US$48 million in 2015.

54. The Government's current policy of subsidizing consumption seems to be inefficient. First, the cross-subsidy schemes embedded in the current tariff structure have benefited the segment of the population that is not most needy. Only 42 percent of the poor households have access to electricity, suggesting an error of exclusion of about 58 percent and an error of inclusion of 52 percent. Second, the direct subsidy on consumption by grid-connected users has resulted in the grid-connected users paying much less than the unconnected residents for getting the same level of electric services, even though evidence shows that the grid-connected users can afford to pay a higher tariff.

55. The challenges ahead include the need for an integrated policy for rural electrification, improving human resource capacity and the funding level of FOSODE, increasing the participation of the private sector and local governments, mobilizing financial resources to meet investment needs, promoting and developing economically viable off-grid solutions, rectifying the error of inclusion in subsidy, and retargeting the resources toward new connections.

56. To meet these challenges on the institutional front, it is recommended to, in the short term: (a) strengthen SERNA as the de facto energy ministry in its capacity of developing strategy, planning, and policy formulations in rural electrification; and (b) strengthen the technical capacity of FOSODE with the necessary training in electrification options based on stand-alone technology, renewable energy, and in the development of business models that use alternative energy options. In the long term, it is recommended to transform FOSODE into an autonomous, unified fund through which all current electrification efforts can be promoted, both for grid extension and stand-alone systems. It is also desirable to correct the distorted residential tariff structure and transfer the residential tariff subsidy to increasing coverage.

57. On the policy alternatives regarding tariffs and subsidies, it is recommended to increase the tariff to the cost-recovery level and retarget the subsidy to the neediest, thus freeing up resources that could be used to increase electricity coverage. A policy mix of increasing the residential tariff by 20 percent and reducing direct subsidy by 10 percent would lead to almost doubling the benefits to the low-consumption customers, increasing the ENEE's revenue from tariff collection by US$2.6 million per month, and freeing up the government's subsidy of US$121,000 per month. If these resources were available, nearly 46,000 new connections could be added each year, assuming an average connection cost of US$700. This would mean that the government target of 400,000 new connections up to 2015 could be met without the need to mobilize other resources (see Table 5).

Table 5 - Summary Matrix of Objectives and Short- and Medium-term Options

Objective	**Policy Measures**	**Short-term Options**	**Medium-term Options**
Improving the financial performance of ENEE and reducing its negative fiscal impact	• Improve sector efficiency	• Institutional options aimed at strengthening management and corporate governance • Reduce system losses • Government support to penalize theft of electricity • New investments with external support including private sector participation in management of low/medium voltage lines	• Institutional options aimed at moving towards a more market-oriented industry structure • Sustain low level of losses • Maintain government support • Investment financed through internal and commercial sources
	• Target subsidies	• Gradually reduce cross-subsidies • Reduce eligible levels of Bono 80	• Maintain lifeline subsidies • Channel subsidies through “poverty cards”
	• Adjust retail tariffs to reflect economic cost of supply	• Gradually increase tariff in real terms • Revise base tariff	• Apply formula for automatic adjustment mechanism to new base tariff
	• Renegotiations of PPAs and SEMEH	• Agree on and start a process of renegotiation	
Improving reliability of supply	• Implement load management measures	• Introduce time-of-the-day tariffs, and interruptible tariffs • Design a program for shaving peak demand	• Implement program
	• Strengthen power planning and energy procurement process	• Follow due regulatory process for approval of expansion program and timely prepare and issue competitive tenders • Increase technical and operational capacity of ENEE, CNE, and SERNA to identify and study site-specific candidate projects • CNE to establish rules and procedures for energy procurement promoting competition and least-cost generation	• Develop appropriate policies to promote public/private partnership for new generation projects
	• Start procurement of new thermal power generation	• Initiate international competitive bidding process for emergency generation projects	• Prepare feasibility and environmental impact assessment studies for new thermal generation projects
	• Enhance investment in transmission and distribution	• Prepare international competitive bidding process for BOO/BOT transmission investments • Promote decentralized solutions for distribution investments and commercial management	
	• Adapt regulations to actively participate in Regional Electricity Market	• Clarify whether new legislation is required to eliminate ENEE’s exclusivity • Establish Business Units in ENEE and transfer prices	• If necessary, amend legislation

Objective	Policy Measures	Short-term Options	Medium-term Options
Diversifying energy sources	• Promote energy efficiency	• Start implementation of the *Campaña de Promoción y Ahorro de Eficiencia Energética*	• Consolidate and expand program
	• Promote hydropower development	• Prepare environmental and social impact assessment for major sites/basins • Prepare plan for private sector participation	• Implement hydropower schemes with public/private sector development under international competitive bidding
	• Promote development of small renewable projects, including microhydro and photovoltaic	• Revise Renewable Energy Bill to promote off-grid renewable projects	
	• Promote coal and LNG based power projects	• Prepare feasibility and environmental impact assessment studies for coal and LNG projects	• Prepare international competitive bidding process for new projects
Improving electricity coverage	• Strengthen the institutional capacity and coordination of SERNA and FOSODE	• Improve the technical capacity of SERNA in developing strategies, planning, and policy formulation in rural electrification • Increase the technical capacity of FOSODE with training in electrification options for stand-alone technologies, renewable energy, and public/private partnership models • Correct distorted tariff structure to provide incentives for increasing electrification	• Transform FOSODE into an autonomous, unified fund to promote both grid extension and stand-alone systems
	• Promote off-grid solutions with private sector and local government participation	• Revise Renewable Energy Bill to promote off-grid renewable projects and private sector and local participation	

EVALUATING THE FINANCIAL IMPACT OF THE OPTIONS

58. On the basis of the previous analyses, financial projections for 2007–15 have been developed. The results for the short term (2007–10) were presented above. Table 6, which summarizes the results in the medium term (2011–15), shows the following:

a) The adoption of major policies, including substantial improvement in corporate governance and the operation of the wholesale market, may bring electricity losses down to efficient levels by 2015, reduce the need for new generation capacity, and provide substantial cash-flow surpluses in the medium term.

b) Increasing the average tariff to the level of efficient reference costs of Lps.2.4/kWh produces large cash-flow surpluses by 2015, when the electricity losses have been reduced and the average generation cost has decreased by about US$15/MWh with respect to the cost for 2009 (as a result of the commissioning of lower cost generation). This indicates that the current reference costs may be high once lower cost generation plants are commissioned, provided that international crude oil prices stay at current levels of about US$60/bbl. Electricity prices could be reduced by 2013 based on the economic generation cost prevailing at that time.

Table 6 - Summary Results Scenarios

	Moderate Policies (base case demand scenario)	**Major Policies (low case demand scenario)**
System Loss Reduction 2006 2015	 25.2% 19.7%	 25.2% 12.0%
Average Retail Tariff 2010 2015	 2.28 2.40.	 2.40 2.40
Medium Term Cumulative Capacity Requirements 2007–2015	1,258MW	1,137MW
Cumulative cash-flow (2011–15)	US$710MM	US$1,180MM
Rural Electrification Investments and target	80% coverage by 2015; investment to be financed by grants, government contributions, and funds released by the reduction of direct subsidies	
Institutional Options	Improving management and corporate governance including through management contract	Moving toward a more market-oriented industry structure with private investments and management

PART A – THE ELECTRICITY SECTOR DIAGNOSTIC

In the last few years, the financial and operational performance of the state-owned vertically integrated utility, the *Empresa Nacional de Energía Eléctrica* (ENEE), has seriously deteriorated, and with a deficit above 2 percent of gross domestic product (GDP) is threatening the stability of the macroeconomic framework and the prospects for poverty reduction. Action is also needed to ensure the availability of additional generation capacity for 2008. The oil price hike of the last two years has translated into a large increase in the cost of electricity supply because Honduras's power generation is largely based on petroleum imports. Furthermore, last year's policy to freeze electricity tariffs and retail petroleum prices on the eve of the national election is being continued by the new administration, and has widened the gap between the utility's costs and revenues. The root causes are (a) the institutional imbalances in the sector; (b) political interference in the operation of the ENEE; (c) poorly targeted subsidies; (d) high generation costs; and (e) uncertain policies regarding the development of new generation projects, including renewable energy. These issues are described in this section.

1. FINANCIAL SITUATION OF ENEE

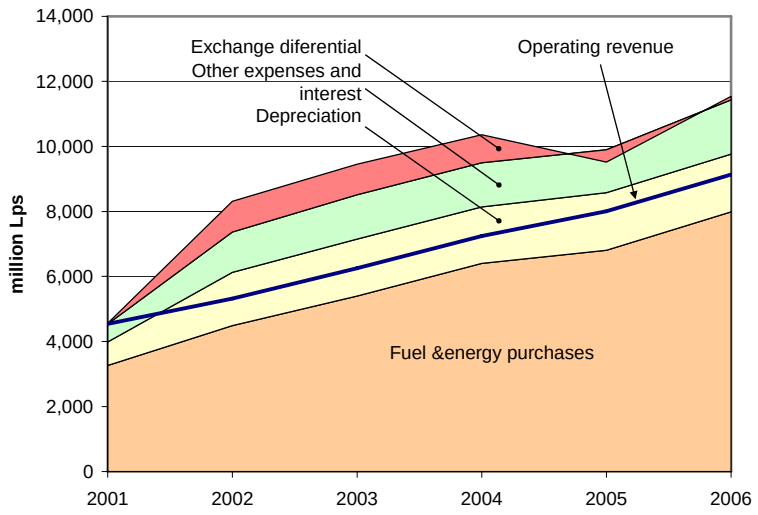
This chapter presents the financial results of ENEE for 2001–05, with the income statement, cash flow, and balance sheet; analyzes the internal and external factors that had a major impact on the results; and identifies the main drivers for financial performance in the future.

1.1 INCOME STATEMENT

For the last six years, ENEE has been incurring substantial financial losses. From 2001 to 2006, net losses increased from Lps.18.9 million to Lps.2.4 billion, after reaching Lps.3.2 billion in 2003. Operating revenues do not cover operating expenses. The financial losses after excluding the "exchange differential," which is a purely accounting "loss" or "gain" due to exchange rate variations, are about Lps.2 billion per year after 2001. Expenses in fuel and energy purchases and depreciation account for about 85 percent of the costs. The financial losses increased substantially after 2001, mainly due to the sharp rise in energy purchase costs and in fuel prices, a large adjustment in depreciation charges, and very limited tariff adjustments (see Figure 1.1).

Figure 1.1

ENEE´s income statement



1.1.1 High costs of energy purchases

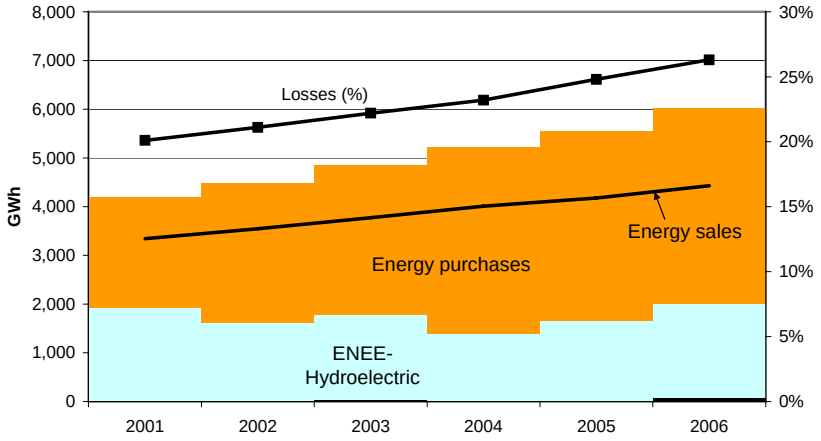
The costs of energy purchases were high during 2001–06 due to: (a) ENEE's poor performance (high commercial losses), (b) inefficiencies in the procurement of energy (additional emergency generation and expensive Power Purchase Agreements [PPAs]), and (c) the dependency of power generation on imported fuels and external shocks (high international fuel prices and below-average water flows). The combination of these factors increased the amount of energy purchases (about 70 percent of total generation needs) and their average price.

The amount of energy purchases increased by 77 percent, while electricity sales increased by only 32 percent. There are two contributing factors: (a) electricity losses—mostly related to theft, fraud, and illegal connections—increased from 20.1 percent to 25.2 percent; and (b) hydroelectric generation decreased and remained below average (see Figure 1.2). The impact of high commercial losses is substantial; an efficient company, with 12 percent losses, could have increased electricity sales by about 15 percent.

Figure 1.2

Honduras

Energy Balance and Losses 2001-2006



The drop in hydroelectric generation is analyzed in detail in Annex 1.1. A combination of factors explains this decrease. First, inflows in the El Cajón reservoir were below 70 percent of the average in 2001, 2002, and 2004, which reduced the run-of-river generation. To make up for the energy shortfall, ENEE depleted the El Cajón reservoir during 2001–04 and increased expensive emergency thermal generation but was limited by financial constraints. The operation of the El Cajón project at low reservoir levels reduced the firm's capacity on this project by about 90 megawatts (MW), requiring additional emergency diesel generation to meet peak demand.

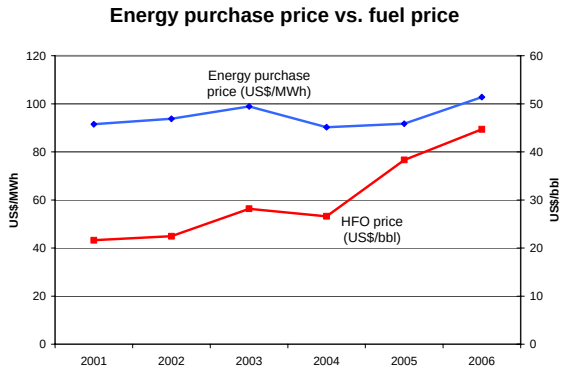
The average annual price of energy purchases during 2001–06 remained high but relatively stable, in the range of US$90/megawatt-hour (MWh) to US$100/MWh, in spite of the fact that the international price of heavy fuel oil doubled in that same period (see Figure 1.3). The stable but high purchase price is explained by the following factors:

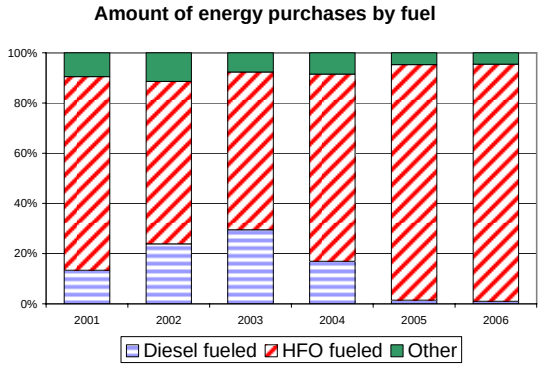
a) During 2002–04, when heavy fuel oil prices where relatively low, in the range of US$22/barrel (bbl) to US$28/bbl, there was a surge in more expensive diesel-fueled generation, which was caused by the delays in adding new plants running on heavy fuel oil.

b) During 2005–06, when the new heavy-fuel-oil-fired plants displaced the diesel-fired emergency generation, a steep increase in the heavy fuel oil price, to about US$45/bbl, caused energy prices to remain at the same level.

c) During this period, ENEE had to pay the additional costs of expensive PPAs that were contracted in the mid-1990s (Lufussa I and Elcosa).

Figure 1.3





1.1.2 Depreciation charges

ENEE has been revaluing its assets yearly since 1978, based on conditions included in an International Development Association (IDA) Credit. More recently, ENEE's external auditors discovered that certain arithmetic errors had been systematically made in applying the method, and they recommended that ENEE go back, correct the mistakes, and adjust the amount of the accumulated revaluation. This adjustment was made in 2002 and, as a result, the net value of fixed assets, including the revaluation, was increased from Lps.14 billion to Lps.33 billion, and the depreciation expenses increased from Lps.0.7 billion to Lps.1.6 billion. A preliminary analysis shows that assets are overvalued, suggesting the need for a revaluation based on an engineering, economic, and legal assessment, in addition to accounting considerations.

1.1.3 Low electricity tariffs

Inadequate electricity tariffs that did not cover supply costs have contributed to the heavy financial losses. Electricity tariffs were low from the financial and economic point of view. From the financial point of view, a comparison of average electricity prices with unit costs (see Figure 1.4) shows that:

a) The average electricity price increased during 2001–06 from US$85/MWh to US$105/MWh.

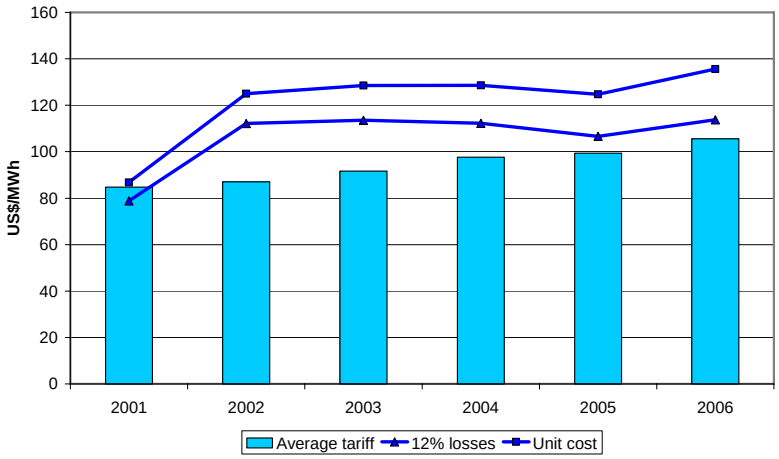
b) The unit cost of supply (total operating expenses and financial costs, excluding exchange rate differential divided by total energy sales) increased from US$87/MWh to US$135/MWh. However, the large increase in unit costs took place in 2002 when there was a substantial adjustment in depreciation expenses plus a surge in diesel-fired generation.

c) Average electricity prices for 2006 did not even cover the unit costs corrected to take into account only efficient system losses (12 percent).[1]

From an economic point of view, an analysis of the efficient supply costs (see Chapter 5 on electricity prices) shows that ENEE's average supply cost is about US$127/MWh. A 23 percent tariff increase would be necessary to cover these costs. This tariff increase in 2006 is equivalent to additional revenues of US$93 million or Lps.1,780 million, sufficient to cover about 75 percent of the financial deficit.

Figure 1.4

Energy supply costs and prices



1.2 ENEE'S CASH-FLOW PERFORMANCE

The analysis of ENEE's cash flow for 2003–05 shows that the internal cash generation was negative during that period, and ENEE had to manage a very difficult cash situation (see Figure 1.5) by:

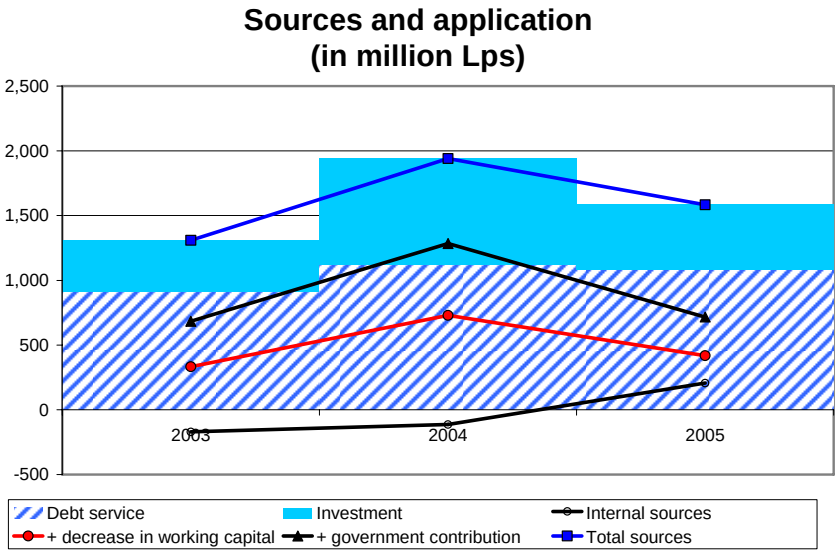
a) Delaying needed investment in transmission and urban distribution. The annual investment was very small, about US$15 million, if the investment in rural electrification is excluded, most of which is financed by government contributions.

b) Financing about 50 percent of the investment plus debt service with expensive revolving loans from local Banks (about Lps.2.3 billion during the period).

c) Government contributions represented about Lps.1.2 billion, 70 percent of which corresponded to rural electrification, with marginal contributions from debt forgiveness (see Chapter 2).

[1] Current regulations allow distribution costs based on 15 percent system losses. However, other countries in the region with good performance have system losses below 12 percent (Costa Rica and El Salvador).

Figure 1.5



Accounts receivable for 2002–04 show a stark contrast between ENEE's performance in collecting bills from private customers and public customers. Average arrears, expressed in months of sales, for public sector customers were 9 months to 13 months, while for private customers they were about 1 month (Table 1.1). Although sales to public sector clients represent only about 6.8 percent of total sales, the amount of accounts receivable from public sector clients at the end of 2005 represented 48 percent of accounts receivable from all clients.

Table 1.1

ENEE
Accounts receivables

	2002		2003		2004	
	Arrears	Receivables	Arrears	Receivables	Arrears	Receivables
	months	M LPs	months	M LPs	months	M LPs
Public Sector	11.4	273	8.9	401	13.4	360
Other sectors	1.0	341	0.8	447	1.1	451
Total	1.7	614	1.4	848	1.9	810

Table 1.2 shows the percentage of amounts billed in February 2006 that were collected up to 12 months after billing.

Table 1.2 - Percentage of Amount Billed in February 2006 Collected up to Twelve Months after Billing

Months from bill	0	1	2	3	4	5	6	7	8	9	10	11	12	After 12 months
% collected in month	52.6%	26.6%	6.4%	2.1%	1.0%	0.4%	0.4%	0.3%	0.3%	0.2%	0.2%	0.2%	0.1%	90.8%

Considering that sales to public sector clients are about 6.8 percent of total sales and that they are paid after 12 months, it would mean that about 2.4 percent of sales are never collected. Table 1.2 also highlights the cash-flow difficulties due to delay in bill collection as less than 80 percent of the electricity bills are paid within 1 month.

1.3 FINANCIAL INDICATORS

Table 1.3 shows key financial indicators that summarize ENEE's financial performance. The current ratio fell below 1 after 2002, reflecting ENEE's difficulties in paying its short-term obligations. As for debt-service coverage, it was satisfactory in 2001, but became negative for the rest of the period. ENEE's contribution to investment was also negative during the same period.

Table 1.3 - Key Financial Indicators that Summarize ENEE's Financial Performance

Indicator	2001	2002	2003	2004	2005
Current Ratio	1.9	1	0.6	0.4	0.4
Debt/Equity Ratio	39/61	26/74	28/72	30/70	30/70
Debt Service Coverage - times	4.9	-0.2	-0.1	-0.1	0.1
Contribution to investment, %		-142.2	-140.4	-114.2	-279.1

2. FISCAL IMPACT

The fiscal impact of the electricity sector is determined basically by the electricity subsidies, comprising direct government subsidies and those implicit in the tariff structure, ENEE's financial losses, equity contributions to ENEE, and the net transfer in a compensation account that is kept between ENEE and the Government. Several tax exemptions granted to the electricity sector also have an indirect fiscal impact represented by the fiscal revenues that are foregone.

2.1 ELECTRICITY SUBSIDIES AND FINANCIAL LOSSES

The electricity subsidies include direct subsidies paid by the Government to residential users that consume less than 300 kWh per month and an implicit generalized subsidy due to the fact that the average electricity tariff does not cover the supply cost.

The direct subsidy was established in 1994 to compensate for any tariff increases to eligible residential users (those consuming less than 300 kWh per month). Beginning in 2001 this direct subsidy was capped at Lps.53/month for eligible residential users with a consumption larger than 35 kWh/month, and an overall cap of Lps.275 million/year was imposed to control its fiscal impact.

The generalized electricity subsidy is reflected in the large annual financial losses incurred by ENEE in recent years, which reduce equity, and represent a contingent liability, because the backlog of postponed investments and deferred maintenance in transmission and distribution causes a gradual accumulation of rehabilitation needs that will soon require extraordinary investments. Total annual electricity subsidies are estimated at about Lps.3 billion, about 90 percent in financial losses (see Table 2.1). It is important to note that the implicit subsidy to the electricity consumers is just a portion of the financial losses, because, by law they are not supposed to pay for inefficiencies in ENEE's operations (commercial losses and high generation costs in some contracts).

Table 2.1 - Annual Electricity Subsidies

Electricity subsidies
million Lps

	2002	2003	2004	2005	2006	Average
Direct subsidy to residential consumers	337	276	247	260	275	279
Financial losses	2,989	3,195	3,118	1,506	2,405	2,643
Total	3,326	3,471	3,365	1,766	2,680	2,922

2.2 EQUITY CONTRIBUTIONS AND NET TRANSFERS TO ENEE

The equity contributions to ENEE include funds provided by the Government to finance rural electrification investments and funds from debt forgiveness left in the utility as an equity reserve.

The funds for rural electrification include annual allocations from the national budget of about Lps.33 million, and loans contracted by the Government directly with foreign donors.

The compensation account is credited with payments made by the Government on ENEE's behalf, mainly foreign-debt service and, until 2003, import tax exemptions for diesel oil used for power generation, and is debited with the direct subsidies for electricity users, which are borne up front by ENEE, and payments to reduce the accumulated arrears for electricity sales to public sector institutions (see details in Annex 2). The fuel tax exemptions were established in 1997 and included in the compensation account because ENEE was supposed to use the "savings" for rural electrification and electricity subsidies. However, for 2002–06, this cannot be counted as a valid government contribution because ENEE's tariffs were no longer recovering costs. Accordingly, for the analysis shown in Annex 2; the fuel taxes were excluded from the compensation account and included as part of the tax exemptions. Total average annual equity contributions and net transfers amounted to Lps.439 million (Table 2.2).

Table 2.2

Equity Contributions and Transfers to ENEE
million Lps

	2002	2003	2004	2005	2006	Average
Equity contributions						
For electrification projects	107	172	495	206	980	392
Increase of debt-forgiveness reserve	128	-70	299	93	10	180
Net contribution from compensation account	-203	-76	-52	-1	-332	-133
Total Government contribution	33	25	743	298	658	439

2.3 TAX EXEMPTIONS

The electricity sector enjoys several tax exemptions: import tax exemptions for fuels used by ENEE and other power companies for electricity generation, import and sales taxes on equipment and materials for rural electrification projects, import taxes on equipment and materials for power plants using renewable energy sources, and sale tax on electricity sales. The total average annual tax exemptions are estimated at about Lps.2 billion, mostly fuel taxes and sales taxes on electricity consumption (Table 2.3).

Table 2.3

Tax-exemptions
million Lps

	2001	2002	2003	2004	2005	Average
Equipment taxes	16	18	20	41	29	25
Sales tax on electricity	527	607	728	844	939	729
Fuel taxes	363	553	1,328	1,820	1,757	1,164
Total:	905	1,178	2,077	2,705	2,725	1,918

Summarizing, direct annual contributions from the Government to the sector are estimated at about Lps.3.4 billion or about 2 percent of GDP, mostly represented by financial losses, and annual indirect contributions in tax exemptions are estimated at about Lps.1.9 billion, or 1.1 percent of GDP.

3. RELIABILITY OF POWER SUPPLY

All segments of Honduras's power system show signs of delayed or insufficient investment to expand infrastructure at the pace required by demand growth. This problem is made more acute by the low tariffs for residential consumers, which inflate demand, thereby hastening the need for new investments, while diminishing the *Empresa Nacional de Energía Eléctrica*'s (ENEE's) ability to finance them.

Installed generation capacity is relatively high compared to peak demand, but much of it is not firm, because of different limitations and operational constraints. Today, ENEE is late in preparing the next procurement process for new generation capacity, so there is again the prospect of a recurring period of higher costs and possible supply disruptions.

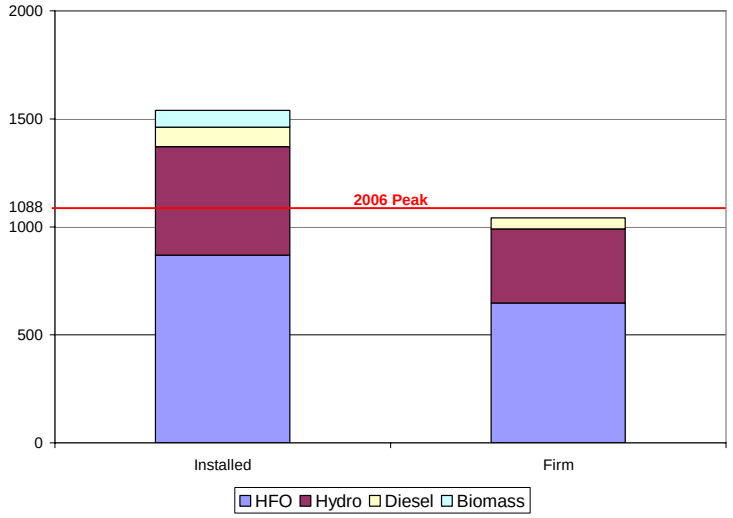
Transmission congestion is forcing ENEE to use expensive local generation around Naco and La Ceiba. The lack of investment in transmission expansion is also constraining distribution network expansion. Transformer capacity at the interface between transmission and distribution is inadequate. Localized power interruptions will become more frequent if investments in the network are not undertaken.

3.1 RETROSPECTIVE

3.1.1 Generation

In Figure 3.1, the firm-capacity bar reflects a tight situation because firm capacity is substantially lower than installed capacity due to seasonality, the natural uncertainty affecting hydroelectric generation, the old age of some of the plants, and mothballing of thermal capacity.

Fig. 3.1 - Generation Capacity (MW) in December 2006



Thermal plants, including the bagasse- and other biomass-fired power stations, account for 67.5 percent of total installed capacity. Thermal plants using only petroleum fuels account for

62 percent of the total. There are 110 MW installed under the incentives regime for renewable energies, or 7.2 percent of the total.

Table 3.1 shows peak demand and available power generation capacity at the end of the month in which peak demand occurred, for 2001–06.

Table 3.1 - Power Generation and Peak Demand (in MW)

	Capacity Available End of Month of Maximum Demand					
	2001	**2002**	**2003**	**2004**	**2005**	**2006**
ENEE thermal	93.1	77.1	91	40.9	34.4	45.5
ENEE hydro	393	388	342.7	253.4	348.5	366
Other state-owned hydro	1.6	1.6	30	30	30	30
Total state-owned capacity	487.7	466.7	463.7	324.3	412.9	441.5
Large private generators	311	401	375.1	739	736	654
Small-hydro, bagasse, other	8.5	8.5	10.2	32.7	33.2	62.5
Total private capacity	319.5	409.5	385.3	771.7	769.2	716.5
GRAND TOTAL	807.2	876.2	849	1,096.00	1,182.10	1,158.00
Peak Demand	758.5	798	856.5	920.5	1,014.00	1,088.00
Imported at peak, MW	4	0	35.5	1	15	29.2

Margins between available capacity and peak demand were tight, except for 2004 and 2005. El Cajón's capacity was limited in most of the years by the low reservoir level, and in 2004 and 2006, also because of maintenance. Table 3.1 shows the power that was being imported at the moment of the annual peak demand.

Table 3.2 shows the trends in energy generation sales and losses.

Table 3.2 - Energy Generation, Sales and Losses (GWh)

	2001	2002	2003	2004	2005	2006
ENEE						
Hydroelectric	1,903	1,610	1,738	1,371	1,647	1,938
Thermal*	352	432	540	484	76	64
Total ENEE	2,255	2,042	2,278	1,855	1,722	2,003
Other sources						
ELCOSA**	332	343	458	422	130	168
EMCE-ENERSA	397	403	361	915	1,347	1,525
LUFUSSA	735	777	691	935	2,052	1,968
Leased plants	159	508	708	570	56	31
Sugar mills	0	4	20	43	76	100
Private small hydro	1	1	3	30	71	132
Industrial self-generators	0	0	0	61	42	13
Total other sources	1,624	2,034	2,241	2,975	3,774	3,938
National production	3,879	4,076	4,519	4,831	5,496	5,940
Imports	311	427	351	456	132	96
Exports	3	5	8	49	84	113
Net Imports	308	422	343	407	48	-17
Total available	4,187	4,498	4,862	5,237	5,543	5,924
Total Sales	3,341	3,541	3,765	3,996	4,172	4,431
Losses, GWh	847	957	1,097	1,241	1,371	1,493
Losses, percent	20	21	23	24	25	25
increase in percent loss		1	1	1	1	1

*Includes generation in ENEE's plants of La Ceiba, Puerto Cortés I, and Puerto Cortés II, operated by *Empresa de Mantenimiento, Construcción y Electricidad* (EMCE).

**Excluding energy produced by Elcosa for direct sale to industrial clients plus the associated transmission-loss.

The table shows the surge in leased-plant generation caused by delays in contracting for new base-load capacity. It also shows the dramatic increase in sugar-mill and small-hydro generation in response to the incentives regime for the development of renewable energy sources. Sales to ENEE by industrial co-generators also took off, because of the guaranteed purchase at the short-term marginal cost on the basis of article 12 (b) of the Electricity Law.

Although generation based on renewable sources offers limited firm capacity, and can be expected to contribute only a small percentage to the total system requirements, it is a desirable complement to the more traditional generation sources because of diversification, domestic development, and lower environmental impact. ENEE could do more to encourage this kind of plant by determining a realistic short-term marginal cost, and also by ensuring sufficient transmission capacity, which is often a constraint to taking up their production.

ENEE's hydroelectric generation decreased from 2001 to 2004, and began recovering after that, but remained below average during the whole period. As already mentioned, this was mostly caused by below-average rainfall. Because of the low reservoir levels, the capacity of El Cajón was below its nominal value most of the time. This implies a cost to replace the capacity

shortfall, and also in energy produced, since a low reservoir level means less energy is generated for each cubic meter of water used.

Concerning energy losses, Table 3.2 shows how they grew from 20 to 25 percent of total energy made available to the grid. However, the rate of growth of this percentage seems to have slowed during the last year, when ENEE began implementing a loss-reduction program.

3.1.2 Transmission

ENEE's transmission network comprises 620 kilometers (km) of 230-kilovolt (kV) lines, 860 km of 138-kV lines, and 400 km of 69-kV lines. Transformer capacity linking these voltage levels is 750 Mega Volt-Ampere (MVA). High- to medium-voltage (HV-MV) transformer capacity, linking the transmission network and the distribution networks is 1,550 MVA.

The lack of financing has hindered ENEE from expanding transmission according to its plans. This has slowed grid development, causing it to lag behind demand and generation growth. The largest investment in transmission after 1985 was the approximately US$38 million laid out in 2004 and 2005 by Lufussa and Enersa to build 230-kV and 138-kV lines and substations in connection with their latest generating plants.

When ENEE launched in 2001 the bidding process that led to those new plants being built, the transmission grid was not capable of absorbing and ensuring the outflow of the 210 MW originally being procured. For that reason, the bidding documents required the bidders to include in their projects the transmission reinforcements needed. All the transmission built with those generation projects was later transferred to ENEE.

Transmission congestion, particularly around Naco, forces ENEE to use expensive diesel generation from leased plants. The most recent industrial complex in this area, the Green Valley Industrial Park, had to install its own generation, 14 MW, in view of ENEE's lack of capacity to supply their demand. Another case is La Ceiba and the Aguan Valley, where load has grown considerably over the 30 years since they were incorporated into the transmission grid in 1974 and 1978, respectively. The transmission lines in those areas have not been upgraded since then, and ENEE is experiencing problems with voltage regulation. ENEE's voltage records at La Ceiba show transmission voltage falling at peak times to 121 kV, or 88 percent of the nominal 138 kV.

ENEE has had in its plans for many years a 230-kV line from Tegucigalpa to the Aguán Valley through the Department of Olancho, which it cannot build for lack of financing. Olancho is a large area currently served from Tegucigalpa through 69 kV lines that have reached the limit of their capacity.

During summer months, there is congestion also between El Cajón and San Pedro Sula and surroundings. One solution would be to convert the connections between El Progreso and San Pedro Sula to 230 kV. The interconnection of Río Lindo and El Cajón is also necessary, and in fact is included in the *Sistema de Interconexión Eléctrica para América Central* (SIEPAC) project.

ENEE recently contracted for the supply of four 25-MVA mobile high- to medium-voltage transformers at a cost of $37 million to shore up capacity at substations in the north. In practically all the cases, the loss of one of the transformers serving a load center causes service interruptions, either because there is no backup transformer, or because the remaining transformers do not have enough capacity to take up the additional load flow.

Concerning the Dispatch Center, its 1970s technology is now obsolete. Links with the system's power plants and substations are also insufficient, because ENEE has not been able to increase them at the same pace as the power system has grown. A new Dispatch Center is included in a recent Inter-American Development Bank (IDB) loan to ENEE.

Insufficient investment in transmission development increases total generation costs:

a) By forcing ENEE to use expensive generation locally in affected areas. This is currently the case around Naco.

b) Similarly, heavy load on certain lines causes voltage to fall below normal in areas relatively far from the main generation centers. In those cases, local generation is required to maintain voltage within the normal range. This is the case around La Ceiba.

c) Also, lightly loaded transmission lines, in periods of low system demand, require absorption of reactive power to maintain voltage within the normal range. The most efficient way of doing this is by means of "reactive power compensators." ENEE uses El Cajón to do this, thus using water inefficiently.

Lack of sufficient backup transmission capacity forces ENEE to keep lightly loaded hydroelectric units running during the early morning hours, which is another deviation with respect to optimal dispatch, to be able to pick up load quickly in case a transmission line is lost. Again, water is used inefficiently.

3.1.3 Distribution

ENEE's distribution networks can be classified into three groups. The first group is formed by those networks serving the larger load centers, with more than 10,000 clients each, specifically: San Pedro Sula, Puerto Cortés, El Progreso, Tela, La Ceiba, Tegucigalpa, and Choluteca. The second group is formed by networks serving small communities with less than 3,000 clients, built during the last 20 years by the rural electrification programs. These networks have acceptable technical conditions, although their secondary circuits are sometimes very long and prone to large voltage drops and high losses. Nevertheless, demand levels are also very low, which limits the impact of these conditions.

The third group is formed by systems of between 3,000 and 10,000 clients. These are very old networks, in bad condition, with high energy losses and offering poor-quality service. ENEE needs to rebuild these networks but does not have the financial means to do so. The second and third groups often serve remote areas and are fed by very long single lines, difficult to maintain and exposed to faults that take a long time to repair.

In the larger urban centers, ENEE takes advantage of the directive in article 43 of the Electricity Law stating that, in urban areas, excepting "marginal zones," it behooves the parties interested in obtaining electric service to build all the installations required. Article 43 is ambiguous concerning transfer of the installations to ENEE and compensation of investors. In practically all cases, developers, or municipalities, in the case of public works, invest in building the network extensions required and then transfer the works to ENEE for free.

ENEE's own investment in urban areas is very limited. For example, the Center-South Distribution Region's investment budget for 2007 is only L32 million, or $1.7 million. Also, as population centers have grown, the lack of financing for transmission expansion has meant that no new source substations could be created as would have been necessary, so that the standards introduced by the Seven Cities Project limiting load per circuit and circuit length have had to be abandoned. This increases energy losses and reduces quality of service.

Because of the tight margins in HV-MV transformer capacity, ENEE recently contracted for the supply of four mobile substations of 25 MVA each that will allow it to shore up the most stressed substations in and around San Pedro Sula.

An essential component of distribution investment would have to be in the electrification of all "marginal colonies." Neglecting this component means growing commercial losses for the utility. The proliferation and growth of these illegal settlements are an important factor in ENEE's energy losses, because these groups build their own rudimentary networks and take electricity from ENEE's grid without paying for it.

3.1.4 Reliability of supply

Annex 3 analyzes transmission grid reliability by detailing the consequences of losing major lines and transformers. In most cases, the loss causes widespread service interruptions. In areas where there is no redundancy, the network is split in two parts, with one of them having a deficit of generation capacity. In areas where there is network redundancy, the parallel routes do not have the capacity to take up the load flowing before through the line that was lost.

ENEE monitors reliability of supply to the distribution networks by means of an indicator designated as "Equivalent Outage Duration," calculated from data on non-served energy.[2] Table 3.3 shows the evolution of this parameter for different geographic areas and for the system as a whole.

[2] For any circuit or region, the "equivalent outage duration" is equal to non-served energy divided by average power demand. A one-hour outage at peak has an equivalent duration greater than one hour. A one-hour outage at 3:00 a.m., when demand is very low, counts for less than one hour in equivalent duration.

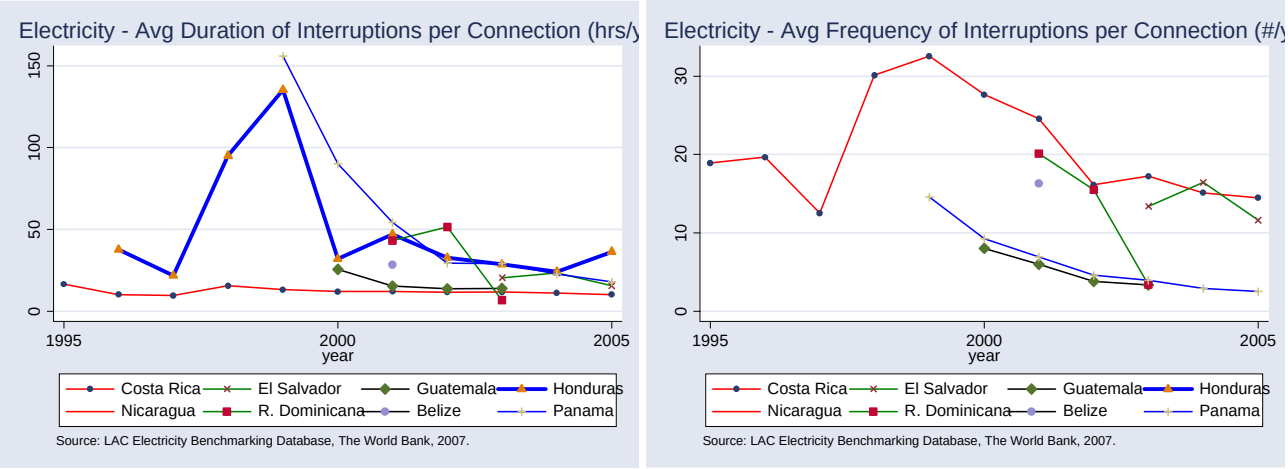
Table 3.3 - Equivalent Outage Duration in Hours

Area	2001	2002	2003	2004	2005
Atlantic Shore	90.4	72.7	29.2	20.3	35.3
North-western	34.5	22.6	23.4	18.5	31.4
Canaveral	419.3	220.2	72.8	79.1	57.4
Center-East	29.1	20.7	31.2	26.5	39.5
South	71.5	48.8	39.2	41.5	50.8
National	47	32.7	28.6	24.1	36.3

Table 3.3 shows the situation improving markedly from 2001 to 2004. ENEE explains this evolution, which appears at first inconsistent with the tightening of capacity margins in 2002 and especially in 2003, as the result of a continued effort, initiated under a "total quality" program implemented by management during 1998–2001, to systematically investigate and correct outages causes in generation, transmission, and distribution systems.

A comparison of indicators of quality of power supply in Honduras with the other Central America countries (see Figure 3.2) shows that duration of interruptions per connection are very high, although their frequency is lower than in neighboring countries.

Figure 3.2



Although the effects of the tight generation capacity margins are not readily detectable in terms of non-served energy and equivalent outage time, ENEE had in fact to resort to peak-shaving from April to September 2003 to meet peak demand. Table 3.4 shows for that period the constrained peak supplied by generation, the power cut at peak time, and what the unconstrained peak would have been. The maximum cut occurred in May and was about 56 MW, or 6.5 percent of unconstrained peak demand.

Table 3.4 - Peak Shaving in MW in 2003

	Apr.	May	Jun.	Jul.	Aug.	Sept.
Peak served	819	810	807.5	812	827	837
Power cut at peak	46.5	56.1	50.5	25.4	0	28.8
Unconstrained peak	865.5	866.1	858	837.4	827	865.8

Non-served energy due only to these cuts is estimated by ENEE at 2.93 GWh, which translates into a contribution of 6.5 hours to the total Equivalent Outage Time of 28.6 hours shown in Table 3.3 for 2003.

3.1.5 Energy losses

A recent study by a Colombian consulting company, in preparation for ENEE's loss-reduction program, a component of the IDB project, determined that ENEE's total technical losses amount to 10 percent of energy injected into the grid, of which 3 percent corresponds to transmission and 7 percent to distribution. Since total loss is estimated at 25 percent of energy injected into the grid, this means that commercial loss corresponds to the remaining 15 percent of the net total energy injected.

Table 3.5 displays the study's breakdown of commercial losses by user category and by cause:

Table 3.5 - Breakdown of Commercial Losses, in Percent

Cause	**Breakdown of Commercial Losses in Percent**				
	Residential	Commercial	Industrial	Other	**Total**
Fraud	15.0	8.4	12.0	3.2	**38.6**
Billing errors	11.4	6.4	9.2	2.4	**29.4**
Marginal settlements	11.1	6.2	8.9	2.4	**28.6**
Meter calibration	0.6	0.3	0.5	0.2	**1.6**
Other causes	0.7	0.4	0.6	0.2	**1.8**
Totals	**38.8**	**21.8**	**31.2**	**8.3**	**100.0**

Source: Consultora Colombiana, Loss study.

The subdivision for the line "marginal settlements," in residential, commercial, industrial, and other, is an estimate based on the consultants' observations. "Industrial" in this case means workshops of different kinds. For the other lines, the subdivision corresponds to the user category in ENEE's commercial roster.

ENEE has already started a loss-reduction program. As part of it, the utility recently launched the highly publicized *Operación Tijera*. This effort, ordered by the President and involving a substantial injection of resources from all Ministries and government agencies—particularly in the form of cars for the large number of crews organized for the purpose—aimed to cut service (a) to delinquent clients, and (b) to any users detected during the operation with irregular service

connections or with meters that had been tampered with. The operation produced an immediate surge in collections when its high profile induced people in arrears or in irregular situations to pay their bills and request regularization to avoid the announced service cuts.

The operation found a large number of irregularities, a clear indication of the inadequate intensity of ENEE's regular loss-reduction effort, for which resources have been significantly cut from 2000 levels, and the deficient supervision of *Servicio de Medición Eléctrica de Honduras* (SEMEH), also attributable to inadequate resources. As the operation winds down and cars from other agencies are withdrawn, ENEE is reverting to former loss-reduction levels. ENEE has to complete as soon as possible the preparations for its proposed loss-reduction program and launch it in force. The operation did show the importance of direct involvement by the top levels of management in the loss-reduction effort, as was already shown in the past when ENEE managed to bring total losses down to 18 percent in 2000 from a high of 28 percent in 1995.

3.2 GENERATION EXPANSION

This section presents an analysis of the generation expansion requirements of Honduras during 2007–15. The analysis is based on three electricity demand scenarios that consider the same GDP growth but different assumptions on key demand drivers that are under the control of ENEE or the Government, such as electricity losses, electricity tariffs, and load factor:

a) A high case corresponds to a "business-as-usual" scenario, where electricity prices are frozen in nominal terms, electricity losses continue to increase, reaching the level of 28 percent in 2015, and the load factor decreases from 65.3 percent to 60 percent as a result of the increasing proportion of residential load and lack of load management policies.

b) In the base case scenario moderate corrective measures are taken. Electricity prices keep up with inflation, but no increases in real terms are made, electricity losses are reduced at a moderate rate beginning in 2008 to reach 19.7 percent in 2015, and the load factor remains unchanged.

c) In the low case scenario substantial corrective measures are taken. Electricity prices are increased 5 percent per year in real terms during 2007–09 to reach a cost level equivalent to economic cost, and electricity losses are decreased by about 2.3 percentage points per year to reach 12 percent by 2013. The annual load factor gradually increases from 65.3 percent to 68 percent by 2015 due to the implementation of load management programs and energy efficiency actions.

3.2.1 Demand projections

The assumptions and methodology used for projecting the demand are explained in Annex 3. The results for the three demand scenarios are summarized in Table 3.6. Of note:

a) The annual rate of growth of energy demand at generation level is between 5.6 percent and 7.3 percent, reflecting the different assumptions regarding prices policies and loss reduction.

b) Peak demand would increase at a rate from 5.2 percent to 8.2 percent, reflecting the assumptions regarding loss reduction and the implementation of load management and energy efficiency programs.

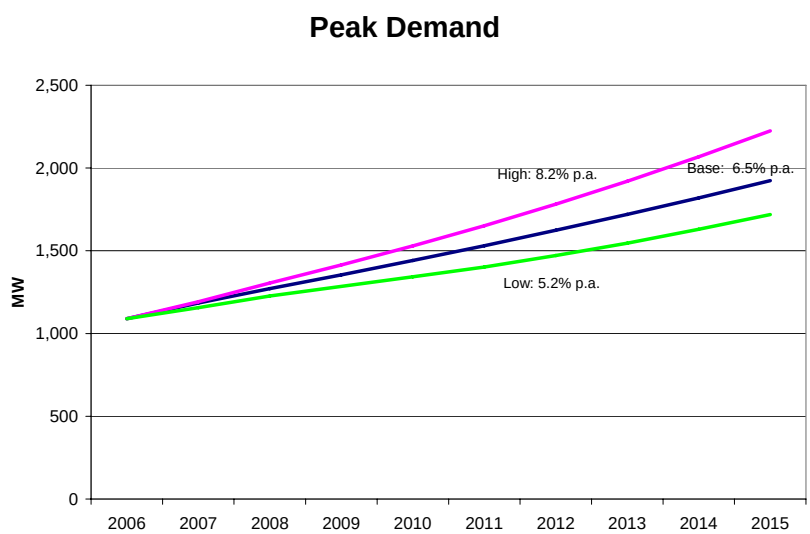
Table 3.6 - Peak Demand Projections: Three Scenarios

Electricity demand projections
2007-2015

	Scen.	Rate of growth	2,006	2,007	2,008	2,009	2,010	2,011	2,012	2,013	2,014	2,015
Generation needs (GWh)	High	7.3%	6,226	6,741	7,319	7,862	8,423	9,011	9,633	10,287	10,974	11,695
	Base	6.5%	6,226	6,731	7,229	7,706	8,200	8,710	9,237	9,785	10,355	10,945
	Low	5.6%	6,226	6,627	7,060	7,428	7,797	8,170	8,620	9,089	9,631	10,199
Peak Demand (MW)	High	8.2%	1,090	1,192	1,306	1,415	1,530	1,651	1,781	1,920	2,068	2,225
	Base	6.5%	1,090	1,184	1,271	1,355	1,442	1,531	1,624	1,720	1,820	1,923
	Low	5.2%	1,090	1,157	1,227	1,285	1,343	1,401	1,472	1,545	1,631	1,719

Figure 3.3 shows the peak demand projections for the three scenarios. The annual rate of growth of demand for 2007–15 fluctuates from 5.2 percent to 8.2 percent for the low and high case scenarios, with 6.5 percent for the base case. The difference in peak demand by 2015 between the low and the high case scenarios represent about 500 MW.

Figure 3.3



3.2.2 The generation capacity reserve during 2007–10

The existing installed generation capacity, complemented by the generation capacity currently under construction, does not provide an adequate firm reserve to meet expected demand for 2007–10. A simple indicator of the reliability problem is the shortfall in firm capacity to meet a 10 percent reserve.[3] Under all the demand scenarios, there is a deficit in 2007 (in the range of 30 MW to 69 MW) which would increase to 172 MW to 377 MW by 2010 ([see Table 3.7]). This

[3] A reserve of 10 percent of peak demand is a simple indicator that can be used to obtain a ballpark estimate of the required reserve in Honduras, and it exceeds the size of the largest unit (75 MW). However, ENEE determines the reserve requirements using the Stochastic Dual Dynamic Programming (SDDP) operation program, which takes into account the availability indexes for individual generation units and the impact of hydrology on firm power.

deficit already takes into account the small renewable projects under construction expected to be commissioned in this period (about 120 MW), some additions in thermal capacity available in the short term[4] (90 MW), and about 36 MW of old diesel engines that will be taken out of service.

The deficit in firm power for 2007–10 can be addressed only by leasing of skid-mounted diesel generation that can be deployed in the short term, imports from the regional energy market, or peak load shaving measures. Preliminary information indicates that firm power would not be available from the regional market for this period because most of the countries in the region have a tight supply/demand balance. Peak load shaving measures (time-of-the-day tariffs, use of efficient lighting fixtures, and so forth), and voluntary power rationing and load shedding could be implemented and make a contribution to reducing peak load, but do not replace the need to lease generation capacity in the short term.

The process of contracting and developing new generation with lower costs (medium speed diesel, hydro plants, coal-fired plants) will take more that four years and therefore would not contribute to reducing the capacity deficit in 2007–10. The renewable power that could be developed before 2011 taking advantage of existing incentives (short-term marginal energy cost plus 10 percent and fiscal incentives) is an attractive option to reduce the capacity deficit, provided that it contributes firm power.

Table 3.7

Peak demand balance 2007-2010
in April of each year

	2007	2008	2009	2010
Peak demand				
High	1,192	1,306	1,415	1,530
Base	1,180	1,267	1,351	1,437
Low	1,157	1,227	1,285	1,343
Firm capacity (existing or under construction)				
Hydro ENEE	419	418	419	418
Small renewable	81	105	114	114
Thermal PPA+ENEE	742	772	771	747
New thermal	0	26	26	26
Total	1,242	1,322	1,329	1,305
Peak demand deficit for 10% reserve				
High	69	114	227	377
Base	56	71	156	275
Low	30	27	85	172
Net capacity additions included in firm capacity				
Small renewable	42	18	0	60
Thermal	90	-19	0	-27

3.2.3 Generation expansion plans

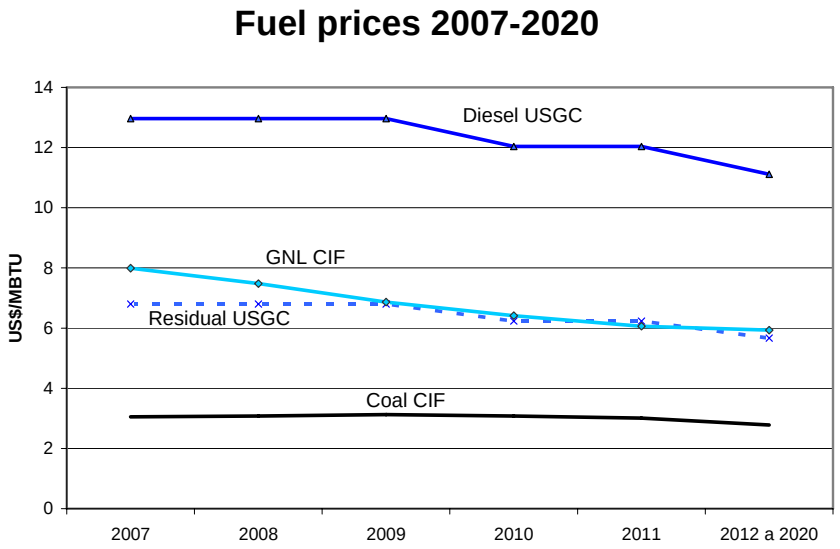
Since the late 1990s, the generation expansion in Honduras has been based mainly on medium speed diesel plants, characterized by relatively low capital costs, short construction periods, and

[4] Put back into service 60 MW of ENEE's diesel generators formerly under a rehabilitate-operate-maintain (ROM) contract and accept a proposal to increase by about 30 MW the capacity currently contracted with the Lufussa III and ENERSA, provided by improvements in the efficiency of these plants.

relatively high efficiency, a combination of factors that reduced project risks for the investors and provided low-cost generation until 2004, before the sharp increase in international oil prices.

The generation expansion plans assume that international oil prices will remain high for 2007–20, in the range of US$50/barrels (bbl) to US$60/bbl. Figure 3.4 compares the annual evolution of prices, expressed in US$/Million British Thermal Unit (MBTU). Prices of heavy fuel oil and liquefied natural gas (LNG) remain in the medium range of US$8/MBTU to US$6/MBTU. Diesel oil prices stay in a very high range (US$13/MBTU to US$11/MBTU) and coal prices in a low range (US$3/MBTU to US$2.5/MBTU).

Figure 3.4



ENEE's generation expansion plans consider a large portfolio of candidate generation projects: thermal generation (diesel generator, conventional steam, fluidized bed combustion plants, gas turbine, and combined cycle gas turbine [CCGT]), medium and large hydro projects with pre-feasibility and feasibility studies, and small renewable projects under development. An analysis of the levelized generation costs shows that the Patuca 2 hydroelectric project, coal-fired steam plants, and gas-fired CCGT are the most attractive projects for baseload operation (generation costs of about US$60/MWh) and could contribute to reducing the generation costs, and that most of the other medium and large hydro projects are competitive for peak load operation, with average costs of about US$90/MWh.

The expansion plan prepared by ENEE in late 2006[5] was revised to take into account the new demand projections, fuel prices, and earliest commissioning dates for the new generation projects considered as candidates. Based on the results for the three scenarios, we note that:

[5] This is an updated version of the expansion plan used by ENEE to calculate the marginal generation cost adopted in 2007, which assumed that coal-fired plants could be commissioned by 2011. The least-cost generation expansion plan is determined using the SUPEROLADE planning model and adjusted to meet reliability standards using the SDDP optimization model.

a) The most competitive projects (coal-fired and hydro) are introduced in the expansion plan at the earliest commissioning date.

b) The postponement of the earliest commissioning dates of coal-fired plants and new hydroelectric projects to 2013, forced the selection of a medium speed diesel project by 2011 (the best option among candidates that can be commissioned by that date) to meet the deficit in supply before 2013.

c) A substantial capacity in emergency generation is needed to meet the deficit before 2011 (between 160 MW and 340 MW).

d) The generation expansion plans select the same technologies for 2007–15, with differences in the capacity that is required (Table 3.8).

e) The investment costs for coal-fired thermal plants and CCGT using LNG are rough estimates that did not assess the required investments in port and fuel-handling facilities and in transmission works. Technical and economic feasibility studies of these alternatives should be prepared.

Table 3.8

Generation expansion plans 2007-2015
Capacity additions (MW)

	ENEE	Base	Low	High
Rentals	300	250	160	340
Expansion & renovation existing thermal	90	90	90	90
MSD	300	160	80	280
Hydros	570	570	570	570
Renewables	161	161	120	120
Coal	600	400	400	600
Retirements	-543	-373	-283	-463
Total	1,479	1,258	1,137	1,537

The following are some important conclusions and observations about the generation expansion plans:

a) Progress made in taking effective measures to reduce electricity losses and implement cost-covering tariffs and energy efficiency measures would have a substantial impact by reducing additional capacity requirements. This would also produce large financial benefits for ENEE by avoiding contracting expensive emergency generation during 2007–10. The difference between the electricity demand of the business-as-usual scenario and the low case scenario is such that about 180 MW of expensive generation could be saved.

b) The expansion plans do not consider the impact of regional energy trade on supply and demand in Honduras. In the short term (2007–10), preliminary information suggests that there is not a generation surplus in the neighboring countries to provide firm power to Honduras. In the longer term, after 2013, Honduras could benefit from economies of scale of large regional projects (thermal plants and some hydroelectric projects) that could be developed for the regional market. In any case, Honduras could continue taking

advantage of the regional market to optimize the operation of its generation plants with transactions in the spot market according to seasonal availability and prevailing spot prices.

c) Substantial capacity additions in large hydroelectric and thermoelectric projects (about 600 MW) will be necessary by 2013 to meet demand growth, replace costly emergency rental contracts, and reduce generation costs. Development of these projects by 2013 is a major challenge because critical activities are pending: seeking or confirming sponsors, preparing technical and economic feasibility studies and environmental impact studies, selecting a project developer, and ensuring financing. A public/private partnership would facilitate the development of these capital-intensive projects.

d) As happened during the 1990s, Honduras would have to rely on expensive emergency solutions to meet demand growth for 2007–10. In addition to demand management and energy-saving programs, it is very important to design adequate bidding procedures to reduce the cost of generation rentals, including multiyear contracts, and call for bids in advance to provide sufficient time for the preparation of proposals and deploying the generation equipment.

e) The expiration of the Elcosa and Lufussa I supply contracts in 2010 will increase the generation capacity deficit in 2011 and call for prompt decisions. These contracts could be replaced by new contracts with generation capacity that could be commissioned by 2011 (gas turbines or diesel generators) if the process of preparing tender documents and bidding is completed in 2007. The other option is to renegotiate new short-term contracts with Elcosa and Lufussa I with substantial reductions in the fixed and variable charges to make these plants competitive with new generation. The negotiation position could be strengthened if ENEE advances the energy procurement process and demonstrates that it has the option to contract energy supply from new generation by 2010–11.

Table 3.9

Generation expansion plans

Año	ENEE Base scenario			Base case scenario			Low case scenario			High case scenario		
	Generation Plant	Capacity		Generation Plant	Capacity		Generation Plant	Capacity		Generation Plant	Capacity	
		Added	Total		Added	Total		Added	Total		Added	Total
2007	Small renewable	42	42	Small renewable	42	42	Small renewable	42	42	Small renewable	42	42
	Thermal Alsthom, Sulzer, ENERSA, Lufussa III	90	132	Thermal Alsthom, Sulzer, ENERSA, Lufussa III	90	132	Thermal Alsthom, Sulzer, ENERSA, Lufussa III	90	132	Thermal Alsthom, Sulzer, ENERSA, Lufussa III	90	132
2008	Small renewable	18	150.4	Small renewable	18	150	Small renewable	18	150	Small renewable	18	150
	Rentals	70	220.4	Rentals	80	230	Rentals	40	190	Rentals	120	270
	Out NACO, Santa Fe	-19	201.9	Out NACO, Santa Fe	-19	212	Out NACO, Santa Fe	-19	172	Out NACO, Santa Fe	-19	252
2009	Rentals	80	281.9	Rentals	70	282	Rentals	40	212	Rentals	100	352
	Wind	60	341.9			282			212			352
2010	Rentals	120	461.9	Rentals	100	382	Rentals	80	292	Rentals	120	472
				Wind	60	442	Wind	60	352	Wind	60	532
	Out Lufussa I, Elcosa	-120	342.4									
	Out Ceiba	-27	315.8	Out Ceiba	-27	415	Out Ceiba	-27	325	Out Ceiba	-27	505
2011	Cangrejal	40	355.8	Cangrejal	40	455	Cangrejal	40	365	Cangrejal	40	545
	Rentals	30	385.8			455			365			545
	Platanares	41	426.8			455			365			545
	Patuca 3	100	526.8			455			365			545
	MSD	300	826.8	MSD	160	615	MSD	80	445	MSD	280	825
2012	Tornillitos	160	986.8			615			445			825
2013	Patuca 2	270	1256.8	Patuca 3	100	715	Patuca 3	100	545	Patuca 3	100	925
			1256.8	Tornillitos	160	875	Tornillitos	160	705	Tornillitos	160	1,085
	PFBC	400	1656.8	PFBC	300	1,175	PFBC	400	1,105	PFBC	600	1,685
	Out rentals	-300	1356.8	Out rentals	-250	925	Out rentals	-160	945	Out rentals	-340	1,345
2014			1356.8	Platanares	41	966			945			1,345
			1356.8	PFBC	100	1,066			945			1,345
	Out Alsthom y Sulzer	-60	1296.8	Out Alsthom y Sulzer	-60	1,006	Out Alsthom y Sulzer	-60	885	Out Alsthom y Sulzer	-60	1,285
2015				Patuca 2	270	1,276	Patuca 2	270	1,155	Patuca 2	270	1,555
	PFBC	200	1496.8									
	Out La Puerta	-18	1478.8	Out La Puerta	-18	1,258	Out La Puerta	-18	1,137	Out La Puerta	-18	1,537

4. INSTITUTIONAL ARRANGEMENTS AND THE REGIONAL POWER MARKET

4.1 INTRODUCTION

Until 1957,[6] when the *Empresa Nacional de Energía Eléctrica* (ENEE) was created as a vertically integrated state-owned company responsible for promoting the country's electrification, electric public service was provided by isolated power systems run by private companies in the north, and by municipalities and the government in other areas. During its first 25 years, ENEE expanded quickly, developing a national transmission grid and the first international interconnection with Nicaragua in 1976. In 1985, with the support of the International Finance Institutions (IFIs), it commissioned the 300-MW hydroelectric plant of El Cajón. This brought total installed capacity to 550 MW, in a year when peak demand reached only 220 MW.

The high demand growth envisioned years before had not materialized, and now the country was left with a large excess capacity and ENEE with an unsustainable debt burden. An aggressive rural electrification program was launched after El Cajón, but the domestic tariff was not adjusted to cover the cost of the debt service, causing ENEE's financial situation to worsen. Eventually, ENEE stopped paying its debt service, contributing to Honduras's 1989 debt default with the multilateral financial institutions. Afterward, devaluation eroded the dollar value of tariff revenues, which, combined with growing electricity losses (eventually reaching 28 percent), led to a financial crisis.

The motivation for the 1994 sector reform was a combination of factors: the financial crisis of the late 1980s, which was the origin of the 1993–94 energy crisis; the urgent need to mobilize private investment for power expansion; the lack of cost-covering tariffs; and the inefficiencies and poor performance of ENEE (high electricity losses, overstaffing, and neglected maintenance of thermal generation).

4.2 THE SECTOR REFORM OF 1994

The Electricity Law of 1994 defines an institutional structure and industrial organization for the electric power industry that contains the basic elements of the standard model used practically worldwide to promote the sustainable development of an efficient and sufficient power supply to meet expected demand. The model introduced competition wherever feasible; economic regulation of natural monopolies; separation of the roles of policymaking, regulation, and service provider; and private provision of electricity services.

The Electricity Law promotes competition in the wholesale power market by vertical unbundling of generation, transmission/dispatch and distribution, freedom of entry to all

[6] See Annex 4 for a historical background of the creation and evolution of ENEE.

sector activities, open access to transmission and distribution networks, and freedom of large consumers to choose their energy supplier and energy transactions in a wholesale market. The monopolistic segments, transmission, and distribution, were subject to price regulation based on economic costs.

Under the Electricity Law the policymaking function was assigned to an Energy Cabinet chaired by the country's President or to the Ministry of Natural Resources and Environment (*Secretaria de Recursos Naturales y Ambiente*, SERNA) as its Secretary and Coordinator. A new regulatory agency, the *Comisión Nacional de Energía* (CNE), was created.

The implementation of the new sector model established in the law was partial and had limited success in addressing the sector problems that motivated the reform. Crucially, distribution networks were not privatized as the law had mandated, leaving ENEE as a vertically integrated utility, sole distributor served from the transmission grid and in control of all generation facilities, either as owner or through the respective Power Purchase Agreements (PPAs). Indeed, in the absence of separate distributors, ENEE became the single buyer for the whole system and retained its dominant presence in the sector.

4.2.1 Achievements: New investments in thermal power generation

The reform solved the root cause of the 1994 energy crisis. Despite difficulties in the energy contracting processes, the de facto single-buyer model has been successful in attracting private investment to expand generation capacity, helped also by the incentives for the development of renewable sources. Since 1994, private developers have invested some US$600 million in about 800 MW of medium speed diesel and gas turbine capacity. In addition, they have invested some US$70 million in 110 MW of small hydro- and bagasse-fired capacity. Reliance on the private sector has thus become the norm for generation capacity expansion.

Since 1994, generation expansion has been predominantly thermal based. Hydropower plant capacity has gone from 90 percent to only 30 percent. This results from a combination of factors. First, once the IFI's soft financing of hydroelectric development disappeared, hydroelectric generation became substantially more expensive and thus much less competitive at the fuel prices prevailing at the time. Second, from the point of view of the private investors, the lower risks and shorter maturity of thermal generation projects favored expansion based on heavy fuel oil, medium speed diesels. Finally, in bidding for new capacity, ENEE has given interested bidders lead times of only 18 to 24 months, limiting the range of available technological choices.

As time has passed, the development of larger hydroelectric projects has also become more difficult because of a greater awareness about their environmental impacts and the now seemingly unavoidable opposition of rural populations organized and supported by international nongovernmental organizations, making their development a more complicated process for the Government.

4.2.2 Difficulties

Policymaking and regulation. The Energy Cabinet has met only a few times since its creation, less than once a year, chaired by the Minister of the Presidency. SERNA has not been proactive in its role as the Cabinet's Secretary and Coordinator to set the agenda and to supply the technical groundwork for decisions. The consequence of this void at the cabinet level is that ENEE becomes for the Government the default focal point for energy expertise, to which it turns even for matters that fall into the field of policymaking or regulation, thus contributing to a weak separation of roles.

SERNA's weakness is due in part to limited budgets, and in part to the weakness of the civil service system. There is a complete turnover of Ministry staff every four years, when a new government takes over, even when it is of the same political party. Governments should be able to count on a professional group at the Ministry, a group with an adequate budget and capable of isolating its staff from the periodic replacement after a new administration takes office.

The power sector planning process has not worked well. Although ENEE has prepared indicative generation expansion plans regularly, the formal presentation to and adoption of these plans by the Energy Cabinet has not taken place. More important, the procurement process to contract new generation capacity has experienced difficulties and delays, making it necessary to contract expensive emergency generation. Recently, the promotion and development of the Patuca 3 hydroelectric project, needed to meet demand growth and diversify energy sources, had substantial delays due to a lack of clear policies and procedures to mobilize private financing, again probably making it necessary to contract expensive emergency generation.

The regulator has had a marginal existence, which is consistent with the incomplete implementation of reform, the lack of awareness by governments of the scheme defined in the law, the continued dominance of state-owned ENEE and the politicization of its management, and the political sensitivity of tariffs. All of this undermines the credibility of a regulatory agency the responsibility of which is a transparent and objective application of the new rules and regulations and to implement cost-covering tariffs.

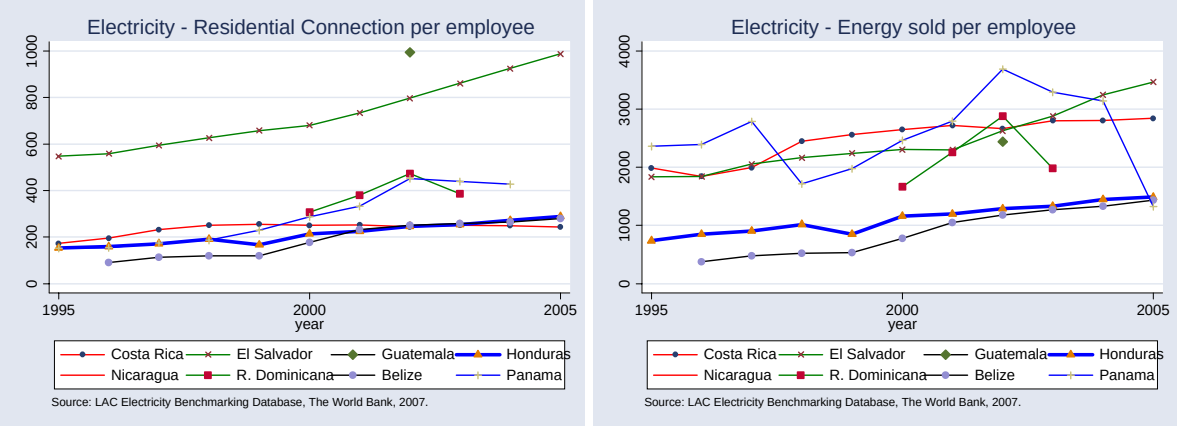
Poor performance of ENEE. After the 1994 reform, the announced restructuring and privatization of ENEE did not take place and its corporate governance and management did not improve. ENEE faces today a new financial crisis, caused in part by poor performance. ENEE's problems can be associated with a lack of commitment by the Government and the political parties to implement cost-covering tariffs and to restructure and improve ENEE's corporate governance. Ensuring sustainable, good-quality electric service requires healthy finances and professional management, including modern information systems.

In Honduras, article 264 of the Constitution states that "general managers of state-owned companies will last *up to four years* in their positions…." Every time a new government is sworn in, a new General Manager—not necessarily with previous knowledge of the sector—is appointed. The heads of ENEE's three Distribution Regions have also become

subjects of political appointment. The rotation at the top levels of management makes it difficult to maintain a long-term strategy.

In terms of employment, Figure 4, which compares the number of residential connections per employee and the energy sold per employee in Honduras with the other utilities in Central America, shows that ENEE appears to be overstaffed.

Figure 4.1



Under the Distribution Regional Managers are the key positions of *Jefes de Sistema*, or District Chiefs, the heads of ENEE's distribution in towns with 5,000 clients or more,[7] who supervise distribution *and commercial* operations in those centers and in a number of smaller towns around them. Despite the fact that since 1991 the Board of Directors issued a directive requiring these positions to be filled by engineers, they have been reserved for political activists, also replaced every three or four years.

From about 1998 to 2001, ENEE carried out a program to professionalize the District Chief positions. It took years to implement, because it had to be done against the resistance of political patrons, but it produced dramatic results, both in terms of commercial-loss reduction and quality-of-service improvements. However, as soon as the next government came in, the engineers were again replaced with political activists.

With the growth of private generation, the new companies have recruited many of ENEE's best professionals. Gradually, ENEE seems to have come to see the private sector and the market mechanisms introduced by the electricity law as a threat, particularly when payments to private generators have increased and tariffs have not.

ENEE's commercial management uses obsolete software, dating from the 1970s, which is all patched up. For perhaps as many as 50 percent of service accounts, ENEE does not know who its clients are. For most residential service accounts, the account is in the

[7] Such as Puerto Cortés, Tela, Trujillo, Progreso, Santa Barbara, Santa Rosa de Copán, Ocotepeque, Gracias, Siguatepeque, Comayagua, La Esperanza, Juticalpa, Catacamas, Choluteca, and others.

name of the first person ever to request service for the premises. Many are dead. The same happens even with large, well-known corporate clients. This means that in most cases ENEE cannot legally sue users for nonpayment, since there is no contract obliging the user.

Tariff regulation. Cost-covering tariffs and focalized subsidies, two principles established in the electricity law, have not been implemented. Rather, electricity prices have become more and more a political issue. ENEE does not apply the methods and procedures established in the law to set tariffs.

ENEE has not submitted to CNE a tariff proposal for busbar or retail tariffs in years, and the current tariff structure and level do not reflect the actual economic supply costs as established in the law.

Implementing a competitive market. The wholesale market design in the Electricity Law ignored the technical and economic limitations of a small power system, which could not meet one of the basic conditions to introduce effective competition: participation of a sufficient number of capable buyers and sellers are necessary to reduce potential problems of market power. The possible gains in lower energy prices due to competition would not compensate for the loss in economies of scale and scope of unbundling companies in a small market; the number of large industrial consumers willing to participate in the market was small, and regional energy trade was constrained by the limited transmission capacity of the regional interconnection. Some analysts argue that the de facto single-buyer model was more appropriate for Honduras and that fortunately the market model envisioned in the law was not fully implemented.[8]

Other basic conditions to ensure effective competition in the market were not met: open access to the transportation networks was hindered when ENEE remained a vertically integrated company; the method used to determine transmission charges is complex and discouraged energy transactions by large users; the methods applied to regulate wholesale prices for distributors, in the busbar tariff, discouraged generation expansion; and the lack of a transparent spot market hindered needed short-term transactions.

Large consumers. The potential market for large industrial consumers (>1 MW) is today, in principle, relatively important: 76 consumers with a non-coincident peak demand of 255 MW (see Table 4.1). However, this market has not developed. There are various reasons that explain this situation:

a) The method to determine the wheeling price, issued by CNE in 2000, charges variable and fixed costs to each transaction, and costs increase with distance. There have been negotiations in several cases, but interested parties have complained that wheeling charges quoted to them by ENEE are excessive.

[8] Ian Walker and Juan Benavides, "Sustainability of Power Sector Reform in Latin America: The Reform in Honduras," IDB, 2002; Jaime Millán, "Entre el Mercado y el estado: tres décadas de reformas en el sector eléctrico de América Latina," IDB, 2006.

b) ENEE, in its position as a vertically integrated monopoly, is not interested in promoting the development of the market of large consumers and risking that local and regional generators try to cream-skim its consumer base.

c) The gradual erosion of ENEE's tariffs for industrial clients removes the incentive to look for alternative suppliers.

Table 4.1

Large consumers

Peak demand (kW)		Number of consumers	Pead demand (non-coincident)
Min	Max		MW
100	200	290	41
200	500	180	53
500	1000	30	23
1000		76	255

Souce: CNE estimations based on billing database. Includes commercial and industrial consumers

Regulation of generation prices. In the pricing scheme introduced by the Electricity Law, the short-term marginal cost is primarily an economic signal for generators, to encourage supply. As a component of the busbar tariff—to be proposed every year *by the generators* to the Regulator—it is the price at which the generators are willing to guarantee supply to distributors. For that reason, it is also the generation cost passed through to final consumers in the tariffs.

The Electricity Law defines the short-run marginal cost as the economic cost of supplying an additional kilowatt and kilowatt-hour over five years. The definition refers to the cost of supplying additional power, or capacity (a kilowatt), and to the cost of supplying additional energy (a kilowatt-hour). However, the current practice is that every year ENEE calculates the short-term marginal cost of energy.

The calculation of a busbar tariff that excludes the marginal costs of capacity and is calculated annually based on a five-year average of future marginal energy costs is effective to ensure price stability, but discourages the development of a contract market between generators and distributors. The theory and the practice show that an efficient generator selling energy at the marginal energy costs may not cover all its investment costs, and that the calculation of future marginal costs is very sensitive to many parameters and assumptions that can be manipulated.[9]

It is therefore not surprising that private generators prefer to sell energy to ENEE under long-term contracts at prices determined by competitive bidding procedures, which include fixed charges and energy charges indexed to fuel prices and variations in the

[9] In Chile and Peru the regulations include a capacity charge and establish that the marginal energy cost should be in line with the price of energy in the market of large consumers, which is competitive.

Consumer Price Index (CPI), or that small renewable-based generators prefer a fixed price of energy for the duration of the contract, eliminating the risk of future reductions in the marginal cost.

The spot market.[10] The Electricity Law allowed spot transactions between generators and ENEE but did not establish a formal spot market based on hourly energy prices. There are only two generators regularly selling to ENEE at the system's short-run marginal cost, *Elásticos Centroamericanos y Textiles, S. A.* (ELCATEX), an industrial self-generator selling between 3 MW and 5 MW excess capacity, and EMCE, one of the private producers, using 5 MW of extra capacity not included in its PPA with ENEE. The sales by generators having PPAs with ENEE, which make offers "on the side" to ensure they get dispatched, could be classified under the same category.

ENEE's dispatch does not determine the system's hourly marginal cost. Although ENEE uses a well-known software tool for medium-term operations planning, the Stochastic Dual Dynamic Programming (SDDP), it has never enabled the program's short-term module, which the dispatch center should be using for day-to-day dispatch and which would allow it to determine the hourly short-term marginal cost. The calculation of the hourly marginal cost would facilitate the implementation of a spot or balance market, required to accommodate flexible energy contracts[11] and increase the efficiency of energy transactions.

The regional energy market.[10] In the late 1990s, the Central American countries of Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua, and Panama decided to increase the bilateral electricity connections among them through the construction of an 1,800km 230kV transmission line. The project would increase the interconnection capacity for commercial transactions of electricity among the six countries from the present 50MW to about 300 MW initially and to 600 MW later on (Figure 4.2).[12] In parallel, two regional institutions, the *Comisión Regional de Interconexión Eléctrica* (CRIE) and the *Ente Operador Regional* (EOR), were created for the regulation and the system operator, respectively, of the regional transactions on the market. The development of more open and competitive market mechanisms, along with the enhanced transmission line for the power interchange, would provide incentives for the development of new generation projects to serve the regional market.

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[10] See Annex 4 for details about the national and regional wholesale power markets.

[11] The existing PPAs are physical contracts that impose constraints on the operation of the power system and the power market. For example, generators refuse to provide ancillary services because the PPAs do not include a specific remuneration for the provision of these services. The PPAs do not require settling the deviations between the contracted energy and energy dispatched by merit order. This is good because they do not constrain economic dispatch, but bad because they cannot handle flexible and efficient financial contracts that settle the differences at marginal costs.

[12] All *Sistema de Interconexión Eléctrica para América Central* (SIEPAC) lines will be built for double circuit, but will be equipped with only one circuit initially.

Figure 4.2

Commercial arrangements among countries are in the form of contracts and spot-market transactions. As shown in Table 4.2, in 2005 most interchanges were made under contracts between countries, and in particular from Guatemala.

Table 4.2 - Electricity Traded in 2007 in Central America (GWh)

	Overall Total		**Net Balance**		**By Contract**		**Spot Market**	
	Inj.	Withdr.	Inj.	Withdr.	Inj.	Withdr.	Inj.	Withdr.
Total	530.05	530.05	357.94	357.94	436.64	417.38	93.41	112.67
Costa Rica	69.76	80.33		10.57	69.19	64.57	0.57	15.76
El Salvador	22.2	300.22		278.02	15.85	264.74	6.35	35.48
Guatemala	322.78	14.77	308.01		283.98	1.03	38.8	13.74
Honduras	2.81	58.26		55.45	0.21	38.94	2.6	19.32
Nicaragua	8.35	22.24		13.9		2.53	8.35	19.71
Panama	104.15	54.22	49.93		67.42	45.57	36.73	8.65

Source: UNDP–CEPAL–*Istmo CentroAmericano Estadisticas del Subsector Electrico* 2005.

5. PRICING POLICIES

5.1 ELECTRICITY PRICE SETTING

Honduras's electricity tariff system is established in the Electricity Law, which in this respect follows the Peruvian Law on Electrical Concessions of 1992. The scheme presented in Box 5.1 corresponds to the industry structure the law envisioned, with multiple generators and multiple private distributors.

Box 5.1. Electricity Tariff Principles and Tariff Setting under the Electricity Law

Distributors were to buy power and energy at a regulated price, designated as the "Busbar Tariff," reflecting generation and transmission costs. This tariff would be calculated every year by the generators and approved by the regulator together with indexation formulas permitting its modification during the year whenever costs changed by more than 5 percent due to variations in fuel prices and the exchange rate. The tariff, and its eventual modifications in case of adjustments, had to be published in the official *Gazette* to become effective.

The distributors would submit every five years retail tariffs and their indexation formulas for approval by the regulator. (The retail tariffs can be recalculated before the end of the five-year period if the adjustment indicated by the indexation formulas exceeds the original tariff value.) These retail tariffs would reflect the cost of power and energy purchased in bulk at the Busbar Tariff plus a "Distribution Value Added" based on the costs of a "Model, efficient, distribution company." Retail tariffs were to be adjusted when costs varied by more than 5 percent due to changes in the Busbar Tariff and the exchange rate.

In calculating the distribution value added, distribution costs are averaged over different types of zones, which implies a subsidy from urban to rural areas. In addition, the law permits, but does not mandate, an explicit cross-subsidy in favor of the "Small Residential Consumers," defined as those using less than 300 kWh per month, and establishes caps on this subsidy. Today, an additional direct government subsidy is provided to small residential consumers, equivalent on average to US$1.90 per client per month, which is deducted by ENEE from the electricity bill, and reimbursed by the Government to ENEE.

The *Empresa Nacional de Energía Eléctrica* ENEE), which has remained vertically integrated, has never applied the official tariff-calculation or tariff-adjustment methods, nor has it observed the indicated frequency of tariff calculations.[13]

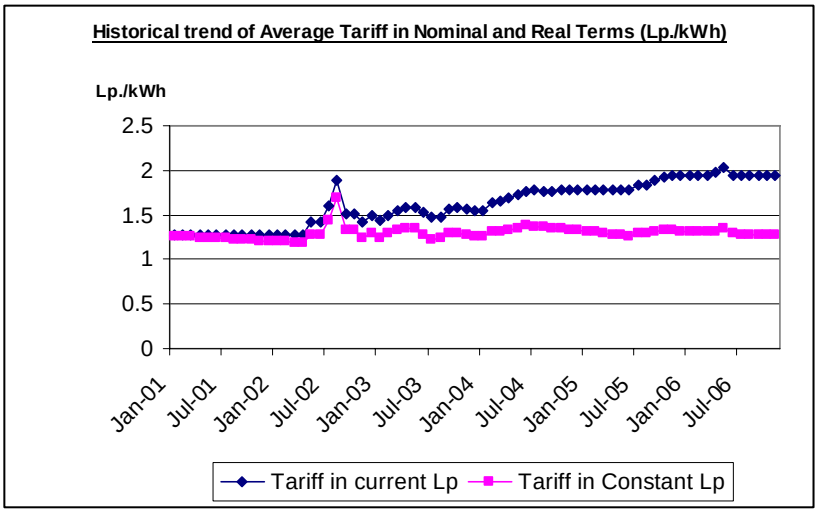
[13] ENEE submitted a tariff proposal at the end of 2001, and new tariffs were published in May 2002, but their application was suspended a few days later following a temporary freeze on public service tariffs agreed by the Government with workers and employers associations. The freeze ended in July 2003, but ENEE has yet to submit a new tariff proposal.

5.2 NEED TO UPDATE TARIFFS

ENEE's current tariffs, published by the *Comisión Nacional de Energía* (CNE) in the official *Gazette* in February 2000, no longer reflect the economic costs of supply. First, the study was based on cost projections covering 2000–04. Since 1999, installed capacity has more than doubled and ENEE's cost structure has changed. The indexation formulas are no longer appropriate. The accumulated adjustment according to the formulas is today more than 100 percent of the original tariff.

Figure 5.1 shows the evolution of ENEE's average price (tariff plus adjustment) in both nominal and real terms. The average price expressed in current lempiras increased by 52 percent between 2001 and 2006. When expressed in constant lempiras of 2005, however, it has remained practically constant.

Figure 5.1



5.3 COMPARISON WITH ECONOMIC COSTS

Table 5.1 shows a comparison for all consumer categories of: (a) economic cost of supply (which recognizes a level of 15 percent losses), (b) ENEE's tariffs, and (c) final prices paid by consumers after deducting the direct subsidy. The economic cost of supply was estimated by CNE applying the methods prescribed by the Electricity Law and using data obtained from ENEE and other sources, as explained in Annex 5.

The table shows that, overall, ENEE's prices cover only 81 percent of the economic cost of supply and a distortion of the tariff structure, with residential prices substantially below economic cost. The average tariff for the residential category is 60 percent of the economic cost of supply, and only 54 percent after deducting the Government's direct subsidy. The tariff for households consuming less than 100 kWh per month is equivalent to 22 percent of cost, and for those consuming between 0 and 300 kWh—84 percent of all residential clients—39 percent of cost. Even clients consuming more than 500 kWh per month pay only 82 percent of the cost of supply. Tariffs for municipalities are

equivalent to about 77 percent of cost. For the other consumer categories, tariffs are at about the same level of cost, thus leaving ENEE with a deficit.

Table 5.1

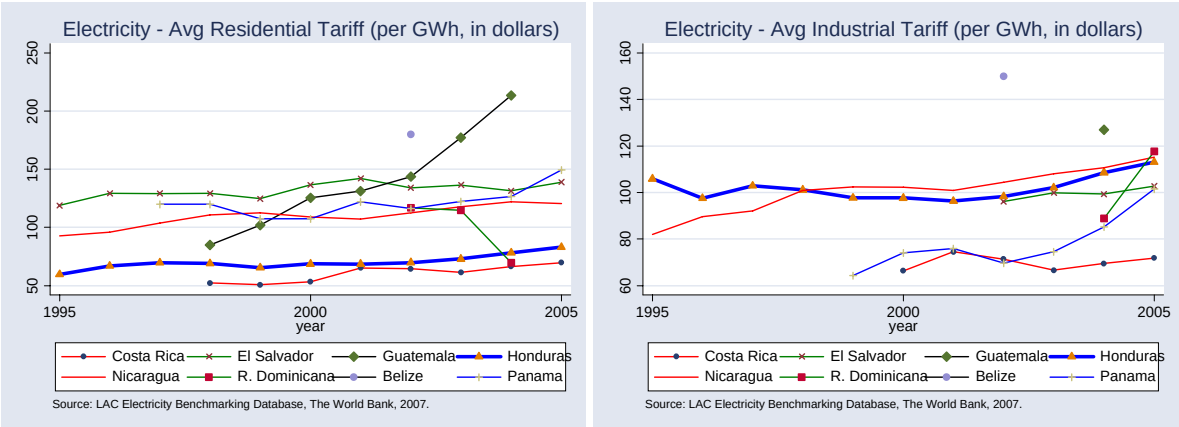
Comparison of Unit Costs, Tariffs (with Cross Subsidy) and Final Prices (after Direct Subsidy)

Customer Class and Consumption Block	Average Economic Cost $/kWh	Average Tariff		Consumption			Direct Subsidy		Price after Direct Subsidy	%
		$/kWh	% of Cost	Nbr of Clients	Σ Dmax MW	Energy MWh	US$	$/kWh		
A- Residential										
0-20 kWh/month	0.4043	0.0917	22.7%	86,498		634	15,159	0.0239	0.0678	
21-50	0.1878	0.0481	25.6%	87,840		3,114	47,978	0.0154	0.0327	
51-100	0.1578	0.0572	36.3%	132,804		10,062	177,397	0.0176	0.0396	
101-130	0.1474	0.0664	45.1%	77,017		9,643	185,838	0.0193	0.0472	
131-150	0.1474	0.0664	45.1%	51,344		6,429	123,892	0.0193	0.0472	
151-300	0.1408	0.0783	55.6%	242,723		51,906	658,408	0.0127	0.0656	
301-500	0.1367	0.0887	64.8%	83,368		31,292	0		0.0887	
> 500	0.1336	0.1091	81.7%	43,747		39,419	0		0.1091	
Total Residential	0.1420	0.0852	60.0%	805,341		152,499	1,208,672	0.0079	0.0773	
B- Commercial										
Single phase	0.1318	0.1328	100.8%	53,950		36,851			0.1328	
Three phase	0.1291	0.1328	102.9%	5,795		58,171			0.1328	
Total Commercial	0.1302	0.1328	102.0%	59,745		95,021			0.1328	
Industrial Medium Voltage	0.1070	0.1052	98.3%	134	114.13	44,919			0.1052	
Industrial High Voltage	0.0985	0.0933	94.7%	18	121.52	51,443			0.0933	
Public Sector	0.1254	0.1362	108.6%	5,041		12,940			0.1362	
Municipal										
Single phase	0.1267	0.0973	76.8%	625		598			0.0973	
Three phase	0.1256	0.0973	77.5%	728		1,542			0.0973	
Total Municipal	0.1259	0.0973	77.3%	1,353		2,140			0.0973	
Total ENEE	**0.1275**	**0.1034**	**81.1%**	**871,632**		**358,963**	**1,208,672**	**0.0034**	**0.1000**	

5.4 COMPARISON WITH CENTRAL AMERICA'S TARIFFS

Figure 5.2 presents a comparison of ENEE's average electricity tariffs for industrial and residential consumers in Central America. The figure shows that residential tariffs are among the lowest in the region while industrial tariffs are among the highest.

Figure 5.2 - Electricity—Average Residential Tariff (per GWh, in dollars); Electricity—Average Industrial Tariff (per GWh, in dollars)



5.5 SUBSIDIES

The explicit cross-subsidy incorporated in the current tariff structure goes beyond the caps set by the Electricity Law. Most residential consumers have been subsidized since the tariffs were published in February 2000. To compensate this, the surcharges to other consumer categories exceeded the limits established in the law. As the cost of service has increased and the tariffs have not been adjusted correspondingly, the subsidy to residential consumers has further escalated, while the surcharges to other consumers have been eroded.

Neither the cross-subsidy nor the direct government subsidy is efficiently targeted. Table 5.2 shows the distribution of both subsidies for July 2006 and the percentage of each that benefits the poor, based on the assumption that electricity use of 130 kWh per month is, on average, the dividing line between poor and non-poor.[14] The table shows the targeting indicator, Ω, defined as the percentage of the total subsidy amount received by the poor divided by the percentage of the population that is poor—62 percent in the case of Honduras. A value of $\Omega = 1.0$ would indicate a neutral distribution. An Ω of less than 1.0 reflects a regressive distribution, with proportionately more subsidies benefiting non-poor households.

[14] This dividing line has been estimated based on surveys by Honduras's *Instituto Nacional de Estadística* (INE) and ENEE's commercial database.

Table 5.2 - Distribution of Subsidies, July 2006

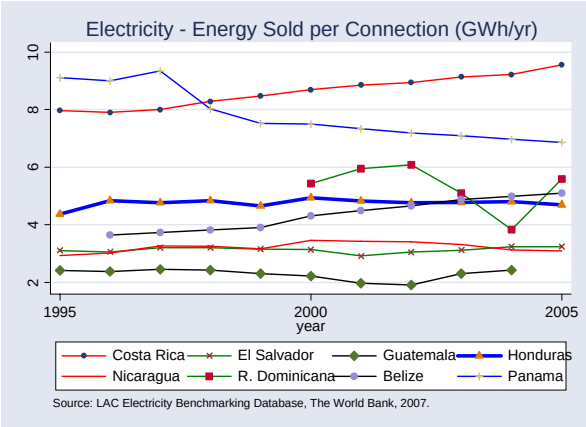
Block kWh/month	Number of Users	Cross-subsidy		Direct Subsidy		Total Subsidy	
		US$	Percentage to Poor and Ω	US$	Percentage to Poor and Ω	US$	Percentage to Poor and Ω
0–20	86,498	200,463	28.102%	15,159	35.3%	215,622	29.0%
21–50	87,840	439,562		47,978		487,540	
51–100	132,804	1,018,727	Ω = 0.453	177,397	Ω = 0.569	1,196,124	Ω = 0.467
101–130	77,017	784,694		185,838		970,532	
131–150	51,344	523,126		123,892		647,018	
151–300	242,723	3,253,443		658,408		3,911,851	
301– 500	83,368	1,508,603				1,508,603	
> 500	43,747	966,229				966,229	
Totals	**805,341**	**8,694,847**		**1,208,672**		**9,903,519**	

Table 5.2 shows that cross-subsidies and direct subsidies are very regressive. The cross-subsidy incorporated in the tariff is the difference between the cost of service valued at the economic cost and the bill based on the current retail tariff. Its total monthly value is US$8.7 million. In terms of direct subsidies[15] provided by the Government, 35 percent benefit poor households.

The low tariffs and the direct government subsidy are promoting excess consumption. Average residential use in Honduras is about 200 kWh per month, almost double the average residential use in El Salvador and Guatemala (see Figure 5.3), despite the fact that per capita income in those countries is more than double what it is in Honduras. The low electricity prices also promote inefficient interfuel substitution, particularly for cooking and water heating, because electricity, although a more inefficient and economically expensive option, is cheaper for the consumer than, say, liquefied petroleum gas (LPG).

[15] The Government's direct subsidy targets all residential users consuming less than 300 kWh per month. The total amount of this subsidy has been capped at Lp275 million per year, equivalent to about $1.2 million per month. The monthly subsidy amount per consumer increases with increasing levels of consumption, up to a certain point, and then it remains flat according to a method proposed by ENEE and approved by the Energy Cabinet. Today, the subsidy remains flat above 135 kWh per month. As the level of consumption to be subsidized has increased over time due to the growing number of consumers, ENEE, to respect the global cap, has gradually reduced both the consumption beyond which the per capita amount remains flat and the maximum per capita amount.

Figure 5.3



5.6 NORMALIZING ENEE'S TARIFFS

In order to determine what ENEE's tariffs should be, a simulation has been carried out by CNE to calculate a reference tariff schedule applying the methods indicated in the Electricity Law and using updated costs. The reference tariff schedule incorporates a cross-subsidy going from non-residential users and from residential users with consumption larger than 300 kWh/month to residential users with consumption lower than 300 kWh/month, with larger subsidies provided to those with a consumption of up to 50 kWh/month. As a result of the simulation, the average residential tariff is about 5.7 percent below the average cost of supply. To finance this gap, other consumer categories have to pay a surcharge of 5.1 percent above their cost of supply. Table 5.3 shows the comparison between the current and reference tariff schedule for residential consumers.

Table 5.3 - Comparison between Current and Proposed Tariff Adjustment

Block kWh/mo	Average Cost $/kWh	Current Tariff		New Tariff		Tariff Increase	Number of Users
		Average $/kWh	% of Cost	Average $/kWh	% of Cost		
0–50	0.224	0.056	24.7%	0.112	50.0%	102.2%	174,338
51–100	0.158	0.057	36.3%	0.106	67.0%	84.7%	132,804
101–150	0.147	0.066	45.1%	0.126	85.4%	89.4%	128,361
151–300	0.141	0.078	55.6%	0.134	94.9%	70.6%	242,723
301–500	0.137	0.089	64.8%	0.139	101.9%	57.2%	83,368
501–	0.134	0.109	81.7%	0.143	106.7%	30.7%	43,747
							805,341

To reduce the tariff impact on the smaller consumers, it is necessary to reallocate the Government's direct subsidy to residential users. Table 5.4 presents a comparison of the final price residential users currently pay, after deducting the direct subsidy, with the final price that would result from applying the reference tariff schedule and deducting a direct subsidy reallocated to target mostly the smaller consumers.

Table 5.4 - Option 1: Current and Proposed Final Price

Block kWh/mo.	Avg. Cost	Current Final Price (after direct subsidy)		New Final Price (after new direct subsidy)		Increase	Number of Users
		Avg $/kWh	% of Cost	Avg $/kWh	% of Cost		
0–50	0.224	0.039	17.2%	0.056	24.8%	44.1%	174,338
51–100	0.158	0.040	25.1%	0.063	39.7%	58.0%	132,804
101–150	0.147	0.047	32.0%	0.091	61.6%	92.5%	128,361
151–300	0.141	0.066	46.6%	0.134	94.9%	103.5%	242,723
301–500	0.137	0.089	64.8%	0.139	101.9%	57.2%	83,368
501–	0.134	0.109	81.7%	0.143	106.7%	30.7%	43,747
							805,341

The tariff structure outlined in Table 5.4 and the direct subsidies, could be further adjusted to maintain about the same final price to residential users with a consumption of up to 150 kWh/month. To do so, it would be necessary to modify the reference tariff schedule in order to reduce, on the one hand, the price for these users, and to increase, on the other, the surcharge on non-residential users, which would become 11 percent of their supply cost. Table 5.5 shows the comparison of final price for residential consumers, with the new tariff and a new reallocation of the direct subsidy after these changes.

Table 5.5 - Option 2: Current and Proposed Final Price

Block kWh/month	Avg Cost $/kWh	Current Final Price		New Final Price		Increase	Number of Users
		Avg $/kWh	% of Cost	Average $/kWh	% of Cost		
0–50	0.224	0.039	17.2%	0.039	17.4%	1.1%	174,338
51–100	0.158	0.040	25.1%	0.041	25.7%	2.3%	132,804
101–150	0.147	0.047	32.0%	0.048	32.6%	1.9%	128,361
151–300	0.141	0.066	46.6%	0.125	89.0%	91.0%	242,723
301–500	0.137	0.089	64.8%	0.139	101.7%	56.9%	83,368
501–	0.134	0.109	81.7%	0.143	106.6%	30.6%	43,747
							805,341

The new tariff will recover the economic cost of service, generating US$8.9 million per month in additional revenue for ENEE. Tariff increases for industrial customers, which today are paying slightly below their cost of service, will be 13 percent for medium-voltage consumers and 17

percent for high-voltage consumers. A comparison of the resulting medium voltage tariff[16] with those prevailing in other Central American countries shows that the impact would not be very large (Table 5.6).

Table 5.6 - Medium Voltage Tariffs in Central America

	Industrial Medium Voltage	
	$/kW-month	$/kWh
Honduras (current)	10.86	0.078
Honduras (under Option 2)	9.41	0.095
Guatemala	9.16	0.062
El Salvador	8.68	0.079
Nicaragua	12.03	0.104
Costa Rica	9.97	0.034
Panama	9.45	0.110

[16] High voltage tariffs were not available for a similar comparison, because in the rest of Central America most large industries procure their energy in the electricity market. Given the relationship between medium voltage and high voltage costs, however, it is estimated that the situation would be similar to the one for the medium voltage tariffs.

6. ACCESS TO ELECTRICITY

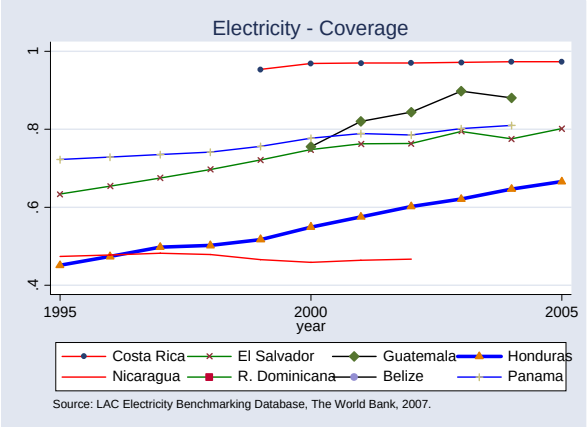
6.1 INTRODUCTION

In the field of electrification, the 1994 Electricity Law set forth the creation of the Social Fund for Electricity Development (*Fondo Social de Desarrollo Eléctrico*, FOSODE) designed to support electrification in both rural and marginal urban areas. FOSODE was to be administrated by the *Empresa Nacional de Energía Eléctrica*, ENEE), through the Social Electrification Office created for that purpose.

The early outcome of social electrification supported by the law was positive in terms of coverage, increasing access at a rate of approximately 2 percent per year, and extending national coverage from 43 percent in 1994 to 69 percent in 2006.[17] In addition, FOSODE has played a key role in connecting isolated and underprivileged communities, extending electricity service to 2,381 rural communities in its first 10 years of operation.[18]

However, in spite of the electrification efforts undertaken in the last 10 years, the overall rate of access to electricity service in Honduras continues to be among the lowest in Latin America and the second lowest in Central America after Nicaragua (see Figure 6.1).

Figure 6.1.



In rural areas, the coverage rate is particularly low compared with the average coverage reported in urban areas (45 percent compared to 94 percent in 2006). There are also extreme cases of unequal access based on both region and income groups. For example, the Department of Cortes reports 98.8 percent average coverage, while the Department of Lempira reaches only 24.6 percent; the poorest quintile of the population is at 30 percent, while the wealthiest quintile

[17] As of December 2006.

[18] As of February 2007; information provided by ENEE *Oficina de Planificación*.

enjoys almost universal coverage.[19] In terms of accelerating electricity access to the most underprivileged population, the area of highest concern is the lack of an adequate institutional framework for implementing rural electrification programs. Although the 1994 law mandated the creation of FOSODE, a structural plan for social electrification, called *Plan Nacional de Electrificación Social*, was not designed until 2002.

This chapter provides a critical description of the core aspects and results of electrification programs in Honduras and the future challenges to meet the government electrification targets.

6.2 THE INSTITUTIONAL FRAMEWORK

ENEE is responsible for social electrification in rural and poor urban areas and, to that end, it manages FOSODE. The Fund was created by the 1994 Framework Law (Section 62, subsequently amended by Decree 89-98, dated October 1998).

The Framework Law mandates that FOSODE be capitalized with at least Lps.15 million on an annual basis by the Federal Government and ENEE. FOSODE is specifically funded by ENEE contributions equivalent to 1 percent of its annual revenues from energy sales (or not less than Lps.15 million). In addition, the Fund gets financing from the fees municipalities impose on electricity companies in their jurisdiction as long as electrification takes place within the particular municipalities. Finally, the Fund also has access to external financing through concession loans and donations.

ENEE created the Social Electrification Office (*Oficina de Electrificación Social*, OES), for planning, managing, and executing social electrification projects in rural and urban areas. At present, OES comprises three major areas: customer service, technical design, and planning.

Although OES has been performing its designated function as part of ENEE, it will not become the agency that directs all the players involved in social electrification. The extremely low level of rural electrification coverage warrants turning social electrification into a state-run policy, led and coordinated at the ministerial level, rather than from a division or office that falls under the state-run energy utility. Therefore, there should be a review of the Long-Term Sector Approach and the Strategic Plan for the Social Electrification Sector prepared by OES, which not only calls for updating the legislation associated with social electrification, but also promotes elevating the sector policy to a higher government echelon.

6.3 EXISTING SOCIAL ELECTRIFICATION POLICIES AND REGULATIONS

Since the establishment of FOSODE, electrification demand from isolated communities has grown considerably. During the Fund's over 10 years of operation, the response to such demand was the funding of rural electrification projects with government funds and other internal and external sources of funding that reached approximately US$10 million per year. Between 1995 and 2006, these efforts enabled the electrification of 2,381 rural communities in Honduras.

Nevertheless, in order to achieve realistic short- and medium-term goals, while relying on an

[19] The worst case in terms of electricity coverage is the Department of Gracias a Dios, reaching just 12.36 percent.

orderly electrification plan that enables the prioritization of projects according to need, OES-FOSODE and ENEE authorities decided to prepare the National Social Electrification Plan (*Plan Nacional de Electrificación Social*, PLANES) in 2002.

OES has led the development of a long-term electrification plan (2005–15), which is aligned with the guidelines set out by the Poverty Reduction Strategy (*Estrategia para la Reducción de la Pobreza*) and which is aimed at coordinating actions and resources with public, private, and international institutions. With the support of the Canadian government (the Canadian International Development Agency, ACDI), and through the *Proyecto de Energía Eléctrica de Istmo Centroamericano* (PREEICA), ENEE prepared PLANES for rural areas. PLANES is made up of two components: (a) a long-term electrification plan (through 2012), and (b) a short-term electrification plan (2003–05).

The methodological process used to prepare PLANES included three main stages applied to a total set of projects exclusively focused on grid extension programs.

The first stage is the short-listing of projects, based on financial sustainability criteria for rejecting projects whose annual tariff revenues are not sufficient to meet at least their recurring costs (that is, the cost of energy purchased by the distributor plus operation and maintenance costs, and commercial costs). The second stage is the arrangement and prioritization of projects, aimed at maximizing the impact of funds allocated to electrification, giving priority to the lower-cost projects. The third and last stage entails the arrangement of projects according to government priorities in order to identify those with a higher impact on poverty reduction.

Based on the 2002 PLANES program, a preliminary definition of investments and programs that would enable meeting the targets set out in the Poverty Reduction Strategy has been completed, and some of these programs are already being implemented.

6.4 CURRENT COVERAGE OF ELECTRICITY SERVICE

The overall rate of access to electricity service reached 69 percent by the end of 2006. According to the last census and subsequent projections, the total population of Honduras's 18 departments, including rural and urban areas, is roughly 7.36 million. Therefore, if the electrification index is applied, approximately 5.09 million inhabitants have access to electricity service and over 2.2 million lack service.

Table 6.1 - Urban and Rural Access to Electricity, 2006

	Population	%	No. of Households	%	No. of Customers	%	Access Rate %
Urban	3.350.081	45,5%	700.507	49,0%	661.582	66,9%	94,4%
Rural	4.016.940	54,5%	729.611	51,0%	327.114	33,1%	44,8%
Total	**7.367.021**	**100,0%**	**1.430.118**	**100,0%**	**988.696**	**100,0%**	**69,1%**

Source: ENEE, Subdirección de Planificación

Taking into account the government's Household Survey, including illegal users (excluded from the coverage ratio calculated by ENEE), total coverage is roughly 75 to 80 percent.

As shown in Table 6.1, it is estimated that more than half the population of Honduras live in rural areas (54.5 percent), where electricity coverage reached only 44.8 percent in 2006. By contrast, there are about 3.35 million inhabitants living in urban areas, of which 94.4 percent have access to electricity.

There are approximately 420,000 unelectrified households in rural areas, totaling 2.2 million people without access to electricity. Meanwhile, in urban areas, just 128,000 people lack service. Moreover, there are significant differences in coverage among departments and, in particular, among the rural areas of the 18 departments. There are extreme cases of unequal access both among regions and among income groups. While the Department of Cortes, for example, has an average coverage of 98.8 percent and over 15,000 unelectrified rural inhabitants, coverage in the Department of Gracias a Dios reaches only 12.4 percent. Moreover, the Departments of Choluteca, Lempira, and Olancho all have over 200,000 unelectrified rural inhabitants (see Annex 6 for details).

There are 298 municipalities in Honduras, 167 of which have fewer than 10,000 inhabitants. Several of these communities have chosen to partner together and form *mancomunidades* with independent legal status, in order to conduct local development and environmental protection progams. Approximately 50 such *mancomunidades* exist in the country, many of which barely have access to electricity service. As shown in Table 6.2, there are 23 municipalities (7.7 percent) that have no access at all and, in 119 municipalities (39.9 percent), coverage is under 30 percent.

Table 6.2 - Access by Municipalities

% of Access	No. of Municipalities	%	Cumulative
90%-100%	41	13,8%	100,0%
80%-90%	11	3,7%	86,2%
70%-80%	13	4,4%	82,6%
60%-70%	19	6,4%	78,2%
50%-60%	30	10,1%	71,8%
40%-50%	27	9,1%	61,7%
30%-40%	38	12,8%	52,7%
20%-30%	41	13,8%	39,9%
10%-20%	33	11,1%	26,2%
Up to 10%	22	7,4%	15,1%
No access (0%)	23	7,7%	7,7%
Total Municipalities	**298**	**100,0%**	

Source: ENEE

6.5 LEVEL OF INVESTMENT AND SOURCES OF FUNDING

In the field of social electrification, the major investments have been made by FOSODE, which has demonstrated ample capacity to raise funds through development resources and from external financing, in addition to the budgetary resources that the Government provides every year as required by law. As shown in Annex 6, Table A6-2, between 1995 and 2006, FOSODE invested US$91.4 million in rural electrification, raising coverage from 45 percent in 1995 to 69.1 percent in 2006, at the relatively low connection cost of US$300 to US$400 per household.

Electrification projects have been carried out with resources from financial organizations such as the Central American Bank for Economic Integration (*Banco Centroamericano de Integración Económica*), and with cooperation from countries like Finland, Japan, Korea, and Norway. In addition, there is an agreement in place with the *Fondo Cafetero Nacional* (FCN) for the electrification of coffee-producing regions. Table A6-2 presents a summary of the social electrification projects conducted from 1995 to 2006.

6.6 ELECTRIFICATION CHALLENGES

The overall target of the social electrification subsector is to extend national electricity coverage to 80 percent of the total population by 2015, giving equal priority to urban and rural areas.

The National Social Electrification Plan (PLANES) in its original version set a target of an electrification access rate of 71 percent by 2012, with an estimated 100 percent electrification of urban areas. These targets would be made possible through the investment of $144.4 million in three phases: 2004–05, 2006–09, and 2010–12. To achieve these goals by 2012, PLANES intends to generate 160,000 new connections, with an annual investment of US$16 million and an average connection cost of US$900.

The electrification program has been updated using the PLANES methodology for 2004–15, aiming to raise the coverage level from 62.1 percent in 2004 (when the program was designed) to 80 percent by 2015, taking into account population growth. This new target of 80 percent national coverage represents more than 400,000 new connections and an annual growth rate of

electricity coverage of 4.9 percent. It is estimated that the new connections will represent 10 percent of residential consumption and 7 percent of total consumption by 2015.

To date, virtually all government-sponsored rural electrification projects have focused on grid extension. However, this technical option is not economically viable for many distant communities that are isolated and more dispersed from the interconnected system. Many of the new connections are more complex than those carried out by ENEE during the first years of the program and, if the new connections are to be efficient, they should use alternative renewable energy technologies for stand-alone systems rather than grid extensions.

As interconnection requirements from the most distant rural communities increase, costs rise rapidly, so much so that in the last projects supported by ENEE, costs have exceeded US$700 per household.[20] Other analysts, like Dussan (2005), believe investment costs per new connection via grid extension to be greater than US$1,000, since ENEE's connection cost estimates did not include the additional investments in subtransmission networks required by such projects.[21] Therefore, to reach the target of 80 percent by 2015, Dussan estimated an annual average investment of US$40 million over the next 10 years, more than four times the annual investment up to 2008 forecasted by FOSODE. In addition, as discussed in Chapter 5, the tariff residential electricity consumption in Honduras is much lower than the supplied cost, and the residential consumption is thus heavily subsidized. The newly connected customers are subject to the same tariff as existing customers and, hence, the subsidy. When the tariff subsidy to the newly connected customers is accounted for, the investment needs for electrification are even larger. An analysis of different institutional, technological, and financing options to meet these challenges is presented in Chapter 9.

[20] According to the "Honduras GEF Project Appraisal Document."

[21] M. Dussan, "Problemática de la energía eléctrica en Honduras: Impacto Fiscal," FIDE, 2005, p.16.

PART B – POLICY OPTIONS TO MEET SECTOR CHALLENGES

The review of the performance of the electricity sector in the last five years (Part A) shows that although progress has been made, many of the problems that motivated the reform process in 1994 still persist. In particular, the sector is affected by inefficiency and poor performance of the *Empresa Nacional de Energía Eléctrica* (ENEE) (high electricity losses, poor corporate governance); a lack of private investment, for power expansion at that time, now for transmission and distribution; a financial crisis of ENEE; delays in taking effective actions to ensure the required generation capacity additions to meet expected demand; electricity tariffs do not cover costs and tariff subsidies are not targeted; and the need to continue expanding electricity access to the rural areas.

The review shows that although the financial crisis and the poor performance of the sector was exacerbated by external shocks (high oil prices, some dry seasons) and some expensive Power Purchase Agreements, it was caused by structural problems and it can continue for many years or become a recurrent event if these problems are not addressed.

First, if the management and corporate governance of the state-owned company is not strengthened, it is unlikely that substantial and sustainable improvements in the performance of the transmission and distribution businesses of ENEE will be achieved. High non-technical losses, nonpayment of electricity by government institutions, and a backlog of needed investments in distribution and transmission are major contributing factors to the current financial crisis and to a looming energy crisis.

Second, no sector structure or market model, public or private, monopolist or competitive, can be sustainable in Honduras if the electricity tariffs do not cover efficient costs, and if electricity theft and fraud are not penalized and payment discipline enforced. Simply, it is not possible to reduce the financial deficit under these conditions, and the Central Government does not have the fiscal space and ENEE does not have the economic rent of hydro resources to finance the expected cash-flow deficit during the next five years. The tariff issue has a strong political component (electricity prices are a political commodity), but also becomes more difficult to tackle when generation prices are vulnerable to high and volatile international oil prices.

Third, the current de facto single-buyer model limits the options to restructure ENEE, improve its performance, introduce workable competition in the market, and take advantage of the benefits of expanded trade in the regional wholesale market.

Fourth, power generation is vulnerable to high and volatile international oil prices, which make it difficult, from the political point of view, to pass through the generation cost to tariffs. Diversification of energy sources is necessary to mitigate this problem.

Fifth, increasing access for the poor to electricity services, mostly in sparsely populated rural areas, requires new policies and strategies focused on off-grid solutions.

The following chapters discuss the short- and medium-term options to implement a new energy strategy, based on four major components, which can be effective in addressing the structural problems: (a) improving sector efficiency, (b) ensuring financial sustainability, (c) improving electricity coverage, and (d) and diversifying energy sources.

7. IMPROVING SECTOR EFFICIENCY

This chapter discusses the following options to improve the efficiency in electricity supply: establishing conditions for a good corporate governance and management of the *Empresa Nacional de Energía Eléctrica* (ENEE), promoting effective competition in the wholesale power market, and strengthening policymaking and regulation.

7.1 GOOD CORPORATE GOVERNANCE AND MANAGEMENT OF ENEE

The delays, uncertainty, and lack of decision in the process of unbundling ENEE and privatizing the distribution activities deteriorated ENEE's management and performance. On one hand, it continued to operate as a vertically integrated state-owned enterprise (SOE) but, with the expectation of pending restructuring, it postponed needed investments and plans to reorganize its operations, and update and improve information and accounting systems, offices, technological platform, and software required to supervise and efficiently manage its operations. On the other hand, it continued operating as an SOE with weak corporate governance. A combination of poor corporate governance and outmoded technology, know-how, commercial practices, and information and management systems contributed to poor performance.[22]

Box 7.1. The Corporate Governance of State-owned Enterprises

Corporate governance of state-owned enterprises (SOEs) refers to the rules that define the relationship between the company and the Government as its owner. Corporate governance of most SOE in developing countries is weak, and ENEE is no exception. There are two fundamental problems: (a) politicians and government officials do not act as ordinary, profit-motivated shareholders, and many times pressure the company to pursue noncommercial goals; (b) the Government faces a conflict of interest as policymaker and provider of electricity service that undermines the quality of policy and regulation, when the rules are modified in a somewhat arbitrary manner to protect SOEs or to achieve noncommercial goals.

This explains why SOEs are usually subject to both micromanagement and politically motivated interference by the Government; accountability for the performance of SOEs is diffuse, with the intervention of boards of directors, ministries, the President's office, and politicians; SOEs sometimes hold a monopoly position and are not subject to the discipline of a market; SOEs do not apply high standards of transparency and disclosure of financial and operational results; the administration of the SOEs lack operational autonomy to define their budget, make investment and borrowing decisions, procure good and services, and so forth; and the board of directors lacks the authority and independence to guide and supervise the management. Furthermore, SOEs are immune to two threats that discipline the management of private corporations and provide incentives for good performance: takeover and bankruptcy.

To improve the performance of government-owned electricity utilities (see Box 7.1), the rules and practices must be changed to make it harder for politicians and other interested parties to use the utilities for noncommercial purposes, and easier to introduce new sources of pressure to perform

[22] Timothy Irwin and Chiaki Yamamoto, "Some Options for Improving the Governance of State-owned Electricity Utilities," World Bank, Energy and Mining Sector Board Paper No. 11, 2004.

well. Privatization, competition, and good regulation are effective instruments to improve corporate governance and were adopted in the Electricity Law. Substantial advances were made in private participation with the development of all new generation capacity by private investors since 1994. Although the privatization of distribution was not implemented and it appears that is no longer an option from the political point of view, some advances were made to get private operators involved in distribution. ENEE hired in 1999 the services of *Servicio de Medición Eléctrica de Honduras* (SEMEH) to manage the commercial operations of reading, billing, and collection. Recently, ENEE tried a short-term build-own-transfer (BOT) scheme to finance, construct, and operate some distribution and subtransmission works and is considering the development of transmission lines under BOT schemes.

However, these actions failed to improve the performance of the distribution business as distribution losses continued to increase. ENEE and the Government are now proposing, as part of the short-term action plan to recover the electricity sector, to modernize ENEE's information, accounting, and management systems and to hire an international consultant to prepare a one-year study of the options to restructure ENEE in independent business units (IBUs) for generation, transmission, distribution, and system control. The IBU would have separate accounts, financial statements, and administrations with financial autonomy.

The creation of IBU for generation, transmission/dispatch, and two or three distribution regions with separate accounts, transfer prices, and financial autonomy can bring several potential benefits:

a) **Provide incentives for better performance.** Each IBU will establish a business plan and performance targets, consistent with ENEE's corporate plan. The performance of individual units can be monitored using economic value added or similar indicators and can be rewarded with salary bonuses, promotions, and benchmarking against other units. Each individual manager will be accountable for the financial and operational results of its business unit and will be isolated from other units by having separate accounts, transfer prices, and transparent procedures to allocate the common costs of the central unit.

b) **Improve and facilitate economic regulation.** The creation of separate regulatory accounts will facilitate the calculation of the value added for distribution and transmission based on economic costs and the application of the principles and procedures for economic regulation of tariffs established in the law. The separation into two or three distribution units will make it possible to use benchmarking regulation.

c) **Facilitate development of competition.** The creation of a separate business unit responsible for transmission/system operation/dispatch will reduce the barriers to open access of large consumers and independent generators to the transmission grid. It will also increase independence and transparency of economic dispatch and the calculation of short-term marginal costs. In addition, the transmission unit will be responsible for transmission planning and expansion and reducing transmission constraints.

The creation of IBUs is not a simple task and will take some time—one year to complete the restructuring study and another year to modernize ENEE's information and accounting systems. However, no substantial improvements in performance might be expected if the IBUs continue

operating as part of ENEE, subject to the problems of weak corporate governance mentioned above. The creation of IBUs represents a transitory arrangement that opens the door to more permanent and sustainable solutions—corporatization of the IBUs with the participation of minority local shareholders; or complements other transitory arrangements—management or lease contracts for distribution with experienced international operators.

7.1.1 Corporatization short of full privatization

The corporatization of SOEs without privatization subjects the utilities to private sector company law and ensures that the utility has a legal identity separate from its shareholders; that the directors, not the shareholders, are legally liable for managing the company; and that the management has operational autonomy but is accountable for the commercial performance of the company. In principle, the corporatization of IBUs, good regulation, and competition would introduce the principles of good corporate governance of the private sector and help improve its performance.

An essential requirement for a successful corporatization is that the SOE is restructured and commercialized first—cost-covering tariffs, renegotiation of debt and other liabilities, renegotiation of labor contracts—so it can become financially viable if it improves performance. Managers cannot be accountable for a company that cannot be financially viable due to structural problems.

The experience in some countries that have tried this solution is that corporatization facilitates a commercial operation of the company (less cumbersome procurement procedures, more operational autonomy, and so forth) but, to be effective in improving performance, an independent board of directors and a professional management should be established to set up a commercial operation to reduce political interference.[23] Additional commercial pressures are usually necessary for a better performance.

The discipline of commercial lending, participation of minority shareholders, and stronger and independent regulation has been used to bring additional commercial pressures to SOEs and improve performance. Requiring the utility to borrow from commercial lenders without the comfort of sovereign guarantees will put the pressure of the lenders for better financial performance. Minority shareholders (pension funds, small local investors, employees) have a residual claim on the utility's assets and depend strongly on the financial performance of the utility to maintain the value of its investment. Supporting a strong and independent regulation mitigates the conflict of interest of the Government as owner, policymaker, and regulator, and puts more pressure on the SOE to improve performance. An essential requirement for the successful participation of minority shareholders is that the corporatized SOEs have achieved adequate financial results and are able to distribute dividends.

[23] Colombia reformed its power sector in 1993, introduced a competitive wholesale power market, and established a leveled playing field for the participation of SOEs and private companies. All SOEs had the option of adopting a new legal entity subject to private company law. Many SOEs were corporatized without private participation, but the results were mixed because many of them remained under the control and interference of politicians and government officials.

There are some success stories. *Interconexión Eléctrica S.A.* (ISA) in Colombia, an SOE with a tradition of good management, was corporatized and placed 24.2 percent of equity among about 90,000 small shareholders in two public offerings of common shares. The national government that controls this company adopted and has respected the principles of good governance, including the protection of the rights of minority shareholders. ISA has been able to expand its operations in Latin America, taking over transmission companies and projects in Bolivia, Brazil, Ecuador, and Peru.

7.1.2 Management and lease contracts

Honduras has used, as a main model for private participation in the power sector, project financing of independent power producers backed by long-term Power Purchase Agreements (PPAs). This arrangement is well suited for a country with a weak regulatory framework with substantial market and country risks. The private investors are shielded from market and price risks under their PPAs with government guarantees. ENEE has also used rehabilitate, operate, and maintain (ROM) contracts to mobilize private capital and know-how for the operation of its thermal units, reducing investment risks taken by the private sector.

In the case of electricity distribution in Honduras, where straight privatization does not appear to be an option now due to political opposition and the unwillingness of private investors to take the high regulatory risks and investment risks involved with a business in financial distress, there are models of public/private partnerships that can be used to attract private operators and improve performance, while reducing the risks assigned to the private partner.

Under a management contract, the SOE continues to own the distribution assets, continues to be responsible for making capital investments, and controls the revenues of the company, but assigns full or partial responsibility for day-to-day operations to an outside private operator. The operator is compensated with a fee for its services. Under a lease contract, the SOE continues to own the assets and is responsible for capital investments, but assigns to a private operator complete control over the management and financial results of the company. The operator makes lease payments to the SOE for the use of the assets.

Management contracts have been used extensively in water supply companies and power distribution companies in countries or companies with distressed public services and poor investment climates, especially in Africa. The evaluation of eight management contracts made in the power sector in Africa during the 1990s (Congo, Ghana, Mali, Rwanda, Sierra Leone, and Zimbadwe) indicates that they were mostly unsuccessful in improving performance and that the service providers did not have enough incentives to take risks.[24] The major difficulties have been the clear definition of responsibilities between the owner and the operator and ensuring the support of the owners and employees for this arrangement. Lessons learned include that the operator should have full autonomy to make key decisions and implement its proposed measures to improve performance, and should have a financial stake in the operation of the utility (payments linked to specific and measurable performance improvements), that the contract

[24] World Bank, "Power for Development: A Review of the World Bank Group's Experience with Private Participation in the Electricity Sector," 2003.

should preferably be financed by the increased revenues, and that the government should be highly committed to the reforms.

Some successes with well-structured management contracts have been reported, like the case of Tanzania where a private operator was able in two years to reduce losses by 5 percentage points, reduce operational expenses by 10 percent, and reverse a financial deficit of the power utility. The management contract was structured with a retainer fee and a success fee funded from increased revenue collections.

A management contract can be considered as an interim arrangement to improve performance of the distribution business in Honduras:

a) Restructuring ENEE could take about two years. Corporatization and commercialization could be implemented in parallel with strong political support. In the meantime, it is essential to reduce electricity losses to mitigate the financial crisis. Implementation of the electricity loss-reduction program without expert support is likely to fail, as demonstrated by the Seven Cities Project (see Annex 3).

b) ENEE is proposing to modernize all its information and management systems as a key action to improve performance. However, if ENEE's management and corporate governance are not improved first, this proposal is unlikely to produce positive results.

c) A two-year management contract to implement a short-term corporate recovery plan (reduce electricity losses, improve information systems, and assist in restructuring of ENEE) can be an effective first step to improving corporate governance and restructuring of ENEE, instead of insisting on ad hoc interventions.

The contract with SEMEH is a management contract with limited scope and many limitations. SEMEH is responsible for most of the commercial functions: reading, providing information to update the billing database, billing, customer service (billing complaints), debugging the consumer database, reducing arrears, servicing disconnection and restoration, reporting illegal connections, and detecting possible fraud. However, ENEE keeps several commercial functions, including updating and maintaining the billing database, handling electricity service complaints, and responsibility for taking actions to reduce electricity losses. The contract with SEMEH has weak incentives for performance: it receives a fee for its services based on a percentage of monthly collections.

Although SEMEH provides critical information for the detection of fraud, the scope of the contract does not include the reduction of electricity losses. SEMEH maintains a geographic information system (GIS) linked to the customer database, but it does not include the distribution network maps. SEMEH is part of the solution to reduce losses but is not responsible for this activity.

With so many links between the SEMEH contract and the loss-reduction program, it is not clear whether a new management contract with a separate operator can be effective in improving ENEE's performance in the short term, taking into account that:

a) The electricity loss-reduction program proposed by the consultant[25] requires as a first step a survey of the distribution networks of the major cities and the preparation of distribution maps linked to the customer database in a GIS. The consultant recommended the outsourcing of these services.

b) The consultant also recommends implementing an Enterprise Resource Planning (ERP) system to integrate into a corporate database the main activities of ENEE. ENEE has accepted this recommendation and has allocated resources in the budget. However, the definition and design of an ERP system should have a clear roadmap for the restructuring, commercialization, and corporatization of ENEE, which has not been defined yet.

We suggest that it would be better to consider options that consolidate most of the operations in one management contract and to:

a) Terminate the contract with SEMEH and solicit international competitive bidding for a new management contract that includes responsibility for all commercial operations, the implementation of the loss-reduction program, and improvements in information systems, with payments linked to performance.

b) Renegotiate the contract with SEMEH to include full responsibility for the reduction of electricity losses and improvements in information systems, with payments linked to performance. However, there are many legal issues to be evaluated, including the experience and technical capability of this company.

c) Another option is to consider a decentralized solution to reduce losses, allocating groups of distribution feeders with high losses to separate operators with full responsibility for loss reduction, with payments linked to increases in revenues related to loss reduction.26

7.2 DEVELOPING A COMPETITIVE WHOLESALE POWER MARKET

A well-designed wholesale market structure should ensure a reliable, sufficient, and economic energy supply to meet electricity demand. Although the de facto single-buyer model used in Honduras has been effective in mobilizing private capital to develop additional generation capacity and was a good transition option for a small power market, the experience in Honduras confirms the risks associated with this scheme when the single buyer is a vertically integrated SOE:

a) The scheme is sometimes used by governments to postpone needed tariff increases and increase cross-subsidies, using the single buyer to finance the shortfall between the real cost of energy supply and the generation price that is passed through to the consumer.

[25] Consultoría Colombiana S.A., "ENEE: Consultoría para la elaboración de un plan de reducción de pérdidas," 2005.

[26] This approach is being considered by EDEESTE, a private distribution company in the Dominican Republic, to address an endemic problem of high commercial losses.

b) It centralizes the decision to purchase new energy, increasing the risk that inefficiency or mistakes in the bidding process may have a major impact on the cost and reliability of supply.

c) It may become an obstacle to moving to more competitive arrangements, because long-term PPAs are physical contracts, which impose many constraints on active participation in the market,[27] and may have prices out of line with market prices (stranded costs).

The use of a five-year average of short-run marginal costs as a reference to regulate the generation prices that are included in retail tariffs imposes serious price risks for buyers or sellers of energy in the regulated market. On one hand, the average of future short-run marginal costs does not necessarily cover the costs of new, efficient generation in a market that does not remunerate firm capacity. On the other hand, the calculation of future marginal costs depends on many assumptions made by the planner and can be manipulated. In these conditions, private generators are not willing to sell power at regulated prices and assume the risk of not being able to recover the investment costs.[28] A distribution company, private or public, is not willing to purchase power at the price determined in competitive bids and assume the risk of not being able to recover the contract costs in electricity tariffs based on short-run marginal costs. Only ENEE, supported by the economic rent of hydroelectric resources and government guarantees, can assume these risks, and keep signing long-term PPAs with private generators to meet demand.

The de facto single-buyer arrangement can be improved to support a market model based on competition for a share in the market of long-term contracts (competition for the market) and can help reduce wholesale electricity prices and improve the quality of supply. Competition for the market is important in Honduras, because long-term power supply contracts will continue to play a dominant role in the wholesale power market since private generators will continue to require the comfort of these contracts to finance the new generation required to meet demand, especially now that capital-intensive projects have to be developed. The basic improvements are:

a) To obtain the benefits of competition for long-term contracts, adequate conditions should be established to promote the participation of a large number of qualified investors: adoption of financing schemes that allocate to the private investor the market and project risks that it can manage efficiently, implement competitive procurement procedures to reduce the costs of power purchases, and improve the financial health of the off-taker. Public/private partnerships are necessary to facilitate private development of capital-

[27] The PPA used in Honduras is a standard physical contract that defines all the rights and obligations of the generator, and in practice insulates the generator from the risks of participating in a competitive power market. The PPAs are suitable for the operation on a single-buyer model. They impose, however, many hindrances to the transition to a competitive market where all generators play an active role in the market and comply with the market rules: instead of balancing its contract position with purchases and sales of energy in the spot market, based on market prices, the generator has the obligation to guarantee a firm capacity and, in the case of default, pay penalties that may not be efficient. Usually the generator does not have the obligation to provide ancillary services according to the market rules, and it does not have the flexibility of selling generation surpluses in the market (above the contracted capacity).

[28] Private generators are developing small renewable projects based on long-term PPAs with ENEE at energy prices equal to the marginal cost adopted by SERNA. However, the price is fixed when the contract is signed and is not adjusted to reflect future marginal costs adopted by the authority.

intensive projects (see section 10.1). The procurement procedures should encourage the participation of new generators, apply transparent competitive bidding principles, facilitate private financing of new generation, and help create a portfolio of contracts to manage price risks. A strong financial position of the off-taker reduces credit risks and encourages more competition.

b) In this regard, it is necessary to improve the expansion planning and energy procurement processes (see Chapter 10).

c) When the procurement procedures are effective in creating competitive conditions in the contract market, the *Comisión Nacional de Energía* (CNE) can authorize passing on to tariffs the costs of energy purchases under contracts and eliminating the price risk of busbar tariffs based on average short-term marginal costs. Short-term marginal costs can be used to provide a benchmark for energy purchases from small renewable power under long-term contracts and from independent generators under short-term contracts.

The de facto single-buyer model can accommodate, with some limitations, a market of large consumers and short-term energy sales by generators, based on the existing trading arrangements. ENEE as a vertically integrated company and system operator can provide wheeling services for transactions between large consumers and independent generators and buy surplus energy from independent generators at marginal costs. However, as explained in Section 4.2.2, the market of large consumers has not developed, and short-term energy transactions are insignificant. Some improvements can be made, mainly by improving the regulation of the transmission activity (simple and transparent wheeling charges).

Competition in the market, based on a wholesale power market of long-term energy contracts between generators, distributors, and large users, complemented with energy transactions in a spot market, is a market model that can capture the benefits of a more dynamic competition: in addition to competition for the market of long-term contracts, the market members (generators, distributors, and large users) can make short-term energy transactions to adjust their positions in the contract market to real-time supply/demand conditions in the national and regional markets.

However, the lessons learned in the design of competitive wholesale power markets in small power systems in the region indicate that it is necessary to mitigate the potential for abuses of market power in the spot market by: (a) establishing the obligation that distribution companies should meet a substantial portion of expected energy demand with long-term contracts, so the spot market is used basically as a balance market and is small compared to the contract market; (b) the spot energy transactions are based on a centralized merit order dispatch of the variable costs of the generating units. Therefore, the power market would continue to be dominated by the market for long-term contracts.

However, the power market of Honduras does not currently meet the minimum conditions to implement competition in the market:

a) The size of the power system in Honduras is too small to create a sufficient number of buyers and sellers that can compete effectively in the market.

b) Vertical unbundling of ENEE in separate generation, transmission/dispatch, and distribution companies is necessary.

c) Open access to transport facilities is essential but will not be effective if ENEE remains vertically integrated. If ENEE maintains generation and transmission/dispatch under the same corporate group, it will have serious conflicts of interest and opportunities for discrimination.

d) The electricity law did not establish the basic principles and regulations for the operation of a spot market (for example, hourly transactions, rules to determine spot prices, a market administrator).

Honduras could meet in the medium term the minimum conditions for the introduction of workable competition in the market: the development of new industrial parks will increase the number of large users able and willing to participate in the market; the commissioning of the SIEPAC project in 2009 will expand both the possibilities for energy trade in the regional market and the number of buyers and sellers that can participate in the national market; a study of options for vertical unbundling of ENEE and the creation of independent business units will be prepared this year; and a simpler methodology for the calculation of transmission charges will be adopted, which would facilitate open access.

A gradual transition from a single-buyer scheme to competition in the market appears to be possible in the case of Honduras, according to the following process:

a) First, implementation of the suggested improvements in the single-buyer model.

b) Second, creation of the independent business units.

c) Third, the generation unit of ENEE performs the function of single buyer and sells energy to the distribution business units at the regulated wholesale price.

d) Fourth, the generation unit of ENEE transfers to the distribution units the PPAs that have competitive prices, and signs supply contracts with the distribution units at the regulated price using the hydroelectric rent to compensate for the higher-cost PPAs that expire in the late 2010s. The distribution units are responsible for competitive procurement of new power and procurement of small renewable power at avoided costs. CNE authorizes passing on to tariffs the cost of energy purchased in a competitive contract market.

e) Fifth, competition in the market is fully implemented with the creation of a spot market.

The first three steps can be implemented based on the existing legislation and the creation of independent business units. However, the market would continue to operate as a single-buyer model with more efficient procurement procedures, but with the shortcomings discussed above.

The fourth step requires the unbundling of ENEE in separate companies, which can be done based on existing legislation. The main objective of this step is to corporatize and commercialize the business units and to create conditions for the operation of a wholesale market where distribution companies meet expected demand with long-term power purchase contracts, subject

to competitive bidding, and can recover in the tariffs the full cost of energy purchases. The participation of large consumers in the market continues to be marginal.

The last step requires changes in the law to establish all the infrastructure necessary to operate a spot market: hourly energy transactions, a capacity market, expanding the functions of the dispatch center to include the function of market administrator, and formulating detailed rules and regulations for the operation of the market (procedures for the economic dispatch based on variable costs, pre-dispatch and post-dispatch arrangements, rules to calculate hourly marginal costs, rules to settle energy transactions, billing and collection, rules for the remuneration of firm capacity, rights and obligations of eligible market agents). This is something similar in scope to the regulations of the regional energy market.

The options and issues to introduce competition in the wholesale market are summarized in Table 7.1.

Table 7.1 - Options and Issues to Introduce Competition in the Wholesale Market

	Options, Improvements, and Constraints			
Issues	**Single-buyer, Vertical Integration**	**Independent Business Units**	**Unbundling**	**Competition in the Market**
Lack of incentives for efficient generation expansion	Improve planning and procurement procedures. Include capacity cost in busbar tariff. Apply cost-covering tariffs. Independent generators sell at marginal costs. ENEE make up for differences between contract costs and busbar tariffs.	Same. ENEE continues as single buyer and sells energy to IBU at busbar tariffs.	Same. ENEE transfer to the new distcos PPAs with competitive prices, and sign supply contracts for the balance at busbar tariffs. Distcos responsible for competitive procurement and purchase power to renewables. CNE authorizes pass-through of cost of energy purchases.	Same. ENNE hydro sells energy under contract at busbar tariffs. Distcos responsible for competitive procurement and purchases to renewables to cover most of expected demand and can buy shortfall in spot market. Same.
Large consumers do not participate in the market	Simplify wheeling charges. ENEE provides balance service. Strengthen regulation to facilitate open access.	Same.	Same.	Large users make spot transactions to balance their position in national and regional contract market. Financial and flexible physical contracts are allowed.
Barriers to expand regional trade	ENEE responsible for system operation and coordination with regional operator but allows third-party deals.	Same.	Gencos, distcos, and large consumers participate in regional contract market. A transmission/dispatch company is created.	Gencos, distcos, and large consumers participate in the regional contract and spot markets. The transmission and dispatch company responsible for administrating the market.
Scope for competition	Competition for long-term contracts. Mostly physical contracts. Limited short-term energy transactions.	Same.	Same.	Competition for long-term and short-term market. Financial and flexible physical contracts. PPAs play an active role in the market and balance its contract position in the spot market. Active spot market in operation.

7.3 IMPROVING THE INSTITUTIONAL ARRANGEMENTS

The separation of roles of the Government as policymaker, regulator, and service provider was an essential element of the electricity sector reform of 1994. The Central Government should

concentrate on its primary role of policymaker and assign to a separate and independent institution the responsibility of applying the regulatory framework to provide credibility and stability to the new rules. The separation of roles is also important to establish a leveled and nondiscriminatory playing field for private and state-owned companies, improve the investment climate for private capital, and improve the corporate governance of SOEs.

However, in Honduras the separation of roles has not worked as envisioned (see Chapter 4). The policymaking and planning functions are dispersed and weak. CNE does not have the autonomy, transparency, and competence required to build credibility. ENEE does not operate as a commercial company and is involved in policymaking. The Central Government continues to intervene in the three roles. The private sector manages the risks of a weak regulatory framework by participating as independent power producers insulated from these risks under the terms of their PPAs, backed by sovereign guarantees.

The separation and strengthening of roles is important for improving the performance of the electricity sector even in the case that distribution is not privatized. The sector reform initiated in 1994 was partially implemented and is necessary to define a new energy strategy and revise the energy policy to address the structural problems faced by the sector. There is a need to have a permanent technical group that supports the formulation of energy policy, and is responsible for designing and coordinating action plans for its implementation. A strong and independent regulator is needed to apply the regulatory framework. ENEE should be restructured and corporatized, as discussed in this chapter, to operate as a commercial enterprise that is not involved in policymaking or regulation.

The Ministry of Natural Resources and Environment (*Secretaria de Recursos Naturales y Ambiente*, SERNA) is the de facto energy ministry with responsibilities for policymaking and supervision of the electricity sector. It is the secretariat and coordinator of the Energy Cabinet, chairman of the board of directors of ENEE, grants operation licenses for distribution companies, issues technical regulations, approves any PPA signed by ENEE, and grants environmental licenses for electricity projects. However, it lacks the resources and a stable technical group to discharge its responsibilities (Chapter 4). A simple solution to improve policymaking is to strengthen the energy group in SERNA and eliminate the Energy Cabinet. However, a different ministry (Ministry of Finance) should be responsible for representing the Government as owner of ENEE to avoid conflicts of interest between policymaking and provision of electricity services.

CNE has played a marginal role in the sector, impaired by lack of autonomy, the difficulties of regulating a vertically integrated SOE, and a lack of the Government's commitment to implement the tariff regulations and the separation of roles. Other regulatory institutions in the region have faced similar difficulties (for example, Nicaragua and the Dominican Republic). However, the lack of a credible and capable institution responsible for applying the new market rules and pricing principles is a barrier to the development of the electricity market, improving the performance of ENEE, and attracting private capital to other activities. Credibility can be improved with autonomy, transparency, and technical competence.

A long-term solution to improve the credibility of CNE is to change the Electricity Law to adopt the best practices for strengthening the regulatory function, which have been used in other countries in the region, mainly: ensure financial resources with a regulatory fee to be paid by the

regulated electricity companies; establish competitive salaries to attract the best-qualified professionals; longer (more that one presidential period) and staggered terms of appointment of commissioners to provide continuity and stability; establish clear procedures for public consultation and transparent reporting and justification of regulatory decisions. These conditions are well known in Honduras, have been discussed in the past, and have been included in several failed initiatives to reform the Electricity Law. However, credible regulation cannot be established if there is a lack of political support and commitment to implement the rules and strengthen regulations. The interference of the Government and of powerful SOEs has weakened the autonomy and credibility of the regulator in many countries in the region.

8. ENSURING FINANCIAL SUSTAINABILITY

The dependency on imported fuel for about 65 percent of power generation, the high costs of some early Power Purchase Agreements (PPAs) with thermal generators, the vulnerability of generation costs to high and volatile oil prices, and the difficulties in passing through these costs to electricity tariffs have weakened the financial position of *Empresa Nacional de Energía Eléctrica* (ENEE) and threatens the sustainability of the electricity industry in Honduras. The cost of energy purchases increased from US$209 million to US$420 million during 2001–06, and the average cost of energy purchases increased in 2006 to about US$103/megawatt-hours (MWh), when the average West Texas Intermediate oil price was US$66/bbl.

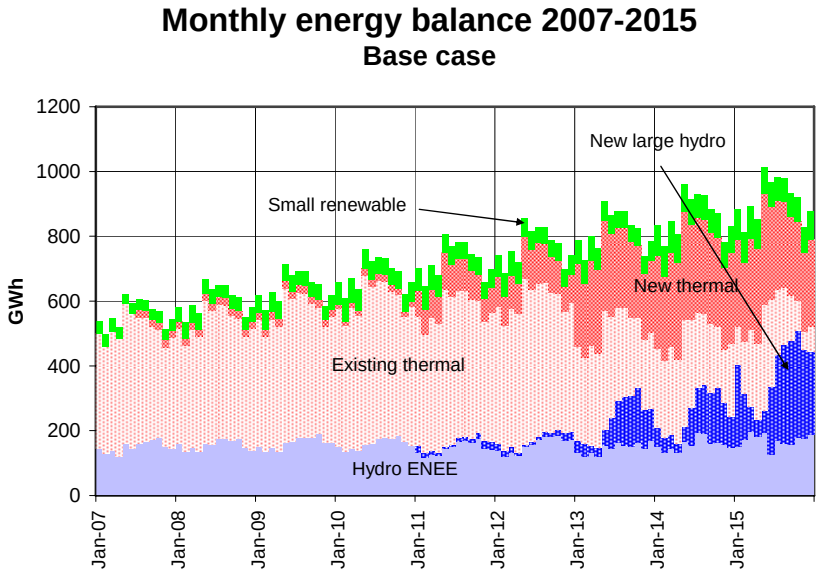
8.1 COST OF ENERGY PURCHASES

The generation costs are basically determined by the cost of energy purchases (70 percent of total generation in 2006). The cost of energy purchases from 2007 to 2010, when only emergency projects can be commissioned, would continue to be determined by external non-controllable factors (high and volatile oil prices and hydrological conditions) and the fixed payments under existing PPAs and new emergency generation. A portion of the fixed costs could be reduced. The capacity charges for new emergency generation will have a substantial impact on the cost of purchases during the transition period until new generation projects are commissioned, and could be reduced by competitive procurement. The diversification of energy sources may contribute to reducing the vulnerability of generation costs to high and volatile oil prices and may also reduce the generation costs, but only after 2012.

The cost of energy purchases was calculated based on the generation expansion plans and the results of economic dispatch for each of the three demand scenarios, using the energy prices established in existing contracts and estimated capacity and energy charges (based on fixed and variable project costs) for new projects.

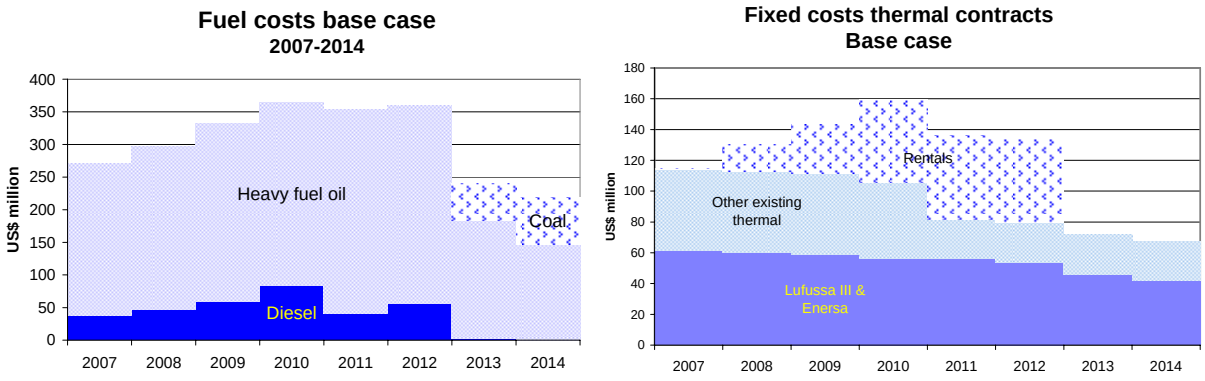
The demand growth until 2011 is met by additional thermal generation from the existing PPAs and emergency generation. Beginning in 2011, lower-cost thermal generation (medium speed diesel [MSD] in 2011 and coal-fired plants in 2013) substitute for the generation of the most expensive PPAs and replace the emergency generation. The generation of existing PPAs is almost completely displaced by 2015 when Patuca 2 is commissioned (see Figure 8.1).

Figure 8.1



For 2007–11, the costs of energy purchases are determined, by and large, by the fuel costs of existing thermal generation and by the fixed charges of the existing PPAs with thermal generators and of new leasing contracts for emergency generation. The fixed payments of rentals by 2011, after the termination of the Lufussa I and Elcosa contracts, are estimated at US$54million in the base case (40 percent of total fixed costs), using a high-capacity charge of US$18/kW/month, which can be reduced in a competitive procurement. By 2013, once new thermal and hydroelectric plants are commissioned and the rental contracts are terminated, the cost of fuel and the fixed payments under existing contracts are reduced by almost 50 percent (Figure 8.2).

Figure 8.2

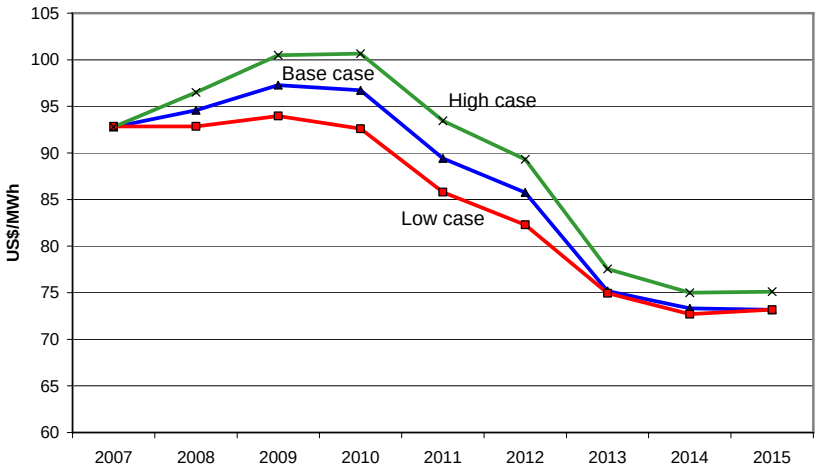


The reduction in the cost of purchases with the retirement of expensive generation and the commissioning of lower-cost generation plants beginning in 2011 have a substantial impact on the average energy purchase costs. For the base case, the average cost is reduced from about US$95/MWh during 2007–10 to about US$87/MWh by 2011 and to US$75/MWh by 2013. A comparison of the average cost in the three scenarios shows significant differences in 2007–12 (about US$7/MWh between low and high) when expensive emergency is used in the margin to

meet any increase in demand, to minor differences by 2013 when new low-cost generation is commissioned to meet expected demand in each case (see Figure 8.3).

Figure 8.3

Average energy purchase cost



8.2 ENEE'S INVESTMENT PROGRAM

ENEE's investment program for 2007–15 is front loaded with a backlog of transmission and subtransmission works that could not be implemented in the past due to financial constraints, investments in a loss-reduction program, and proposed investments to improve ENNE's information and management systems. It also includes the implementation of the Inter-American Development Bank's (IDB's) energy investment loan (see Table 8.1). About 70 percent of the US$630 million investment program corresponds to the strengthening of the high-voltage transmission and subtransmission grids and the rehabilitation and expansion of the distribution networks. This is a very ambitious investment program and represents an increase in ENEE's average annual investments from US$21 million (2001–05) to US$70 million.

The investment program does not include investments in rural electrification (on grid or off grid), which may amount to more than US$200 million during the period. It was assumed that rural electrification will be financed by grants and soft loans taken by the Government, government contributions, and contributions of the communities to cover connection costs.

Table 8.1

ENEE´s Investment Plan 2007-2015
US$M

	Total	2007	2008	2009	2010	2011	2012	2013	2014	2015
IDB project	41.1	17.3	17.2	6.6	0.0	0.0	0.0	0.0	0.0	0.0
Capitalized financial costs IDB porject	0.7	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity loss reduction program	30.4	27.6	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Substations and transmission lines	299.8	0.5	102.5	79.8	29.6	3.8	11.3	38.3	33.3	0.6
Distribution expansion	141.6	18.7	25.8	13.9	13.9	13.9	13.9	13.9	13.9	13.9
Other investments (generation)	47.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Rural electrification	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Information and management systems	23.8	10.6	6.6	6.6	0.0	0.0	0.0	0.0	0.0	0.0
Other (equipment&materials)	44.7	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Total	629.3	85.2	165.6	117.1	53.6	27.9	35.4	62.4	57.4	24.7

Table 8.2 shows the investment program for transmission and subtransmission works, with details about projects with investment over US$10 million. We note that:

a) Almost all the large projects are components of the 230 kV transmission expansion plan to (i) improve the quality and reliability of supply to the north and eastern regions now served by 69 kilovolts (kV) and 138 kV lines, respectively, and to facilitate the connection to the grid of hydroelectric projects in the Patuca basin: Amarateca substation, Amarateca-Juticalpa-Reguleto-El Progreso transmission lines; and (ii) improve the quality and reliability of supply to the distribution networks in Tegucigalpa and San Pedro Sula: expansion of Tocontín Substation, new San Pedro Sula Sur substation, and Rio Lindo-San Pedro Sula Sur transmission lines.

b) Some urgent substransmission works (at a cost of about US$40 million) were awarded using a three-year build-own-transfer (BOT) financing scheme.

Table 8.2

ENEE
Transmission lines and substations Investment Program
000 US$

	Total	2007	2008	2009	2010	2011	2012	2013	2014	2015
Lines and substations										
BOT	39.8	11.4	16.0	12.5						
Expansion Tocontín I& II	15.1		13.0	0.8	1.3					
Amarateca substation	16.9		16.9							
San Pedro Sula Sur substation	12.3		1.2	4.4	6.6					
Line Rio Lindo-SSS 230 kV	10.3			4.1	6.2					
La Entrada substation	11.0		4.4	6.6						
Line Amarateca-Juticalpa 230 kV	39.8		15.9	23.9						
Line Juticalpa-Reguleto 230 kV	30.4		12.2	18.3						
Line El Progreso-Reguleto	53.5							21.4	32.1	
Lne Tocontín-Danli 138 kV	14.8						5.9	8.9		
Oher works	95.7	0.5	38.9	21.7	15.5	3.8	5.4	8.1	1.3	0.6
Total lines and substations	339.7	11.9	118.5	92.3	29.6	3.8	11.3	38.3	33.3	0.6
Total w/o BOT	299.8	0.5	102.5	79.8	29.6	3.8	11.3	38.3	33.3	0.6

8.3 FINANCIAL PROJECTIONS

The main critical drivers of ENEE's financial performance, which are under the control of ENEE or the Government, are electricity losses and electricity prices. The three basic demand scenarios

described in Chapter 3 consider different corrective actions on the key drivers: the high case corresponds to a business-as-usual scenario, the base case corresponds to a scenario where moderate results are achieved, and the low case corresponds to a scenario where substantial actions are taken and substantial improvements are achieved.

The average electricity tariff was adjusted according to the underlying assumptions made in each scenario, (fixed in nominal terms for the high case, fixed in real terms for the base case, and 15 percent increase in real terms for the low scenario), until the average tariff reached the level of efficient costs (US$126/MWh or Lps.2.4/kWh). Therefore, the cost of inefficiencies (high losses and high generation costs) are not passed through to consumers.

The analysis of the financial projections for the three scenarios was divided in two distinctive periods: 2007–10, when the energy purchase costs are high; and 2011–15, when these costs decrease with the commissioning of new low-cost generation. The results for 2007–10, summarized Table 8.3, show that:

a) The business-as-usual (high case) scenario is not sustainable. Financial losses will continue to grow from Lps.2,405 million (US$126 million) in 2006 to Lps.4,407 million (US$232 million) in 2010. Likewise, the cash-flow deficit will increase from US$91 million in 2006 to US$205 million in 2010.

b) The scenario of gradual improvements in tariffs and losses (base case) reduces the financial losses and cash-flow deficit by 2010 to US$89 million and US$61 million, respectively, but the deficit is not manageable taking into account that the financial projections are based on the assumption that about US$300 million in transmission and distribution investments can be financed 100 percent, a dubious proposition. This scenario assumes that electricity tariffs will be adjusted in nominal terms to the pace of the projected inflation, resulting in a 14 percent nominal increase by 2010. In this case, a reduction of 2.6 percentage points by 2010 in electricity losses is not good enough to solve the financial crisis.

c) The scenario of major improvements (low case) produces a cash-flow surplus by 2008, which increases to US$66 million by 2010. The combination of a drop of 9 percentage points in electricity losses by 2010 and a 20 percent increase in the average tariff in nominal terms quickly improves ENEE's financial situation.

Table 8.3

ENEE´s Financial projections
2007-2010

		Real		Projected		
	Scenario	**2006**	**2007**	**2008**	**2009**	**2010**
Electricity losses (%)	High	25.2%	25.5%	25.8%	26.1%	26.4%
	Base	25.2%	25.2%	23.8%	23.1%	22.6%
	Low	25.2%	23.0%	20.7%	18.5%	16.2%
Average tariff (Lps/kWh)	High	2.00	2.00	2.00	2.00	2.00
	Base	2.00	2.07	2.15	2.22	2.28
	Low	2.00	2.18	2.37	2.40	2.40
Revenues (Mlps)	High	9,133	9,792	10,614	11,373	12,154
	Base	9,133	10,201	11,575	12,866	14,191
	Low	9,133	10,853	12,954	14,223	15,355
Generation costs (Mlps)	High	7,985	8,613	9,842	11,180	12,307
	Base	7,985	8,579	9,512	10,541	11,545
	Low	7,985	8,379	9,034	9,728	10,386
EBITDA (Mlps)	High	-67	-413	-932	-1,556	-1,738
	Base	-67	14	321	516	982
	Low	-67	841	2,125	2,633	3,258
Profit (losses) (Mlps)	High	-2,405	-2,454	-3,258	-4,117	-4,407
	Base	-2,405	-2,028	-2,005	-2,044	-1,687
	Low	-2,405	-1,200	-201	73	589
Cash flow surplus (deficit) (Mlps)	High	-1,737	-1,224	-1,790	-3,285	-3,905
	Base	-1,737	-854	-562	-1,221	-1,168
	Low	-1,737	-116	1,216	938	1,158

The results of the financial projections for 2011–15 for the base and low case scenarios (see summary in Table 8.4) show that increasing the average tariff to the level of efficient reference costs of Lps.2.4/kWh produces large cash-flow surpluses by 2015, when the electricity losses have been reduced to 19.7 percent and 12 percent, respectively, and the average generation cost is reduced to about US$15/MWh with respect to the cost for 2009, as a result of the commissioning of lower-cost generation. This indicates that the current reference costs may be high once lower-cost generation plants are commissioned.

Some basic conclusions can be reached from the analysis of the financial results:

a) Substantial improvements in electricity losses and electricity tariffs are required (low case scenario) to reverse ENEE financial losses for 2007–10. Gradual improvements in losses and tariffs (base case scenario) would reduce financial losses but would accumulate a cash-flow deficit during this period of about US$200 million, in addition to any shortfalls in mobilizing about US$300 million financing for transmission and distribution investments during that period.

b) Substantial improvements in electricity losses (low case), but with no tariff adjustments, would produce a cash-flow deficit of about US$236 million during 2007–10 and will not resolve the financial crisis.

Table 8.4

ENEE´s Financial projections
2011-2015

	Scenario	2011	2012	2013	2014	2015
Electricity losses (%)	Base	22.1%	21.5%	20.9%	20.3%	19.7%
	Low	14.0%	13.0%	12.0%	12.0%	12.0%
Average tariff (Lps/kWh)	Base	2.34	2.39	2.40	2.40	2.40
	Low	2.40	2.40	2.40	2.40	2.40
Revenues (Mlps)	Base	15,577	17,046	18,301	19,533	20,822
	Low	16,534	17,668	18,861	20,011	21,213
Generation costs (Mlps)	Base	11,904	12,061	11,373	11,658	12,217
	Low	10,493	10,566	10,389	10,494	11,354
EBITDA (Mlps)	Base	1,913	3,123	4,971	5,822	6,452
	Low	4,243	5,215	6,494	7,446	7,691
Profit (losses) (Mlps)	Base	-672	526	2,327	3,147	3,811
	Low	1,658	2,619	3,850	4,771	5,050
Cash flow surplus (deficit) (Mlps)	Base	335	1,375	3,158	3,998	4,652
	Low	2,710	3,512	4,702	5,643	5,909

c) Under the scenario of gradual improvements (base case), ENEE's financial position could be reversed only as of 2012, once cost-reflective electricity tariffs are applied, some expensive contracts expire, and new low-cost generation can be commissioned. In the meantime, for about five years, a cash-flow deficit of more than US$200 million will accumulate. It is difficult to argue that this is a transitory financial problem that can be addressed with financial measures (postpone the payment of short-term obligations and finance the shortfall).

d) It would be necessary to revise and eventually reduce the investment program to more realistic levels.

The financial crisis is not a problem caused by a juncture of high oil prices and expensive thermal contracts. These adverse conditions only made evident a structural problem of poor performance and governance of ENEE, electricity tariffs that do not cover efficient costs, underinvestment in transmission and distribution, and contracting expensive emergency generation because of cumbersome and protracted bidding procedures that delayed the contracting of new power supply. This financial crisis comes at a critical moment when the national budget does not have fiscal space to provide financial support to ENEE and the hydroelectric rent is not sufficient to compensate for the high costs of energy purchased by ENEE under PPAs.

ENEE proposed a short-term plan[29] to improve and reverse the critical financial situation, with the following main actions:

[29] "Plan de acción para la recuperación del sector eléctrico 2007–2015," ENEE, diciembre de 2006.

a) Implementing a loss-reduction program comprising: a short-term investment of about US$30 million, approval of a new law to penalize electricity fraud and theft, and formation of several field teams responsible for controlling losses;

b) Renegotiating the existing PPAs with thermal generators to reduce the cost of energy purchases by 15 percent;

c) Resuming a monthly increase of the tariff adjustment factor in 2007, which would result in an increase of about 8.5 percent of the average tariff (this action has not been supported by the Central Government);

d) Approving a new law that provides additional incentives for the development of renewable energy;

e) Targeting of the Bono 80;

f) Restructuring ENEE in business units and implementing a program to improve its information and management systems; and

g) Refinancing the short-term debt with generators and local banks.

The results of the financial projections show that the proposed actions (a) and (c), to reduce electricity losses and increase tariffs are both essential to reverse the financial losses, but are not sufficient. The loss-reduction program had a slow start and may not achieve the short-term improvements that are required.[30] The proposed tariff increase does not reach the level of cost recovery and was not approved by the Government. Actions (d), (e), and (f) would not have a short-term impact on financial results of ENEE.

Actions (b) and (g) aim to renegotiate ENNE's short-term obligations and postpone their payment, but are not sufficient to resolve the financial crisis if tariffs are not increased. Renegotiations of PPAs usually are based on the principle that the cash flow of capacity and energy payments may change to better suit the financial limitations of the buyer, but the present value of the cash flow of payments does not change. The new government is renegotiating the PPAs with thermal generators and it has been reported that the capacity charges for 2007–09 could be reduced by about US$20 million per year. This action reduces the cash-flow deficit but cannot substitute for a tariff increase. It is important to note that an extension of the contract of Lufussa I and Elcosa (keeping the same prices) to compensate for the reduction in capacity charges will increase the cost of energy purchases after 2010 and would reduce the space for commissioning lower-cost generation by 2012.

[30] There are delays in providing transportation and other equipment to the task force responsible for detecting and correcting illegal connections and fraud. The targets established in the low case seem to be too optimistic if the current arrangements are not improved. The base case scenario seems more likely.

Two other short-term actions that would contribute to reducing the cost of energy purchases are:

a) Implementing load management and energy-saving programs to reduce the peak demand and the need for expensive generation rentals.

b) Studying options to reduce the cost of generation rentals: multiyear contracts and international tendering to promote competition. A reduction of 30 percent in the capacity charge of US$18/kW/month would represent annual savings of US$16 million.

9. IMPROVING ELECTRICITY COVERAGE

This chapter: (a) evaluates the electrification policies, including the related institutional framework; (b) identifies investment needs in rural areas and the appropriate incentives for encouraging alternative energy programs; and (c) analyzes policy options for improving tariff design and subsidy targeting mechanisms for rural electrification.

9.1 ASSESSMENT OF ELECTRIFICATION POLICIES

The National Social Electification Plan (*Plan Nacional de Electrificación Social*, PLANES) was designed and structured using comprehensive data on Honduras's rural areas, in which customer consumption patterns and service needs were identified. However, the grid extension model applied by Social Fund for Electricity Development (*Fondo Social de Desarrollo Eléctrico*, FOSODE) under PLANES, while effective in extending coverage by conventional means—mainly grid extension—has performed poorly in the application of decentralized options. Decentralized electrification projects were partially studied within PLANES to extend service to 25 isolated communities by means of diesel generators, but other technologies, such as photovoltaic (PV) systems or micro/small hydroelectric stations, which could be more efficient and profitable because they do not depend on fossil-fuel consumption, were left aside.

The existence of a weak institutional framework for the electricity sector affects the quality and efficiency of rural electrification efforts. The main problem in this field is that Honduras does not have an integrated policy for rural electrification. This is evidenced by the fact that, while FOSODE has the resources to implement grid extension projects selected under the PLANES methodology, the Honduran Ministry of Natural Resources and the Environment (*Secretaría de Recursos Naturales y Ambiente*, SERNA) is in parallel promoting some renewable energy projects even though it does not have a mandate on electrification.

The existence of two entities promoting electrification programs—FOSODE and SERNA—undermines the legitimacy of the efforts and diminishes the credibility of social electrification programs by weakening the institutional framework and the incentives to attract other players, such as private investors, communities, and nongovernmental organizations. Moreover, there are other issues that are challenging the ability to promote social electrification: (a) lack of political will to enforce prices that strictly reflect the actual cost of service (even accepting that cross- but explicit subsidies available to the neediest are reasonable); (b) the State as the only service provider in rural areas in practice; (c) weak governmental structure in the sector, without ministerial presence; and (d) delays in the implementation of flexible environmental standards.

The criticism of Honduras's social electrification programs is attributable to the fact that a specific or detailed model of how to carry out electrification with non-conventional options was never designed. What existed instead was, on one hand, an articulated proliferation of grid extension projects carried out under PLANES and, on the other hand, an unarticulated promotion of renewable energy, which lacked planning or coordination by a government agency with clear functions and objectives to undertake an electrification strategy.

This policy gap over the past 10 years, and the absence of adequate rural electrification models, has encouraged the emergence of proposals that tend to deepen a delivery model that is dependent on the State and, in particular, on the *Empresa Nacional de Energía Eléctrica* (ENEE). The fact that ENEE has dominated the electrification programs has led to public and community skepticism regarding the possibility of a stronger participation of private and nongovernmental players. The thesis proposed in this report is that social electrification projects in Honduras, mostly grid extensions, have been carried out without a clearly defined program that articulates, among other processes, the decentralization at a local level, the involvement of municipalities and the private sector, and the use of various alternative energy supply methods, which could optimize the use of local resources.

Corrective measures that could be implemented in the short term include: (a) strengthening SERNA as the de facto energy ministry in the capacity of developing strategy, planning, and policy formulations in rural electrification; and (b) strengthening the technical capacity of FOSODE with the necessary training in electrification options based on stand-alone technology, renewable energy, and the development of business models that use alternative energy options.

In the long term, it is recommended to transform FOSODE into an autonomous, unified fund through which all current electrification efforts can be promoted, both for grid extension and stand-alone systems. FOSODE's successful experience with grid extension, and its serious and practical track record as an implementer, suggest that it could transform into an autonomous organization with clear policies and transparent rules for project selection based on cost-benefit criteria, using rational and realistic financing mechanisms.

9.2 IDENTIFYING INVESTMENT NEEDS

In electrification projects, the more remote and dispersed the community, the more difficult and expensive the extension of access. The paradox in these cases is that these isolated communities are generally the poorest ones and, consequently, have a lower payment capacity, requiring significant subsidization.

As mentioned in Chapter 6, only 44.8 percent of households in rural areas are currently electrified. It is estimated that in those areas there are approximately 416,879 unserved households (over 2.1 million people).

Rural areas in Honduras are the regions with the most acute need for investment in electricity infrastructure. These areas are typically very poor with many unmet basic needs and surviving on subsistence agriculture. Consequently, infrastructure needs mostly relate to subsistence energy supply.

The electrification process of households in isolated regions of Honduras can take two forms. One consists of electrifying isolated rural areas by connecting them to the national or regional grid, thus integrating them into Honduras's national interconnected system. The other form of electrification consists of providing rural areas with stand-alone energy solutions when connecting to the grids is not a viable option due to either technical or economic restrictions associated with their geographic location.

When electrification using stand-alone solutions is considered, the options are to use conventional sources of energy (basically, hydroelectric mini-stations or diesel plants), or to select alternative, non-conventional energy sources (for example, wind, solar, biomass). As will be seen in the renewable energy chapter of this report, the adoption of solutions based on non-conventional sources has been rare in Honduras.

To evaluate investment needs in rural areas, three types of scenarios were examined:

- First, investment needs were simulated to enable increasing service provision with conventional diesel systems. This was applied to a set of projects identified within the PLANES and to different departments, considering different prices for diesel fuel and investment and operation costs of the equipment. To that end, data available from ENEE were used.

- Second, assuming that the population that is currently not being reached by some type of service provision scheme is made up of dispersed households, a simulation was made of what it would cost to provide electricity by building microhydro facilities, assuming that a certain percentage of the areas meet the conditions to benefit from this type of technology.

- Third, assuming once again that the population that is currently not being served by some type of service provision scheme is made up of dispersed households, a simulation was made of what it would cost to install a 20 windpower (Wp) or 50 Wp photovoltaic panel in each of those houses.

For each case, the costs were added up to come up with the net present value of investments (total amount in 2006 U.S. dollars) that would be necessary to increase coverage by 10 percent, 25 percent, 50 percent, and 100 percent in rural areas. The annuities for some of these options were also estimated, considering the financial restriction reported by FOSODE. The results of those analyses are reported in Annex 9, Table A9-1 and briefly discussed below.

It should be noted that the estimated investments correspond with several of the many possible combinations, and the analysis has omitted the intertemporal needs of financing the investments. In other words, although the estimates indicate how much it would cost to improve service and extend coverage today, this does not mean to imply that the investments should all be made in the same time period.

Table 9.1 compares the unit connection cost of each technology and shows that: (a) grid extension is not necessarily the most cost-efficient option; (b) the microhydro plants are quite expensive and should be used only when the local water resources are available and when pre-investment studies have been done to show it is the least-cost option for the local communities; and (c) solar home systems (SHS) stand out as an attractive option in terms of cost. Nonetheless, it is important to note that the business model used for delivering the SHS is critically important, with the particular challenge of providing technical support and service in rural communities, as experiences in Honduras and other countries showed.

Table 9.1 - Cost of Initial Investment per Connection Using Different Technologies

Technology	Unit Cost per Connection	Remarks
Grid Extension[a]	US$400	Average cost in the past 10 years by FOSODE
	US$700	Projected for the future without investments in subtransmission
	US$1,000	Projected for the future with investments in subtransmission
Isolated Diesel Plant[b]	US$950	Operating 6 hours per day
	US$1,900	Operating 12 hours per day
	US$3,800	Operating 24 hours per day
Microhydro	US$2,700	Excl. productive uses, program costs of US$400,000
	US$3,300	Excl. productive uses, program costs of US$500,000
SHS (PV technology)	US$400–500	Installing 20 Wp solar PV panels
	US$600–750	Installing 50 Wp solar PV panels

a. This does not include the marginal cost of supply of electricity, which is currently calculated by ENEE as US$79/MWh for 2006–10.
b. The costs include capital costs, diesel, and operation and maintenance costs over the 15 years of the expected system lifetime.

According to the simulations, the most economic option to meet the Government's goal of 400,000 new connections by 2015 would be installing in 50 percent of the targeted households (80,000) SHS of 20 Wp at an approximate program cost of US$400, and installing in the other 50 percent SHS of 50 Wp at an approximate program cost of US$600. This combination would have a net present value of US$200 million, much lower than the cost of grid extensions. This economic SHS option would require annual disbursements from the Government of approximately US$22 million in its initial years, well above the US$16 million that were programmed under PLANES.

If the Government's intention is to invest around US$16 million per year (according to PLANES), none of the annuities from the different options presented in Table A9-4 provide a viable scenario. In other words, more financing sources will definitely be required to meet the target of 80 percent electrification by 2015. However, the annuities presented in Table A9-4 provide flexibility in terms of making different combinations of electrification programs with different technologies.

Furthermore, the State need not be the one that finances all the investments. Investments can be implemented with funds from various sources, and they can even be partially financed by the beneficiaries themselves, provided that their payment capacity is considered.

Finally, the problem with energy service provision for rural areas is not strictly financial in nature, considering that the mere injection of funding in and of itself—without changing the

current structure—would not suffice to improve service delivery. This funding deficit aggravates the other deficiencies associated with the lack of parties responsible for the service and the scarcity of technical and administrative skills.

Although communities have taken part in service provision on prior occasions, a general framework is required to stimulate their participation, such as support and training, in order to adapt the relevant organizations, and with the additional benefit of creating a source of employment for the communities.

Therefore, one of the major challenges faced by the Honduran government is to design service provision business models for the electrification of isolated rural areas that are distinct from grid extension projects. There are currently multiple technologies available for stand-alone systems that are more economical and flexible in meeting demand than grid extensions, and there are positive international experiences reported with the different business models.

Nevertheless, certain obstacles must be surmounted in order to enable the introduction of electrification projects based on alternative technologies and different business models.

The first such obstacle has to do with the fact that there is currently no institutional mechanism for subsidy allocation to off-grid renewable energy projects.

The second obstacle is that due to the technical characteristics and the different types of ownership of service provision in rural areas, it is necessary to adapt the existing regulations to the different types of renewable energy business models. The process is not a simple one and, on occasion, it requires delegating responsibility, control, and oversight tasks to specialized organizations. This issue will be discussed thoroughly in the next chapter.

Finally, it is essential to work on the technical training of FOSODE personnel so that in the short term electrification projects can be undertaken in communities that cannot connect to the grid. Lack of the necessary knowledge and skills for off-grid electrification technologies, and the inadequate business models, are some of the major barriers to implementing these projects.

9.3 ANALYSIS OF TARIFFS AND SUBSIDIES - RECOMMENDATIONS FOR A SUSTAINABLE SCHEME

This section presents the results of the tariff analysis and of the subsidy mechanism related to electrification that are currently used by Honduras. Considering that a thorough tariff analysis was carried out in Chapter 5, in the first part of this section, a brief evaluation is made of the subsidy disbursement mechanism, emphasizing the amounts disbursed as subsidies and the number of beneficiaries, and also verifying that the subsidy recipients are really from the neediest sectors of the population. In a second part, policy options with tariffs and subsidies are evaluated, an analysis is made of how the Government's direct subsidy can be refocused, and how the new connections that are planned to be carried out under the PLANES will impact ENEE's finances.

9.3.1 Subsidies: Beneficiaries and recipients

In contradiction to the provisions set out in the Electricity Law, currently tariffs have been set at levels much lower than the requested level in order to cover at least part of the service costs. Hence, a generalized subsidy for all residential customers is currently being applied (rather than a stepped rate), leading to many non-poor customers getting subsidies. Table 9.2 summarizes the number of poor and non-poor households that benefit from the cross-subsidies and the direct subsidies provided by the Government.

Table 9.2 - Households Benefitting from Subsidies

Households	Subsidies Beneficiaries	Non-beneficiaries	Total
Poor	384,159	525,523	909,682
Non-poor	421,182	185,362	606,544
Total	805,341	710,885	1,516,226

It is possible to derive from Table 9.2 the error of exclusion (percentage of poor households that benefit from the subsidies), which is equivalent to 58 percent, and the error of inclusion (non-poor benefiting from the subsidies over total subsidy beneficiaries), which is equivalent to 52 percent. These high levels indicate that electricity subsidies in Honduras are highly mistargeted.

Because in Honduras a significant percentage of the population is without access to the grid in the lowest-income deciles, subsidizing consumption is not the most equitable solution. A more sensible alternative would include subsidizing access, a proposal that should be considered in the Government's electrification strategy. However, no information was available about subsidies to connection, which is FOSODE's current practice. Hence, it is necessary to evaluate how the subsidy level is determined on a connection-by-connection basis.

9.3.2 Policy options with tariffs and subsidies

It is possible to design different policy alternatives that permit refocusing the subsidy or achieving a higher cost recovery for ENEE through tariff increases. A summary of those options is presented in the matrix shown in Table A9-14, which combines different policy alternatives dealing with tariff or direct subsidy modifications, thus freeing up resources that could be used to promote other electrification activities.

This kind of analysis is useful for policymaking purposes. For example, looking at the analyses illustrated in Table A9-14, a policy option is to increase residential tariffs by 20 percent and reduce direct subsidies by 10 percent. Under this option, the average tariff for residential customers with consumption levels between 0 kWh and 20 kWh would move from recovering 16 percent of the service cost to 32 percent; for those with consumption levels of between 101 kWh and 150 kWh, the average tariff would increase cost recovery from 32 percent to 66 percent; for those with consumption levels of between 151 kWh and 300 kWh, from 47 percent to 74 percent; and for those with consumption levels greater than 501 kWh the average tariff would be almost at par with the service cost (98.5 percent).

Though residential customers will continue to be heavily subsidized, the above pricing policy option would have significant financial impacts. It would increases ENEE's revenues from residential tariff collection by US$2.6 million per month and free up about US$1.5 million per year of direct government subsidy that can be employed in alternative electrification investments. To put this in perspective, the overall resources made available by this policy option are sufficient to finance approximately 46,000 additional new connections per year, assuming US$700 per connection, if tariffs were modified and subsidies were better targeted.

If the policy objective is to release the largest amount of resources for alternative electrification uses, then the optimum mix of measures in this case would require increasing tariffs at par with service provision costs, while completely eliminating the Government's subsidy to residential users and redirecting the money to promote connections in remote rural areas. It is necessary, however, to assess the degree of social and political acceptance that such measures would face.

Another policy option would be increasing tariffs by 20 percent and eliminating the government's direct subsidy, while maintaining cross-subsidies for the residential category. Such a pricing policy would imply freeing up resources amounting to approximately US$3.8 million per month (about 65,000 new connections per year, assuming US$700 per connection). Again, the social and political acceptance of increasing tariffs and eliminating the direct subsidy would need to be evaluated.

For example, Foster and Yepes (2006) studied the burden that these kinds of charges might represent for urban households in Latin America and in Honduras.[31] They found that in Bolivia, Honduras, and Nicaragua, utility bills of around US$10 per month already represent a substantial burden for 30 to 50 percent of urban households. However, when the same exercise is repeated in public/private partnership (PPP) terms for Honduras, utility bills in the range US$10 to US$15 per month appear to be affordable to a greater percentge of the population, while less than 14 percent of the population would appear to face genuine problems of affordability at any of the levels considered.

An additional issue that needs to be considered is the impact that the new connections, planned under the PLANES, will have on ENEE's finances. The financial burden on ENEE will increase substantially, as will the amount of direct subsidy that the Government will have to provide, if it is assumed that the adjusted tariff and direct subsidy are kept as they are today, and that all 400,000 new connections planned under the PLANES are of poor customers with an average monthly consumption in between 51 kWh and 100 kWh. If approximately 45,000 new connections are made per year until 2015, (in order to meet the target set under the PLANES), and each new customer has an average monthly consumption of 65 kWh,[32] then the estimated

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[31] Foster and Yepes estimated the percentage of the urban population within each Latin American country that would need to spend more than 5 percent of their income to purchase a subsistence block of water or electricity at different cost levels in current U.S. dollars. For greater detail, see V. Foster and T. Yepes, "Is Cost Recovery a Feasible Objective for Water and Electricity? The Latin American Experience," World Bank Policy Research Working Paper 3943, June 2006.

[32] In the PLANES, annual average consumption rates are presented for different departments. The national annual average consumption rate was estimated using an average of the different consumption rates per department, reaching approximately 777 kWh (approx 65 kWh/month).

annual tariff deficit caused by the new connections is US$3.5 million. In turn, the additional direct subsidy needed per year from the Government would be approximately US$619,000. The estimated annual tariff deficit caused by the new and existing connections in 2015 could reach US$41.1 million, while the amount of the direct subsidy, to keep the status quo, will be US$7.1 million.

9.3.3 Targeting subsidies and improving tariff design: Summary

A key issue in tariff design is the tradeoff that exists between the economic criterion of allocation efficiency and the political considerations relating to tariff acceptance by the public. This issue can be particularly complex with some specific social sectors. The analysis presented in Annex 9 shows that the status quo is not financially sustainable for ENEE, that there are different options to improve tariff design and subsidy targeting, and that financial resources currently focused inefficiently can be liberalized and directed to the neediest. However, these policy options are dependent on the political will of the Government and the social acceptance of the public.

The governance structure of marginal urban and rural areas, and the informal relations that characterize these settings, make it difficult to reach the desired beneficiaries. For example, different experiences in other countries have shown that, frequently, subsidies collected by the utilities through tariffs paid by existing customers were channeled to the benefit of other customers who were not in need or, in the worst cases, to the utility's own benefit. In other cases, the subsidies provided to residents in marginal urban areas frequently ended up in the hands of illegal service providers.

Hence, one of the major challenges to providing subsidies lies in minimizing errors of inclusion; that is, minimizing the proportion of subsidy recipients who are not the intended customers. Thus, how to transfer subsidies becomes a truly relevant policymaking challenge for the government authorities in Honduras. Further analytical work on subsidy delivery mechanisms will have to be done, and revision of alternative experiences with, for example, cash payments/transfers should also be evaluated.

In turn, when designing lifeline tariffs, the main challenge is to arrive at the appropriate level of consumption to be subsidized, if inclusion and exclusion errors are to be minimized and perverse incentives are to be avoided. Some mechanisms, such as effective metering systems, like the prepaid meters, can be used to minimize exclusion errors, that is, the proportion of intended subsidy recipients who do not actually get the benefits. However, exclusion errors may still appear if there is difficulty in accommodating household size in setting the tariff, something that can easily happen in slums.

10. DIVERSIFYING ENERGY SOURCES

The diversification of energy sources is a key element of the energy strategy to reduce the volatility of generation prices, reduce dependency on imported fuel, and improve energy security. The experience in Honduras shows that reliance on a single source of energy to meet energy demand (for example, hydroelectric generation or oil-based thermal generation) increases the vulnerability of energy supply, either to energy shortages during drought conditions or to the volatility of oil prices. Reliance on a single source of supply—a large generation project, energy imports from one country—is also a risky strategy because energy supply is vulnerable to disruptions in the source of supply.

Diversification of energy sources usually comes at an additional cost. It may be that a single source of energy or a source of supply is cheaper than other sources, and that the use of other sources to diversify supply increases costs. The additional costs should be compensated by the benefits of increased security or reduced vulnerability.

Fortunately, the diversification of energy sources in Honduras under current conditions may contribute to reducing generation costs. The results of the generation expansion plans (Chapter 3) show that diversification based on the development of hydroelectric resources, renewable power, and coal-fired generation is consistent with least-cost generation expansion.

It is the right moment to promote a diversification policy because of the following:

a) A long-term scenario of high international oil prices is likely.

b) Oil-fired thermal generation is no longer competitive under a high oil price scenario.

c) About 120 MW in expensive Power Purchase Agreement (PPAs) with thermal plants will expire in 2010.

d) There is a substantial potential of untapped hydroelectric and small renewable resources.

e) The *Sistema de Interconexión Eléctrica para América Central* (SIEPAC) project will be commissioned in 2009.

f) The high per capita energy consumption.

Moreover, Honduras has many options to diversify energy sources, including:

a) Development of indigenous renewable resources, mainly large and medium hydro, minihydro, windpower, and biomass, which can be economically competitive.

b) Development of coal-fired or gas-fired thermal generation based on imported fuels.

c) Expanding electricity trade with the regional energy market.

d) Promoting energy efficiency and load management programs. More efficient and better use of energy is a diversification option that reduces the need to expand energy supply.

10.1 DEVELOPMENT OF LARGE AND MEDIUM-SIZED CAPITAL-INTENSIVE PROJECTS

The indicative least-cost generation expansion plans for the three demand scenarios are dominated by coal-fired plants and hydroelectric projects, capital-intensive projects that increase market and project risks for private developers. Hence, the scenarios represent a policy challenge in terms of how to create the right incentives and conditions to mobilize private investment to finance these projects. This section discusses these issues.

10.1.1 Hydroelectric projects

The development of hydroelectric projects in Honduras faces the following difficulties:

a) The lower Patuca river basin is a protected area in the Mesoamerican Biological Corridor. In the past, initiatives to develop the Patuca 2 project were unsuccessful due to the opposition of international environmental groups and nongovernmental organizations. The development of the Cangrejal project also has had strong opposition from environmental groups for other reasons. Therefore, the development of the Patuca river basin requires careful consideration of the environmental impact in the downstream area and a complex process of public consultation with native populations and local communities, which have substantial political clout (international support).

b) Several licenses and permits should be obtained to develop a hydroelectric project, in addition to a long-term supply agreement: environmental license, water rights contract, and operation contract, which have to be approved by the National Congress (except for the environmental license). The operation contract adds complexity and uncertainty because it duplicates part of the PPA and gives to the Government the right to terminate in advance the contract and the intervention of the project for reasons of national interest (provisions to guarantee an essential public service).

c) The hydroelectric projects in the Patuca river basin are located in the northeast part of the country, a region with weak interconnections to the load centers in Tegucugalpa and San Pedro Sula. The US$40 million Amarateca-Juticalpa 230 kilovolt (kV) transmission line is needed to interconnect the Patuca 2 and 3 projects to the load center. However, the full cost of this transmission line should not be charged to the generation projects, because this line is necessary to attend the demand growth of the northeast region and has been included in the transmission expansion plans.

The development of hydroelectric projects by the private sector under non-recourse project finance schemes has faced difficulties. The arrangements whereby all risks are ring-fenced by contracts is expensive, because each shareholder should make a generous provision for risks that are expensive to manage if they are not pooled. Thus it makes sense that the public sector assumes the risks that cannot be managed efficiently by the private sector. In this case, a public/private partnership is necessary and justifiable to mobilize private participation (see section below).

10.1.2 Coal-fired and gas-fired thermal plants

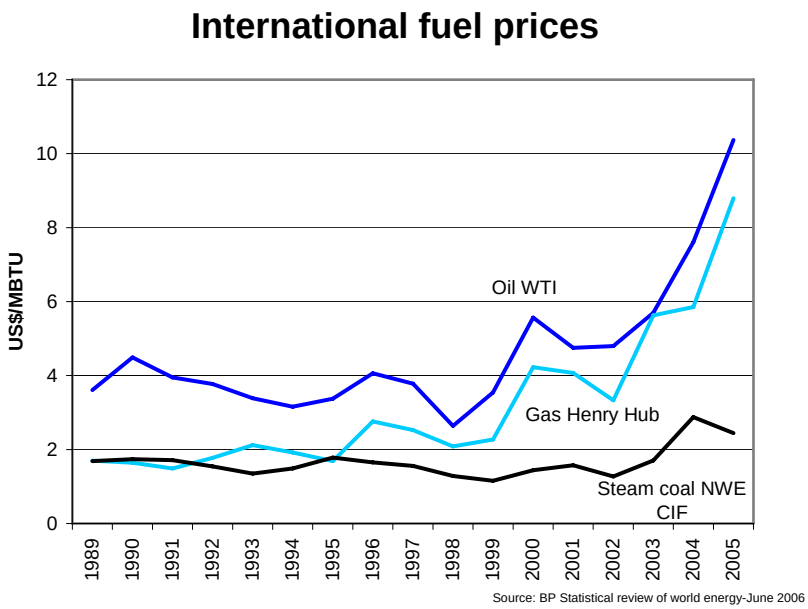
A coal-fired generation plant is very attractive as a baseload plant to meet projected demand in the 2010s. The levelized generation costs are in the range of US$56/megawatt-hour (MWh) to US$70/MWh depending of the investment costs and the technology. At the higher cost range a combined cycle gas turbine (CCGT) plant using imported liquefied natural gas (LNG) becomes competitive.

Coal-fired plants are an interesting option to diversify energy sources in Honduras and help reduce generation costs and price volatility. Although these plants do not reduce the dependency on imported fuels, they can substantially reduce the oil bill (cost per Million British Thermal Unit [MBTU] is about 25 percent of oil). International coal prices have been stable in the past and have shown a low correlation with oil prices, and could contribute to reducing the volatility of generation prices (see Figure 10.1).

But the combustion of fossil fuels, especially coal, is a major source of air pollution (sulfur oxide [SOx], nitrogen oxide [NOx], particulate matter [PM], and carbon dioxide [CO_2]). SOx and NOx contribute to acid rain and CO_2 to greenhouse gases (GHG) and to climate change. The conventional sub-critical pulverized coal steam plants require specialized equipment and good-quality coal to reduce SOx, NOx, and PM emissions within the limits established by environmental regulations,: electrostatic precipitators to remove PM, scrubbers for SOx, low NOx burners, and selective catalytic reduction equipment for NOx.

Fluidized bed combustion (FBC) is a well-established clean coal technology that uses a combustion process that captures more than 90 percent of the sulfur and prevents the formation of 70 to 80 percent of the nitrogen oxides. FBC systems provide a high sulfur-capture rate without degrading thermal efficiency and also have the ability to use high-ash coals.

Figure 10.1



However, FBC cannot sequester CO_2 emissions, and coal-fired plants produce more GHG emissions than any other thermal plant: 100 percent more than gas-fired CCGT and 35 percent more than medium speed diesel using heavy fuel oil (see Table 10.1).

Table 10.1

Thermal generation
GHG emissions

Fuel	CO_2 emission factor (fuel) a/ tCO_2/TJ	Technology	Heat rate TJ/GWh	Efficiency %	CO_2 emission factor (generation) tCO_2/GWh
Residual fuel oil	77.4	MSD	8.6	42%	666
Residual fuel oil	77.4	ST	10.0	36%	774
Diesel oil	74.1	CCGT	7.8	46%	580
Natural gas	56.1	GT	11.5	31%	644
Natural gas	56.1	CCGT	7.8	46%	439
Coal (Cerrejon)	94.6	AFBC	9.5	38%	896

a/ 2006 IPCC Guidelines for National Greenhouse Inventories (default values)

Coal-fired plants also require adequate port facilities to unload, store, and handle the coal. Preliminary information indicates that the Port of Castilla in the Trujillo Bay on the Atlantic coast may be used to import coal from nearby Colombia. It is estimated that a 600 MW plant will require about 120,000 tons per month. A feasibility study is necessary to evaluate the port conditions, the investment and operation costs of the port and fuel-handling facilities, and the power transmission lines required to connect the plant to the 230 kV transmission grid at Reguleto, if the Amarateca-Juticalpa-Reguleto transmission line is developed.

A gas-fired CCGT option, which has the advantage of using a clean fuel with low environmental impact, poses other problems. The idea of a gas pipeline interconnection project from

Venezuela/Colombia or from Mexico to Central America was studied in the 1990s and will be studied in more detail in 2007 under the Mesoamerican Energy Integration Program. The feasibility of this project is not clear because Mexico is importing gas from the United States and Colombia does not have enough gas reserves. This may be a long-term solution when Venezuela completes the gas pipelines to bring gas from the huge gas reserves of eastern Venezuela to the Colombian border, and the gas demand in Central America is large enough to justify the gas interconnection with Colombia. Other options are being considered to bring natural gas to Central America. The technology to transport compressed natural gas (CNG) by ship may be commercialized in the near future[33] and Colombia and Panama are studying this possibility.

LNG is an option to bring gas to countries in the region, and has the advantage of having limited cross-border issues. The Atlantic basin market for LNG in the Americas is dominated by Trinidad Tobago as the major exporter and the United States as a major importer. Puerto Rico and the Dominican Republic represent about 5 percent of the LNG market in the Americas with imports for power generation. The price of LNG imported in the Americas is driven by the price of pipeline gas, the competing fuel in the United States (supplies about 98 percent of the gas market), which is highly volatile and correlated with oil prices (see Figure 10.1). Therefore, this solution is not very effective in reducing the volatility of power generation in Honduras.

The investment costs of unloading, storage, and regasification facilities for LNG are site specific and have substantial economies of scale. A 600 MW CCGT generation plant will require a regasification capacity of about 0.7 million tons of LNG per year, considered to be a small-scale facility with an investment costs of about US$90 million. A CCGT in the Atlantic coast of Honduras will also need a 230 kV transmission line to connect it to the transmission grids. All these problems have to be evaluated at the feasibility level before taking a decision to use the LNG option.

10.1.3 Public/private partnerships (PPPs)

The role of private participation in the electricity sector in Honduras will be determined not only by policy decisions and political considerations but also by the investment, project, market, and country risks that the private sector is willing or able to take under specific country and project conditions. In countries like Honduras, with a weak regulatory framework and high country risks, the private sector is not willing to take all investment risks of financing, developing, and operating generation projects to sell power in a wholesale power market. In these cases, public/private partnerships (PPPs) have been used to share the investment risks between the public and private sector and to allocate to the private sector the project and country risks it is able to manage.

The development of generation capacity in Honduras by independent power producers under long-term PPAs is a PPP arrangement that allocates to the private sector risks it is willing and able to manage: (a) the local private sector has taken full responsibility for the construction, financing, and operation of diesel generators, an option with low project risks (relatively low investment costs, short preparation and construction periods, and easy deployment and

[33] Sea NG Corporation received authorization in late 2006 to build the first CNG ship, using Coselle containers (coiled pipeline), which may be competitive to transport gas over medium distances from 200 km to 2,000 km.

operation); (b) *Empresa Nacional de Energía Eléctrica* (ENEE) and the Government have taken all the market risks (long-term PPA with fixed charges that remunerate the investment costs and variable charges that cover real fuel costs) and credit and foreign exchange risks (PPAs with energy prices in U.S. dollars and payments guaranteed by the Government).

This PPP arrangement does not work for the development of hydroelectric projects and large thermoelectric projects that are included in the least-cost generation expansion plan, characterized by high capital costs, long construction and amortization periods, complex environmental issues, and need of additional investments in transmission and/or fuel-handling facilities. It is unlikely that the private sector will be willing to take all the construction and development risks of these projects: completion of feasibility and environmental impact studies, obtaining all the required licenses and permits, completing the required port facilities and transmission expansion, obtaining long-term financing, and so forth.

For these kinds of partnerships to work, they must provide their members with a prospect that allows them to advance their interests. Specifically, the results of these kinds of partnership agreements should not be uncertain; they should be predictable to a certain degree of likelihood rather than in a discretionary manner. Experience shows that it is necessary to define ex ante what the rights and obligations of each member of the partnership are. The rights and obligations of public and private players have to be related to the extent of control that each stakeholder has over the factors that give rise to risks. The rationale behind this is that stakeholders should have incentives to mitigate/eliminate the adverse events from which risks emerge.

Hence, what is needed is a PPP arrangement where the public partner supports the completion of feasibility and environmental impact studies; secures timely granting of licenses and permits; supports the process of public consultation, approval, and implementation of the environmental mitigation plan; facilitates resettlement of displaced population; provides payment guarantees and facilitates other financial support mechanisms that reduce the financial costs and ensure required long-term financing; and takes responsibility for implementing the transmission expansion plans to strengthen the 230 kV grid. The private sector will provide its technical, commercial, and managerial expertise to design, structure, ensure financing for, construct, and operate and maintain generation projects.

10.1.4 Improving expansion planning and energy procurement

The generation expansion planning and energy procurement process operates as follows:

a) ENEE prepares an indicative generation expansion plan, submits it for the consideration of the *Comisión Nacional de Energía* (CNE), and CNE presents it to the Energy Cabinet for approval.

b) The expansion program is an indicative plan that provides information to investors about future electricity demand growth, and needs and options, to develop a sufficient and efficient power supply.

c) Project developers can request SERNA to grant exclusive rights to study site-specific generation projects for a maximum of two years.

d) ENEE, acting as a single buyer, uses the indicative plan to determine the size and timing of additional generation capacity and the type of plant that is required (peak, baseload, and so forth).

e) ENEE requests proposals to provide required generation capacity using competitive bidding procedures and gives flexibility to bidders for the selection of the location, technology, and fuel for the new generation. The proposals include the transmission works required to connect the plant to the transmission grid, complying with reliability norms.

f) Bidders should submit proposals to supply firm capacity.

g) The tender documents require that thermoelectric generation plants are subject to economic dispatch based on merit order of energy price bids.

The expansion planning and procurement procedures for a single-buyer scheme or a wholesale market that allows competition for the market should guide future government actions (policies and regulations) and provide a signal to investors to induce an efficient allocation of resources. Private investors respond to these signals and to government policies and investment incentives, and take investment decisions based on their strategies and their expectations on rate of return adjusted for risk. Although the existing procedures are reasonable, some improvements are necessary to facilitate the development of large capital-intensive generation projects that help diversify the energy sources:

a) The government units responsible for planning and policy formulation should strengthen its technical and operational capabilities to identify and assess the potential and prepare basic studies for site-specific candidate projects: small hydro, wind, medium, and large hydroelectric projects.

b) The Government should formulate and adopt appropriate policies and incentives to develop the generation projects that can contribute efficiently to the implementation of the diversification policy, including the PPP arrangements discussed above.

c) The generation expansion plans should provide sufficient information and analysis to guide government policy: for example, need to promote renewable power, assess vulnerability of power supply and actions to manage risks, and options to mobilize private financing. A least-cost solution alone is not very helpful.

d) CNE should establish rules and procedures for energy procurement that promote competition and least-cost generation expansion: sufficient lead time for the preparation of proposals and commissioning of competitive projects; nondiscriminatory and transparent procedures to evaluate different generation technologies; planning in advance of the bidding process to ensure timely commissioning of required capacity; establish limits on contract duration, long enough to facilitate private financing, but short enough to promote competition and reduce the risks of stranded costs; and promote energy pricing schemes and dispatch requirements adequate for the operation of a competitive wholesale power market.

10.2 DEVELOPMENT OF SMALL RENEWABLE ENERGY PROJECTS

The development of renewable energy generation projects (defined as up to 50 MW) has been promoted by Decrees No. 85-98 and 267-98, complementing the Electricity Law of 1994. This law contemplates tax breaks to developers and a secure buyer for energy at attractive prices (ENEE is the default buyer at prices with a premium.). Under this umbrella, private sponsors have negotiated about 30 PPAs with ENEE for small renewable energy plants.

Despite this, the potential for the development of off-grid renewable sources appears to be largely untapped, though a resource base assessment for the different sources is not available. Generation projects based on biomass,[34] geothermal,[35] and wind[36] are at a more advanced stage of development, while little has been done to promote and develop microhydro power[37] and the use of photovoltaic (PV) capacity,[38] due to the lack of specific incentives and policies for off-grid rural electrification programs. Even the new Renewable Bill, which is now before the Congress and is reviewed in Annex 10, section 1.3, fails to emphasize specific incentives and mechanisms for off-grid solutions.

A review of the international experience on the development of renewable energy is presented in Annex 10, section 1.5.

10.3 EXPANDING ENERGY TRADE WITH THE REGIONAL MARKET

The *Comisión Regional de Interconexión Eléctrica* (CRIE) approved in 2005 the final Rules and Regulations for the Regional Electricity Market that will apply once the SIEPAC project is commissioned in 2009. These regulations confirmed the basic market design proposed by the consultants in 2003:

a) The regional market is the seventh market, independent of the six national markets, that can handle all the market models adopted in the region: single buyer, and competitive wholesale markets with spot markets based on declaration of variable costs or energy price bids.

b) The regional market is based on the principle that market agents (generators, distributors, marketers, or large consumers) can trade energy freely, with open access to the regional and national transmission grids, and have the right to install generation plants in any of the national grids.

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[34] Nine projects for 81.8 MW are now in operation.

[35] Three projects for a combined 85.5 MW of installed capacity are at different stages of implementation.

[36] Wind projects for about 60 MW of installed capacity are currently under study.

[37] No information on microhydro appears to be available. A project co-financed by IDA, GEF, and the European Union is developing some potential on a pilot basis.

[38] It is estimated that there are 5,000 PV systems installed in the country. The size of the potential rural market, including households, commercial users (retail stores, restaurants, and so forth), and institutions (schools, clinics, community centers) appears to be very large.

c) Energy trade in the regional market is done in a regional contract market and a regional spot market. The contract market allows firm and non-firm physical contracts and financial contracts. The spot market is based on hourly price bids for incremental sales and purchases of energy.

d) According to the framework treaty for the regional market, a country can authorize a single vertically integrated company to do all energy transactions with the regional market provided that this company has established independent business units with separate accounts.

The expansion of the capacity for energy trade in the regional market in 2009 represents an opportunity to diversify the energy sources in Honduras and facilitate the development of a competitive wholesale national market: private investors can develop generation projects in Honduras to sell energy to the local and the regional markets, the distribution units can have the option to buy energy in the regional market, and large consumers in Honduras can have the option to purchase energy from the regional market.

Apparently not all benefits of the regional market can be achieved with the existing legal framework in Honduras. The Electricity Law of 1994 grants to ENEE exclusive rights to sign energy import and export contracts (art. 9) and establishes that the local demand should be supplied first with the local generation, and only surplus energy can be exported (art. 13). These rules would limit the potential benefits of the regional market: (a) ENEE becomes an intermediary in all international contracts and may have a conflict of interest when a large consumer wants to buy energy from the regional market, and (b) generators installed in Honduras would not be able to sign firm physical contracts to export energy.

However, the Government may have the option to clarify, through regulations, the scope of the exclusivity clause and to give it a less restrictive interpretation. Third parties may participate in the regional contract and spot markets provided that they have signed agreements with the ENEE for the use of the transmission lines and comply with the rules and regulations for the operation and economic dispatch of the national interconnected system. ENEE has exclusive rights for the coordination of international energy trade, in its role of system operator and power market administrator, but is not an intermediary that takes ownership of all energy that is traded with the regional market.

The adoption of policies and regulations in Honduras that promote regional energy trade and competition in the regional market will facilitate the transition from a de facto single-buyer model to a competitive wholesale power market (see Chapter 7). The barriers for regional trade established in the Electricity Law can be reduced substantially in the medium term by taking actions that do not require changes in the law: a less restrictive interpretation of the exclusivity clause, the restructuring of ENEE and the creation of independent business units, and the application of simple transmission charges to facilitate open access. Remaining barriers can be eliminated in the longer term with changes in the law to create a spot power market and allow exportation of firm energy, and by the corporatization of the independent business unit.

10.4 ENERGY EFFICIENCY

Energy efficiency measures at both supply and demand are the most economical options to reduce the need for additional generation capacity, and to improve security of supply through a reduction in consumption. In the case of Honduras, the implementation of energy efficiency measures could effectively reduce the short-term need for emergency generation and/or power rationing. Furthermore, energy efficiency measures on the demand side could be used in conjunction with rural electrification programs to improve access, and reduce the impact of higher electricity tariffs. Under the *Proyecto de Generación Autónoma y Uso Racional de Energía Eléctrica* (GAUREE), financed by the European Union since 1999, ENEE has developed a number of studies to identify energy efficiency opportunities. A compact fluorescent bulbs program for the marketing and sales pilot program to increase the use of energy-efficient compact fluorescent lamps (CFLs) has been designed. The program envisions giving away, in a three-phased operation, a free 20W CFL bulb to 800,000 households (the majority of Honduran households still use inefficient 60W, 75W, and 100W bulbs).

Although some progress has been achieved, Honduras is still lagging behind other countries in the region in terms of design and implementation of energy efficiency programs. Large efficiency improvements could be made in the areas of air conditioning for both the residential and commercial sectors. The electricity tariff structure for residential consumers is also an impediment to the success of energy efficiency programs. The potential for energy efficiency is presented in Annex 10.

Recently, an Inter-Institutional Group for the Efficient Use of Energy (GIURE) was established in Honduras with the participation of SERNA, the *Consejo Hondureño de la Empresa Privada* (COHEP), the Ministry of Education, ENEE, the *Universidad Nacional Autónoma de Honduras* (UNAH), the *Consejo Empresarial Hondureño para el Desarrollo Sostenible/Proyecto de Eficiencia Energética en los Sectores Industrial y Comercial de Honduras* (CEHDES/PESIC), CNE, and the *Colegio de Ingenieros Mecánicos, Electricistas y Químicos* (CIMEQH) to promote energy efficiency measures. GIURE has set out a plan to reduce the national energy demand by 100 MW in 2008, equivalent to an 8 percent reduction of the peak demand forecasted by ENEE. To that end, it has designed the following programs, outlined in Table 10.2:

Table 10.2 - Program to Reduce Energy Demand

Activities	Entity Responsible
Program of energy-efficient bulb replacement	GAUREE/ENEE/SERNA/UNAH
Promotion of gas stove use	COHEP/SERNA
Rationalization of subsidies and tariffs	ENEE/SERNA
Use of clean development mechanisms	SERNA/ENEE
Educational campaign	GAUREE/ENEE-SERNA
Efficiency in the industrial and commercial sectors	PESIC
Mass communication campaign	COHEP
Create a Foundation	COHEP/PESIC

Source: Campaña de Promoción y Ahorro de Eficiencia Energética, February 2007.

GIURE is also working on a strategic partnership with the Ministry of Education to implement the *Guardianes de Energía* (Energy Guardians) program to help children become drivers of change at home. In addition, the strategic partnership seeks the inclusion of Energy Efficiency in the school curriculum using dynamic and interactive programs.

Furthermore, ENEE's GAUREE designed a pilot project to deliver energy-saving lamps. To that end, arrangements are being made to purchase 50,000 bulbs, to be used as part of a pilot project that will take place in certain cities in Honduras, including major ones. They will be sold by public and private school students, who will train potential users in how to use the lamps. The pilot project is in the demonstration phase and the discussion regarding its continuity has not started yet.