PN. ABU-495

USAID

Center for Envirnoment
Office of Energy, Environment, and Technology

ENERGY FROM SUGARCANE COGENERATION IN HONDURAS

U.S. Agency for International Development
Bureau for Global Programs, Field Support, and Research
Center for Environment
Office of Energy, Environment, and Technology
Washington, D.C. 20523-1810

Report No. 94-02

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

ENERGY FROM SUGARCANE COGENERATION IN HONDURAS

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Biomass Energy Systems and Technology Project
DHR-5737-A-00-9058-00
August 1994

This publication was made possible through support provided by the Office of Energy, Environment, and Technology; Center for Environment; Bureau for Global Programs, Field Support, and Research; U.S. Agency for International Development. The opinions expressed herein are those of the author(s) and do not necessarily reflect the views of the U.S. Agency for International Development.

ACKNOWLEDGEMENTS

This report results from the efforts of a team organized by Winrock International Institute for Agricultural Development and funded by the Office of Energy, Environment, and Technology of the U.S. Agency for International Development (USAID). The project manager was Mr. Bradford Hollomon of Winrock's Renewable Energy and the Environment Program, and the team included Mr. Felix Ah-Kee, who analyzed sugar mill operations and designed conceptual cogeneration systems, and Mr. H. Mike Jones, who handled utility economics and planning aspects of the study. Ms. Fay Ellis assisted with administrative arrangements and with preparation of the report.

The team is indebted to several organizations and individuals in Honduras for their assistance and insight. First, the project would not have been possible without the active cooperation we received from the managers and superintendents at each of the country's eight sugar mills. Although space does not allow us to acknowledge all of these people individually, the initial interest and encouragement of Ing. Marcio Valenzuela, the General Manager of Azucarera Yojoa, were important factors in our being able to initiate the study. Managers of the Central de Ingenios and Asociación Nacional de Productores de Azucar were also helpful.

The project also could not have gone forward without the assistance of the Planning Department of the Empresa Nacional de Energía Eléctrica (ENEE) under the direction of Lic. Mauricio Mossi. The team is particularly grateful to Ing. Ana Carranza and Lic. Wilfredo Girón for accompanying us on our initial mill visits and to Ing. María David for supplying utility transmission and distribution system data and helping to secure critical comments on the draft report from mill managers. Thanks are also due to Ing. José Humberto Moncado of the Interconnected Grid Operations Department.

Other indispensable contributors include Mr. John Williams and Mlle. Pascale Brière of SNC Shawinigan, ENEE Master Plan consultants, and Ms. Marjorie Stern of the National Rural Electric Cooperative Association. Finally we acknowledge the essential support of Ing. Carlos Flores, the US Agency for International Development Energy Officer in Tegucigalpa at the outset of the study and his successor, Ing. Francisco Figueroa.

TABLE OF CONTENTS

ACKNOWLEDGEMENTS 3
TABLE OF CONTENTS 5
SUMMARY 7
1.0 INTRODUCTION 9
2.0 THE HONDURAN SUGAR INDUSTRY 11
2.1 BACKGROUND 11
2.2 SUGAR MILLS 15
2.2.1 Río Lindo 15
2.2.2 Santa Matilde 16
2.2.3 Central Progreso 16
2.2.4 Chumbagua 17
2.2.5 Los Mangos 18
2.2.6 El Porvenir 18
2.2.7 San Ramón 19
2.2.8 La Grecia 20
3.0 ANALYSIS OF COGENERATION POTENTIAL AND COST 21
3.1 TECHNICAL APPROACH AND ASSUMPTIONS 21
3.2 CAPITAL AND OPERATING COST ESTIMATES 25
3.2.1 Santa Matilde 25
3.2.1.1 CASE 1: In-season operation only. 25
3.2.1.2 CASE 2: Year-round operation. 26
3.2.1.3 CASE 3: Year-round operation. 26
3.2.2 Río Lindo 27
3.2.2.1 CASE 1: In-season operation only. 27
3.2.2.2 CASE 2: Year-round operation. 28
3.2.2.3 CASE 3: Year-round operation. 28
3.2.3 San Ramón 29
3.2.3.1 CASE 1: In-season operation only. 29
3.2.3.2 CASE 2: Year-round operation. 30
3.2.3.3 CASE 3: Year-round operation. 31
3.2.4 Chumbagua 32
3.2.4.1 CASE 1: In-season operation only. 32
3.2.4.2 CASE 2: Year-round operation. 32
3.2.4.3 CASE 3: Year-round operation. 33
3.2.5 El Porvenir 34
3.2.5.1 CASE 1: In-season operation only. 34
3.2.5.2 CASE 2: Year-round operation. 35
3.2.5.3 CASE 3: Year-round operation. 35
3.2.6 Central Progreso 36
3.2.6.1 CASE 1: In-season operation only. 36

3.2.6.2 CASE 2: Year-round operation..... 37
3.2.6.3 CASE 3: Year-round operation..... 38
3.2.7 Los Mangos..... 38
3.2.7.1 CASE 1: In-season operation only..... 38
3.2.7.2 CASE 2: Year-round operation..... 39
3.2.7.3 CASE 3: Year-round operation..... 40
3.2.8 La Grecia 41
3.2.8.1 CASE 1: In-season operation only..... 41
3.2.8.2 CASE 2: Year-round operation..... 41
3.2.8.3 CASE 3: Year-round operation..... 42
3.3 ENVIRONMENTAL CONSIDERATIONS 43

4.0 POWER DEMAND, SUPPLY AND POTENTIAL COGENERATION PRICES.. 45
4.1 BACKGROUND..... 45
4.2 ELECTRIC SECTOR LAW - AUTHORIZATION FOR PRIVATE POWER AND DISTRIBUTION PRIVATIZATION 48
4.2.1 Pricing Terms and Conditions under the New Electricity Law 49
4.2.2 Retail Tariffs..... 49
4.2.3 Avoided Cost 49
4.3 MARGINAL COST ANALYSIS 51
4.3.1 Avoided Cost 51
4.3.2 Application Of Avoided Cost Principles In Honduras 54
4.3.2.1 Loan Subsidies 54
4.3.2.2 Short-term Capacity and Energy Shortages..... 54
4.3.2.3 Average Peaker Method of Marginal Cost Analysis 55
4.3.2.4 Value of Cogeneration - Loss Reduction 55
4.3.2.5 Regional Load Characteristics and the Value of Cogenerated Power 56
4.3.3 Marginal Cost Estimates..... 57
4.3.4 Methodology Applied..... 58
4.3.5 Time Varying Avoided Costs 61

5.0. ECONOMIC COSTS AND BENEFITS..... 63
5.1. ASSUMPTIONS 63
5.2. RESULTS 64
5.3. DISCUSSION 65

APPENDIX A
System Design Parameters

APPENDIX B
ENEE New Generating Options and Operating Assumptions

APPENDIX C
Economic Evaluation

ENERGY FROM SUGARCANE COGENERATION IN HONDURAS

SUMMARY

Honduras has eight sugar mills, operated by seven companies, with a combined crushing capacity of approximately 25,000 tons of cane per day. Total sugar production in 1992 was 3,905,323 hundredweight, of which 92 percent was consumed domestically, and 8 percent filled Honduras' quota of exports to the U.S.. Five of the mills representing most of the production capacity, are located in the northern part of the country in the valleys to the south and west of San Pedro Sula. Two mills are near the Pacific coast in the vicinity of Choluteca, and one small mill lies to the east of Tegucigalpa. With the exception of the mill near Tegucigalpa, which is undergoing privatization, all of the mills are owned by private companies.

Using bagasse as a fuel, the Honduran sugar industry should be in a position to generate approximately 36 megawatts of power, for the nation during the five-month cane crushing season from January to May, when low rainfall diminishes hydroelectric capacity. In addition, the three mills in the Choluteca and Santa Bárbara Departments may be advantageously situated to help limit power transmission and distribution costs associated with nearby load growth, especially if they can generate power all year with supplemental fuel.

The objective of the study is twofold: to establish from a technical perspective how much power each of the mills could export and at what cost; and to estimate what the power would be worth to the national electric system in the context of ENEE's expansion plans, given the specific timing and location of possible power production at the mills. To accomplish this, "avoided cost" criteria, based on ENEE planning data, have been applied in an economic analysis of mill cogeneration options to yield projections of the power production potential and to screen candidate installations for further development. Specific findings appear below:

1. Except under special circumstances, none of the mills studied can profitably produce power for export at a cost below US$0.10 per kWh if they are confined to operation during the crushing season only. This is primarily because the season is too short, and some of the mills are too small or inefficient in their use of steam. (See Figure 5.1.)

2. Exceptions may exist at Río Lindo, where the existing boiler is capable of increased pressure, and at Central Progreso, where the management is already contemplating purchasing additional boiler capacity to accommodate plant expansion. In both of these instances, the mill owners would not have to amortize the full cost of installating high-pressure boilers with electric sales revenues and could therefore possibly justify investments in power sales confined to the crushing season.

3. If the mills generated power throughout the year using Bunker C as a supplemental fuel, the industry could profitably export over 300,000 megawatt hours per year at a price at or below US$0.085 per kWh, as also shown in Figure 5.1.

4. If suitable port facilities were built for importing fuels for other power generation purposes, perhaps on the north coast, the cost of power produced by the mills located nearby could be reduced by approximately US$0.02 per kWh by substituting coal for oil as the supplemental fuel for off-season generation. Other biomass fuels like sawmill waste or possibly cane field trash could also improve economic or environmental performance.

5. The value of cogenerated power to the national grid, based on ENEE's estimated five-year average avoided generation costs, is now approximately US$0.095 per kWh. As illustrated in Appendix B, this figure will probably decrease gradually to about US$0.081 per kWh by the end of the century, when it should begin to rise again. In the near term, the value is independent of time of year because of ENEE's ability to level seasonal load fluctuations by storing energy at hydroelectric dams.

6. In the case of the Chumbagua mill, power cogenerated year-round may be worth more than the avoided generation cost, because of transmission and distribution system improvements that ENEE might be able to scale back or postpone. If the utility could obtain power from this mill, located in the vicinity of La Flecha, it might be able to meet new demand at the proposed industrial park at Naco, for example, without adding substation or transmission line capacity.

7. With the exceptions of San Ramón, Los Mangos and La Grecia, all of the mills appear to represent promising investment opportunities, at least for year-round cogeneration. The decisions as to whether to invest the needed resources at each site will depend on the strategic interest of each company in diversifying into the electric power market and on the outcome of power sales contract negotiations with ENEE. The principal barrier to cogeneration investments in the eyes of several sugar industry managers is the absence of clear long-term pricing and contract terms for power sales.

8. In-season cogeneration will not result in any incremental environmental degradation, since no additional fuel will be burned, and environmental quality will benefit from corresponding reduced combustion emissions at ENEE oil-fired powerplants. Use of oil or coal as a supplemental fuel for year round operation will result in local emissions of acid gases, ash, and uncombusted organic materials, but these will be at least partially offset by further reductions by ENEE.

1.0 INTRODUCTION

This study arises out of the need for economical new supplies of electric energy to suppport future growth and development in Honduras. The national utility, the Empresa Nacional de Energía Eléctrica (ENEE), depends primarily on hydropower to supply its customers, and diminished rainfall in past years has combined with increasing demand to force scheduled curtailments in the major cities. Growing industries have no alternative to generating their own power, at a significant cost.

Against this background, ENEE has undertaken a major master planning effort (Plan Maestro) to project future power demand and to evaluate alternative new generation options. At the same time, the national legislature is considering a new law that would pave the way for ENEE to purchase power generated independently by private entities. In anticipation of the passage of the new law, ENEE has already solicited bids from independent developers for 150 MW of new supply.

In some places in the world, notably the islands of Hawaii, Mauritius and Cuba, the sugar industry contributes substantially to local electric supply. In other locations, like Honduras, the industry burns waste bagasse to generate electricity and steam for its own needs but not for export to the surrounding community. With no incentive in the form of an opportunity to sell power, mill managers generally configure their installations in such a way as to burn all of the bagasse produced, while providing only for energy self-sufficiency.

Where the managers have the opportunity to sell power at a price comparable to the cost of conventional generation, investments in plant modifications to produce surplus power can become attractive. This generally involves replacing existing low pressure boilers, rated typically at around 20 atmospheres, with higher pressure ones capable of generating steam in the vicinity of 60 atmospheres; installing extraction condensing turbines to expand the steam on its way to the existing sugar milling process or condenser; and tightening up the design and operation of the mills to minimize process steam requirements.

Since sugar production is seasonal, the profitability of cogeneration investments can often be enhanced by instituting year-round power production through the use of supplemental fuels. Non-bagasse fuels must be purchased, but their cost is likely to be more than offset by added revenues from power sales, and the additional capital expenditures required for larger condensers and fuel storage and handling equipment are minimal. While oil and coal are more typical supplemental fuels, other forms of biomass like sawmill waste or cane field trash are possible alternatives as well.

Because of interest expressed by ENEE's management and representatives of the Honduran sugar industry, the U.S. Agency for International Development has sponsored this assessment of the potential for sugar industry contribution to the nations electric supplies. The purpose is to estimate how much power the sugar industry could produce at what cost and to suggest the value of the power to the national grid, given the location and timing of its availability.

The pages that follow report the results of analyses performed after a visit to Honduras in June of 1993. At that time the project team visited with ENEE staff and consultants, sugar industry association representatives, and managers and superintendents at each of the country's eight mills. The body of the report is organized in four chapters. Chapter 2 provides technical and historical background on the present design and operation of each individual mill, and Chapter 3 presents alternative cogeneration system configurations and associated costs for seasonal operation using bagasse only and for year-round generation using either bunker fuel or coal. Chapter 4 discusses at length the value, in the context of ENEE's anticipated costs, of the power that the sugar industry might make available to the national grid. Finally, Chapter 5 integrates the material in the preceding chapters in an overall analysis of economic costs and benefits.

2.0 THE HONDURAN SUGAR INDUSTRY

2.1 BACKGROUND

The sugar industry is one of the most important economic activities in Honduras, producing the third most important contribution to the country's exports. The eight sugar factories in Honduras are also the largest producers of biomass in the country. The principal waste product of the sugar factories is bagasse, which represents about 30 percent of the weight of cane entering the factories. Bagasse, a useful fuel, contains about 50 percent moisture, the rest being mostly combustible fiber. Sugars and ash are also present in small amounts.

Bagasse is burned in the sugar factory boilers to produce steam, which is used to run turbines to produce electricity and to provide thermal energy to process sugar cane juice into commercial sugar. In general, the sugar factories in Honduras burn bagasse inefficiently and require supplementary fuels and purchased electricity to satisfy their total energy requirements.

Table 2.1 shows the present ownership structure of the eight sugar factories in operation in Honduras. Table 2.2 presents 1992 production levels.

TABLE 2.1 HONDURAS SUGAR FACTORIES

Company	Factories Owned
Azucarera Yojoa (AYSA)	Río Lindo
Compania Azucarera Chumbagua	Chumbagua
Compania Azucarera Hondurena S.A. (CAHSA)	Santa Matilde
	San Ramón
Azucarera Cantarranas S.A. (ACANSA)	El Porvenir
Azucarera La Grecia (formerly Central)	La Grecia
Azucarera Choluteca (ACHSA)	Los Mangos
Azucarera del Norte (AZUNOSA)	Central Progreso

TABLE 2.2 SUGAR FACTORIES IN 1992
(In Descending Order of Sugar Production)

Factory	1992 Sugar Production (Tons)
Santa Matilde	50,742
Río Lindo	29,122
Progreso	28,664
La Grecia	26,072
Chumbagua	17,024
Los Mangos	16,930
El Porvenir	13,940
San Ramón	12,771

Figure 2.1 is a map of Honduras showing the location of the eight sugar factories. Five factories, Santa Matilde, Río Lindo, Progreso, San Ramón and Chumbagua are located in the northern part of the country. El Porvenir is close to Tegucigalpa. The two other factories, Los Mangos and La Grecia are located in the southern part of Honduras.

FIGURE 2.1 LOCATION OF HONDURAS SUGAR FACTORIES

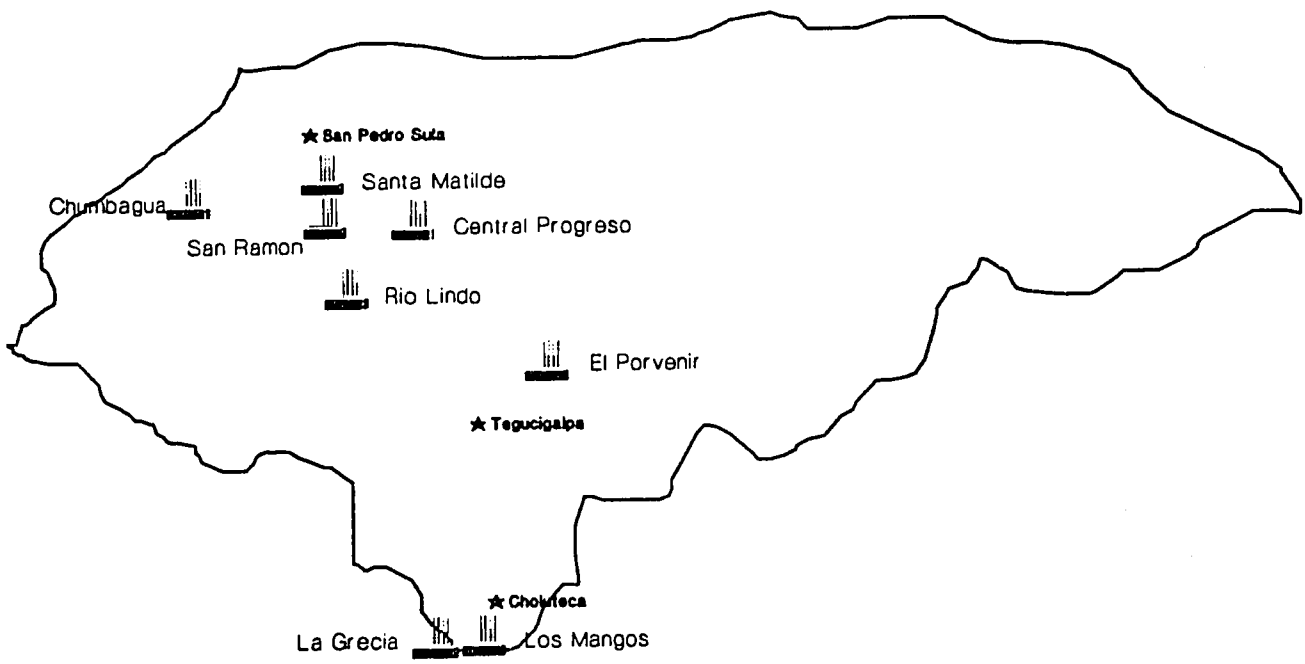


TABLE 2.3 PRODUCTION OF BAGASSE IN IN 1992
(tons)

Factory	Bagasse Production 1992
Santa Matilde	158,622
Río Lindo	91,156
Progreso	117,504
La Grecia	69,420
Chumbagua	48,264
Los Mangos	52,843
El Porvenir	40,273
San Ramón	38,121

The sugar cane harvest occurs only during the dry season, approximately from December to May, limiting the length of the harvest to no more than six months of the year. Most factories operate only during five months of the year. During the harvest season the factories are able to produce electricity for most of their production requirements, although none presently export electricity to the grid.

Due to the availability of low-cost hydro power, most factories have found it expedient in the past to purchase power from ENEE even during the harvest season to supplement their power requirements for processing cane. Some factories such as Río Lindo and Santa Matilde have recently implemented measures to reduce the consumption of steam and electricity with the objective of eliminating electricity purchases from ENEE for processing cane. Even if a factory cannot justify the financial investments required to install a high pressure boiler and an efficient turbogenerator, it may find energy conservation requiring relatively small expenditures to be financially appealing.

HISTORY OF THE HONDURAS SUGAR INDUSTRY

The sugar industry of Honduras started in the mid 1920's with the construction of two sugar factories, Sula Sugar Co., located near La Lima, and Montecristo, near La Ceiba. By 1928, the two factories were producing a total of about 25,000 tonnes of sugar annually. The two factories shut down during the depression year of 1929.

The Cia. Azucarera Hondurena S.A. (C.A.H.S.A.) was founded in 1938 near San Pedro Sula. Its first factory, El Suguete, had capacity of 150 tons cane per day, and produced 12,500 tons of sugar during its first crop on a cultivated area of 250 manzanas. (75 hectares). In 1948, the company built a new factory, San Jose, with a capacity of 600 tons per day and increased the cultivated area to 400 manzanas (120 hectares). During the same year, the Cia. Azucarera Chumbagua S.A. was started in the valleys of Quionita, Santa Barbara, which was an important development project for the region.

During the 1960's CAHSA decided to expand its operations and moved the old factory, San Jose to Choluteca, where the Cia. Azucarera Choluteca S.A., was formed in 1968. During the same decade, the San Ramón factory was built in Villanueva. During the succeeding years the sugar industry increased its production capacity with the creation of four new companies: Azucarera del Norte, S.A. (1974), Azucarera Cantarranas S.A. (1976), Azucarera Central S.A. (1976), and Azucarera Yojoa S.A. (1976).

Today, the sugar industry of Honduras is made up of seven companies owning eight factories and 16,000 manzanas (4,791 hectares) of land under sugar cane, and producing about 200,000 tons of sugar annually. Other owners of sugar cane land include the Cooperativas Campesinas which own 4,000 manzanas (1,198 hectares), and independent farmers who own 21,000 manzanas (6,289 hectares) of land under sugar cane cultivation.

The bulk (92%) of the sugar produced in Honduras is used for local consumption. The remaining 8 percent is exported to the U.S.A., and sold at preferential prices under the U.S. sugar quota system.

Source: Central de Ingenios (CISA)

2.2 SUGAR MILLS

2.2.1 Río Lindo

The Río Lindo sugar factory is owned by Azucarera Yojoa (AYSA). It was built in 1976 and is located in the municipality of Río Lindo, Cortes. It has a daily grinding capacity of 2,600 tons and produced 29,122 tons of sugar in 1992. The area under sugar cane cultivation is 5,001 manzanas (1,498 hectares).

The milling train at Río Lindo consists of five 3-roller Fulton mills. Each roll is 48 inches wide and 28-1/2 inches in diameter. The cane is prepared by cutting with two sets of knives of Cuban design. The mill achieves good extraction at 93 percent. Bagasse moisture is about 51 percent.

Steam is generated in two Riley boilers built in 1948. They were installed at Río Lindo as used boilers in 1977. The boilers are rated at 100,000 pounds per hour each at 600 psi. However, they are presently underutilized, as they are run at only about 80,000 pounds per hour each and at 200 psia. in order to meet the factory's requirements for process steam and electricity. The 160,000 pounds per hour of steam at 200 psia. is piped to two Allis Chalmers/General Electric turbogenerators that produce 1.5 and 1.0 MW of electric power respectively. The 2.5 MW of electricity thus produced is adequate to meet the factory requirements. The exhaust steam at 20 psia. is used for process heat, mostly for juice heating and evaporation. The evaporator is a quadruple effect evaporator with a pre-evaporator.

Río Lindo is the fourth largest sugar factory in Honduras in terms of capacity and the second largest in terms of annual sugar production. It has demonstrated its interest in developing cogeneration of electricity for sale to ENEE. It has completed a detailed engineering study to install new turbogenerators.

AYSA will benefit from cogeneration in several ways. It will eliminate the cost of transporting and storing excess bagasse for later use; it will receive revenues from ENEE for the sale of electric power. The factory will also avoid the expenses of purchasing electricity from ENEE during the harvest months, although in 1992, it was able to meet this goal as a result of the current energy conservation effort.

The factory personnel at Río Lindo are carrying out a program to reduce steam consumption. So far, the effort has resulted in the elimination of purchases of Bunker C fuel as a supplementary fuel.

Río Lindo's current plan for cogeneration consists of increasing boiler pressure to 450 psia. and to run the boilers at 100,000 pounds per hour each. Two new turbogenerators of 4 MW capacity each will replace the existing inefficient Allis Chalmers/General Electric units. The company expects to produce 6 MW net, consume 2.5 MW and have 3.5 MW for export to ENEE during the harvest months.

To establish whether the boiler drums at Río Lindo can withstand the increased pressure, the boiler was inspected and July 1993 and determined to be safe.

2.2.2 Santa Matilde

Santa Matilde factory, with an annual sugar production of 50,742 tons is the largest in Honduras. Together with its sister factory, San Ramón, it is owned by Compania Azucarera Hondureña (CAHSA). Its is located in the northern part of the country in the municipality of Villanueva, Cortes.

The factory was built in 1938 and has a daily grinding capacity of 6,300 tons of cane. The area under cane cultivation is 12,411 manzanas (3,717 hectares).

Santa Matilde factory has a six-mill tandem for grinding cane. the first 4 mills are 54 inches wide and Mills 5 and 6 are 78 inches wide. The mill rolls have a diameter of 36 inches. The mills are driven by individual turbines with inlet steam at 225 psia. and exhaust at 20 psia. Cane is prepared by cutting with two sets of Farrell cane knives.

Steam is generated with three boilers. Two units are rated at 80,000 pounds per hour each at 220 psia. The third unit is rated at 100,000 pounds per hour at 300 psia. The boilers were all built by Bigelow Company in 1975. They all have air preheaters, but no economizers.

There are two turbogenerators of 1.3 MW capacity each made by Terry Company and one 1.5 MW unit made by Worthington Company. The Terry units use about 30-32 pounds of steam per KW-HR generated while the Worthington unit is more efficient, requiring 26-27 pounds of steam per KW-HR generated.

The energy utilization at San Matilde is presently inefficient, and the management is currently undertaking an effort to improve energy conservation using air preheat and improving instrumentation. Other improvements that are under review include changes in the evaporator design to save steam and to eliminate electricity purchases from ENEE during the harvest season.

Underscoring the present energy inefficiency of the factory is the fact that it has to purchase electric power from ENEE for its sugar production operations, and requires the use of diesel fuel as a supplementary fuel to bagasse. While the situation has improved since 1992, the potential for large financial savings still exist, as shown in Table 2.4.

TABLE 2.4 ENERGY AND FUEL PURCHASED (1992-93)

	1993	1992
Energy purchased from ENEE (kWh)	2,138,000	2,768,000
Diesel fuel purchased (Gallons)	3,827	8,097

2.2.3 Central Progreso

The Central Progreso factory is owned by Azucarera Del Norte (AZUNOSA), and is an affiliate of Standard Brands Company. It is located about 16 Km from El Progreso, in the municipality of Gunchias, Yoro.

The factory has a daily grinding capacity of 4,000 tons of cane. In 1992, it produced 28,664 tons of sugar.

Progreso has two Babcock & Wilcox boilers rated at 85,000 pounds per hour each and 150 psi pressure, and superheated to 450 deg. F. They were built in 1926. There is an additional boiler rated at 80,000 pounds per hour and 300 psia. pressure which is severely worn out and may possibly be permanently out of commission. The resulting shortage of steam generation capacity has limited the daily cane processing capacity to only 1,800 tons of cane. Plans to expand sugar production and install a refinery would raise steam requirements from the present 195,000 pounds per hour (only 170,000 pounds per hour available) to 208,000 pounds per hour. The possibility of installing a new 600 psia boiler is under study.

The turbogenerator set consists of one 2.5 MW General Electric turbine using 150 psi steam at 450 degrees F, and exhaust at 15 psi. This unit is very old, dating back to 1952. It requires 45,000 to 50,000 pounds per hour. The factory requires 1.75 MW of peak power.

The Progreso factory is interested in cogeneration because it wants to decrease electricity purchases from ENEE, to decrease downtime due to steam shortage, and to increase sugar production and install a sugar refinery. In the past, it also considered generating power for irrigation use by a sister company during the dry season which coincides with the sugar harvest.

2.2.4 Chumbagua

Chumbagua sugar factory was built in 1948 and is owned by Compania Azucarera Chumbagua. It is located in the municipality of San Marcos, Santa Barbara, near the town of La Flecha, 7 Km to the South by road over the Chamelecon river.

The factory has a daily grinding capacity of 2,300 tons of cane, and produced 17,024 tons of sugar in 1992. Sugar cane is grown over an area of 4,455 manzanas (1,334 hectares) of company land.

Cane is prepared by two sets of cane knives. The mill tandem consists of four 3-roller mills, 48 inches wide and 29 inches diameter, with individual turbine drives. The factory can achieve a mill extraction of 92 percent. Moisture percent bagasse is about 50%.

Two years ago, Chumbagua installed a new Babcock & Wilcox boiler to replace four old Bigelow units. The new boiler operates at 200 psi. and is rated at 125,000 pounds per hour. The old boilers operated at 200 psi. and were rated at 20,000 pounds per hour each, for a total of 80,000 pounds per hour.

The steam from the boiler is at 200 psi pressure and superheated to 500 deg. F. It is sent to two Elliott turbogenerators with a capacity of 1000 KW each. The exhaust steam is at 15 psi. It is used to heat juice in juice heaters and to evaporate juice in a quadruple effect evaporator.

The factory burns all the bagasse that it produces. It also burns bunker C fuel during factory shutdowns for maintenance. This amounts to about 41,000 gallons per

year. In addition, about 5,000 gallons of diesel fuel is burned to produce electricity per year. The factory does not purchase power from ENEE, in part because the nearby power line from Níspero to Copán has insufficient capacity to meet electricity demand from ENEE's customers in the area.

Chumbagua plans a major expansion of sugar production. It expects to have sufficient steam, with the installation of its new boiler two years ago, to add a fifth mill. It will then replace its old generators to produce more electricity and eliminate purchase of diesel fuel.

2.2.5 Los Mangos

The Los Mangos factory is the oldest in Honduras. In 1930, it was originally brought to a location near San Pedro Sula from the Dominican Republic, where it had already been in operation for an unknown number of years. The factory was moved in 1968 to its present location in the municipality of Marcovia in Choluteca. It is owned by Azucarera Choluteca (ACHSA).

The factory has a daily grinding capacity of 2,000 tons of cane. In 1992 it produced 16,930 tons of sugar. The company has 3,986 manzanas (1,194 hectares) under sugar cane.

Sugar cane preparation is achieved using two sets of cane knives. The cane is crushed in a 5-mill tandem. Four of the mills are made by Fulton and have three rolls each, measuring 42 inches wide and 28 inches diameter. One mill is made by Farrell, and has three rolls measuring 42 inches width and 26 inches diameter. Four of the mills have individual turbines of 375 HP each. A fifth 600 HP turbine drives the last two mills.

Steam is generated by two Babcock and Wilcox boilers operating at 170 psi. and superheated to 450 deg. F. They are rated at 60,000 pounds per hour each. 1.5 MW of electricity is generated from an old General Electric turbogenerator, dating back to 1926. Incoming steam to the turbogenerator is at 150 psi. and exhaust is at 20 psi.. The evaporator system is quintuple effect, with five evaporator cells.

Los Mangos has a severe problem of energy deficiency. It purchases 120,000 kWh of electricity from ENEE annually. Improvements in sugar cane throughput or in energy efficiency may be difficult and costly to achieve at the existing location. The equipment dates back to 1926 when it was first put into operation in the Dominican Republic. The original mill capacity was 1,300 tons cane per day, and the Los Mangos factory has undergone an expansion to increase the capacity to the present 2,000 tons per day. The lack of physical space in the factory precludes any capacity expansion or the modernization of the existing equipment.

2.2.6 El Porvenir

The El Porvenir factory was built in 1926, and is owned by Azucarera Cantarranas S.A. (ACANSA). It Is located in the municipality of San Juan de Flores, Fco. Morazan.

El Porvenir has a daily grinding capacity of 2,400 tons of cane. In 1992, it produced 13,940 tons of sugar and grew sugar cane on 2,405 manzanas (720 hectares) of company-owned land.

The factory prepares the incoming cane using two sets of cane knives which are driven by a single turbine. Four 3-roll mills grind the sugar cane. Each roll is 54 inches wide and 30 inches in diameter. There is one turbine drive for every two mills.

Steam is generated in two Dedini boilers operating at 300 psi and producing 60,000 pounds per hour of steam superheated to 275°C. Although there are two installed Dedini turbogenerators, rated at 800 KW each, only one unit is used at any given time. The shortage of electricity is made up by 600 kW purchased from ENEE. In 1992, El Porvenir purchased 389,072 kWh of electricity from ENEE.

The grinding season lasts from December to May. However, El Porvenir factory remains in operation for only two months of the year due to a lack of cane. The percentage of land owned by the company is only 20 percent and the remaining sugar cane land is owned by independent growers who find it more profitable to grow other crops instead of sugar cane.

2.2.7 San Ramón

San Ramón is the smallest sugar factory in Honduras. It is a sister factory of Santa Matilde, as they are both owned by Compania Azucarera Hondurena S.A. (CAHSA). It is located in the municipality of Villanueva, Cortes, about 3 Km south of the main road to San Pedro Sula from Tegucigalpa.

San Ramón was built in the 1960's. It has a daily grinding capacity of 1,570 tons of cane, and produced 12,771 tons of sugar in 1992.

The factory has two sets of knives to prepare the incoming cane which is ground in four turbine-driven mills with three rolls each. There is one turbine driving two mills, making a total of 2 mill turbines.

Steam is generated in two Babcock and Wilcox boilers designed for 200 psi. pressure and operating at 175-200 psi., and 386 deg. F. They are rated for 40,000 pounds per hour and 30,000 pounds per hour each, for a total of 70,000 pounds per hour. A third small boiler can burn bunker C fuel. Electricity is generated in a 40-year old, 800 KW Worthington turbogenerator. The 800 KW of electricity that is generated is insufficient to run the factory which has to purchase 180 KW of power constantly from ENEE, for a total 180,400 per month during the crop. In the offseason San Ramón buys 43,200 kWh per month from ENEE.

San Ramón also requires supplementary fuel. In 1992, it burned 57,853 gallons of Bunker C oil.

The factory personnel recognize the high inefficiency of energy use at San Ramón. They are considering a number of measures to improve energy efficiency such as changing the evaporator system, installing an air preheater in the boilers, and replacing the existing turbogenerator if and when steam output is adequate. However, CAHSA is considering shutting down the San Ramón factory and moving it to a different location.

2.2.8 La Grecia

La Grecia, with an annual cane grinding capacity of 450,000 tons of cane per year, is the second largest factory in Honduras, after Santa Matilde. It is located in the municipality of Marcovia in Choluteca. The factory, owned until recently by the public sector Azucarera Central (ACENSA), has been purchased by a consortium of private interests and local cane growers.

La Grecia factory's daily cane grinding capacity averages 4,500 tons of cane, and its annual sugar production is approximately 40,500 tons. Cane is grown over an area of 5,500 manzanas.

The milling tandem consists of five mills with individual turbine drives. Mill rolls are 40 inches in diameter and 78 inches in length. The factory has three boilers with the following characteristics.

Steam Flow (lb/hr)	120,000	100,000	96,000
Pressure (psig)	250	250	150
Temperature (deg. F)	506	506	366
Year	1965	N/A	1941
Make	Bigelow	Alpha	Riley-Stoker

As shown above, the factory operates three boilers with a total steam capacity of 316,000 pounds per hour. Two of the boilers produce steam at 250 psi for two of the five mill drives and for two turbogenerators, each with capacities of 3 MW of power, at the steam rate of 30 pounds steam per kWh. The third boiler produces steam at 150 psi for the remaining three mill drives. All five mill drives consume about 30,000 pounds of steam per hour each, for a combined total of 150,000 pounds per hour.

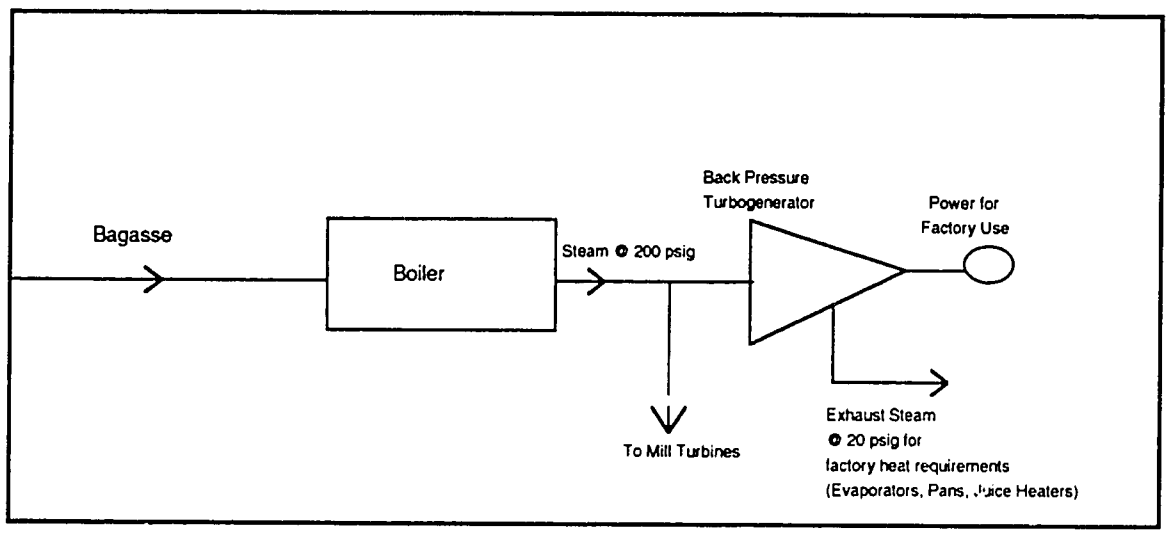
La Grecia is currently inefficient in its steam and power consumption. A preliminary steam balance calculation shows that even when the factory is operating steadily, there is a severe shortage of steam and electricity. The factory meets its steam requirements by supplementing its bagasse fuel with Bunker C oil, which is consumed at the rate of 0.47 gallons per ton of cane. The power produced by the turbogenerators is augmented by the purchase of power from ENEE at the rate of 3.75 kWh per ton of cane, for a total of 1,575,000 kWh annually. Substantial savings in fuel and electrical energy should be possible, and the new mill manager has expressed his intention to effect improvements in the next year or two that will eliminate oil purchases and reduce total internal electric consumption to approximately 3 MW.

3.0 ANALYSIS OF COGENERATION POTENTIAL AND COST

3.1 TECHNICAL APPROACH AND ASSUMPTIONS

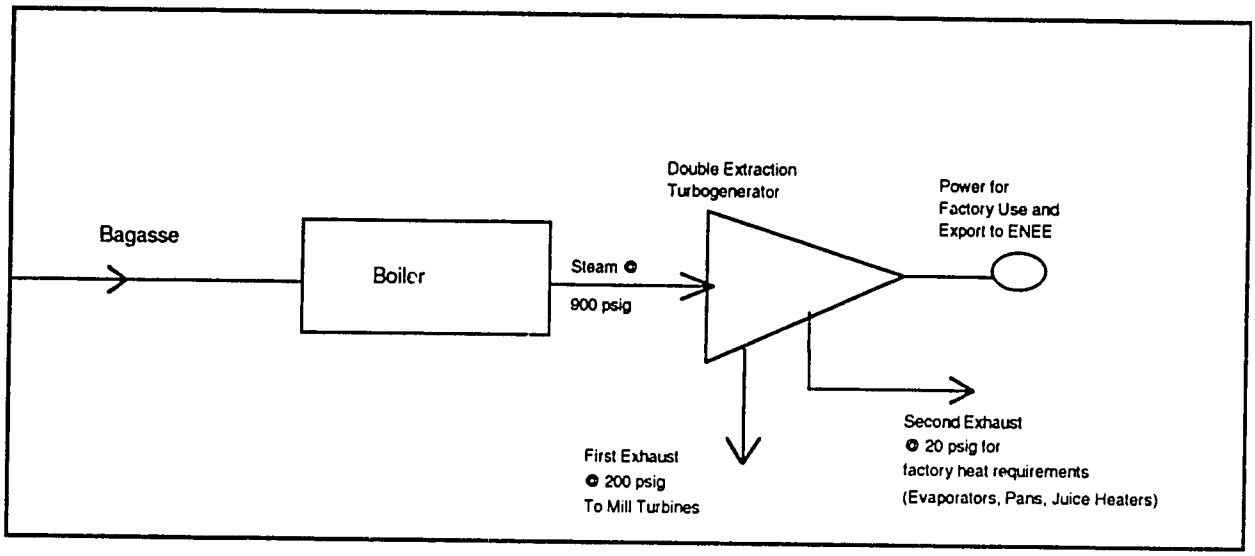
Sugar factories in Honduras generally produce steam at between 200 and 300 psig by the combustion of bagasse. Part of the steam is used to run steam turbines, which drive the mills that crush the incoming cane. The rest of the steam is passed through one or more turbogenerators to produce enough electricity for use by the factory. Exhaust steam from the mill turbines and the turbogenerator, at approximately 20 psig pressure, provides the heat requirements of the evaporators and vacuum pans. The figure below depicts a typical existing installation.

FIGURE 3.1 EXISTING CONFIGURATION



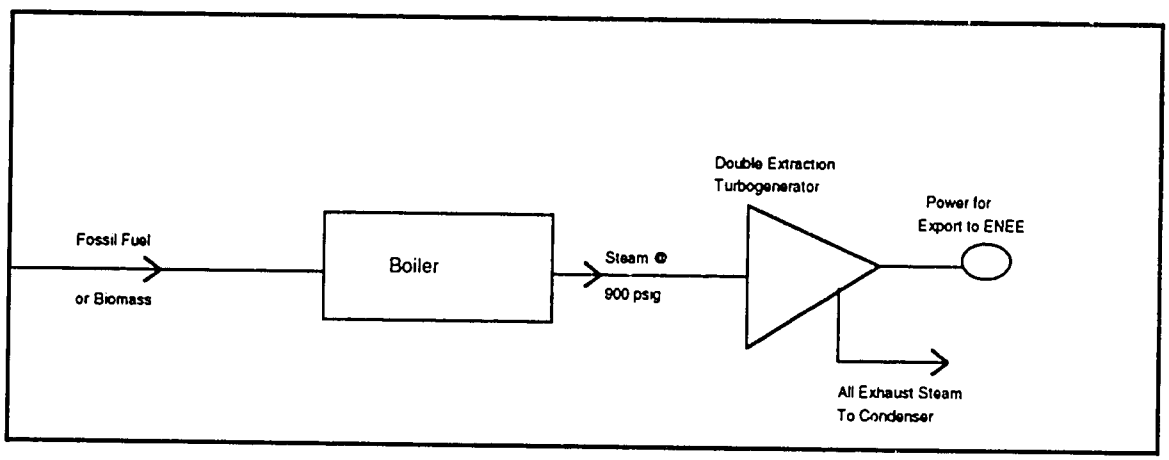
In the proposed system, steam is produced at 900 psig and piped through a double extraction turbine generator. The first extraction, occurring at 200 psig, provides steam to turn the mill turbines. The second extraction, occurring at 15 psig, together with exhaust steam from the mill turbines, provides the steam needed to run the evaporators and vacuum pans. This configuration appears in Figure 3.2.

FIGURE 3.2 PROPOSED IN-SEASON CONFIGURATION



For year-round operation, the generator continues running during the off-season, and all of the steam condenses after passing through the high-pressure turbine, as illustrated in Figure 3.3. Since the system is sized to consume all of the available bagasse during the grinding season, bunker oil or coal, supplemented perhaps by other sources of waste biomass, would be used as a secondary fuel when the remainder of the mill is not in operation.

FIGURE 3.3 PROPOSED OFF-SEASON CONFIGURATION



For each of the eight sugar factories in Honduras, three cases are presented for evaluation in terms of profitable potential for cogeneration.

CASE 1 In-season production of electricity from bagasse only.

CASE 2 Year-round production of electricity using Bunker C fuel oil during the off-season as a supplementary fuel.

CASE 3 Year-round operation using coal during the off-season as a supplementary fuel.

For purposes of evaluating these cases, a reference Base Case is considered to reflect the existing conditions, with seasonal factory operations and no power sales to ENEE.

The sizing of the boilers and turbogenerators used in developing the capital costs is based on designing the boilers to burn all the bagasse that is produced per hour. A smaller boiler would require adding storage capacity for bagasse whereas a larger unit would require the in-season burning of supplementary fuels. Storing bagasse, a labor-intensive and energy-consuming operation, adds to its cost as a fuel without any increase in energy availability. Oversizing a sugar factory boiler to burn oil or coal in-season would not be financially beneficial to the sugar company or to ENEE as its own boilers specifically designed to burn oil or coal will operate more efficiently than any sugar factory boiler.

However, the burning of oil or coal during the off-season may be justified on the basis of more efficient capital utilization even if the sugar factory does not enjoy a comparative advantage on fuel as bagasse is not available. Most of the inefficiencies associated with burning oil in a bagasse boiler can be eliminated at the start of the off-season. For example, the grates may be covered with bricks to reduce heat losses, and the boiler controls can be reset for oil or coal. During the off-season, Cases 2 and 3 assume that gross power generation remains the same as in Case 1 (in-season), but net power sales to ENEE will be higher because no power is needed for the sugar factory operations.

Capital costs for boilers and turbogenerators are estimated using actual quotations for new equipment from major international manufacturers, and adjusted for size at the various factories. The boilers are high-pressure units, operating at 900 psi and 850 degrees F. The turbogenerators are double extraction units providing steam for the existing factory requirements.

The cost of piping, civil, electrical, foundation works, buildings, water cooling, pollution control, instrumentation etc. are based on actual projects implemented elsewhere. However, large variations may exist at individual locations based on the availability of existing infrastructure. For example, some locations with plentiful supplies of cooling water may not require any investment in a cooling tower. In other instances, the existing building or foundations may be used. Furthermore, the bidding process may further reduce costs, especially for engineering and erection, depending on the degree of participation of local contractors.

For off-season operations, an availability factor of 90 percent is assumed. During the season, each factory is assumed to operate at its current grinding time efficiency. The total estimated capital costs include 20 percent for miscellaneous items and for contingency.

The cost of a boiler capable of burning bagasse during the season and oil during the season is almost the same as one that burns bagasse only during the season. The additional installation for burning oil consists of an oil pump, piping and oil burners and its cost is relatively small compared to the total project cost. Fuel oil has the advantage of being easier to transport to all the sugar factories. The capability already exists to increase oil shipments to all factories, if required.

Adding the capability to burn coal in a bagasse boiler requires the installation of coal storage facilities, conveyors and feeders. These costs are included in the capital costs estimates. However, these do not include any investments in port facilities or transportation equipment and infrastructure upgrades required to unload coal from ships, store it and transport it to various factory locations. Coal, while being a cheaper fuel than oil, will require investments for its handling, storage and transportation not only at the factory sites, but also at the ports and between the ports and the factories. The delivery of coal to Los Mangos and La Grecia in the southern part of the country may present severe logistical problems.

The assumptions of fuel prices are US$20 per barrel for oil and US$1.48 per mKJ for coal. In a recent study to evaluate power generation alternatives, ENEE made estimates of US$21.73 per KW per year for fixed costs, and US$2.50 per MWh for variable costs when burning oil. When coal is burned these figures are respectively US$23.99 per KW per year, and US$2.70 per MWh respectively. One economic advantage of power cogeneration in a sugar factory is that one may argue that most of the fixed costs of power generation have already been met in the existing sugar operations. However, there will be an increase in management and engineering personnel costs if year-round operation is contemplated. Assuming that fixed costs are already paid for during the season, the additional fixed cost for year-round operation will be a fraction of 7/12 of the fixed costs estimated by ENEE for year-round operations. Thus the additional fixed cost when burning oil during the off-season will be US$21.73 times 7/12, i.e. US$12.68 per KW per year. When burning coal the additional fixed cost will be US$23.99 times 7/12, i.e. US$13.99 per KW per year.

The cost estimates used in this study assume that there is no existing infrastructure. For actual construction, the costs should be reevaluated in greater detail, taking into account specific features of the individual factories. Detailed design and cost assumptions appear as Appendix A.

3.2 CAPITAL AND OPERATING COST ESTIMATES

3.2.1 Santa Matilde

3.2.1.1 CASE 1: *In-season operation only.*

Bagasse fuel only.

The capital cost of installing a 250,000 pounds per hour bagasse-fired boiler operating at 900 psi and 850 degrees F, and a 16 MW double extraction turbogenerator is estimated at US$ 23,102,000, broken down as follows:

Boiler	$5,313,000
Turbogenerator	$3,366,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$7,289,000
Erection and Engineering	$2,846,000
Miscellaneous	$2,042,000
Contingency	$2,246,000
Total	$23,102,000

In Case 1, Santa Matilde will, after meeting its current needs for steam and electrical power, sell 27,294 MWh of electricity to ENEE during the season by burning the same amount of bagasse and without burning additional fuel. Gross power generation will be 15 MW. With an internal usage of 4 MW, there will be net exportable power of 11 MW.

No additional personnel will be required, and fixed O&M costs will remain the same. There will be a small increase in variable costs due to increased power production. Compared to the base case (present operations), the following changes in costs are estimated.

Additional fuel cost	$0
Additional fixed cost	$0
Additional variable cost (27,294 MWh/yr x $2.50/MWh)	$68,235

3.2.1.2 CASE 2: *Year-round operation.*

Bagasse only in-season; fuel oil off-season.

The capital cost will increase slightly compared to Case 1, to US$23,212,000. Compared to Base Case, the following changes in annual power production will occur.

Net exportable power	(in-season)	11 MW
	(off-season)	15 MW
MWh sold to ENEE	(in-season)	27,294
	(off-season)	73,205
	(total)	100,499

Additional costs will be as follows:

Additional costs for fuel oil (178,643 barrels @ US$20/barrel)	US$ 3,572,854
Additional fixed O&M cost (15 MW x $12,680/MW/yr)	US$ 190,200
Additional variable O&M cost (100,499 MWh x US$2.50/MWh)	US$ 251,248

3.2.1.3 CASE 3: *Year-round operation.*

Bagasse only in-season;coal off-season.

The capital cost is estimated to be US$24,712,000, broken down as follows:

Boiler	$5,829,000
Turbogenerator	$3,366,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental etc.	$7,997,000
Erection and Engineering	$3,122,000
Miscellaneous	$2,042,000
Contingency	$2,246,000
Total	$24,602,000

Power production will be similar to Case 2. Increases in O&M and fuel costs compared to Base Case will be as follows:

Additional costs for coal (44,303 tonnes coal/yr)	US$1,554,063
Additional fixed O&M cost (15 MW x $13,990/MW/yr)	US$ 209,850
Additional variable O&M cost (100,499 MWh x US$2.70/MWh)	US$ 271,347

3.2.2 Río Lindo

3.2.2.1 CASE 1: *In-season operation only.*

Bagasse fuel only.

The capital cost of installing a 120,000 pounds per hour boiler and an 8 MW turbogenerator is estimated at US$15,082,000, broken down as follows:

Boiler	$3,186,000
Turbogenerator	$2,221,000
Piping, cooling water, condenserelectrical, foundation, civil, instrumentation, environmental, etc.	$5,213,000
Erection and Engineering	$1,677,000
Miscellaneous	$1,326,000
Contingency	$1,459,000
Total	$15,082,000

The boiler will operate at 900 psi and 850 degrees F. In Case 1, bagasse will be the only fuel that is burned and power will be produced only during the season.

Río Lindo will produce and sell to ENEE 14,476 MWh of electricity during the harvest season, compared to none in the Base Case. Net exportable power will be 5 MW after allowing for 2.5 MW of internal power usage.

No additional personnel will be required during the season, and fixed O&M costs will remain the same. There will be a small increase in variable costs due to increased power production. Compared to the Base Case (present operations), the following changes in fuel and operating costs are estimated.

Additional fuel cost	$0
Additional fixed cost	$0
Additional variable cost (14,476 MWh/yr x $2.50/MWh)	$36,190

3.2.2.2 CASE 2: *Year-round operation.*

Bagasse only in-season; fuel oil off-season.

The capital cost will increase by approximately US$70,000 to US$15,182,000 due to the installation of oil lines and fuel injectors to allow burning of oil during the off-season.

Power production during the season and off-season will be as follows:

Net exportable power	(in-season)	5 MW
	(off-season)	7.5MW
MWh sold to ENEE	(in-season)	14,476
	(off-season)	34,906
	(total)	49,382

Additional costs will be as follows:

Additional costs for fuel oil (85,181 barrels @ US$20/barrel)	US$1,703,620
Additional fixed O&M cost (7.5 MW x $12,680/MW/yr)	US$ 95,100
Additional variable O&M cost (49,382 MWh x US$2.50/MWh)	US$ 123,455

3.2.2.3 CASE 3: *Year-round operation.*

Bagasse only in-season;coal off-season

The capital cost is estimated to be US$16,047,000, broken down as follows:

Boiler	$3,491,000
Turbogenerator	$2,221,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$5,712,000
Erection and Engineering	$1,838,000
Miscellaneous	$1,326,000
Contingency	$1,459,000
Total	$16,047,000

Power production will be similar to Case 2.

Increases in O&M and fuel costs compared to Base Case will be as follows:

Additional costs for coal (21,125 tonnes coal/yr)	US$ 741,013
Additional fixed O&M cost (7.5 MW x $13,990/MW/yr)	US$ 104,925
Additional variable O&M cost (49,382 MWh x US$2.70/MWh)	US$ 133,331

At Río Lindo a fourth option is being pursued. This option consists in increasing the operating pressure of the the two existing boilers from 200 psi to 450 psi, which is lower than its its design pressure. The steam flow in each boiler will be increased from 80,000 pounds per hour each to 100,000 pounds per hour each. Two new turbogenerators of 4 MW capacity each will replace the existing inefficient Allis Chalmers/General Electric units. The company expects to produce 6 MW net, consume 2.5 MW and have 3.5 MW for export to ENEE during the harvest months.

Considering that only a relatively small amount of capital will be required and the revenue increase will be substantial, the selected option may likely be the best option. However, some remaining questions regarding the remaining economic life of the boilers and their ability to operate at the increased pressure of 450 psi are still under discussions.

3.2.3 San Ramón

3.2.3.1 CASE 1: *In-season operation only.*

Bagasse fuel only.

The capital cost of installing a 60,000 pounds per hour boiler and a 4 MW turbogenerator is estimated at US$9,948,000, broken down as follows:

Boiler	$2,102,000
Turbogenerator	$1,465,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$3,438,000
Erection and Engineering	$1,106,000
Miscellaneous	$875,000
Contingency	$962,000
Total	$9,948,000

The boiler will operate at 900 psi and 850 degrees F. In case 1, bagasse will be the only fuel that is burned and power will be produced only during the season.

San Ramón will produce and sell to ENEE 5,615 MWh of electricity during the harvest season, compared to none in the Base Case. Net exportable power will be 2.5 MW after allowing for 1 MW of internal power usage.

No additional personnel will be required during the season, and fixed O&M costs will remain the same. There will be a small increase in variable costs due to increased power production. Compared to the Base case (present operations), the following changes in fuel and operating costs are estimated.

Additional fuel cost	$0
Additional fixed cost	$0
Additional variable cost (5,615 MWh/yr x $2.50/MWh)	$14,037

3.2.3.2 CASE 2: Year-round operation.

Bagasse only in-season; fuel oil off-season.

The capital cost will increase by approximately US$47,000 to US$9,995,000 in order to modify the boiler to burn oil during the off-season through the installation of oil lines and fuel injectors.

Power production during the season and off-season will be as follows:

Net exportable power	(in-season)	2.5 MW
	(off-season)	3.5 MW
MWh sold to ENEE	(in-season)	5,615
	(off-season)	16,256
	(total)	21,871

Additional costs will be as follows:

Additional costs for fuel oil (39,670 barrels @ US$20/barrel)	US$793,400
Additional fixed O&M cost (3.5 MW x $12,680/MW/yr)	US$ 44,380
Additional variable O&M cost (21,871 MWh x US$2.50/MWh)	US$ 54,678

3.2.3.3 CASE 3: *Year-round operation.*

Bagasse only in-season;coal off-season

The capital cost is estimated to be US$10,585,000, broken down as follows:

Boiler	$2,303,000
Turbogenerator	$1,465,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$3,768,000
Erection and Engineering	$1,212,000
Miscellaneous	$875,000
Contingency	$962,000
Total	$10,585,000

Power production will be similar to Case 2.

Increases in O&M and fuel costs compared to Base Case will be as follows:

Additional costs for coal (9,838 tonnes coal/yr)	US$ 345,098
Additional fixed O&M cost (3.5 MW x $13,990/MW/yr)	US$ 48,965
Additional variable O&M cost (21,871 MWh x US$2.70/MWh)	US$ 59,052

3.2.4 Chumbagua

3.2.4.1 CASE 1: *In-season operation only.*

Bagasse fuel only.

The capital cost of installing a 105,000 pounds per hour bagasse- fired boiler operating at 900 psi and 850 degrees F, and a double extraction 7 MW turbogenerator is estimated at US$ 13,923,000, broken down as follows:

Boiler	$2,942,000
Turbogenerator	$2,050,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$4,813,000
Erection and Engineering	$1,547,000
Miscellaneous	$1,224,000
Contingency	$1,347,000
Total	$13,923,000

In Case 1, Chumbagua will, after meeting its current needs for steam and electrical power, sell 9,672 MWh of electricity to ENEE during the season by burning the same amount of bagasse and without burning additional fuel. Gross power generation will be 7 MW. With an internal usage of 2 MW, there will be net exportable power of 5 MW.

No additional personnel will be required, and fixed O&M costs will remain the same. There will be a small increase in variable costs due to increased power production. Compared to the base case (present operations), the following changes in costs are estimated.

Additional fuel cost	$0
Additional fixed cost	$0
Additional variable cost (9,672 MWh/yr x $2.50/MWh)	$24,180

3.2.4.2 CASE 2: *Year-round operation.*

Bagasse only in-season; fuel oil off-season.

The capital cost will increase by $65,000 compared to Case 1, to US$13,988,000.

Compared to Base Case, the following changes in annual power production will occur.

Net exportable power (in-season)	5 MW
(off-season)	7 MW
MWh sold to ENEE (in-season)	9,672
(off-season)	32,964
(total)	42,636

Additional costs will be as follows:

Additional costs for fuel oil (80,443 barrels @ US$20/barrel)	US$1,608,860
Additional fixed O&M cost (7 MW x $12,680/MW/yr)	US$ 88,760
Additional variable O&M cost (42,636 MWh x US$2.50/MWh)	US $106,590

3.2.4.3 CASE 3: *Year-round operation.*

Bagasse only in-season;coal off-season

The capital cost is estimated to be US$14,813,000, broken down as follows:

Boiler	$3,223,000
Turbogenerator	$2,050,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$5,273,000
Erection and Engineering	$1,696,000
Miscellaneous	$1,224,000
Contingency	$1,347,000
Total	$14,813,000

Power production will be similar to Case 2.

Increases in O&M and fuel costs compared to Base Case will be as follows:

Additional costs for coal (19,950 tonnes coal/yr)	US$ 699,793
Additional fixed O&M cost (7 MW x $13,990/MW/yr)	US$ 97,930
Additional variable O&M cost (42,636 MWh x US$2.70/MWh)	US$115,117

3.2.5 El Porvenir

3.2.5.1 CASE 1: *In-season operation only.*

Bagasse fuel only.

The capital cost of installing a 105,000 pounds per hour boiler operating at 900 psi and 850 degrees F and a 4 MW double extraction turbogenerator is estimated at US$13,923,000, broken down as follows:

Boiler	$2,942,000
Turbogenerator	$2,050,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$4,813,000
Erection and Engineering	$1,547,000
Miscellaneous	$1,224,000
Contingency	$1,347,000
Total	$13,923,000

In case 1, bagasse will be the only fuel that is burned and power will be produced only during the season.

El Porvenir will produce and sell to ENEE 7,918 MWh of electricity during the harvest season, compared to none in the Base Case. Net exportable power will be 5.5 MW after allowing for 1.5 MW of internal power usage.

No additional personnel will be required during the season, and fixed O&M costs will remain the same. There will be a small increase in variable costs due to increased power production. Compared to the Base case (present operations), the following changes in fuel and operating costs are estimated.

Additional fuel cost	$0
Additional fixed cost	$0
Additional variable cost (7,918 MWh/yr x $2.50/MWh)	$19,795

3.2.5.2 CASE 2: *Year-round operation.*

Bagasse only in-season; fuel oil off-season.

The capital cost will increase by approximately US$65,000 to

US$13,988,000 in order to modify the boiler to burn oil during the off-season through the installation of oil lines and fuel injectors.

Power production during the season and off-season will be as follows:

Net exportable power	(in-season)	5.5MW
	(off-season)	7 MW
MWh sold to ENEE	(in-season)	7,918
	(off-season)	47,162
	(total)	55,080

Additional costs will be as follows:

Additional costs for fuel oil (115,090 barrels @ US$20/barrel)	US$2,301,800
Additional fixed O&M cost (5.5 MW x $12,680/MW/yr)	US$ 69,740
Additional variable O&M cost (55,080 MWh x US$2.50/MWh)	US$ 137,700

3.2.5.3 CASE 3: *Year-round operation.*

Bagasse only in-season;coal off-season

The capital cost is estimated to be US$14,813,000, broken down as follows:

Boiler	$3,223,000
Turbogenerator	$2,050,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$5,273,000
Erection and Engineering	$1,696,000
Miscellaneous	$1,224,000
Contingency	$1,347,000
Total	$14,813,000

Power production will be similar to Case 2.

Increases in O&M and fuel costs compared to Base Case will be as follows:

Additional costs for coal (28,542 tonnes coal/yr)	US$1,001,201
Additional fixed O&M cost (7 MW x $13,990/MW/yr)	US$ 97,930
Additional variable O&M cost (55,080 MWh x US$2.70/MWh)	US$ 148,716

3.2.6 Central Progreso

3.2.6.1 CASE 1: *In-season operation only.*

Bagasse fuel only.

The capital cost of installing a 200,000 pounds per hour bagasse- fired boiler operating at 900 psi and 850 degrees F, and a double extraction 13 MW turbogenerator is estimated at US$ 20,376,000, broken down as follows:

Boiler	$4,427,000
Turbogenerator	$2,972,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$6,942,000
Erection and Engineering	$2,271,000
Miscellaneous	$1,792,000
Contingency	$1,972,000
Total	$20,376,000

In Case 1, Central Progreso will, after meeting its current needs for steam and electrical power, sell 20,013 MWh of electricity to ENEE during the season by burning the same amount of bagasse and without burning additional fuel. Gross power generation will be 13.2 MW. With an internal usage of 3.5 MW, there will be net exportable power of over 9 MW.

No additional personnel will be required, and fixed O&M costs will remain the same. There will be a small increase in variable costs due to increased power production. Compared to the base case (present operations), the following changes in costs are estimated.

Additional fuel cost	$0
Additional fixed cost	$0
Additional variable cost (20,013 MWh/yr x $2.50/MWh)	$50,032

3.2.6.2 CASE 2: Year-round operation.

Bagasse only in-season; fuel oil off-season.

The capital cost will increase by $96,000 compared to Case 1, to US$20,472,000.

Compared to Base Case, the following changes in annual power production will occur.

Net exportable power	(in-season)	9.7 MW
	(off-season)	13.2 MW
MWh sold to ENEE	(in-season)	20,013
	(off-season)	67,079
	(total)	87,092

Additional costs will be as follows:

Additional costs for fuel oil (144,330 barrels @ US$20/barrel)	US$3,273,899
Additional fixed O&M cost (13 MW x $12,680/MW/yr)	US$ 164,840
Additional variable O&M cost (87,092 MWh x US$2.50/MWh)	US$ 217,730

3.2.6.3 CASE 3: *Year-round operation.*

Bagasse only in-season;coal off-season

The capital cost is estimated to be US$21,688,000, broken down as follows:

Boiler	$4,744,000
Turbogenerator	$2,972,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$7,716,000
Erection and Engineering	$2,492,000
Miscellaneous	$1,792,000
Contingency	$1,972,000
Total	$21,688,000

Power production will be similar to Case 2.

Increases in O&M and fuel costs compared to Base Case will be as follows:

Additional costs for coal (40,596 tonnes coal/yr)	US$1,424,028
Additional fixed O&M cost (13 MW x $13,990/MW/yr)	US$ 181,870
Additional variable O&M cost (87,092 MWh x US$2.70/MWh)	US$ 235,148

3.2.7 Los Mangos

3.2.7.1 CASE 1: *In-season operation only.*

Bagasse fuel only.

The capital cost of installing an 80,000 pounds per hour bagasse-fired boiler operating at 900 psi and 850 degrees F, and a 5 MW double extraction turbogenerator is estimated at US$11,656,000, broken down as follows:

Boiler	$2,496,000
Turbogenerator	$1,675,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$4,023,000
Erection and Engineering	$1,307,000
Miscellaneous	$1,026,000
Contingency	$1,129,000
Total	$11,656,000

In Case 1, Los Mangos will, after meeting its current needs for steam and electrical power, sell 6,114 MWh of electricity to ENEE during the season by burning the same amount of bagasse and without burning additional fuel. Gross power generation will be 4.5 MW. With an internal usage of 1.8 MW, there will be net exportable power of nearly 3 MW.

No additional personnel will be required, and fixed O&M costs will remain the same. There will be a small increase in variable costs due to increased power production. Compared to the base case (present operations), the following changes in costs are estimated.

Additional fuel cost	$0
Additional fixed cost	$0
Additional variable cost (6,114 MWh/yr x $2.50/MWh)	$15,285

3.2.7.2 CASE 2: Year-round operation.

Bagasse only in-season; fuel oil off-season

The capital cost will increase by $56,000 compared to Case 1, to US$11,712,000 in order to allow the combustion of oil in addition to bagasse. Oil will be used during the off-season when no bagasse is available.

Compared to Base Case, the following changes in annual power production will occur.

Net exportable power	(in-season)	2.7 MW
	(off-season)	4.5 MW
MWh sold to ENEE	(in-season)	6,114
	(off-season)	20,983
	(total)	27,097

Additional costs will be as follows:

Additional costs for fuel oil (51,206 barrels @ US$20/barrel)	US$1,024,120
Additional fixed O&M cost (5 MW x $12,680/MW/yr)	US$ 63,000
Additional variable O&M cost (27,097 MWh x US$2.50/MWh)	US$ 67,743

3.2.7.3 CASE 3: *Year-round operation.*

Bagasse only in-season;coal off-season

The capital cost is estimated to be US$12,413,000, broken down as follows:

Boiler	$2,737,000
Turbogenerator	$1,675,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$4,412,000
Erection and Engineering	$1,434,000
Miscellaneous	$1,026,000
Contingency	$1,129,000
Total	$12,413,000

Power production will be similar to Case 2.

Increases in O&M and fuel costs compared to Base Case will be as follows:

Additional costs for coal (12,669 tonnes coal/yr)	US$445,451
Additional fixed O&M cost (5 MW x $13,990/MW/yr)	US$ 69,950
Additional variable O&M cost (27,097 MWh x US$2.70/MWh)	US$ 73,162

3.2.8 La Grecia

3.2.8.1 CASE 1: *In-season operation only*

Bagasse fuel only

The capital cost of installing a 175,000 pounds per hour bagasse- fired boiler operating at 900 psi and 850 degrees F, and a double extraction 8 MW turbogenerator is estimated at US$ 19,625,000, broken down as follows:

Boiler	$4,378,000
Turbogenerator	$2,201,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$7,211,000
Erection and Engineering	$2,312,000
Miscellaneous	$1,673,000
Contingency	$1,840,000
Total	$19,615,000

In Case 1, La Grecia will, after meeting its current goal of consuming only 3 MW and electrical power, sell 12,132 MWH of electricity to ENEE during the season by burning the same amount of bagasse and without burning additional fuel. Net power generation will be 8 MW. With an internal useage of 3 MW, there will be net exportable power of over 5 MW.

No additional personnel will be required. Fixed O&M costs will remain the same. There will be a small increase in variable costs due to increased power production. Compared to the base case (present operations), the following changes in costs are estimated.

Additional fuel cost	$0
Additional fixed cost	$0
Additional variable cost (12,132 MWh/yr x $2.50/MWh)	$30,330

3.2.8.2 CASE 2: *Year-round operation.*

Bagasse only in-season; fuel oil off-season

The capital cost will increase by $110,000 compared to Case 1, to US$19,725,000.

Compared to Base Case, the following changes in annual power production will occur.

Net exportable power (in-season)	5 MW
(off-season)	8 MW
MWh sold to ENEE (in-season)	12,132
(off-season)	42,627
(total)	54,759

Additional costs will be as follows:

Additional costs for fuel oil (104,024 barrels @ US$20/barrel)	US$2,080,488
Additional fixed O&M cost (8 MW x $12,680/MW/yr)	US$ 101,440
Additional variable O&M cost (54,759 MWh x US$2.50/MWh)	US$ 136,898

3.2.8.3 CASE 3: *Year-round operation.*

Bagasse only in-season;coal off-season

The capital cost is estimated to be US$21,688,000, broken down as follows:

Boiler	$4,793,000
Turbogenerator	$2,201,000
Piping, cooling water, condenser electrical, foundation, civil, instrumentation, environmental, etc.	$7,211,000
Erection and Engineering	$2,312,000
Miscellaneous	$1,673,000
Contingency	$1,840,000
Total	$20,030,000

Power production will be similar to Case 2.

Increases in O&M and fuel costs compared to Base Case will be as follows:

Additional costs for coal (25,798 tonnes coal/yr)	US$904,937
Additional fixed O&M cost (8 MW x $13,990/MW/yr)	US$ 111,920
Additional variable O&M cost (54,759 MWh x US$2.70/MWh)	US$ 147,849

3.3 ENVIRONMENTAL CONSIDERATIONS

In addition to the financial costs, some of the options will have incremental environmental impacts associated with them as well. In the case of in-season cogeneration with bagasse fuel only, the same material will be burned in the same quantities and in the same ways as before, and the impacts on air, land and water quality should remain unchanged. For year-round generation, however, additional fuel will be consumed, and the impacts will depend largely on the type of secondary fuel selected. In each case, a favorable effect of independent cogeneration will be to offset generation by ENEE to meet the same level of demand for power.

While other waste biomass resources may be available in specific locations, bunker oil and coal are the most likely supplemental fuels for off-season operation. Sugar mills in Honduras now employ no flue gas emission controls, and while impacts will vary substantially among grades and sources of the coal and oil, either one would evolve oxides of sulfur and nitrogen, ash, and uncombusted organic material. In the case of coal, sulfur content can be high. Also, its ash content is approximately five times that of bagasse, and unlike ash from bagasse, it should be disposed of in appropriate landfills due to the presence of heavy metals and harmful organic substances. Finally, while the off-season is rainy, operation with any fuel while the remainder of the mill is not operating will require additional cooling water to condense steam.

Since the mills are small, the incremental environmental effects may be minor, especially at isolated rural installations. However, their cumulative impact in combination with other nearby polluting activities should be evaluated on a case by case basis.

ENEE has an energy cost incentive to use hydropower in preference to fossil fuel-fired generation, and capacity additions for the remainder of the decade are likely to be gas turbines. (See Table 4.3 below.) For this reason, the probable environmental benefits due to cogeneration at sugar mills will lie in reduced fossil fuel (oil) combustion at ENEE facilities. These benefits would result, in different amounts, from both in-season and all-year operation.

4.0 POWER DEMAND, SUPPLY AND POTENTIAL COGENERATION PRICES

4.1 BACKGROUND

Government policy in Honduras is currently promoting new private power generation, as well as, prospectively distribution privatization. This policy is being driven by a number of factors, among the most important are the shortage of capital for the required power generation expansion, and the complexity of planning and building a large number of new power plants. In addition, the Empresa Nacional de Energía Eléctrica (ENEE) is currently experiencing shortages of energy and capacity due to both substantial growth in consumption and the recent drought. Another important recent policy change, intended to improve the financial viability of ENEE, has been the change in pricing policy to increase future tariffs to equal the long-run marginal cost of electricity supply. This has resulted in very large and controversial rate increases.

Even though ENEE is expecting substantially higher revenues in future years due to recent adjustments in tariff rates, future funds required for expansion of their system are still expected to seriously strain their financial capacity. Information from the Central Bank indicates that expected income of ENEE is $126.9 million with new tariffs in 1993.[1] Official projections of long run marginal cost of electricity for tariff purposes in 1990, put this cost at $0.083 U.S. in 1991 (in 1990 $'s), rising to $0.105 in the year 2000.[2] Capacity expansion expenditures are expected to increase even faster, with amounts of US $15 - US $30 million per year projected to be needed solely for generation investment under plans for the period 1994-2000, with a projected need for US $244 million in 2000, US $192 million in 2002 and US$405 million in 2005 (at 1988 prices).[3]

Power consumption in Honduras has been growing rapidly in recent years, with internal consumption increasing by about 10.9 percent between 1991 and 1992, from 2,115 GWh to 2,347 GWh. Maximum demand reached 433.0 MW on the 25th of November 1992, an increase of 14.9 percent from 377 MW in 1991. This peak was 6.7 percent over that projected the year before by ENEE. The majority of energy supplies are derived from hydroelectric power, with much smaller amounts coming from thermal facilities, respectively, 2,215.1 GWh from hydro and 126.7 GWh from thermal plants in 1992. Due to a multi-year drought being experienced in Honduras, the output of the major hydroelectric facilities on an energy and capacity basis has been significantly decreased in recent years. The result has been an increase in the consumption of Bunker C and diesel fuels by ENEE, reaching 3.6 million gallons Bunker C and 5.0 million

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[1]Banco Central de Honduras, Cuadro 6 "Honduras: Operations of the Rest of the Public Sector," 1992.

[2]Empresa Nacional de Energia Eléctrica, "Costo de La Electricidad en Honduras," Junio 1990, pg.33.

[3]Empresa Nacional de Energía Eléctrica, "Plan de Expansión de Generación," Noviembre 1988, Tabla No.2.

gallons diesel, in 1992. Thermal generation increased from 2.85 GWh in 1991 to 126.7 GWh in 1992. The drought has also contributed to an increased experience of power rationing, outages and higher prices.[4]

The largest power generation facility in Honduras is the El Cajon Hydroelectric Plant, located in the Northern part of the country. Even with the drought, El Cajon provided a maximum of about 310 MW toward peak demand in the month of November 1992, and produced 63 percent of all hydroelectric energy (1,383.5 GWh) for the entire year for ENEE. The next largest hydro facility, Río Lindo, produced about 25 percent of hydro output or 553.5 GWh, and 80 MW (only 40 MW in November).

As part of the process of developing its new electric sector master plan, "Plan Maestro", ENEE and its consultants, SNC-Shawinigan of Canada, have developed sales and peak demand projections by consumption sector and region. These forecasts are based on the most recent available data. These forecasts were reviewed for this report, and appear to be soundly constructed, and therefore are considered the best available forecasts for assessing the potential market for sugar industry cogeneration within Honduras. The base case forecast is shown in Table 1 below, and projects near-term consumption growth rates in 1993 of 6.9 percent, dropping to about 5.9 percent by the year 2000. These near-term growth rates are consistent with recent experience with large new industrial loads being added, for example, for maquiladoras (enterprise zones) and camaroneras (shrimp processing), and consistent with the recent economic recovery being experienced. Load growth varies substantially by geographic zone due to both economic activity, degree of urbanization and variation in household income.

Also shown in Table 4.1 is an adjustment for losses from the current combined technical and non-technical[5] losses of 27 percent to a level of only 14 percent by the year 1997 and thereafter. Total energy consumption rises from 2635 GWh in 1993 to 3707 GWh by the year 2000. System load factor (which is equal to kWh sales divided by maximum demand (kW) multiplied by 8760 hrs/year) is projected to remain the same based on the actual 1980 to 1991 experience. Load factor has been applied to consumption to derive maximum demand forecasts.

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[4]ENEE, "Informe Anual de Operación-1992," Unidad de Planificación y Estadísticas de Operación.

[5]Technical losses refer to those having to due with resistance losses in transmission, and transformation, as well as distribution equipment. Non-technical losses refer to theft and fraud.

Table 4.1. SALES, TOTAL LOSS AND PEAK DEMAND PROJECTIONS ENEE INTERCONNECTED SYSTEM

Projection Case/Year	1993	1994	1995	2000	2005	2010
Consumption (GWh)	2635	2798	2918	3707	4824	6122
Consumption -Growth Rate	6.9%	6.2%	4.3%	5.9%	5.2%	4.8%
Total kWh Losses*	24%	21.5%	19.0%	14.0%	14.0%	14.0%
Maximum** Demand (MW)	477	507	529	671	873	1106
Load Factor	63%	63%	63%	63%	63%	63%
Peak Demand Growth Rate		6.2%	4.3%	5.9%	5.2%	4.8%

Source: BASE CASE-Plan Maestro ENEE-SNC Shawinigan, 1993)

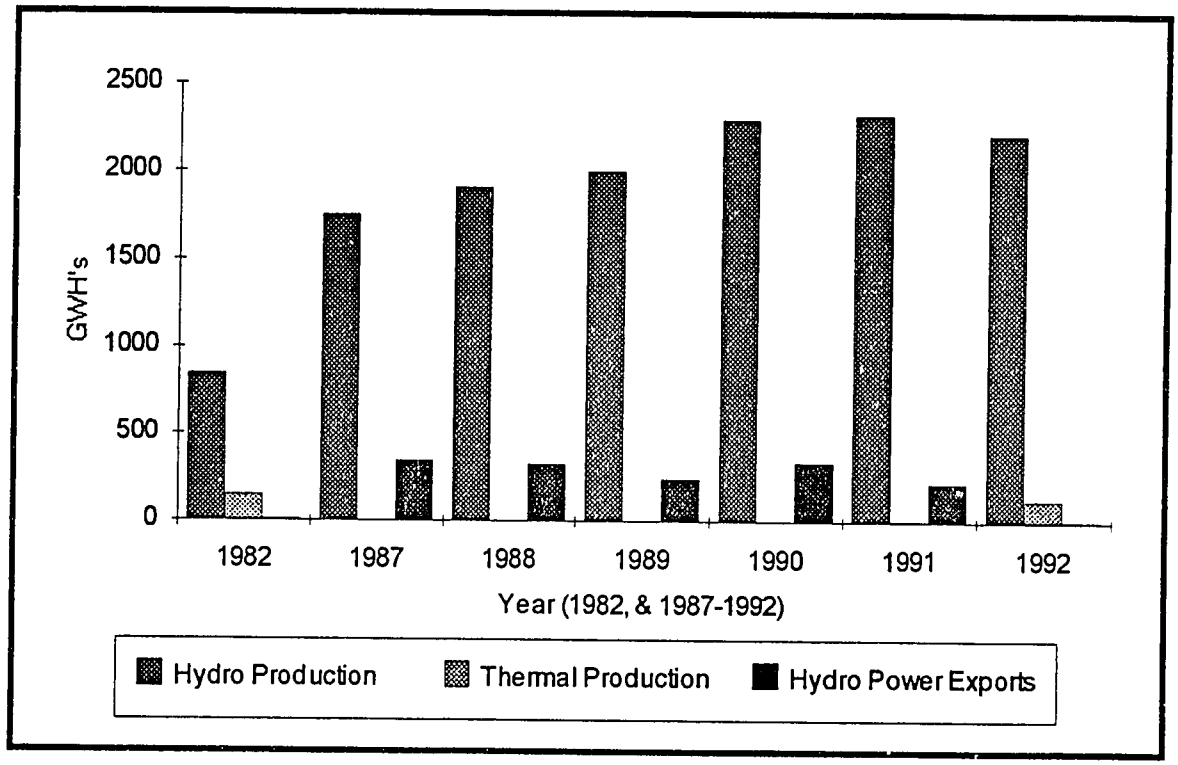
*Approximately 1/3 of loss improvements in the Base Case Forecast, a significant part of which are non-technical losses, are converted into new loads.

**The forecast of maximum demand is for the interconnected system only and excludes about 1% of total load which is in isolated systems.

New loads determine the level of electricity generation capacity required, and the location of transmission and distribution investments. The Plan Maestro forecast disaggregates sales and maximum demand by region to assist in identifying investment levels and sites. Dispersed generation sources such as cogeneration of power from sugar factories are potentially more advantageous when one considers their ability to contribute to meeting new regional loads more cost-effectively than conventional utility generation. For example, in the Choluteca area near local sugar factories, there has been substantial growth in shrimp farming and processing. Camaroneras plan to add from 8-20 MW new load by 1994. In the North West area, on the road from San Pedro Sula to Copán (near the town of La Flecha), power supplies from ENEE are of poor quality and require reinforcement. In this latter area, additional cogenerated power from the Chumbagua sugar factory would be beneficial in strengthening the local system, and could potentially offset ENEE distribution strengthening investment.

Due to the importance of hydroelectric power in the supply system of ENEE, the price of power and availability of electric energy has depended substantially on the adequacy of rainfall. The impact of the drought and increase in thermal generation is demonstrated in Figure 4.1. The drought has caused a major return to thermal generation, although the amount of thermal generation is itself limited due to the small size of installed capacity. Thermal capacity in the 3 primary stations in Honduras is only about 73 MW (1992) vs hydro installed capacity of 435.5 MW. As the figure shows, thermal generation in 1992, approached the levels of 1982 prior to the construction of El Cajon. More striking in economic terms is the elimination of hydro-based sales to other countries after 1991. Such sales ranged from 9.4 percent to 20 percent of total generation during the years 1987 to 1991 following the completion of the El Cajon hydro project.

FIGURE 4.1 ENEE ENERGY PRODUCTION AND EXPORTS



With an estimated peak demand of between 477-489 MW in Honduras in 1994, the total hydro and thermal capacity actually available on a firm basis to the ENEE system still is expected by ENEE operations staff to leave a deficit of 135-147 MW's in 1994. From an energy standpoint, the deficiency is estimated at about 215.18 GWh in 1994. ENEE hydro generation available to meet peak demand requirements in November of 1994 is estimated at 282.9 MW, which is about 83 percent of total potential capacity at that time of 342 MW. Of this amount, the El Cajon plant alone makes up 52 percent. These figures are lower than reported above for November, 1992 because of reduced water level in the reservoirs.

4.2 ELECTRIC SECTOR LAW - AUTHORIZATION FOR PRIVATE POWER AND DISTRIBUTION PRIVATIZATION

ENEE, with the help of a World Bank supported technical adviser, has drafted a new electricity sector law (Ley Marco del Sub-Sector Electrico (12-5-93) LMSE-Draft) which is expected to be submitted to the Honduran legislature in July 1993. Given the broad implications of this law for private power generation, as well as privatization of the power sector, the law is discussed in detail in the box below.

4.2.1 Pricing Terms and Conditions under the New Electricity Law

The draft electricity law provides specific guidance on the terms of private power sales, and this report has tried to incorporate these as closely as possible in financial calculations.

The general objectives of the law are to: 1) provide electricity at minimum cost, 2) promote economic, secure and reliable power supply; 3) ensure efficient use of electric energy, 4) protect the rights of users, and provide special consideration for small consumers, 5) facilitate the private provision of generation and transmission, and promote private participation in distribution; and 6) regulate competition and anticompetitive practices. The Comision Nacional de Energia Electrica (CNEE), created by the law, also is to ensure the financial health of the electric sector and protect the environment, among other duties. Transmission is to remain in the sole ownership of the Government, although private or mixed companies will have complete access to transmission facilities.

4.2.2 Retail Tariffs

Retail tariffs are to be based on marginal cost of supply, including transmission and distribution (including annualized value of investment including O&M); and incorporating revaluation of assets, useful life and cost of capital. With the exception of residential consumers, the proposed law provides that customers ought to pay 100-120 percent of total cost of supply. Residential tariffs would charge: 110 percent of supply for consumption less than 500 kWh per month, for 301-500 kWh per month 100 percent of cost, for 101-300 kWh per month not less than 80 percent of cost, and for 0-100 kWh not less than 45 percent. Public lighting is to be charged to various classes proportionally to billed consumption, and at a rate of 1/2 the average revenue per kWh sold. Public subsidies to distributors would be permitted if the revenues generated from tariffs by distributors, owing to the type of market served (e.g. rural electrification), are insufficient to allow a reasonable rate of return.

Tariffs would be established by distribution area for a period of 5 years, with automatic adjustments in wholesale tariffs for certain factors, including changes in foreign exchange valuation, if these would produce retail tariff changes of 5 percent or more.

4.2.3 Avoided Cost

Cost of supply, according to the proposed Honduras electricity law, is defined as annualized investment required based on net revalued assets, useful life and discount rate-based on the opportunity cost of capital in Honduras, plus cost of O&M. Supply or bus bar tariffs are to be annually recalculated. Avoided cost is defined as the marginal short-term cost for the year in question, averaged with estimated marginal cost in the four subsequent years (after discounting each year to year 1). This is considered the economic cost of supply of an additional kilowatt and kilowatt hour average over a period of 5 years. Economic cost of supply includes generation, transmission and technical losses assuming reasonably efficient management.

Electric Sector Law (LMSE)
Authorization for Private Power Generation and Distribution Privatization

Comisión Nacional de Energía Eléctrica (CNEE). The LMSE would create the CNEE. The CNEE would be the administrator for the LMSE and regulator of the electric sector. Among the specific responsibilities of the CNEE is the establishment of norms to provide for safe supply and use of electricity, as well as standards to provide for adequate quality of electrical supply. In addition, the CNEE will define the conditions under which ENEE will provide extension of lines and provide installations for new service. The CNEE would be the primary agency responsible for private power generation sales terms and establishment of wholesale and retail tariffs.

The CNEE is to be made up of 5 professionals, with up to 6 staff positions. Members of the commission and employees will not be subject to civil service rules and regulations, and salary will be based on professional qualifications.

Economic Cabinet. The Economic Cabinet which serves directly under the President of Honduras is the main economic policy body in Honduras, made up of Minister's from the largest and most involved government ministries. The law would provide that a similar body, Energy Cabinet (Gabinete Enérgetico) would be established for the energy sector. The functions of the Gabinete with regard to the electric sector would include: 1) comparative studies of prices of alternative forms of energy to ensure rational use and avoid distortions, 2) establish evaluation criteria for multiple use projects, 3) make final decisions when involving major market liberalization, including direct sales of generating entities in general, as well as direct sales to large consumers using the national grid, and deregulation of prices of power generating entities and distributors; 4) approve electrical sector expansion plans, or in case of majority private firms, provide recommended but not binding direction; and 5) based on the studies of ENEE, establish norms to promote the efficient use of electric energy.

National Electricity Commission. Specifically CNEE would have the following functions: 1) approve wholesale tariffs, tariffs for final consumers, and automatic adjustment formulas, 2) present ENEE's expansion plans for approval to the Energy Cabinet, 3) approve ENEE's contracts with private generators and calculations of short-term marginal cost, 4) approve distribution company contracts for sales, 5) establish quality, reliability and safety standards, and norms for electric system equipment, 6) deal with failure of distributors to pay in a timely manner for generation, 7) approve the volume of energy to be billed annually as public lighting, and 8) propose for consideration further liberalization of prices, including direct sales by private generators to large consumers using the national grid, deregulation of tariffs among generation companies, and between these latter and distribution companies.

Generation, Sales and Pricing. Under the LMSE, sales of electricity by any generator would be permitted (prior to any complete deregulation). The law would authorize: 1) sales directly to large consumers (rates are not subject to approval) or sales to distributors (terms would be regulated by CNEE); and 2) sales on the initiative of a private or mixed ownership entity to ENEE, for which the law would provide that ENEE would guarantee to purchase if the price is equal or less than the short-run marginal cost. Another private power sales option, would be for ENEE to solicit power supply. In this case, the purchase terms would be the rate which results from bidding, and the contractual terms specified in the tender. In order to protect the private power developer, the law would provide that payments to generators by ENEE would have preference over any other payments except those to workers.

Transmission. ENEE would retain responsibility under the new law for control of the national interconnected system. Those wishing to connect will be responsible for financing their own facilities. Owners of transmission are to be required to allow the use of their lines by any electric utility or large consumer which requests use, as well as self-generators, cogenerators or consumers. CNEE will determine technical norms and payments applicable for these transactions.

Distribution Privatization. Entities operating their own transmission and/or distribution are authorized and would be regulated under the law. Private distributors and sellers are permitted to generate their own energy, however only when this is the most economic manner to do so. ENEE is obliged to sell power to any distributor.

The procedure proposed to be followed for privatization of existing ENEE distribution is as follows: ENEE is to divide the country into concession zones based on standards of technical and economic efficiency, within 12 months of implementation of the law. Thereafter within 6 months, ENEE is to sell distribution assets. If assets cannot be sold, the ENEE distribution system may be converted into a limited company for management of proposed concessions.

Comisión Nacional Supervisora de Servicios Públicos (CNSPP) Another important public authority as regards electric and energy sector pricing in general, is the CNSPP. The commission, created by Decree in 1991, has general responsibility for review, analysis and public service pricing. Under the new law, the CNSPP will maintain responsibility for supervising relationships among generators and distributors, protecting the rights of consumers, assuring that approved tariffs and automatic adjustments are applied for all distributors, monitoring quality of electric service (including use of periodic surveys of quality of service) and mediating disputes having to do with new electrification installations.

Generation and/or distribution companies engaging in the business of electricity supply would be subjected to only normal duties, taxes and financial regulations. Each electric company including ENEE is to contribute to a fund for social development of electricity an amount equal to one half of the taxes paid on profits earned (this amount is to be credited against taxes to be paid). The fund will be administered by ENEE to finance studies and construction of electrification for social purposes (e.g. rural electrification).

Under the LMSE, concession contracts for the operation of power generation and/or distribution will be administered by the Ministry of Communication, Public Works and Transportation (SECOPT- Ministerio de Comunicaciones, Obras Publicas y Transporte) which will evaluate qualifications of contractors. The contracts would provide for technical norms to be met, and duration of contract (usually 30-50 years). Contracts would permit state intervention, sanctions or contract termination if service is not adequately provided, and establish a reserve fund for insurance to compensate consumers damaged by service interruptions or poor quality. On termination of contracts (concessions) SECOPT will acquire the assets specified by contract, after payment of the depreciated value of assets.

4.3 MARGINAL COST ANALYSIS

A preliminary analysis of avoided costs, which are defined by the proposed Honduras electricity law as short-run (5 years) average marginal costs, was undertaken for this report. These costs are used to provide a baseline for our preliminary analysis of cogeneration alternatives in the various sugar factories. It is anticipated that the Plan Maestro being carried out by the Planning Department of ENEE and their consultants SNC-Shawinigan of Canada, will be able to provide more exact numbers in August for the completion of our analysis.

The main alternatives which have been used in the past in the United States for estimating the price for private power purchases from cogenerators or others are discussed below. In principle, the method for determining the price to be paid for privately generated power should be simple to use, and permit adjustments over time for contingencies which might arise such as changing exchange rates, taxes, inflation, etc.

4.3.1 Avoided Cost

In tariff design, the principle that rates should reflect marginal cost of supply has been fairly-well accepted as economically efficient. This basis should ensure that national economic resources are allocated efficiently within the power sector. This principle when applied to tariffs and combined with an adjustment which should not distort the marginal cost pricing structure, allows the company to earn an allowed return on rate base. This result is intended to provide for a fair allocation of costs among customers according to the costs they impose on the system. Applying this marginal cost principle to purchases from cogenerators leads to a similar result, that is, power supplied is essentially worth the cost "avoided" by the utility.

Avoided costs consist of two parts, an energy component, which is based on the short-run incremental operation cost of the utility; and a capacity component, which is based on the marginal cost of new capacity, both adjusted for losses. The basic objective of avoided cost pricing is to find a fair and readily implementable means for determining the value to the utility for additional private generation.

Several factors enter into the valuation of private power, and computation of price to be paid for private power purchases. The most prominent factors are:

- Reliability--to what extent will the power generated be available when needed and in the amount needed.
- Energy and capacity value of power--how are the values for kWh's and kW's supplied to be determined. What utility costs are displaced by private power sources, are these merely short-run operating costs (e.g. for cogenerators of small amounts of non-firm power) or do they offset new capital investment by the utility?
- Balancing incentives to cogenerators with consumer costs.
- Transmission and distribution impacts and line loss differences which are achieved due to the location of the cogeneration capacity versus location of consumers, as compared to location of utility capacity.

A variety of approaches have been applied to estimate avoided costs, including the "Peaker Method", "Average Incremental Cost", "Generation Expansion", and "Competitive Bidding". These methods are briefly discussed in the box on the following page:

Avoided Cost Options

1. **Peaker Method:** In this method short-run marginal operating costs of the utility system are used for valuing energy supplied, and capital costs avoided are assumed to be equal to the annualized costs of a new combustion turbine or other peaking facility (including O&M, fuel inventory costs and adjustment for revenue requirements). Adjustments for reliability (e.g. required additions to reserve margin) and forced outage adjustment are also normally made. **Comment:** This approach is convenient and relatively easy to calculate. However, the approach may also underestimate actual avoided cost, as the long-run costs of new baseload generation would normally be higher than a peaking unit.

2. **Average Incremental Cost Approach** This approach is similar to the peaker method and also utilizes the capital and operation cost of an "avoided" unit in the generation mix. However, rather than only use a peaking unit, it would normally use the next expected generation unit in the optimal generation expansion plan, as the basis for estimated avoided cost payments for the private generator. Differences in reliability of the private generation versus utility power production may be incorporated. **Comment:** While this method is simple like the peaker method, it is likely to be more accurate, although still only a rough estimate of avoided cost, in that it does not consider other system effects or costs based on the planned dispatching of the "avoided" unit, or exact project timing. Incremental costs in the "Peaker" and AIC approaches are both calculated without explicit consideration of financing costs and methods for each unit of capacity, and therefore may give results somewhat different from results of a detailed financial model.

3. **Generation Expansion Plan - Differential Revenue Requirements Method** This approach requires the modeling of the system over a substantial period of time, e.g. 25 years, with the development of a least-cost expansion plan for the period. Addition of the private power project into the plan or deletion (or delay) of a planned addition is used to generate a revised least-cost plan, together with revised revenue requirements each year. Differences in the present worth of required revenues due to the private project are the amounts which could be paid the private generator. **Comment:** The cost, data intensiveness and time consuming nature of this approach are the principal disadvantage. Small increments of capacity such as cogenerated power generation would not normally justify such an analysis.

4. **Competitive Bidding** This approach is meant to approximate the results of a free-market for power supply. It is based on the utility requesting offers which may differentiate based on type and size of capacity, timing, reliability, and baseload-intermediate-peaking needs. The utility would compute its avoided cost, for example, utilizing the generation expansion method above, to establish a baseline for evaluating proposals. Other factors than price would affect the evaluation, including the utilities judgement of the capability of the bidder, fuel type and future cost of fuels proposed, type of generation and perceived reliability and performance, etc. Comment: This method would only work with a substantial number of willing bidders, with the utility committed to purchase, and with the utility willing and able to facilitate arrangements once bids are accepted.

5. **Standard Offers.** Where the size of individual projects is likely to be small, for example, in systems with sugar industry cogeneration of electricity and steam, or with initial small private projects, another option is the "standard offer". After calculating its avoided cost, the utility prepares a standard offer similar to a power sales tariff. Comment: This approach avoids costly negotiation and analysis by the private generator, and is likely to be conducive to sales from small-generators. The offer will normally differentiate respectively, between only energy purchases, firm capacity supplied, dispatchable capacity, etc.

4.3.2 Application Of Avoided Cost Principles In Honduras

Several aspects of avoided costs are specific to Honduras. These result partly, but not only, from the prospective new Honduran electricity law, which provides general rules and pricing principles which would influence the basic financial assumptions used to determine revenue requirements and avoided cost.

4.3.2.1 Loan Subsidies

While avoided costs are strictly speaking economic rather than financial costs and therefore exclude specific financing terms, very often such total economic costs will be compared with the alternative of utility direct investment (in financial terms). It is important to recognize that such comparisons can be misleading on several grounds: first, since a true economic comparison should exclude specific financing terms; and second, since often the utility will receive loan subsidies from international donors. Financial subsidies in terms of grants and/or below market interest loans received by ENEE would lower avoided financial cost. However, these subsidized sources of finance provide capital at costs significantly lower than the cost of capital for private developers, while understating the true social cost of capital. Considering also that such limited subsidized financing can be transferred to other public purposes with no loss to the country, it is not appropriate to reflect such subsidized financing terms in comparison of public vs. private generation.

4.3.2.2 Short-term Capacity and Energy Shortages

Another important factor affecting the value of cogenerated electricity during the next 3-5 years in Honduras, is the general shortage of energy and capacity in the National Interconnected System. Under ordinary circumstances, it would be appropriate to determine avoided cost on a seasonal and daily peak and off-peak basis, and pay cogenerators according to when power is provided. However, under current circumstances the system is short of energy and capacity, and is hydro dominated. Given characteristics of the hydro system, the system can utilize whatever additional energy is provided to shift hydro capacity to peak periods.[6] Therefore the value of any cogenerated power in the near-term, 3-5 years should be equal at a minimum to seasonal and daily peak avoided cost, and at a maximum to the value of unserved energy. After 3-5 years, cogeneration should be valued in the conventional manner according to its seasonality and hourly availability characteristics, degree of firmness, etc. Cogenerated power which offsets capacity would receive full capacity credit, while non-firm capacity would be valued at marginal operating costs plus a capacity value corresponding to its

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[6]Operation of hydroelectric facilities are programmed on the basis of operational studies which attempt to minimize the cost of power and avoid the possibility of not being able to serve peak demand. In the short-term due to the drought, plans are to utilize all available thermal capacity to the limit, also trying to maximize the contribution to meeting peak of El Cajon and other hydro plants, with the need to still maintain minimum hydro potential consistent with hydro carry-over criteria for the following year.

capacity value for that specific period. Both with appropriate adjustment for loss reduction and other factors discussed in the box above.

4.3.2.3 Average Peaker Method of Marginal Cost Analysis

Based on a review of the options and considerations above, it was determined that for purposes of this study, to estimate cost of power utilizing the "peaker method". This approach appears to be consistent with the approach proposed in the new electricity law, and is computationally feasible within the study.

4.3.2.4 Value of Cogeneration - Loss Reduction

The value of dispersed generation from sugar factories in Honduras is increased when supplied in the southern and central part of the country due to the reduction in energy and capacity losses from high voltage transmission from generators in the north of Honduras which otherwise would be serving load centers in the south. The magnitude of transmission and distribution losses are not exactly known, but have been estimated based on ENEE data and data from the Plan Maestro. ENEE has estimated that total transmission, subtransmission and transformation losses on peak, to be about 7.47 percent (based on the "Informe Anual de Operacion-1992 " of ENEE). According to ENEE about 16.5 percent of these losses come from 230kV and 38.7 percent from 138 kV transmission, respectively, transformers add 31.1 percent and the balance of 13.7 percent of losses comes from 69 kV and 34.5 kV primary distribution. The potential loss reductions from cogenerated power supplied at 34.5 kV directly into primary distribution network, based on the above loss relationship, are estimated at 6.45 percent for energy and 8.6 percent for capacity. (Capacity losses are higher since these relate to maximum capacity requirements, determined by losses at time of peak which are greater since they vary with the square of current delivered.)[7]

[7]Peak capacity losses are calculated using a standard equation for relating average to peak losses based on system load factor; that is, Average losses = Loss Factor * Peak Losses, and Loss factor = 0.2*Load Factor+0.8*Load Factor^2.

TABLE 4.2 ESTIMATED ENEE LOSSES AND LOSS REDUCTION POTENTIAL OF COGENERATED POWER

Year	Average Energy Losses (% of kWh's)	Portion of kWh Lost Due to Transmission & Transformation Losses*	Peak Capacity Loss (% of MW's)	Portion of Capacity Lost Due to Transmission and Transformation Losses**
1995	19%	6.45%	27%	8.6%
1996	16.5%	6.45%	23.4%	8.6%
1997	14%	6.45%	19.9%	8.6%
1998	14%	6.45%	19.9%	8.6%
1999	14%	6.45%	19.9%	8.6%
2000	14%	6.45%	19.9%	8.6%

Sources: ENEE, "Informe Anual de Operacion-1992", Table "Distribución de Energía, Demandas Máximas y Factores de Carga"; and SNC-Shawinigan, "Honduras Power System Master Plan," Phase II-Load Forecast Report, Cuadro E.2.

*This column represents the % of energy losses per kWh supplied which could be avoided by cogenerated power.

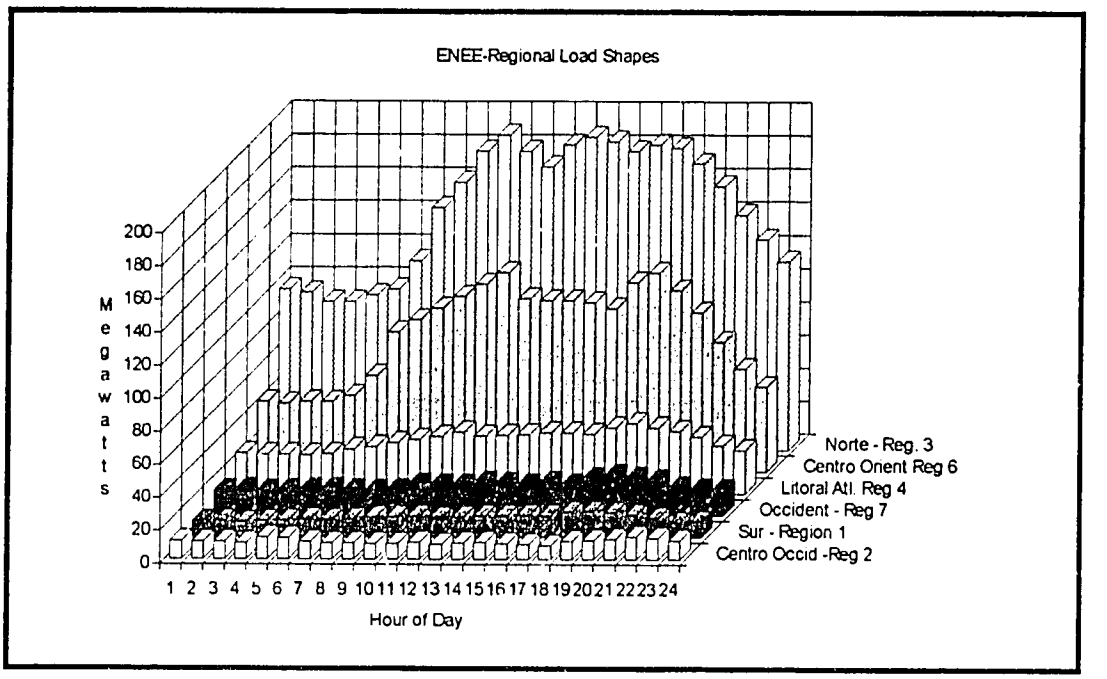
**This column represents the % of capacity losses which could be avoided by cogenerated power delivered at system peak.

Taking the example of generation of cogenerated power at a location south of Tegucigalpa for the city of Choluteca from the La Grecia sugar factory, ENEE transmission and high voltage transformation energy and capacity losses could be significantly reduced from those based on supply from the ENEE generation. The site of the principal hydroelectric sources serving Honduras are in the north, for example, the El Cajon hydroelectric facility. The net result of locally produced cogeneration would be to produce benefits greater than avoided cost, due to loss reduction roughly as follows. For 5 MW of capacity from La Grecia operating 5 months, credits for reduced energy losses would be about 6.45 percent equal to approximately 1 GWh, and capacity loss credits of 8.6 percent equal to a maximum of approximately 432 kW. Such loss reduction benefits should be included in the avoided cost estimates for this specific project..

4.3.2.5 Regional Load Characteristics and the Value of Cogenerated Power

In addition to the lower losses of dispersed cogeneration nearer load centers, it is possible that the cogenerated power may be more valuable if supplied at peak hours of the day and during peak months. Figure 4.2 demonstrates both the great variation in magnitude of loads by time of day, for example, in urban and industrialized areas such as Region 3 (which includes Tegucigalpa) and Region 6 (which includes San Pedro Sula), and the major difference in load characteristics between these areas, and other regions of the country. It is clear that the more industrialized and urban areas (Regions 3 & 6) contribute disproportionately to the daily peaks, while the more rural and agricultural areas have more balanced demand and higher load factors.

Figure 4.2 ENEE REGIONAL LOAD SHAPES



4.3.3 Marginal Cost Estimates

There appear to be four major generation options which can be considered financially viable or competitive for addition to the ENEE system through the year 2010. The generation options which appear in the least-cost plan options include:

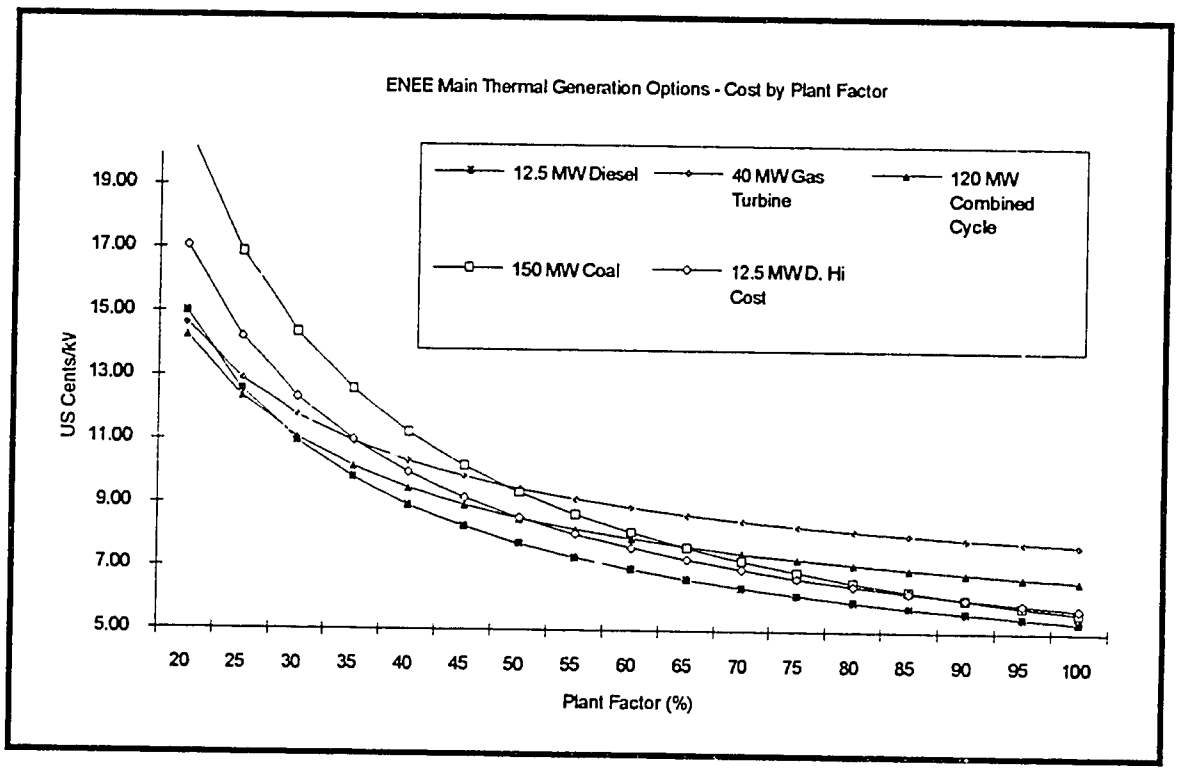
1. Diesel generation fueled by Bunker C (Two cases are analyzed here: conventional cost and higher-cost cases);
2. Gas Turbine and Combined-Cycle generation, respectively, fueled by distillate oil;
3. Coal-Fired steam generation; and
4. Hydroelectric power.

SNC-Shawinigan has provided preliminary estimates of the capital, operating and efficiency characteristics of these plants which are used for our initial analysis in this report. Appendix B presents the basic economic assumptions used for analysis of generation options for ENEE.

In Figure 4.3 below, these data for thermal alternatives are used to calculate cost/kWh by plant factor (percent of average available capacity utilized) to demonstrate the main differences between these generation sources. It can be seen the larger and more capital intensive alternatives such as coal-fired generation must be operated as base-load capacity (high plant factor) in order for costs to be competitive with other sources. Diesel generation based on Bunker C under optimistic assumptions of capital and operating cost is the most economic source of generation, although also the smallest

generation unit size, only 12.5 MW per unit on average. The alternative case with Diesel, reflecting less favorable capital cost experience (capital costs are 24 percent greater) based on results of a world-wide study by the World Bank and AID, removes its cost advantage. Assuming the higher cost case for Diesel, combined-cycle generation, followed by gas turbines, would be the most economic choices at plant factors below 50 percent, and coal above 50 percent. Another major factor given the immediate need for new capacity by ENEE, is the lead time required for planning new generation. This consideration favors the Diesel and Gas Turbine options, with hydro and coal feasible only after 4 and 4-5 years lead time, respectively.

FIGURE 4.3 ENEE MAIN THERMAL GENERATION OPTIONS



4.3.4 Methodology Applied

The estimates of marginal cost described below and avoided cost estimates based on these, are developed utilizing what is called the "peaker method", further discussed in the box above. There are two basic marginal cost components: 1) capacity cost which is the annualized cost of purchase and installation of a generic peaking plant plus fixed operating costs, adjusted for station use/losses and reserve requirements; and 2) composite energy or variable costs for meeting peak period loads throughout the year. These variable costs are essentially a weighted average of the cost of suppling peaking energy over all hours of the year. Finally, in order to derive avoided costs, energy and capacity costs must be adjusted for losses and reserve considerations. Energy costs must be adjusted for losses to the level of private generation input to the system, and capital

costs must be adjusted for peak period losses to this same point, as well as to reflect the fact that no credit is given to the cogenerator for the reserve component of capacity costs which is not supplied.

Table 4.3 presents the basic capital cost information for the "peaking plant" determined in ENEE's Plan Maestro to be the optimum peaking candidate. The capital and fixed operating costs are for 1992, adjusted for average inflation to 1994, and then annualized using a 12 percent discount rate and 20 year useful life. The resulting capital cost is US $183.95/kW, or approximately $0.025 (based on a maximum producible output of 7,300 kWh/kW.

TABLE 4.3 GENERATION CAPACITY COST -- PEAKER METHOD
1994

Marginal Plant	Aero. Gas Turbine
Capacity (MW)	34.2
Year Required	1995
Useful Life (years)	20
Capital Cost/kW - 1992	$1,169.00
Inflation Multiplier to 1994	1.166
Capacity Cost /kW - 1994	$1,363.52
Annual Capital Cost/kW	$182.55
Annual O & M Cost/kW	$1.40
Total AnnualCapital Cost/kW	$183.95
kWh/kW/yr with 28.5 MW Available	7,300
Total Capital Cost/kWh	$0.025

Table 4.4 contains a calculation of average avoided costs, using the above capital costs plus fuel and variable O&M costs for the incremental peak plants for the ENEE system. Fuel costs are weighted according to estimated utilization. No data was available to determine the precise expectation for dispatching these plants, and therefore these energy costs are approximate. Estimated variable O&M costs are added to fuel costs based on aggregate average O&M costs for all ENEE plants. Total energy costs are then adjusted for energy losses to the point of prospective cogeneration. Capital costs are derived from Table 4.3, and are adjusted for peak losses to the point of cogeneration, then are added to variable costs. These total marginal costs are then converted into avoided cost.

It is important to note that the marginal and avoided costs in Table 4.4 apply to electricity delivered to the distribution system, that is, they take into account all costs and losses upstream of distribution substations. This approach is intended to capture all costs upstream of where a prospective cogeneration would connect to the ENEE system. The final adjustment of marginal costs to determine avoided costs is to reflect the absence of reserve backup and associated costs from the cogenerated capacity. Conversion of total

TABLE 4.4 CALCULATION OF AVERAGE AVOIDED COSTS

Honduras: Calculation of Marginal Short–Term Avoided Costs
(Constant 1994 $)

Cost Category	Year 1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Marginal Short–term Energy Cost																
1. Fuel Costs for Marginal Oil Fired Plant*																
New Diesels (assume 25% peak support)																
GWH (25% of expected generation)		49.6	65.0	103.3	196.2	191.7	223.8	175.5	215.3	243.5	245.3	259.0	0.4	16.3	84.0	130.5
Cost/kWh		3.1	3.2	3.3	3.4	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
New Distillate No. 2																
GWH	180	7	8.6	6.8	8.6	1.9	8.2	0.1	1	5.5	1.6	11.1	0	0	0	0.03
Cost/kWh	7.5	7.6	7.9	8.1	8.4	8.5	8.6	10.7	8.9	8.7	8.6	8.6	N.A.	N.A.	N.A.	N.A.
New GT San Pedro Sula																
GWH		130.2	135.5	166.9	123.4	53.9	122	10.2	44.9	135.7	156	306				
Cost/kWh		5.8	6	6.2	6.5	6.6	6.6	6.6	6.6	6.6	6.6	6.6				
Total GWH Produced	180	186.8	209.1	277.0	328.2	247.5	354.0	185.8	261.2	384.7	402.9	576.1	0.4	16.3	84.0	130.5
Weighted New Oil Fuel Cost (USc/kWh)	7.50	5.15	5.21	5.17	4.70	4.21	4.69	3.67	4.05	4.67	4.72	5.24	3.50	3.50	3.50	3.50
2. Variable O&M Costs																
Variable O&M Cost (US$ 000)*	$7,515	$9,168	$10,320	$11,888	$15,361	$17,860	$21,485	$23,789	$26,544	$29,183	$33,247	$36,089	$39,047	$43,090	$47,343	$51,533
Variable O&M per kWh (USc/kWh)	0.26	0.30	0.33	0.36	0.44	0.48	0.55	0.58	0.61	0.64	0.69	0.71	0.73	0.77	0.81	0.84
Transmission Energy Losses	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Total SR Variable Cost (USc/kWh) – 1992 $	7.76	5.45	5.54	5.53	5.14	4.70	5.24	4.25	4.66	5.30	5.41	5.96	4.23	4.27	4.31	4.34
Total SR Variable Cost (USc/kWh)–1994 $	9.05	6.36	6.46	6.45	5.99	5.48	6.11	4.96	5.44	6.19	6.31	6.95	4.94	4.98	5.03	5.06
Loss Adjusted SR Var. Cost (USc/kWh–1994	9.43	6.63	6.73	6.71	6.24	5.70	6.36	5.16	5.67	6.44	6.57	7.24	5.14	5.19	5.24	5.27
Marginal Capital Costs																
3. Capital Costs																
Short–Run Capital Cost (USc/kW)** – 1994 $	183.9															
Short–Run Capital Cost (USc/kWh) – 1994 $	2.52	2.52	2.52	2.52	2.52	2.52	2.52	2.52	2.52	2.52	2.52	2.52	2.52	2.52	2.52	2.52
Peak Transmission Losses***	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%
Loss Ajusted Capital Cost (USc/kWh) – 1994 $	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66
Short–Run Marginal Cost (USc/kWh)	12.09	9.29	9.39	9.38	8.90	8.37	9.02	7.83	8.33	9.11	9.24	9.90	7.81	7.86	7.90	7.94
Avoided Cost Calculation																
Reserve Adjusted SR Avoided Cost USc/kWh (Capital cost/kWh x 0.85)	11.69	8.89	8.99	8.98	8.50	7.97	8.62	7.43	7.93	8.71	8.84	9.50	7.41	7.46	7.50	7.54
5 Year Average Avoided Cost																
Total Sales (GWH)	2918	3023	3130	3297	3500	3707	3918	4135	4356	4587	4824	5067	5317	5574	5841	6122
Adjusted SR Avoided Cost – 1994$ (Sales weighted average)	**9.50**	**8.69**	**8.63**	**8.33**	**8.11**	**8.12**	**8.29**	**8.42**	**8.48**	**8.43**	**8.20**	**7.93**				

Source: SNC–Shawinigan, "Plan Maestro–Financial and Tariff Studies–Prel. Draft," August 1993. Hydroelectric Scenario

** Based on peaker method, see table above.

*** Peak losses based on relationship: Peak losses= Average losses/(.3+(.7*Load factor)

Inflation multiplier 1992 to 1994 = 1.166

Peak support % = 0.25 ps

marginal costs into avoided costs involves reduction of the marginal capacity cost component by 15 percent (in this case as reserve margin of 15 percent is assumed) to reflect the fact that the cogenerator will not be supplying the reserve requirement included in Table 4.3 capital costs.

As shown in the avoided cost table in Table 4.4, 1995 estimated costs in 1994 US$'s indicate average fuel costs of US$0.075/kWh, variable O&M costs of US$0.0026/kWh and total loss adjusted variable or energy costs of US$0.0943/kWh. Capital costs are US$0.0252/kW, assuming the marginal plant is an aeroderivative gas turbine as found in the Plan Maestro planning study, or US$183.90/kW (including reserves and station use in 1994 $'s). Total marginal costs for 1995 are US$0.1209/kWh. Reserve adjustment to determine avoided cost reduces this value to US$0.1169. As the new electricity law indicates that a five year average of short-run marginal costs will be used to determine payments to cogenerators/private suppliers, we have computed these averages in the final line of the table. These averages are weighted according the respective years sales (discounted). The 1995 five year average avoided cost becomes US$0.095, dropping to US$0.087 in 1996 which is the highest level through 2006, where a low of US$0.079 is reached.

The above avoided cost might normally be considered a maximum price level from which to negotiate and/or competitively bid. However, due to the current shortfall of energy and capacity during the next 3-5 years, ENEE needs all the additional capacity and energy which it can possibly buy or develop. Thus the avoided cost value of new power sources can even be considered the cost of unserved energy (maximum estimate and not dealt with in this report), which would normally be considered to be many times higher than the avoided cost.

4.3.5 Time Varying Avoided Costs

It would be appropriate to refine the estimates of avoided cost in this report for the period after 1998, and estimate seasonal or time varying avoided costs. Such costs would be appropriate indicators of the value of cogenerated energy and capacity if this electricity supply is only available during certain seasons or periods. Insufficient information was available to make an estimate of time sensitive avoided costs for this report. For the future when substantial experience has been gained with private power, and cogenerators have sufficient economic incentive and confidence to proceed with projects seasonal and time of day pricing might very well be worthwhile.

The first step in developing time varying avoided costs is to choose a limited number of periods for which costs will be estimated. The choice will be based on whether the periods have significantly different characteristics, and are therefore likely to have different avoided costs. In reviewing various time periods and choosing which to use, the following questions would be asked:

1. Is there a seasonal peak or is load in one season significantly higher?
2. Do energy costs vary by season, e.g. due to seasonal difference in availability of water, required maintenance on more efficient plants, or other factors?
3. Are different units used to meet peak in different seasons?

4. Is the probability or loss of load (that is, reliability) different by season?

One of the most common methods of attributing capacity costs to time periods is in terms of system reliability. The planner establishes a target level of reliability which recognizes costs of shortage versus cost of new capacity. The Loss of Load Probability (LOLP) is the common reliability criteria, and is defined as the probability that system load will exceed available capacity in a specified period of time (for example, an hour, month or year). LOLP values are computed for the time periods for which avoided demand costs are desired. The relative proportion of total LOLP occurring in each period is then used to apportion the marginal demand cost to respective time periods. Hourly, daily or monthly demand related costs could be estimated if desired, assuming availability of suitable LOLP information.[8]

Marginal energy costs can be determined based on the running costs of plants in the system during the time periods in question. Historic and future years are normally used for this analysis, and past and estimated system load curves. The marginal energy costs are the fuel and variable O&M expenses required for meeting a kW increase or decrease in load.[9]

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[8].ICF Incorporated, "Costs and Rates Workbook- Part I: Textbook", EPRI September 1981, pp. 5-17 - 5-21.

[9]ICF Incorporated, "Costs and Rates Workbook- Part I: Textbook", EPRI September 1981, pp. 6-1 - 6-9.

5.0. ECONOMIC COSTS AND BENEFITS

The preceding chapters present estimates of cogeneration system performance and cost at each mill and projects of the value of power that could be produced by the sugar industry in the context of ENEE's system and cost structure. The purpose of this chapter is to integrate these supply and demand considerations in an analysis that provides a sense of the profitability of possible individual cogeneration investments, as well as their collective potential contribution to meeting future Honduran electric requirements.

5.1. ASSUMPTIONS

For purposes of calculating returns on investment, the value of the energy exported to ENEE is assumed to be US$0.085 per kWh, corresponding roughly to the first several years' weighted average marginal short term avoided generation cost shown in the table in Appendix B. As indicated in the last chapter, the table presents an initial value of US$0.095 per kWh for 1995, followed by a decline to US$0.0811 per kWh in 1999. After that, the value rises to US$0.0848 in 2003 and then begins to fall off gradually in succeeding years. Because of the capacity of the nation's hydroelectric dams to redistribute power generation over time, the same value is applied for both all-year and seasonal mill operation.

For consistency with the Plan Maestro, the time-value of money is reflected in cost calculations at a real disount rate of 12 percent per year. Debt leveraging is ignored for simplicity, and profitability is expressed in terms of total pre-tax returns on employed assets. Including tax implications of cogeneration investments would have required intimate knowledge of the individual mills' financial circumstances, and the Plan's cost estimates for other generation alternatives appear to reflect tax-exempt status for ENEE. Unit costs of coal and bunker oil are taken from draft Plan documents, and savings from eliminating present mill electricity consumption are valued at the same US$0.085 per kWh as the assumed utility avoided cost, again for reasons of comparability with the Plan.

The assumed project economic life is 20 years, based on the predicted longevity of the larger items of capital equipment. Although useful for illustration, this duration may not be reasonable in certain specific circumstances where the mill in question may face an uncertain future for other mechanical or economic reasons. The San Ramón mill, for example, may be moved to a new location elsewhere for want of adequate cane to process, or Los Mangos may not remain in operation that long on account of the condition of the facility as a whole.

The analysis also assumes that high-pressure boilers and new turbine generators would be purchased for the sole purpose of cogenerating electricity. While boilers are the most expensive single items in the systems, they must occasionally be replaced or refurbished to keep the mill in operation. If a boiler is replaced for other reasons, the added cost of a higher pressure rating is likely to be small in relation to the total price, making cogeneration more profitable than in the cases presented here. The existing

boiler at Río Lindo has a higher pressure rating already, allowing for more economical cogeneration. The management of Central Progreso, as mentioned earlier, is considering purchasing a higher pressure boiler to meet steam requirements of a planned new refinery and expanded production. Ideally, one would design a cogeneration system into any new mill at the time of construction at a substantially lower incremental capital cost and possibly with a better optimized overall plant configuration.

5.2. RESULTS

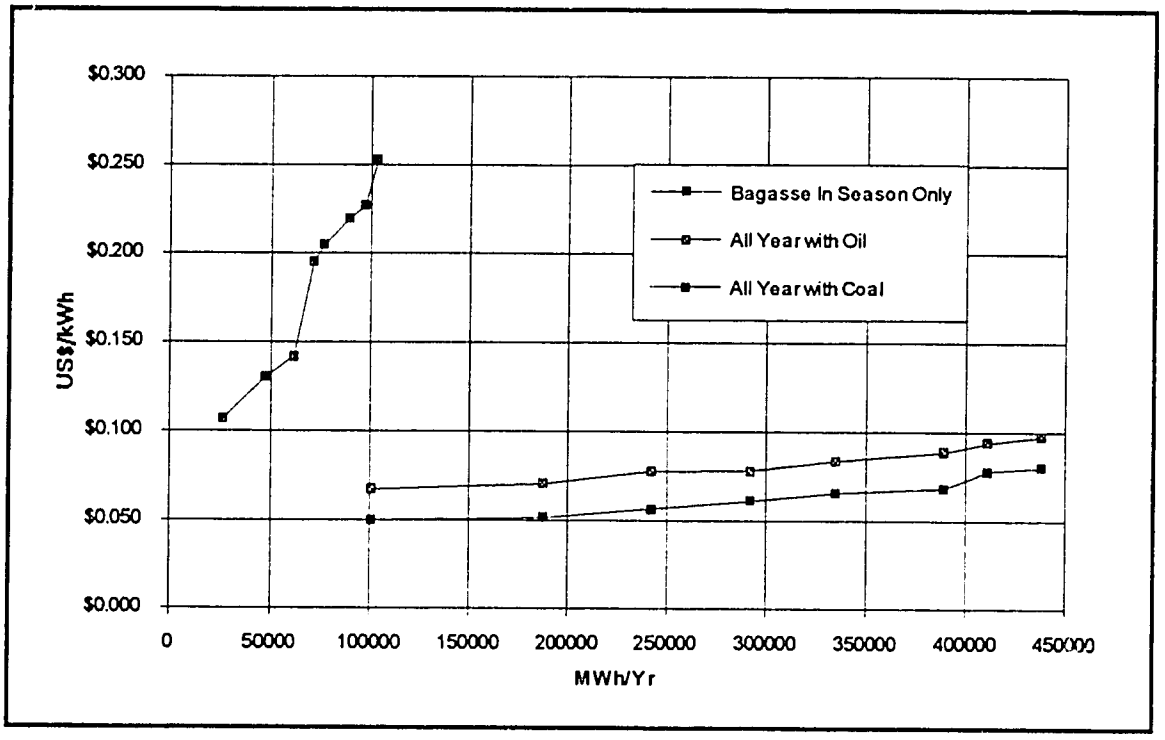
Table 5.1 below presents for each mill the estimated returns on investment for the three different cogeneration configurations discussed in Chapter 3. One involves cogeneration during the crushing season only, utilizing all of the available bagasse. The other two involve year-round operation to make more efficient use of the capital invested in boilers and generators. In one case, oil is the supplemental fuel, and the second case illustrates the effect of substituting lower-cost coal at the expense of a small increase in capital cost corresponding to additional material handling requirements. Details of the economic evaluation appear in Appendix C.

TABLE 5.1. COGENERATION RETURNS ON INVESTMENT (PERCENT PER YEAR)

MILL	IN-SEASON ONLY	ALL-YEAR (OIL)	ALL YEAR (COAL)
Santa Matilde	8.46%	20.74%	27.83%
Río Lindo	4.84%	14.62%	20.21%
Central Progreso	5.90%	19.04%	26.76%
Chumbagua	1.37%	12.48%	18.32%
San Ramón	1.16%	9.50%	13.78%
El Porvenir	-0.14%	15.33%	23.73%
Los Mangos	-1.16%	8.32%	13.26%
La Grecia	0.19%	10.75%	17.23%

Instead of calculating return on investment for a postulated value of the power generated, one can estimate the price at which the power must be sold to yield an annual return equal to twelve percent. Combining prices derived in this way with the power production rates from Chapter 3 alows one to create "supply curves" corresponding to the three generation schemes. These appear below, illustrating how much cumulative energy could be supplied by the sugar industry at a given price for purchased power.

FIGURE 5.1 POTENTIAL ELECTRIC SUPPLY FROM HONDURAN SUGAR MILLS



5.3. DISCUSSION

As the graph indicates, no power can be produced at a price below ENEE avoided cost under the assumed conditions for in-season operation only. This is because the growing season is too short to amortize the considerable capital invistment. The steep slope of the curve reflects economies of scale to some degree but mainly differences in annual hours of operation, which vary quite widely among mills. Year-round operation, however, is much more economical, since with little if any increase in capital cost, annual energy sales can be increased by a factor of four in many cases.

While bunker oil is generally available to Honduran sugar mills, coal would be more economical, despite a slightly higher capital cost for material handling and storage facilities. On the other hand, coal would have to be imported, probably from Colombia, and no port facilities presently exist for this purpose. If port facilities were constructed on the Caribbean coast, perhaps in conjunction with a future powerplant contemplated by ENEE, coal might become a logical choice for the mills located near San Pedro Sula.

Other sources of biomass that might be suitable as supplemental fuels include sawmill wastes and cane field trash. While a number of sawmills are located where they could supply a cogeneration facility, the available volumes of waste are small in

comparison to the sugar mills' potential requirements.[10] While delivery of these wastes to the sugar mills probably will not affect the outlook for cogeneration significantly, it may still represent an economically and environmentally sound alternative to present disposal practices by the forest products industry. Cane trash also represents a potential fuel supply, approximately equal in volume and heating value to the bagasse generated in sugar production. Although harvesting, storage, and material handling technologies are largely experimental, the Cuban sugar industry harvests trash for this purpose, and research is proceeding on improved methods with lower costs.

The postulated value of US$0.085 per kWh is based on the presumption of no unique costs or benefits corresponding to power transmission and distribution. Given the location of substantial generating capacity in the northern and central parts of the country, the value of power generated in the South would be somewhat higher, since it would help to serve the growing demand there without incurring transmission losses experienced now. With year-round operation, power from a mill like La Grecia might serve to postpone the need for added transmission and substation capacity in the future.

Perhaps more significant in this regard is the Chumbagua mill's oportunity to improve reliability and to reduce transmission costs in serving communities along the highway from San Pedro Sula to Copán, including a planned industrial park, to be located near Naco, projected to represent 10 MW of new demand. Power supplies there are constrained by substation and power line capacity along this route, preventing the mill from consuming grid power even during the idle season and constraining economic growth in the existing industrial zones to the east. If Chumbagua were to generate power year-round for the benefit if its nearer neighbors, ENEE could meet the growing industrial demands without having to upgrade substations and reconducter lines as soon as might otherwise be the case.

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[10]Winrock International Institute for Agricultural Development, *Energy from Sawmill Waste in Honduras - Industry Overview*, Washington, DC, US Agency for International Development, Office of Energy and Infrastructure, 91-05, 1991.

APPENDIX A

System Design Parameters

SUGAR MILL

	STA. MATILDE	RIO LINDO	SAN RAMON	CHUMBAGUA	EL PORVENIR	C. PROGRESO	LOS MANGOS	LA GRECIA
ASSUMPTIONS								
BOILER PRESSURE, psig	900	900	900	900	900	900	900	900
STEAM TEMP., DEG. F	850	850	850	850	850	850	850	850
ENTHALPY, BTU/LB	1424	1424	1424	1424	1424	1424	1424	1424
1ST EXTR								
PRESSURE, psig	200	200	200	200	300	200	200	200
ENTHALPY, BTU/LB	1260	1260	1260	1260	1295	1260	1260	1260
2ND EXTR								
PRESSURE, psig	15	15	15	15	15	15	15	15
ENTHALPY, BTU/LB	1110	1110	1110	1110	1110	1110	1110	1110
TG EFFICIENCY	85%	85%	85%	85%	85%	85%	85%	85%
BOILER EFFICIENCY	65%	65%	65%	65%	65%	65%	65%	65%
TWO-YEAR AVERAGE DATA								
TONS CANE/YEAR	565758	312628	149660	188204	138563	345804	168178	450000
TONS BAGASSE/YEAR	156154	88024	36150	53256	41687	110623	48788	117000
TONS CANE/HR	243.84	108.33	66.65	99.20	99.03	167.87	74.77	187.5
BAGASSE % CANE	27.60	28.16	24.15	28.30	30.09	31.99	29.01	26
TONS BAGASSE/HR	67.29	30.50	16.10	28.07	29.79	53.70	21.69	48.75
POL% BAGASSE	3.12	3.10	3.50	3.5	4.1	3.5	4.2	3.5
MOISTURE% BAGASSE	51.25	50.50	49.85	50	49.91	50.3	51.5	51
ASH% BAGASSE	2	2	2	2	2	2	2	2
CALCULATIONS								
BTU/LB BAGASSE	3904	3966	4021	4008	4016	3983	3883	3925
MILLION BTU INPUT/HR	525.32	241.96	129.46	225.01	239.27	427.77	168.44	382.64
LB STEAM/HR	239,788	110,445	59,093	102,710	109,217	195,260	76,886	174,660
LB STEAM EXTR./HR								
1ST EXTR.	80,000	30,000	30,000	25,000	30,000	55,000	40,000	150,000
2ND EXTR.	159,788	80,445	29,093	77,710	79,217	140,260	36,886	24,660
POWER GENERATED, MW								
1ST STAGE	3.27	1.23	1.23	1.02	0.96	2.25	1.63	6.13
2ND STAGE	12.50	6.29	2.28	6.08	6.19	10.97	2.88	1.93
TOTAL	15.76	7.52	3.50	7.10	7.16	13.21	4.52	8.06

SUGAR MILL

	STA. MATILDE	RIO LINDO	SAN RAMON	CHUMBAGUA	EL PORVENIR	C. PROGRESO	LOS MANGOS	LA GRECIA
POWER CONSUMED, MW	4	2.5	1	2	1.5	3.5	1.8	3
NET EXP. POWER, MW	11.8	5.0	2.5	5.1	5.7	9.7	2.7	5.1
KWH PURCHASED/YR (POTENTIAL SAVINGS)	2,453,000	42,900	1,136,000	0	389,072	1,300,000	120,000	1,575,000
HOURS OF GRINDING PER YEAR	2,320	2,886	2,246	1,897	1,399	2,060	2,249	2,400
MWH PRODUCED/YR (HARVEST SEASON)	36,575	21,690	7,861	13,467	10,017	27,223	10,163	19,332
MWH USED/YEAR (HARVEST SEASON)	9,281	7,214	2,246	3,794	2,099	7,210	4,049	7,200
MWH SOLD TO ENEE/YR (HARVEST SEASON)	27,294	14,476	5,615	9,672	7,918	20,013	6,114	12,132
HARVEST SEASON								
CALENDAR DAYS	150	150	150	150	60	130	150	120
HOURS	3600	3600	3600	3600	1440	3120	3600	2880
OFF-SEASON								
CALENDAR DAYS	215	215	215	215	305	235	215	245
HOURS	5160	5160	5160	5160	7320	5640	5160	5880
AVAILABILITY FACTOR	90%	90%	90%	90%	90%	90%	90%	90%
HOURS PROD. ELECT.	4644	4644	4644	4644	6588	5076	4644	5292
GENERATION CAPACITY, MW								
GROSS	17.51	8.35	3.89	7.89	7.95	14.68	5.02	8.95
NET	15.76	7.52	3.50	7.10	7.16	13.21	4.52	8.06
ENTHALPY COND. STEAM (BTU/LB @ 1.2 psig)	930	930	930	930	930	930	930	930
LBS. STEAM/HOUR	142,362	67,881	31,613	64,105	64,652	119,348	40,806	72,747

SUGAR MILL

	STA. MATILDE	RIO LINDO	SAN RAMON	CHUMBAGUA	EL PORVENIR	C. PROGRESO	LOS MANGOS	LA GRECIA
IF BUNKER C FUEL IS USED								
BTU/BBL	6,200,000	6,200,000	6,200,000	6,200,000	6,200,000	6,200,000	6,200,000	6,200,000
BOILER EFFICIENCY	85%	85%	85%	85%	85%	85%	85%	85%
MILLION BTU INPUT/HR	238.50	113.72	52.96	107.40	108.31	199.94	68.36	121.87
BBL/HR	38.47	18.34	8.54	17.32	17.47	32.25	11.03	19.66
BBL/OFF-SEASON	178,643	85,181	39,670	80,443	115,090	163,695	51,206	104,024
COST/BBL	$20	$20	$20	$20	$20	$20	$20	$20
TOTAL FUEL COST	$3,572,854	$1,703,619	$793,394	$1,608,852	$2,301,803	$3,273,899	$1,024,111	$2,080,488
NET EXPORTABLE MWH'S DURING OFF-SEASON	73,205	34,906	16,256	32,964	47,162	67,079	20,983	42,627
FUEL COST/MWH EXP. ($)	$48.81	$48.81	$48.81	$48.81	$48.81	$48.81	$48.81	$48.81
IF COAL IS USED								
FUEL COST								
per mKJ	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48
per million BTU	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40
BOILER EFFICIENCY	85%	85%	85%	85%	85%	85%	85%	85%
MILLION BTU INPUT/HR	238.50	113.72	52.96	107.40	108.31	199.94	68.36	121.87
MILLION BTU/TONNE COAL	25	25	25	25	25	25	25	25
COAL/HR (TONNES)	9.54	4.55	2.12	4.30	4.33	8.00	2.73	4.87
COAL/YR (TONNES)	44,303	21,125	9,838	19,950	28,542	40,596	12,699	25,798
COST OF COAL/HR	$335	$160	$74	$151	$152	$281	$96	$171
COST OF COAL/YR	$1,554,063	$741,013	$345,098	$699,793	$1,001,201	$1,424,028	$445,451	$904,937
COAL COST/MWH EXPORT	$21.23	$21.23	$21.23	$21.23	$21.23	$21.23	$21.23	$21.23

APPENDIX B

ENEE New Generating Options and Operating Assumptions

Basic Cost and Operating Assumptions - ENEE Generation Options

	Basic Plant Cost Assumptions					Plant Operating Assumptions				Costs/kWh and Long-Run Incr. Costs			
Size Project Name/ Plant Type	No. of Units	Useful Life (Years)	Capital Cost (US$ M)	Capital Recovery Factor (%)	Annual Cost (US$ M)	Plant Factor	Fuel Cost (US$ M)	Fixed O&M (US$ M)	Variable O&M (US$ M)	Capital Cost (c/kWh)	Fuel Cost (c/kWh)	O&M Cost (c/kWh	LRIC** (Net Gen.) (c/kWh)
12.5 MW Diesel	1	15	16.48	0.147	2.42	0.89	2.33	0.06	0.19	2.80	2.69	0.29	5.77
12.5 MW Diesel (HiCost)*	1	15	20.41	0.147	3.00	0.89	2.33	0.06	0.19	3.46	2.69	0.29	6.44
40 MW Gas Turbine	1	20	33.20	0.134	4.44	0.71	9.69	0.06	1.29	2.51	5.47	0.76	8.74
120 MW Combined Cycle	1	25	119.55	0.127	15.24	0.75	26.15	0.55	1.95	2.58	4.43	0.42	7.43
150 MW Coal Steam	1	25	275.39	0.127	35.11	0.75	11.74	3.60	1.99	4.77	1.60	0.76	7.13
80 MW Congrejal	1	50	151.70	0.120	18.27	0.44	0.00	2.00	0.38	6.29	0.00	0.82	7.11
52 MW Agua Reina	1	50	206.45	0.120	24.86	0.53	0.00	2.90	0.52	11.59	0.00	1.59	13.18
135 MW Los Unitos	1	50	371.00	0.120	44.67	0.40	0.00	4.90	0.93	10.06	0.00	1.31	11.37
193 MW Pataca 3	1	50	377.31	0.120	45.43	0.37	0.00	4.90	0.94	12.63	0.00	1.62	14.25

Sources: SNC-Shawinigan, "Memorandum Técnico No. 15 - Evaluación y Clasifición de los Sitios Hidroeléctricos," June, 1992; and "Memorandum Técnico No.10 - Selección de Las Opciones Térmicas para La Planificación de la Generación, April, 1993.

* Hi Cost Diesel estimate from World Bank, "Core Report of the Electric Power Efficiency Improvement Study," Sept 1991.

** Long-run incremental cost in this table are based on output of plants only and exclude transmission, transmission and distribution losses.

APPENDIX C

Economic Evaluation

ECONOMIC EVALUATION

MILL	SANTA MATILDE			RIO LINDO		
CHARACTERISTIC	In Season	All Year (Oil)	All Year (Coal)	In Season	All Year (Oil)	All Year (Coal)
Net Capacity (MW)	11	15	15	5	7.5	7.5
Revenues/Savings						
Electricity Sold (MWh/Yr)	27,294	100,499	100,499	14,476	49,382	49,382
Price per kWh	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085
Electricity Saved (MWh/Y	2,138	2,453	2,453	0	43	43
Price per kWh	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085
Oil Savings	$0	$1,740	$1,740	$0	$0	$0
Annual Value	$2,501,720	$8,752,660	$8,752,660	$1,230,460	$4,201,117	$4,201,117
Capital Cost						
Initial Investment	$23,102,000	$23,212,000	$24,712,000	$15,082,000	$15,182,000	$16,047,000
Project Life (Years)	20	20	20	20	20	20
Discount Rate (%/Yr)	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
Annual Capital Cost	$3,092,868	$3,107,594	$3,308,412	$2,019,160	$2,032,548	$2,148,353
Operating Cost						
Fixed O & M	$0	$190,200	$209,850	$0	$95,100	$104,925
Variable O & M	$68,235	$251,248	$271,347	$36,190	$123,455	$133,331
Purchased Fuel	$0	$3,572,854	$1,554,063	$0	$1,703,620	$741,013
Annual Operating Cost	$68,235	$3,824,102	$1,825,410	$36,190	$1,827,075	$874,344
Annual Profit (Loss)	($659,383)	$1,820,964	$3,618,837	($824,890)	$341,494	$1,178,419
Computations						
ROI at $0.085/kWh	8.46%	20.74%	27.83%	4.84%	14.62%	20.21%
Power Cost at 12% ROI	$0.107	$0.067	$0.050	$0.142	$0.078	$0.061

ECONOMIC EVALUATION

CHARACTERISTIC	MILL	SAN RAMON		CHUMBAGUA		
	In Season	All Year (Oil)	All Year (Coal)	In Season	All Year (Oil)	All Year (Coal)
Net Capacity (MW)	2.5	3.5	3.5	5	7	7
Revenues/Savings						
Electricity Sold (MWh/Yr)	5,615	21,871	21,871	9,672	42,636	42,636
Price per kWh	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085
Electricity Saved (MWh/Y	834	1,136	1,136	0	0	0
Price per kWh	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085
Oil Savings	$26,297	$26,297	$26,297	$2,273	$20,909	$2,273
Annual Value	$574,462	$1,981,926	$1,981,926	$824,393	$3,644,969	$3,626,333
Capital Cost						
Initial Investment	$9,948,000	$9,995,000	$10,585,000	$13,923,000	$13,988,000	$14,813,000
Project Life (Years)	20	20	20	20	20	20
Discount Rate (%/Yr)	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
Annual Capital Cost	$1,331,826	$1,338,118	$1,417,107	$1,863,994	$1,872,696	$1,983,146
Operating Cost						
Fixed O & M	$0	$44,380	$48,965	$0	$88,760	$97,930
Variable O & M	$14,038	$54,678	$59,052	$24,180	$106,590	$115,117
Purchased Fuel	$0	$793,400	$345,098	$0	$1,608,860	$699,793
Annual Operating Cost	$14,038	$848,078	$404,150	$24,180	$1,715,450	$814,910
Annual Profit (Loss)	($771,402)	($204,270)	$160,669	($1,063,782)	$56,823	$828,276
Computations						
ROI at $0.085/kWh	1.16%	9.50%	13.78%	1.37%	12.48%	18.32%
Power Cost at 12% ROI	$0.205	$0.094	$0.078	$0.195	$0.084	$0.066

75

ECONOMIC EVALUATION

MILL	EL PORVENIR			CENTRAL PROGRESO		
CHARACTERISTIC	In Season	All Year (Oil)	All Year (Coal)	In Season	All Year (Oil)	All Year (Coal)
Net Capacity (MW)	5.5	7	7	9.7	13	13
Revenues/Savings						
Electricity Sold (MWh/Yr)	7,918	55,080	55,080	20,013	87,092	87,092
Price per kWh	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085
Electricity Saved (MWh/Y	389	389	389	1,300	1,300	1,300
Price per kWh	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085
Oil Savings	$0	$0	$0	$0	$0	$0
Annual Value	$706,101	$4,714,871	$4,714,871	$1,811,605	$7,513,320	$7,513,320
Capital Cost						
Initial Investment	$13,923,000	$13,988,000	$14,813,000	$20,376,000	$20,472,000	$21,688,000
Project Life (Years)	20	20	20	20	20	20
Discount Rate (%/Yr)	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
Annual Capital Cost	$1,863,994	$1,872,696	$1,983,146	$2,727,914	$2,740,766	$2,903,563
Operating Cost						
Fixed O & M	$0	$88,760	$97,930	$0	$164,840	$181,870
Variable O & M	$19,795	$137,700	$148,716	$50,033	$217,730	$235,148
Purchased Fuel	$0	$2,301,800	$1,001,201	$0	$3,273,900	$1,424,028
Annual Operating Cost	$19,795	$2,439,500	$1,149,917	$50,033	$3,491,630	$1,659,176
Annual Profit (Loss)	($1,177,688)	$402,675	$1,581,808	($966,342)	$1,280,924	$2,950,581
Computations						
ROI at $0.085/kWh	-0.14%	15.33%	23.73%	5.90%	19.04%	26.76%
Power Cost at 12% ROI	$0.227	$0.078	$0.056	$0.130	$0.071	$0.052

ECONOMIC EVALUATION

CHARACTERISTIC	MILL	LOS MANGOS			LA GRECIA		
	In Season	All Year (Oil)	All Year (Coal)		In Season	All Year (Oil)	All Year (Coal)
Net Capacity (MW)	2.7	5	5		5	8	8
Revenues/Savings							
Electricity Sold (MWh/Yr)	6,114	27,097	27,097		12,132	54,759	54,759
Price per kWh	$0.085	$0.085	$0.085		$0.085	$0.085	$0.085
Electricity Saved (MWh/Y	120	120	120		0	0	0
Price per kWh	$0.085	$0.085	$0.085		$0.085	$0.085	$0.085
Oil Savings	$0	$0	$0		$0	$0	$0
Annual Value	$529,890	$2,313,445	$2,313,445		$1,031,220	$4,654,515	$4,654,515
Capital Cost							
Initial Investment	$11,656,000	$11,712,000	$12,413,000		$19,615,000	$19,725,000	$20,030,000
Project Life (Years)	20	20	20		20	20	20
Discount Rate (%/Yr)	12.00%	12.00%	12.00%		12.00%	12.00%	12.00%
Annual Capital Cost	$1,560,491	$1,567,988	$1,661,837		$2,626,032	$2,640,759	$2,681,592
Operating Cost							
Fixed O & M	$0	$63,400	$69,950		$0	$101,440	$111,920
Variable O & M	$15,285	$67,743	$73,162		$30,330	$136,898	$147,849
Purchased Fuel	$0	$1,024,120	$445,451		$0	$2,080,480	$904,937
Annual Operating Cost	$15,285	$1,091,863	$518,613		$30,330	$2,217,378	$1,052,786
Annual Profit (Loss)	($1,045,886)	($346,406)	$132,995		($1,625,142)	($203,621)	$920,137
Computations							
ROI at $0.085/kWh	-1.16%	8.32%	13.26%		0.19%	10.75%	17.23%
Power Cost at 12% ROI	$0.253	$0.098	$0.080		$0.219	$0.089	$0.068

U.S. Agency for International Development
Bureau for Global Programs, Field Support, and Research
Center for Environment
Office of Energy, Environment, and Technology

The Center for Environment of the Bureau for Global Programs, Field Support, and Research houses the environmental programs of the U.S. Agency for International Development (USAID). One of five *Centers of Excellence* within the Agency, the Center for Environment provides field support to U.S. bilateral assistance efforts, manages global environmental program activities, oversees USAID's environmental research efforts, and is USAID's principal liaison on technical environmental issues to the rest of the U.S. Government, non-governmental organizations and universities, and other bilateral and multilateral donors.

The Office of Energy, Environment, and Technology is a part of the Center for Environment and helps developing countries and emerging economies find market-oriented solutions to their energy and environment problems. The Office helps set the energy policy direction for the Agency and responds to the short-term needs of USAID's field offices in assisted countries.

A lack of energy is seriously curtailing economic growth in developing countries and countries in transition. Expansion of energy supplies imposes a huge financial burden while increasing environmental threats in these countries. In addition, many countries lack the institutional capability and appropriate technology to operate and manage energy systems efficiently. These factors contribute to the role energy development plays as a leading contributor to global climate change and regional and local environmental problems.

To address these problems, the Office of Energy, Environment, and Technology leverages the financial resources of multilateral development banks, such as The World Bank and the InterAmerican Development Bank, the private sector, and other bilateral donors to increase energy efficiency and expand energy supplies, enhance the role of private power, and implement novel approaches through research and adaptation. These approaches include improving power sector investment planning ("integrated resources planning") and encouraging the application of cleaner technologies that use both conventional fossil fuels and renewable energy sources. The Office's promotion of greater private sector participation in the power sector and a wide-ranging training program also help to build the institutional infrastructure necessary to sustain cost-effective growth.

Further information regarding the Office's projects and activities is available in our annual Program Plan, which can be requested by contacting the Office of Energy, Environment, and Technology at the following address.

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