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ENERGY FROM SUGARCANE COGENERATION IN EL SALVADOR

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SUMMARY

In 1992-1993, El Salvador produced 346,503 tons of sugar from sugarcane in ten factories, ranging in capacity from 50 to 240 tons of cane per hour. Four of the factories are privately owned, and the rest are owned and operated within the public sector. Privatization of the public mills is under active consideration by the government.

Using bagasse as a fuel in high-pressure boilers, the Salvadoran sugar industry should be in a position to export economically 55 megawatts of power for the nation during the four month cane crushing season from December to March, and over 75 megawatts during the remainder of the year if the generators continue to operate with supplemental fuel. These amounts represent, respectively, 6.7 percent and 9.2 percent of the country's installed generating capacity. In addition, the mills located to the north of San Salvador may be advantageously situated to help limit power transmission and distribution costs associated with serving nearby communities.

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 CEL's expansion plans, given the specific timing and location of possible power production at the mills. To accomplish this, "avoided cost" criteria, based on CEL 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. If the mills were to generate power throughout the year, using Bunker C as a supplemental fuel, the industry could profitably export 565,000 megawatt hours per year at a price at or below US$0.058 per kWh, as shown in Chapter 4 (Figure 4.1). This represents 23% of the nation's power production in 1992. Achieving this level would entail installation of high-pressure (900 lb. per square inch) boilers and extraction turbines.

2. The industry also could produce power for sale economically using a lower steam pressure (600 lb. per square inch), but in lower volumes and at higher cost. Under these conditions the potential would be 473,000 megawatt hours, or 19% of 1992 national production, at or below a cost of US$0.062 per kWh. The advantage of the less efficient technology would be lessened need to train mill workers and supervisors in the operation of water treatment systems and automated controls required for higher pressures.

3. The cost of cogenerating power could be reduced in a number of circumstances. Central Izalco, for example, is installing a new boiler in conjunction with a planned expansion, and specifying a higher pressure rating to permit cogeneration will add only marginally to the cost. Purchasing used equipment may also reduce initial capital requirements, but possibly at an added cost in terms of maintenance, efficiency and useful life. Finally, old equipment that is replaced while it is still useful may still have a signficant salvage value. Purchasing available equipment that is not matched to the remainder of the system also will result in sub-optimal performance.

4. The power output levels estimated in this report assume that the mills' internal steam requirements remain the same as they are currently. With a market for surplus electricity, mill owners have an incentive to conserve steam and thereby to increase power sales beyond the levels presented here. The volume of power exported could theoretically be increased in this way by a factor of two or three.

5. The value of cogenerated power to the national grid, based on CEL's estimated five-year average avoided generation costs, is now between approximately US$0.0685 and US$0.0745 per kWh. The value is dependent on time of year because of seasonal fluctuations in rainfall influencing CEL's ability to produce hydropower, and it varies by time of day as well because of cycles in demand.

6. In the case of the La Cabaña and San Francisco mills, cogenerated power may be worth more than the avoided generation cost, because CAESS, the local distribution company, would probably be able to scale back or postpone needed transmission and distribution system improvements along a nearby power line extending to the north from San Salvador. If the utility could obtain 6 MW from these mills, it would be able to restore minimum voltages (now around 90 V) to more acceptable levels and to reduce line losses by approximately 500 kW, without adding substation or conductor capacity beyond 8 kilometers of new line to connect the mills.

7. With the exceptions of Ahuachapán, Chanmico, La Magdalena and El Carmen, all of the mills appear to represent promising investment opportunities. 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 CEL.

8. One of the principal barriers 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 to CEL. To justify an investment of of several millions of dollars at a single installation will require assurance that the project revenues will continue far enough into the future to amortize the expenditure. Since CEL is the only prospective purchaser, the utility will need to provide that assurance. On another level, the sugar mill managers will need a clear indication of their rights and obligations concerning interconnection, metering, personnel safety, protection of electrical system integrity, supply reliability, and conflict resolution.

9. 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 CEL oil-fired powerplants. Use of oil 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 corresponding reductions in thermal power production by CEL.

1.0 INTRODUCTION

This study arises out of the need for economical new supplies of electric energy to suppport future growth and development in El Salvador. The national utility, the Comisión Ejecutiva Hidroeléctrica del Río Lempa (CEL), depends on a mixture of hydropower and thermal generation to supply its customers, but increasing demand will requires new sources of power in the future to meet the requirements for economic growth and social well-being.

In other parts of the world, notably the islands of Hawaii, Mauritius and Cuba, the sugar industry contributes substantially to local electric supply. In other locations, like El Salvador, 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 energy only for self sufficiency.

Against this background, CEL is evaluating alternative new generation options and is studying legislative proposals to legalize purchases of power from the private sector. In a letter to the sugar industry in July, 1993, CEL indicated that it was disposed to acquire 80 megawatts of power, or 599,960 megawatt-hours of energy per year, beginning in January, 1995. The letter anticipated an additional 40 megawatts of requirements in 1998 and suggested a range of between US$0.06 and US$0.07 as a basis for price projections, and it invited the industry to participate in drafting private power enabling legislation and regulatory frameworks to be proposed to the government.

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 be 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. While non-bagasse fuels must be purchased, their cost is likely to be more than offset by added revenues from power sales, and the required additional capital expenditure for larger condensers and fuel storage and handling equipment is 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.

From a national perspective, private sugar mill cogeneration could represent a near-term opportunity to acquire electric power at a cost equal to or less than that of alternative sources. Using an indigenous waste resource instead of imported fossil fuel, at least for part of the year, will save foreign exchange and reduce exposure to world oil price fluctuations. Cogeneration could also enhance the productivity of the Salvadoran sugar industry, by both providing an additional revenue stream and intensifying the economic incentive for improved plant efficiency and reliability. Finally, the experience of successful cogeneration in the sugar mills may facilitate similar projects in other energy intensive industries.

Because of interest expressed by CEL's management, the US 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 El Salvador in December of 1993. At that time the project team visited with CEL staff and consultants, sugar industry association representatives, and managers or superintendents at each of the country's ten mills. The body of the report is organized in three chapters. Chapter 2 provides technical and historical background on the present design and operation of each individual mill, and it presents alternative cogeneration system configurations and associated costs for operation at two different steam pressures. Chapter 3 discusses at length the value, in the context of CEL's anticipated costs, of the power that the sugar industry might make available to the national grid. Finally, Chapter 4 integrates the material in the preceding chapters in an overall analysis of economic costs and benefits.

2.0 THE SUGAR INDUSTRY IN EL SALVADOR

2.1 BACKGROUND

In 1992-1993, El Salvador produced 346,503 tons of sugar from sugarcane processed in ten factories, which range in capacity from 50 to 240 tons of cane per hour. Last year's production was comparable to that of the year before, which for the first time since the decade of armed conflict exceeded the earlier record of 318,000 tons set in 1977.

Four of the factories are privately owned, and the rest are owned and operated by INAZUCAR and CORSAIN, two public entities. Privatization of the public sector mills is currently under consideration by the national government. The following table summarizes the production characteristics of the ten factories, and Figure 2.1 indicates their geographic locations.

TABLE 2.1: PRODUCTION CHARACTERISTICS OF SUGAR FACTORIES

Factory	**Ownership**	**Annual sugar production (tons)**
Central Izalco	Private	78,177
El Angel	Private	53,119
Ingenio Jiboa	CORSAIN	57,804
La Cabaña	INAZUCAR	44,560
San Francisco	Private	35,298
Chaparrastique	INAZUCAR	25,768
El Carmen	INAZUCAR	15,466
La Magdalena	INAZUCAR	15,032
Chanmico	INAZUCAR	14,610
Ahuachapán	Private	6,669
Total		346,503

The sugar factories generate all or most of their steam and electricity requirements by burning bagasse in furnaces to generate steam at pressures that range from 200 to 300 psi. Part of the steam is expanded through turbogenerators in order to produce electricity.

The rest of the steam is generally used in turbine drives to provide mechanical power directly, and exhaust steam from the turbines is used for heating purposes in the factories. In some instances, a portion of the steam for heating comes directly from the boilers via a pressure reduction valve.

FIGURE 2.1 LOCATION OF EL SALVADOR SUGAR FACTORIES

A number of factories are finding it necessary to purchase up to 25% of their electrical power requirements from CEL even during the harvest season. Others, such as Central Izalco, Jiboa and San Francisco, either do not require any purchased electricity or have kept such purchases at low levels, having successfully implemented measures to reduce their consumption of process steam and mechanical power. Jiboa is also reducing its percentage of lost time, during which the factory is not producing any bagasse and is consuming steam and electricity. At the beginning of the 1993-1994 crop, San Francisco began exporting 500 kW of power to the local community during the season as part of an experiment in conjunction with CEL and is contemplating a cogeneration project in conjunction with future plant expansion. Central Izalco has installed a new 600 psi boiler and plans to export 5 MW of power to CEL during the crop season.

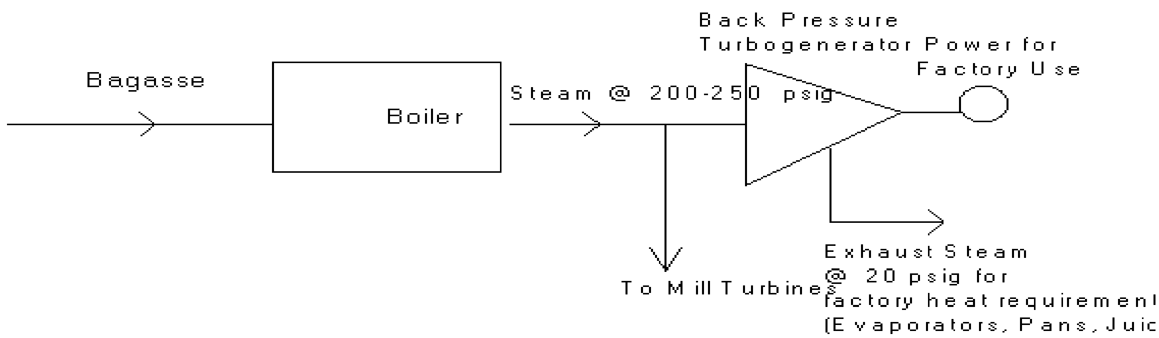
An objective of this study is to determine the potential for cogeneration by the ten factories if the existing boilers were replaced with high pressure units in order to produce more electricity for sale to the public utility company. Features that make mills attractive candidates for this kind of investment include large scale, long grinding seasons, full use of milling capacity with minimum downtime, and low process steam requirements.

2.2 CASE ANALYSIS OF COGENERATION POTENTIAL

Sugar factories in El Salvador 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 passes 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, supplies the heat requirements of the evaporators and vacuum pans. The figure below depicts a typical existing installation.

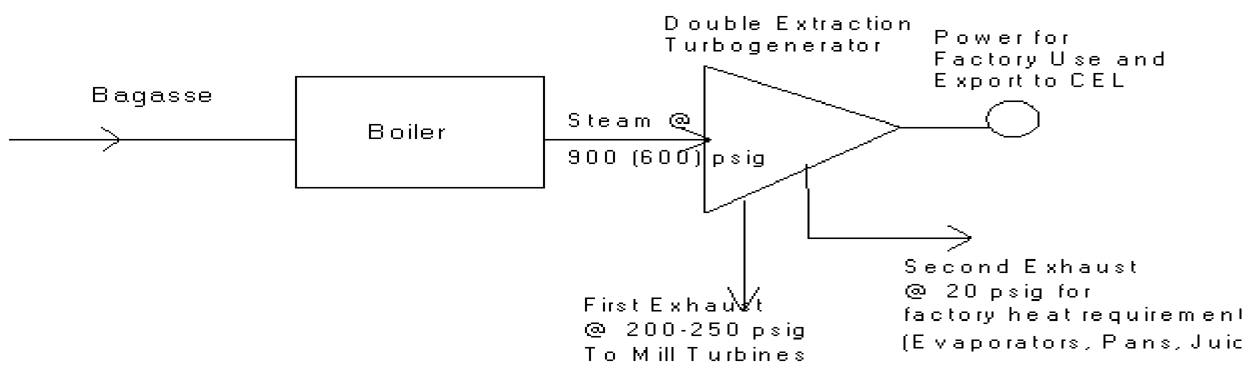
Since the volume of steam required at the higher pressure for the mill turbines is not usually measured in practice, the proportion of the steam to be extracted at the lower pressure was assumed to equal the volume currently exiting the back pressure turbogenerator in the existing system. In most cases this was derived from the generator's power output and its specific steam consumption per kWh. Flows estimated in this way are inexact, especially if confounded by significant present use of the expansion valve to by-pass the turbogenerator. Another way to derive these flows would be to postulate a horsepower requirement per ton of cane and a specific steam consumption per horsepower-hour for the mill drives in order to calculate the higher pressure steam flow. This too would be inexact and would not reflect the factories' individual steam consumption characteristics. Appropriate instrumentation would help to improve the reliability of any future analysis.

FIGURE 2.2: EXISTING CONFIGURATION



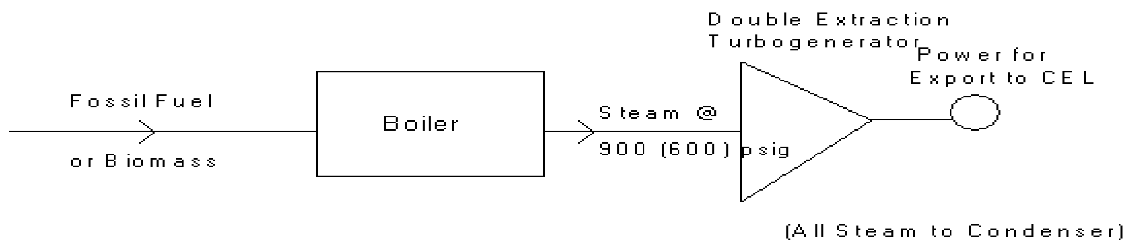
In the proposed systems, steam is produced at either 600 or 900 psig and piped through a double extraction turbine generator. The first extraction, occuring at 200 psig, provides steam to turn the mill turbines. The second extraction, occurring at 15 psig, together with exhaust steam from the mill turbines, provides the steam needed to run the evaporators and vacuum pans. This configuration appears in Figure 2.3.

FIGURE 2.3: PROPOSED IN-SEASON CONFIGURATION



For more economical 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 2.4. Since the system is sized to consume all of the available bagasse during the grinding season, bunker oil, 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 2.4: PROPOSED OFF-SEASON CONFIGURATION



For each of the ten sugar factories in El Salvador, we have developed two cases for the evaluation of its potential for cogeneration.

CASE 1 Installation of a boiler producing steam at 900 psia and 850 degrees F, together with a double extraction condensing turbogenerator.

CASE 2 Installation of a boiler producing steam at 600 psia and 750 degrees F, together with a double extraction condensing turbogenerator.

For purposes of evaluating these two cases, the Base Case is considered to describe the existing configuration, with in-season factory operations and no power sales to CEL. Net exportable power and energy are calculated separately for in-season and for off-season operations.

The sizes of the boilers and turbogenerators used in developing the capital costs are based on designing the boilers to burn all the bagasse that is produced each hour. Smaller boilers would require adding storage capacity for bagasse, whereas larger units 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 in-season would not be financially beneficial to the sugar company as its dual fuel boilers cannot be as efficient as CEL's boilers, which are specifically designed to burn fuel oil.

In practice, most of the mills in El Salvador need little or no additional fuel now to supplement bagasse in the boilers, while at the same time, they do not generally have surplus bagasse at the end of the season. This allows one to derive the steam needed for the mill drives and factory heat requirements from the present volume of bagasse produced by the mill and burned in the existing boilers. The volume of steam that can be generated with the same fuel at higher pressure will be somewhat less, but the assumption is that a replacement boiler will be more efficient, and that other simple economy measures will enable the mill to accommodate the reduction.

Experience in Hawaii, Mauritius and elsewhere indicates that when a market exists for exported power, steam savings measures, like improved evaporators and electric mill drives, become financially attractive. When these measures are implemented, a portion of the steam can pass through the turbogenerator to a condenser, generating considerable additional power for sale. In this study, however, we have assumed that no steam will be available for condensing, since the the arrays of economy measures will require additional investments to finance them and will vary among the individual mills.

Even if the sugar factory does not enjoy a comparative fuel cost advantage when bagasse is not available, burning oil during the off-season may be desirable for more efficient capital utilization. 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. During the off-season gross power generation remains the same as during the season, but net power sales to CEL will be higher because no power is needed for the sugar factory operation.

Appendix A contains design details for all of the individual factories and presents power production and fuel consumption calculations for both of the alternative cases outlined above.

Capital costs for boilers and turbogenerators are estimated using actual quotations from major international manufacturers, and adjusted for size at the various factories. For Case 1, the boilers are high-pressure units, operating at 900 psig and 850 degrees F. For Case 2, the boilers operate at 600 psig and 750 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. Utility interconnection is included as an electrical cost, assuming transformers, switchgear, meters, etc. necessary to deliver power at up to 15 kV will be charged to the project. Utility improvements (or reduced need for them) beyond the mill substation are not included here but are discussed in Section 3.6 below.

Costs at individual locations will vary 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, competition among contractors may further reduce costs, especially for engineering and erection, as may the participation of local labor, depending on its productivity. The total estimated capital costs include 20% for miscellaneous items and for contingency.

The cost estimates used in this study assume that no useful cogeneration infrastructure already exists. For actual construction, some of a new installation's cost may be justified by more efficient or expanded sugar production, and old equipment that is replaced may have a salvage value. This consideration would argue for building cogeneration systems gradually in concert with other plant improvements.

The cost of a boiler capable of burning bagasse during the season and oil during the off 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 at a cost that is relatively small compared to that of the total project.

The price of Bunker C fuel prices is assumed to be $14 per barrel for oil. Operating and maintenance costs are assumed to be $21.73 per kW per year for fixed costs on a year-round basis, and US$2.50 for variable costs for every MWh that is exported. One economic advantage of power cogeneration in a sugar factory is that the fixed costs of power generation have already been met in the existing sugar operations. However, management and engineering personnel costs will increase if year-round operations are 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 205/365 (where 205 is the number of off-season days per year), i.e. 0.5616, times the fixed costs of $21.73 per kW per year. Thus the additional fixed cost when burning oil during the off-season will be 0.5616 x US$21.73 , i.e. $12.20 per kW per year.

For off-season operations, an availability factor of 90% is assumed. During the season, each factory is assumed to operate at its current grinding time efficiency.

2.2.1 Central Izalco

Central Izalco, a privately owned sugar factory, is the largest in El Salvador, with a designed capacity of 6,500 metric tons cane per day. During the 1992-1993 crop, the factory processed an average of 5,274 tons of cane per day and produced a total of 78,177 tons of sugar, of which 61,200 tons were either plantation white or refined.

The cane harvest season lasts about 160 days a year. The factory is nearly self-sufficient in electricity; of the 13,131 MWh consumed in the 1991-1992 season, only about 5 MWh were purchased from CEL. The consumption of bunker oil is also low (1,200 gallons in 1991-1992 and none in 1992-1993). Table 2.2 shows some of the relevant production statistics.

TABLE 2.2: PRODUCTION STATISTICS -- CENTRAL IZALCO

	1989-1990	**1990-1991**	**1991-1992**	**1992-1993**
Crop days	148	158	164	160
% Lost time	7.38	6.41	4.68	4.28
Tons cane/year	728,956	842,987	870,171	838,565

Tons cane/hr	223.1	238.7	234.5	230.5
Tons sugar/year	61,389	70,189	84,114	78,177
Gallons bunker	0	0	1,200	0
Gallons diesel	0	0	0	0
Pol % cane	11.79	11.61	12.99	12.51
Pol % bagasse	3.28	3.6	3.69	3.83
Fiber % cane	12.84	12.65	12.60	12.86
Fiber % bagasse	47.70	47.67	44.70	45.57
Moisture % bagasse	47.78	47.34	50.24	49.44
kWh generated	10,228,000	11,684,500	13,125,900	13,034,100
kWh purchased (season)	0	0	4,800	24,000
kWh purchased (off-season)	681,120	678,865	184,090	575,983

The milling tandem consists of a shredder and four mills with individual turbine drives. Three boilers supply steam at 250 psig pressure to the factory and to two Worthington turbines coupled to Electrical Machinery generators for power generation. The turbine-generators are rated at 2,500 and 3,500 kW respectively. The boilers, made by Babcock and Wilcox, were installed in 1964. Two have a capacity of 65,000 pounds per hour of steam each, and the third can produce 95,000 pounds per hour of steam. The first two boilers are equipped with economizers, and the third has an air preheater.

Central Izalco presently produces an excess of bagasse in spite of a refinery operation annexed to the raw sugar factory, and a 600 psi boiler is under construction to generate an estimated 5 MW of power for export to CEL. The company plans to expand sugar cane processing to 12,000 tons cane per day in order to obtain enough bagasse for use as fuel in the new boiler.

Table 2.3 shows the potential for export of cogenerated power based on burning the bagasse that is currently being produced to generate steam in 600 psi or 900 psi boilers

TABLE 2.3: POTENTIAL FOR EXPORT OF COGENERATED POWER

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Pounds steam per hour	265,000	276,000
Gross generation capacity, MW	17	14
Net exportable power(season), MW	11	8
Net exportable power (off-season), MW	17	14
Net exportable MWh (season)	41,952	32,790
Net exportable MWh (off-season)	73,622	63,288
Net exportable MWh per year	115,574	96,078

Table 2.4 shows the capital cost of installing new 900 psi or 600 psi boilers and turbogenerators at Central Izalco.

TABLE 2.4: CAPITAL COST OF INSTALLING NEW BOILERSAND TURBOGENERATORS

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Boiler	$5,185,000	$4,714,000
Turbogenerator	$3,238,000	$2,944,000
Piping, civil, electrical, foundation	$8,424,000	$7,658,000
Erection	$1,791,000	$1,628,000
Engineering	$932,000	$847,000

Miscellaneous	$1,957,000	$1,779,000
Contingency	$2,153,000	$1,957,000
TOTAL	$23,680,000	$21,527,000
$ million per gross MW	1.41	1.49

Table 2.5 shows the estimated annual operating cost of power generation. Production costs are based on the assumptions that only bagasse is burned during the season, and only bunker C fuel is burned during the off-season.

TABLE 2.5: ESTIMATED ANNUAL OPERATING COST OF POWER GENERATION

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Fuel cost (season)	0	0
Fuel cost (off-season)	$2,197,308	$2,005,825
Variable operating and maintenance costs (season)	$104,881	$81,974
Variable operating and maintenance costs (off-season)	$184,054	$158,220
Fixed operating and maintenance costs (season)	0	0
Fixed operating and maintenance costs (off-season)	$202,917	$174,436

2.2.2 El Angel

El Angel sugar factory is a also privately owned and is the second largest in El Salvador with a designed capacity of 4,800 metric tons cane per day. During the 1992-1993 crop the factory processed 625,468 tons of cane. The hourly grinding rate adjusted for lost time is about 210 tons of cane. The factory produced 59,061 tons in 1992-1993, of which 42,728 tons were plantation white sugar and 16,333 tons were refined.

The cane harvest season lasts about 120-130 days a year. The factory is nearly self-sufficient in electricity and fuel. Of the 5,720 MWh consumed in the 1991-1992 season, only 110 MWh were purchased from CEL, and the plant consumed no bunker oil.

Table 2.6 shows some relevant production statistics for the 1989-1990 crop through the 1992-1993 crop.

TABLE 2.6: PRODUCTION STATISTICS -- EL ANGEL

	1989-1990	1990-1991	1991-1992	1992-1993
Crop days	102	122	128	128
% Lost time	11.25	9.7	9.7	11.08
Tons cane/year	431,383	533,689	593,986	625,468
Tons cane/hr	200	202	214	229
Tons sugar/year	34,908	55,049	53,119	59,061
Gallons bunker		1,100	0	
Gallons diesel		0	0	
Pol % cane	11.51	11.44	11.99	11.3
Pol % bagasse	3.03	3.97	2.98	
Fiber % cane	15.13	15.09	13.4	14.4
Fiber % bagasse	46.66	44.77	46.79	

Moisture % bagasse				
kWh generated	4,500,000	5,500,000	5,610,000	
kWh purchased (season)	30,720	79,440	110,400	
kWh purchased (off-season)	297,360	260,400	99,181	

The milling tandem consists of five mills driven by three turbines rated at 400 HP, 900 HP and 900 HP respectively. Cane is prepared in a shredder driven by a Dresser Rand turbine rated at 800 HP. The turbines take in steam at 300 psi and exhaust at 18 psi.

Steam is supplied by two Dedini boilers operating at 300 psi and 280 degrees C. The Dedini boilers have capacities of 60,000 kg/hr and 40,000 kg/hr respectively. Electricity is generated by three Dresser Rand turbines and Marathon generators rated at 1,500 kW each.

El Angel produces a mix of plantation white sugar and refined sugar. Although it does not require supplemental fuels in the form of diesel or bunker C, El Angel purchased over 110,000 kWh from CEL in 1991-1992. One reason given for this electricity purchase was mechanical problems with a turbogenerator.

Table 2.7 shows the potential for export of cogenerated power based on burning the bagasse that is currently being produced to generate steam in 900 psi or 600 psi boilers.

TABLE 2.7: POTENTIAL FOR EXPORT OF COGENERATED POWER

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Pounds steam per hour	245,000	254,000
Gross generation capacity, MW	14	12
Net exportable power(season), MW	10	8
Net exportable power (off-season), MW	14	12

Net exportable MWh (season)	29,871	23,410
Net exportable MWh (off-season)	74,956	63,780
Net exportable MWh per year	104,834	87,190

Table 2.8 shows the capital cost of installing new 900 psi or 600 psi boilers and turbogenerators at El Angel.

TABLE 2.8: CAPITAL COST OF INSTALLING BOILERS AND TURBOGENERATORS

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Boiler	$5,023,000	$4,566,000
Turbogenerator	$2,972,000	$2,702,000
Piping, civil, electrical, foundation	$7,995,000	$7,268,000
Erection	$1,735,000	$1,577,000
Engineering	$886,000	$806,000
Miscellaneous	$1,861,000	$1,692,000
Contingency	$2,047,000	$1,861,000
TOTAL	$22,519,000	$20,472,000
$ million per gross MW	1.56	1.66

Table 2.9 shows the estimated annual operating cost of power generation. Production costs are based on the assumptions that only bagasse is burned during the season, and only bunker C fuel is burned during the off-season.

TABLE 2.9: ESTIMATED ANNUAL OPERATING COST OF POWER GENERATION

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Fuel cost (season)	0	0
Fuel cost (off-season)	$2,237,138	$2,021,408
Variable operating and maintenance costs (season)	$74,693	$58,524
Variable operating and maintenance costs (off-season)	$187,390	$159,449
Fixed operating and maintenance costs (season)	0	0
Fixed operating and maintenance costs (off-season)	$206,595	$175,791

2.2.3 Ingenio Jiboa

The Jiboa factory is publicly owned, and is the third largest in El Salvador. It has a designed capacity of 4,800 metric tons of cane per day and in 1992-1993 processed 713,586 tons of cane.

The harvest season lasts about 180 days. In 1992-1993, 4,800 tons of cane were processed per day of crop on average. After adjustments for lost time, the mills grind on average 211 tons of cane per hour.

The Jiboa factory produces a mix of raw sugar, white sugar and refined sugar. In 1992-1993 total production amounted to 57,804 tons, of which 24,799 tons were raw sugar, 32,442 tons white sugar and 563 tons refined sugar.

Jiboa factory's milling tandem consists of four mills driven by individual Peter Brotherhood turbines rated at 400 HP each. Cane is prepared by two sets of cane knives, and a fiberizer.

Table 2.10 shows some relevant production statistics for Jiboa.

TABLE 2.10: PRODUCTION STATISTICS -- JIBOA

	1989-1990	1990-1991	1991-1992	1992-1993
Crop days	111	153	184	173

% Lost time	10.0	13.7	16.3	18.6
Tons cane/year	403,931	591,702	777,814	713,586
Tons cane/hr	171	188	212	211
Tons sugar/year	15,485	25,268	32,558	57,804
Gallons bunker	10,880	54,5720	104,220	102,549
Gallons diesel	1,014	1,438	1,147	1,802
Pol % cane	12.11	12.06	11.87	11.54
Pol % bagasse	3.55	3.56	3.86	4.19
Fiber % cane	13.47	13.12	13.59	13.41
Fiber % bagasse	43.29	44.46	43.50	43.79
Moisture % bagasse	51.66	50.43	50.92	50.03
kWh generated	5,739,100	7,961,000	10,410,000	9,779,000
kWh purchased (season)	188,400	0	0	
kWh purchased (off-season)	650,000	415,800	656,000	

Electricity is generated by means of two Peter Brotherhood turbogenerators installed in 1975 and rated at 1,750 KVA each. The turbines take in steam at 300 psi and exhaust at 18 psi.

Steam is supplied by two Clarke Chapman boilers which were first installed in 1976. Each boiler has a capacity of 100,000 pounds per hour of steam at 300 psi pressure and a temperature of 350 degrees C. The boilers are equipped with air preheaters but do not have economizers.

The steam supply is a bottleneck which limits the capacity of the entire factory to its present rate of 4,800 tons cane per day. The factory could potentially process up to 6,500 tons cane per day with adequate boiler capacity.

The factory has two batteries of quadruple effect evaporators which can operate as a quintuple effect evaporator.

Table 2.11 shows the potential for export of cogenerated power based on burning the bagasse that is currently being produced to generate steam in 900 psi or 600 psi boilers.

TABLE 2.11: POTENTIAL FOR EXPORT OF COGENERATED POWER

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Pounds steam per hour	214,000	222,00
Gross generation capacity, MW	12	10
Net exportable power(season), MW	8.4	6.6
Net exportable power (off-season), MW	11.9	10.0
Net exportable MWh (season)	36,424	28,301
Net exportable MWh (off-season)	47,678	40,162
Net exportable MWh per year	84,102	68,465

Table 2.12 shows the capital cost of installing new 900 psi or 600 psi boilers and turbogenerators at Injiboa.

TABLE 2.12: CAPITAL COST OF INSTALLING BOILERS AND TURBOGENERATORS

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Boiler	$4,600,000	$4,182,000
Turbogenerator	$2,689,000	$2,444,000

Piping, civil, electrical, foundation	$7,288,000	$6,626,000
Erection	$1,589,000	$1,445,000
Engineering	$808,000	$735,000
Miscellaneous	$1,697,000	$1,543,000
Contingency	$1,867,000	$1,697,000
TOTAL	$20,538,000	$18,672,000
$ million per gross MW	1.72	1.86

Table 2.13 shows the estimated annual operating cost of power generation. Production costs are based on the assumptions that only bagasse is burned during the season, and only bunker C fuel is burned during the off-season.

TABLE 2.13: ESTIMATED ANNUAL OPERATING COST

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Fuel cost (season)	0	0
Fuel cost (off-season)	$1,423,006	$1,272,955
Variable operating and maintenance costs (season)	$91,060	$70,753
Variable operating and maintenance costs (off-season)	$119,196	$100,411
Fixed operating and maintenance costs (season)	0	0
Fixed operating and maintenance costs (off-season)	$131,412	$110,702

2.2.4 La Cabaña

La Cabaña is government-owned and is the fourth largest sugar factory in El Salvador. It has a designed capacity of 4,800 metric tons of cane per day. In 1992-1993, La Cabaña processed 505,963 tons of cane.

The harvest season lasts about 126 days. In 1992-1993, 4,016 tons of cane was processed per day of crop on average. After adjustments for lost time, the mills grind on average 193 tons of cane per hour.

La Cabaña produces a mix of raw, white and refined sugar. In 1992-1993 total sugar production amounted to 44,560 tons, of which 25,026 tons were white sugar, 17,214 tons were raw sugar and 2,320 tons were brown sugar.

The milling tandem consists of five mills driven by three Elliott turbines rated at 750 HP, 1,000 HP and 1,000 HP respectively. Cane is prepared by a set of cane knives and a fiberizer. Table 2.14 shows some relevant production statistics for La Cabaña.

TABLE 2.14: PRODUCTION STATISTICS -- LA CABAÑA

	1989-1990	1990-1991	1991-1992	1992-1993
Crop days	106	115	119	126
% Lost time	11.2	15.3	10.2	13.2
Tons cane/year	415,736	454,025	530,751	505,963
Tons cane/hr	184	194	206	193
Tons sugar/year	30,206	34,628	44,032	44,560
Gallons bunker	26,635	27,069	23,266	29,203
Gallons diesel		0	0	0
Pol % cane	10.61	11.06	11.93	12.64
Pol % bagasse	4.06	4.61	5.2	5.34
Fiber % cane	14.25	13.38	13.4	13.56

Fiber % bagasse	44.52	43.84	42.69	43.00
Moisture % bagasse	49.5	49.38	49.68	49.38
kWh generated	4,896,000	5,184,000	4,896,000	5,282,000
kWh purchased (season)	531,123	804,960	554,880	624,585
kWh purchased (off-season)	649,248	583,866	196,800	560,354

Steam is generated in four boilers producing a total of 290,000 pounds of steam per hour at 200 psi and 488 degrees F. Boiler 1 is a Babcock and Wilcox unit installed in 1947 and with a capacity of 90,000 pounds of steam per hour. Boilers 2 and 3 are Heine units installed in 1948 and with a capacity of 75,000 pounds per hour each. Boiler 4 is a Combustion Engineering unit installed in 1969 with a capacity of 50,000 pounds of steam per hour. The Babcock and Wilcox unit has an economizer, and the Heine units and the Combustion Engineering boiler are equipped with air preheaters but do not have economizers.

La Cabaña's electrical power demand is 3,000-3,200 kW, and power is generated by 2 turbogenerators, a Siemens unit installed in 1969 and rated at 1,500 kW, and an Ideal Electric unit installed in 1975 and rated at 2,000 kW. Thus, the turbogenerators have adequate capacity, but shortages have resulted from the requirement of the factory to supply both steam and electricity to an adjoining distillery, which produces ethanol from molasses. The shortfall amounts to as much as 1,200-1,400 kW, which is made up by electricity purchases from CEL. During the 1991-1992 season, the energy purchased from CEL amounted to 10% of the total consumption during the season.

The evaporator station at La Cabaña consists of one preevaporator and a quadruple effect evaporator.

Table 2.15 shows the potential for export of cogenerated power based on burning the bagasse that is currently being produced to generate steam in 900 psi or 600 psi boilers

TABLE 2.15: POTENTIAL FOR EXPORT OF COGENERATED POWER

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Pounds steam per hour	228,000	237,000

Gross generation capacity, MW	16	14
Net exportable power(season), MW	12.3	10.3
Net exportable power (off-season), MW	15.8	13.8
Net exportable MWh (season)	34,505	28,858
Net exportable MWh (off-season)	84,569	73,801
Net exportable MWh per year	119,072	102,659

Table 2.16 shows the capital cost of installing new 900 psi or 600 psi boilers and turbogenerators at La Cabaña.

TABLE 2.16: CAPITAL COST OF INSTALLING BOILERS AND TURBOGENERATORS

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Boiler	$4,744,000	$4,312,000
Turbogenerator	$3,238,000	$2,944,000
Piping, civil, electrical, foundation	$7,982,000	$7,256,000
Erection	$1,639,000	$1,490,000
Engineering	$880,000	$800,000
Miscellaneous	$1,848,000	$1,680,000
Contingency	$2,033,000	$1,848,000
TOTAL	$22,364,000	$20,330,000

$ million per gross MW	1.42	1.48

Table 2.17 shows the estimated annual operating cost of power generation. Production costs are based on the assumptions that only bagasse is burned during the season, and only bunker C fuel is burned during the off-season.

TABLE 2.17: ESTIMATED ANNUAL OPERATING COST OF POWER GENERATION

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Fuel cost (season)	0	0
Fuel cost (off-season)	$2,524,054	$2,339,021
Variable operating and maintenance costs (season)	$86,257	$72,145
Variable operating and maintenance costs (off-season)	$211,423	$184,503
Fixed operating and maintenance costs (season)	0	0
Fixed operating and maintenance costs (off-season)	$233,091	$203,412

2.2.5 San Francisco

San Francisco is a privately-owned sugar factory and the fifth largest in El Salvador. It has a designed capacity of 3,800 metric tons of cane per day. In 1992-1993, San Francisco processed 367,846 tons of cane.

The harvest season lasts about 127 days. In 1992-1993, 2,896 tons of cane were processed per day of crop on average. After adjustments for lost time, the mills grind on average 193 tons of cane per hour.

San Francisco factory produces a mix of raw sugar and white sugar. In 1992-1993 total production amounted to 35,297 tons, of which 26,964 tons were white sugar, and 8,333 tons were raw sugar.

The milling tandem consists of five mills with individual Buckau-Wolf turbine drives, one of which is rated at 530 HP, and the four others are rated at 330 HP each. Cane is prepared with a a set of cane knives and a shredder. Table 2.18 shows some relevant production statistics for San Francisco.

TABLE 2.18: PRODUCTION STATISTICS - SAN FRANCISCO

	1989-1990	1990-1991	1991-1992	1992-1993
Crop days	110	124	130	127
% Lost time	10.7	11.7	11.2	10.2
Tons cane/year	338,579	407,269	422,610	367,846
Tons cane/hr	146	157	155	138
Tons sugar/year	26,593	34,100	36,064	35,298
Gallons bunker	150	2,464	2,032	1,233
Gallons diesel	0	0	0	0
Pol % cane	11.45	11.33	11.93	15.60
Pol % bagasse	3.92	3.92	4.44	4.35
Fiber % cane	15.55	14.81	14.00	14.28
Fiber % bagasse	44.52	43.84	42.69	46.28
Moisture % bagasse	49.5	49.38	49.68	47.65
kWh generated	3,864,509	4,077,120	4,583,634	
kWh purchased (season)	34,464	9,024	18,528	
kWh purchased (off-season)	308,448	308,736	322,368	

Steam is generated in three boilers producing a total of 167,000 pounds of steam per hour at 300 psi and 285 degrees F. Boilers 1 and 2 are Buckau-Wolf units installed 26 and 19 years ago respectively. They each have a capacity of 40,000 pounds of steam per hour. Boiler 3 is an EVT unit installed thirteen years ago with a capacity of 88,000 pounds steam per hour. Boilers 1 and 2 are equipped with economizers, and Boiler 3 has an air preheater.

About 3,300 kW of power is generated by 3 turbogenerators: a Worthington unit installed in 1965 and rated at 800 kW, a Siemens unit installed in 1971 and rated at 1,000 kW, a second Worthington unit installed recently and rated for 1,500 kW.

The San Francisco factory had to purchase only 9,024 and 18,528 kWh from CEL during the 1990-1991 and 1991-1992 seasons, or 0.2% and 0.4% respectively of total consumption. The management of San Francisco plans to be self-sufficient in electricity and to sell 500 kW to CEL beginning at the start of the 1993-1994 season.

The evaporator station at San Francisco consists of a quadruple effect evaporator and a preevaporator.

Table 2.19 shows the potential for export of cogenerated power based on burning the bagasse that is currently being produced to generate steam in 900 psi or 600 psi boilers. The mill's management is planning a major expansion of the mill and anticipates installing cogeneration capacity as part of the overall project. The increased production will enable the mill to export power substantially in excess of the 8 to 10 MW illustrated here.

TABLE 2.19: POTENTIAL FOR EXPORT OF COGENERATED POWER

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Pounds steam per hour	187,000	194,000
Gross generation capacity, MW	11	9
Net exportable power(season), MW	7.7	6.0
Net exportable power (off-season), MW	11.0	9.3
Net exportable MWh (season)	23,405	18,392
Net exportable MWh (off-season)	56,440	47,985
Net exportable MWh per year	79,846	66,377

Table 2.20 shows the capital cost of installing new 900 psi or 600 psi boilers and turbogenerators at San Francisco sugar factory. If installed in conjunction with plant

capacity expansion, these items will not need to be justified solely in terms of power sales.

TABLE 2.20: CAPITAL COST OF INSTALLING BOILERS AND TURBOGENERATORS

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Boiler	$4,226,000	$3,842,000
Turbogenerator	$2,539,000	$2,308,000
Piping, civil, electrical, foundation	$6,766,000	$6,151,000
Erection	$1,460,000	$1,327,000
Engineering	$750,000	$681,000
Miscellaneous	$1,574,000	$1,431,000
Contingency	$1,731,000	$1,574,000
TOTAL	$19,046,000	$17,314,000
$ million per gross MW	1.73	1.86

Table 2.21 shows the estimated annual operating cost of power generation. Production costs are based on the assumptions that only bagasse is burned during the season, and only bunker C fuel is burned during the off-season.

TABLE 2.21: ESTIMATED ANNUAL OPERATING COST OF POWER GENERATION

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Fuel cost (season)	0	0
Fuel cost (off-season)	$1,684,521	$1,520,813

Variable operating and maintenance costs (season)	$58,513	$45,980
Variable operating and maintenance costs (off-season)	$141,101	$119,962
Fixed operating and maintenance costs (season)	0	0
Fixed operating and maintenance costs (off-season)	$155,562	$132,257

2.2.6 Ingenio Chaparrastique

Ingenio Chaparrastique, a government-owned sugar factory, is the sixth largest in the country. With a designed capacity of 3,800 metric tons of cane per day, Chaparrastique processed 276,359 tons of cane in 1992-1993.

The harvest season lasted 104 days in 1992-1993, and has varied between 82 days in 1989-1990 and 136 days in 1991-1992. In 1992-1993, 2,658 tons of cane were processed per day of crop on average. After adjustments for lost time, the mills grind on average 129 tons of cane per hour.

Chaparrastique factory produces only white sugar. In 1992-1993 total sugar production amounted to 25,768 tons.

The milling tandem consists of four mills with individual turbine drives, each rated at 700 HP. Mills 1 and 2 are driven by Worthington-Turbodyne turbines and Mills 3 and 4 are equipped with Elliott turbine drives. A shredder is used to prepare cane before milling.

Table 2.22 shows some relevant production statistics for Chaparrastique factory.

TABLE 2.22: PRODUCTION STATISTICS -- CHAPARRASTIQUE

	1989-1990	**1990-1991**	**1991-1992**	**1992-1993**
Crop days	82	113	136	104
% Lost time	5.7	18.6	11.9	14.0
Tons cane/year	159,602	222,156	352,5370	276,359
Tons cane/hr	67	102	124	129
Tons sugar/year	12,0583	17,172	30,889	25,768

Gallons bunker	3,812	8,747	3,812	1,416
Gallons diesel		0	0	0
Pol % cane	10.84	11.64	12.34	
Pol % bagasse	3.36	3.21	3.05	
Fiber % cane	13.05	13.46	12.14	
Fiber % bagasse	45.89	47.21	45.18	
Moisture % bagasse				
kWh generated		3,752,405	4,888,493	
kWh purchased (season)		570,384	193,392	
kWh purchased (off-season)		353,328		

Steam is generated in two boilers producing a total of 190,000 pounds of steam per hour. Both boilers were installed in 1988. Boiler 1 is a Distral unit with a capacity of 100,000 pounds per hour of steam at 240 psi and 300 degrees C. Boiler 2 is a Babcock and Wilcox unit with a capacity of 100,000 pounds per hour of steam at 240 psi and 300 degrees C. Boiler 2 does not have an economizer or a preheater. Boiler 1 is equipped with an economizer but not a preheater.

During the 1990-1991 and 1991-1992 crops, the Chaparrastique factory had to purchase 570,384 and 193,392 kWh from CEL during the season, or 13% and 4% respectively of total consumption in those years. Power is generated by an Ideal Electric turbogenerator rated at 2,000 kW. The management of Chaparrastique plans to replace an existing 600 kW unit installed in 1967 with a new 1300 kVA one which would allow them to eliminate power purchases from CEL and to export 500 kW to the grid during the season. They also plan to increase the cane grinding rate from 3,000 tons per day to 4,000 tons per day, as the existing factory capacity allows.

The evaporator station, which presently consists of two sets of quadruple effect evaporators, will be modified. Three vessels will be removed and the station will operate as a single quintuple effect evaporator.

Table 2.23 shows the potential for export of cogenerated power based on burning the bagasse that is currently being produced to generate steam in 900 psi or 600 psi boilers

TABLE 2.23: POTENTIAL FOR EXPORT OF COGENERATED POWER

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Pounds steam per hour	127,000	132,000
Gross generation capacity, MW	8	7
Net exportable power(season), MW	6.3	5.2
Net exportable power (off-season), MW	8.3	7.2
Net exportable MWh (season)	18,075	14,851
Net exportable MWh (off-season)	43,797	37,873
Net exportable MWh per year	61,873	52,724

Table 2.24 shows the capital cost of installing new 900 psi or 600 psi boilers and turbogenerators at Ingenio Chaparrastique.

TABLE 2.24: CAPITAL COST OF INSTALLING BOILERS AND TURBOGENERATORS

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Boiler	$3,491,000	$3,174,000
Turbogenerator	$2,221,000	$2,019,000
Piping, civil, electrical, foundation	$5,712,000	$5,193,000
Erection	$1,206,000	$1,096,000

Engineering	$632,000	$574,000
Miscellaneous	$1,326,000	$1,206,000
Contingency	$1,459,000	$1,326,000
TOTAL	$16,047,000	$14,588,000
$ million per gross MW	1.94	2.04

Table 2.25 shows the estimated annual operating cost of power generation. Production costs are based on the assumptions that only bagasse is burned during the season, and only bunker C fuel is burned during the off-season.

TABLE 2.25: ESTIMATED ANNUAL OPERATING COST OF POWER GENERATION

	CASE 1 900 psi	**CASE 2** 600 psi
Fuel cost (season)	0	0
Fuel cost (off-season)	$1,307,178	$1,200,320
Variable operating and maintenance costs (season)	$45,188	$37,127
Variable operating and maintenance costs (off-season)	$109,494	$94,682
Fixed operating and maintenance costs (season)	0	0
Fixed operating and maintenance costs (off-season)	$120,7153	$104,385

2.2.7 El Carmen

Ingenio El Carmen is a government-owned sugar factory and is among the four smallest in El Salvador, with a designed capacity of 2,000 tons of cane per day. In 1992-1993, El

Carmen processed 182,534 tons of cane during the crop season, which lasted 110 calendar days. The daily cane processing rate averaged 1,659 tons.

After adjustments for lost time, the mills grind on average 91 tons of cane per hour. The factory produces only raw sugar. In 1992-1993 total sugar production amounted to 15,466 tons.

The milling tandem consists of four mills driven by three turbines. Mill 1 is driven by a turbine rated at 350 HP, Mill 2 has a 500 HP turbine drive, and Mills 3 and 4 are driven by a single 750 HP turbine. A shredder is used to prepare cane before milling.

Table 2.26 shows some relevant production statistics for El Carmen factory.

TABLE 2.26: PRODUCTION STATISTICS -- EL CARMEN

	1989-1990	**1990-1991**	**1991-1992**	**1992-1993**
Crop days	110	144	124	110
%Lost time	20.8	35.7	20.2	24.0
Tons cane/year	187,342	187,282	219,843	182,534
Tons cane/hr	67	84	98	91
Tons sugar/year	12,802	14,253	19,531	15,466
Gallons bunker	4,000	8,000	6,000	9,982
Gallons diesel	0	0	0	0
Pol % cane				12.75
Pol % bagasse	4.38	4.99	4.21	4.32
Fiber % cane	12.99	13.93	13.98	11.56
Fiber % bagasse	42.38	42.26	43.92	43.45
Moisture % bagasse				50.9
kWh generated		40,944		

kWh purchased (season)		13,649		
kWh purchased (off-season)				

Steam is generated in three boilers producing a total of 120,000 pounds of steam per hour at 200 psi and 250 degrees C. Boiler 1 generates 40,000 pounds of steam per hour. Boilers 2 and 3 generate 30,000 pounds per hour and 50,000 pounds per hour of steam respectively. Boiler 2 is equipped with an air preheater, but Boilers 1 and 3 are not. Two of the boilers are equipped with economizers.

Using steam at 200 psi and exhausting at 10 psi, two turbogenerators generate 750 kW and 500 kW of electricity respectively.

The evaporator station consists of one quadruple effect system.

Table 2.27 shows the potential for export of cogenerated power based on burning the bagasse that is currently being produced to generate steam in 900 psi or 600 psi boilers.

TABLE 2.27: POTENTIAL FOR EXPORT OF COGENERATED POWER

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Pounds steam per hour	82,000	85,092
Gross generation capacity, MW	4.3	3.6
Net exportable power(season), MW	3.1	2.4
Net exportable power (off-season), MW	4.3	3.6
Net exportable MWh (season)	9,938	7,620
Net exportable MWh (off-season)	21,656	18,059
Net exportable MWh per year	31,595	25,679

Table 2.28 shows the capital cost of installing new 900 psi or 600 psi boilers and turbogenerators at El Carmen.

TABLE 2.28: CAPITAL COST OF INSTALLING BOILERS AND TURBOGENERATORS

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Boiler	$2,570,000	$2,336,000
Turbogenerator	$1,465,000	$1,332,000
Piping, civil, electrical, foundation	$4,035,000	$3,668,000
Erection	$888,000	$807,000
Engineering	$448,000	$407,000
Miscellaneous	$941,000	$855,000
Contingency	$1,035,000	$941,000
TOTAL	$11,382,000	$10,346,000
$ million per gross MW	2.62	2.86

Table 2.29 shows the estimated annual operating cost of power generation. Production costs are based on the assumptions that only bagasse is burned during the season, and only bunker C fuel is burned during the off-season.

TABLE 2.29: ESTIMATED ANNUAL OPERATING COST OF POWER GENERATION

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Fuel cost (season)	0	0
Fuel cost (off-season)	$646,351	$572.368
Variable operating and maintenance costs (season)	$24,846	$19,050

Variable operating and maintenance costs (off-season)	$54,141	$45,149
Fixed operating and maintenance costs (season)	0	0
Fixed operating and maintenance costs (off-season)	$59,689	$49,776

2.2.8 La Magdalena

The government-owned La Magdalena sugar factory and is also among the four smallest in El Salvador. It has a designed capacity of 2,000 tons of cane per day but processes about 1,700 tons cane per day on average. In 1992-1993, La Magdalena processed 151,760 tons of cane during a crop season, which lasted 94 calendar days. After adjustments for lost time, the mills grind on average 74 tons of cane per hour.

La Magdelena factory produces only plantation white sugar, and in 1992-1993, total sugar production amounted to 18,568 tons.

The milling tandem consists of six mills driven by four turbines. Mills 1 and 2 are driven by a turbine rated at 400 HP. Mills 3 and 4 have another 400 HP turbine. Mills 5 and 6 are individually driven by 200 HP turbines. There is no cane preparation prior to milling.

Table 2.30 shows some relevant production statistics for La Magdalena.

TABLE 2.30: PRODUCTION STATISTICS -- LA MAGDALENA

	1989-1990	**1990-1991**	**1991-1992**	**1992-1993**
Crop days	77	106	108	94
% Lost time	11.2	22.9	15.0	11.7
Tons cane/year	108,116	136,491	175,908	151,760
Tons cane/hr	71	70	80	76
Tons sugar/year	10,858	13,535	18,568	15,032
Gallons bunker	47,384	21,064	26,508	
Gallons diesel	0	0	0	

Pol % cane				13.19
Pol % bagasse	4.16	4.08	3.35	
Fiber % cane	12.41	12.69	13.00	
Fiber % bagasse	44.19	44.87	45.44	
Moisture % bagasse				
kWh generated	564,102	67,162	45,334	
kWh purchased (season)	256,641	328,812	13,876	
kWh purchased (off-season)	487,872	67,162	68,429	

Steam is generated in two boilers producing a total of 80,000 pounds of steam per hour at 250 psi and 480 degrees F. Boiler 1, a Babcock and Wilcox unit, generates 45,000 pounds of steam per hour, and Boiler 2, an ERTE unit, produces 35,000 pounds per hour of steam. Neither boiler is equipped with an economizer or a preheater.

Electrical power is generated by a single turbogenerator. An Elliot turbine coupled with an Allis-Chalmers generator generate 1,000 kW of power using steam at 200 psi and exhausting at 10 psi.

Due to inadequate amounts of bagasse, the factory burns Bunker C fuel during the season to maintain steam flow. The factory also experiences a shortage of electricity which is made up by means of electricity purchases from CEL.

Table 2.31 shows the potential for export of cogenerated power based on burning the bagasse that is currently being produced to generate steam in 900 psi or 600 psi boilers

TABLE 2.31: POTENTIAL FOR EXPORT OF COGENERATED POWER

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Pounds steam per hour	72,000	75,000
Gross generation capacity, MW	4.1	3.5

Net exportable power(season), MW	3.1	2.5
Net exportable power (off-season), MW	4.1	3.5
Net exportable MWh (season)	7,983	6,350
Net exportable MWh (off-season)	22,896	19,352
Net exportable MWh per year	30,879	25,702

Table 2.32 shows the capital cost of installing new 900 psi or 600 psi boilers and turbogenerators at La Magdalena.

TABLE 2.32: CAPITAL COST OF INSTALLING BOILERS AND TURBOGENERATORS

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Boiler	$2,417,000	$2,197,000
Turbogenerator	$1,465,000	$1,332,000
Piping, civil, electrical, foundation	$3,882,000	$3,529,000
Erection	$835,000	$758,000
Engineering	$430,000	$391,000
Miscellaneous	$903,000	$821,000
Contingency	$993,000	$903,000
TOTAL	$10,925,000	$9,931,000
$ million per gross MW	2.66	2.86

Table 2.33 shows the estimated annual operating cost of power generation. Production costs are based on the assumptions that only bagasse is burned during the season, and only bunker C fuel is burned during the off-season.

TABLE 2.33: ESTIMATED ANNUAL OPERATING COST OF POWER GENERATION

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Fuel cost (season)	0	0
Fuel cost (off-season)	$683,351	$613,347
Variable operating and maintenance costs (season)	$19,957	$15,874
Variable operating and maintenance costs (off-season)	$57,240	$48,381
Fixed operating and maintenance costs (season)	0	0
Fixed operating and maintenance costs (off-season)	$63,106	$53,339

2.2.9 Chanmico

Chanmico is government-owned and is the second smallest sugar factory in El Salvador in terms of annual sugar production. It has a designed capacity of 2,000 tons of cane per day, but processes about 1,800 tons cane per day on average. In 1992-1993, Chanmico processed 164,454 tons of cane. The crop lasted 93 calendar days. After adjustments for lost time, the mills grind on average 84 tons of cane per hour.

Chanmico factory produces a mix of plantation white sugar and raw sugar. In 1992-1993 total production amounted to 14,609 tons, of which 4,973 tons were plantation white sugar and 9,636 tons were raw sugar.

The milling tandem consists of five mills driven by two KKK turbines rated at 375 HP each. A shredder driven by a 500 HP Elliott turbine and an electrically driven set of knives prepare cane prior to milling.

Table 2.34 shows some relevant production statistics for Chanmico factory.

TABLE 2.34: PRODUCTION STATISTICS -- CHANMICO

	1989-1990	1990-1991	1991-1992	1992-1993
Crop days	103	103	113	93
% Lost time	30.3	25.4	24.1	14.3
Tons cane/year	120,300	139,289	202,190	164,454
Tons cane/hr	71	78	99	86
Tons sugar/year	7,759	11,447	17,041	14,610
Gallons bunker	110,563	27,360	25,195	750
Gallons diesel	0	0	0	0
Pol% cane	12.11	12.15	12.16	12.00
Pol% bagasse	3.6	4.2	3.83	3.67
Fiber % cane	13.26	12.88	12.84	13.5
Fiber % bagasse	46.8	45.32	45.35	42.65
Moisture % bagasse	47.5	49.5	49.4	48.0
kWh generated	2,086,112	1,846,560	2,061,120	1,892,256
kWh purchased (season)	688,704	369,312	412,224	378,432
kWh purchased (off-season)	1,056,960	628,800	604,800	655,200

Steam is generated in a Fives Cail Babcock (FCB) unit installed thirteen years ago, which generates about 80,000 pounds of steam per hour at 300 psi and 330 degrees C. The boiler is not equipped with an economizer or a preheater.

Electric power is generated by a single turbogenerator. The Terry turbine and Scholch generator generate 1,000 kW of power.

Table 2.35 shows the potential for export of cogenerated power based on burning the bagasse that is currently being produced to generate steam in 900 psi or 600 psi boilers.

TABLE 2.35: POTENTIAL FOR EXPORT OF COGENERATED POWER

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Pounds steam per hour	85,000	88,000
Gross generation capacity, MW	4.7	4.0
Net exportable power(season), MW	3.8	3.1
Net exportable power (off-season), MW	4.7	4.0
Net exportable MWh (season)	9,515	7,662
Net exportable MWh (off-season)	26,877	22,635
Net exportable MWh per year	36,392	30,297

Table 2.36 shows the capital cost of installing new 900 psi or 600 psi boilers and turbogenerators at Chanmico.

TABLE 2.36: CAPITAL COST OF INSTALLING BOILERS AND TURBOGENERATORS

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Boiler	$2,633,000	$2,394,000
Turbogenerator	$1,465,000	$1,332,000
Piping, civil, electrical, foundation	$4,099,000	$3,726,000
Erection	$910,000	$827,000

Engineering	$455,000	$414,000
Miscellaneous	$956,000	$869,000
Contingency	$1,052,000	$956,000
TOTAL	$11,570,000	$10,518,000
$ million per gross MW	2.44	2.63

Table 2.37 shows the estimated annual operating cost of power generation. Production costs are based on the assumptions that only bagasse is burned during the season, and only bunker C fuel is burned during the off-season.

TABLE 2.37: ESTIMATED ANNUAL OPERATING COST OF POWER GENERATION

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Fuel cost (season)	0	0
Fuel cost (off-season)	$802,157	$717,368
Variable operating and maintenance costs (season)	$23,788	$19,155
Variable operating and maintenance costs (off-season)	$67,191	$56,586
Fixed operating and maintenance costs (season)	0	0
Fixed operating and maintenance costs (off-season)	$74 078	$62,388

2.2.10 Ahuachapán

Ahuachapán is privately-owned and is the smallest sugar factory in El Salvador in terms of annual sugar production. It has a designed capacity of 1,200 tons of cane per day, but processes about 650 tons cane per day on average. In 1992-1993, Ahuachapán processed 73,438 tons of cane during a crop season that lasted 113 calendar days. After adjustments for lost time, the mills grind on average 50 tons of cane per hour.

Ahuachapán factory produces a mix of plantation white sugar and raw sugar. In 1992-1993 total production amounted to 6,669 tons, of which 3,709 tons were plantation white sugar and 2,960 tons were raw sugar.

The milling tandem consists of three mills driven by a single Worthington turbine rated at 750 HP. There is no cane preparation prior to milling.

Table 2.38 shows some relevant production statistics for Ahuachapán factory.

TABLE 2.38: PRODUCTION STATISTICS -- AHUACHAPÁN

	1989-1990	**1990-1991**	**1991-1992**	**1992-1993**
Crop days	54	90	135	113
% Lost time	33.4	33.6	46.1	45.9
Tons cane/year	45,327	67,620	83,838	73,438
Tons cane/hr	52	47	48	50
Tons sugar/year	4,348	5,861	7,017	6,669
Gallons bunker	0	0	0	0
Gallons diesel	0	0	0	0
Pol % cane	14.5	14.6	14.6	
Pol % bagasse				
Fiber % cane	13.37	13.7	13.8	
Fiber % bagasse	41.4	40.0	38.8	
Moisture % bagasse				
kWh generated		728	831	

kWh purchased (season)		243	277	
kWh purchased (off-season)		78	40	

A Babcock and Wilcox boiler generates about 60,000 pounds of steam per hour at 290 psi and 263 degrees C. The boiler is not equipped with an economizer or a preheater.

Electrical power is generated by a single turbogenerator. The KKK turbine and NEBB generator generate 800 kW of power. This amount of power is insufficient to meet the needs of both the factory and an adjoining distillery, requiring the purchase of 300 kW from CEL.

Table 2.39 shows the potential for export of cogenerated power based on burning the bagasse that is currently being produced to generate steam in 900 psi or 600 psi boilers.

TABLE 2.39: POTENTIAL FOR EXPORT OF COGENERATED POWER

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Pounds steam per hour	42,000	43,000
Gross generation capacity, MW	1.9	1.5
Net exportable power(season), MW	0	0
Net exportable power (off-season), MW	1.9	1.5
Net exportable MWh (season)	0	0
Net exportable MWh (off-season)	10,200	8,189
Net exportable MWh per year	10,200	8,189

Table 2.40 shows the capital cost of installing new 900 psi or 600 psi boilers and turbogenerators at Ahuachapán. The high capital cost of US$4 million or more per MW, owing to the small size of the mill, combined with the extensive lost time, appear to make cogeneration at this mill an unattractive investment.

TABLE 2.40: CAPITAL COST OF INSTALLING BOILERS AND TURBOGENERATORS

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Boiler	$1,806,000	$1,642,000
Turbogenerator	$813,000	$740,000
Piping, civil, electrical, foundation	$2,619,000	$2,381,000
Erection	$624,000	$567,000
Engineering	$293,000	$266,000
Miscellaneous	$616,000	$560,000
Contingency	$677,000	$616,000
TOTAL	$7,448,000	$6,772,000
$ million per gross MW	3.98	4.51

Table 2.41 shows the estimated annual operating cost of power generation. Production costs are based on the assumptions that only bagasse is burned during the season, and only bunker C fuel is burned during the off-season.

TABLE 2.41: ESTIMATED ANNUAL OPERATING COST OF POWER GENERATION

	CASE 1 **900 psi**	**CASE 2** **600 psi**
Fuel cost (season)	0	0
Fuel cost (off-season)	$304,416	$259,539
Variable operating and maintenance costs (season)	$0	$0

Variable operating and maintenance costs (off-season)	$25,499	$20,473
Fixed operating and maintenance costs (season)	0	0
Fixed operating and maintenance costs (off-season)	$28,112	$22,571

2.3 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 CEL to meet the same level of demand for power.

While other waste biomass resources may be available in specific locations, bunker oil is the most likely supplemental fuels for off-season operation. Sugar mills in El Salvador now employ no flue gas emission controls. Oil combustion, depending on specific fuel content, would evolve oxides of sulfur and nitrogen, unburned organic material, and a small amount of ash. 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.

CEL has an energy cost incentive to use geothermal and hydropower in preference to fossil fuel-fired generation, and capacity additions for the remainder of the decade are likely to be either geothermal or oil-fired power plants. (See Table 3.5 below.) For this reason, the probable environmental benefits due to cogeneration at sugar mills will lie in reduced fossil fuel (oil) combustion at CEL facilities. These benefits would result, in different amounts, from both in-season and all-year operation.

Since much of CEL's oil-fired capacity involves diesels or gas turbines, which burn a cleaner distillate oil and have higher efficiencies than bunker fueled steam generators, the net impact of generation by sugar mills during the off-season will probably be adverse. The pollutants will be different, however, in that the internal combustion engines are likely to evolve more NOx and less SOx and particulates than bunker-fired boilers.

3.0 EL SALVADOR'S ELECTRIC POWER SYSTEM AND AVOIDED COST

3.1 OVERVIEW OF ELECTRIC SECTOR

La Comision Ejecutiva Hidroelectrica del Rio Lempa (CEL), is the state-owned national power generation authority in El Salvador. CEL has been primarily responsible for all new power generation and transmission in El Salvador since 1948. DISCEL, a unit of CEL, is responsible for the distribution and sale of power to the final consumer in rural areas in El Salvador. Distribution to the major portion of the remainder of the country is the responsibility of four state owned distribution companies. Until 1986, when concessions expired, these were private companies under the administration of CEL. The four formerly private companies are: CAESS-Compañía de Alumbrado Electrico de San Salvador, CLES-Compañía de Luz Electrica de Sonsanate, CLEA- Compañía de Luz Electrica de Ahuachapán and CLESA-Compañía de Luz Electrica de Santa Ana.

A number of important factors are adversely affecting both the supply system of CEL and planning for future generation resources. The majority of current generation equipment is 20 years old or greater, reducing reliability and raising costs of maintenance. Expansion of the system in recent years has not been adequate to meet loads, and the drought which occurred in 1991 made it necessary to add emergency capacity with two new gas turbines of 37.5 MW. Subsequently with the failure of the Soyapango oil-fired plant in 1992, an additional gas turbine of 82.1 MW had to be added. As discussed further below, the electric power system in El Salvador has experienced much more rapid growth in demand (9.7% versus 7.2%) than had been previously forecast for planning purposes. This growth rate even if later moderated, will require significantly greater additions to the CEL system than had been programmed only as recently as last year.

While electricity is clearly a critical input to most economic activity in El Salvador, it also constitutes one of the largest expenditure obligations for the government. Expenditures for the electric power sector during the 1970's constituted 25% of total public investment and 8% of total national investment. CEL's investments reached 16.9% of total public investment in 1990. The indebtedness of the power sector, of which CEL is a major part, at the end of September 1993, totaled 2,613 million colones (US $296.9 million). As a condition of recent financing by IDB, CEL has agreed to adhere to strict financial management and indebtedness guidelines over the next 10 years. These will limit CEL borrowing and affect tariff policy. The most important accords provide that CEL will:

1. Maintain a current ratio of not less than 1.5 (current assets/current liabilities).

2. Not assume, without prior agreement with IDB, new financial obligations greater than one year duration which would:

    a. cause indebtedness to rise above a ratio of 0.75 (total liabilities/total assets),

    b. cause debt coverage for long-term obligations to fall below 1.5, except for 1993-94 where a ratio of not less than 1.0 is agreed. (ratio of actual cash flow to maximum projected debt service), and

    c. not incur new investments without prior agreement if these exceed 2% of the average of fixed assets.

Recent tariff studies by CEL consultants have provided detailed analysis of both price levels and tariff structures. In general, these show CEL revenues at the bulk tariff level, using 1992 financial results, were only 0.4054 colones/kWh (US $ 0.046) versus strict long run marginal costs of 0.8698 colones/kWh (US $ 0.099). At the retail level, current revenues are 0.5415 colones/kWh (US $0.0615) versus costs for CAESS, which were 1.022 colones/kWh (US $0.116), at 8.8 colones/US dollar.

The projected heavy financial burden of electric sector expansion, as well as poor past financial performance, have led to a number of important reforms affecting the market for, and economics of private power generation. The Government of El Salvador (GOES) intends to reduce the intervention of the government in electric sector, including consideration of private generation, new regulatory mechanisms and reprivatized electricity distribution. Accords with the Interamerican Development Bank (IDB) and other donors commit the GOES to substantial additional tariff increases to bring electricity prices to the level of long-run marginal cost by 1996, and to maintain prices at these levels thereafter.

It will become increasingly difficult politically to expand the power system in the future due to the very large tariff increases, financing restrictions and the heavy financing burden that will be required for this expansion. As the discussion which follows explains, the GOES is now considering a variety of means to mitigate the financial burden of power sector expansion, among which is partial reliance on private power.

3.2 INSTITUTIONAL AND LEGAL BASIS FOR COGENERATION AND PRIVATE POWER

3.2.1 Institutional Structure for Private Power and Power Sector Regulation

The Government of El Salvador (GOES) is proceeding rapidly to establish a legal framework for power sector restructuring in El Salvador. The Unidad de Estudios Sectoriales (UES) is the GOES interagency body responsible for overseeing the preparation of legal and institutional reform proposals. Various draft reform laws are currently being prepared for consideration, including a new electricity sector law (Anteproyecto de Ley General de Electricidad), a law to create a new energy regulatory agency or CREH (Anteproyecto de Ley de Creación de la Comisión Reguladora de Electricidad e Hidrocarburos) to deal with the electricity and petroleum sectors, and a law to establish a new national energy commission or CNE (Anteproyecto de la Ley de Creación del Consejo Nacional de Energía).

The CNE would be the highest energy policy making body in government and would be made up of the Ministry of Planning, Ministry of the Economy, Ministry of Housing, Ministry of Agriculture and Livestock and President of the Central Bank. The CNE would be responsible for such matters as development of national energy strategy and associated legislation, including promotion of private investment, approve quality of service standards for energy supply, and establish policy for exploration and exploitation of national energy resources.

The regulatory agency, CREH, would be responsible for the actual regulatory activities having to do with the development and supply of energy resources within the country, including monitoring of adherence to technical and environmental norms and to both the laws dealing with hydrocarbons and electricity. This agency would be responsible for fixing tariffs for generation, transmission and distribution of electricity, and guaranteeing that quality of service standards are met.

The new Ley General de Electricidad (LGE) would provide a comprehensive framework for management of the electricity sector, and in so-doing provide a number of innovations which will be important for the effective introduction of competition in the electricity sector and for private power investment. For example, among the objectives of the LGE is the promotion of free competition in the generation of electricity and free access of generators to transmission and distribution, as well as the guarantee that the prices of electricity reflect costs of generation, transmission and distribution. Concessions for private generation would generally be required by the law, except that thermal and non-conventional electricity generators below levels to be prescribed under the law would be exempt. Published national generation and transmission expansion plans would form the basis upon which interested parties would be able to bid for generation and/or transmission concessions, either on their own motion or in response to public solicitations, and proposers would present brief feasibility studies along with schedule, budget and sources of funds.

The new law provides eminent domain procedures for use of private property for electricity generation, transmission or distribution, and provides for use of hydrologic, geothermal, wind and solar natural resources without additional payment to the state by electricity generators. The responsibility of developers will be primarily for facilities necessary to exploit these resources. Distribution concessions are described and rules for operation given, and the Ministry of Economy would have one year formally to grant the concessions. In addition, the procedure for determining prices of wholesale power sales to distributors is specified, generally making these prices equal to the prospective 5 year average of short-term marginal costs of generation plus a cost for use of transmission. There is also authority, but few details are specified, for eventual complete liberalization of wholesale power sales prices, that is, authority for competitive purchase under regulatory supervision. Criteria for transmission access or use and appropriate payments are also described.

Criteria for determining final tariffs to consumers are provided, generally corresponding to cost of purchased power, plus value-added by the distribution company assuming "efficient" (defined) operation. Tariffs for classes of customers are to be cost-based, taking into account losses and associated energy and capacity costs. Studies by distributors are to be prepared proposing tariff levels by class of customer. These are then reviewed by the CREH to determine the internal rate of return on investment (from revenues less costs of operation), using an historic test year. The allowed rate of return will be the discount rate defined for calculation of tariffs (opportunity cost of capital fixed by CNE) plus a maximum of 4 percent.

3.3 ELECTRIC POWER SUPPLY AND DEMAND IN EL SALVADOR

3.3.1 Current CEL and Distribution

Company Growth Projections

3.3.1.1 CEL Projections

The forecast of sales and power demand prepared by CEL is the basis for investment planning in El Salvador. The methodology for preparing this forecast involves analysis of demand patterns at the national level using an econometric model of historic power sales by economic sector versus various economic variables. The projection of these economic variables at the national level by economic officials and/or international organizations, are used as the basis for CEL's forecast of the corresponding future electrical consumption up to 2010. In addition, the staff of CEL separately take into consideration plans for additional large private and public projects.

The future growth of El Salvador's electricity sector as well as the economy has recently been very robust due to the end of the conflict of the 1980's. Unfortunately, this has also added substantially to the uncertainty of forecasts and corresponding supply plans. As an example, the consumption of electricity grew at an average of 3.8% during the period 1980 to 1989, versus 10.3% from 1970-79, and in 1993 appears to have grown at a rate of about 9.7%. Potentially damping the need for new capacity will be a number of other new factors. During the next 5-10 years El Salvador's electricity sector will be subject to a large number of important policy interventions, including more concerted effort to reduce large transmission and distribution losses (which lower need for new capacity), as well as price reform leading to large increases in electricity rates, and introduction of load management and energy conservation programs.

The following tables present both previous and current electricity sales and demand forecasts for comparison. The recent but no longer accepted forecast growth rates used by CEL to prepare the 1992 CEL-IDB supply plan, as well as recent revisions used for the current plans, are shown in Table 3.1 below. The most recent forecast projects average demand growth over the period 1994 to 2010 at 8.8% per year.

TABLE 3.1: PAST AND CURRENT FORECAST NATIONAL ELECTRICITY GROWTH RATES (1992-2010)

Year	**Scenario Intermedio**	**Scenario Optimista**	**Scenario Pesimista**
Previous Forecast			
1992/1995	6.6%	7.5%	4.9%
1996/2000	7.7%	9.5%	5.8%
2001/2005	7.2%	8.8%	5.3%

2006/2010	7.0%	8.0%	4.9%
Total	7.2%	8.4%	5.2%
Current Forecast	8.8%	-	-

An important element of the forecast process used for generation planning purposes is the projection of losses in energy and capacity in transmission and distribution from both technical and non-technical (e.g., theft) sources, shown below. These are combined with forecast consumption and maximum demand to determine generation capacity requirements.

TABLE 3.2: TOTAL SYSTEM LOSSES - CEL ESTIMATE

Year	**Transmission Losses (%)**	**Distribution Losses (%)**	**Total Losses (%)**
1992/94	6.5%	9.5%	16.0%
1995/97	6.0%	9.0%	16.0%
1998/2000	5.5%	8.5%	14.0%
2001/2010	5.0%	8.0%	13.0%

TABLE 3.3: PREVIOUS AND CURRENT CEL GENERATION AND MAXIMUM DEMAND FORECAST

Year	**Net Generation (GWh)**	**Maximum Demand (MW)**	**Load Factor**
1992 Previous/ Current	2,434.6/ 2,503.4	455.6/ 476.0	0.61
1995 Previous/ Current	2,929.7/ 3,307.0	539.4/ 625.0	0.61
2000 Previous/	4,225.6/	765.7/	0.61

Current	5,203.5	974.0	
2005 Previous/ Current	5,957.5/ 7,851.5	1,062.5/ 1,446.0	0.62
2010 Previous/ Current	8,366.9/ 11,421.0	1,492.4/ 2,069.0	0.63

Source: CEL, Plan Complementario del Sistema de Generacion 1993 - 2010, PLANICEL/SPDE/26/10/93

3.3.2 El Salvador's Generation System and Its Operation

3.3.2.1 National Supply System (CEL)

The total installed capacity in El Salvador as of September 1993 was 817.5 MW, of which 47.5% was hydroelectric, 12.8% geothermal and 39.7% oil-fired. The generation system of El Salvador is heavily dependent on hydroelectric generation which provided some 52% (1,066 GWh) of total energy produced from national resources in 1993 (2,055 GWh) through September. Hydroelectric generation is made-up of four major units, with installed and available capacity (September 1993) as follows:

Hydroelectric Capacity

<u>Available</u> <u>Installed</u>

Guajoyo 15.0 MW 15 MW

Cerron Grande 135.0 MW 135 MW

5 de Noviembre 72.0 MW 81.4 MW

15 de Septiembre <u>156.6 </u>MW <u>156.6 MW</u>

Subtotal 378.6 MW 388.0 MW

Geothermal resources in El Salvador are substantial, with 2 sites operational in the Ahuachapán field and one in the Berlin field. In 1993, geothermal generation made-up 14% (290 GWh) of internally generated energy through September 1993. Average plant factor was 39%.

Geothermal Capacity

<u>Available</u> <u>Installed</u>

Ahuachapán 58 MW 95 MW

Berlin <u>5 MW 10 MW</u>

Subtotal 63.0 MW 105 MW

Thermal generation is next in importance after hydroelectric generation with 5 major stations providing 34% (699 GWh) of internal energy production through September 1993, with an average plant factor of 52%.

Thermal (Oil-fired) Capacity

	Available	Installed
Acajutla (Steam)	58 MW	63 MW
Acajutla (Gas)	138 MW	157.1 MW
Miravalle	12 MW	18.6 MW
Soyapango	0 MW	53.9 MW
San Miguel	23 MW	31.9 MW
Subtotal	112.6 MW	167.4 MW

Of the total CEL generation system ,with an installed capacity of 817.5 MW, 672.6 MW was available capacity as of September 1993.

3.3 National Transmission and Distribution System

Decentralized generation sources, such as the sugar sector, will not only potentially impact the generation system of CEL, but also will have an impact on transmission and distribution to varying degrees. Although smaller size cogeneration and/or seasonable capacity, may not impact required transmission investment to serve national loads, decentralized generation would reduce transmission losses and possibly substation power requirements and investments. By improving the quality of power supply at intermediate points in the distribution system, decentralized generation may have significant benefits for quality of service, reduced distribution losses and possibly lower distribution investment requirements. Distribution power quality in many rural areas is now substandard and requires changes such as substation relocation or improvement, changing voltage, and line reconductoring.

The principal transmission system in El Salvador operates at 115 kV system with the exception of the interconnection with Guatemala which is 230 kV. The system consists of some 29 lines of 848 kms interconnecting generating stations with CEL's main substations. CEL's Operations Center controls the transmission and distribution of electricity, through the six main distribution companies, to 7 direct clients of CEL and 13 rural electrification zones (distributed by DISCEL). Figure 3.1 below contains a line diagram of the national interconnected system.

The distribution system in El Salvador consists of some 16,672 kms of primary and secondary distribution lines. While no exact figure is available it is normally assumed that the rural distribution system consists of at least 7,842 kms, which is the entire system of DISCEL. Most rural primary distribution is at 13.2 KV, while the majority of urban primary distribution (CAESS) is at 23 KV. Long line lengths , along with inadequate conductor sizes, are major contributors to large losses and low voltage levels experienced in rural El Salvador. DISCEL reports average distribution losses of

22.8% in 1992 for example. These unfavorable characteristics substantially influence (increase) the potential distribution benefits of decentralized generation.

FIGURE 3.1

3.3.3.1 Planned Expansion of the National Interconnected System

Until very recently CEL had planned to accommodate annual demand growth of 7.2%, consistent with recent projections of growth in national income of 4.0% (1993) to 4.6% (1996 and thereafter). The plan contemplated financing by the IDB of 4 projects during the period 1993-1996. These were: the third well-head unit of the Berlin geothermal field, the steam-turbine to be added to the existing combined-cycle unit, a feasibility study of the San Vicente geothermal field and rehabilitation of the steam units of Acajutla. The Acajutla rehabilitation will be carried out with funds from the Overseas Economic Cooperation Fund of Japan.

In order to respond to the accelerated rate of demand growth, CEL has performed additional operational and planning studies to ascertain the implications for immediate action and planned new generation. Given the critical nature of the supply situation, CEL has also incorporated private power generation as an alternative for the first time in its official generation planning. In order to understand the worst-case implications of not expanding their system adequately, CEL performed several operational studies, *assuming no additional short-term generation is added* (due to delays in planned projects, etc.) with the following results:

- Under average hydro conditions during the period 1993-1996, there would be a deficit in energy of 183.2 GWh and 508.7 GWh in the years 1995 and 1996 respectively.
- Under dry hydro conditions during this same period, an energy deficit of 530 GWh and 575 GWh in 1995 and 1996, respectively, would occur
- Assuming only rehabilitation of Soyapango by 1995, the system would have a deficit of 25 GWh in 1995 under dry hydro conditions.

Tables 3.4 - 3.5 describe CEL planning assumptions and results of the previous generation plan done as input to IDB loan evaluations.

TABLE 3.4: AVERAGE CAPITAL AND O&M COSTS OF THE INVESTMENT PLAN

Energy Resources	Average Costs	
	Capital US $/kW	O&M US $/kWh
Hydro Projects	1528.12	0.0265

Geothermal Projects	2148.40	0.0413
Thermal Projects	1064.7	0.0807

Source: Summary of the Electricity Generation and Transmission Plan 1992 - 2010, PLANICEL/SPDE/10-01-92/36/92.

TABLE 3.5: ORIGINAL CEL-IDB INVESTMENT PLAN

Year	Number of Units	Project	Capacity (MW)
1993	2 1	Gas Turbine Gas Turbine	37.5 80
1994	1	Chipilapa Well-Head Geothermal	5
1995	1	Berlin Well-Head Geothermal	5
1996	1 1	Steam Turbine/for Combined Cycle Rehab Acajutla	32 58
1997	1 1	Berlin Geothermal Ahuachapán Stabilization	23.7 21
1998	1 1	Berlin Geothermal Chipilapa Geothermal	23.7 23.7
1999	1	C.H. 5 de Noviembre	120
2000	1	Oil-fired Steam	69
2001	2	C.H. San Marcos Lempa	80
2002	1	Oil-fired Steam	69
2003	1	San Vicente Geothermal	23.7

CEL has now reformulated their least-cost expansion plan taking into account a number of other adverse factors in addition to the higher demand growth they are experiencing These factors include delays in expansion of the 5 de Noviembre Hydro facility, delay of 8 months in the third Berlin well-head unit, delay of the steam turbine for the existing combined cycle unit, and finally, failure of Chipilapa field studies to indicate adequate geothermal steam for that development.

The two tables in Appendix B below are reproduced from CEL's revised plan and presents two versions. The first table, "con recursos CEL," shows the revised plan utilizing only CEL resources. This plan would produce an effective addition of 299.7 MW of capacity net of retirements by the year 2010, at a net present value of costs of $1,505.8 million. In the second case, "con generación privada," private power generation is allowed to enter the plan, with amounts of 80 MW in 1995, and 115 MW in 1998. The same total effective capacity of 299.7 MW would be added, with the net present value of CEL's investment costs dropping to $1,164.6. In most future years adequate reserve margin are maintained with only CEL generation, however 1996-7, 2002 and 2006 reserve margins are below 10%. Reserve margins under the plan with private participation only fall below 10% in 1996, and thereafter generally exceed 15%. Both plans show that short-term energy needs can be satisfactorily met.

3.3.4 CEL Actions Regarding Private Power Supply

CEL is currently attempting to determine the potential for private generation through a public solicitation to provide an 80 MW unit for operation by January 1995. This appears to be the most attractive option for CEL, as it would offer an alternative to acquiring 3 gas turbines 1995 (2x37.5 MW) and 1997 (1x37.5 MW). The break-down of near-term requirement assuming private generation is as follows:

Rehabilitation of Soyapango

Units 1 and 3 April 1995

Unit 2 July 1995

Rehabilitation of Acajulta

58 MW Dec 1995/May 1996

Steam turbine Combined-Cycle

32 MW January 1996

Berlin Geothermal

5 MW 1996

23.7 MW 1997

Private Generation

Unit of 80 MW January 1995

Unit of 115 MW January 1998

The latest CEL generation plan (SPDE/26/10/93) indicated that a decision would be reached on whether or not to pursue private generation for the above 80 MW facility by November 1993. This schedule appears to now have slipped. The plan does not go into detail concerning what terms and conditions would be required, nor criteria for pricing. However, it is noted in the report that CEL will require an 80% availability rate, and that the cost must not exceed the objective function of the least-cost plan (assumed here to mean equal to or lower than long-run marginal cost). The failure of the private generation approach would require CEL to proceed immediately to acquire two 37.5 MW gas turbines for 1995, and another 37.5 MW in 1997, plus a 75 MW oil-steam plant in 1998. With or without private generation, CEL would continue with rehabilitation of the oil-fired steam units at Acajutla for December 1995 and May 1996, and acquire a steam turbine for its combined cycle plant by January 1996.

3.4 AVOIDED COST PRICING FOR PRIVATE POWER

A preliminary analysis of marginal costs, and adjustments to them to establish appropriate avoided costs for valuing private power supply, is presented below. The current supply plan and forecast considered most likely by CEL and described above is used for this analysis, with the avoided cost estimate derived form marginal cost analyses done for CEL in its recent tariff study.

3.4.1 Avoided Cost

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. In tariff design, the principle that rates should reflect marginal cost of supply has been generally accepted as economically efficient. This basis should ensure that national economic resources are allocated efficiently within the power sector and when applied to tariffs and combined with non-distorting adjustment for achieving an appropriate return on rate base, should result in a fair allocation of costs among customers according to the costs they impose on the system. Applying the 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, adjusted for losses; and a capacity component, which is based on the marginal cost of new capacity, also 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. While short-run costs are recognized as the correct economic basis for pricing, they can fluctuate widely from year to year. Other bases, such as average short-run costs or long-run marginal cost are often used to approximate this cost, since they offer a more stable basis.

In order to achieve the least-cost for purchased power, competitive bidding is also being introduced in many countries for acquisition of large blocks of power. In this case, avoided costs may be considered a ceiling, with the utility attempting to purchase each successive block of power needed at the lowest prices and presumably from the most efficient producer.

Several factors enter into the valuation of private power and computation of prices to be paid for it. 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?
- Balance between incentives to cogenerators and consumer costs.
- Transmission and distribution impacts and line loss differences to be achieved due to the location of the cogeneration capacity in relation to loads, as compared to location of utility capacity.

A variety of approaches have been applied to estimating of avoided costs and establishing private power prices, including the "Peaker Method", "Average Incremental Cost", "Generation Expansion", "Competitive Bidding" and "Standard Offers". These approaches are briefly discussed in the box below:

3.4.2 Application of Avoided Cost Principles in El Salvador

A number of consideration specific to the case of El Salvador must be considered in estimating avoided costs. These are apart from prospective new electricity policy and law in El Salvador which the Government is now considering.

3.4.2.1 Investment Funds Shortage and Loan Subsidies.

The existence of loan subsidies to CEL from international donors warrants special attention. Financial subsidies in terms of grants or below-market interest loans received by CEL tend to lower actual CEL cost. Subsidized sources of finance provide a distorted signal relative to the cost-effectiveness of private generation, and if used as a basis of comparison, would put private generators at an inappropriate disadvantage. Considering that subsidized financing is always rationed and can be transferred to other public purposes with no loss to the country, it would appear inappropriate to utilize subsidized financing terms in considering the relative benefit of private versus public power supplies.

The current terms of CEL's long-term debt, and in some cases joint debt with CAESS and/or the GOES, is presented below. Total long-term debt amounted to $278.7 million in major loans as of November 1993. These consist of loans from the Inter-American Development Bank for $125.9 million, Overseas Economic Cooperation Fund (OECF) $72.9 million and CITIBANK and Eximbank $43.2 million, as well as the World Bank $11.0 million, among others. Terms from major lenders are shown in Table 3.6 below. Costs in the case of OECF funds are clearly heavily subsidized.

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). 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. .

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 additions is used to generate a revised least-cost plan, together with revised fund 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 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.

TABLE 3.6: FINANCIAL TERMS OF PAST AND PROSPECTIVE CEL BORROWING

Financing Terms	**Inter-American Development Bank**	**Overseas Economic Cooperation Fund**	**CITIBANK & Eximbank**	**World Bank**
Amortization Period Grace Period	20 years 5 years	20 years 10 years	5 - 7 years 6 months	15 years 3-5 years

Interest Rate	7.29%	3.0%	LIBOR + 0.375%-0.55%	7.8%
Inspection & Review Fund	1.0%			
Credit Commission or Guarantee	0.75%	1.0%	0.125-0.1875% plus 5.06%-6.33% (Flat)	0.75%

3.4.2.2 Short-term Capacity and Energy Shortages

Another factor affecting the value of cogenerated electricity during the next 3-5 years in El Salvador is the general shortage of energy and capacity. Under ordinary circumstances, it would be appropriate to determine avoided cost, including seasonality, time of day, and "firmness" and then to set avoided cost payments accordingly. However, due to a current shortage of energy and capacity, CEL is able to utilize any additional capacity regardless of the time of year to avoid unserved energy and more fully achieve reserve criteria. Thus, even if sugar sector cogeneration were seasonal, and therefore did not provide "firm capacity" all year, the value of this capacity to CEL in the near-term is still equal at a maximum to seasonal and daily peak avoided cost during each period, and at a minimum to the value of unserved energy. Furthermore, from a review of the seasonality of hydroelectric energy and capacity available in El Salvador, it is clear that the dry season where hydroelectricity is least available, is also the harvest period during which the majority of sugar cogeneration would be available. For example, available hydro capacity using 1993 data on reservoir levels for the two main storage reservoirs in El Salvador, Guajoyo (Guija) and Cerron Grande, showed that decrease or outflows due to dry conditions were in December - April, while maximum inflows were in May to October-November, that is, outside the cane harvest season.

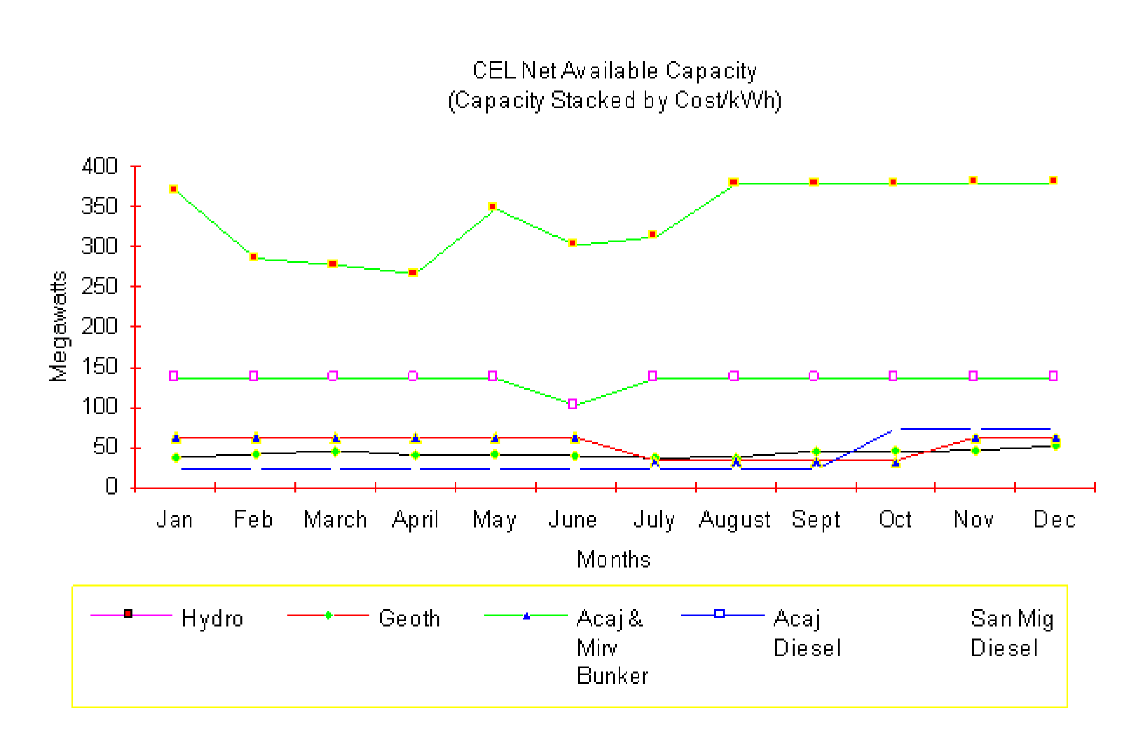
In the short-term however, particularly given the relatively small amount of cogeneration from industrial sources such as the sugar industry, explicit GOES and CEL incentives, such as payment of full-peak season avoided cost for all cogeneration in order to stimulate development of this resource, would appear to be a reasonable option. In the future, when and if the CEL system can again operate without unserved energy, and with adequate reserves during all seasons, etc., then seasonality and hourly availability characteristics would become relevant for determining avoided cost payments.

3.4.2.3 High-Cost of Marginal Energy Supply

A review of CEL marginal costs showed the high cost of current energy and capacity shortages. During the period January 1993 to September 1993 for example, CEL suffered from unusual overhaul, unavailability or failure of some or all units of the Ahuachapán, Acajutla, Miravalle, and Soyapango facilities. Partly as a consequence, it was necessary to utilize higher cost diesel at Acajutla and San Miguel throughout the period, except for September. Costs per kWh for fuel alone averaged 0.68 colones/kWh (US $0.077/kWh) for San Miguel and 0.58 colones/kWh (US $0.066/kWh) for Acajutla. As a result, the average cost of fuel for all thermal generation was a very high 0.516 colones/kWh (US $ 0.059/kWh). As can be seen as well in Figure 3.2 and Table 3.7, "Diesel Requirement", the prospective operation for 1994 shows that the available capacity from lower cost generation capacity, that is, hydroelectric, geothermal and bunker oil-fired capacity, will be substantially below requirements to meet peak demand. Therefore, high cost peaking capacity using diesel (Acajutla and San Miguel) will be called upon to meet from a low of 42 MW (8%) of annual seasonal peak demand to a high of 148 MW (28%) when demand is projected at 523 MW demand. Implied in these figures is a substantial requirement from high cost diesel burning facilities.

TABLE 3.7: CEL PLAN OF OPERATION - NET AVAILABLE CAPACITY 1994

FIGURE 3.2: CEL NET AVAILABLE CAPACITY



3.5 GENERATION EXPANSION PLAN AND ESTIMATION OF AVOIDED AND LONG-RUN MARGINAL COST

CEL maintains both short and long-term investment plans and has just completed a major study of marginal costs and tariffs, which is the primary basis for avoided cost calculations in this section. The analysis provides estimated long-run marginal cost on a basis similar to what is normally termed "short-run marginal cost" in other avoided cost analyses. The essential differences are that short-run cost, strictly speaking, refers to responses which take place solely with existing equipment,so they include no capital cost component. "Short-run marginal" costs refer to those incurred in response to an increase in demand which is sustained indefinitely into the future, and to corresponding capital investment for peaking facilities to maintain system reliability given this increased demand. "Short-run marginal costs" as defined here for avoided cost analysis purposes therefore reflect the optimization of the system not just for a given hour, but for an increase sustained in the future including capital investment requirements. These costs, converted to an amount per kWh, reflect the "life-cycle" concept utilizing the annualized cost for a specific increment in demand..

3.5.1 Marginal Energy Costs

An analysis of energy costs was undertaken for the entire year, with classification into dry and wet seasons respectively, and peak, mid-peak and outside peak periods. This is the necessary approach both to calculate the average marginal energy cost properly, as well as to permit seasonal and/or time of day rate making. In the case of analysis of the avoided cost for small amounts of cogenerated power, to undertake so comprehensive an analysis would normally not be necessary. However, the availability of this information does permit a more refined analysis and allows clarification of an important issue, that is, the relative marginal cost during the dry and wet seasons.

Marginal energy costs are the cost to supply a marginal or incremental kWh during each hour of the year. The generating system is dispatched (additional kWh's generated by additional plants which are brought into service) in a so-called "merit order", that is, in the manner that always uses the lowest cost source of energy given reliability, maintenance and other constraints. Since the level of demand varies by hour of the day, day of the week and time of year, the type of plant generating this incremental kWh will also vary. Normally low operating cost plants such as hydro, geothermal, and bunker oil fired plants are loaded first, with higher operating cost plants such as gas turbines and diesels units used last. Marginal energy cost analysis requires an estimate of which plants generate the marginal energy during each hour of the year, the type, and fuel and variable O&M costs.

Table 3.8 a-d provides basic assumptions used for determining marginal energy costs, and calculations of seasonal and time of day costs for three hydrological conditions (with associated probabilities): normal, low water and high water. The estimate of marginal energy cost normally involves use of a generation dispatch model of the marginal plants for each of the three daily periods, and for each season. For simplification, the analysis for CEL used two plants, which were found to be the most likely peaking units selected for each period, and based on their estimated percentage of use, calculated the marginal weighted energy cost (Table 3.8 b-d). Data for representative generation plans and utilization for the year 1997 is used as a proxy for plant selection. In the table under the normal hydrologic condition (Table 3.8 b), one can see that peak energy is provided 35% by a large gas turbine and 65% by combined cycle generation. Their respective variable costs, US$0.0722 and US$0.054 are averaged on a weighted basis using percentages of use, and an average of US$0.0604 is calculated. Following the calculation for each of the three hydrological conditions, a probability weighted average marginal energy cost by period and season is calculated below Table 3.8 d. This hydrological probability weighted average is used for avoided cost analysis in Table 3.10.

The costs shown in Table 3.8 for various generation options demonstrate the differences between the base, intermediate and peaking plants. Baseload hydro plant costs are not shown, as these are nearly zero and not used for meeting peak demand. Peaking hydro also has nearly zero variable costs and is not considered for meeting incremental demand as it is always already fully used given the system requirements, and therefore is not one of the options for meeting increases in load. Annual hours of utilization indicate the duty each type is expected to provide. These utilization rates are determined by relative variable costs (and reliability criteria) as shown in the 5th and next-to-last columns, varying from US$ 0.0979 (fuel costs alone) for the small gas turbine to US$ 0.0024 for geothermal generation. The three remaining parts of the table c-d, show the calculation of seasonal and daily demand period costs. Using the dry season peak period and low water conditions for comparison, we can see that variable costs reach a high of US$ 0.0735. The lowest variable costs of US$ 0.0258 are for wet season off-peak and high water condition. This range, US$ 0.0735 - 0.0258 reflect the significance of using seasonal and daily cost bases to set prices for private power.

Table 3.8 Basic Assumptions Merit Order Ranking of CEL Plants ** (1997 Plan Basis)

3.8 a. Plant Costs (1992)

Type Name	Plant Groups	Capacity MW	Average Hrs/Yr	Variable Costs $/kWh	Variable Costs Col./kWh	Heat Rate Btu/kWh	Fuel Type	Fuel Cost $/MMBtu	Variable O&M $/kWh	Variable O&M %fuel
BH	Base Hydro	36/73	-	-	-	-	-	-	-	-
GEO	Geothermal	116	8337	$0.0024	0.0199	17000	Steam	-	$0.0024	
FO	Fuel Oil Fired	60	7682	$0.0336	0.2786	10714	Bunker	$3.03	$0.0011	3.4%
CC	Combined Cycle	88	3571	$0.0540	0.4486	8134	Diesel	$6.30	$0.0028	5.5%
GTL	Large Gas Turbine	64	785	$0.0722	0.5994	10559	Diesel	$6.30	$0.0057	8.6%
GTS	Small Gas Turbine	16	212	$0.0979	0.8126	14635	Diesel	$6.30	$0.0057	6.2%
PHYD	Peak Hydro	283/262	-	-	-	-	-	-	-	-

Source: CEL-RCB/Hagler, Bailly Inc. Cuadro 5-3.

Table 3.8 b-d Marginal Plants by Season

Table 3.8-b

Hydrology	Categories	Wet Season			Dry Season		
		Peak	Mid-Peak	Off-Peak	Peak	Mid-Peak	Off-Peak
Normal							
Water	Aver. Hrs/Yr	785	785	7682	785	785	3571
Probability	Plant Types>	GTL	GTL	FO	GTL	GTL	CC
60.0%		35%	20%	80%	35%	10%	80%
	Aver. Hrs/Yr	3571	3571	8337	3571	3571	7682
	Plant Types>	CC	CC	GEO	CC	CC	FO
		65%	80%	20%	65%	90%	20%
	Percent	100%	100%	100%	100%	100%	100%
Weighted hrs/yr	3951	2595.9	3013.8	7813	2595.9	3292.4	4393.2
Variable Energy Cost (colones/kWh)		0.501	0.479	0.227	0.501	0.464	0.415
Variable Energy Cost ($/kWh)		$0.0604	$0.0577	$0.0273	$0.0604	$0.0559	$0.0499

Table 3.8-c

Hydrology	Categories	Wet Season			Dry Season		
		Peak	Mid-Peak	Off-Peak	Peak	Mid-Peak	Off-Peak
Low							
Water	Aver. Hrs/Yr	212	785	785	212	785	785
Probability	Plant Types>	GTS	GTL	GTL	GTS	GTL	GTL
20.0%		5%	100%	20%	5%	100%	30%
	Aver. Hrs/Yr	785		3571	785		3571
	Plant Types>	GTL		CC	GTL		CC
		95%		80%	95%		70%
	Percent	100%	100%	100%	100%	100%	100%
Weighted hrs/yr	1472	756.35	785	3013.8	756.35	785	2735.2
Variable Energy Cost (colones/kWh)		0.610	0.599	0.479	0.610	0.599	0.494
Variable Energy Cost ($/kWh)		$0.0735	$0.0722	$0.0577	$0.0735	$0.0722	$0.0595

Table 3.8-d

Hydrology	Categories	Wet Season			Dry Season		
		Peak	Mid-Peak	Off-Peak	Peak	Mid-Peak	Off-Peak
High							
Water	Aver. Hrs/Yr	3571	3571	7682	3571	3571	3571
Probability	Plant Types>	CC	CC	FO	CC	CC	CC
20.0%		80%	50%	75%	100%	40%	30%
	Aver. Hrs/Yr	7682	7682	8337		7682	7682
	Plant Types>	FO	FO	GEO		FO	FO
		20%	50%	25%	0%	60%	70%
	Percent	100%	100%	100%	100%	100%	100%
Weighted hrs/yr	5654	4393.2	5626.5	7845.75	3571	6037.6	6448.7
Variable Energy Cost (colones/kWh)		0.415	0.364	0.214	0.449	0.347	0.330
Variable Energy Cost ($/kWh)		$0.0499	$0.0438	$0.0258	$0.0540	$0.0418	$0.0397
Hydrology Weighted Costs							
Variable Energy Cost (colones/kWh)		0.506	0.480	0.275	0.513	0.467	0.413
Variable Energy Cost ($/kWh)		$0.0609	$0.0578	$0.0331	$0.0618	$0.0563	$0.0498
Weighted Hours	3796						

Exchange Rate = 8.3 colones/US$

Calculation of Variable Cost is as follows: For the case of two plants used for peaking, plants n and o:

Variable Energy Cost = Peaking Plant n % (Heat rate n/kWh * Fuel cost n/MMBtu + Var. O&M n cost)
+ Peaking Plant o % (Heat rate o/kWh * Fuel cost o/MMBtu + Var. O&M o cost)

3.5.2 Marginal Capacity Cost

Table 3.9 shows the marginal capacity costs for both the "peaker" and incremental plant methods. Here again the CEL tariff study is the basis for this calculation. The peaker methodology assumes that the incremental capacity during any peak period will be supplied by the lowest capital and highest operating cost unit, that is, a peaking plant. The incremental plant method is somewhat more realistic, in that it attempts to utilize the actual plant addition which is expected to be added to meet growth in demand. However, with the incremental plant method, the additional benefit that the plant will also normally displace some of existing kWh's generated by higher cost plants must be taken into account. The normal procedure is to use such fuel savings to reduce the capital charge for this plant (shown below the table).

The table shows, for example, for the peaker method, basic economic assumptions on plant cost, lifetime, O&M costs, foreign vs. local costs (local costs are adjusted using the IDB's 1992 conversion factor of 0.87 to convert to economic or border prices), and calculated annualized capital cost. In the case of the incremental plant method, fuel savings are calculated and subtracted from capital costs. This approximate fuel savings calculation assumes the operation of a combined cycle to replace a large gas turbine for 785 hours per year, and a large gas turbine replacing a small gas turbine for 212 hours per year.

Costs for the peaker in colones at border (economic) prices is 3,554 colones/kW (US$386/kW), or adjusted for reserve margin and station losses 4,868 colones/kW (US$529/kW) or 652 colones/kW on an annualized basis. The annualized capital cost of a combined-cycle unit, which is the optimal choice using the incremental plant method, 1230 colones/kW, less fuel savings of 169 colones/kW, or 1,516 colones/kW. The final annualized cost including O&M for each is: "Peaker" 782 colones/kW vs."Incremental Plant" 1,766 colones/kW. While the incremental plant may be a nearer approximation to the actual addition planned, not all of the capacity added is actually strictly for meeting incremental demand. That is, this higher capital cost plant is also added to reduce energy costs for non-incremental sales. On the other hand, the peaking plant is clearly only being added to serve the incremental demand. Neither capital cost can be considered better than the other, although for reasons of simplicity and cost of analysis, it is more common to use the peaker method. The peaker method is the one employed here for calculating the capacity component of avoided cost.

TABLE 3.9A: GENERATION CAPACITY COST PEAKER AND INCREMENTAL PLANT

(1994 Costs in Colones)

	Peaker Method	**Incremental Plant Method**
Marginal Plant	Gas Turbine	Combined Cycle
Life (years)	20	30

O&M and A&G (% of capital)	0.0268	0.0184
Capital Cost (colones/kW)		
Foreign	3,010.50	10,023.05
Local Materials	1,115.04	1,237.44
Capacity Cost (discounted to study year)		
Border Price	3,554.09	9,910.38
Capital Cost (colones/kW)	4,868.12	13,573.00
Capital Cost per Year (colones/kW/yr)	651.74	1,685.00
Associated Fuel Savings (colones/kW/yr)	--	168.51
Capital Cost Net of Fuel Savings (colones/kW/yr)	651.74	1,516.50
O & M Cost per Year (colones/kW/yr)	130.47	249.74
Total Capital Cost per Year (colones/kW/yr)	782.20	1,766.24

TABLE 3.9B: FUEL SAVINGS CALCULATION (INCREMENTAL PLANT)

Generation Type		**Cost (colones/kWh)--Linked**		**Hrs/Yr**	**Savings/kW**
New	Original	New	Original		
cc	gtl	0.4486	0.5994	785	118.44
gtl	gts	0.5994	0.8126	212	45.18

Total Fuel Savings = 163.62

Source: Update to Cuadro 5-6, CEL-RCG/Hagler, Bailly, Inc.

3.5.3 Avoided Cost

Table 3.10 is used to calculate avoided cost. The concept of avoided cost includes both energy and capacity as does marginal cost, however it varies from marginal cost in that with avoided costs, we are interested only in costs to the level at which cogenerated power will off-set CEL generation. In the case of *energy cost* by season and time of day, adjustment is made only for average high voltage transmission losses and station losses. Marginal cost on the other hand, normally corresponds to the end user level and would include distribution, transformation and non-technical losses. In the case of capital costs, adjustment is made to include only peak period high voltage transmission and station losses, and for lack of reserves provided by the cogenerator. This latter adjustment is made to reflect the fact that for any new demand of 1 kW, CEL costs must reflect this 1 kW plus additional capacity to provide a reserve margin. Thus if an additional 1 kW of cogenerated capacity is added, it offsets only a part of 1 kW plus reserve requirement faced by CEL. The CEL tariff study has used a reserve percentage of 33% or 0.33 kW addition for each 1 kW of new demand.

The last difference between avoided and marginal costs is that transmission capital costs are excluded from avoided costs. These are excluded since it is not realistic to think that addition of small amounts of cogenerated power will actually reduce the need for high voltage transmission. It is possible however, that additional benefits in substation costs, distribution line loss reduction and quality of service may result from such decentralized generation. An analysis performed by CAESS to estimate these benefits in the cases of the San Francisco and La Cabaña mills appears in the next section.

The total avoided cost estimates for 1994 in Table 3.10 range from a high in the dry season during peak hours of US$ 0.0823/kWh to a low for the wet season off-peak of US$ 0.0480/kWh. Averaging wet season marginal costs using weighting according to base, intermediate and peak hours in each daily period gives a 1994 avoided cost of US$ 0.0685/kWh. The corresponding average for the dry season is US$ 0.0745/kWh.

TABLE 3.10: CALCULATION OF AVOIDED COSTS

(1994 US$'s)

	Rainy Season			**Dry Season**		
Hours	**Peak**	**Mid-peak**	**Off-peak**	**Peak**	**Mid-peak**	**Off-peak**
Marginal Energy Cost	0.0668	0.0634	0.0363	0.0677	0.0617	0.0546
HV and Station Losses	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%
Loss-Adjusted Energy Cost	0.0730	0.0692	0.0396	0.0739	0.0674	0.0596

Annual kWh/kW Capacity	7,500	7,500	7,500	7,500	7,500	7,500
Short Run Capital Cost/kWh*	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115
Peak HV and Station Losses	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%
Loss Adjusted Capital Cost	0.0125	0.0125	0.0125	0.0125	0.0125	0.0125
Reserve Adjusted Capital Cost**	0.0084	0.0084	0.0084	0.0084	0.0084	0.0084
Total Avoided Cost	0.0813	0.0776	0.0480	0.0823	0.0758	0.0680
Daily Average for Season	US$0.0685/kWh					US$0.0745/kWh

* Peaker method (see text.)

** Reserve requirement reduction factor = 0.67

Reference: Hagler Bailly, *Estudio del Sistema Tarifarico del Subsector Eléctrico*, Julio, 1993, Cuadros 5-10, 5-11 (HV and HV peak losses) and Cuadro 5-13 (short-run capital costs)

3.6 TRANSMISSION AND DISTRIBUTION

SYSTEM IMPACTS

In addition to affecting CEL's future generation cost, purchasing power from sugar mills will also impact the performance and cost of operating and expanding the transmission and distribution system. Power generated where it is not needed must be transported to where it is and distributed to users. On the other hand, a mill producing power at a location with growing demand and inadequate power line or substation capacity may offer benefits beyond the traditional avoided generation cost estimated above.

Two of the mills included in this study, San Francisco and La Cabaña, are served by a power line extending along the northern arterial highway from San Salvador. This line, circuit number 109613 from CAESS' Nejapa substation, now experiences resistance losses of 935 KW and delivers power to customers at its remote end in the village of Citalá at just over 90 volts. To determine the effect of importing power from the mills, the Planning Department at CAESS used the load flow simulation model MILLSOFT in an analysis of four cases: 1)the present situation, 2)San Francisco exporting 6 MW alone, 3)La Cabaña exporting 5.4 MW alone, 4)and the two mills exporting a total of 6.3 MW.

As shown in the following table, the effect of the mills supplying about 6 MW to the system would be to increase the minimum voltage on the line by 15 volts and to reduce losses by approximately 500 kW, equivalent to eight percent of the amount delivered by the mills.

TABLE 3.11: LOAD FLOW SIMULATION RESULTS

CASE	MAXIMUM VOLTAGE	MINIMUM VOLTAGE	LOSSES
1	120.0 V	90.7 V	935 KW
2	120.2 V	104.8 V	457 KW
3	120.2 V	105.9 V	484 KW
4	120.6 V	106.7 V	426 KW

Source: CAESS Planning Department

The analysis goes on to point out that eight kilometers of new three phase line would be needed to connect the mills, and that while the mills could deliver several times the postulated 6 MW, larger volumes would create excessive voltages in the immediate vicinity in the absence of increased local demand. Thus in order to take full advantage of the 27 MW of combined capacity at the mills, CAESS would have to invest in additional line capacity to transport the power south toward the capital. In this regard, the entire line currently serves a load of only 19 MW, so the direction of the current would be reversed south of the mills.

The CAESS Planning Department did not go so far as to estimate the investment requirements for controlling the losses along the line and bringing minimum voltages up to standard with and without higher levels of power output from the mills. However, the analysis does illustrate that the effect of cogeneration on the local transmission and distribution system can be significant and, in some instances, positive.

4.0. ECONOMIC COSTS AND BENEFITS

The preceding two chapters present estimates of cogeneration system performance and cost at each mill and project the value of power that could be produced by the sugar industry in the context of CEL'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 Salvadoran electric requirements.

4.1. ASSUMPTIONS

For purposes of calculating returns on investment, the value of the energy exported to CEL is assumed to be US$0.075 per kWh during the dry season from November to April and US$0.69 during the remainder of the year when hydropower is more abundant. These figures correspond to the avoided costs in Table 3.10 in the previous chapter, with the daily peak, mid-peak and off-peak components averaged over time, since the mills' outputs are nearly constant throughout the day. In this analysis, the value of power supplied to CEL is not expected to change in real terms over the course of any project.

The time-value of money is reflected at a real disount rate of 12 percent per year, which is consistent with the utility avoided cost calculations in the previous chapter. 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 cogeneration costs derived without taxes are more nearly comparable to CEL's avoided costs, as discussed in the preceeding chapter. The unit cost of bunker oil is US$14 per barrel, as indicated in Chapter 2, and savings from eliminating present mill electricity consumption are valued at the same US$0.075 per kWh, since crushing occurs entirely within the dry season.

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 mills are assumed to generate steady output while the mill is running (based on individual downtime experience) during the grinding season and at 90 percent availability during the off-season. A high level of reliability is necessary in order to represent firm capacity to the CEL system. Achieving adequate reliability will require improvements in the operation of some of the mills, but the reduced downtime will benefit them in terms of improved sugar production and lower costs.

The analysis also assumes that higher-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. Furthermore, the power available for export could be enhanced as much as two- or threefold by reductions in mill process steam requirements, which may become cost-effective as a result of access to an attractive market for the power. Ideally, one would design a cogeneration system into any new mill so as to achieve a a substantially lower incremental capital cost of construction and possibly with a better optimized overall plant configuration.

4.2. RESULTS

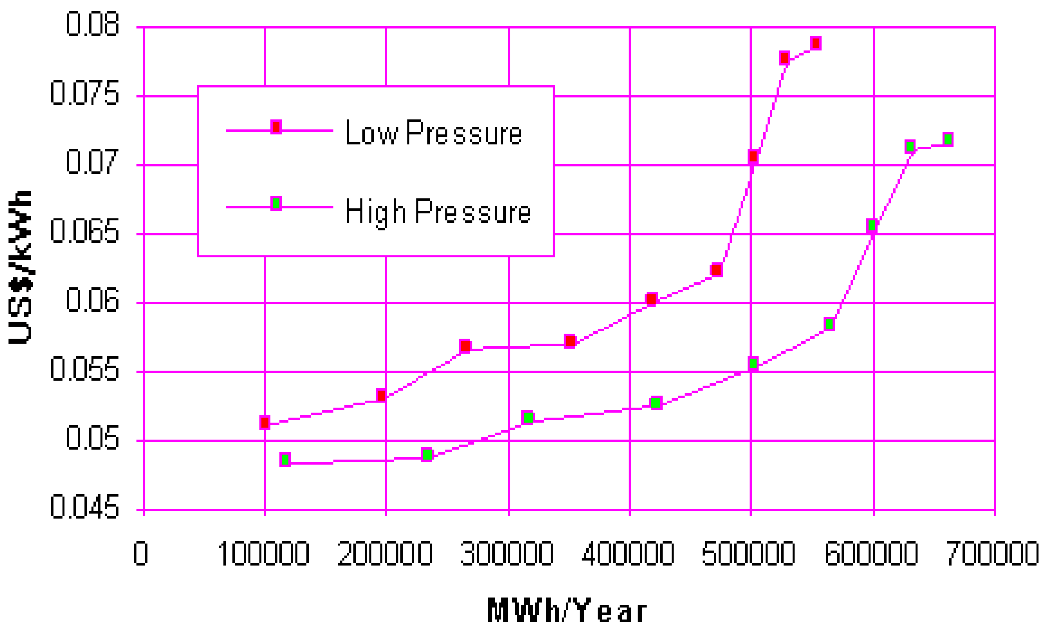
Table 4.1 below presents for each mill the estimated returns on investment for the two different cogeneration configurations discussed in Chapter 2. Both utilize all of the available bagasse for cogeneration during the crushing season, and they achieve year-round operation to make more efficient use of the capital invested in boilers and generators by burning oil as a supplemental fuel while cane is not being processed. Details of the economic evaluation appear in Appendix C.

TABLE 4.1: COGENERATION RETURNS ON INVESTMENT (PERCENT PER YEAR)

MILL	HIGH PRESSURE	LOW PRESSURE
Central Izalco	24.06%	20.97%
El Angel	21.71%	18.84%
Ingenio Jiboa	21.12%	18.08%
La Cabaña	25.56%	23.39%
San Francisco	19.56%	16.93%
Cahparrastique	17.80%	15.86%
El Carmen	12.07%	9.77%
La Magdalena	11.95%	10.05%
Chanmico	14.37%	12.44%
Ahuachapán	0.34%	-1.28%

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 a real annual return equal to twelve percent. Combining prices derived in this way with the power production rates from Chapter 2 allows one to create "supply curves" corresponding to the two generation schemes. These appear below, illustrating how much cumulative energy could be supplied by the sugar industry at a given price for purchased power. Note that higher boiler pressures both reduce the cost of the power and increase the output.

FIGURE 4.1: POTENTIAL ELECTRIC SUPPLY FROM SALVADORAN SUGAR MILLS



4.3. DISCUSSION

As the graph indicates, six of the mills are able to produce power for US$0.062 or less per kWh at a steam pressure of 600 psi, and for US$0.058 or less per kWh at 900 psi. The potential corresponding annual power sales volumes are 473,000 MWh and 565,000 MWh respectively. Three other mills could produce smaller volumes of power at increasingly higher costs, and the last mill, Ahuachapán, would be unable to produce surplus power for export during the grinding season and has been excluded from the graph.

Replacing present low-pressure boilers and installing new turbogenerators at the six promising mills would entail a capital cost of between US$1.50 and US$2.00 per watt of capacity, depending primarily on the size of the facility. Incremental operating costs are negligible during the four to five month grinding season, when mill boilers are fueled by bagasse. Because year-round operation is necessary to amortize the investment, and seasonal supply is of less value to CEL, the mills will probably need to burn bunker oil or some other fuel for the remainder of the year.

Other forms of biomass might be suitable as supplemental fuel. Cane trash 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, research is proceeding on improved methods with lower costs in Thailand and the Philippines, for example. A study based on harvesting trials by Winrock International in 1990 concluded that baled cane trash could be delivered to a mill in Thailand at a cost equivalent, in heating value terms, to the price of Bunker C assumed for this analysis.

The postulated values of US$0.069 and US$0.075 per kWh are based on the presumption of no unique costs or benefits corresponding to power transmission and distribution. Transmission capacity to the north from San Salvador is insufficient to meet demand in the region surrounding Aguilares and Colima without substantial line losses, and voltages in Citalá on the border with Honduras are as low as 91 volts. According to the local distribution company's load flow analysis summarized at the end of the preceding chapter, power from the San Francisco or La Cabaña mills could increase minimum voltages, reduce the present high line losses, and help to postpone the need for added transmission and substation capacity to supply these northern communities. In fact, the mills have the potential to meet the entire demand served by CAESS circuit 109613 along the northern arterial highway and still have power left over to deliver to San Salvador, but this would require some investment to upgrade the south end of the line to take full advantage of this supply.

4.4 CONSIDERATIONS IN THE BUYING AND SELLING OF COGENERATED ELECTRICITY

It is important for CEL to have an in-depth understanding of pricing and related considerations to implement avoided cost or competitive bidding for cogeneration, even though in the final analysis, the pricing and terms for sale of electricity, and the manner in which it is provided, must be a process of negotiation. The following is intended to provide background information for CEL on the actual process of contracting for the supply of private cogeneration, including risk mitigation and contract issues. The main risks may be summarized as follows:

4.4.1 Seller - Cogenerator

The seller faces four basic types of risks: sales, payment, regulatory and political. Given the large capital investment by the seller, he must be guaranteed that power produced can be sold. Related to this sale, the amount to be paid must be reasonably certain to be available for payment, and the price received must be adequate to cover future costs, even if there should be some escalation. The sales of power and purchase arrangements will be subject to some sort of control or regulation. This regulation may involve such areas as general legal authority for power generation and sales, regulation of price terms, foreign exchange control relative to expatriation of profits or loan repayment, quality of service and safety standards. Future legislation or political considerations can also affect risks for the seller by changing groundrules for cogeneration or changing the conditions under which foreign investment in general is handled.

4.4.2 Buyer - CEL

The buyer faces three general types of risk. These are purchase risks, maintaining quality and continuity of service, and price risk. The buyer has the obligation to meet the needs of its customers. The buyer may incur higher costs and other problems if the seller is unable to supply the power contracted. The greater the amount of the power in relation to the size of the system, the greater the risk. The buyer also assumes some risk that the operation of the seller may actually cause damage to the buyers electricity system. Price risks refer to the potential that the buyer will pay too much, or that it may not be able to recover its purchase costs from its customers. Terms of the contract may be too liberal for example, locking the buyer into long-term arrangements which foreclose more attractive future opportunities, including purchases from other cogenerators.

4.4.3 Power Purchase/Sales Contract

The contract for power sales from the cogenerator will cover a number of specific areas, generally specifying the technical configuration of the plant and specifications; the amount, firmness, dispatchability and seasonal or daily availability of energy and capacity to be provided; interconnection requirements, including metering, protection equipment and transformer characteristics; and the contract start-date, length and pricing. Among the most important categories of conditions will be the contract term, frequency and form of payment, sanctions for failure of either party to meet contractual terms, and means to resolve disputes.

4.4.3.1 Term of Contract

The term of the contract should be adequate to permit the seller both to recover his investment and to earn a reasonable rate of return. The term should also meet the buyers need to ensure continuity of service. A term of 10 years is normally considered a minimum, however longer terms are necessary as the investment and useful life of the facility increases. A shorter term, for example, 5-7 years before any changes, might be preferable when cogeneration is initially implemented to allow adjustments in certain terms to be made based on experience. However, this shorter term should not unduly prejudice the position of the seller.

4.4.3.2 Form of Payment

Fixing payment terms in US dollars, or some equivalent currency, paid monthly appears to be appropriate, although alternatively payment might be in colones at the prevailing free-market exchange rate, provided conversion and repatriation is guaranteed. This is to account for the fact that much of the cost of cogenerated power is amortization of capital expended for imported equipment, and loans may be denominated in foreign currency. Agreement on how to measure the quantity of power sold and specifically how energy and capacity loses are to be recorded and taken into account is very important. Sanctions for late payment are appropriate.

4.4.3.3 Determining Prices

Assuming the use of calculated avoided costs as a basis for pricing, there must be an accord on the methodology used, assumptions for projections. Prices may be set to provide for seasonal and/or time of day marginal cost differences. Although the complexity of performing seasonal pricing and the disincentive for cogenerators in the first stage of implementing a new program, should be weighed against the potential efficiency benefits. While a fixed set of prices in the contract is possible, it is likely to be more realistic to allow adjustments for factors beyond the sellers control, in order to permit adjustment if assumptions in the estimated investment financial analysis change over time. For example, if the cogenerator is using oil as a supplemental fuel for out-of-season generation, then international oil price fluctuations should reasonably be incorporated as a variable, as might local labor and tax rates, etc.

Similarly to seasonal or time of day pricing, separate payment for the value of firm capacity are possible. This involves separating purchase prices into two elements, one for energy or variable cost, and the other for the cost of new capacity (which would otherwise need to be added by CEL) to meet demand. Separately dealing with whether cogeneration capacity is firm, that is, available at peak, may be particularly important where private generation is large, and where it substantially affects the reliability of the system. In the case where there are only small amounts of cogeneration capacity however, capacity payments while not inappropriate, may discourage cogenerators unnecessarily. This is the case where the firmness of the capacity has little affect on the reliability of the utility, for example, where large quantities of hydro and hydro storage is available, when the cogeneration is of very small-size in relation to the system, or when the number of cogenerators is large (increasing group availability probabilities over individual probabilities).

4.4.3.4 Competitive Bidding

While avoided costs are an appropriate benchmark, and we believe an appropriate basis for initial cogeneration contracts, it would normally be more financially advantageous for CEL to use competitive bidding for large purchases. It would not appear reasonable however, in the short-term when no clear competitive market exists for cogeneration, to expect competitive bidding either to encourage generation to be offered or to influence price terms significantly.

In the sugar industry, as well as other enterprises, ancillary power generation is not likely to be a major factor in the near-term in overall profitability. Significant investment in additional power generation capacity on the other hand, would increase financial risks, alter operations, and increase the complexity and possible outside interference in production. Furthermore, the private sector in El Salvador appears hesitant about contractual arrangements with government and CEL, and could not be expected to be aggressive in bringing cogeneration on-line without a distinctly positive environment. The secondary and potentially significant additional benefits of decentralized generation in El Salvador, that is, reduction of distribution system losses and investment requirements and improved power quality, are also likely to be difficult for the private generators to quantify and properly reflect in their bidding.

APPENDIX A

System Design Parameters

APPENDIX B

CEL Least-Cost Expansion Plans

APPENDIX C

Economic Evaluation