NON-UTILITY GENERATION OF ELECTRICITY IN THE CARIBBEAN:

OPPORTUNITIES, NEEDS AND IMPEDIMENTS

SUMMARY REPORT

Prepared for:

THE AGENCY FOR INTERNATIONAL DEVELOPMENT
BUREAU FOR LATIN AMERICA AND THE CARIBBEAN

Under the Regional Energy Resource Project
(No. 598-0606)

December 1984

ENERGY/DEVELOPMENT INTERNATIONAL
100 North Country Road
Setauket, N.Y. 11733

e/di

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BARBADOS

JAMAICA

DOMINICAN REPUBLIC

I. INTRODUCTION

I. INTRODUCTION

A. BACKGROUND

In most developing nations expanded electricity supply to both urban and rural areas is a priority. Due to the expansion of their economies and the major influx of people into cities from rural areas, national governments and utilities must meet expanding urban demand. They must expand supply in urban areas to assure delivery of expected minimal levels of service and, in rural areas, assure that electricity is used to help create conditions which will keep or attract people and economic activity. Utilities are having difficulty in expanding their generation, transmission and distribution capability in light of national economic problems, competing priority areas for government investment, institutional and manpower limitations and their poor financial conditions. In addition, developing country utilities often rely almost entirely on imported oil as fuel. Except for hydro-based generation, other country-held and renewable energy resources have not been used or developed. It is evident that new and creative mechanisms are needed to encourage the utilization of renewable energy resources.

A candidate mechanism which has proven to be a very powerful stimulator of increased electricity generation and supply capacity in the U.S. is PURPA (the Public Utility Regulatory Policy Act of 1978). This legislative and regulatory package was directed at stimulating off-system or non-utility generation of electricity by private and public sector entities using renewable energy resources and technologies. PURPA is recognized as having been very successful in creating new economical and reliable supplies of electricity, especially through private sector investment. In California alone, alternative energy based electricity generating capacity almost quadrupled from 1981 to 1983. In this time period, cogeneration supplies rose from 200MW to almost 800MW and an additional 5,500MW

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were being developed. Because of its success in the U.S., it has been identified as a possible model for developing country activities.

B. OBJECTIVE

This project involves a preliminary investigation of the past, present and future of non-utility generation and sale of electricity in several Caribbean countries. The status and potential of private sector renewable energy based cogeneration (electricity generation by a private sector entity such as an industry) and the sale of excess capacity to a utility was also investigated. As part of this project, Barbados, Jamaica and the Dominican Republic were visited and smaller Caribbean islands were evaluated without field trips. Separate reports on Barbados, Jamaica and the Dominican Republic have been prepared.

The principal objectives of the study, as stated in the Scope of Work (Appendix A), are to provide a study for AID and host countries that:

- Analyzes the existing electrical system and identifies policy, legal, regulatory, institutional and technical impediments to private sector generation of electricity based on renewable energy for sale to the utility.
- Identifies renewable energy opportunities for the generation of electricity for sale to the national utility grid.
- Provides recommendations to foster private sector renewable energy based electrical generation in each country.

The nature and history of the U.S. Public Utility Regulatory Policies Act of 1978 (PURPA) was used as a principle source of information and comparison in this study. PURPA, an historic piece of U.S. energy legislation, requires that U.S. utilities buy power from private sector generators which primarily use renewable energy sources. It allowed private sector entities to generate and sell

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electricity under certain specific conditions without having to become a public utility. The selling price was defined as the utilities avoided cost or which is essentially their marginal cost of generation. Implementation of the act was slow due to utility resistance and other problems which were ultimately resolved in court cases. However, the successful resolution of major issues and the major stimulative impact it has had on the development of non-utility renewable energy applications can be instructive. It has been particularly successful in California where the government actively used it to encourage renewable energy development in the utility and private sectors. It has also been shown to provide an economical and reliable additional source of electricity to help utilities meet demands without expansion of their oil based generating capacity. The goals of PURPA to stimulate the use of renewable energy resources by non-utility generators are also important in other countries and it was felt that an investigation of the potential for PURPA or other types of stimulative arrangements would be valuable in the countries covered by this study.

Appendix B contains a summary description of the act and the concepts of costs associated to it. These goals are also important in other countries and it was felt that an investigation of the potential for PURPA or other types of stimulative arrangements in key Caribbean countries would be valuable.

C. APPROACH AND TEAM

The project was carried out with one or two week visits to each country during which a two-person team met with a wide range of people to discuss private Off-System Generation (OSG) of electricity and to collect information. A list of the major meetings which were held is presented in the individual country reports. The team visited those institutions and individuals known to be involved in or considering generation and/or sale of electricity. Meetings were prearranged by local AID Mission personnel and by team members. Additional meetings

were scheduled with others as a result of information gained and contacts made while in-country. The project scope of work was explained and used as the basis of each meeting.

The E/DI team included Dr. James Westfield, overall Project Manager (Barbados team); Mr. Andres Doernberg, Assistant Project Manager (Jamaica and Dominican Republic teams); Dr. Harry Davitian (Jamaica team); and Mr. Shibu B. Dhar (Barbados and Dominican Republic teams). The one or two week visits, though short, were very efficient and were supported by considerable background and relevant experience of the team members and of E/DI. Many individuals of the respective USAID Missions provided local support to the teams. Government and private sector personnel in each country were also extremely helpful.

D. REPORT ORGANIZATION

The overall project includes consideration of Off-System Generation (OSG) of electricity and PURPA applicability in three countries. Because of this, one summary report and three separate country reports have been prepared. The format and organization of each country report is standardized and some sections of common interest are identical in all country reports.

The information presented in each country report is organized to define the present situation and preview the future with respect to private sector renewable energy based generation of electricity. The use of PURPA and its status in the U.S. provides a benchmark to measure and illuminate opportunities, needs and impediments in each country. This report summarizes the overall findings and also contains the specific recommendations contained in each country report. It also contains an Appendix with useful detailed information on PURPA in the U.S., including its key provisions as well as a detailed definition of avoided costs and its different methods of calculation prevalent in the industry.

The summary report can be understood without referring to any of the country reports. However, because a number of the concepts and issues are complex and may not be familiar to all readers, we recommend that if questions arise, at least one country report be read. The discussions and explanations in the country reports are much more thorough and a review of specific chapters can clear up confusion and prevent misinterpretations.

II. GENERAL FINDINGS AND RECOMMENDATIONS

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A. GENERAL FINDINGS

Present Status

The three Caribbean countries selected in this study share several characteristics that are relevant to the applications of PURPA-type laws and others that are quite different. Among the similarities are:

- There are no provisions in any country that make it mandatory for the utility to purchase power from off-system renewable energy based generation, private or publicly owned. Neither are there provisions for defining terms and setting rates for purchase of electricity by a utility, or the institutional mechanism to establish these rates.

- The utilities in all three countries purchase, or have purchased, electricity from private or public producers. Sellers range from large mining operations and sugarmills, to small industries; examples exist in all three countries.

- The rates at which utilities purchase electricity from private sector generators are negotiated on a one-to-one basis in all cases. Some recent prices are tabulated in Table II-1.

- The concept of PURPA-type laws to be applied in these countries was received with enthusiasm by government officials that oversee energy planning in these countries. Industrialists were also generally favorable. Private sector people interviewed were enthusiastic about selling electricity to utilities. However, they wanted assurance that utilities would continue to purchase power from off-grid generators. They also felt that utility policies and contract terms should be made public and prices paid should be fairer (higher). The full marginal cost of utility generation was recommended as a fair purchase price. The position of the electric utilities was unanimous: they are open for negotiation of electricity purchase contracts from private (or public) entities at all times, and legislative action is not needed. In this position,

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they differ little from the initial reaction of U.S. utilities to the PURPA legislation.

- Current electric rate structures in all countries have similarities, among which are several that result in disincentives to OSG applications in industry. In particular, self-generation of electricity by industry that requires standby or supplementary power is penalized. These disincentives include utility demand charges that are calculated on the basis of maximum demand during a period of 12 months (11 months in Barbados) prior to the current bill. A self-generator, who, because of a short-term equipment breakdown must supply his peak demand using the utility supply, will incur a substantial long-term rate increase. This one-time and short-term high demand will establish the demand charge he must pay for all electricity purchased during the year. Thus, potential cost savings from lower average demand throughout the year can be wiped out because of a one-time short-term problem. Another built-in disincentive is the declining block tariff used for industrial customers in Jamaica (Barbados and the Dominican Republic have a single energy charge for large consumers and increasing blocks for residential ones).

- With the exception of hydro, utilities in these countries are not generating electricity with renewable energy or cogeneration.

Institutional Characteristics

There are large differences between countries in institutional aspects, as well as the technical potential for off-system generation and the ability of non-utility generators to provide electricity at prices competitive with subsidized utility costs. Utilities in Barbados and Jamaica have similar legislative backgrounds, rooted in a shared historical development, while that in the Dominican Republic is quite different.

- Barbados Light and Power (BLP) is a private company with minority government ownership, while Jamaica Public Service (JPS) and Corporacion Dominicana de Electricidad (CDE) are wholly owned by the government.

- CDE is directly under the President of the Republic; its Board and General Manager are appointed by the

President and the Presidency promulgates electric tariffs.

- BLP is private and overseen by the Public Utilities Board (PUB); JPS is government-owned and under the Minister of Public Utilities. In the case of Barbados, PUB members are appointed by the Minister of Finance, Industry and Energy. In Jamaica, the functions of a PUB are performed within the Ministry of Public Utilities. No PUB-type organization (equivalent to the Public Service Commission in most states of the U.S.) exists in the Dominican Republic whatsoever.

- The licenses whereby BLP and JPS acquire the right to generate and sell electricity are non-exclusive, i.e., the Minister has the powers to license others. The CDE has exclusive rights to sell electricity by law.

Utility Expansion Plans and OSG Potential

- The potential for off-system generation (OSG) of electricity for sale to the utility is large in the Dominican Republic; it exists in Jamaica but requires integration of the grid with alumina production facilities; and it is not large in Barbados except that there are additional bagasse and wind-based generation opportunities. The CDE includes OSG purchases in its capacity expansion planning activities, and has recently concluded contract negotiations with the State Sugar Corporation (CEA) that will ultimately provide it with 80 MW or more. Furthermore, CDE includes in its expansion plans technologies usually associated with potential small power producers, such as fuelwood plantations.

- The three utilities differ widely in the magnitude of new capacity requirements and therefore, in need for funds. In the Dominican Republic, electric demand is growing fast and CDE proposes to add as much as 1900 MW between now and the year 2000. On the other hand, Barbados has, at the moment, surplus capacity, and Jamaica will not need a new power plant until 1992 after currently programmed hydro projects (20 MW) and diesel sets (40 MW) are in place.

- Electric tariffs are a barrier to OSG by private producers when subsidies to utilities make their financial avoided costs too low to compete successfully. In Barbados, electric tariffs accurately reflect true costs to BLP and the Barbados economy; in Jamaica electric rates have recently been increased and also reflect generation costs to the utility, although

the financial condition of JPS is not good. In the Dominican Republic, large indirect subsidies (of at least 50 percent of fuel costs) are provided to the CDE via preferential exchange rates; electric rates are therefore too low. Off-system renewable energy based generators would also have much higher costs for foreign components of their generation systems than the utilities have. Removal of this indirect subsidy could come about soon; the rate increase will likely affect future demand growth and with it, CDE's long-term expansion plans. Thus, the marginal cost of new generation capacity built by the utility will more nearly approach that of a non-utility generator.

B. GENERAL RECOMMENDATIONS

1. The notion of promoting PURPA-type applications via National action, such as enabling legislation, should be surfaced and debated by the energy community in each country.

While the existing mechanism of situation specific negotiations with individual OSG producers can result in the development of alternative electric generation capacity, a more institutionalized approach, whether it is legislation or ministry regulations, would be a more efficient promoter of OSG and accelerate its implementation as was seen in the U.S. The advantages of proposing passage of laws by the legislative branch are specific to each country, and have to be weighed against executive branch orders or decrees as alternative mechanisms. However, either mechanism can eliminate risks and address uncertainties which are presently disincentives to private sector involvement. The issue should be raised by government planners and the private sector, and debated.

2. In the short term, governments should see that terms and conditions of existing power purchase agreements are widely known.

As a first step in promoting potential applications of renewable energy OSG from qualifying producers, the governments should publicize the terms of the existing contracts between private and

government-owned OSG suppliers to the grid. The teams found that the terms of these contracts were generally unknown outside the utility and the suppliers themselves. Government energy planning institutions should become familiar with the terms of these contracts and should be the mechanism whereby these become known to potential suppliers.

3. In the short term, there is a need to educate government energy planners and utility planners in the details of PURPA-type contract negotiations. The appropriate mechanism is a USAID technical assistance program.

Even though government energy planners were found to be generally familiar with the concept of PURPA, many of the details related to actual contract negotiations are complex and unfamiliar to them. This is also true for utility personnel. They include evaluation of fair values for intermittent, small OSG electricity, and the evaluation of the value of standby, auxilliary or supplementary power to qualifying self-generation. We recommend a technical assistance program of USAID be designed to train government energy planners and utility planners in these methodologies.

4. In the absence of institutional changes in the power sector, we recommend that governments designate an existing agency responsible for endorsing qualifying facilities and assisting them in contract negotiations.

In order to promote and accelerate introduction of OSG sources, the responsibility of acting as an intermediary between OSG producers and the utilities should be assigned to an existing government institution. Its function would be to promote OSG suppliers by assisting in the procurement of fair prices for the power while at the same time ensuring that the economic benefits to the country are served by the OSG production (i.e., approve that proposed schemes are the country's equivalent of PURPA's qualifying facilities). These benefits may vary from country to country for any particular technology.

5. USAID should consider similar studies in other countries.

The studies carried out clearly demonstrate that there is not only a technical potential for OSG production, but that there are great needs to initiate a dialogue between potential parties on these concepts. Moreover, as the reception of energy planners and the private sector to these concepts in three countries visited demonstrate, there is correlation with country size (and their economies) to the advantages of promoting PURPA-type applications. Therefore, the policy dialogue process, such as the one initiated by this study, should be replicated elsewhere, in particular, in countries with larger and more complex industrial infrastructure.

C. COUNTRY SPECIFIC RECOMMENDATIONS

1. Dominican Republic

a. Drafting PURPA-Type Laws

We recommend that technical and legal expertise be hired to draft PURPA-type legislation appropriate to the energy situation of the Dominican Republic. A political climate could emerge in the next few years that may lead to passage of PURPA-type legislation in the National Congress. An institution presently capable of preparing a draft for this legislation is the Comision Nacional de Politica Energetica (COENER).

b. Clarification of Specific Legal Situations

We recommend that legal expertise be engaged by the government to clarify the following concepts:

- Corporacion Dominicana de Electricidad (CDE) -- Third Party Power Purchase Agreements: Determine the legal statue of these contracts, what risks to private

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investors these entail as well as what rights, determine legal standing on contract renewal, etc.

- The National Institute of Water Resources (INDRHI) -- Rights over Water Resources: We recommend that legal experts be hired to determine the ramifications of INDRHI's control over water resources. This review should confirm the accepted view that it is not possible for the private sector to exploit hydro resources; it should also recommend what negotiations to pay for water rights or royalties could be undertaken.

c. Assistance in Determining Avoided Costs

The CDE expressed interest in obtaining assistance in the methodological aspects of avoided cost (marginal cost) calculations, in particular, as it applies to purchases of power from small-scale, intermittent producers such as wind turbines. This assistance also would include the appropriate computer models currently used in the U.S. for this purpose. We recommend that AID consider providing such assistance.

d. Contract Negotiation for Power Producers

It is generally true that potential power producers do not have experience negotiating PURPA-type agreements. For example, Falconbridge (a mining company interested in selling power to CDE) hired a consultant to assist them in their negotiations with CDE. CEA expressed interest in having our team review, critically, the agreement on power sales it recently signed with CDE. We recommend that technical assistance be provided to a professional institution in the Dominican Republic that can assist private and public sector parties in similar negotiations in the future. In the absence of a body with the functions of a Public Utilities Commission, we suggest that this expertise be developed in the COENER.

e. Develop Information of Potential Resources

Of all potential renewable energy generation option applications in the Dominican Republic, wind turbines emerge as the most promising application for which not enough reliable information is available. COENER is currently starting an activity with USAID funding to determine wind profiles at several promising sites in the country. We recommend that this activity be started as soon as possible, and that a study be designed to move forward the date of implementation of a wind energy demonstration project.

2. Jamaica

a. Technical and Economic Evaluation of Integration of the Power Systems of the Alumina Industry and the Utility

We recommend that a study be carried out that will analyze the technical and economic feasibility of maximization of surplus electricity generation from cogeneration within the power plants of Jamaica's alumina plants, for sale of the excess to JPS.

b. Promotion and Publicity for PURPA-Type Arrangements

The visit by this team found that government institutions with responsibilities in energy planning are, in general, familiar with the concepts contained in PURPA; in addition, the potential generation of electricity from bagasse for sale to JPS, creates an opportunity for a PURPA-type mechanism. We recommend that, at this time, the policy dialogue be publicized widely and broadened to include private as well as public sector entities that have the potential to generate electricity for sale to JPS. Regional and international development organizations should also consider offering assistance or at least monitoring these discussions.

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c. Structure of Electric Tariffs

We recommend that if the existing tariffs of JPS are modified, the new structure be designed to accomodate the needs of qualifying off-system generation better than the existing structure. Subjects such as formulas for demand charge calculation which include less stringent or shorter than one year duration criteria should be considered.

d. Development of Information Base for Evaluation of Potential Resource

Among potential off-system generation technologies that can be envisioned for Jamaica is wind generation. The information required to perform technical and economic evaluations is not adequate. We recommend that financial support be given to produce longer term and more accurate 24-hour wind profile data at promising sites on the island.

3. Barbados

a. Government should continue to remove technical uncertainties and regulatory/institutional barriers to the development of preferred energy options.

The Government and utilities should initiate a series of utility policies, experiments and demonstrations to identify and resolve problems of integrating intermittent energy sources into utility electricity grids. They should also work with other agencies such as those which grant permits and those which could be substantial users (such as the water authority) to eliminate stumbling blocks and encourage examination of opportunities.

In the Caribbean islands, several of the alternative energy sources, including wind and bagasse, offer great promise, but will produce electrical energy only on an intermittent basis. Integrating

the energy from these dispersed sources into the utility grid presents policy, technical and managerial challenges. To expedite the introduction of alternative energy resources into the utility electrical system, the island's regulatory agency should authorize and direct the utility to define the system operating requirements of dispersed energy technologies. In addition, those cogeneration power sources, which are expected to have potential in the Caribbean, should be examined by utilities to define how they can best be integrated and taken advantage of.

b. The Government should modify the energy cost adjustment clause (ECAC) mechanism to reward utilities who reduce imported fuel costs and to penalize utilities who fail to use available alternatives to reduce such costs.

Under the present ECAC mechanism, utilities, BLP in Barbados for example, are generally allowed to pass on to their customers the added costs of fuel price increases. These increases are typically imposed by fuel suppliers on the utilities. However, because the fuel prices may be passed on, utilities do not have to consider development of less costly supplies. If utilities had to use the least costly supply, renewable energy based off system generators might be cost competitive. Utilities are also not required to meet a minimum combustion or conversion efficiency and thus, fuel adjustment pass-throughs may be excessive. If utilities were penalized for inefficient equipment, they might have to consider retiring these generators. If this was the case, substitution of this capacity through contract purchases from OSGs might be the most economical alternative.

The PUB should consider requiring BLP to meet minimum combustion efficiencies or have their fuel adjustment charges reduced.

c. The Government should establish policy guidance for the use of renewable energy as a substitute for imported oil.

The Government should consider introducing legislation or taking other policy guidance actions such as ministry regulations or executive branch orders which will make it clear to utilities and the private sector that the development and use of renewable energy resources is a priority. Any public or private entity which can participate in the switching from imported oil to other indigenous energy resources should be encouraged to help. With respect to the electricity sector, the governments should be clear in their commitment to help and encourage the transition to non-imported oil-based generation.

d. The utility should develop and publish policies for dealing with purchase of electricity from other generators.

Subjects such as electricity purchase contract terms, avoided cost formulas, amounts of electricity they desire to purchase from OSG's, availability of lines for wheeling, etc. should be defined.

The PUB should require BLP to adopt a set of regulations covering power buy back including conditions, price and requirements. BLP should also be required to develop a position and calculate and publish its rates for line leasing or "wheeling".

e. Other agencies which offer help to the private sector should be publicized.

Programs such as regional development bank financing programs should be made known. In Barbados, for example, the Caribbean Financial Services Corporation, funded by USAID, CANADA AID, private banks, etc., has low interest money for qualifying regional energy projects. This could be a place for OSGs to look for help especially if their project involved use of a renewable energy resource.

f. USAID should consider supporting Government in some of the above activities by offering technical assistance and entering into policy dialogues.

AID can be particularly helpful to Government by making technical assistance available in areas such as legislation creation, assistance with standard OSG/utility contracting formats, calculating avoided costs, etc. They can also help by including, where possible, off-system generation emphasis in their other projects and programs.

Table II-1

EXAMPLES OF EXISTING ELECTRICITY SALES
BY COMPANIES IN THE CARIBBEAN TO UTILITIES

Country	Seller & Energy Source	Sale Price per kWh	
		Local Currency	US cents/kWh
Barbados	Barbados Sugar Industry Ltd. (bagasse cogeneration)	12 B¢	6.06
Barbados	Williams Electric Co. (wind)	10-12 B¢	5.05-6.06
Jamaica	Alcoa Jamaica Ltd. (fuel oil cogeneration)	32 J¢	6.8
Dominican Republic	Consejo Estatal de Azucar (bagasse cogeneration)	3 DR ¢	3.0 (*)
Dominican Republic	Falconbridge Dominicana (fuel oil steam)	2.5 DR ¢ + fuel	2.5 + fuel (*)
Dominican Republic	Productos del Tropico (coconut husks steam)	8.0 DR ¢	8.0 (*)
Dominican Republic	Consejo Estatal de Azucar, new contract (bagasse cogeneration)	Capital recovery factor (18% rate of return) with bagasse priced at cost of coal equivalent	

* Official exchange rate; 40-70% lower for the electricity utility than rates set for commodities other than oil.

Table II-2

ELECTRIC UTILITIES - INSTITUTIONAL FACTORS

Name	Ownership	Rate Setting Mechanism	License to Sell
Barbados Light & Power	26% Government 74% Private	Public Utilities Board, appointed by Minister	non-exclusive to 1991
Jamaica Public Service	Government	Ministry of Public Utilities	Minister can license others
Corporacion Dominicana de Electricidad	Government	Office of the President	Strict exclusivity nationwide by law

Table II-3

ELECTRIC UTILITY EXPANSION PLANS

Country	Planned Expansion	Long Term Options, Planned and Proposed
Barbados	Replacement of old and inefficient diesels	Domestic natural gas is a possible substitute for oil
Jamaica	120 MW of coal-fired steam or 60 MW peat-fired steam in 1992	Imported coal or domestic peat for new capacity
Dominican Republic	1990 MW between now and year 2000	Bagasse; firewood; imported coal for new capacity

Table II-4

ELECTRIC TARIFFS FOR LARGE POWER CONSUMERS

Country	Energy Charges/kWh	Demand Charge	Maximum Demand	Average Price per kWh(US¢) (Nov. 1984)
Barbados	19.6 B¢ + F.A.* (U.S.9.9¢)	B$3.0/KVA (US$1.51)	previous 11 months	NA
Jamaica(1)	24.9 J¢ + F.A. (US 12.3¢)	J$1.44/KVA (US$0.31)	previous 12 months for 15 min. intervals	10.6-12.7
Dominican Republic	12.355 DR¢+F.A. (US 12.3 ¢)	RD$2.471/KVA US$2.471	previous	15-19(2)

* F.A.: Fuel Adjustment

(1) Energy Charges in Jamaica have been increased monthly since promulgation of published rates cited here.

(2) At official exchange rate; at the exchange rate paid for petroleum imports for non-electric uses, average price is 10-12.7 US¢ per kWhr.

Table II-5

OFF GRID RENEWABLE ENERGY BASED GENERATION POTENTIAL

Energy Resource	Country		
	Barbados	Jamaica	Dominican Republic
Bagasse/Sugar Cane Wastes	1.2 MW *	60-80 MW	80-100 MW
Agricultural Wastes	No	small	30 MW
Wind	Large?	Promising	Promising
Small Scale Hydro	No	10 MW	15-35 MW
Cogeneration, industries	No	small	small
Woodfuel Plantations	No	25 MW max	50 MW by CDE planned
Other	No	alumina industry 50 MW, coal generation	nickel mining 60 MW fuel oil steam **

* Sales in 1984 amounted to 1.13 Gwh.

** Sales in 1982 were 468.1 Gwh.

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APPENDIX A

SCOPE OF WORK

ARTICLE I - TITLE

LAC Regional Energy Resource Development Project (Project No. 598-0600)

ARTICLE II - OBJECTIVE

The purpose of this work order is to provide a study for AID and host countries that:

1. Analyzes the existing electrical system and identify policy, legal, regulatory, institutional and technical impediments to private sector generation of electricity for sale to the utility.

2. Identifies renewable energy opportunities for the generation of electricity for the sale to the national utility grid.

3. Provides recommendations to foster private sector renewable energy based electrical generation in each country.

ARTICLE III - STATEMENT OF WORK

The Contractor shall perform the following functions:

1. Describe briefly the United States Public Utilities Regulatory Policy Act (PURPA) and its impact.

2. Describe the existing utility including but not limited to ownership, generation/transmission/distribution, fuel use, average and marginal cost of generation (if available), system generation plans, tariff structure, current and projected load (particularly industrial load where cogeneration opportunities may exist) and any purchase of electricity.

3. Identify source and type of any significant electrical generation by non-utility entities such as larger industries. In particular, identify any renewable-based generation.

4. Analyze the policy/legal/regulatory framework governing the utility focusing on the generation of electricity by the utility and others including:

   a. Government policy on non-utility generation of electricity for sale to the national grid.

b. Legal and regulatory authority for generation of electricity.

c. Rate setting mechanism and source of authority.

5. Analyze the institutional impediments; determine the positions of key institutions, industries and individuals concerning the problems and potential for off-system generation including but not limited to the utilities, government ministries or commissions responsible for energy and utilities, key industries and policy- and law-makers.

6. Determine the utility's technical concerns such as system protection, metering, reliability, etc., and any related concerns about the purchase of off-system generation.

7. Identify the factors affecting the utility's avoided cost. Derive to the extent possible an estimated "avoided cost" and the price a utility might reasonably be expected to pay for intermittent power. Determine whether fuel credits should be used in establishing the price to be paid by the utility for intermittent power or whether some level of capacity credit can reasonable be expected to be used.

8. Using existing information briefly identify the likely renewable energy options for off-system generation of electricity such as hydropower, wind, bagasse, wood and other biomass that might be feasible to exploit assuming the utility pays a reasonable price. Estimate the potential magnitude of generation and assess the character of the generation, i.e., intermittent, seasonal, daily peaks, etc. Identify any projects under discussion or in the planning stage.

9. Identify the benefits of renewable energy based off-system electrical generation; provide policy/legal/regulatory recommendations that will foster introduction of private renewable energy-based electrical generation for sale to the grid; describe AID's options to foster renewable energy generations.

10. Tasks 2-9 will be done for Jamaica, the Dominican Republic and Barbados.

In this Statement of Work references to renewable energy also includes cogeneration.

APPENDIX B

THE PUBLIC UTILITIES REGULATORY POLICIES ACT IN THE UNITED STATES

THE PUBLIC UTILITY REGULATORY POLICIES ACT IN THE UNITED STATES

1 INTRODUCTION

The Public Utility Regulatory Policies Act [PURPA] passed by the United States Congress in 1978 dramatically altered the legal standing of certain broad categories of private power production in the United States. Prior to 1978, U.S. electric utilities were under no obligation to interconnect with private power producers for the purpose of accepting power from them, nor were there clear guidelines regarding how rates for supplementary and backup power to such facilities should be developed.

Today, that is no longer true; U.S. electric utilities are obligated to purchase power from qualifying cogenerating and small power producing facilities at rates that reflect the value of the power to the utility, and they must provide supplementary, standby, and maintenance power to such facilities at reasonable rates.

2 ACTION AT THE U.S. FEDERAL GOVERNMENT LEVEL

2.1 PURPA

2.1.1 Key Provisions

PURPA contains several key provisions that significantly alter the legal standing of cogenerators and small power producers meeting certain size, fuel use, and efficiency criteria ("qualifying facilities" or "QFs"). First, it authorizes the Federal Energy Regulatory Commission [FERC] to order electric utilities to interconnect with such qualifying facilities for the purpose of purchasing power from them and selling power to them. Second, it requires that the rate for purchase of power from such facilities be based on the energy (i.e., fuel and O&M costs) and capacity costs the electric utility avoids incurring as a consequence of the power provided by the qualifying facility. Third, it requires electric utilities to sell power to the facilities for the following purposes: 1) to supplement a facility's own generation, 2) to serve as backup for use during forced outages at the facility, and 3) for use during

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periods of scheduled maintenance. Finally, it exempts most qualifying facilities from federal and state regulation as electric utilities.

2.1.2 Eligibility Criteria

To be eligible for the benefits of PURPA, a facility must qualify as either a "small power producer" or a "cogenerator." A small power producing facility is defined as one using biomass, waste, a renewable resource, or any combination of these as its primary energy source. More than 50% of the total energy input must be from these sources, and the use of oil, natural gas, and coal must not, in the aggregate, exceed 25% of the total energy input. Futhermore, the total capacity of a small power production facility cannot exceed 80 MW.

Cogeneration facilities are defined as those using energy sequentially to generate both electricity and thermal energy that is usefully employed. Cogenerators must meet certain operating and efficiency standards: for topping cycle cogeneration systems, the usefully employed thermal energy must constitute at least 5% of the total energy output. For oil or natural gas burning cogeneration systems it is further required that the sum of the electrical output and one-half the total useful thermal output be at least 42.5% of the total oil and gas input to the facility, or 45% if the useful thermal energy output is less than 15% of the total energy output of the facility. For bottoming cycle cogeneration facilities, the only requirement is that the useful power output be at least 45% of any oil or natural gas used for supplementary firing. There is no upper limit on the size of a qualifying cogeneration system.

2.1.3 Exemption from Regulation

Cogenerating and small power producing facilities satisfying the above criteria are also generally exempt from regulation as electric utilities. Small power producing facilities with capacities less than 30 MW and all cogeneration facilities are exempt from most provisions of the Federal Power Act (FPA), from the Public Utility Holding Company Act [PUHCA], and from State regulation as an electric utility. Small power producing facilities with capacities greater than 30 MW are subject to the FPA but not to State regulation or to PUHCA.

2.1.4 Implementation Process

PURPA established a two step implementation procedure that involves both the FERC and the state commissions. The FERC's role is to establish broad rules defining the fuel use and efficiency criteria that must be met to qualify for the benefits of PURPA and to specify how rates for purchases and sales are to be determined. Based on these FERC rules, the state commissions were then to establish

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detailed rules covering the determination of avoided costs and to be responsible for the estalishment of tariffs, rates, and interconnection equipment standards.

2.2 The FERC's Order 69

In 1980, the FERC issued Order 69 implementing PURPA. This order contains several important interpretations of PURPA and the Federal Power Act:

1. The Order imposes a blanket obligation on all electric utilities to interconnect with all qualifying facilities. The FERC's objective in instituting this blanket obligation was to relieve the facilities of the burden of an expensive and lengthy FERC application and hearing process.

2. The rate for purchase of power from qualifying facilities is equal to the full energy and capacity costs avoided by the utility in association with the power contributions of the qualifying facilities. In determining avoided capacity costs, future needs for capacity, not just present needs, are to be evaluated. Furthermore, in determining the effects of power produced by qualifying facilities on utility needs for capacity, the power output of the facilities is to be considered in the aggregate and not on a facility by facility basis. In concluding that full avoided costs (as distinguished from some fraction of avoided costs) are the appropriate basis for purchase rates, the FERC reasoned that the purpose of PURPA was to provide the maximum encouragement to cogeneration and small power production consistent with keeping the remaining ratepayers whole; full avoided cost rates were considered to be the proper mechanism for accomplishing this objective. Ratepayers would benefit from the resource diversification and energy conservation consequences of increased cogeneration and small power production, not from rate reductions.

3. The facility can sell power to the utility on an "as available" basis, in which case the rate for purchase is based on the utility's avoided costs as experienced. Alternatively, the facility can sell power "pursuant to a contract or legally enforceable obligation," in which case the avoided costs can, at the option of the facility, be based on an estimate of the avoided costs over the term of the contract, thus providing price security to the cogenerator or small power producer.

4. The facility can engage in arbitrage--continuing to purchase its full power requirements from the utility and selling the entire output of the cogeneration or small power production system to

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the utility. The purpose of this is to allc the facility to receive payment for all of the power it generates at a rate equal to avoided costs irrespective of the level of power consumption at the facility. In situations in which the avoided costs are greater than the utility's rate for the sale of power, the qualifying facility is given the maximum incentive to generate, consistent with keeping the ratepayers whole.

5. Should the utility and the facility mutually agree, the utility can wheel the power produced by the facility to a second utility which then incurs the purchase obligation. However, nothing in the PURPA statute nor in the FERC's Order 69 requires utilities to wheel power for QFs.

3 STATE IMPLEMENTATION—NEW YORK'S PURPA RULES AS AN ILLUSTRATIVE EXAMPLE

In 1982, after three years of hearings and consideration, the New York Public Service Commission issued its PURPA rules in a generic case that established interconnection and rate guidelines for purchases from and sales to qualifying facilities. The rules provide detailed guidelines regarding how these rates should be calculated and how tariffs should be designed. They require that a tariff include an energy component consisting of the utility's current marginal energy costs (as determined through separate rate proceedings) and an avoided capacity cost component consisting of avoided generation, transmission, and distribution system costs. The avoided generation capacity costs are calculated using the "peaker" approach in which they are defined to be the costs of the cheapest type of generating capacity--namely, those of a peaking unit.

In some areas, the PSC's rules go beyond the minimal requirements of the FERC Order. The New York rules, unlike those in most states, require that to the extent that capacity costs can be avoided, these costs be included in the rates paid to all qualifying facilities irrespective of whether the facility enters into a contract with the utility. The avoided capacity costs are to be paid on a per unit of power delivered basis (i.e., per kWh) for power generated during peak periods.

The PSC also decided to require that standard purchase rates be available to all qualifying facilities. The FERC rules required that standard tariffs be established for qualifying facilities with capacities less than 100 KW, and most states have established ceilings of between 100 kW and 1000 kW on the applicability of standard rates.

The PSC's decision not to set a ceiling (other than the ceiling set in the PURPA legislation by the qualifying criteria for small power producers) makes it possible for large qualifying facilities in New York to sell power to the utility without having to negotiate a rate. They can simply choose to sell power pursuant to the utility's purchase tariff. Making standard tariffs available to all qualifying facilities alleviates many of the administrative burdens associated with PURPA, since it removes the necessity to negotiate both for the qualifying facility and the utility, and it eliminates the need for PSC review of many agreements that would otherwise have been negotiated individually.

4 AVOIDED COSTS

4.1 What Are Avoided Costs?

The FERC Order required that rates for purchase be set equal to the electric utility's full "avoided costs." Avoided costs were defined to be those "energy" and "capacity" costs that the utility would avoid incurring as a consequence of the power provided by the qualifying facility (QF)--i.e., the utility's marginal savings. Avoided costs have little relation to the utility's normal rates for sales which are based on the utility's average costs; avoided costs may be either higher or lower than rates for sales.

The energy component of the avoided costs, consisting of fuel and O & M expenses, can be interpreted as the variable cost component of the utility's marginal savings. Since there will always be some variable costs savings when power is provided by a QF (except during rarely occuring low load periods), there will always be some energy component to the avoided costs.

The capacity component consists of those generation, transmission, and distribution capacity expenses that can be avoided due to the contributions of the QFs. In determining the utility's ability to avoid capacity costs, future needs for capacity, not just immediate needs, must be considered and the value of power from an aggregate group of QFs should be evaluated (rather than considering the effect of each facility individually). Also, a utility's ability to avoid purchases from other utilities and to increase sales to other utilities should be accounted for.

The determination of when capacity costs are actually avoided and the magnitude of these costs is not a simple matter. For example, the mere fact that a utility will be purchasing new capacity, whether in

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the form of a unit it will own or in the form of firm purchases from other utilities, does not always imply that there are capacity costs that can be avoided. Consider, for example, a utility with excess capacity which has high operating costs because it is burning expensive oil at the margin. Assume also that this utility is experiencing slow growth or no growth in load. If there are new capacity options available to the utility that will provide power at a cost below the variable costs of oil, then, even though new capacity is not needed to maintain system reliability due to growing loads, investment in new capacity may yet be justified on the basis of economic efficiency; i.e., the purchase of a new unit may result in lower costs to the ratepayers even though it will add even more excess capacity. In many such cases, contributions from QFs are unlikely to alter the conclusion that the purchase of new capacity for economic reasons is justified. Consequently, such purchases should not properly be considered to be "avoidable" and there would be no avoided generation capacity costs associated with them.

4.2 Methods for Calculating Avoided Costs

Several methods of computing avoided costs have been developed for use in designing purchase rates. Avoided costs are, for all practical purposes, marginal costs, and these methods are essentially marginal cost computational procedures. The approaches differ not only in their computational details but also in their implicit conception of marginal cost. Among the major differences in the methods are whether short- or long-run costs form the basis for the analysis and the treatment of capacity costs.

The three most frequently used approaches to computing avoided costs are 1) the peaker approach, in which both marginal energy and marginal capacity costs are computed in the short-run, 2) the proxy unit approach, and 3) the long-run differential revenue requirements approach (LRDRR), in which both marginal energy and marginal capacity costs are computed in the long run.

4.2.1 The Peaker or Short-Run Approach

One of the more common methods for separately calculating marginal energy and capacity costs involves using the so-called "peaker" approach. In this approach, short-run production costs are combined with short-run capacity costs. This approach has the virtue of simplicity; short-run production costs can be obtained from a utility system simulation model or from recent data on actual utility operations, yielding the short-run production costs with a minimum of effort. The marginal capacity cost is estimated as the cost of a small peaking unit.[8]

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The peaker approach will yield acceptable marginal cost results if a utility's generating mix is already optimal. Even in a non-optimal utility such an approach may yield reasonable estimates of the short-run marginal costs of energy and capacity if oil-fired peaking units are used during peak loading periods. As long as oil is the marginal fuel during most of the hours of the year, the peaker approach will yield approximately correct marginal costs. The peaker approach is especially suitable for determining short-run avoided costs for use in tariffs for the purchase of energy provided on an "as-available" basis--i.e., with no firm commitment by the facility owner.

However, this approach is generally inappropriate for estimating long-run marginal costs if 1) oil is not the marginal fuel most of the time, and 2) the utility is also investing in new capital intensive baseload facilities. Only if the "energy" component is redefined to include that portion of a capital intensive plant that is properly associated with the plant's fuel displacement function will the peaker approach yield an acceptable result. Such a broad interpretation of "energy" costs is rarely seen in practice. Hence, the sum of the components of the marginal costs computed using the peaker approach as it is usually applied, is not necessarily representative of actual present or future marginal costs.

Although this may appear to be an academic issue, the practical effects of using the peaker approach in situations where the use of high priced fuels at the margin is minimal can be dramatic, contrary to the intent of PURPA, and strongly counter to the interests of the QF. Where utility oil use at the margin is minimal, the simplified application of the peaker approach (in which marginal energy costs are defined to include only marginal production costs) leads to avoided

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* The main justification for using the cost of the small peaking unit as a surrogate for the capacity costs is that a utility could, at least theoretically, purchase such a unit on short notice if load growth warranted doing so. That is, if the utility actually purchases some other, more expensive, type of capacity, it will do so because the overall costs of operating the utility system will be lower as a result of the lower operating costs of the more capital intensive plant. The more expensive unit is not being purchased solely to meet the utility's capacity needs but is serving also to lower energy costs; marginal capacity costs are then properly measured by the cheapest type of capacity that can be purchased to fulfill capacity requirements.

cost rates that range from 1 - 3¢/kwh while, at the same time, the utility is probably incurring total costs for electricity from new plants in excess of 6¢/kwh.

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4.2.2 The Proxy Unit Approach

Another approach which is used in several states in the US for long run rates for long term contacts is the "surrogate" or "proxy" plant approach. In essence, this is a long run marginal costing procedure. In this approach, the cost of a generic generating facility or a generating facility actually being planned by the utility is selected as a measure of the value of power to the utility, and hence as an appropriate measure of marginal costs. Marginal energy and marginal generation capacity costs are calculated jointly.

There are various ways of implementing this approach. One possibility provided as an illustration is as follows: If a utility coal plant is selected as the basis for the rates, the energy costs associated with that facility, namely its fuel and its O&M costs, are paid to the QF on a kWh basis, based upon the costs for the fuel and estimated O&M costs in each year.

The total estimated installed cost of the utility plant is deflated to the year in which the QF begins providing power and is converted into a levelized annual payment. This annual payment can be paid on a peak kW basis provided the QF meets certain reliability and supply characteristics criteria, or on a kWh basis where the kWh rate is determined using the estimated annual capacity factor for the utility plant.

4.2.3 The Long-Run Differential Revenue Requirements Approach

In this approach, avoided costs are based on long-run marginal costs; i.e., both energy and capacity costs are estimated over the long run. The utility's future revenue requirements (i.e., total annual costs) are estimated both with and without the contribution of the QFs for a 15 to 25 year period into the future. The utility's capacity plan is separately optimized for the two cases; i.e., the present value of utility operating and capacity expenditures over some defined period (e.g., usually about 20 years) is minimized for utility loads that in the first case ignore the QFs and in the second include their contributions. The differences in future revenue requirements between the two cases are directly attributable to the assumed contributions from the QFs and, hence, is the estimated total avoided cost. Order 69 specifically cites the differential revenue requirements (LRDRR) approach as an acceptable method for computing avoided costs.

With the long run differential revenue requirements approach, the avoided costs are computed in a single, integrated analytical

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procedure, eliminating the need for separate avoided energy cost and avoided capacity cost computations. This integrated computation ensures that energy and capacity components of the resulting total avoided cost are consistent.

The LRDRR procedure permits the avoided costs of the small power producing and cogenerating facility to be tailored to the particular supply characteristics of the generating facility. In calculating the utility's revenue requirements with the facility present, the net loads to be met by the utility are reduced in a manner consistent with the supply characteristics of the qualifying facility. Furthermore, by breaking up the utility's future capacity options into small increments, and by treating the contributions from the facility as being part of an aggregated group of similar facilities, a realistic assessment of the capacity value of the facility to the utility is obtained.

5 LONG RUN PRICING ARRANGEMENTS

5.1 Importance of Long Run Rate Option

While the establishment of tariffs for the purchase of power from private power producers on an as-available basis, subject to periodic review of the regulatory authority, is an essential step to the encouragement of cogeneration and small power production facilities, it is important not to rely upon this type of pricing arrangement alone. The absence of at least one clearly defined procedure whereby a project developer and a utility can develop a long term pricing arrangement can be a significant deterent to the development of cost-effective, resource diversifying projects.

Project developers face substantial risks if they invest in projects whose economics are based upon operation over a long period of time if the revenues to be derived over that time are uncertain. This is the situation that would be faced by a developer if the only purchase tariff that were available was the as-available purchase tariff. This type of purchase tariff provides no assurance regarding the level of future revenues. Tariffs of this type inevitably increase the costs of achieving satisfactory financing for the project; i.e., bank financing is considerably harder to obtain.

The importance of clearly defined proceedures for developing long run purchase prices for long term contacts process cannot be over-emphasized. The reasons for this are as follows:

First, while project owners are not regulated with regard to the

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level of permissible profit, their revenues are very much subject to a regulatory risk since the revenues are directly proportional to the avoided costs of a regulated entity. Because of this strict and continuing regulation of their revenue stream under the as-available tariff concept, project owners face a double layer of uncertainty with regard to the future economic viability of their projects: In addition to the normal uncertainties regarding the impact of economic factors (e.g., raw material prices, inflation, general business conditions) on revenues that is faced by investors operating in the private sector, facility owners face additional uncertainties having to do with the potentially shifting vagaries of regulatory policy and its implementation with regard to alternative power generation.

From the perspective of the facility owner, not only is it possible for the government to modify statutes, regulations, and policy positions affecting the purchase rate but the procedures for implementing those policies--i.e., the specific guidelines for calculations, eligibility criteria, etc.--are subject to change as a result of political, theoretical, or other reasons. This is especially true at the present time as policies and procedures are in a process of development and rapid evolution. Such changes add to the risks faced by a QF.

Second, cogenerating and small power producing projects tend to be more capital intensive than the average business. Hence, the QF investor faces a greater relative risk than does the average investor.

Third, pricing arrangements are a familiar feature of the private sector, serving to protect both the buyer and seller from uncertainty. Commission action to develop guidelines regarding long term pricing arrangements is not regulatory intervention to distort the marketplace but rather the reverse. The intent would be to facilitate important options available in the non-regulated marketplace.

Fourth, because the risks are higher without a long run pricing arrangement, potential investors would require a greater differential between estimated revenues and estimated costs before proceeding with their projects in order to provide a margin of safety. Thus, fewer projects would meet investors' criteria for acceptability and ratepayers would be deprived of some of the resource diversification and other benefits of cogeneration and small power production.

5.2 Benefits to Ratepayers

With long term pricing arrangements, ratepayers offer the project developers a guaranteed payment for their output. In return, the developers offer the ratepayers a guaranteed cost for electricity. It is a fair deal. The ratepayers aren't giving something away

without getting something valuable in return. Long term pricing arrangements provide certainty to both sides, not just to one party. In general, uncertainty of and by itself is generally viewed as something that increases costs. Insofar as the securing of power at a known cost reduces uncertainty to the utility and the ratepayers, they gain in the process.

More specifically, the ratepayers would have a contractual assurance that power will be delivered to them over a period into the future in accordance with a known pricing formula. Given the significant changes in rates that resulted from the rapidly increasing costs experience by utilities over the past decade, the cost security provided by such an assurance should be perceived as a desirable development.

In other words, this type of pricing arrangement has the characteristics of a positive sum game; both sides come out ahead. The initial effort on the part of the Commission to develop the guidelines for such long term arrangements can be very cost effective.

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