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Volume V
Electric Utility Rate Analysis

Prepared For

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16. Abstract (Limit: 200 words)

Because heavy dependence on costly imported fuel is greatly hindering Jamaica's economic development, USAID/Jamaica and the Government of Jamaica sponsored a preliminary assessment to identify viable alternative energy options. Technological studies were published in three volumes (with volume three being in four parts, for a total of six volumes), to which two introductory volumes were added, providing, respectively, an executive summary of the entire assessment and an economic assessment of the individual areas. This study, the last of the three technical volumes, analyzes the electric utility rate structure of the Jamaica Public Service Company (JPS) in order to determine whether it promotes economically efficient use of electricity, is based on principles of equity and fairness, and provides JPS with sufficient resources to maintain acceptable service quality. Current tariffs are described, and features such as declining block tariffs (decreasing unit price with increasing volume used), expander clauses (decreasing rate if total energy use increases without increasing maximum power demand) and ratchet clauses (little or no reduction in charges if use falls below a previously set high), which may not encourage conservation or efficient system usage, are noted. Various tariff options, based on marginal cost pricing principles (tying prices to the additional cost of supplying the electricity), are presented for each rate category in the JPS system (residential, small commercial, industrial, and large commercial). Flat rate (with and without demand charges), time of use pricing, fuel adjustment, and cost of service adjustment are considered. These options demonstrate immediate or interim steps that can be taken to gradually approach marginal cost pricing. The effects of each step in tariff development and the associated customer bill impacts are indicated. As requested by JPS, specific recommendations for the type of tariff system to be adopted are not presented. It is recommended that JPS review and analyze these options and present its own suggestions to the Ministry of Public Utilities. Appended are a 10-item bibliography (1958-77) and a summary of a splinter group discussion.

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PRELIMINARY
ENERGY SECTOR ASSESSMENTS OF JAMAICA

CHAPTER 8

ELECTRIC UTILITY RATE ANALYSIS

for

UNITED STATES AGENCY FOR INTERNATIONAL DEVELOPMENT

CONTRACT NUMBER AID 532-79-11

TASK 6

ENERGY SYSTEMS INTERNATIONAL
8301 GREENSBORO DR., SUITE 30
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JANUARY 1980

FOREWARD

The eight reports of the Preliminary Energy Sector Assessments of Jamaica conducted by the United States Agency for International Development Energy Team are contained in the following five volumes:

Volume	I	Executive Summary
	II	Economic Assessment
	III	Renewable Energy:
		(a) Solar Energy - Commercial & Industrial
		(b) Solar Energy - Agricultural
		(c) Biogas Applications
		(d) Energy Conversion from Waste
	IV	Coal Prefeasibility Study
	V	Electric Utility Rate Analysis

These studies were initiated by the USAID in conjunction with the Government of Jamaica to further the objectives of Jamaica's Five Year Development Plan and its Energy Sector Plan. The studies also represent USAID's first energy assessment of a developing country.

Due to the diverse technology requirements and the high degree of specialization required by each of the studies, a United States Energy Team of experts was assembled. The individual team members were selected based upon a demonstrated balance between academic and "hands-on" experience in the specific study area.

Energy Systems International (ESI), had overall responsibility for systems planning, project management and integration of all elements of the Preliminary Energy Sector Assessments.

These reports should not be considered as the final product of any study area, but as baseline documents to be used for identifying specific energy programs and projects for implementation in the near-term to assist Jamaica in alleviating its critical energy problem.

Any comments or questions concerning this study should be directed to:

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The success of the Preliminary Energy Sector Assessments of Jamaica was assured through the joint cooperation, professionalism, competence and diligence of the entire U.S. Energy Team and their key Jamaican counterparts. The assessment was a concentrated effort over a fifteen week period in Kingston, Jamaica, during which many government agencies, institutions, private sector organizations and individuals became involved and generously supported study development. The many excellent people involved are too numerous to mention herein, but a few have been singled out for recognition because their outstanding effort and support helped to provide study continuity and progress.

Special thanks go to Dr. Henry G. Lowe, Director, Energy Division of the Ministry of Mining and Natural Resources and to the MMNR staff for providing the inspiration and leadership from the Jamaican side to ensure that there was enthusiastic support and contributions to this study from all Jamaican counterparts. A special note of appreciation goes to Mr. Alvaro Casserly of Jamaica Public Service Company Ltd. for his capable technical guidance, support and collaboration with the Energy Team during the Electric Utility Rate Study.

Special thanks must also be given to the United States Agency for International Development, in particular, Mr. Jerome Hulehan, General Development Office, USAID Kingston, Jamaica Mission and Dr. Jerome Bosken, Deputy Director, Energy Office, USAID Headquarters, Washington, D.C., for their encouragement and support of the project and for their assistance throughout the study.

CREDITS

Dr. Charles Cicchetti, Mr. William Gillen, Mr. Rod Shaughnessy of the Madison Consulting Group and Mr. Warren Smith of the Jamaican National Investment Corporation were the principal investigators for this study. Their outstanding efforts made this product an extremely useful tool for decision makers in Jamaica. Energy Systems International was responsible for study integration, edit and final report preparation.

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8.1 EXECUTIVE SUMMARY

8.1.1 Introduction

The structure for pricing electricity in Jamaica has evolved over a period of many years. The current pricing system contains a number of features which were instituted for very good reasons. Many circumstances have changed since these features were adopted, however thus providing reason to question their continued use. Tremendous price increases for imported oil, reduced customer demand, high costs for any new generation and distribution equipment, and the desire to reduce foreign exchange expenditures have all been factors which precipitated this study. The foreign exchange situation has been very damaging to the Jamaican economy, especially that caused by foreign oil imports. As the disparity between goods sold abroad or foreign currency brought into Jamaica and that Jamaican currency which must be used to purchase goods abroad (such as oil) increase, the Jamaican currency loses value. The situation is self-perpetuating in that one encourages the other, consequently the cost of oil imports in real Jamaican dollars is increasing more drastically.

8.1.2 Terms of Reference

The electric utility rate analysis has as its goal a thorough examination of the tariff structure of the Jamaica Public Service Company (JPS) in order to determine whether it (a) promotes an economically efficient use of electricity in the society; (b) is consistent with basic principles of equity and fairness, and (c) provides the company (JPS) with sufficient resources to maintain an acceptable quality of service. JPS officials specifically requested that the study focus on findings and options so that JPS could examine these options and draw specific conclusions and recommendations themselves for presentation to the Ministry of Public Utilities.

8.1.3 Background Information

There has been a worldwide movement toward marginal cost pricing for electricity as a means of keeping costs as low as possible. Marginal cost pricing may be used to modify the accounting approach traditionally used to price electricity. Pricing signals to customers are important factors in reducing electricity use and imports of foreign oil. The current declining block pricing structure, based on accounting costs, does not provide adequate pricing signals to customers. Customers are given a pricing signal which, in the higher usage blocks, charges them less than the average cost of providing the power. This signal does not provide enough conservation information, and also has the effect of reducing earnings for JPS as the customer uses increased amounts of power in the higher usage blocks. This study, using marginal cost pricing philosophy, offers options to policymakers in Jamaica for changing the JPS electricity pricing structure.

8.1.4 <u>Study Method</u>

During the study, the team members attempted to become knowledgeable about the social and economic goals of Jamaica, and to take them into account when picking the most likely options for analysis. With this in mind, options for JPS have been developed. However, only those in Jamaica, with the ongoing knowledge of their nation, can make the final decisions on which of these options to implement.

In performing the analysis, several assumptions were made which are important to reader understanding of the efforts:

(1) Total revenues to JPS will not be increased or decreased by the adoption of the prepared options;

(2) Customer categories continue to generate revenue in the same relationship to one another as at present;

(3) Declining block pricing should be eliminated;

(4) Ratchet and expander clauses should be eliminated;

(5) Time of use pricing will be considered if appropriate; and

(6) The fuel adjustment and cost of service clauses will be continued.

Taking into account these considerations, Jamaican decision-makers have been provided several options for electricity customers, including tariffs for immediate or phased-in adoption, which move toward marginal cost-based rates.

8.1.5 <u>Findings</u>

Table 8-A is a summary of existing JPS tariff structure. The discussion of this structure follows:.

TABLE 8-A
SUMMARY OF EXISTING ELECTRIC TARIFFS IN JAMAICA

CONSUMER CLASS	TABLE REFERENCED	GENERAL TARIFF DESCRIPTION	TARIFF STRUCTURE, JAN 1980	
			Customer Charge	$1.99/month
			Use(kWh)	
Residential (Rate 10)	8 - 10	o Declining Block (cost decreases with usage)	10 or less	0
			Next 20	18.88¢
		o Monthly rate adjusted for inflation	Next 70	15.13¢
		o Fuel adjustment clause	Next 200	11.01¢
			Next 200	7.00¢
			Over 500	6.25¢
Small Commercial (Rate 20)	8 - 11	o Declining Block (cost decreases with usage)	Customer Charge	$1.99/month
			Use(kWh)	
		o Monthly rate adjusted for inflation	10 or less	0
		o Fuel adjustment clause	Next 90	29.64¢
			Next 900	13.51¢
			Next 9,000	10.63¢
			Next 10,000	8.00¢
Large Commercial (Rate 40)	8 - 12	o Two-part tariff - power (kW) and energy (kWh)	Demand Charge	$2.15/kW/month
			First 100 hrs demand	6.38¢/kWh
		o Demand charge = 12 mo. ratchet*	Next 200 " "	5.38¢/kWh
		o Energy charge = Declining Block + expander**	Over 300 " "	4.50¢/kWh
		o Fuel clause		
		o Monthly rate adjusted for inflation		
Industrial	8 - 13	o Two-part tariff - power (kW) and energy (kWh)	First 100 hrs demand	6.38¢/kWh
			Next 200 " "	5.38¢/kWh
		o Demand charge = 12 mo. ratchet*	Next 200 " "	4.00¢/kWh
		o Energy charge = Declining Block + expander**	Over 500 " "	3.50¢/kWh
		o Fuel clause		
		o Monthly rate adjustment for inflation		

* Ratchet: A disincentive charge for increased use of power. A specific billing period's maximum demand is compared to previous months' (usually 11 or 12 months) maximum demand.

** Expander: Reduction in customer's energy charge when use in kWh's increase for a fixed level of maximum power, kW.

8.1.5.1 Residential Tariffs (Rate 10)

Residential tariffs currently appear to be structured with steeply declining blocks. The effect of declining block tariffs is to reduce the conservation signals which are given to the residential customers. However, cost of service and fuel clause adjustments levied by JPS significantly reduce the relative differentials paid for levels of consumption in the different blocks.

Several tariff options are offered based upon marginal cost pricing principles, including those which might be termed ultimate tariffs, and several which could be used in phases, including modifications to the present tariff, an inverted block tariff and a declining block tariff. Detailed comparisons are provided to illuminate the impacts of the various tariffs on customer billings.

8.1.5.2 Small Commercial Tariffs (Rate 20)

Small commercial customers are served under a tariff with declining block features similar to the residential tariff. As with the residential sector, the most accurate price signals are not being provided to the customers. Jamaican decision-makers may choose from various tariffs developed herein, including eliminating two of the blocks in the declining block structure, utilizing flat rates, or using a tariff with a slightly inverted block structure. As with the residential options provided, phasing-in alternatives are included and detailed bill analyses are provided.

8.1.5.3 Large Commercial Tariffs (Rate 40) and Industrial Tariffs (Rate 50)

Not only the amount of power, but the time during which it is used must be considered. In the JPS system there are differences in generation costs depending on the time of day. Although the differences are not large, they are large enough to warrant installation of time-of-day recording meters for the large industrial customers and modification of the electricity pricing structure to take into account the time-differentiated generation costs. If the current system was operating at design capabilities (excess generation capacity) equipment could be retired which could, at some point in the future, increase the time-of-day generation cost differential. This provides another reason to consider placing the 24 industrial customers on a time-of-day tariff. If such a tariff is adopted, it should be carefully explained to the customers before its effective date, and could be offered as an optional, rather than a mandatory, tariff. A period of time during which customers receive billing comparisons for both old and new tariffs might also be considered.

It is suggested that other features of the large customer tariffs, such as the "ratchet" and "expander" clauses, be examined. "Ratchet" clauses discourage customer growth in maximum demand, but, at the same time, encourage demand up to a level established by the customer during a previous billing period. "Expander" clauses, while encouraging customers to improve their individual load factors, do not ensure that system load is levelized.

8.1.5.4 Large Commercial Tariffs (Rate 40)

The currently offered two-part tariff is not consistent with marginal cost pricing principles. However, options are presented both to continue and to eliminate the two-part tariff. It is suggested that the "expander" clause be eliminated early in any changes to the tariff structure, with eventual elimination of the "ratchet" clause. Additional tariffs are also provided which take into consideration differences in generation costs between peak and off peak times. For better understanding of the impact of the options presented, detailed bill comparisons are provided.

8.1.5.5 Industrial Tariffs (Rate 50)

As with the Rate 40 tariff, the elimination of the "expander" and "ratchet" clauses is suggested. Several possible options provided for consideration include two-part, one-part, flat, and time of use tariffs. As with the other rate categories, detailed bill analyses are presented to explain customer impacts.

8.1.6 Discussion of Findings

The structure of the existing JPS tariff system was reviewed and the findings are summarized in Table 8-A.

The study team then developed options based on marginal costs principles. Marginal cost is simply the cost (or savings) incurred by the utility in providing more (or less) electricity. In very general terms the following statements will help explain the marginal cost principles used to develop options for JPS:

- Marginal cost of providing electricity as stated above is passed on to the consumers;

- These costs must be equitably apportioned among consumers;

- The allocation of society's scarce resources among alternative uses must be efficient;

- Resources are channeled from one use to another primarily as a response to pricing signals;

- This channeling as a response to price may be distorted by (1) absence of competition or (2) existence of societal concerns. Both exist in the pricing of electricity;

- The primary task of regulators and decision-makers is to see that prices perform the signalling function.

Table 8-B is an overview of options which utilize marginal costs principles in electricity pricing in Jamaica. The following general conditions applied to the development of these options.

(1) Total revenue requirements will not be changed;
(2) Total revenue allocations between customer categories will not be altered;
(3) Declining block pricing will be eliminated;
(4) Ratchet provisions will be eliminated;
(5) Expander tariffs will be eliminated;
(6) Flat (both all-energy and two-part) demand and energy tariffs will be considered;
(7) When metering and customer acceptance seems reasonable, time of use pricing will be considered;
(8) The very progressive (from an efficiency standpoint) fuel adjustment clause will be continued;
(9) The innovative Cost of Service adjustment will be retained;
(10) Continuing the residential customer flat rate with the firts 10 kWh included free will be presented.

These marginal cost pricing principles were used to develop the tariffs which follow for each customer category.

TABLE 8-B

A SUMMARY OF OPTIONS BASED ON MARGINAL COST PRINCIPLES

CUSTOMER	TARIFF OPTION	DISCUSSION	EXAMPLE TARIFF STRUCTURE*	REFERENCED TABLES
Residential (Rate 10)	o Flat Tariff	o The same rate regardless of usage	All Usage 11.66¢/kWh	8-19A
	o Inverted Block	o Costs increase with usage	0-10 kWh 0¢ 10.60¢ 11-100 kWh 12.19¢ 10.60¢ over 100 kWh 12.60¢ 12.60¢	8-19B 8-20A 8-20B
Small Commercial (Rate 20)	o Flat Tariff (Low)	o The same rate regardless of usage	All Usage 12.42¢ 12.77¢/kWh	8-21A
	o Inverted Block	o Costs increase with usage	0-1000 11.274¢ over 1000 13.274¢	8-21B 8-22
Large Commercial (Rate 40)	o Flat Tariff with Demand Charge	o The same rate regardless of usage - Two factors determine Rate: (1) Maximum power requirement (kW) above established level; (2) Total energy demand over a period of time (kWh)	2.15¢/kW/mo. + 6.11¢/kWh	8-23 8-24
	o Peak - Off-Peak with Demand Charge	o Less is charged during periods of low demand - Same two factors above (kW and kWh) determine charge	2.15¢/kW/mo. + 7.11¢ during peak or 4.11¢ during off-peak	8-25
	o Increased Revenue	o Declining Block (more usage - less cost) -- not as steep as existing blocks	First 100 hrs 6.38¢ + 2.15¢/kWh Next 200 hrs 5.38¢ + 2.15¢/kWh Over 300 hrs 4.50¢ + 2.15¢/kWh	
	o Flat Tariff - No Demand Charge	o Flat rate with no two-part charge as above	All Usage 6.11¢/kWh	
	o Peak - Off-Peak No Demand Charge	o Flat rate for peak time usage -- another less expensive flat rate for off-peak usage	Peak Usage 7.89¢/kWh Off-Peak Usage 4.89¢/kWh	

TABLE 65 CONTINUED

A SUMMARY OF OPTIONS BASED ON MARGINAL COST PRINCIPLES

CUSTOMER	TARIFF OPTION	DISCUSSION	EXAMPLE TARIFF STRUCTURE*		REFERENCED TABLES
Industrial (Rate 50)	o Flat Tariff with Demand Charge	o Same principle as Large Commercial (Rate 40)	All Usage	5.82¢ + 1.83¢/kWh	8-26
	o Peak - Off-Peak	o Same principles as Large Commercial	Peak Usage Off-Peak Usage	6.82¢ + 1.83¢/kWh 3.82¢ + 1.83¢/kWh	8-27 8-28
	o Flat Demand Tariff - No Demand Charge	o Same as Large Commercial	All Usage	6.55¢/kWh	
	o Peak - Off-Peak No Demand Charge	o Same as Large Commercial	Peak Usage Off-Peak Usage	7.55¢/kWh 4.55¢/kWh	

* Certain "Phase-in" tariff options have not been included.

8.1.7 Conclusions and Recommendations

Rather than making specific recommendations as to what type electric tariff structure JPS should adopt this study, in response to JPS request, outlines basic tariff options and compares them to the existing tariff structures. The impacts and introduction schemes of these tariff options for various sectors of the economy are discussed. The structure of these options are too detailed for this executive summary to sufficiently discuss their meanings and impacts. Thus, the reader is referred to Section 8.7 for a review of the options for various sectors of Jamaica. Several assumptions are made with some in the form of recommendations. These were shown previously in Section 8.1.4.

The overall conclusion is that JPS and Jamaican decision-makers should review and compare these options in light of their overall economic goals and plans. From these options discussions should be made for rate tariff changes which will derive the most benefit for all concerned.

8.2 INTRODUCTION

This is a study of electricity tariffs in Jamaica. The purpose of the analysis is to develop electricity tariff options for the Jamaica Public Service Company (JPS) based upon the economic principle of marginal cost. Present tariffs will be discussed and compared to tariffs developed from the estimates of marginal cost that are discussed.

The study is outlined as follows: there will be two general discussions of the concepts of marginal cost and demand in order to lay the groundwork and to provide an introduction for the following empirical analysis of the marginal cost of electricity and demand for electricity in Jamaica.

Next, there will be a more specific discussion and critique of the traditional principles used to design electricity tariffs. The general tariff discussion will serve as an introduction to a complete description of the present JPS electricity tariffs.

An analysis of the JPS revenue requirements and customer load characteristics will be provided. Tariffs based upon marginal cost principles will be offered. Various tariff options to move from the current tariffs toward marginal cost-based tariffs will be described and compared to present JPS tariffs. The provision of policy choices for Jamaican decision-makers will be the major emphasis of the tariff portion of the analysis.

8.3 TERMS OF REFERENCE

8.3.1 Objectives

The original Terms of Reference for the Electric Utility Rate Analysis are contained in Task 6, Appendix A. Though all elements of the Terms of Reference were addressed, the study emphasized the following key points:

(1) The marginal costs of supplying electricity to different JPS customers;

(2) The extent to which the existing rate structure deviates from marginal cost; and

(3) The potential impact of marginal cost pricing on JPS revenues and on the demand for electricity in Jamaica.

The study should provide tariff options based on marginal cost. This new structure should be presented along with suggestions for its implementation. JPS officials specifically requested that the study focus on findings and options so that JPS could examine these options and draw specific conclusions and recommendations themselves for presentation to the Ministry of Public Utilities.

In addition to the tasks contained in the specific study Terms of Reference, the Energy Team members were also responsible for completion of the requirements outlined in the Project Management and Detailed Study Plan (discussed in Chapter 1). During the course of the study, the team members were to conduct three assessment reviews to ensure that timely progress checks and necessary study alterations were made. The team members were also requested to make two presentations. The first was a seminar to be held midway through the assessment; the second to be at study completion in which the results, conclusions and recommendations were highlighted at the Final Report Conference, held November 13-14, 1979. In this particular study, a progress report was presented at the conference.

As a result of the project summary given during the first day of the conference, a number of questions were asked to clarify study procedures, options, constraints, and considerations made when formulating specific options. The questions were fielded by the team experts and Jamaican counterparts during splinter group discussions held the second day. The tapes of the Electric Utility Rate Analysis splinter group question and answer session were transcribed and are contained in Appendix B.

8.3.2 Schedule

The United States Energy Team members conducted the Electrical Utility Rate Analysis in cooperation with the Jamaica Public Service Company and Mr. Warren Smith, Senior Investment Analyst with the Jamaican National Investment Company. The study was initiated by Mr. Smith prior to the arrival of the U.S. Energy Team in August, 1979. The final report, prepared by Mr. Smith and the Madison Consulting Group, will be presented in January-February, 1980. All study recommendations are in the form of options available to JPS and government officials to alter the current tariff structure to one based on marginal cost pricing.

8.4 STUDY METHOD

8.4.1 Pertinent Data Reviewed

The calculation of marginal cost involved the determination of the incremental cost to the system of installing additional:

a) generating capacity
b) transmission and distribution capacity.

along with the incremental fuel and operating cost requirements, when an additional unit (kWh) of electrical energy is consumed.

The data needed to calculate marginal cost is obtained primarily from the system planning department of the utility. This department develops expansion plans of the company in response to projected additional future demand.

Data on costs associated with adding another customer to the system were obtained from the Consumer Engineering Department. Details on the relative efficiencies of the generating units were gathered from personnel in Production. Data on the costs of fuel were determined from the Finance and Accounting Departments, as were data on revenues, sales and tariffs.

Load data were supplied by the System Dispatch Center and Electric Operations.

8.4.2 Sites Visited

Because of the nature of the study, visits to the various stations of the company were not required. However, a visit was made to the System Dispatch Center -- the nerve center of the company, and much time was spent analyzing the Accounting data of the company.

8.4.3 Surveys Made

A preliminary survey has been made of the load curve shapes of different classes of consumers on the JPS system. This was done for the purpose of better understanding which groups imposed the greatest burden on the system because of the patterns of their consumption.

A detailed study was also undertaken of the elasticity of demand for electricity by customer class.

The purpose of the following analysis is to provide a benchmark for evaluation of tariff structures. The premise here is that tariff structure should reflect the structure of marginal costs -- subject, of course, to a number of other relevant considerations. Among these considerations will be the avoidance of disruptive effects upon consumers, the maintenance of the financial stability of the utility and the overall consequences of electricity consumption and production within the Jamaican economy, particularly the need for conservation and the efficient use of energy resources.

8.5 BACKGROUND INFORMATION

8.5.1 Generating Capacity

JPS is 99 percent state-owned, and is the sole supplier of electricity in Jamaica. The largest industrial consumers in Jamaica (bauxite/alumina, cement and sugar industries, along with a number of smaller ones such as the Goodyear tire factory) operate their own generation facilities and provide much of their electricity needs. Formal arrangements exist permitting the sharing of power between the public and private systems whenever the need may arise.

Despite the magnitude of privately owned generating capacity in Jamaica, the average electricity consumer is likely to be more concerned with the performance of JPS, since it is from this source that most customers receive their electricity. The residential customers have experienced the largest growth in numbers, although consumption per customer has been declining over time. The growth in numbers can be attributed largely to a government-supported drive to bring electricity to a large number of rural villages through a rural electrification program. There has been a decline in per customer consumption across all categories coinciding with rapidly increasing electricity rates since the oil embargo of 1973. Other factors in this decline have been a severe recession in the local economy and a decline in real per capita income.

Existing generating capacity was put into place to meet a rapidly growing demand for electricity. Maximum demand increased from 88 megawatts (MW) in 1965 to 239 MW in 1976, an increase of 172 percent. This growth pattern ended in 1977 as the economy went further into recession and electricity prices climbed even higher. JPS energy sales from 1963-1978 followed a pattern somewhat similar to maximum demand, with annual growth rates by class varying from 8 percent (large Commercial and Industrial) to 20 percent (Other) during this period. However, for the period from 1973-1978, average annual growth fell 2 percent for large Commercial and Industrial customers and 8 percent for the "Other" customers.

A close relationship exists between (a) any growth in peak demand which JPS would be required to meet, (b) the efficiency with which electricity is generated and delivered, and (c) the balance of Jamaica's foreign exchange accounts. At a time when the OPEC nations have exhibited never-ending demands for higher prices for their oil, JPS finds itself in the unfortunate position of being approximately 92 percent dependent upon foreign oil for electricity generation. This dependence can only aggravate the Jamaican foreign exchange situation. In 1978 the foreign deficit totalled J. $68 million, almost 2 percent of the Gross National Product (GNP).

Jamaican oil imports during 1978 exceeded 16 million barrels at a cost of over J. $358 million. JPS during the same time used more than 16 percent (2.6 million barrels) of the oil imported. The cost of this fuel to JPS was J. $51.3 million over 14 percent of the nation's total oil expense.

The pricing of electricity should always be given considerable attention no matter what type of generating fuel is used, regardless of the utility firm's operating environment. The situation confronting JPS dictates that an even greater than normal attention be given to the pricing structure of electricity. The size of JPS oil expenditures alone, if viewed considering the constant OPEC pressure for price increases, would focus attention on pricing structures which are more closely related to marginal costs than the current pricing structure. Even more concern is generated when this is added to the fact that JPS 1978 revenues of J. $132 million amounted to almost 4 percent of the GNP of Jamaica (J. $3492 million).

Anything which can be done by JPS to reduce oil imports, or to increase the efficiency with which oil is used, will benefit the entire Jamaican economy and the customers of JPS.

8.5.2 General Tariff Principles

This study requires some consideration of the reasons for conducting the analysis. Accordingly, a discussion of the tradition of tariff design, the principles which suggest the use of marginal cost for the design of electric utility tariffs, and some comments on areas where there has been a lack of understanding about the difficulties attendant to implementing marginal cost pricing, are all presented. This discussion, while not limited to Jamaica and its unique and special concerns, is provided to give background information.

The basic forms for pricing electric power were developed at about the turn of the century. While increases in electricity consumption, coupled with improvements in electricity metering technology, have led to some modifications in tariffs, the majority of electricity consumed is still priced according to methods devised by Dr. John Hopkinson in 1892 and Arthur Wright in 1896. These tariffs provided for:

(1) A "customer" component, based (more or less) on the cost of connecting a single customer to the utility network, including service drops, meters, meter-reading, etc.;

(2) A "demand" component, based on the maximum kilowatt demand of the customer during the billing period (usually one month); and

(3) An "energy" component based on the total kilowatt-hours during the billing period.

The customer component consists of a fixed monthly charge. The demand and energy components usually consist of a number of declining steps in which prices for kW or kWh, respectively, decrease in succeeding blocks. Since these tariffs require separate metering of demand and energy, simplified variations of the tariffs are applied to smaller (primarily residential) customers by compressing the demand and energy components into a single rate which likewise consists of a number of declining blocks. For these consumers, the customer component is sometimes included in a single rate and expressed as a relatively high charge for the first few kWh of consumption.

Of interest is the rationale offered for these tariff designs at their inception, which is quite similar to the argument now being advanced to abandon them, at least as they are presently applied. In the early days of the electric power industry, the primary use of electricity was for lighting. To price such usage, a simple flat charge per kWh was adequate. Since all consumers used electricity at essentially the same time, peak and off-peak distinctions simply did not exist. As power usage expanded to other services it was recognized that, to the extent such additional uses could be served by plants which would otherwise be idle, "off-peak" use could be promoted by selling larger volumes of electricity at lower prices. That is, non-lighting uses, to the extent they did not occur simultaneously with lighting uses, could be furnished at basically the cost of the additional fuel consumed. Since utilities served relatively small, homogenous territories, it was not difficult to discern typical or "average" usage patterns. Few consumers used electricity in any pattern significantly different from normal patterns. As service territories and usage patterns expanded, however it became far less useful to speak in terms of "normal" or "average" patterns of electricity use.

Concurrently, industrial use of electricity expanded to the point that it became feasible to increase the sophistication of usage metering beyond the single dimension of total kWh consumption. It became equally as important to know how much electricity was consumed at one time as how much was consumed over a longer period of time, since the size of the utility's generating plant was a function of its maximum demand. Hence, the emergence of maximum demand metering developed in addition to energy metering. The fact that industrial consumers' maximum demand did not occur at precisely the same time was a limitation on the usefulness of the technique, but one that did not matter all that much since usage patterns tended to be similar among the relatively small number of consumers. In addition, metering to measure the coincidence of consumer demands was impracticable. What stands out in these early developments in electricity tariff design is the extent of the effort to have prices reflect the structure of costs of the utility.

Soon, two circumstances combined to diminish concern for the relationship between two patterns of cost to the utility and tariff design. First, because of the monopolistic structure of the electric power industry, greater attention was paid to the overall level of profitability of the companies and relatively less concern was accorded to the design of particular tariffs. Second, technological progress in power supply was very rapid, so that the price of electricity relative to other goods and services declined quite rapidly. Both of these factors tended to make tariff design a subject of lesser importance. As recently as 1973, electric utilities were regularly advised that the price of electricity was still such a small item in the budget of firms and households that tariff structure did not significantly influence consumer demands. Such assertions are now as rare as they once were commonplace.

During the period of concern with overall profitability and with "revenue requirements", the principal consideration in tariff design became the allocation or apportionment of the total revenue requirement among various classes of customers.

The structure of tariffs remained essentially unchanged. What mattered more was the level of the tariffs. That is, how much was the total revenue requirement and how was it apportioned to each class of consumer? Given the resolution of that question, previous tariffs would be raised or lowered, often across the board, but sometimes with modifications in the size of the various "blocks".

Overall profitability, revenue requirements, and the apportionment of these among consumers, remains an important aspect of utility regulation. However, by the early 1970s concern with the design and structure of tariffs re-emerged as a parallel consideration. The reasons for these concerns were, first, that electricity costs increased dramatically as fuel costs increased and technological progress tapered off. Second, there was a heightened perception of the need for conservation of scarce resources of all types. Questions then arose about:

1) Who should bear the increased costs of electricity?

2) What incentives were built into ages-old tariff structures which promoted or thwarted efforts to conserve energy?

Much of the public debate centered around the existing structure of tariffs. Attempts were made to show the virtue of consumers in one "block" while showing the profligate waste of users in other blocks. What emerged from this debate was the awkwardness of the framework within which this discussion was set. Simple empirical distinctions were exceedingly difficult to make between consumers in various tariff blocks on the one hand and their relative rates of consumption, their incomes, or their propensities to conserve energy on the other. Logical distinctions were no less elusive. The convenient correlations of an earlier part of the century were no longer useful as they could not be pushed, stretched or scaled to fit present circumstances.

The confused state of the debate and the complex nature of the problem require a return to first principles. Broadly stated, there is a dual objective in the design of tariffs for electricity, <u>viz</u>. equity and efficiency. One objective is that the costs of producing electricity be equitably apportioned among consumers. Rates must be just, reasonable, and sufficient. The specific means by which this objective is met is by the determination in industrial cases of a total revenue target, which is designed to generate a level of profit equitable to the utility and to the rate payers. (Usually this is expressed as the "revenue requirement".)

This is an unfortunate misstatement of the true objective criterion, which is profitability or rate of return. It is not revenues, per se, which are important, but earnings. Despite the misnomer, the point is generally understood and deserves mention only because of occasional ill-considered statements such as those to the effect that stability of revenues is a desirable end. Stable earnings, which may indeed be desirable, might be completely inconsistent with stable revenues. Having determined a total revenue target, it is then necessary to apportion the total sum among the various classes of consumers to arrive at their respective contributions. The latter step is required only if *a priori* there is some condition which makes it necessary to have class distinctions in the first place. As discussed below, it may be more appropriate to distinguish consumers by the voltage at which they receive service rather than by the usage characteristics of the consumer. In any case, the determination of the aggregate revenue target and its distribution among consumers is the principal means by which the equity objective is met.

A second, equally important objective is the efficient allocation of society's scarce resources among alternative uses.

While the definition and objective of efficiency in the use of resources can be stated abstractly, rigorously, and with mathematical precision, it is not obvious that the task of setting electricity tariffs for JPS is much facilitated by doing so. Indeed, the idea is basically a simple one. To wit:

> We (society) have limited resources to satisfy a multiplicity of needs; and
>
> Resources ought to be channeled to various uses in a way which maximizes the benefits society receives from the use of those resources.

Resources are channeled from one use to another primarily as a response to pricing signals. If the price which a resource will attract in one use is higher than that resource will attract in some other use, resources will tend to flow toward the higher valued use. This is as true of fossil fuels and generating capacity as it is of land, human labor, and other resources.

For the most part, the prices attached to resources reflect the value society attaches to those various uses, and these prices are determined in the marketplace. In the case of some commodities and services, however, unfettered market transactions would not yield prices which could be expected to accurately reflect the value of those resources to society. Two important causes of such distortions are:

1) The absence of competition in certain markets; and

2) The existence of societal concerns which, for any number of reasons, may not be appropriately weighted by individuals acting independently.

Both of these conditions prevail in the case of electricity. In any given service territory there is only one supplier of electricity; there is no competition. In addition, while each of us (i.e., society at large) has an interest in energy conservation, there is no way for us individually to reflect the full benefits or costs of energy usage in independent consumer decisions. We will bear the cost of abrupt energy shortages, for example, not individually, but jointly -- regardless of whether as individuals our behavior contributed to the onset of such shortages or helped to avert them. A critical function of government, therefore, is to regulate when the free market fails to do so.

One task (among many) is to see to it that prices perform the signalling function discussed above. Consumers should have some way of knowing whether it is relatively cheap or relatively expensive to satisfy their demands for electricity. The crux of the task is to see to it that, as consumers make decisions to increase or decrease their consumption of electricity or to alter the pattern of their consumption, those consumers are faced with a tariff structure which reflects the structure of costs to the utility and to society of meeting those demands. This, essentially, is what is encompassed in the economic concept of marginal cost. Marginal cost is simply the cost (or savings) incurred by the utility in providing more (or less) electricity.

The concept of marginal cost itself is a fairly simple one. The process of supplying electricity, however, is rather complicated, in Jamaica and elsewhere. Accordingly, the structure of marginal cost for electricity is also rather complicated. Inevitably, electricity tariffs must not perfectly follow actual marginal costs if tariffs are to perform the function of being price signals. At the same time, a serious effort must be made to reflect the essential characteristics of marginal cost structure in tariffs.

Marginal cost pricing is the first principle for efficient pricing in the regulated as well as non-regulated sectors. The theoretical objective from which this principle flows, the maximization of total social welfare, can be reduced to somewhat less grand terms and recast for present purposes as an objective either to minimize the investment necessary to meet consumer demands for electricity, or to maximize the benefit of electricity given a fixed level of plant investment.

What, then, are the principle features of a tariff which reflects the basic structure of marginal costs? Three characteristics of electricity production dominate the structure of marginal costs. One is heat losses in transmission and distribution. Such losses vary primarily with distance and voltage changes between the points of generation and consumption. Consequently, the voltage at which a consumer receives power is one of the determinants of marginal cost. Second, the size of the physical plant is determined mainly by the expected demand on the system during peak periods (allowance being made for forced outage, maintenance, and reserve requirements). It follows that there are considerable periods, (nights, weekends, and sometimes entire seasons) during which additional energy can be supplied without expanding existing facilities.

Time, therefore, becomes a significant determinant of cost structure in the sense that there are times when additional consumer demand requires the expansion of facilities, and times when additional consumer demand requires little more than an expenditure for fuel (and some maintenance). Finally, electricity production plants vary in the efficiency with which fuel is converted to electrical energy. Efficient operation of the system requires that units with higher operating costs run as infrequently as possible. This, too, imposes a time dimension on marginal costs.

Generally speaking, tariffs which conform to marginal cost structure will have the following characteristics. First, different tariffs will be established for each of the principal voltages at which consumers receive service. This will reflect both the differences in transmission and distribution losses at each voltage level and the fact that some consumers use only a portion of the transmission and distribution network. Second, for service at a particular voltage level, different prices will be established for electricity consumption at various hours, days, and seasons of the year. For example, there may be one price for winter weekdays between 9:00 a.m. and 7:00 p.m., a second price for summer weekday afternoons, and a third price for all other times. These price differentials will reflect the effects of transmission and distribution losses, as well as variations in system operating or fuel costs and system capacity costs for generation, transmission, and distribution. (Additional tariff provisions may be appropriate for larger volume consumers, or for high or low power factors, for example.) It cannot be stressed too much, however, that a particular set of marginal costs and tariffs are relevant only to a given set of expectations about the amount and pattern of additional consumer demand and the given structure of the electric utility in question. The development of data pertaining to marginal costs and consumer response is a continuing process.

The tendency of marginal costs to vary according to time of day and according to peaks and valleys in the demand for electricity often leads to the description of these tariffs as "time-of-day pricing" or "peak load pricing." Both descriptions obviously convey more information than the technically more correct and more precise term "marginal cost pricing." Two reasons suggest that the expression "peak load pricing" may have been a particularly unfortunate simplification. First, marginal costs merely tend to vary with peaks and valleys in utility loads. There are many exceptions. (Present circumstances in Jamaica may be one; more on this follows.) Second, it has sometimes been suggested that even if marginal costs do not correspond to peaks and valleys in loads, prices nonetheless ought to do so. This, it appears, reflects a greater commitment to nomenclature than to good sense. (More will also be said about this for Jamaican circumstances.)

8.5.3. Demand Concepts and Tariff Policy

Knowledge of the demand for electricity is important for the establishment of electricity policy.

First, the level and rate of growth of electricity consumption provide the basis for planning the expansion (system planning) and operation (system dispatching and maintenance) of a modern electrical utility. Second, revenues which must be collected in order to recover previous investment costs must be based upon analysis of current and projected sales. In a period of rapidly rising electricity prices, such as Jamaica is experiencing because of the escalating costs of fuel oil used to produce electricity, the level and pattern of electricity use may be subject to significant change. Indeed, since the first oil embargo in 1973, the demand for electricity has declined in Jamaica. In the past year of dramatic imported oil price increases, electricity sales have declined seven percent in Jamaica. A key to understanding the importance of the demand for electricity in establishing tariffs is the economic concept of price elasticity.

$$\underset{(\%\ TR)}{\text{Percent change in Revenue}} = \underset{(\%\ Q)}{\text{Percent Change in Quantity}} + \underset{(\%\ P)}{\text{Percent Change in Price Total}} \qquad \text{---(1)}$$

This equation states that the percentage change in quantity sold plus the percentage change in price equals the percentage change in total revenue. A cornerstone of consumer demand theory is the notion that the more one consumes of any commodity, the less he will be willing to pay for additional units of it. Economists use a demand function to describe such an inverse relationship between the quantity demanded and its price. Therefore, moving along a demand schedule or function as price increases, quantity demanded will decline and vice versa.

The elasticity of demand is derived from equation (1) as the following:

$$\text{Elasticity} = \frac{\text{Percent Change in Quantity}}{\text{Percent Change in Price}}$$

$$E = \frac{(\%\ Q)}{(\%\ P)}$$

A good that is totally insensitive to price is called perfectly price inelastic and has a zero price elasticity. Changing price would not affect the quantity of the good demanded, but it would affect total revenue. However, the consumption of most commodities is believed to be sensitive to price and a price increase will cause the quantity consumed to decline. Such offsetting effects will determine the new total revenue. In fact, if percentage price increase exceeds the percentage quantity decrease, total revenue will increase, and vice versa for a price decrease.

A situation like this would occur if the price elasticity of demand was inelastic, that is, its value was between 0 and minus one. On the other hand, if the price elasticity of demand had an absolute value greater than unity, then with a price increase a percentage change in price would be more than offset by the percent decline in quantity demanded and total revenue would decline, and vice versa for a price decrease. Table 8-1 summarizes these effects.

TABLE 8-1

THE EFFECT OF PRICE ELASTICITY ON TOTAL REVENUE

Price Elasticity (Absolute Value)	Price Change	Quantity Change	Effect on Total Revenue
Equal 0	increase	no change	increase
	decrease	no change	decrease
Less than 1	increase	decrease	increase
	decrease	increase	decrease
Equals 1	increase	decrease	no change
	decrease	increase	no change
Greater than 1	increase	decrease	decrease
	decrease	increase	increase

If one is concerned about assessing the implication of price increases, whether it be for determining the effect on the quantity consumed or the firm's total revenue, the price elasticity of demand is a most important factor. In the past, electric utilities generally assumed the price elasticity of demand for electricity to be zero. The asymmetry between the effects of a price increase and a price decrease is important in this regard. During a period of price and cost decline, this assumption of zero price elasticity means that expected revenue calculations are underestimated if price elasticity was non-zero, since no adjustments were made for any increase in volume attributable to the price decrease. During the present period of price increases this practice causes a revenue shortfall, puts additional financial strains on the utility, and is likely to cause revenue and earnings erosion. The reason for this is that if price increases cause a reduction in consumption as a non-zero price elasticity would imply, then the company would not earn the revenue requirements previously approved, since the loss in volume attributable to the price increase would not be taken into account.

Tariffs that are designed to collect a previously established revenue target should include a consideration of the effect of price levels, and any increase in them, on the firm's revenue collection. In a period of rapidly increasing prices and government calls for conservation, the most recent usage and sales data available should be used in establishing electricity tariffs. In the studies discussed below, this has been the tariff guide. Further, most comparisons of tariff alternatives for a particular customer category, as discussed below, will be keyed to the same revenue requirement levels.

Another use of price elasticity in tariff design is sometimes suggested; it is called the inverse elasticity rule. While this rule has some advocates, it also has some important limitations.

The proponents of the inverse price elasticity rule suggest that when an electric utility must price its product below its marginal cost, which could occur if its fixed accounting costs are below its future expansion costs, those customers who are least responsive to price (demand inelastic) should receive the greatest discount. Conversely, if prices must be raised, the inverse elasticity rule proponents suggest that the group which is most price insensitive (price inelastic) should pay the largest proportionate increase.

The reason for our less than glowing acceptance of this concept for tariff design has nothing to do with its theoretical virtuosity, but with its practical weakness. There are several important points to be made relating to matters discussed above.

Since electricity is now more expensive in terms of capacity cost than it has been in the past, most people believe that marginal cost pricing will produce revenues which exceed those which are set to recover past investments. Generally, in our experience in marginal cost studies, this has not been the case. The reason for this is, notwithstanding the fact that capacity costs are higher, base load units often produce substantial energy cost savings. To calculate marginal generating cost, such energy savings should be subtracted from the incremental capacity costs. The resultant true measure of marginal generating cost does not necessarily produce revenues which exceed the historic average cost-based revenue requirement levels.

If there is excess revenue within each customer category, it is best to reduce those parts of a multiple part tariff which are least likely to affect the level and pattern of consumer use. It does not make as much sense to base the pattern of reductions on prices paid by consumers on an average customer category-by-customer category basis, which is the essence of the inverse price elasticity rule as it is usually stated. Adjusting tariff structures rather than tariff levels will frequently mean that customer charges or perhaps early block charges will be reduced. These are infra-marginal; that is, they will not affect the level of use for any particular customers.

Finally, there is some theoretical and practical value in the inverse price elasticity rule, if there is a single price for electricity within a particular customer category. The rule itself becomes quite cumbersome and complicated, and far exceeds any current informational possibilities concerning the cross elasticities of demand between various time periods of use, as well as across customer categories. Therefore, the rule becomes quite impossible to apply in practice when tariffs based upon various times of use and voltage differences are considered.

In the Jamaica context, two other considerations reduce the relevance of applying the inverse price elasticity rule to the JPS tariffs. First, we will show that using strict marginal costs for JPS would not generate sufficient revenue. This means that if the JPS elasticity estimates were to be used to adjust marginal cost-based revenues, the least elastic customers would be forced to pay prices based upon a greater differential between cost and selling price. This would usually mean small, low-income residential customers would be forced to help reduce the bills of other customers who are somewhat better able to pay for their escalating electric bills. At a time of dramatically escalating energy prices, and other economic hardships caused by the sharp increase in world oil prices, such a policy would seem to be particularly harsh and extreme. No one in Jamaica would be likely to suggest such a policy. As such, the shortcomings of the inverse price elasticity rule in the Jamaican context is apparent. Additionally, the quantitative estimates for price elasticity for various customer categories in Jamaica, as will be discussed below, do not seem sufficiently at variance with one another to warrant further consideration of the use of the inverse elasticity rule for the design of JPS tariffs.

8.5.4 Price and Income Elasticities of Demand

A knowledge of the responsiveness of electricity consumers to electricity price changes is an important consideration in the process of rate restructuring. The magnitude of the response not only has a direct bearing on the level of the revenues received by the electric utility, but also provides the company with potentially useful information on the demand characteristics of different customer groupings.

In this Section, a description is given of an econometric approach to estimating the price and income elasticities of demand for publicly produced electricity in Jamaica. The methodology selected recognizes that the quantity of electric energy (kWh) consumed is a function of both the quantity of electricity -- using equipment (appliances and machinery) -- and the intensity of the use of such equipment. The central hypothesis, therefore, is that when price and income change, consumers will adjust both their stock of equipment and the intensity of its use. The practical significance of this approach is that it recognizes the inability of consumers to immediately alter their stock of appliances. Therefore, estimates of elasticity are obtained in the short-run (principally, reflecting the change in the intensity with which existing equipment is utilized), and long-run elasticities which accommodate the stock adjustment phenomenon.

The methodology used in this study also takes into account the heterogeneous nature of electricity consumers. As such, separate elasticities are estimated for the following categories of customers.

(1) Residential (Rate 10)
(2) Small Commercial and Industrial (Small C & I - Rates 20 & 40)
(3) Large Commercial and Industrial (Large C & I - Rate 50)
(4) "Other" - mostly street lighting and municipal customers.

The above groupings closely parallel the rate classifications currently in use by the Jamaica Public Service Company Limited (JPS), the sole supplier of publicly produced electric power in Jamaica.

8.5.4.1 Theoretical Background

8.5.4.1.1 Residential Demand for Electricity: The theoretical underpinning of the estimating equation for residential (or household) electricity demand is the well-known utility maximizing construct which forms the basis for much demand theorizing in economics.

According to the utility maximizing formulation, individual households are assumed to try to maximize their satisfaction (utility) from the consumption of goods and services. The extent of this satisfaction is, however, constrained by the size of the household income (the so-called "budget constraint"). This contrained maximization problem can be represented mathematically as:

$$U^i(X^i_1, -----, X^i_n) + \lambda^i \left[I^i - \Sigma^n_j p_j X^i_j \right] \quad ---(1)$$

where U^i is the utility index of the i^{th} household, which is itself a function of the levels of the n goods, X_i's, consumed by the household, I^i is household income, p_j is the price of the j^{th} commodity and λ^i is a LaGrange multiplier.

By manipulating the first-order conditions from equation (1), it can be shown that:

$$X_j = f\,(p_1, p_2, ----, p_n; I) \quad ---------- \quad (2)$$

i.e., the quantity demanded of good i depends on its own price, the price of related goods, and the income level.[1]

Because of the declining block nature of the traditional electricity tariff structure, the marginal price of electricity (which is the theoretically correct price for determining demand) falls as consumption increases.[2] This presents a practical difficulty of identifying a "typical" marginal price for electricity. To circumvent this problem, most applied work in this area uses of the "average" price of electricity instead of the marginal price. One justification for using the average price is that it is indicative of the tariff level, while the marginal price determines tariff shape. Available evidence seems to suggest that it is the level, rather than the shape, of the tariff which influences the demand for electricity.[3]

8.5.4.1.2 Commercial and Industrial Demand: For commercial and industrial consumers of electricity, the behavioral hypothesis differs from that of residential consumers. The hypothesis adopted is grounded in the Theory of the Firm.

In general, two alternate sets of behavioral assumptions can be invoked. First, we can argue that, in an environment where individual firms have no control over the prices of their inputs (such as electricity), the optimal level of inputs purchased by the firm for a given level of output are determined by minimizing a cost function subject to a production function constraint. The first-order conditions yield the following input demand equation:

$$Y_i = f\ (Q,\ P_1,\ \text{-----}\ P_k)\ \text{for } i = 1,\ \text{---},\ k.\text{----}(3)$$

where Y_i is the equilibrium quantity of input i used by the firm, Q is the output of the firm and the P's are the input prices.

An alternate hypothesis is to assume a profit maximization model by the firm determining optimal levels of inputs and outputs. The equilibrium conditions which emerge from such a model are, in fact, input demand equations such as:

$$Y_i = f(P,\ P_1,\ P_2,\ \text{----},\ P_k)\ \text{for } i = 1,\ \text{----},\ k\ \text{----}(4)$$

where P is the price of the commodity produced by the firm and the other variables are as previously defined.

8.5.4.1.3 Street Lighting and Municipal Demand: In many respects, street lighting and municipal demand for electricity is a policy variable, largely dependent on the state of the national economy. As such, there is little theoretical justification which can be ascribed to the variables.

8.5.4.2 Data Collection

Most of the electricity-specific data used to estimate the models were taken from annual reports published by JPS. These included electricity prices, consumption and number of customers. The data related to the national economy such as GDP, price indices, price of other inputs, etc., were gathered either from the National Planning Agency (NPA) or the Department of Statistics.

All prices used are average, annual prices and are deflated by the consumer price index (CPI) on a 1975 base. National income is also deflated by the CPI, and is on a per capita basis.[4]

The data used are time series, ranging from 1963 to 1978, which are displayed by sector in Tables 8-2 through 8-5. The choice of 1963 as the beginning of the series was dictated by the unavailability of values for some of the variables prior to this year.

Data on charcoal and kerosene prices are unpublished. However, it was possible to go back to the work sheets used by the Department of Statistics in computing a fuel price index. These work sheets recorded the average monthly prices of these two fuels over the relevant time period. It was not possible to use the fuel price index published by the Department of Statistics as it was biased by the inclusion of items such as household floor polish.

8.5.4.3 Estimating the Demand Models

The theoretical models described above are all static, i.e. they assume instantaneous adjustments of demand to changes in price. It is argued that the nature of electricity consumption is such that the full adjustment process needs to be spread over a number of periods, i.e. until the stock of electricity-using equipment is adjusted to a new equilibrium. To capture this effect, the demand models were estimated using a geometric lag model of Nerlove type.[5]

In Nerlove's partial adjustment framework, the equilibrium quantity demanded in period t, $\bar{Y}_t$, is given by:

$$\bar{Y}_t = \alpha + \beta X_t + e_t \quad \text{------------} \quad (5)$$

where X_t represents the explanatory variables, e_t is the error term β is the coefficient on the explanatory variable and α the intercept. The X_t's are observable but $\bar{Y}_t$ is not, and thus an estimation problem arises. Nerlove, however, postulates a partial adjustment structure which defines the form of the dynamic lag structure of the model and facilitates estimation. The form of the lag proposed is:

$$\gamma = \frac{Y_t - Y_{t-1}}{\bar{Y} - Y_{t-1}} \quad \text{-------------------} \quad (6)$$

where the numerator defines the actual adjustment that would occur in each time period, while the denominator defines the total adjustment that would take place until the effect of the price change has worn out. γ , therefore, is the proportion of the adjustment which takes place in each time period.

TABLE 8-2

PARAMETER ESTIMATES OF MODELS OF

RESIDENTIAL ELECTRICITY SALES (1963-1978)

MODEL	DEPENDENT VARIABLE	INDEPENDENT VARIABLES*										
	Residential Electricity Consumption	(1) Real Average Charcoal Price	(2) Real Dispos-able National Income Per Capita	(3) Real Residen-tial Average Price of Electricity	(4) Number of Electricity Consumers	(5) Residential Electricicity Consumption in Previous Period	Constant	Adjusted R^2	Durbin-Watson Statistic	Standard Error of Estimate	Adjustment Coefficient (α)	Long Run Price (t) Elasticity
Static		-.15024 (-1.558)	-.42891 (2.868)	-.23282 (-2.560)	1.30656 (21.635)	--- ---	-.11600	.99	1.794	.035		
Dynamic		-.14346 (1.551)	.36166 (1.960)	-.22015 (-2.309)	1.10088 (3.453)	.15102 (0.658)	-.23612	.99	1.998†	.036	.849	.259

*t statistics in parentheses

†Durbin-Watson statistic biased when lagged dependent variable included. Statistic shown only for purposes of comparison.

N.B. All models were estimated in logarithms (natural)

TABLE 8-3

PARAMETER ESTIMATES OF MODELS OF SMALL COMMERCIAL

AND INDUSTRIAL ELECTRICITY SALES (1963-1978)

MODEL	DEPENDENT VARIABLE	INDEPENDENT VARIABLES*										
	Small Commercial & Industrial Electricity Consump.	(1) Real Unit Labor Cost	(2) Real Average Charcoal Price	(3) Number of Small Commercial and Industrial Electricity Consumers	(4) Real Small Commercial & Industrial Average Price of Electricity	(5) Small Commercial and Industrial Elect. Consumption in Previous Period	Constant	Adjusted R^2	Durbin-Watson Statistic	Standard Error of Estimate	Adjustment Coefficient (α)	Long Run Price (t) Elasticity
STATIC		.07001 (.546)	-.35134 (-2.740)	2.28494 (14.941)	-.32892 (-4.320)	---	-13.14038	.99	1.928	.044	---	
DYNAMIC		.01677 (0.142)	-.16352 (-1.087)	1.09239 (1.727)	-.21093 (-2.304)	.48543 (1.931)	-6.24903	.99	2.354+	.039	.515	.410

*t statistics in parentheses.

+Durbin-Watson statistic biased when lagged dependent variable included. Statistic shown only for purposes of comparison.

N.B. All models were estimated in logarithms (natural).

TABLE 8-4

PARAMETER ESTIMATES OF MODELS OF LARGE

COMMERCIAL AND INDUSTRIAL ELECTRICITY SALES (1963-1978)

MODEL	DEPENDENT VARIABLE	INDEPENDENT VARIABLES*										
	Large Commercial & Industrial Electricity Consumption	(1) Real Unit Labor Cost	(2) Real Large Commercial & Industrial Average Price of Electricity	(3) Number of Large Commercial and Industrial Electricity Consumers	(4) Dummy Variable	(5) Large Commercial and Industrial Elect. Consumption in Previous Period	Constant	Adjusted R^2	Durbin-Watson Statistic	Standard Error of Estimate	Adjustment Coefficient (λ)	Long Run Price (t) Elasticity
STATIC		.43248 (3.137)	-.24936 (-2.315)	.75142 (9.514)	.06583 (.893)	--- ---	9.40566	.97	1.890	.056	---	---
DYNAMIC		.27567 (1.876)	-.19783 (-1.984)	.55439 (4.502)	.05108 (.772)	.24984 (1.951)	6.81069	.97	2.756+	.050	.750	.264

*t statistics in parentheses.

+Durbin-Watson statistic biased when lagged dependent variable included. Statistic shown only for purposes of comparison.

N.B. All models were estimated in logarithms (natural).

TABLE 8-5

PARAMETER ESTIMATES OF MODELS OF "OTHER" ELECTRICITY SALES (1963-1978)

MODEL	DEPENDENT VARIABLES	INDEPENDENT VARIABLES*									
	"Other" Electricity Consumption	(1) Real "Other" Average Price of Electricity	(2) Number of "Other" Electricity Consumers	(3) Real Gross Domestic Product	(4) "Other" Electricity Consumption in Previous Period	Constant	Adjusted R^2	Durbin-Watson Statistic	Standard Error of Estimate	Adjustment Coefficient (α)	Long Run Price (t) Elasticity
STATIC		.60970 (6.302)	.55151 (11.662)	1.02513 (5.336)	--- ---	8.96993	.99	2.527	.07529	---	---
DYNAMIC		.65670	.58366	1.11863	-.06403	9.53571	.99	2.442†	.078	---	---

*t statistics in parentheses.

†Durbin-Watson statistic biased when lagged dependent variable included. Statistic shown only for purposes of comparison.

N.B. All models were estimated in logarithms (natural).

To obtain an estimable form of equation (5), we can rewrite equation (6) as follows:

$$\gamma(\bar{Y}_t - Y_{t-1}) = Y_t - Y_{t-1} \text{ ------------ } (7)$$

Now substituting equation (5) into (7) we get:

$$\gamma(\alpha + \beta X_t + e_t - Y_{t-1}) = Y_t - Y_{t-1} \text{ ------ } (8)$$

which can be rewritten as:

$$Y_t = \alpha\gamma + \beta\gamma X_t + (1 - \gamma) Y_{t-1} + \gamma e_t \text{ --} (9)$$

or as:

$$Y_t = \Pi_0 + \Pi_1 X_t + \Pi_2 Y_{t-1} + \omega_t \text{ ------------ } (10)$$

Equation (10) can be estimated with time-series data. An estimate of Π_2, i.e., the coefficient on the lagged dependent variable also yields an estimate of γ, the adjustment coefficient, since -

$$\Pi_2 = 1 - \gamma \text{ ------------------------------------ } (11)$$

therefore -

$$\gamma = 1 - \Pi_2 \text{ --------------------------------- } (12)$$

With an estimate of γ, it is, in turn, possible to get estimates of α and β in (5), by way of Π_0 and Π_1.

The coefficients in both (5) and (10) have interesting interpretations. If X_t is price, Π can be interpreted as the short-run price elasticity of demand while β is the long price elasticity of demand if the equations are estimated in logs. A similar interpretation would apply to the coefficient on an income variable in the equation.

The magnitude of γ, the adjustment coefficient, permits an evaluation of the length of time over which consumers will adjust their use of electricity in response to a price change.

A static and dynamic (i.e., a distributed lag model) version of the models was estimated for each of the categories of electricity customers. All models were estimated using the ordinary least squares (OLS) estimator. From a statistical standpoint, OLS should produce consistent estimates of π's in equation (10) if the error term in (5), e_t, has the classical properties.[6] This follows from the fact that ω_t is simply e_t multiplied by a constant, γ.

It should also be pointed out that a problem which plagues models of this nature is the degree of multi-collinearity among the regressors, mainly because of the presence of the lagged dependent variable on the right-hand side of the equation.

Another disconcerting aspect of estimating partial adjustment models is the fairly frequent occurrence of a coefficient on the lagged dependent variable which is close to 1. From equation (12), this implies a very small value for, γ, which suggests that only a very small proportion of the adjustment takes place in each period, implying further that the adjustment process will be drawn out over a very long time period.

Although economic theory suggests the main explanatory variables which should be included in the models, additional variables which capture the peculiar aspects of the environment being modelled must be included. In all the models a dummy variable was included to try to capture the effect of a conservationist mood which developed in Jamaica as a result of the inordinate increases in the price of electricity in the post-1973 period. This dummy variable, however, proved to be successful (in the sense that it improved the statistical fit of the data) only in the models for Large C & I customers.

8.5.4.4 Evaluation of Results

From a purely statistical point of view, the models fit the historical data remarkably well. Adjusted coefficients of determination, $\bar{R}^2$, (adjusted for degrees of freedom) ranged from .97 to .99. As can be seen in Figures 8-1 through 8-4, the models tracked the historical data, missing an occasional turning point mainly in the post-1973 period.

In both residential models (see Table 8-2), all variables, except for lagged consumption, are significant at least at the 10 percent level. The expected negative sign on the price variable obtains, while the negative sign on the charcoal price variable suggests, a complementary relationship

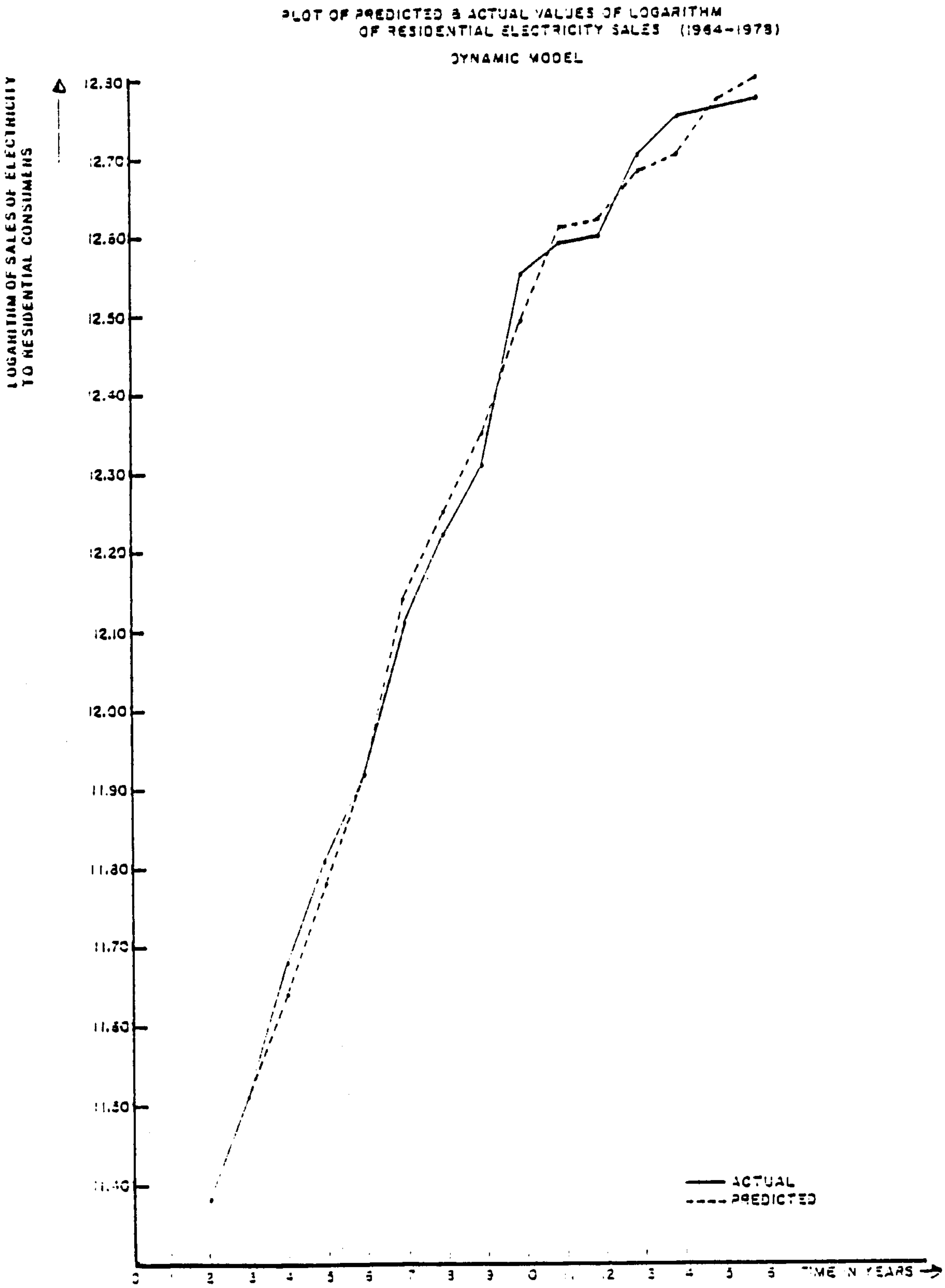
PLOT OF PREDICTED & ACTUAL VALUES OF LOGARITHM
OF RESIDENTIAL ELECTRICITY SALES (1964-1978)
DYNAMIC MODEL
LOGARITHM OF SALES OF ELECTRICITY
TO RESIDENTIAL CONSUMERS
12.80
12.70
12.60
12.50
12.40
12.30
12.20
12.10
12.00
11.90
11.80
11.70
11.60
11.50
11.40
ACTUAL
PREDICTED
TIME IN YEARS

FIGURE 8-1

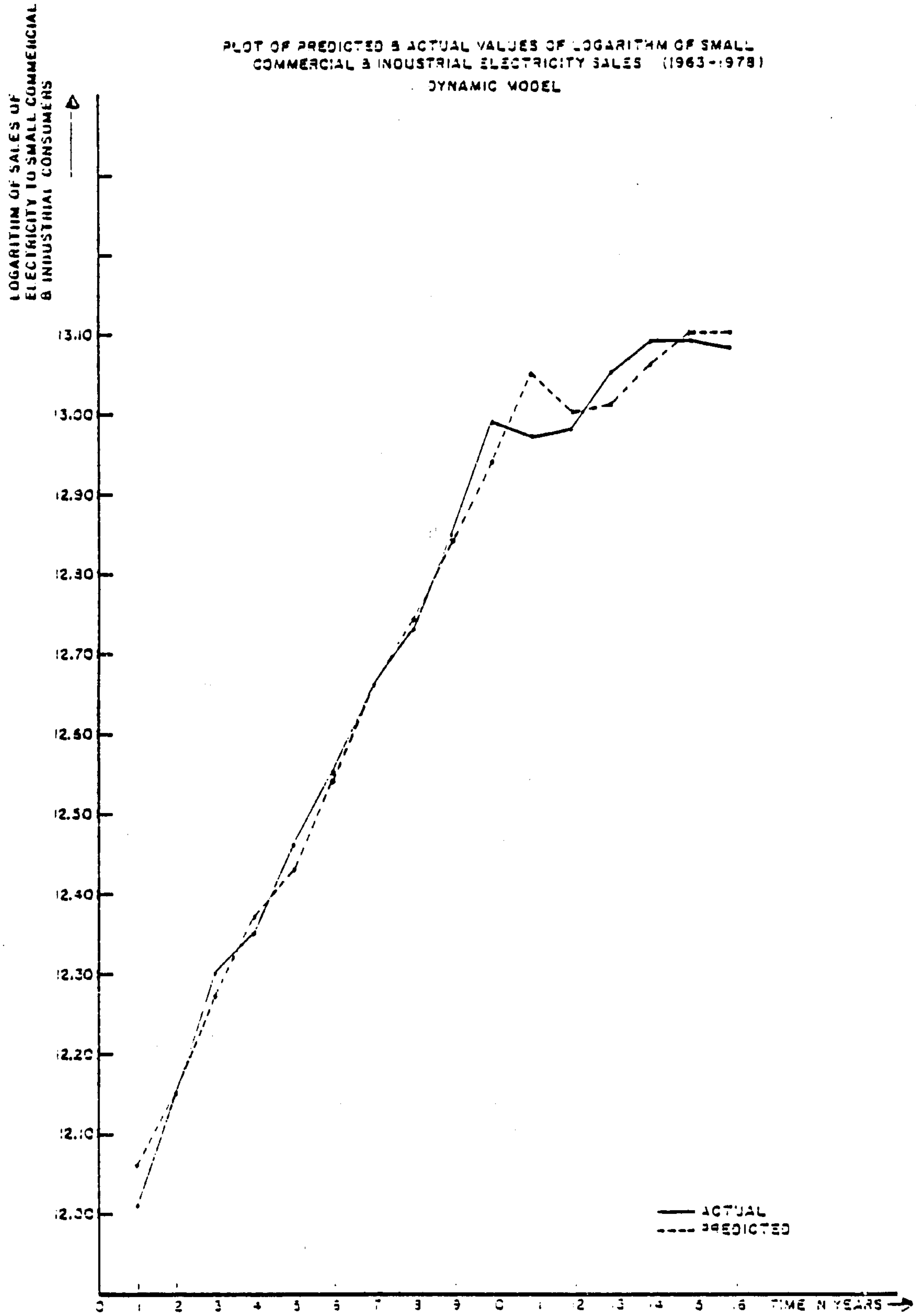
PLOT OF PREDICTED & ACTUAL VALUES OF LOGARITHM OF SMALL
COMMERCIAL & INDUSTRIAL ELECTRICITY SALES (1963-1978)
DYNAMIC MODEL
LOGARITHM OF SALES OF ELECTRICITY TO SMALL COMMERCIAL & INDUSTRIAL CONSUMERS
13.10
13.00
12.90
12.80
12.70
12.60
12.50
12.40
12.30
12.20
12.10
12.00
ACTUAL
PREDICTED
TIME IN YEARS

FIGURE 8-2

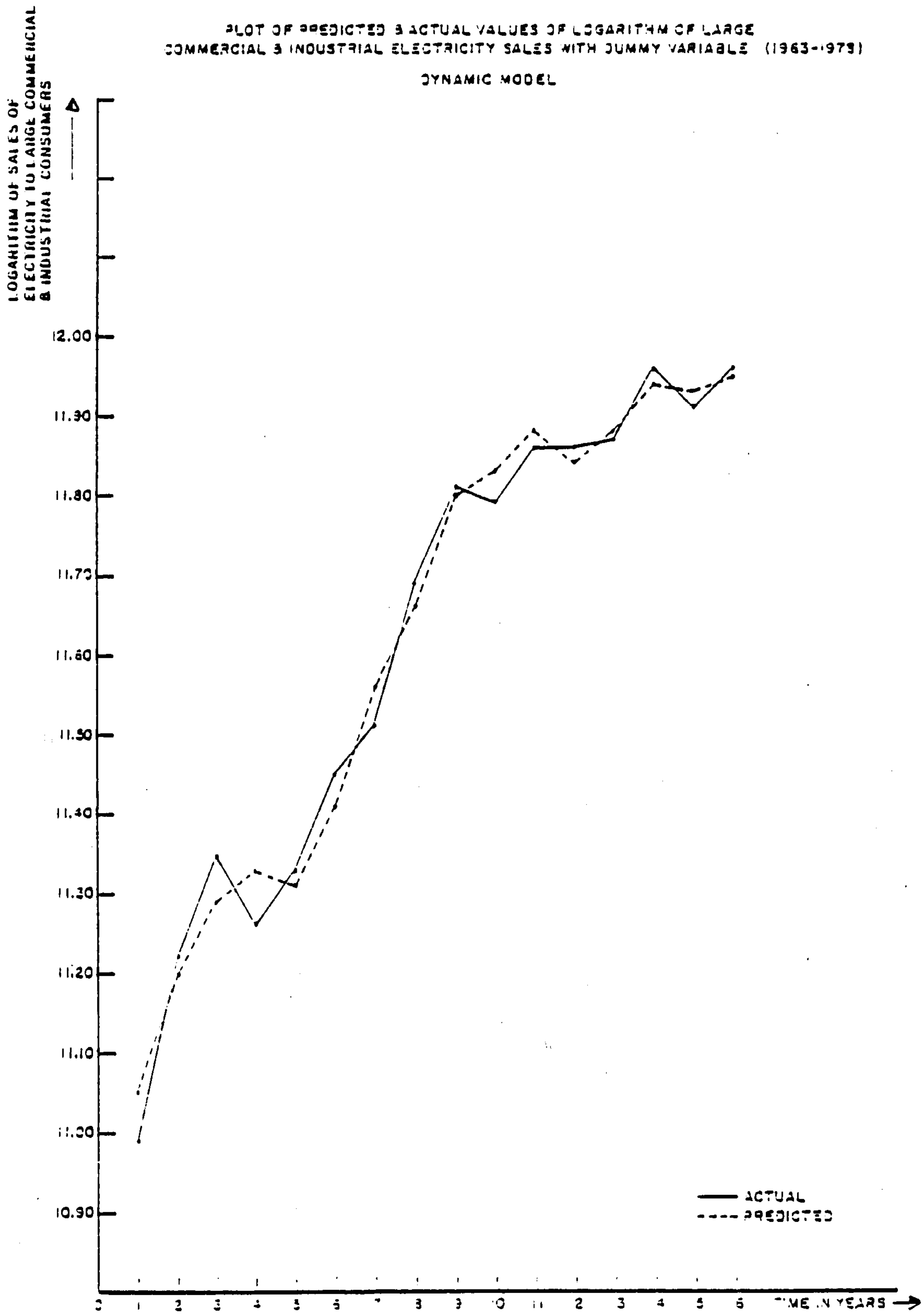
PLOT OF PREDICTED & ACTUAL VALUES OF LOGARITHM OF LARGE
COMMERCIAL & INDUSTRIAL ELECTRICITY SALES WITH DUMMY VARIABLE (1963-1979)
DYNAMIC MODEL
LOGARITHM OF SALES OF ELECTRICITY TO LARGE COMMERCIAL & INDUSTRIAL CONSUMERS
12.00
11.90
11.80
11.70
11.60
11.50
11.40
11.30
11.20
11.10
11.00
10.90
ACTUAL
PREDICTED
TIME IN YEARS

FIGURE 8-3

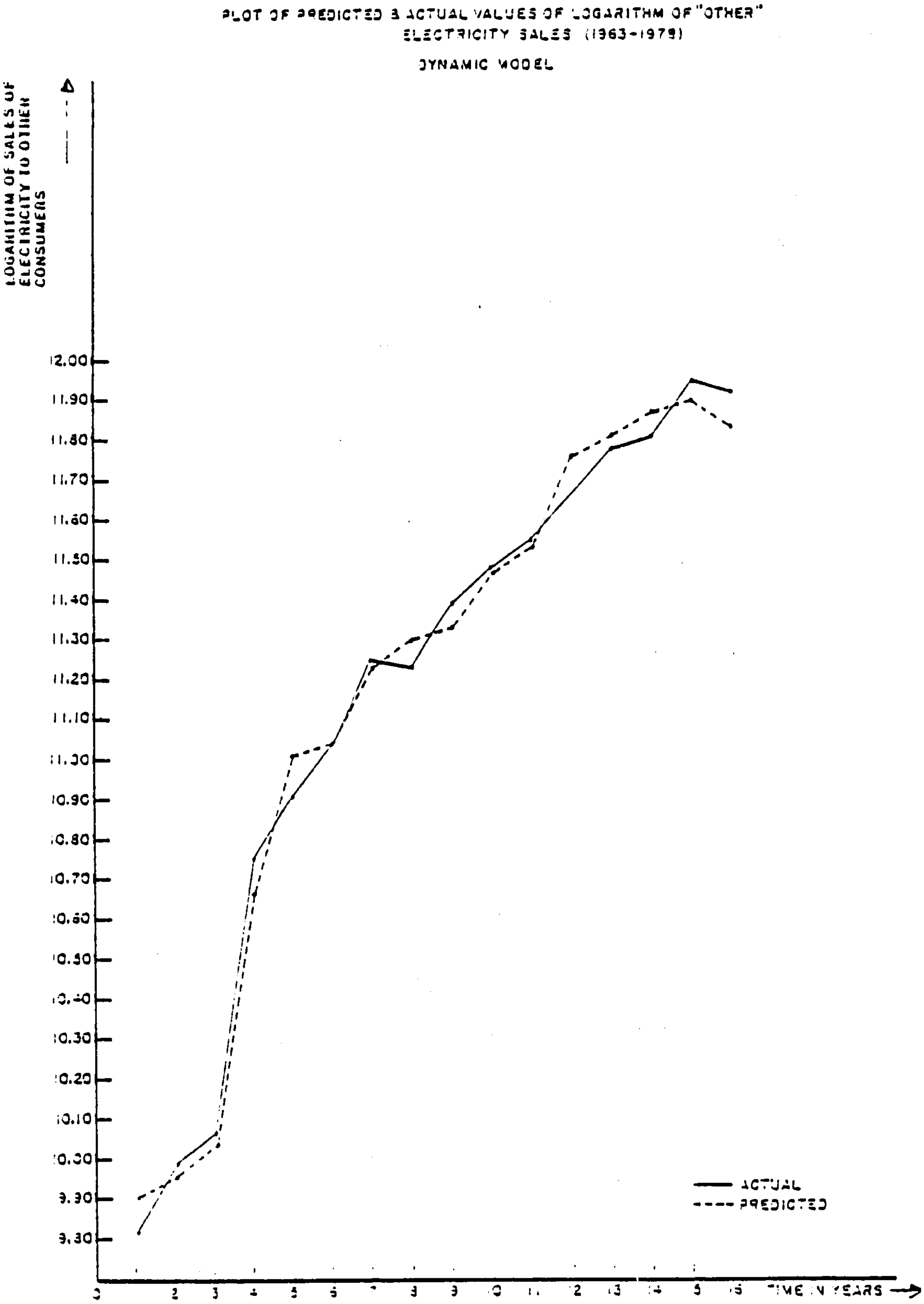
PLOT OF PREDICTED & ACTUAL VALUES OF LOGARITHM OF "OTHER" ELECTRICITY SALES (1963-1979)
DYNAMIC MODEL
LOGARITHM OF SALES OF ELECTRICITY TO OTHER CONSUMERS
12.00
11.90
11.80
11.70
11.60
11.50
11.40
11.30
11.20
11.10
TIME IN YEARS
ACTUAL
PREDICTED

FIGURE 8-4

between electricity and charcoal. It is clear that charcoal and kerosene are not substitutes for most electricity consumers in Jamaica. Charcoal and kerosene are the principal fuels of the poorer classes (who would not consume electricity) while the average electricity user would tend to use charcoal mainly for barbecues and emergencies.

Autocorrelation does not present a serious problem in the residential electricity models and the coefficient of adjustment, γ , is of a reasonable magnitude. The size of γ indicates that the adjustment to a price change would be complete after three years for residential consumers.

The length of adjustment is calculated as follows:

Time Period (Yrs.)	Proportion of Adjustment	Cumulative Adjustment
1	.85	.85
2	.13*	.98
3	.02	1.00

*.13 = .85 (1-.85) where (1-.85) is the amount of adjustment remaining after the 1st period.

Demand in price inelasticity in the short- and the long-run is -.14 and -.26 respectively. One would expect the long-run coefficient to be more elastic than that in the short-run since consumers have an opportunity to make stock adjustments following price changes.

For the Small C & I models, the real unit labor cost was included as an explanatory variable on theoretical grounds even though it was statistically insignificant in both models. Demand is again inelastic, although less so than is the case with the residential models. Elasticity in the short-run is estimated to be -.21 (in the dynamic model) while it is -.41 in the long-run. All models are estimated in logs so that

$$\partial \ln Y_i / \partial \ln P_i = (\partial Y_i / \partial P_i)(P_i / Y_i)$$

which is the price elasticity.

In adjusting to price changes, the length of the lag is estimated to be about seven years (about 99.5% of the adjustment is complete) for the Small C & I models. This is symptomatic of the scarcity of short-term options available to small enterprises in the face of rising electricity prices.

The results of the Large C & I models are not much different than those already described. Demand for electricity is price inelastic both in the short- and the long-run. The short-run coefficient is -.20 and the long-run coefficient is -.26. In both the static and dynamic models, a dummy variable -- denoting the conservation effect of the post-oil embargo period -- improved the fit of the models to the data, even though the coefficients of these variables are statistically insignificant. All other variables in both models are significant at least at the 10 percent level.

The length of the lag for the Large C & I model is approximately five years. Table 8-6 summarizes the long- and short-run elasticities for all the models, including the length of the lag.

Table 8-6

Summary of estimated Long- and Short-Run Price Elasticities of Demand and Length of Lag for Electricity by Customer Category

Models	Elasticities		Length of Lag (Years)
	Short-Run	Long-Run	
1. Residential	-.22	-.26	3
2. Small C & I	-.21	-.410	7
3. Large C & I	-.20	-.26	5
4. Other	-	-	-

Although the models for the "Other" category of electricity consumption had impressive adjusted R^2's (.99) and tracked the data reasonably well, a theoretically perverse sign, (+), was obtained on the coefficient of the price variable. Because of this problem it is not possible to place considerable confidence in the estimates. As such, the statistical results are reported, but no attempt is made to compute the long-run price elasticity or to determine the length of the lag.

8.5.4.5 Summary and Conclusions of Background Data
The demand for electricity supplied by the JPS is inelastic with respect to price for all categories of electricity customers. In no case, however, is

the demand perfectly inelastic, so that a price change will elicit a less than proportionate and opposite response in terms of the number of kWh's consumed.

In the short-run, all the elasticity coefficients are remarkably similar in magnitude, ranging from -.20 to -.22. In the long-run, two of the elasticities are identical (-.26, for Residential and Large C & I customers), but for Small C & I it is -.41.

The most rapid overall response to a price change will come from Residential customers, who, it is estimated, will complete their adjustment in three years. Large C & I and Small C & I customers require an adjustment period of five years and seven years, respectively.

The first policy conclusion which can be drawn from this analysis is that the revenue position of the JPS would not be seriously jeopardized should a rate restructuring necessitate increases in the real average price of electricity. This is true both in general, and for each of the individual customer categories. The significance of this conclusion is that a rate restructuring exercise can proceed without undue fear of eroding the product utility's financial integrity. The second policy conclusion, already noted in Section 8.4.2, is that the near equivalence of price elasticity across customer categories makes any application of the inverse elasticity rule a needless exercise.

8.5.5 Marginal Costs

There are multiple reasons why a marginal cost analysis might be undertaken. One may be to determine the advisability of an investment, such as an investment in equipment to reduce electrical losses in transmission. Another may be to provide reference points for electricity tariffs, there being an argument that prices which reflect marginal costs are better than those which do not; the premise is that marginal costs should be used as benchmarks in devising tariffs. Because of special circumstances existing in this case, a brief discussion of some broad principles is in order before proceeding to the details of the JPS system.

The marginal costs of electricity supply may be broadly characterized as those relating to the capacity of an expanding system and those relating to running a given system. Marginal capacity costs, including both generation and reticulation, are usually approached from the standpoint of achieving or maintaining a desired level of reliability. Reliability in this context refers to a generally high probability that consumer demands for electricity at a given time will be met. Marginal running costs are determined by estimating the costs of operating a given system more or less intensively. This analysis framework has been widely employed for some time. It is, in fact, the approach which was used in the present case.

It should be pointed out from the beginning that such an approach is a special case of marginal costs; that is, marginal costs as measured by the effect of changes in consumer demand on the supplying electric utility. The more general case is that which measures the societal effect of changes in consumer demand for electricity. In this case, marginal costs are measured either by the value of resources which are given up (foreclosed from some alternative use) in order to produce electricity, or by the cost to society of doing without electricity under given circumstances; this is called the "shortage cost".

Shortage cost, however, is not very often used as a measure of marginal costs for two reasons. First, it is virtually impossible to measure with any confidence. Second, actual shortages in the more heavily industrialized countries are extremely rare. Consequently, the focus is most frequently on the costs to provide and run an expanding utility system. It is important to note that these alternative ways of viewing marginal costs may produce different results. Since our premise has to do with marginal costs and pricing, it is useful to consider the implications of each case for the development of pricing criteria.

In instances where increases in consumer demand are met by expanding supply, marginal cost is the cost of expansion. In cases where increasing consumer demand eventually cannot be met, then marginal is whatever is necessary to alleviate the shortage. The concomitant pricing rule is to set the price of electricity at that level which restrains demand to available supply.

The relevance of the preceding discussion arises from an anomalous situation of electricity supply in Jamaica. The JPS system has installed capacity considerably in excess of maximum demand. At the same time, the incidence of "rolling blackouts" and unscheduled outages is far higher than is deemed desirable. Although the former usually eliminates the latter, the fact is that a significant amount of the installed capacity is not presently operable. The importance of this consideration in formulating tariffs depends upon how long that capacity will continue to be unavailable; it is a matter of expectations. JPS's expectation is that the shortage of available capacity will be alleviated in the near future. Nonetheless, the recent frequency and persistence of outages warrants some mention of marginal costs and consistent pricing criteria under such circumstances.

When outages occur because consumer demand has risen beyond the capacity of the utility, the costs are borne directly by consumers instead of by the utility. At such times, concentration on matters such as the costs associated with building additional power plants is misdirected. Neither relevant marginal costs nor prices have little impact if the nexus between tariffs and marginal costs is being maintained. Beyond the fact that the outage situation is believed to be transitory (unlike tariffs), imposing marginal-costs-as-prices under these circumstances may be beyond the limits of the acceptability of pricing schemes or rationing devices. The consequences of rationing-by-the-purse may be intolerably harsh on some consumers. Additionally, because electricity is so pervasive a service in the economy, a more even distribution of the consequences of excess demand may be deemed appropriate. The point is that the means of rationing is as much a matter of social policy as it is economics. While marginal cost considerations alone may imply significant variations in price between periods of relatively high and relatively slack demand, this conclusion is tempered by social policy factors as well as the expected change in capacity availability.

For the above reasons, the approach to marginal costs used in this analysis was based on the direct effects of variations in consumer demand upon the JPS system.

8.5.5.1 Marginal Generation and Reticulation Capacity Costs

These costs are those which the system incurs when consumer demand increases to the point that, in order to maintain a desired level of reliability, provisions must be made for the addition of new generating capacity and/or transmission facilities. This may be provided either by the purchase of new equipment or by accelerating an already contemplated plan of expansion. In either case, the additional facilities must take into account that they not only provide additional capacity, but may also increase the overall level of operating efficiency of the system. The amount of such gains in operating efficiency reduces the cost of the additional capacity, and may even be sufficient to reduce the cost to zero.

As shown in Table 8-7, the total installed generation capacity of the JPS system is about 487 MW. There are no present plans to add more generating capacity; as shown in Table 8-8, there will be excess generation capacity until the 1990's. Since system generating capacity exceeds anticipated demand throughout the forecast period, the effective marginal cost is zero.

A similar conclusion applies with respect to reticulation capacity, although for different reasons. Marginal transmission and distribution (T & D) capacity costs may in most instances be estimated by determining the relationship between changes in consumer demand and in the length of conductors or transformer capacity of T & D facilities. In the JPS case, however, the vast bulk of contemplated additions to the network consists of the installation of a 155 mile, 138 KV backbone system with associated interbus and step-down transformers, which is being installed irrespective of the level of consumer demand. The only other transmission capacity contemplated is 51 miles of 69 KV circuit in 1980, which will complete an island loop. These facilities, which apply more to extension of the bulk transmission system than to consumer demand, do not constitute marginal transmission capacity cost, which therefore is also zero. Similarly, there is a rural electrification program and a program of assistance to households for initial connections underway; these are also unrelated to the level of demand.

It should be noted that two elements of a typical marginal cost structure do not apply to the JPS system. It should also be noted that these two elements (generation and reticulation capacity) are the main source of variation in marginal costs at different times of day, hence the main impetus for time-of-day pricing of electricity.

8.5.5.2 <u>Marginal Running Costs</u>

As noted, marginal running costs are those associated with operating a given system more or less intensively. These costs will continuously vary with the level of consumer demand and the availability of generating capacity. In more capital-intensive systems with large amounts of fuel-efficient nuclear, coal or hydro capacity, there tends to be considerable relative variation. In more

TABLE 8-7

TOTAL SYSTEM GENERATION CAPACITY

Unit		Type	Capacity (normal C.N.R.)
Hunts Bay	1	Steam	10
	2	"	10
	3	"	15
	4	"	15
	5	"	20
	6	"	68.5
Old Harbor	1	"	30
	2	"	60
	3	"	68.5
	4	"	68.5
Gas Turbines (5)		Gas	86
Diesels		Diesel	20.4
Hydros		----	15
TOTAL			486.9

Source: JPS, 11/79

TABLE 8-8

FORECAST DEMAND AND SUPPLY CAPACITY

Year	Peak Demand (MW)	Surplus (Table 8-7 total less column 2)	%
1979	233	254	109
1980	233	254	109
1981	235	252	107
1982	240	247	103
1983	246	241	98
1984	247	240	97
1985	248	239	96
1986	257	230	89
1987	263	224	85
1988	270	217	80
1989	283	204	72
990	292	195	67
1991	304	183	60

Note: Percent reserve margins as reliability criteria must be interpreted differently for island environments than similar levels for continental areas, owing to the absence of interconnecting systems.

Source: JPS, 11/79

fuel-intensive systems such as JPS, the relative variation is less, owing to smaller differences in the efficiency with which fuel is converted to electricity in the various units of essentially similar type.

In order to estimate both the level of marginal running costs and the degree of variability, an economic dispatch program shown in Table 8-9A was run for a number of cases representing various combinations of load and equipment availability. From the thirty-five simulations run, it became clear that there is a greater difference in marginal running cost depending on the level of demand and the equipment used. The pattern of variation, although considerably less than that usually found in North America, was still significart. The results of five selected simulations are shown in Tables 8-9A through 8-9F. Each case represents a typical weekday with three levels of demand represented, using current fuel prices at each unit. The array of equipment dispatched to meet load distinguishes each case, which represents an optional dispatch for the given assumption, as shown in Table 8-9A. Case 1 represents an ideal situation under current circumstances. Cases 2 and 3 are simply efforts to seriously disrupt the system. Cases 4 and 5 were randomly chosen from availability logs within the past several months to represent recent "real" cases.

The most significant figures are those identified as "specific production costs" ($/mWh). They range from the mid-fifties for the ideal (first) case to the upper seventies and eighties for the fifth ("real") case. Although these figures are only suggestive of what may occur on a given near-term future day, they also suggest what will happen as consumer demand increases over time. Given the repair and return to service of the more efficient units, marginal running costs during periods of slack demand will approach those of Case 1. During periods of relatively high demand, however, the less efficient plants, including the gas turbines and diesel facilities, will be required; costs therefore tend toward those of Cases 3 and 5. Again, these values are only suggestive only of <u>relative</u> magnitudes of marginal running cost and would require adjustment for availability and demand conditions, as well as contemporary fuel prices.

Transmission and distribution losses increase with the square of load, times resistance. It is usually advisable to examine the effect on marginal costs of losses at different voltage levels. In the present case, analysis of losses indicated negligible differences between primary and secondary

TABLE 8-9A

ECONOMIC DISPATCH SIMULATIONS

	Assumptions	
Case 1	All equipment available to meet load; no "must run" equipment	
	Forced outage of	**"Must run"**
Case 2	Hunts Bay 1 & 2 Old Harbor 4	None
Case 3	- As above -	Gas turbines 2,3,4
Case 4	As above, plus Hunts Bay 4 Old Harbor 2 Gas turbines 1 & 5 All diesels All hydros	None
Case 5	Hunts Bay 1,2,6 Old Harbor 3 Gas turbines 1 & 4 All diesels All hydros	None

Summary of Results: Specific Production Cost, System

Demand Level:	Off-Peak	Shoulder ($ MWH)	On-Peak
Case 1	53.87	56.76	57.03
Case 2	57.40	57.85	60.96
Case 3	81.40	79.52	76.22
Case 4	60.99	61.60	63.04
Case 5	78.16	82.97	86.29

TABLE 8-9B
CASE NUMBER 1

GENERATOR LOADING TABLE

GENERATING UNIT INDEX	STATION	NO.	AVAIL. CAP. (MW)	*	151.0	182.0	215.0
1	HUNTS BAY A	1	10.0	*	0.0	0.0	0.0
2	HUNTS BAY A	2	9.5	*	0.0	0.0	0.0
3	HUNTS BAY A	3	11.0	*	0.0	0.0	0.0
4	HUNTS BAY A	4	11.0	*	0.0	0.0	0.0
5	HUNTS BAY A	5	18.0	*	0.0	0.0	0.0
				*			
6	HUNTS BAY B	6	58.5	*	48.1	51.0	53.5
				*			
7	OLD HARBOUR	1	27.0	*	0.0	0.0	0.0
8	OLD HARBOUR	2	45.0	*	0.0	22.9	30.5
9	OLD HARBOUR	3	50.0	*	43.4	48.8	50.0
10	OLD HARBOUR	4	55.0	*	44.5	47.4	55.0
				*			
11	HUNTS BAY, GT	1	13.0	*	0.0	0.0	0.0
12	HUNTS BAY, GT	2	15.0	*	0.0	0.0	0.0
13	HUNTS BAY, GT	4	20.0	*	0.0	0.0	0.0
14	HUNTS BAY, GT	5	20.0	*	0.0	0.0	0.0
				*			
15	EOGLE, GT	3	20.0	*	0.0	0.0	0.0
				*			
16	DIESEL GENS.	0	10.0	*	0.0	0.0	0.0
				*			
17	HYDRO GENERS	0	15.0	*	15.0	15.0	15.0
				*			

TOTAL NET OUTPUT (MEGAWATTS)	151.0	183.2	214.0
TTL. NET SPINNING CAPACITY (MW)	188.5	233.5	233.5
TOTAL SPINNING RESERVE (MW)	37.5	50.3	19.5
TOTAL HOURLY COST, FUEL ($/MW)	$134.34	*****	*****
SPECIFIC PRODUCTION COST ($/MW)	53.87	56.76	57.03
SYSTE, INCREMENTAL COST ($/MW)	55.04	56.34	61.85

TABLE 8-9C

CASE NUMBER 2

GENERATOR LOADING TABLE

GENERATING UNIT INDEX	STATION	NO.	AVAIL. CAF. (MW)	*	151.0	182.0	215.0
1	HUNTS BAY A	1	0.0	*	0.0	0.0	0.0
2	HUNTS BAY A	2	0.0	*	0.0	0.0	0.0
3	HUNTS BAY A	3	11.0	*	0.0	0.0	6.9
4	HUNTS BAY A	4	11.0	*	0.0	0.0	0.0
5	HUNTS BAY A	5	18.4	*	0.0	0.0	17.6
6	HUNTS BAY B	6	65.5	*	52.5	67.4	
7	OLD HARBOUR	1	27.0	*	11.2	15.5	18.3
8	OLD HARBOUR	2	45.0	*	33.8	32.9	38.7
9	OLD HARBOUR	3	50.0	*	48.6	50.0	30.0
10	OLD HARBOUR	4	0.0	*	0.0	0.0	0.0
11	HUNTS BAY, GT	1	13.0	*	0.0	0.0	0.0
12	HUNTS BAY, GT	2	15.0	*	0.0	0.0	0.0
13	HUNTS BAY, GT	4	20.0	*	0.0	0.0	0.0
14	HUNTS BAY, GT	5	20.0	*	0.0	0.0	0.0
15	EOGLE, GT	3	20.0	*	0.0	0.0	0.0
16	DIESEL GENS.	0	10.0	*	0.0	0.0	0.0
17	HYDRO GENERS	0	15.0	*	15.0	15.0	15.0

	151.0	182.0	215.0
TOTAL NET OUTPUT (MEGAWATTS)	151.1	180.8	215.0
TOTAL NET SPINNING CAPACITY (MW)	205.5	205.5	234.5
TOTAL SPINNING RESERVE (MW)	84.4	24.7	19.5
TOTAL HOURLY COST, FUEL ($/H)	6670.86	***********	
SPECIFIC PRODUCTION COST ($/MWH)	57.40	57.86	60.98
SYSTEM INCREMENTAL COST ($/MWH)	66.98	63.57	67.72

TABLE 8-9D

Case Number 3

GENERATOR LOADING TABLE

GENERATING UNIT			AVAIL.				
INDEX	STATION	NO.	CAF. (MW)	*	151.0	182.0	215.0
1	HUNTS BAY A	1	0.0	*	0.0	0.0	0.0
2	HUNTS BAY A	2	0.0	*	0.0	0.0	0.0
3	HUNTS BAY A	3	11.0	*	0.0	0.0	0.0
4	HUNTS BAY A	4	11.0	*	0.0	0.0	0.0
5	HUNTS BAY A	5	18.0	*	0.0	0.0	0.0
6	HUNTS BAY B	6	66.5	*	43.3	47.9	64.1
7	OLD HARBOUR	1	27.0	*	0.0	0.0	0.0
8	OLD HARBOUR	2	45.0	*	0.0	21.0	30.9
9	OLD HARBOUR	3	50.0	*	37.7	43.1	50.0
10	OLD HARBOUR	4	0.0	*	0.0	0.0	0.0
11	HUNTS BAY, GT	1	13.0	*	0.0	0.0	0.0
12	HUNTS BAY, GT	2	15.0	*	15.0	15.0	15.0
13	HUNTS BAY, GT	4	20.0	*	20.0	20.0	20.0
14	HUNTS BAY, GT	5	20.0	*	0.0	0.0	0.0
15	EOGLE, GT	3	30.0	*	20.0	20.0	20.0
16	DIESEL GENS.	0	10.0	*	0.0	0.0	0.0
17	HYDRO GENERS	0	15.0	*	15.0	15.0	15.0
TOTAL NET OUTPUT (MEGAWATTS)					151.0	132.0	215.0
TOTAL NET SPINNING CAPACITY (MW)					188.5	233.3	233.3
TOTAL SPINNING RESERVE (MW)					37.5	51.5	18.5
TOTAL HOURLY COST ($/H)					******	******	*******
SPECIFIC REDUCTION COST ($/M&H)					81.40	79.82	76.22
SYSTEM INCREMENTAL COST ($/M&H)					52.92	54.95	62.12

TABLE 8-9E

CASE NUMBER 4

GENERATOR LOADING TABLE

GENERATING UNIT			AVAIL.				
INDEX	STATION	NO.	CAP. (MW)	*	151.0	182.0	215.0
1	HUNTS BAY A	1	0.0	*	0.0	0.0	0.0
2	HUNTS BAY A	2	0.0	*	0.0	0.0	0.0
3	HUNTS BAY A	3	11.0	*	0.0	0.0	6.4
4	HUNTS BAY A	4	0.0	*	0.0	0.0	0.0
5	HUNTS BAY A	5	18.0	*	0.0	14.2	17.0
6	HUNTS BAY B	6	65.5	*	49.6	54.5	65.5
7	OLD HARBOUR	1	27.0	*	10.4	11.8	17.1
8	OLD HARBOUR	2	0.0	*	0.0	0.0	0.0
9	OLD HARBOUR	3	50.0	*	45.1	50.0	50.0
10	OLD HARBOUR	4	55.0	*	46.0	50.7	55.0
11	HUNTS BAY, GT	1	0.0	*	0.0	0.0	0.0
12	HUNTS BAY, GT	2	15.0	*	0.0	0.0	0.0
13	HUNTS BAY, GT	4	20.0	*	0.0	0.0	0.0
14	HUNTS BAY, GT	5	0.0	*	0.0	0.0	0.0
15	EOGLE, GT	3	20.0	*	0.0	0.0	0.0
16	DIESEL GENS.	0	0.0	*	0.0	0.0	0.0
17	HYDRO GENERS	0	0.0	*	0.0	0.0	0.0

TOTAL NET OUTPUT (MEGAWATTS)	151.0	131.0	213.9
TOTAL NET SPINNING CAPACITY (MW)	200.3	218.3	229.3
TOTAL SPINNING RESERVE (MW)	49,5	37.4	15.6
TOTAL HOURLY COST, FUEL ($/H)	$209.20	******	*****

TABLE 8-9F

CASE NUMBER 5

GENERATOR LOADING TABLE

GENERATING UNIT			AVAIL.				
INDEX	STATION	NO.	CAF.(MW)	*	151.0	182.0	215.0
1	HUNTS BAY A	1	0.0	*	0.0	0.0	0.0
2	HUNTS BAY A	2	0.0	*	0.0	0.0	0.0
3	HUNTS BAY A	3	11.0	*	5.6	6.9	9.3
4	HUNTS BAY A	4	11.0	*	5.6	6.9	9.3
5	HUNTS BAY A	5	18.0	*	16.1	17.6	18.0
6	HUNTS BAY B	6	0.0	*	0.0	0.0	0.0
7	OLD HARBOUR	1	27.0	*	15.3	18.2	23.3
8	OLD HARBOUR	2	45.0	*	32.5	38.8	45.0
9	OLD HARBOUR	3	0.0	*	0.0	0.0	0.0
10	OLD HARBOUR	4	55.0	*	55.0	55.0	55.0
11	HUNTS BAY, GT	1	0.0	*	0.0		
12	HUNTS BAY, GT	2	15.0	*	0.0	0.0	15.0
13	HUNTS BAY, GT	4	0.0	*	0.0		0.0
14	HUNTS BAY, GT	5	20.0	*	20.0	20.0	20.0
15	EOGLE, GT	3	20.0	*	0.0	20.0	20.0
16	DIESEL GENS.	0	0.0	*	0.0	0.0	0.0
17	HYDRO GENERS	0	0.0	*	0.0	0.0	0.0

TOTAL NET OUTPUT (MEGAWATTS)	150.0	183.2	215.0
TOTAL NET SPINNING CAPACITY (MW)	187.0	207.	222.
TOTAL SPINNING RESERVE (MW)	37.0	23.8	7.0
TOTAL HOURLY COST, FUEL ($/H)	*******	******	******
SPECIFIC PRODUCTION COST ($/MWH)	73.16	82.97	86.29
SYSTEM INCREMENTAL COST ($/MWH)	63.27	67.66	73.46

voltage (less than 1%), but differences on the order of 3:1 in loss factors are evident between periods of high and slack demand. JPS System Planning engineers, who provided the analysis, cautioned against too certain an interpretation of the data. For these they are used only to reinforce the conclusion derived by inspections of the marginal running cost simulations; namely, that marginal costs for the JPS system vary moderately by time of day in the approximate magnitude of 5 to 8 cents per kWh.

8.5.6 A Critique of Traditional Tariff Designs

There are two generally accepted objectives of electricity pricing which must be understood to bring order to the current conflict concerning electricity pricing. First, spreading the use of a given fixed generating and transmission system is a goal of all concerned. The more kilowatt-hours sold for a fixed kilowatt of installed capacity, the greater their utilization. The system's load or utilization factor will improve and short-run average costs will fall; therefore prices may be reduced. Second, some system growth is due to exogenous factors such as changing consumer tastes, income, or population. It is desirable to avoid this growth by achieving a better utilization of existing capacity. Only when the total running costs of the existing system can be reduced by adding new, more efficient capacity, does it make sense to expand the system capacity when it is not dictated by demand. In either case, the fact that real resources are utilized for capacity expansion must be noted in these times of financial difficulty.

Historically, a pricing system evolved which tended to meet the requirements of both the short-run load factor improvement and long-run capacity expansion objectives. Typically, electricity (kilowatt-hours) is sold to small users (e.g., residential customers) in a declining block fashion; the more used, the less the unit price charged. Generally, larger users are confronted with a two-part tariff. One component is a declining energy charge similar to the smaller users' tariffs, usually at lower prices. The second is a capacity or some variant thereof, which depends upon the kilowatts of installed capacity utilized at the time of maximum customer use. The demand charge may also be priced in a declining block fashion. (This is not the case in JPS; the demand charge is constant.)

It is easy to understand how the first objective, load factor improvement or fixed cost spreading, will tend to be met by this pricing practice. Quantity discounts encourage greater use and, if the available capacity is not surpassed, this will mean greater spreading of fixed costs and therefore tend to improve system load factors and reduce unit costs. A conflict arises when expansion in energy consumption occurs at the same time other customers want to use electricity. This is called the system peak, and, if the energy consumption exceeds the available generating capacity of the system, it becomes necessary to expand system facilities. In the past, when such system expansions occurred, technological improvements generally meant that the utilities reduced their unit or average costs. Thus, promoting use in both the short-run and the long-run did not conflict. The historical promotional pricing was widely adopted, excepting any external costs such as environmental degradation or encouraging the use of imported fuel oil.

The currently experienced conflict comes from two sources. Newly installed capacity is being brought on line at significantly higher than historical costs per kilowatt. This is partially due to inflation outrunning technology; rising relative prices such as environmental improvement, higher site values, excessive dependence on imported oil, etc. Unit kilowatt costs are no longer declining as expansion continues (long-run) but in a fixed time period (short-run) it is still true that the greater the use (kilowatt-hours) of the available capacity, the greater the spreading of fixed costs. Thus the long-run and short-run objectives of electricity pricing are presently in conflict and the current pricing policy has come under criticism. The conflicting objectives of pricing are minimizing incremental capacity costs while at the same time improving system load factor and reducing energy use due to the balance of payment consideration.

A pricing system has long been available, but until recently was not given serious consideration, except in France and England. It is called "peak load pricing" or "time of use pricing" and directly confronts the short-run load factor improvement and long-run capacity cost minimization objectives. (Note that, even with declining costs, avoiding unnecessary capacity expansion is an important objective.) This is accomplished by charging a low price based upon variable costs "off-peak" and a high price based upon variable and capacity cost "on-peak." Price differences of two to one to perhaps as much as five to one between the hours of the year designated "peak" and the hours designated "off-peak" will encourage system load factor improvement. Additionally, any expansion that requires resource expenditures to add additional capacity is discouraged, since high prices based upon marginal capacity costs are charged for use that takes place at times when the system must directly confront the prospects of expansion.

Several types of expertise are needed to set tariff policy. First, the system planner must estimate the mix of facilities that the firm must acquire to meet its demands. This involves determining when old plants must be retired and new plants added. The type of new plant -- e.g., coal- or oil-fueled base load, peaking, etc. -- must also be determined.

Second, the system dispatcher must estimate system loads and thereby determine which plants will be used, and when power will be purchased from other members of the power pool. With both investment cost estimates and running cost estimates, the accountant must undertake the third task; namely, the estimation of the firm's total cost of service. Fourth, the firm must determine the necessary required rate of return on its finances to meet old and new financial obligations.

Fifth, the economist's role is most important. Tariffs are designed to collect sufficient revenues to cover the costs reflected in the first four steps. An accounting approach has been selected in which total costs are allocated across customer categories on the basis of average use and cost calculations. However, there are a virtually unlimited number of ways in which revenues may be collected in total or by customer category.

Economists believe that tariffs should provide signals to each customer, permitting the use of his or her discretion concerning electricity consumption. In ultimate form, such tariffs should allow each customer to be granted price discounts when system costs are lowest, and price penalties when system costs are highest. Such a system would balance firm revenues and costs. Moreover, it would contribute to the financial integrity of the utility, stabilize tariffs, and increase customer satisfaction.

It must be emphasized that such a pricing system is sometimes called marginal cost or incremental cost pricing because it ties prices and therefore incremental revenues to the additional or incremental costs of supply. Suppose over a given month the cost of supplying a particular customer with 1,000 killowat-hours was $100. The utility could collect this revenue in a wide variety of ways. The economist recommends pricing each unit of electricity on the basis of the utility's cost of supply. However, a far more simple method might be to determine the average cost by dividing $100 by 1,000 kilowatt-hours, or ten cents per kilowatt-hour, and then charge this amount for each kilowatt-hour taken.

The utility would receive its $100 in revenue and the customer would contribute its $100 to defer the utility's cost.

It is important to consider the signals this average cost pricing implies. Suppose one-half, or 500 kilowatt-hours, cost the utility five cents to supply the customer, and the other one-half cost the utility 15 cents to supply. The reason for the difference is that the lower cost reflects less expensive running costs, when the system can utilize its most efficient and cheapest to operate plants. (This is sometimes called base load.) The higher cost reflects both higher running cost and the fact that the use occurs at times when excess generation, transmission and/or distribution costs are not available and the utility must incur additional capital expenses in one or more of these areas.

For example, the declining block pricing system might charge 15 cents for the first 500 kWh consumed and 5 cents for the next 500 kWh, thus collecting the same $100 for 1,000 kWhs as the flat 10 cents per kWh charge. If the first half of the billing period had higher costs and the second had lower costs, such a declining block pricing system might be compatible with an attempt to track revenues and costs. However, this seems implausible. If there are both high and low cost periods in both halves of a billing period, some kWh's will be underpriced and some overpriced in both halves of the billing period. More significantly, consumers will believe that increasing use beyond the 1,000 kWh will cost 5 cents per kWh. If costs are on average 10 cents, and perhaps 15 cents in some time periods, the utility will lose earnings as the customer mistakenly assumes increased use costs of only 5 cents per kWh for both the utility and the consumer.

Putting aside any difference in billing difficulty or costs, the economict would recommend two prices: one at 15 cents per kWh for the 500 hours when this price reflected the utility's cost and the other at 5 cents per kWh for the 500 hours when the lower price reflected the lower system costs. Note that this tariff would also yield $100 in revenue to the firm: 15 cents per kWh x 500 kWh=$75 + 5 cents kWh x 500 kWh=$25.

Notwithstanding the fact that both the consumer and utility exchange identical dollar and energy amounts, there are two important issues incorporated in the numerical example. First, suppose the customer, priced on an average cost basis, contemplated increasing use from the current 1,000 kWh's per month to 1,001 kWh's per month. He or she would determine that the additional cost would be ten cents. If the benefits derived exceeded this amount, the additional consumption would make sense from the consumer's standpoint. However, it is useful to consider the importance of such a decision on the utility. If by chance the consumer's additional kWh's took place when system costs were low (e.g., five cents per kWh), the utility would find an additional source of earnings and thereby consider lowering overall system tariffs to reflect this gain.

But suppose instead the consumer decided to purchase the additional kWh's when the system was operating at its highest running costs, and to meet the additional demand it was necessary for the system to expand its capital investment requiring an additional cost of 15 cents per kWh. The rational consumer decision of consuming one more kWh at a cost of ten cents when benefits exceeded or equaled the price, has a deleterious effect on the utility's earnings. The revenues rise by ten cents, but costs increase by 15 cents (or some 50 percent more if we seek to magnify the significance of this relatively minute transaction). If the utility had only been earning its regulated income, it would have an erosion of earnings and would have to apply to raise its prices to make up this additional cost. If such increases are "rolled-in" or averaged, the consumer will still perceive the additional cost to be closer to ten cents per kWh than the 15 cents that it actually costs.

Multiply this adverse experience over millions of consumer decisions, and the earnings erosion can be great. The current electricity pricing controversies are important evidence that the distinction between average and marginal cost pricing is worthy of consideration. Under the latter, the price the consumer would pay would be either 5 cents or 15 cents per kWh, depending on the actual utility costs. It would not be necessary to adjust prices. The system self-adjusts, deriving benefits for both the consumer and the utility. The consumer is given the opportunity to save money by consuming the extra kWh's at 5 cents per kWh instead of 15 cents per kWh. Additionally, the utility earnings are preserved.

There is an additional way of interpreting the above-mentioned example. When the utility prices each kWh equally or uses declining blocks, no incentives exist for the consumer to alter the time pattern of consumption of the initial 1,000 kWh's. Under the time of use price system, however, the customer is given the discretion of saving money by altering the pattern of use. When such prices reflect cost differences to the utility, such consumer savings equal system savings and a balance is preserved.

The declining block pricing traditionally adopted by electric utilities has typically been applied to residential and commercial customer; the number of blocks is usually four or five. The tariffs adopted for the larger commercial and industrial customers are often similarly constructed with respect to declining energy charges. However, the larger volume customers are often encouraged to flatten out or more equally spread their usage patterns, as described above. This is called customer load factor improvement.

There are three generally accepted methods for achieving the customer load factor improvement objective:

(1) The two part energy (kWh) and capacity (kW) tariff charges more for each increase in the demand for capacity, kW, measured for a specific continuous period of time (usually 15 minutes to 30 minutes). This discourages larger customers from increasing their individual use of electric power, kW. The charges are usually several dollars per kW of maximum demand in a billing period.

(2) Some utilities add to the demand charge disincentive for increased power, kW, use by employing a demand ratchet clause. Ratchets mean that for billing purposes the specific billing period's maximum demand is compared to previous months (usually 11 or 12 months) maximum demand. If it is less, the higher demand or some splitting of the difference between the two is utilized for billing in the specific period under consideration.

    This means a customer who increases use above the previously set maximum demand for power must expect to pay for that increase in the present billing as well as in subsequent periods. The cost of increased kW consumption above a previous high can quickly multiply to many times the several dollars per kW that appears in the tariff. As such, growth in power, kW, consumption is discouraged. However, if a customer realizes that use is well below a previously set high power (kW) use level, the customer can increase power use at no additional charge. For ratchets to hold down system growth in power demand, several large volume customers must not simultaneously consider their demand use to have already been paid for and, therefore, all decide to increase use at the same time.

(3) A tariff policy used somewhat less frequently to encourage larger volume commercial users to spread their use patterns more equally over a billing cycle is called an "expander" tariff. This tariff provides a reduction in a customer's energy charge when use in kWh's increases for a fixed level of maximum power use, kW. The reverse is also true, however. A customer who increases demand or power, kW, without increasing energy use, kWh, will be required to pay more per unit of the kWh's consumed. Most expander tariffs provide a given amount of kWh at a particular price for a specific number of hours of maximum use. For additional kWh, unit price will decline, this process perhaps being repeated for several declining prices.

Expander tariffs are often difficult to understand. They also have the unique feature of customers who have individualized tariffs that typically vary from month to month for the same customer.

Thus far the importance of metering costs has been avoided. A principle of any pricing policy is that the gains from diversity in pricing (that is, charging different prices when costs vary) must be greater than any additional costs in billing and/or customer inconvenience. It would be foolish to implement a pricing system that costs more to implement than it is worth. A balance must be struck between the cost-based pricing principle and practical billing and metering constraints.

The benefits of saving running costs, avoiding unnecessary capital expansion, providing greater security to utility earnings, reducing the need for frequent price changes, and providing consumers with the opportunity to save money by altering use with the knowledge that system costs will be comparably reduced, are the benefits that must be compared with the additional metering and billing costs.

The first factors sometimes used to encourage individual customer load leveling are the two part demand, power (kW) and energy tariff. This tariff is called a Hopkinson Tariff and was first introduced in 1892. For any two customers subject to this tariff (assuming equal energy consumption), the consumer with the highest "load factor" will pay the lowest average price. Load factor is defined as the ratio of the average load during a designated period to the peak or maximum load during the same period. A high ratio means a relatively steady load; a low ratio is a more erratic load. If a customer increases energy consumption without increasing maximum kilowatt demand, or increases average use more than proportionally, load factor will rise and average price fall. Conversely, a fall in load factor means an increase in average price.

A Hopkinson schedule, then, penalizes erratic loads and rewards even loads. The penalty is for causing capacity to be held available but not used; the reward is for requiring less capacity to be held available for infrequent use. But does the Hopkinson Tariff actually work to the benefit of the system as a whole? That is, does it minimize or even reduce the amount of excess capacity in the system through an efficient and effective set of incentives?

Clearly, it does not accomplish these beneficial results with certainty and that is the problem. The Hopkinson tariff does encourage customers to distribute their demands on kilowatt capacity more evenly over the daily cycle, but that does not necessarily benefit the system as a whole. The incentive for customers to distribute their demands evenly is more than likely to make matters worse. Cost minimization requires an even distribution of demand on the system as a whole. One is interested in the distribution of individual demands only as they affect the entire system.

In Figure 8-5 the heavy line describes a hypothetical system load over a 24-hour cycle. The lighter line describes the load of a particular customer over the same cycle. Suppose the customer responds to the Hopkinson incentive to even out demand. He does so by adding a block of demand (shaded area) during the 8 p.m. - 4 a.m. period. This improves <u>his</u> load factor and results in a lower unit price. Unfortunately, the additional demand increases the peak demand on the system, which now must maintain more excess capacity than was previously needed.

Figure 8-6 considers a customer who contemplates shifting a portion of his load from the 8 p.m. - 4 a.m. period to the 4 a.m. - noon period. If he does so, the distribution of his load will be less even and his price per unit will

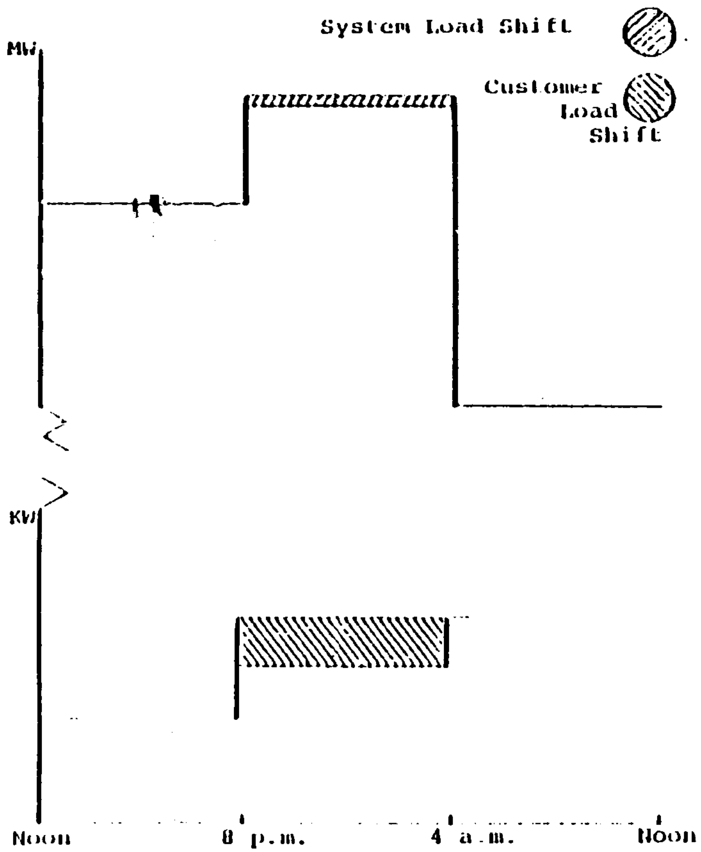

Figure 8-5 System and Customer Load Curves

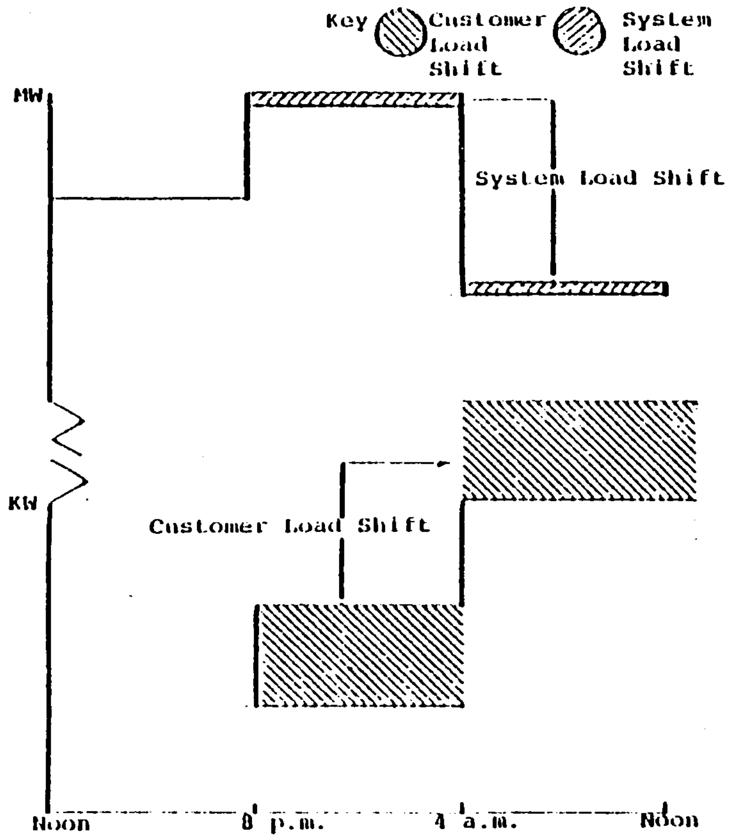

Figure 8-6 Shifting Load Curves

increase. Simultaneously, however, the peak demand on the system would decrease. Yet, the Hopkinson tariff penalizes such a shift.

In Figure 8-7, consider the customer who has a 100 percent load factor, a case where a Hopkinson tariff has produced an even pattern of load (the straight line). It is clear that the system, which has peaks caused by other customers, would benefit if the customer shifted the pattern of his load, changing his 100 percent load factor as indicated by the dotted lines. However, the Hopkinson tariff would penalize such a shift.

Finally, there is a limiting case in which the Hopkinson tariff works well -- that is, when all customers load distribution is perfectly even. Then it must follow that the system load has perfectly even distribution. The system load factor is 100 percent and each individual load factor is 100 percent, but that is the limiting case; what is true at the extreme is not necessarily true anywhere else.

If, for example, a system has a 98 percent load factor (very slight unevenness), the system will not necessarily move in the direction of 100 percent load factor by persuading all customers to even their own load. It depends on just how the customers respond. If even a single customer does not achieve a perfect pattern, then the thing to do is to encourage other customers to produce offsetting unevenness in their loads. In short, for a Hopkinson tariff, or any other customer load leveling incentive (such as ratchet clauses and expander tariffs) to work with assured effectiveness, it must work flawlessly.

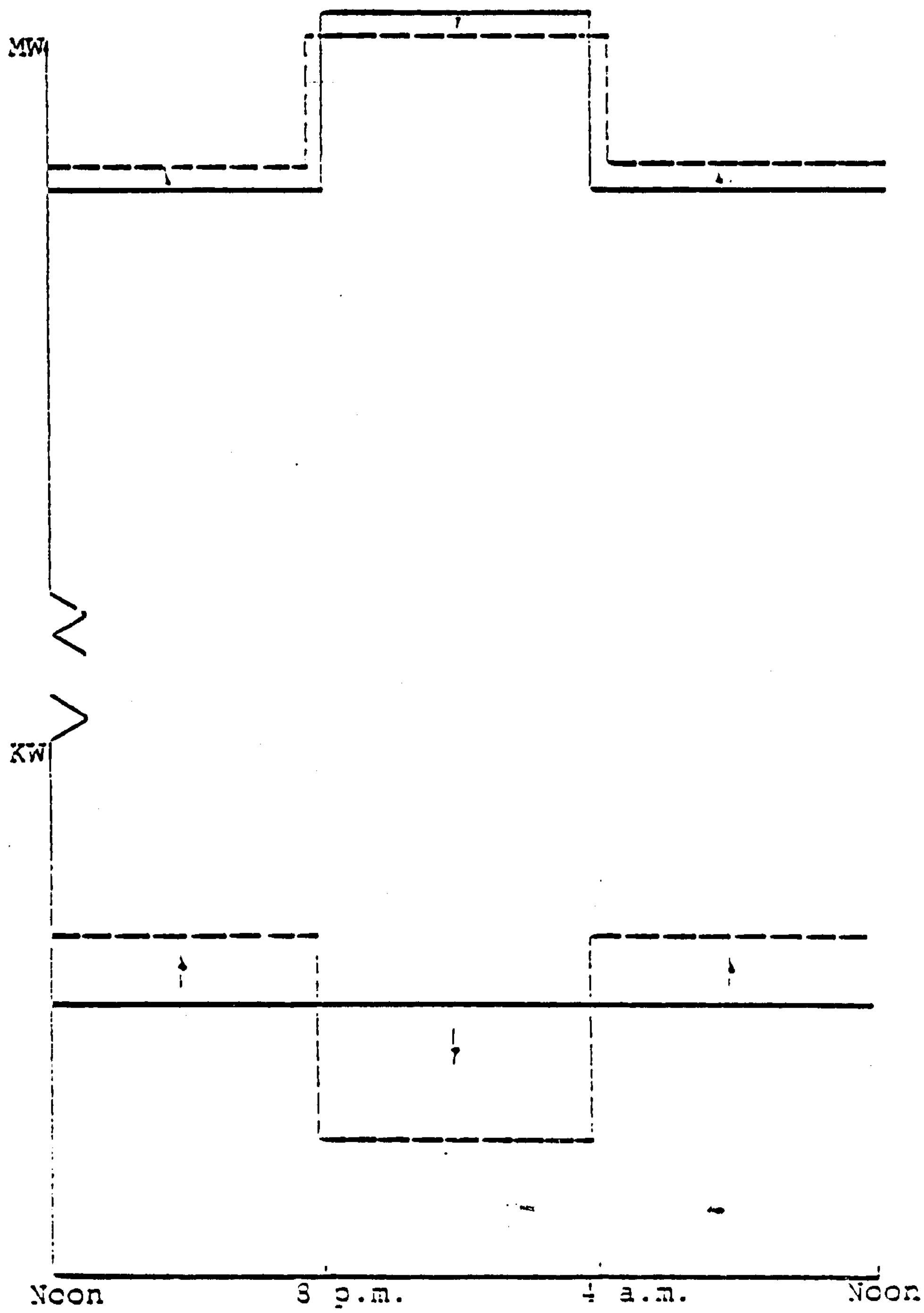

Figure 8-7 Exception Load Curves

8.6 FINDINGS

8.6.1 A Description of Current JPS Tariffs

8.6.1.1 Residential

Table 8-10 contains the current residential tariffs for the Jamaica Public Service Company. These rates were established in June of 1978. They represent a very traditional declining block electric tariff. As presented, the size of the blocks and rate of price decrease indicate a very steep rate of declining block.

The tariff shown in column 2 is the published tariff of JPS. It is subject to two adjustments. First, rather than periodic rate case adjustments, which plague most utilities, JPS has adopted a monthly cost of service adjustment clause in order to keep its revenues in line with inflation. From June of 1978 through January of 1979, these prices per kWh increased by 1.5 percent per month. From February through the present, the rate of increase in JPS's cost of service adjustment has been 1 percent per month. Column 3 shows the prices that would be effective on January 1, 1980 based upon the cumulative Cost of Service Adjustment.

In addition, JPS has adopted a fuel clause adjustment. It was one of the earliest adopted in the world. For a utility almost entirely dependent on imported oil, JPS's fuel clause is most useful. There are four adjustments for fuel use in the JPS clause. First, the current month's fuel costs are converted from a price per million Btu of oil use to a price per kWh by multiplying the fuel price by a heat rate level of 13,500 Btu per kWh. This rate was lowered from 14,500 Btu per kWh in February 1979. The heat rate utilized is below the average rate expected by JPS. As such it provides managerial incentive to conserve fuel oil and to improve operating efficiency. This is a rather ingenious modification to typical fuel adjustment clauses. The February reduction added additional incentives to the fuel oil conservation objective.

Second, about .37 cents per kWh of fuel cost is presently included in the basic rates subtracted from the fuel adjustment clause.

Third, system losses, defined as kWh's sold divided by kWh's generated and purchased, are divided into the fuel adjustment price per kWh. In order to create an incentive

TABLE 8-10

RATE 10

JPS Residential Rates**
June 1, 1978 and January 1, 1980

	June 1, 1978	January 1, 1980*
Customer Charge	$1.59 per Month	$1.99 per Month
(1)	(2)	(3)
Monthly Use (kWh)	Price	Price
10 or less	0¢	0¢
20 next	15.1¢	18.88¢
70 next	12.1¢	15.13¢
200 next	8.8¢	11.01¢
200 next	5.6¢	7.00¢
over 500	5.0¢	6.25¢

Tariffs were increased at 1.5% per month from June 1978 to January, 1979, and 1% per month from February 1979 to January 1980, or by a factor 1.2506 inclusive.

Note: The above rates do not include the fuel clause adjustment. All prices are in Jamaican dollars and cents.

to cut system losses, either due to pilferage or equipment, the maximum loss ratio is set at 85 percent. This is another good example of built-in incentives for management efficiency. This is not typically found in fuel adjustment clauses.

Fourth, about eight percent of JPS's generation comes from hydropower. The past twelve months' average hydropower generation is used to put the fuel clause on a fossil fuel use basis. This adjustment also creates management incentive to keep its hydropower available and even to increase it, if that is physically possible.

In the most recent month, October 1979, the fuel adjustment clause, with the above mentioned factors taken into account, was 8.97 cents per kWh (Jamaican). With current escalation in foreign oil prices this adjustment will be approximately 10 cents, or more, per kWh by January 1980.

The fuel adjustment clause is an important component of a customer's bill. It also sharply reduces the rate of rate decline in the filed JPS basic tariffs. In those tariffs, shown in Table 8-10, the initial block to tail block ratio is more than 3 to 1, or approximately a 200% difference, when the fuel clause adjustment is omitted. However, as 9 cents or 10 cents per kWh for fuel cost adjustment is added to the basic rates, the differential falls to less than 2 to 1, or approximately an 80 percent difference.

8.6.1.2 Commercial

There are two categories of tariffs for the commercial customers of JPS. The difference is based upon the volume of customer use and the type of metering adopted by JPS. The smaller volume commercial customers (Rate 20) are billed using a declining block tariff for energy use similar to the residential tariff, plus a flat charge of $.99 per month for connected load above 1 kW for single phase customers. The minimum billing for 3-phase customers is based on at least 7.5 horse power (hp), with 1 hp = .75 kW.

Table 8-11 shows the basic filed tariffs for Rate Code 20, as well as the effect of the monthly Cost of Service Adjustment, which is applied to the energy only prices in a manner identical to the residential tariff of JPS. The same fuel adjustment clause as described for Rate Code 10.

is added to the prices shown in Table 8-11. Considering only the prices shown in Table 8-11 the rate of decline in the tariff appears even steeper than for the residential customer tariff. Without the fuel adjustment the ratio of the initial tail price is 3.7 to 1. With fuel adjustment, that same price falls to nearly 2 to 1. However, the size of the blocks is considerably larger, and the number of blocks is one less. These factors tend to flatten the relative rate of price decline.

Nevertheless, both Small Commercial and Residential customers are sent a signal that the more they use, the less they pay per unit. This creates a disincentive to conserve. The fuel adjustment clause does, however, dampen this tendency. While the current fuel adjustment clause is averaging 9 cents to 10 cents per kWh, and this certainly causes consumers to think conservation, the average cost of fuel purchased per unit of sale, less the .37 cents per kWh in the basic prices, is running as much as 12 cents or more. JPS has apparently decided to encourage management efficiency as described above by charging 9 or 10 cents per kWh. In so doing, they are not recovering the full cost of foreign oil, and therefore, they are sparing their customers some of the impact of rising costs. However, this also reduces some of the conservation signal. The rapid escalation in world oil prices often, as in this case, puts otherwise important social objectives in conflict with one another. The JPS adjustment clause seems to have been developed by a management entirely aware of the inherent social conflicts. It is a pragmatic solution to the tradeoffs implied by the above discussion.

The larger volume Commercial customers are charged under Rate 40. The tariff has two parts: power (kW), and energy (kWh). The demand charge is a flat price per kW, subject to a twelve month billing demand ratchet. The energy charge is a declining block subject to an expander provision. All three features encourage customers on Rate Code 40, and similarly for Rate Code 50, the industrial tariff to be described below, to equalize their individual customer load. It is rather unique to find a tariff with all three of these customer load leveling features included.

Additionally, the Cost of Service monthly adjustment and fuel clause adjustments are applied to the energy portion

TABLE 8-11

RATE 20*

JPS Small Commercial
June 1, 1978 and January 1, 1980

	June 1, 1978	January 1, 1980
Customer Charge**	$1.59 per Month	$1.99 per Month
(1)	(2)	(3)
Monthly Use (kWh)	Price	Price
10 or less	0¢	0¢
90 next	23.7¢	29.64¢
900 next	10.8¢	13.51¢
9000 next	8.5¢	10.63¢
over 10,000	6.4¢	8.00¢

* The footnotes for Rate Code 10, Table 8-10, also apply to Table 8-11.

** Additionally, charges for connected load above 1kW are added, but these are not increased by the cost of service adjustment.

of the Rate Code 40 tariff. Additional conditions for power factors, transformer ownership, voltage taken, and metering ownership are provided into resultant discounts and/or price changes.

Table 8-12 shows the Rate 40 tariff.

8.6.1.3 Industrial

Industrial customers are priced under Rate 50. It is similar to the large volume commercial Rate 40 in design. The tariff has both a demand, power (kW), flat charge, and an expander declining block energy charge. Demand is subject to a twelve month ratchet, and must exceed 1,000 kW. Similar additional conditions are included in Rate Code 50 as in 40.

Table 8-13 shows the Rate 50 tariff.

For a system with nearly twice the generating capacity demanded, as are JPS's circumstances, the individual customer use leveling features of Rate Codes 40 and 50 are surprising. This is especially true when all three of the standard tariff approaches, sometimes used to achieve this somewhat dubious objective, are included in the JPS tariffs. The more revenue and incentive provided for the purpose of achieving customer load leveling, the less that is available to encourage customer energy conservation.

In other words, assuming such large volume customers are to pay the same annual bill in any case, the more revenue attached to customer demands for power, the less there is to discourage energy use. Nevertheless, the same 9 cents to 10 cents per kWh of fuel adjustment are added to the tariffs shown in Tables 8-12 and 8-13, and this undoubtedly has an energy conservation incentive effect. For one thing, it increases average energy prices nearly 200 percent. Additionally, the cost of service adjustment is only applied to the energy component of the Rate 40 and 50 tariffs. This encourages the larger volume user to think more of energy conservation.

Finally, JPS sells electricity and sometimes provides the lighting equipment to public entities. These sales are billed under Rates 20 and 40 or a special Street Lighting Tariff 60. In the analysis below such sales and volumes are usually described as "Other".

TABLE 8-12

RATE 40*

JPS Large Commercial
June 1, 1978 and January 1, 1980

	June 1, 1978	January 1, 1980
Demand Charge**	$2.15 per kW per Month	$2.15 per kW per Month
(1)	(2)	(3)
	Price per kWh	Price per kW
First 100 hours of demand	5.1¢	6.38¢
Next 200 hours of demand	4.3¢	5.38¢
Over 300 hours of demand	3.6¢	4.50¢

* The footnotes for Rate Code 10, Table 8-10, also apply to Table 8-12.

** Demand is based upon a 12 month ratchet, the demand interval is 15 minutes, and in no case shall it be less than 20 kW.

TABLE 8-13

RATE 50*

JPS Industrial
June 1, 1978 and January 1, 1980

	June 1, 1978	January 1, 1980
Demand Charge*	$1.83 per kW per Month	$1.83 per kW per Month
(1)	(2)	(3)
	Price per kWh	Price per kWh
First 100 hours of demand	5.1¢	6.38¢
Next 200 hours of demand	4.3¢	5.38¢
Next 200 hours of demand	3.2¢	4.00¢
Over 500 hours of demand	2.8¢	3.50¢

* The footnotes for Rate Code 10, Table 8-10, also apply to Table 8-13.

** Demand is based upon a 12 month ratchet, the demand interval is 15 minutes, and in no case may it be less than 1000 kW for the demand charge or 1000 kW for the energy charge.

8.6.2 JPS Revenue Requirements and Use by Customer Category

The basic rates included in the JPS tariffs were designed to produce about J. $100 million in 1979 inclusive of the monthly cost of service adjustment, but exclusive of the fuel cost adjustment. It is important to note that volume declined about 7 percent over the initial 1979 estimate which was based upon an assumption of no-growth above the 1978 volume. Fuel cost increases caused price increases, which may have caused the decline in use. As a result of fuel cost increases, total revenue projections also increased.

Table 8-14 summarizes the revenue volume estimates for 1979. Columns 1 and 2 reflect the initial pre-fuel cost increase, lower revenue and higher volume estimates. Columns 3 and 4 represent the most realistic projections for 1979, since they are based on the first ten months of actual operations projected to year's end. Columns 5 and 6 show the annual revenues, and their percentage breakdown respectively, when fuel adjustments are subtracted from total revenue estimates.

Note, however, that because of the cost of service adjustment, if the year end prices that are in effect in December 1979 were multiplied by annual consumption, the basic rates would produce more than J. $100 million in revenue. Column 5 shows annual revenue from the basic tariffs (i.e., no fuel adjustment) while Column 7 shows annual revenue as calculated using the December 1979 basic tariffs.

The Cost of Service Adjustment represented by this calculation is derived as follows:

$$\text{Annual Total Revenue} = TR = \underset{\text{Jan}}{X(1)} + \underset{\text{Feb}}{X(1.015)}$$

$$+ \underset{\text{Mar}}{X(1.015)(1.01)} + \underset{\text{Apr}}{X(1.015)(1.01)^2}$$

$$+ \ldots\ldots\ldots\ldots\ldots\ldots + X(1.015)(1.01)^{10}$$

$$= 1 + 11.57(1.015) = 12.74$$

$$TR = X(12.74)$$

TABLE 8-14

1979 REVENUE AND VOLUME ESTIMATES FOR JPS BY RATE CATEGORY

(all revenues in J.$$10^6$ and all volumes in 10^6 kWh)

	Estimates*		JPS 120 Estimates**					¢ per kWh	
Rate Category	Revenue (1)	Volume (2)	Revenue (3)	Volume (4)	Revenue Net Fuel (5)	% Net (6)	Adjusted Net Revenue (7)	December Average Price (8)	January Average Price (9)
10	55.4	354	60.0	332	39.2	39.2	41.4	12.432¢	12.557¢
20+	24.4	151	32.7	177	21.7	21.7	22.9	12.947	13.077
40+	36.4	301	34.8	274	17.7	17.7	18.7	6.825	6.893
50	17.7	164	17.2	140	8.5	8.5	9.0	6.412	6.476
Other***	21.3	168	21.2	134	12.8	12.8	13.5	10.088	10.189
TOTAL	155.2	1138	165.9	1057	99.9	100%	105.5	9.981¢	10.081¢

*JPS memorandum from May 21, 1979, dealing with rates.

**From JPS 120 run on November 2, 1979, first ten months were projected forward to year end by a 1.20 factor, with fuel adjustment of $J60.9 through September, $J9 for October, prorated forward to year ened.

***Includes rate codes 25.45 and 60 from JPS 120.

+Note the volume splits for the initial estimate came from 35.5% code 20 and 66.5% code 40 with revenue splits of 40.1% and 59.9% respectively, as provided by JPS.

$$\text{J. } \$100 \times 10^6 = 12.74X$$

$$X = \text{J. } \$7.85 \times 10^6$$

$$\text{December} = X(1.015)(1.01)^{10}$$

$$= \text{J. } \$8.800549 \times 10^6$$

$$\text{Annual Revenue Based on December} = 12(\text{December})$$

$$= \text{J. } \$105.6 \times 10^6$$

$$\text{January 1, 1980} = \text{December}(1.01)$$

$$= \text{J. } \$8.89 \times 10^6$$

Columns 8 and 9 were derived by dividing the adjusted net revenue, column 7, by the volumes in column 4. They represent the average prices per kWh in effect by year end, and on Jnauary 1, 1980, respectively. These average prices are from the revenues derived from the basic rates, and the assuption that, despite volume losses of 7 percent, the basic rates are still expected to yield J. $100 X 10^6 in revenue. Unless noted below, the tariff analyses that follow will be based upon the average prices shown in column 9, volumes in column 4, and the net revenues in column 7 times (1.01) to adjust for the January 1, 1980 cost of service adjustment.

8.6.3 Typical Consumers by Customer Category and Use by Rate Block

8.6.3.1 Residential (Rate 10) (Table 8-15)

The average residential customer uses 144 kWh per month. There are 192,462 Rate 10 customers. By November of 1979, use for all residential customers had declined by 5 percent, compared to 1978. Table 8-15 shows residential consumption and revenues by the rate blocks in the current JPS tariffs projected to January 1, 1980. Total annual revenue based on the 1979 annual volumes shown in column 1, multiplied by the prices for January 1, 1980, for the basic energy (kWh) equals J. $37.95 X 10^6. The most recent estimate of the number of customers from the November run of JPS 120, a computer report, is 192,462. Multiplying the monthly charge of J. $1.99 times 12 months times this number of customers yields J. $4.6 X 10^6.

TABLE 8-15

RESIDENTIAL CONSUMPTION AND REVENUE BY RATE BLOCKS ON JANUARY 1, 1980; CODE 10

Block	Volume* 10^6 kWh	Price January 1, 1980 ¢ per kWh	Revenue (10^6 J.$) Annual Volume and January Prices
	(1)	(2)	(3)
0 to 10	21.15	0¢	0.0
11 to 30	38.11	18.88	7.20
31 to 100	102.62	15.13	15.53
101 to 300	91.61	11.01	10.09
301 to 500	24.37	7.00	1.71
over 500	54.76	6.25	3.42
TOTAL	332.62×10^6 kWh		J. $\$37.95 \times 10^6$

$1.99/month = Customer Charge based on:

JPS 928 Computer Run with average use of 151.7 kWh — J. $\$4.36 \times 10^6$

J.$\$42.31 \times 10^6$

OR

Based on JPS 120 Computer Run

192,462 x 1.99 x 12 (Customers) (Months) — J. $\$4.60 \times 10^6$

J.$\$42.55 \times 10^6$

OR

Based on Table 8-14, adjusted to January 1, 1980

J. $41.4 (1.01) = J.$\$41.81 \times 10^6$

---

* The volumes shown are based upon an earlier period's percentage breakdown.

Total annual residential revenues based upon January, 1980 prices and use equals J. $\$42.55 \times 10^6$ (= J. $\$37.95 \times 10^6$ 4.6×10^6). As indicated in Table 8-15, if the computer report JPS 928 data is used to estimate customer charge revenue, there is a slight decrease to J. $\$4.36 \times 10^6$, and this reduces the total Rate 10 revenue estimate to J. $\$42.31 \times 10^6$. The lower estimate is closer to the category-by-category revenues shown in Table 8-14, and is consistent with the block by block volume data. Therefore, most of the tariff comparison work which is described below is based on the lesser revenue estimate of J. $\$42.31 \times 10^6$. Considering the differences and the degree of rounding, this seems to be a relatively minor factor (about one-half of 1 percent). (Note also that the JPS 928 computer run is based upon data from an earlier period of time and there is no way to know how relative use by block may have changed.)

8.6.3.2 <u>Small Commercial (Rate 20)</u> (Table 8-16)

Based upon the JPS 928 computer run for Rate 20, the average small commercial customer used about 767.5 kWh per month. However, when one considers the JPS 120 computer run which covers a more recent period, both average and total use have declined about twenty percent in 1979, to 641.4 kWh per month. The most recent estimate of the number of customers is 23,016. Table 8-16 shows small commercial consumption and revenue by the rate blocks in the current JPS tariffs projected to January 1, 1980.

Total revenues from the energy charges produce J. $\$22.07 \times 10^6$ in revenue and customer charges, producing an additional J. $\$0.55 \times 10^6$. The total billing using January 1, 1980 prices and 1979's annual volume would equal J. $\$22.62 \times 10^6$ This falls about J. $\$0.50 \times 10^6$ short of the revenue estimate shown in Table 8-14. The lower revenue estimate was used for tariff comparisons described below because the Rate 20 category also charges customers 99 cents per month for each kW of connected load for single phase service. There is also a comparable charge for three-phase service. Since no data on such revenue is available and when the level of rounding is considered, tariffs designed to recover about J. $\$22.62 \times 10^6$ annual revenue based upon January 1, 1980 prices are considered below, unless otherwise noted.

TABLE 8-16

SMALL COMMERCIAL CONSUMPTION AND REVENUE BY RATE BLOCKS ON JANUARY 1, 1980; RATE 20

Block	Volume* 10^6 kWh	Price January 1, 1980 ¢ per kWh	Revenue (10^6 J.$) Annual Volume January Prices
	(1)	(2)	(3)
0 to 10	2.17	0¢	0
11 to 100	14.93	29.64¢	4.43
101 to 1000	54.13	13.51¢	7.31
1001 to 10,000	70.95	10.63¢	7.54
over 10,000	34.82	8.00¢	2.79
TOTAL	177.00		J. $22.07 x 10^6

Customer Charge $1.99 per month

1.99 x 23,016 x 12 = J. $0.55 x 10^6

(Note: Due to the small number of customers, customer charge revenue estimate consistency between JPS 120 and JPS 928 computer runs is unimportant)

Total Revenue** J. $22.62 x 10^6

* The volumes shown are based upon an earlier period's percentage breakdown by block (JPS 928).

** Revenue from Table 8-14

J. $22.9 X 10^6(1.01) = J. $23.13 X 10^6

8.6.3.3 Industrial Customers (Rate 50) (Table 8-17)

Data for Rate 50 customers is relatively more available than data for larger commercial customers, Rate 40. The Rate 50 customer data have been used to form assumptions about Rate 40 customers. Therefore, Rate 50 will be considered first. JPS 945, a computer run, provides information on 120 Rate 50 bills. Total energy use is 58,873,400 kWh. Therefore,

$$\text{Average monthly energy use} = \frac{58{,}873{,}400}{120} = 491 \text{ mWh}$$

Energy consumption data by block for Rates 40 and 50 is not useful since both tariffs have expander blocks. This means customer blocks may vary from month to month, as well as between customers. JPS provided an analysis of demand (kW and kWh) and revenue derived from demand charges in the month of October for 23 industrial customers. There are 24 customers according to the JPS 120 computer run.

Average demand can be estimated from these data by dividing total revenue from the demand charge by its per unit price, and dividing this in turn by the number of customers, 23.

$$\text{Average Demand} = \frac{\text{Total Demand}}{\text{Number of Customers}}$$

$$= \frac{\text{Revenue from Demand Charge October, 1978}}{\text{Unit Price X Number of Customers}}$$

$$= \frac{\text{J. \$85,703.95}}{\text{1.83/Kva X 23}}$$

$$= 2{,}036 \text{ Kva}$$

For simplicity, assume 1 kW = 1 Kva

Average Demand = 2.036 kW

TABLE 8-17

TYPICAL INDUSTRIAL CUSTOMER'S BILL USING JANUARY 1, 1980 RATE 50 PRICES

Average Use 491 MWH per Month
Average Demand 2.036 MW = 2,036 Kva

	Price/kWh	Volume (kWh)	Revenue $J.
First 100 hours of demand	6.38¢	203,600	12,989.68
Next 200 hours of demand	5.38¢	287,400	15,462.12
Next 200 hours of demand	4.00¢	0	0
Over 500 hours of demand	3.50¢	0	0
TOTAL		491,000	$28,451.80

Plus demand charge*

1.83 x 2,036 = 3,725.68

Total = $32, 177.68

Average price per kWh = $32,177.68/491,000 kWh

= 6.553¢ per kWh

Total Revenue Estimate**

6.553¢/kWh x 140 x 10^6 kWh = J. $9.17 x 10^6

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* Note: This is underestimated but the kW demand is overestimated.

** Total Revenue from Table 8-14 is J. $9.09 x 10^6

In 1978, large industrial users consumed about 541 mWh per month, and use has declined 10 percent this year according to the JPS 120 computer run. This means average use is about 487 mWh. Using the estimates derived above for average use and average demand, the bill for a customer having these use characteristics for an expanding tariff can be calculated. This customer will be referred to as a typical Rate 50 customer. Consider Table 8-17 for an analysis of a typical Rate 50 customer's bill. Total annual revenue for all Rate 50 customers, derived from such a typical user, is J. \$9.17 X 10^6. This is slightly larger than the J. \$9.09 X 10^6 estimated in Table 8-14. A further complication is that the demand charge is based on Kva and the expander calculation is based upon kW. These are not likely to be equal due to power factors. To some extent the average price per kWh in the expander is adjusted in an offsetting direction by the fact that 1 Kva will not usually equal 1 kW. If one uses the number of customers, 24, and the average use of 491 mWh, the annual consumption estimate rounds off at a slightly higher, 141 X 10^6 kWh (= 491 X 24 X 12). Revenues estimated on this basis yield J. \$9.25 X 10^6 for January prices, using the 1979 typical customer characteristics and total use estimates. Tariff comparisons below are made on dual, low (J. \$9.17 X 10^6) and high (J. \$9.25 X 10^6) bases, but the principal one considered is the higher revenue, in part because the Rate 10 and 20 choices were made with some leaning towards lesser revenue. Still the difference in revenue estimates is less than 1 percent.

8.6.3.4 Larger Commercial Customers (Rate 40) (Table 8-18)

JPS did not have information readily available on the demand (kW) patterns of its Rate 40 customers. There are 765 Rate 40 customers. According to the November 1979 JPS 120 computer run, average monthly consumption is 29,854.3 kWh. With 12 months and 765 customers, annual volume is estimated to be 274.1 X 10^6 kWh, which is consistent with Table 8-14.

If one assumes that the percentage of demand revenue within Rate 40 is the same as for Rate 50, then demand for a typical Rate 40 customer can be determined.

$$\frac{\text{(kW Revenue 40)}}{\text{(Total Revenue 40)}} = \frac{\text{(kW Revenue 50)}}{\text{(Total Revenue 50)}}$$

TABLE 8-18

TYPICAL LARGE COMMERCIAL CUSTOMER'S BILL USING JANUARY 1, 1980 RATE 40 PRICES

Average Use 29,854.3 kWh/month
Average Demand 108.3 kW

	Price/kWh	Volume (kWh)	Revenue \$ J.
First 100 hours of demand	6.38¢	10,830	690.95
Next 200 hours of demand	5.38¢	19,024	1,023.49
Over 300 hours of demand	4.50¢	0	0
TOTAL		29,854 kWh	\$1,714.44

Demand Charge	\$2.15 per kW	
	\$2.15 x 108.03 =	232.95
		\$1,947.29

Average price energy only = 5.743¢ per kWh

Average price total = 6.523¢ per kWh

Revenue Check \$1,947.29 x 765 x 12 = J. \$17.88 x 10^6

From Table 8-14: J. \$18.7 X 10^6(1.01) = J. \$18.89 X 10^6

$$= \frac{\text{J. \$1,028,447}}{\text{J. \$9.0 X } 10^6}$$

$$= .11427$$

kW Revenue 40 $= .11427 \text{ (J. \$18.7 X } 10^6)^*$

$$= \text{J. \$2,136,884}$$

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*From Table 8-14

<u>kW Use per Customer</u>

Average Demand = kW Revenue 40/$2.15/12/Number of customers

= J. $2.137 X 10^6/2.15/12/765 = 108.3 kW

Therefore, the typical Rate 40 customer is estimated to use 29,854 kWh per month and is billed for 108.3 kW.

Table 8-18 shows the bill calculations for a typical Rate 40 customer. Given the spread of about J. $1.00 X 10^6 between the revenues generated by the typical Rate 40 customer, that was deduced as described above, and the revenues indicated for Rate 40 in Table 8-14, the tariff comparisons made for Rate 40 below will use both revenue targets, but the higher revenue will be emphasized as in Rate 50.

If the category revenues indicated in this section as the principal revenues for the purposes of tariff comparisons below are considered in total, they yield about the same revenue as the total for Table 8-14 adjusted for January prices. The Table 8-14 annual revenue estimate for December 1979 is J. $105.5 X 10^6. Increasing it to January 1980 price levels yields a revenue estimate of J. $106.56 X 10^6. The category revenue break down emphasized in this section is as follows:

Residential (10)	J. $42.31
Small Commercial (20)	22.62
Large Commercial (40)	18.89
Industrial (50)	9.25
	93.07
Other	13.50
Total	J. $106.57 X 10^6

8.7 DISCUSSION OF FINDINGS

8.7.1 Tariff Targets Based Upon Marginal Cost Pricing Principles and Interim Steps

Establishing electricity tariffs in the best of economic times is an art, not a science. When inflation, balance of payments, the overall state of the economy, rural electrification, and conservation objectives are added to the process, the difficulties encountered in making tradeoffs and decision-makers' challenges are increased. During the study, the team members attempted to become knowledgeable about the social and economic goals of Jamaica, and to take them into account when picking the most likely options for analysis. With this in mind, options for JPS have been developed. However, only those in Jamaica, with the ongoing knowledge of their nation, can make the final decisions on which of these options to implement.

The tariffs developed in this Section can serve either as a target that in better future times JPS might move toward, or as a basis upon which present tariffs and those derived in this Section can be used to establish a range for comparison. The options outlined below will then be compared to each other, and to their ranking within the range.

The marginal cost principle for tariff design will be used in this Section. The following general conditions will apply:

(1) Total revenue requirements will not be changed.
(2) Total revenue allocations between customer categories will not be altered.
(3) Declining block pricing will be eliminated.
(4) Ratchet provisions will be eliminated.
(5) Expander tariffs will be eliminated.
(6) Flat (both all-energy and two-part) demand and energy tariffs will be considered.
(7) When metering and customer acceptance seems reasonable, time of use pricing will be considered.
(8) The very progressive (from an efficiency standpoint) fuel adjustment clause will be continued.
(9) The innovative Cost of Service adjustment will be retained.
(10) Continuing the residential customer flat rate with the first 10 kWh included free will be presented.

These marginal cost pricing principles were used to develop the tariffs which follow for each customer category.

8.7.1.1 Residential (Rate 10)

8.7.1.1.1 Tariff Development: Table 8-19A shows the present JPS tariff and the residential tariffs most in keeping with the ten marginal cost pricing conditions just outlined. However, because the rate of implementation of such tariff changes is a Jamaican decision, Table 8-19B outlines some possible phase-in tariffs. These vary from declining to inverted block pricing. For the most part, the present tariff sheet customer charge of \$1.59 per month is retained, and the first 10 kWh of use are included in that price. All but the tariff designated "modified present" yield identical revenues of J. \$42.3 X 10^6.

The four tariffs based on marginal cost pricing principles shown in Table 8-19A differ only with respect to the size of the customer charge, and whether or not the first 10 kWh are included in same. Given discussions with JPS management, retaining the \$1.59 charge and continuing the first 10 kWh in it seems to be the most likely choice. Therefore, the tariff flat rate with first 10 kWh free (I), which charges 12.411 cents per kWh over 10, will be emphasized.

In Table 8-19B the modified tariff represents an earlier consideration by JPS to reduce their number of consumption blocks and to begin the flattening process. The other two declining block tariffs show more complete steps to consolidate blocks in a move towards flat prices. The first shown is based upon a weighted average of January 1, 1980 prices in the two consumption blocks that were selected. Since some customers in the 11 to 200 kWh block will have a price increase, the second declining block tariff was developed to prevent this. It is based upon an arbitrary 2 cent differential in the remaining two block prices.

The three remaining tariffs in Table 8-19B represent inverted block pricing. These may be considered one step beyond the flat rates. The first inverted rate has the same block definitions as the two step declining block rates shown in Table 8-19B, and retains the first 10 kWh as being priced in the customer charge. The last two inverted rate tariffs reduce the tail block break to 100 kWh, because the average use is about 140 to 150 kWh's per month. Some believe most, if not all, customers should confront the highest unit price for their marginal use. The last inverted rate was derived first using an arbitrary 2 cent differential, the middle

TABLE 8-19A

STRUCTURE OF PRESENT AND MARGINAL COST BASED RESIDENTIAL (RATE 10) TARIFFS

Usage In kWh	Present Tariff*	Flat Rate (I)	Flat Rate First 10 kWh Free (I)	Flat Rate (II)	Flat Rate First 10 kWh Free (II)*
0 to 10	0¢	11.669¢	12.411¢	11.405¢	0¢
11 to 30	18.88¢	11.669¢	12.411¢	11.405¢	12.13¢
31 to 100	15.13	11.669¢	12.411¢	11.405¢	12.13¢
101 to 300	11.01	11.669¢	12.411¢	11.405¢	12.13¢
301 to 500	7.00	11.669¢	12.411¢	11.405¢	12.13¢
over 500	6.25	11.669¢	12.411¢	11.405¢	12.13¢
EST TOT REV Jan. 1,1980 Prices and 1979 Volume	J$42.3x$10^6$	J$42.3x$10^6$	J$42.3x$10^6$	J$42.3x$10^6$	J$42.3x$10^6$

TABLE 8-19B

POSSIBLE PHASE-IN TARIFFS

Usage In kWh	Modified Present	kWh	Declining Block (I)	Declining Block (II)	Inverted Block (I)	kWh	Inverted Block (II)	Inverted Block (III)
0 - 10	0¢	0 - 10	0¢	0¢	0¢	0 - 10	0¢	10.60
11 - 100	16.47	11 - 200	14.55	13.10	11.73	11 - 100	12.19	10.60
101 - 300	11.33	over 200	8.33	11.10	11.73	over 100	12.60	12.60
301 - 500	7.25							
over 500	6.50							
EST TOT REV	J$42.56 x 10^6		J$42.3 x 10^6	J$42.3 x 10^6	J$42.3 x 10^6		J$42.3 x 10^6	J$42.3 x 10^6

All prices are shown per kWh except estimated total revenue.

*$1.99 per month customer charge; all other tariffs on this page use a $1.59 per month customer charge.

inverted rate was derived from it, assuming the revenue lost by charging for the first 10 kWh at a 0 cent per kWh price was made up by increasing the price for the 11 to 100 kWh block. This tariff might be considered a very mild inversion, based upon the retention of current customer charge provisions in the JPS tariffs.

In a conservation campaign, JPS may wish to discourage further use of electricity through inverted, conservation oriented prices. There are several cautions to note. First, the fuel adjustment clause of nearly 10 cents per kWh, which will probably rise to 12 cents per kWh, will be added to all the tariffs shown in Tables 8-19A and 8-19B. This will certainly create a conservation incentive. Second, the more revenue shifted to the tail block, the greater the likelihood of negative consequences for missing the revenue requirements target in a period of declining customer use. On the other hand, those who conserve might argue for greater proportional bill reductions. Further, luxury electricity use may be considered as a taxable commodity to help reduce foreign oil bills. Going beyond flat rates is a choice for Jamaica to make. There is no "right" answer.

8.7.1.1.2 Bill Impact: Tables 8-20A and 8-20B show the comparable bill impacts of the various tariffs outlined in Tables 8-19A and 8-19B. For 12 customer consumption levels the customer bill is calculated without adjusting for fuel costs. Below each bill, in parentheses, is the percent change calculated by subtracting the bill for each consumption level using the published JPS tariffs, adjusted to January 1, 1980 from the bill under the proposed tariff and dividing this difference by the present bill. Omitting fuel adjustment clauses has the effect of making all the percent changes appear to be larger, in a relative sense, than they would actually be. Taking the largest percent change, which is found in column (e) of Table 8-20B for 1,000 kWh of consumption to be 59.9 percent, and adding 10 cents per kWh to both prices for fuel adjustment, would reduce this percent change to 27.3 percent. Note also that column (c) shows the percent changes for each consumption level, when 12 cents per kWh fuel adjustment is called for.

Similarly, taking the largest reduction for 100 kWh of consumption, which is also found in column (e) of Table 8-20B to be 25.7 percent, and adding 10 cents per kWh to both prices for fuel adjustment changes, the change is reduced to 16.0 percent. All of the tariff structures considered

TABLE 8-20A

BILL IMPACT COMPARISONS, RATE 10

Consumption in kWh	(a) Bill for Present Tariff	(b) Bill for Flat Rate (I)	(c) Percent Bill Change with 12¢ FAE Added to (b)	(d) Bill for Flat Rate with 12¢ FAE Added to (I)	(e) Bill for Flat Rate (II)	(f) Bill for Flat Rate First 10 kWh Free (II)	
10	J.$1.99	J.$2.75 (38.2%)	(23.8%)	J.$1.59 (-20.1%)	J.$[illegible] (57.[illegible]%)	J.$1.99 (0%)	
50	8.78	7.42 (-15.5)	(-9.2)	6.55 (-25.4)	7.[illegible] (-12.[illegible])	6.84 (-22.1)	
100	16.35	13.25 (-18.9)	(-10.9)	12.75 (-22.0)	13.39 (-18.1)	12.90 (-21.1)	
200	27.36	24.92 (-8.9)	(-4.8)	25.17 (-8.00)	24.80 (-9.4)	25.03 (-8.5)	*Break-even Blocks
300	38.37	36.59 (-4.6)	(-2.4)	37.58 (-2.1)	36.20 (-5.7)	37.16 (-3.4)	
400	45.37	48.26* (6.4)	* (3.1)	49.99* (10.2)	47.61* (4.9)	49.29* (8.6)	
500	52.37	59.93 (14.4)	(6.7)	62.4 (19.2)	59.01 (12.7)	61.42 (17.3)	
600	58.62	71.60 (22.1)	(9.9)	74.81 (27.6)	70.42 (20.1)	73.55 (25.5)	
700	64.87	83.27 (28.4)	(12.4)	87.22 (34.5)	81.82 (26.1)	85.68 (32.1)	
800	71.12	94.94 (33.5)	(14.3)	99.63 (40.1)	93.23 (31.1)	97.81 (37.5)	
900	77.37	106.61 (37.8)	(15.8)	112.04 (44.8)	104.63 (35.2)	109.94 (42.1)	
1000	83.62	118.28 (41.4)	(17.0)	124.45 (48.81)	116.04 (38.8)	122.07 (46.0)	

TABLE 8-20B

BILL IMPACT COMPARISONS, RATE 10

Consumption in kWh	Bill for Present Tariff	a Bill for Modified Present Tariff	b Bill for Declining Block (I)	c Bill for Declining Block (II)	d Bill for Inverted Block (I)	e Bill for Inverted Block (II)	f Bill for Inverted Block (III)
10	J.$1.99	J.$1.59 (-20.1%)	J.$1.59 (-20.1%)	J.$1.59 (-20.1%)	J.$1.59 (-20.1)	J.$1.59 (-20.1)	J.$2.65 (-33.2%)
50	8.78	8.17 (-6.9)	7.41 (-15.6)	6.83 (-22.2)	6.28 (-28.5)	6.46 (-26.4)	6.89 (-21.5)
100	16.35	16.41* (.4)	14.68 (-10.2)	13.38 (-18.2)	12.14 (-25.7)	12.56 (-23.2)	12.19 (-25.4)
200	27.36	27.74 (1.4)	29.23 (6.8)	26.48 (-3.2)	23.87 (-12.8)	25.16 (-8.0)	24.79 (-9.4)
300	38.37	39.07 (1.8)	37.56 (-2.1)	37.58 (-2.1)	37.60 (-2.0)	37.76 (-1.6)	37.39 (-2.6)
400	45.37	46.32 (2.1)	45.89* (1.1)	46.68* (7.3)	51.33* (13.1)	50.36* (11.0)	49.99* (10.2)
500	52.37	53.57 (2.3)	54.22 (3.5)	59.78 (14.1)	65.06 (24.2)	62.96 (20.2)	62.59 (19.5)
600	58.62	60.07 (2.5)	62.55 (6.7)	70.88 (20.9)	78.79 (34.4)	75.56 (28.9)	75.19 (28.3)
700	64.87	66.57 (2.6)	70.88 (9.3)	81.98 (26.4)	92.52 (42.6)	88.16 (35.9)	87.79 (35.3)
800	71.12	73.07 (2.7)	79.21 (11.4)	93.08 (30.9)	106.25 (49.4)	100.76 (41.7)	100.39 (41.2)
900	77.37	79.57 (2.8)	87.54 (13.1)	104.18 (34.7)	119.98 (55.1)	113.36 (46.5)	112.99 (46.0)
1000	83.62	86.07 (2.9)	95.87 (14.6)	115.28 (37.9)	133.71 (59.9)	125.96 (50.6)	125.59 (50.2)

*Break-even blocks.

reduce bills for consumption under 300 kWh and raise them for consumption over 400 kWh. Based upon the November 3, 1979 computer run of JPS 928, 81.4 percent of the bills in Rate 10 are at or below 300 kWh, and 9.7 percent of the bills at or above 400 kWh, with 8.9 percent falling between 300 kWh and 400 kWh.

JPS and public officials must decide how fast they wish to move from present promotional prices to flatter, flat or even inverted residential rates. Tables 8-20A and 8-20B outline the consequences of the choice on customer bills. The first step is to decide whether the first 10 kWh will continue to be included in the customer charge. Then, the ultimate tariff form should be selected. Finally, the implementation strategy should be formulated. It must be emphasized that in making these choices the percent changes indicated in Tables 8-20A and 8-20B do not include fuel adjustments and therefore generally exaggerate the differences by a factor of two, using present fuel costs. Note, if the world oil price trend continues, the actual percent differences will be even smaller.

8.7.1.2 Small Commercial (Rate 20)

8.7.1.2.1 Tariff Development: Table 8-21A shows the present JPS tariff and small commercial tariffs most in keeping with the ten tariff conditions outlined above which are based on marginal cost pricing principles.

Additionally, in order to present phase-in implementation options similar to the Rate 10 Residential Customers, Table 8-21B outlines three two-block tariffs. Two of them are declining blocks; one is an inverted conservation tariff. All three were designed to produce revenue equal to the present tariff. The first was developed using the current weighted average prices, while changing the blocks from four to two. Note, in all the new tariffs the first 10 kWh have been removed from the customer charge, and the customer charge was increased from its published level to its current level.

The next two tariffs in Table 8-21B are simple 2 cent differential tariffs designed to generate the same revenue. The first is a flatter declining block than the declining block I tariff and the second is a slightly rising inverted block tariff. A three step declining block tariff, retaining

TABLE 8-21A

STRUCTURE OF PRESENT AND OTHER SMALL COMMERCIAL RATE 20 TARIFFS

NOTE: All tariffs contain a $1.99 per month Customer Charge

Usage in kWh	Present Tariff	Flat Tariff (Low*)	Flat Tariff (High*)
0 to 10	0¢	12.42	12.77
11 to 100	29.64	12.42	12.77
101 to 1000	13.51	12.42	12.77
1001 to 10,000	10.63	12.42	12.77
over 10,000	8.00	12.42	12.77
Estimated Total Revenue	J. $\$22.62 \times 10^6$	J. $\$22.53 \times 10^6$	J. $\$23.15 \times 10^6$

As discussed in the text

TABLE 8-21B

POSSIBLE PHASE-IN TARIFFS

Usage in kWh	Declining Block (I)	Declining Block (II)	Inverted Block
0 to 1000	16.48	13.664	11.274
Over 1000	9.77	11.664	13.274
Estimated Total Revenue	J. $\$22.62 \times 10^6$	J. $\$22.62 \times 10^6$	J. $\$22.62 \times 10^6$

Usage in kWh	JPS Modified Decl. Block
0 to 10	0¢
11 to 100	20¢
101 to 1000	13.51¢
over 1000	11.13¢
Estimated Total Revenue	J. $\$22.62 \times 10^6$

the first 10 kWh as free is presented in Table 8-21B along with a modified phase-in to flatten rates considered previously by JPS for Rate 10 customers. It was derived by arbitrarily setting the first block price at 20 cents per kWh instead of 29.64 cents per kWh and making up the difference in revenue in a combined third and fourth step rate block.

8.7.1.2.2 Bill Impact: Table 8-22 shows the bill impact of the various tariffs outlined in Tables 8-21A and 8-21B. Columns (b) and (d) show the bill impacts of flat rates. Note, column (b) produces about J. $90,000 less than current tariffs, while column (d) produces about J. $520,000 more than current tariffs. All other columns are based upon the same revenue as current tariffs. The first declining block modification, which is shown in column (e) should not be given serious consideration. First customer bills decline, then increase, then decline. And while not shown, beyond 10,000 kWh they will start to increase again. The reason for this strange behavior is the fact that the new blocks and revenue weights used to determine prices did not match well with the existing blocks. The declining block tariff shown in column (f) corrects such matters. Column (c) shows the percent changes when a 12 cent per kWh fuel adjustment is added to both current and the flat rates shown in column (b). Note, as with Residential Rate 10, the consideration of fuel adjustment affects changes the percent change by a factor of approximately one-half. Column (h) shows the modified JPS traditional tariff, which is slightly flatter than present tariffs.

Decision-makers in Jamaica will, once again, be required to choose between reducing their current blocks from 4 to 3 or 2, establishing completely flat rates, or even introducing a small inversion in the commercial rates.

The break-even point for the tariffs, other than the previously rejected weighted average price declining block tariff, is between 2,000 and 3,000 kWh. About eighty-three (82.7) percent of the Rate 20 bills are 1,000 kWh or below, but about sixty (59.8) percent of the consumption is above 1,000 kWh as reported in the November 3, 1979 JPS 928 computer run. One note of caution, the Small Commercial consumption has fallen more than twenty percent in 1979. This would seem to indicate both conservation and an economic slowdown are present in the commercial accounts. Therefore, a slow phase-in such as column (f) may be a more preferable target

TABLE 8-22

BILL IMAPCT COMPARISONS, RATE 20

Consumption in kWh	a Bill for Present Tariff	b Bill for Low Flat Tariff	c Percent Bill Change with 12¢ FAE Added to (b)	d Bill for High Flat Tariff	e Bill for Declining Block (I)	f Bill for Declining Block (II)	g Bill for Inverted Rate	h JPS Modified Declining Block
100	J.$28.66	J.$14.41 (-49.7%)	(-35.0%)	J.$14.76 (-48.9%)	J.$18.47 (-35.6%)	J.$15.65 (-45.4%)	J.$13.26 (-53.7%)	J.$19.99 (-30.3%)
500	82.70	64.09 (-22.5)	(-13.0)	65.84 (-20.4)	84.39* (2.0)	70.31 (-14.9)	58.36 (-29.4)	74.03 (-10.5)
1000	150.25	216.19 (-16.0)	(-8.9)	129.69 (-13.7)	166.79 (11.0)	138.63 (-7.7)	114.73 (-23.6)	141.58 (-5.8)
2000	256.55	250.39 (-2.4)	(-1.2)	257.39* (.3)	264.49 (3.1)	255.27 (-.5)	247.47 (-3.5)	252.88 (-1.4)
3000	362.85	374.59* (3.2)	(1.6)	385.09 (6.1)	362.19* (-.2)	371.91 (2.5)	380.21* (4.8)	364.18* (.4)
4000	469.15	498.79 (6.3)	(3.1)	512.79 (9.3)	459.89 (-2.0)	488.55 (4.1)	512.95 (9.3)	475.48 (1.3)
5000	575.45	622.99 (8.3)	(4.0)	640.49 (11.3)	557.59 (-3.1)	605.19 (5.2)	645.69 (12.2)	586.78 (2.0)
6000	681.75	747.19 (9.6)	(4.7)	768.19 (12.7)	655.29 (-3.9)	721.83 (5.9)	778.43 (14.2)	698.08 (2.4)
7000	788.05	871.39 (10.6)	(5.1)	895.89 (13.7)	752.99 (-4.4)	838.47 (6.4)	911.17 (15.6)	809.38 (2.7)
8000	894.35	995.59 (11.3)	(5.5)	1023.59 (14.5)	850.69 (-4.9)	955.11 (6.8)	1043.91 (16.7)	920.68 (2.9)
9000	1000.65	119.79 (11.9)	(5.7)	1151.29 (15.1)	948.39 (-5.2)	1071.75 (7.1)	1176.65 (17.6)	1031.98 (3.1)
10,001	1107.03	1244.11 (12.4)	(5.9)	1279.11 (15.5)	1046.18 (-5.5)	1188.50 (7.4)	1309.52 (18.3)	1143.39 (3.3)

*(A comparison showing percentage change from present tariff is shown in parentheses below the actual billing amounts for each tariff shown.) Break-even blocks (block where comparison with present tariff moves from negative to positive) billing amounts are shown in J.$.

than columns (b) or (d). More information on where the consumption reduction has actually taken place should be known in order to make this decision.

8.7.1.3 Large Commercial (Rate 40)

8.7.1.3.1 Tariff Rate Development: As indicated previously, Large Commercial (Rate 40) and Industrial (Rate 50) customers are priced with two-part demand (kW) and energy (kWh) tariffs. Such a two-part tariff distinction is not inconsistent with marginal cost pricing principles. However, since the system has extra capacity and it is important to conserve foreign oil, tariffs will be developed both keeping and eliminating the two-part power and energy charges.

Existing large user tariffs also make use of expander and ratchet provision. As already indicated, these tariff features are inconsistent with marginal cost pricing principles. If the new large user tariffs are to be phased-in cautiously, eliminating the expander should be given a higher priority than eliminating the ratchet. Note also that the ratchet is sometimes useful in assessing transformer and transmission costs on a marginal cost pricing principle basis. In any event, both features have been presumed to be excluded from the new Rate 40 and 50 tariffs considered below.

In addition to flat energy and two-part flat energy and demand tariffs, the following analysis will consider peak to off-peak tariffs based upon a 3 cent per kWh ($30 per mWh) operating cost differential found in Section 8.5.4 and the assumption that two-thirds of the current sales are on peak.

Table 8-23 outlines the present and new tariffs considered for large commercial customers (Rate 40). Since present tariffs fall short of the revenue target by about J. $1 million, they have been increased in column (b) for the purposes of the bill impact analysis. For the typical customer each tariff in columns (b) to (f) is designed to produce the same bill, J. $1,947.29 per month for 108.3 kW and 29,854 kWh.

8.7.1.3.2 Bill Impact: Table 8-24 examines the bill impact for various customer consumption levels, without time variation.

TABLE 8-23

LARGE COMMERCIAL TARIFFS BASED ON MARGINAL COST PRICING PRINCIPLES (RATE 40)

	Add $2.15 per kW per month				No demand charge	
Present Tariff	Current Price (a)	Inc Revenue Price (b)	Flat Energy Price (c)	PEAK-OFF PEAK Price (d)	Flat Energy Price (e)	PEAK-OFF PEAK Price (f)
First 100 hours of Demand	6.38¢	6.75¢				
Next 200 hours of Demand	5.38¢	5.75¢	All kWh 6.11¢	PEAK kWh 7.11¢ OFF kWh 4.11¢	All kWh 6.11¢	PEAK kWh 7.89¢ OFF kWh 4.89¢
Over 300 hours of Demand	4.50¢	4.87¢				
ESTIMATED TOTAL REVENUE	J.$71.88 x 10^6	J.$18.89 x 10^6	J.$18.88 x 10^6	J.$18.88 x 10^6	J.$18.88 x 10^6	J.$18.88 x 10^6

TABLE 8-24

LARGE COMMERCIAL RATE 40
TYPICAL ELECTRIC BILLS WITHOUT TIME VARIATION

Consumption		kWh Charge				Total Bills		
		Present Expander	Inc Rev Expander	Energy Only Part 2	Demand Charge	Inc Rev Expander	Energy Part 1	Part 2 Energy and Demand
Energy kWh	Demand (kW)	(a)	(b)	(c)	(d)	(e)	(f)	(g
5,000	100	J.$ 319	J.$ 338	J.$ 306	J.$ 215	J.$ 553	J.$ 345	J.$531
5,000	200	319	338	306	430	768	345	736
10,000	100	638	675	611	215	890	689	826
10,000	200	638	675	611	430	1,105	689	1,041
25,000	100	1,445	1,538	1,528	215	1,753	1,723	1,743
25,000	200	1,545	1,638	1,528	430	2,068	1,723	1,958
25,000	300	1,595	1,688	1,528	645	2,333	1,723	2,173
50,000	100	2,614	2,799	3,055	215	3,014	3,445	3,270
50,000	200	2,890	3,075	3,055	430	3,505	3,445	3,485
50,000	300	2,990	3,175	3,055	645	3,820	3,445	3,700
100,000	100	4,864	5,234	6,110	215	5,449	6,890	6,335
100,000	200	5,228	5,598	6,110	430	6,028	6,890	6,540
100,000	300	5,592	5,962	6,110	645	6,607	6,890	6,755
100,000	400	5,780	6,150	6,110	860	7,010	6,890	6,970
150,000	100	7,114	7,669	9,165	215	7,884	10,335	9,380
150,000	200	7,478	8,033	9,165	430	8,463	10,335	9,595
150,00	300	7,842	8,397	9,165	645	9,042	10,335	9,810
150,000	400	8,206	8,761	9,165	860	9,621	10,335	10,025
150,000	500	8,570	9,125	9,165	1,075	10,200	10,335	10,240
175,000	100	8,239	8,887	10,693	215	9,102	12,058	10,908
175,000	200	8,603	9,251	10,693	430	9,681	12,058	11,123
175,000	300	8,967	9,615	10,693	645	10,260	12,058	11,338
175,000	400	9,331	9,979	10,693	860	10,839	12,058	11,553
175,000	500	9,695	10,343	10,693	1,075	11,418	12,058	11,768

Columns (a), (b) and (c) of Table 8-24 indicate the energy charge portion of the bill. Column (d) is the corresponding demand charge that should be added to each to determine the total bill. Column (e) equals column (b) plus column (d), and column (g) equals column (c) plus column (d). Column (f), which is also a total bill, is derived from a single all flat energy charge. That is, there is no separate demand charge. Very large energy users bear a significant shift in revenue responsibility. As such, this column is analogous to the inverted conservation Rate Codes (10) and (20).

The most significant columns for decision-makers to consider are (e), (f) and (g). Retaining the expander means charging smaller volume Commercial users more than the all-energy, one-part tariff as well as the two-part flat energy and demand tariff. This situation generally holds for consumption of 100,000 kWh and above. A similar pattern is observed when the two-part flat energy and demand charge tariff show in column (g) is compared to column (e). Note, however, the differences between (g) and (e) are smaller than between (f) and (e) because column (g) continues the two-part option, and therefore does not favor lower energy consumption as much, nor does it penalize higher energy consumption as much. All tariffs produce about the same revenue for the typical Rate 40 customer (108.3 kW and 29,854 kWh). The bills for 100 kW and 25,000 kWh in columns (e), (f) and (g) are J. $1,753, J. $1,723 and J. $1,743, respectively.

Columns (a), (b) and (c) show the energy charge portion of a customer's bill for two-part tariffs (note the demand portion would be equal for each). When time variation is introduced, even large volume customers, who use fifty or more percent of their use in the off-peak periods (assumed to be set at about 10 hours for weekdays and Saturdays, and all day Sunday), will be able to reduce their bills. It is the large volume Commercial customers, who use most of their use (70 percent or more) on-peak, that will pay more than the present tariff, and even flat energy columns (d), (e) and (f) show identical results for total bills, but because the demand portion has been rolled into the energy charge for both the flat (d) and time of use tariffs (e), discounts for lower energy use and penalties for higher energy use are more severe. Accordingly, the conservation message is stronger.

Generally, it is not a good idea to move to a two-part time of use tariff as a transition step to an all-energy charge time of use tariff. However, given the experience with two-part tariffs in Jamaica, the Jamaican situation may call for as a transition, or even as a final step, the move towards a two-part time of use tariff from the current, two-part expander tariff.

In summary, both Tables 8-24 and 8-25 customers who are supplied by tariff Rate 40 and whose use is at or below average energy and demand levels (about 30,000 kWh and 100 kW respectively) would find their bills lowered under either a one-part flat energy, two-part flat energy and flat demand, one-part time of use (peak/offpeak) tariff, or two-part time of use tariff.

Larger volume consumers, who receive strong discounts from the expander, would receive bill increases of about ten percent. However, when time variation is considered, the large customers who use fifty percent or less of their energy during peak periods (the class average is assumed to be 66.7%) will also receive bill reductions under the peak/off-peak tariff options.

If tariffs are to be reformed as discussed above for Rate 40 customers, the larger volume high system load factor (high percentage off system peak) customer should certainly be offered an optional time of use tariff. Assuming the energy charge is flattened, keeping a demand and energy charge also seems desirable when the very large volume user bill impact is analyzed in Tables 8-24 and 8-25. In subsequent tariff modifications this could also be changed.

Finally, if demand charges, either with or without time of use charges, are retained, the reading should be made during the peak periods for the larger volume of Rate 40 customers.

8.7.1.4 Industrial (Code 50)

8.7.1.4.1 Tariff Development: Tariff development and philosophy for Rate 50 closely parallel the tariff development of Rate 40. Table 8-26 outlines the present and new tariffs which are based upon marginal cost pricing principles. Therefore, the expander and ratchet are eliminated. Both two-part and one-part, flat and time of use tariffs are considered. All tariffs in Table 8-26 produce about the

TABLE 8-25

LARGE COMMERCIAL RATE 40
TYPICAL ELECTRIC BILLS WITH TIME VARIATION

Consumption			Energy Charge Revenue			Total Bills		
Energy kWh	Demand kW	% on Peak	Increase Revenue Expander (a)	Energy for Part 2 (b)	Energy for Part 2 PEAK (c)	Part 1 Flat Energy (d)	Part 1 PEAK (e)	Increased Revenue Expander Plus Demand (f)
5,000	100	50	J.$ 338	J.$ 306	J.$ 281	J.$ 345	J.$ 320	J.$ 553
5,000	100	60	338	306	296	345	335	553
5,000	100	70	338	306	311	345	350	553
50,000	200	50	3,075	3,055	2,805	3,445	3,195	3,505
50,000	200	60	3,075	3,055	2,955	3,445	3,345	3,505
50,000	200	70	3,075	3,055	3,105	3,445	3,495	3,505
100,000	200	50	5,598	6,110	5,610	6,890	6,390	6,028
100,000	200	60	5,598	6,110	5,910	6,890	6,390	6,028
100,000	200	70	5,598	6,110	6,210	6,890	6,390	6,028
150,000	200	50	8,033	9,165	8,415	10,335	9,585	8,463
150,000	200	60	8,033	9,165	8,865	10,335	10,035	8,463
150,000	200	70	8,033	9,165	9,315	10,335	10,485	8,463
150,000	400	50	8,761	9,165	8,415	10,335	9,585	9,621
150,000	400	60	8,761	9,165	8,865	10,335	10,035	9,621
150,000	400	70	8,761	9,165	9,315	10,335	10,485	9,621

TABLE 8-26

INDUSTRIAL TARIFFS BASED ON MARGINAL COST PRICING PRINCIPLES RATE 50

	Add 1.83 per Kva per month			Total Bill No Demand Charge	
Present Tariff	Current	Flat Energy Part 2 Price	PEAK-OFF PEAK Part 2 Price		
	Price (a)	Price (b)	Price (c)	Price (d)	Price (e)
First 100 hours of Demand	6.38¢				
Next 200 hours of Demand	5.38¢		PEAK kWh 6.82¢		PEAK kWh 7.55¢
Next 200 hours of Demand	4.00¢	All kWh 5.82¢	OFF kWh 3.82¢	All kWh 6.55¢	OFF kWh 4.55¢
Over 500 hours of Demand	3.50¢				
ESTIMATED TOTAL REVENUE	J.$9.25 x 10^6	J.$9.28 x 10^6	J.$9.28 x 10^6	J.$9.24 x 10^6	J.$9.24 x 10^6

same revenue. Estimated bills for the typical Rate (50) customer produce about the same revenue. The typical Rate (50) customer uses 491,000 kWh per month and 2,036 Kva of demand. (It is assumed that 1 Kva = 1 kWh for billing purposes.)

8.7.1.4.2 <u>Bill Impact</u>: Tables 8-27 and 8-28 are developed in a manner similar to Tables 8-24 and 8-25 for Rate 40. The conclusions are similar. Rate 50 consumers of an average or less than average amount of energy and demand would receive reduced bills. The large energy users on Rate 50 would receive increased bills of about 10 percent or less if use is about 1,000,000 kWh. However, the very large Rate 50 customers (there are not many) could receive increases of 25 percent and more, if they used a high proportion (70% or more) of their use during peak periods.

In Table 8-27 the total bill comparisons in columns (d), (e) and (f) are most important. They show that industrial customers using 250,000 kWh or less would pay less under either the flat all-energy charge or flat two-part tariffs than the present two-part expander tariff. Above that amount, customer bills increase, although the typical customer's bill (about 500,000 kWh and 2,000 kWh) is approx-mately equal: for the two-part expander (d), one-part flat energy (e) and two-part (f), the bills are respectively J. $32,560, J. $32,750 and J. $32,760. The differences with respect to the present bills are greater for the flat all-energy tariff option than the two-part option.

In Table 8-28 the time of use variation is introduced. The very high system load factor customer (more use offpeak) may avoid any penalties that may be associated with the elimination of the expander. Columns (d), (e) and (f) are the most important. They show results similar to the Rate 40 comparison, and the conclusions are identical, and perhaps, given the size of the Rate 50 consumers, even more apropos. If Rate 50 customers are having their tariff structures altered, the very largest should be given optional, or mandatory, time of use tariffs. Such customers in the 1,500,000 kWh range could then actually have bill decreases if fifty percent or more of their use was off-peak. If two-part tariffs, demand and energy, are selected, the large Rate 50 customers should be put on meters that only record demand during peak times.

TABLE 8-27

INDUSTRIAL RATE 50
TYPICAL ELECTRIC BILL WITHOUT TIME VARIATION

Consumption Energy kWh	Demand (kW)	kWh Charge: Present Expander (a)	kWh Charge: Energy of Part 2 (b)	Demand Charge (c)	Total Bills*: Energy & Demand of Expander (d)	Total Bills*: Part 1 Flat Energy (e)	Total Bills*: Part 2 Flat Energy (f)
50,000	1,000	3,190	2,910	1,830	5,020	3,280	4,740
50,000	2,000	3,190	2,910	3,660	6,850	3,280	6,570
100,000	1,000	6,380	5,820	1,830	8,210	6,550	7,640
100,000	2,000	6,380	5,820	3,660	10,040	6,550	9,480
250,000	1,000	14,450	14,550	1,830	16,280	16,380	16,380
250,000	2,000	15,450	14,550	3,660	19,110	16,380	18,210
250,000	3,000	15,950	14,550	5,490	21,440	16,380	20,040
500,000	1,000	25,140	29,100	1,830	26,970	32,750	30,930
500,000	2,000	28,900	29,100	3,660	32,560	32,750	32,760
500,000	3,000	29,900	29,100	5,490	35,390	32,750	34,590
1,000,000	1,000	42,640	58,200	1,830	44,470	65,500	60,030
1,000,000	2,000	50,280	58,200	3,660	53,940	65,500	61,860
1,000,000	3,000	55,420	58,200	5,490	60,910	65,500	63,690
1,000,000	4,000	57,800	58,200	7,320	65,120	65,500	65,520
1,500,000	1,000	60,140	87,300	1,830	61,970	98,250	89,130
1,500,000	2,000	67,780	87,300	3,600	71,440	98,250	90,960
1,500,000	3,000	75,420	87,300	5,490	80,910	98,250	92,790
1,500,000	4,000	80,560	87,300	7,320	87,880	98,250	94,620
1,500,000	5,000	85,700	87,300	9,150	94,850	98,250	96,450
1,750,000	1,000	68,890	101,850	1,830	70,720	114,630	103,680
1,750,000	2,000	76,530	101,850	3,660	80,190	114,630	105,510
1,750,000	3,000	84,170	101,850	5,490	89,660	114,630	107,340
1,750,000	4,000	90,560	101,850	7,320	97,880	114,630	109,170
1,750,000	5,000	95,700	101,850	9,150	104,850	114,630	111,000

*Columns (d) and (f) equal (a) + (c) and (b) + (c) respectively.

TABLE 8-28

INDUSTRIAL RATE 50
TYPICAL ELECTRIC BILLS WITH TIME VARIATION

Consumption			Energy Charge Revenue			Total Bills		
Energy kWh	Demand kWh	% on PEAK	Present EXPANDER (a)	Energy for Part 2 (b)	Energy for Part 2 PEAK (c)	Part 1 Flat Energy (d)	Part 1 PEAK (e)	Expander plus Demand (f)
50,000	1,000	50	J.$ 3,190	J.$ 2,910	J.$ 2,660	J.$ 3,280	J.$ 3,030	J.$ 5,020
50,000	1,000	60	3,190	2,910	2,810	3,280	3,180	5,020
50,000	1,000	70	3,190	2,910	2,960	3,2[illegible]0	3,330	5,020
500,000	2,000	50	28,900	29,100	26,600	32,750	30,250	32,560
500,000	2,000	60	28,900	29,100	28,100	32,750	31,750	32,560
500,000	2,000	70	28,900	29,100	29,600	32,750	33,250	32,560
1,000,000	2,000	50	50,280	58,200	53,200	65,500	60,500	53,940
1,000,000	2,000	60	50,280	58,200	56,200	65,500	63,500	53,940
1,000,000	2,000	70	50,280	58,200	59,200	65,500	66,500	53,940
1,500,000	2,000	50	67,780	87,300	79,800	98,250	90,750	71,440
1,500,000	2,000	60	67,780	87,300	84,300	98,250	95,250	71,440
1,500,000	2,000	70	67,780	87,300	88,800	98,250	99,750	71,440
1,500,000	4,000	50	80,560	87,300	79,800	98,250	90,750	87,880
1,500,000	4,000	60	80,560	87,300	84,300	98,250	95,250	87,880
1,500,000	4,000	70	80,560	87,300	88,800	98,250	99,750	87,880

8.7.1.5 Large Commercial and Industrial Tariff Phase-In

In addition to those already discussed, there are other considerations to make when phasing-in new tariffs for large customers. The following simple rules should be considered:

(1) Meet with the large Rate 40 and Rate 50 consumers and explain the new tariffs and the philosophy behind them.

(2) Decide to provide dual billings for six months or a year in order to help the large consumers adjust.

(3) Do not pick a phase-in policy that creates a middle step inconsistent with the end result. For example, if demand charges are to be eliminated it does not make sense to put on peak demand readings into the tariffs for a short interim period (six months or a year).

(4) If new tariffs make sense for the average Rate 40 and 50 consumer, but not the largest, consider special negotiated tariffs for these largest customers.

8.8 CONCLUSIONS AND RECOMMENDATIONS

As discussed with JPS, specific recommendations as to which type of tariff should be adopted are not presented in this report. Instead, various tariff options, based on marginal cost pricing principles, have been presented for each Rate category in the JPS system. These options demonstrate immediate or interim steps that can be taken to gradually approach marginal cost pricing so that the implementation rate of tariff changes can be completely controlled. The effects of each step in tariff development, and the associated customer bill impacts are indicated.

The overall conclusion is that JPS and public officials should review these options and develop strategy compatible with economic goals and plans, social considerations and other factors. From this an implementation plan should be established to sequence Rate tariff changes consistent with Jamaican needs and plans.

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8.10 APPENDICES

APPENDIX A - Terms of Reference

Task 6 - Electric Utility Rate Analysis

The purpose of this study is to derive a practical tariff structure which will:

1. Promote a more economic use of electricity in the Jamaican society.

2. Maintain the financial viability of the electric utility.

3. Optimize the use of fuel and foreign exchange.

4. Meet any income distribution objectives (e.g., subsidizing poorer consumers) which the electricity tariff may be required to serve.

The study should include the following elements:

1. The determination of the long-run marginal cost of supply by analyzing the marginal costs of generating transmitting and distributing electricity to consumers at different places, times and voltage levels. This will require attention to the daily and seasonal variations in actual and forecast demands and, to the extent possible, in forecast demands of various consumer classes. Much of the required information may have to be specially collected, e.g., by taking substation readings, by enquiring about shift-working and seasonal work patterns and by statistical analysis of available load curves. Particular attention should be given to identification of consuming sectors responsible for unusually high demands during peak load periods.

2. An examination of the present customer classifications to determine if each class exhibits appropriate characteristics (e.g., cost/consumption). Based on this examination, a recommendation for modifications to the customer classifications would be developed.

3. An analysis of price elasticities and associated response times for each customer classification

(using available historical data). This analysis would include the effect of changes in the prices of electricity, appliances and equipment on consumer demand.

4. An investigation of the social benefits to be derived from subsidizing poorer consumers and the development of a quantitative index of the benefits derived (or the identification of such an index developed in other studies).

5. A determination of the revenue requirements to maintain the financial viability of the electric utility.

6. A determination of the foreign exchange required to operate the utility.

7. A new tariff structure should be developed based on consideration of the factors outlined above, along with considerations of practicality, such as metering and administration.

8. A determination should be made of the sensitivity of the foreign exchange requirement to changes in the tariff structure, in particular a structure that promotes shift of selected loads from peak to off-peak.

9. The new tariff structure should be compared with the existing tariff structure, and the implications of a change to the new tariff investigated. Of particular concern would be the effect of price elasticity (for each consumer classification), the effect on present or potential industrial growth and probable consumer reaction.

10. A formula permitting automatic adjustment of the new tariff to allow for changes in the cost of fuel should be developed.

11. Recommendations for the expedient implementation of the new tariff structure (as proposed after any required revisions) should be developed.

12. A load forecast study involving the development of a computer-based model to be used by the JPS

for electric load forecasting, including projections of the requirements for additional generating capacity, transmission lines and major substations and geographic distribution of the electric load.

The study should be conducted in such a way that the maximum amount of training is imparted to the Jamaican counterparts in order that they may undertake their own future updating of the tariff structure.

APPENDIX B Final Report Conference
Splinter Group Discussion

Before the U.S. Energy Team members left Jamaica, a Final Report Conference was held at the Jamaica Pegasus Hotel on November 13 and 14, 1979. During the first day of the conference, the U.S. Energy Team members and Jamaican counterparts presented the findings, conclusions and recommendations of each of the specialized studies. For greater exposure and increased audience participation, splinter group discussions were held during the second day. Each of the studies had a 2-3 hour question and answer session in which study parameters were reviewed and results highlighted. The following is a synopsis of the Electric Utility Rate Analysis splinter group discussion.

Respondents: Al Casserly - Jamaica Public Service Company
Warren Smith - Jamaican National Investment Company
William Gillen - U.S. Energy Team Member

Q.8.1. Is there a target watts per capita for Jamaica to achieve?

A.8.1. (Casserly) No, there is no target as such. Whether or not there should be such a policy to limit per capita consumption is something that one can look at. But I think what we should recognize that one of the barometers of economic progress is the per capita use of electricity. Most countries tend to encourage its use and, in fact, point to the per capita usage as a sign of growth in the economy or general development of the country.

A.8.1. (Gillen) I would like to comment about the first part of the question and partially in response to what Mr. Casserly has just said. If you look at some of the Scandanavian countries, you will find good economic growth with low growth in energy consumption. I think the point to be made is that one can maintain the levels of economic growth without, necessarily, having a corresponding increase in energy consumption. We can achieve this by reducing the waste of energy and increasing the efficiency.

Q.8.2. Generally, to what level of income was there a linear relationship to energy usage?

A.8.2. (Smith) The nature of the relationship between energy consumption and national income depends, to a large extent, on the availability of substitutes. The problem is tha in the past, these have been very, very cheap relative to inputs in the production process. The real price of petroleum actually fell up to 1975 and there is still some question as to whether the real price of petroleum has actually risen since 1973. Because of the relative cheapness of energy as a production input relative to other inputs one does find this positive and somewhat linear relationship. Whether this will continue into the future, I believe, depends largely on the relative cost of the different sources of energy.

A.8.2. (Casserly) There is an additional point which should be made on the question of per capita usage. The market and the economy tend to regulate themselves and recently when we looked at the average use per residential customer on the island, we found that the average domestic customer usage in 1978 was in fact just below what it was in 1968 or 1969. This means you haven't grown in line on customer usage of energy. It didn't, of course, remain the same throughout the entire period; in 1973-1974, it was at its peak. For example, you are looking at an average usage in 1968 of about 2000 kWh per residential customer. By 1974, it was about 2450 kWh per residential customer but by 1978 it had gone down to, I think, 1965 kWh - again, emphasizing that it tends to be a reflection of what's happening in the economy (the market regulating itself).

Q.8.3. How would we go about trying to regulate electricity prices?

A.8.3. (Gillen) We have experience in perhaps a dozen countries and perhaps twenty states in the U.S. where we have dealt with this problem. The problem is, in regulating electricity prices, one is trying to do two things: (1) Produce a set of tariffs which are rational from the standpoint of the allocative functions of prices. That is, informing the people what the cost to society is in the consumption of electricity. (2) This is a constraint. That is, one would like to make sure that the utility earns enough money to continue to be a stable, financial and viable entity and at the same time not make too much money. This is somewhat less of a problem when the government itself owns and operates the electrical utility. But when you have a privately owned utility which operates as a monopoly under government charter, then it's a more severe problem. One wishes to develop tariffs which provide both useful information to consumers about the societal cost of electricity consumption, and also produce revenues which are fair, appropriate and justifiable for the utility as a whole. Now there is absolutely no reason why one would expect one tariff to produce the same amount of money as another. That is, the marginal cost base tariffs will not, except by unlikely happenstance, yield the amount of revenues that are determined to be appropriate to growth. So, a way has to be found to reconcile these conflicting objectives. The procedure most frequently used in the U.S. has been to adjust elements of the tariff structure which are felt to have the least impact on a consumer's decision to consume more or less electricity. There are certain costs that utility incurs whether electricity is consumed or not. But, gènerally speaking, the decision to consume more or less electricity is not affected by the size of that fixed charge. That is an element in the cost structure which can be adjusted in the marginal cost structure, in order to meet the revenue constraint or the profit constraint without doing much damage to the signalling function of prices as a whole.

There are other additional tactics which can be used. For example, one might maintain prices in the same ratio to the marginal costs although different in absolute amounts, or maintain the same absolute difference between the prices of electricity consumed under one circumstance as electricity consumed under another. Largely, those are judgment calls, and usually have to be decided on a case-by-case basis. There are three approaches which have been used with some success in the United States. ("Success" in that people find them acceptable, from the standpoint of overall profitability or they are not seriously objectionable to those who advocate marginal costs.)

Q.8.4 Can you explain the meaning of elasticity in your

Terms of Reference?

A.8.4 (Smith) One item in the Terms of Reference in this particular study was that elasticity estimates should be carried out for the category of electricity consumers. This analysis has actually been completed. We tried to build a statistical model which recognized the types of adjustment problems that electricity consumers face; in other words, when electricity consumers respond to price changes in two basic ways: (1) Initial response to a price increase, for example, would be to try to conserve the use. This is a short-term response. (2) A longer-term response to a price increase might be that one may decide that when his stock of electrical appliances wears out, then he might replace his electric water heater with a gas or solar water heater. So, there are two types of responses: short-term and long-term. The elasticity estimates have tried to capture that two-fold response. The estimates we have received for both the short- and long-run elasticities indicate that demand is more in the short- rather than the long-term. But in general, the response is inelastic. The percentage of change in consumption is not as great as the percentage of change in price.

A.8.4. (Gillen) Mr. Smith used the term "inelastic" which means an insensitivity of consumption to price. This is a technical term, whereby an exact proportion between change in consumption and change in price is said to have an elasticity of 1. If the change in consumption is more than proportional with change in price, it is said to be elastic and, if less, it is said to be inelastic.

A.8.4. (Casserly) Looking at the tariff cost structure on a marginal cost price basis, the first step we will take is to look at this class of customers and try, when we've adjusted the tariff, to maintain the same amount of revenues within the class. We wouldn't structure it in such a way as to cause a hotel to close down because it can't afford to run the equipment. If that happened, it would mean that we would, in fact, be transferring revenue from other categories into the hotel's category. On the reverse, the same would hold true, for the hotel to get electricity much cheaper would mean that others would have to be subsidized in that group and we don't propose to do that.

A.8.4 (Gillen) The question is of distribution of revenue within the class rather than between the classes. Marginal cost analysis does not focus, per se, on generation capacity. Generation capacity costs are an element in marginal cost analysis such as transmission capacity, losses and marginal running costs and, in fact, they all flow. We are at a preliminary stage in the analysis. One thing that has become clear is that marginal capacity costs for both generation and transmission are wide open questions in this particular case. It seems to us the JPS is in a somewhat different circumstance than other cases we've looked at. This is an especially good reason not to make suppositions of relative levels of on-peak and off-peak prices, or on-peak and off-peak marginal costs.

A second consideration has to do with the definition of conservation. One might say the general idea is to reduce energy consumption wherever possible. Clearly, one wants to reduce consumption the most for those users who are most expensive. That's the general philosophy which one expects to follow in marginal cost pricing. That means that some uses of electricity at certain, less costly conditions (essentially because they consume less oil), have a lower price than electricity consumed under other circumstances by more expensive machines. An additional element worth bringing up is one that Mr. Smith mentioned yesterday: the logic behind marginal cost analysis is a general belief that prices have an allocative function. However, resources can be allocated in society by means other than price. Thus, if the suggestion is that there are certain uses of electricity which constitute the squandering of a nation's resources, there are elements other than price which can control that. You can use those other allocative means such as administrative policies either as a substitute for, or in connection with, a price rationing scheme. The difference one wishes to capture in doing a marginal cost analysis is that some facilities are more expensive to build and use than others.

Q.8.5. Does marginal costing allow the use of different customer rates? Can you retain what you now have as a rate structure encompassing residential, commercial, etc.?

A.8.5. (Smith) A marginal cost exercise attempts to identify the structure of the rates. It doesn't concern itself, at that stage, with the level of the rate. In designing this structure, one would try to identify or group together those classes of customers which impose a similar type of cost on the system. Thus, if residential type consumers impose a greater cost on the system than large industrial users, they would be in a different category.

The answer, then, is yes. There would be different classes, though they might not necessarily be classified as they presently are. In other words, we examine the existing structure to see if, in fact, those existing classifications are cost justifiable.

A.8.5 (Gillen) In Wisconsin, we have different rates for rural and residential use. At the time the rate difference was set up, the people who ran the utility knew that there was a cost difference and tried to reflect it. However, that was some twenty or thirty years ago. Over time what we now have, in Wisconsin, is not so much a regular and a rural ratio, but an urban and suburban. There is an instance in which there is a difference in rates which do not now reflect differences in cost, although at the same time the rates were instituted they clearly did.

This is exactly the type of re-examination that is going on now at JPS.

Q.8.6. Is it possible to change the rate structure?

A.8.6. (Casserly) In changing the rate structure we would have to install additional equipment. Then we would have to evaluate additional costs in relation to the revenue we would expect to derive. This evaluation would have to be part of the economic study.

The cost of the implementation would also have to be taken into account.

Q.8.7. Is the tariff adequate today? What would be the impact in general terms?

A.8.7. (Gillen) Ultimately, it should be none. Marginal cost is constrained by other considerations such as the financial end.

Q.8.8. The rural electrification extension scheme is a socially rather than economically viable scheme. Therefore, to what extent will this scheme affect the proposed practical tariff structure, and will there eventually be a cut-off of the rural electrification program?

A.8.8. (Casserly) The first statement is correct. It is, to some extent, a social program and by itself would not be economically viable. What we have endeavored to do is finance that program on terms other than what we would normally use for the electric utility. We have IADB loans and government equity inputs, all of which have helped to bring down the cost of the capital investment. We also have an extended payment program so that the annual cost to the companies is considerably less that it would have been. The repayment begins some 5-6 years after the investment has been made, which allows some time for the investment to begin to earn.

A cut-off of major expansion will come, but as the country grows, there will always be small pockets needing those extensions, so we might have a continuing rural electrification program on a much smaller scale. What I hope we would have is a program continuing for a very long time with a house-wiring program. I want such an adjustment program because we have found that while JPS lines went into many areas, there weren't as many customers as we would have liked; they couldn't afford the initial house-wiring costs. The large-scale program as such will scale down as we take the supply into the accessory areas, but there is still a need for continuing a small program.

A.8.8. (Smith) The essential purpose of a marginal cost exercise is to identify the true social cost of an increased unit of electricity. What does it cost to provide that incremental unit? If one were to go on strictly economic grounds, perhaps one might not provide electricity to a person in a remote rural community; however, this may have a detrimental effect on the advancement of society.

A.8.8. (Casserly) To what extent will this affect the proposed practical tariff structure?

In the past, we have not set a tariff for REP customers as such, and we wouldn't propose to set a tariff for REP. The goal is to have one unified tariff which is applicable throughout the island. So, whether you are in a rural or an urban area, residential or commercial, the same basic tariff would apply. There is no plan to develop any specific tariff for the REP.

Q.8.9. What considerations are taken into account in order to optimize the use of natural resources in determining rate structures?

A.8.9. (Smith) My presentation yesterday was prefaced by a discussion of the theoretical justification of marginal cost pricing. What economists love to argue is that it can be shown, through mathematics, that if you price goods and services at marginal cost you maximize the benefits to society. What you would end up with is optimum allocation of the resources in your society, or even optimum use of your resources, natural or otherwise.

A.8.9. (Gillen) I am also an economist and I share Warren's appreciation for the models mentioned before. However, we must also recognize that they have almost no significance to us as practical people.

The general hypothesis is that if you can find out the economic cost of resources, then there is something you can use to weight our natural resources against other factors. We can't guarantee that an optimum use of natural resources will coincide with a marginal cost.

Q.8.10. Would the interrupted load be capable of incorporation with the load management system in air conditioning?

A.8.10. (Casserly) In JPS, we haven't done anything on the interrupted load capability system for air conditioning. We had some discussions on interrupted load systems for irrigation pumping which recommended that farmers use electricity during off-peak hours. No policy on handling and cost of electricity has been established.

A.8.10. (Smith) The interrupted load rate system uses the combination of pricing and administrative technique in allocating resources. We don't allow a certain class of consumers complete freedom in deciding the period of time to consume electricity. We allocate a certain period of time in a day for them, e.g., an agricultural rate on pumping. At times other than the assigned period, they would not obtain the agricultural rate for pumping. This is the most effective rationing system.

Q.8.11. Are you implying this will cut down the electricity consumption for pumping?

A.8.11. (Casserly) We simply mean to shift the pumping from the peak period to the off-peak period.

Q.8.12. Would it be the same price for the electricity consumption of pumping during the assigned period?

A.8.12. (Casserly) No, there should be an attractive price to entice farmers to shift to that pumping period.

Q.8.13. Is that process applicable to industrial business?

A.8.13. (Gillen) The interrupted load system would only apply to industrial processes that can be interrupted. This system would need an agreement between the utility and the consumer. There are additional analyses to be performed, such as efficiency on power generation, period of maximum power demand, amount of power generation, period of consumption and power requirement, etc., before the system could be used. A study was performed to establish policy and benefits of using this type of system. This system would actually be able to reflect the decrease of the cost of electricity.

Q.8.14 How should the utility go about improving the efficiency of its service?

A.8.14. (Gillen) The utility controls the generation of electricity because it knows when production is less expensive. It can also shut off power supply in certain applications without interrupting the service to customers. On the other hand, tariffs affecting costs indicate consumers should use the utility wisely. The load management interrupted power division and the tariff working together should produce a substantial benefit.

Q.8.15. What will be the maximum demand cost for the rate of a community of 30, 40 or 50 customers?

A.8.15. (Gillen) At the present time, I don't know the answer. We propose to answer this question at the end of this study.

Q.8.16. How does the aluminum company produce cheaper electricity than JPS?

A.8.16. (Casserly) The aluminum company's power is a by-product of the steam from the plant, some of which is used to generate power. So, its electric cost does not reflect the total cost of the plant.

Q.8.17. Do you take the natural resources in this country, such as hydropower, into consideration of power generation?

A.8.17. (Casserly) We have explored the possible uses of hydropower. The topography of this island provides good locations for hydropower in a range from 18,000 kW to 70 MW. The utilization of other alternative energies is also being explored.

Q.8.18. Why do we have the oil adjustment cost?

A.8.18. (Casserly) I would think that we still have to maintain fuel price by adding the oil adjustment cost because the oil price rises as the supply lessens. This is also true of coal because there are costs incurred to explore possible locations of coal reserves.

Q.8.19. Is it common in the U.S. power tariff structure to have an oil adjustment cost?

A.8.19. (Gillen) Yes, in the U.S. we call it fuel adjustment cost.

Q.8.20. When will the study be submitted?

Q.8.20. (Casserly) I expect the study to be completed by the end of this year (1979).

Q.8.21. When you receive the study, will you review and ask recommendations based on your conclusions?

A.8.21. (Casserly) Yes.

Q.8.22. Do you have plans on how to improve JPS electric service? How about nuclear power?

A.8.22. (Gillen) Some nuclear reactors which are of suitable size for JPS can generate electricity within the present JPS facility. However, the reactor is designed to produce nuclear material for weapons. The electricity produced is a by-product. Its cost is much higher than oil. Another plan is to buy a 1000 MW generator. There is one in Jamaica, but you need several to act as back-up units in each plant. This constraint is a technical problem.

A.8.22. (Casserly) A few years ago, we made a survey on nuclear power, and found problems in the areas of technology, safety, environment, and international organizational funding.

Q.8.23. How do you structure the electricity cost to customers? Do you take care of the correction factor too?

A.8.23. (Casserly) We use the demand charge and power factor charge to structure the tariff system. Yes, we take care of the correction factor; when it is off, we will call it to their attention and correct it.