Office of Utilities Regulation

Jamaica Public Service Company Limited Tariff Review for period 2004 -2009

Determination Notice

OUR
OFFICE OF UTILITIES REGULATION

June 25, 2004

DOCUMENT TITLE AND APPROVAL PAGE

DOCUMENT NUMBER: Elec 2004/02.1

1. DOCUMENT TITLE: Jamaica Public Service Company Limited - Tariff Review for period 2004 - 2009 - Determination Notice

2. PURPOSE OF DOCUMENT

This document sets out the expanded version and reasons for the Office's decisions, which were made public on June 1, 2004, regarding the prices to be charged and the mechanism for price control for electricity services provided by Jamaica Public Service Company.

3. RECORD OF DOCUMENTS ON ISSUE

Document Number	Description	Date
Elec 2004/2	Summary of Decisions - JPS Tariff Review 2004-2009	May 31, 2004

4. APPROVAL

This document is approved by the Office of Utilities Regulation and the Decisions therein became effective June 1, 2004.

On behalf of the Office:

……………………………..
J Paul Morgan
Director General

June 25, 2004
Date

Abstract

This determination of the non-fuel rate base for the Jamaica Public Service Company Limited (JPS) is made in accordance with the JPS All-Island Electricity Licence 2001 ("The Licence"). The Licence stipulates that the current tariffs, which were fixed by the Office of Utilities Regulation (the Office) effective April 1, 2001, expire on May 31, 2004. JPS submitted an application for tariff review and proposed tariffs on March 1, 2004. The Licence provides for the proposed tariffs to become effective ninety (90) days after acceptance of the filing by the Office, that is on June 1, 2004, unless varied by the Office.

Under the current Tariff arrangement JPS has been regulated under a three year Price Cap Regime of the form RPI – X ±Q, where "X" and "Q" were set at zero. The rationale for this was to provide JPS with time to improve to improve efficiency while at the same time to provide the Office with the opportunity to consult on and develop the methodology for determining "X" among other things with the view to fixing the values of "X" and "Q" at the tariff review in 2004.

This tariff review coincides with the introduction of a new regulatory framework, effective June 1, 2004, which is aimed at securing greater efficiency in the provision of electricity services. The review of JPS submission is therefore based on three primary objectives:

- the need to minimise electricity cost;
- the need for continued improvement in the service provided by JPS; and
- to provide the opportunity for investors to earn reasonable returns on their investments.

The new regulatory framework and price control will be characterised by a price cap regime, which will fix the non – fuel base rates for five years subject only to annual adjustments to allow for the impact of inflation less imposed allowances for efficiency gains and quality of service targets to which JPS will be held. The objective of the price cap regime is to ensure that the company continually makes efficiency improvements and that the benefits of these gains are passed on to consumers. This will be achieved by the introduction of penalties and incentives to ensure that JPS operates as efficiently as possible, taking into consideration the constraints of the macroeconomic environment within which the company operates.

The new generation market environment will see the introduction of competition in the development of new generating capacity. This will ensure that future generation expansion is done in the most cost-effective manner, which will be in the best interest of consumers.

Glossary

ABNF = Non-fuel base rate
ADC = Average Dependable Capacity
CAIDI = Customer Average Interruption Duration Index
CAPM = Capital Asset Pricing Model
CIS = Customer Information System
CML = Customer Minutes Lost
CPI = Consumer Price Index
CRP = Country Risk Premium
CT = Current transformer
CWIP = Construction work in progress
DCF = Discounted Cash Flow
DEA = Data Envelope Analysis
EFLOP = Equivalent Full Load Provision
EMS = Environmental Management System
EPMU = Equi-proportional mark-up method
GDP = Gross Domestic Product
GoJ = Government of Jamaica
IPP = Independent Power Producer
IVR = Interactive voice response
MFP = Multifactor productivity
MVA = Mega volt amperes
MW = Megawatt
MWh = Megawatt-hours
NWC = National Water Commission
O & M = Operations and maintenance
OCB = Oil circuit breakers
PBRM = Performance based rate-making mechanism

PPA = Power Purchase Agreement
PT = Potential transformer
RDC = Required Dependable Capacity
REP = Rural Electrification Programme Limited
RPD = Revenue Protection Department
SAIDI = System average interruption duration index
SAIFI = System average interruption frequency index
SCADA = Supervisory Control and Data Acquisition
SFA = Stochastic frontier analysis
TFP = Total Factor Productivity
TOU = Time of Use
WACC = Weighted Average Cost of Capital

Summary of Decisions

Background

Jamaica Public Service Company Limited (JPS), the monopoly supplier of electricity in Jamaica submitted an application for tariff review to the Office of Utilities Regulation ("the Office") on March 1, 2004, in accordance with the All-Island Electricity Licence 2001, (the Licence). The Licence stipulates that the current Non-Fuel Base Rate tariffs, which are fixed by the Office, expire on May 31, 2004. Further, it requires JPS pursuant to Schedule 3 paragraph 2 (c) to:

> "submit a filing with the Office, no later than March 1, 2004 and thereafter on each succeeding fifth anniversary, with an application for the recalculation of the Non-Fuel Base Rates. The new Non-Fuel Base Rate will become effective ninety (90) days after acceptance of the filing by the Office. This filing shall include an annual non-fuel revenue requirement calculation and specific rate schedules by customer class. The revenue requirement shall be based on a test year in which the new rates will be in effect and shall include efficient non-fuel operating costs, depreciation expenses, taxes, and a fair return on investment. The components of the revenue requirement which are ultimately approved for inclusion will be those which are determined by the Office to be prudently incurred and in conformance with the OUR Act, the Electric Lighting Act and subsequent implementing rules and regulations."

The Licence requires that the price control for JPS be a Price Cap Regime of the form dPCI = dI ± X ±Q±Z,

Where:

"dCPI"	=	annual rate of change in Non-Fuel electricity prices;
"dI"	=	the annual growth rate in an inflation and devaluation measure;
"X"	=	the offset to inflation (annual real price increase or decrease) resulting from productivity changes in the electricity industry;
"Q"	=	the allowed price adjustment to reflect changes in the quality of service provided to the customers; and
"Z"	=	the allowed rate of price adjustment for special reasons not captured by the other elements of the formula.

In 2001, when this regime was introduced “X” and “Q” were set at zero.

The objective of this tariff review is to utilize the regulatory framework to provide incentives to ensure that JPS achieves increasing efficiency. The review is therefore based on three primary objectives:

- the need to keep electricity costs down;
- the need for continued improvement in the service provided by JPS; and
- to provide the opportunity for JPS to earn reasonable returns on its investment while at the same time being able to finance the operations of the business.

Under this regime, caps on tariffs will be set for a five-year period (2004 – 2009). Specifically, tariffs are set in the first year, based on the revenue requirement of the company. Going forward, these tariffs will be adjusted for:

- inflation and exchange rate movements;
- expected efficiency gains based on differentials in productivity trends between JPS as well as the United States and Jamaican economies; and
- a bonus or penalty based on JPS’ performance on selected quality of service parameters.

The success of a price cap regime depends critically on the regulator providing incentives for the company to operate as efficiently as possible. In these arrangements it is important that JPS be allowed to retain the benefits of any gains over and above those which were targeted for the period. Hence, it is important that the performance targets that are set for JPS are not only established at the start of the price-cap period but that no unexpected adjustments are made during the period.

It is against this background and pursuant to its duties under the Licence that the Office makes the decisions set out hereunder:

DECISION IS HEREBY TAKEN that for the period June 1, 2004 to May 31, 2009:

1. With effect from June 1, 2004 the average Non-Fuel revenue to be recovered from customers by JPS is J$5.627/kWh. This is calculated from the following:

- Non-Fuel Revenue requirement estimated at J$17.332 billion to finance JPS operational expenses, depreciation and amortization and to realize a reasonable return on investment for the 'test year".

- Forecasted Sales Demand of 3,075,800 MWh for 2004 (being 4% over 2003); and

- A base Exchange Rate of US$1 = J$61

2. JPS' return-on-investment as measured by the Post-tax weighted average cost of capital (WACC) is estimated at 12.00%. This is made up of the following components:
   - JPS weighted Cost of debt of 12.56%
   - OUR determined Real Cost of Equity of 14.85%
   - Gearing of 44%
   - A tax rate of 33.1/3%

   The Office is of the view that a gearing of 48% is appropriate for JPS and it therefore expects JPS to achieve this level by 2009.

3. The value of the "Test year" rate base is J$35.01 billion

4. The expected productivity efficiency gains for JPS (X-factor) is 2.72%. The X-factor will be applied at the 2006 adjustment.

5. The Q-factor remains at zero until June 2005 when the data on forced outages at both the feeder and sub-feeder levels will have been collected, audited and analysed. Baseline data on System average interruption duration index (SAIDI)[1], the System average interruption frequency index (SAIFI)[2] and Customer average interruption duration index (CAIDI)[3] will then be available at that time in order that the Q-factor can be applied at that date. Should JPS not provide the supporting data, the Office will apply international benchmarks to inform the derivation of 'Q' with effect from June 2005.

[1] This index is commonly referred to as customer minutes of interruption or customer hours, and is designed to provide information about the average time the customers are interrupted.

[2] This index is designed to give information about the average frequency of sustained interruptions per customer over a pre-defined area.

[3] This index represents the average time required to restore service to the average customer per sustained interruption.

6. In activating the Z-factor, a materiality threshold of $13 million adjusted annually for Jamaican inflation shall be imposed

7. The price cap will be applied on a global basis. Specifically, the annual adjustment factor (1+dPCI) will be applied to the tariff basket instead of each individual tariff. The adjustment in each tariff will be weighted by an associated quantity for each element. The weighted average increase of the tariff basket must not exceed the price adjustment factor (1+dPCI).

8. The inflation adjustment formula (dI) to be used during the 2004 -2009 tariff period, has been changed to more accurately reflect the inflation costs incurred on JPS. The base Non-Fuel tariffs shall be adjusted annually, as follows:

   $b_1 = b_o [1 + dI]$

   $dI = [\ 0.76^* \quad e + 0.76\ ^*0.922\ ^* \quad e^*i_{US} + 0.76^*0.922\ ^*i_{US} + 0.24^*\ i_j\ ]$

   b_0 =Base non-fuel tariff at time period t = 0

   b_1 = Base non-fuel tariff at time period t = 1

   e = percentage change in the Base Exchange rate

   i_{US} = US inflation rate (as defined in the licence)

   i_j = Jamaican inflation rate (as defined in the licence)

   f_{US} = US factor =0 .76

   f_i = Local (Jamaica) factor = 0.24

9. The actual fuel cost will be passed through in the fuel charge with efficiency modifications for heat rate and system losses. This will be included in the Fuel and IPP charge line item on the bill.

10. The billing heat rate target shall be set at 11,200 kJ/kWh for the 5-year price cap period.

11. System losses target will remain at 15.8% to be used in the derivation of fuel rates over the five year period. That is, the deemed sales for the calculation of the fuel rate is Net Generation less 15.8%.

12. JPS shall apply separate fuel and Non-Fuel foreign exchange adjustment mechanisms as follows:

- Conversion of the fuel rates from United States currency to Jamaican currency using prevailing billing exchange rate ; and

- Apply a foreign exchange formula to the Non-Fuel base tariff only, using –

$$Tariff_m = Tarriff_b \times [1 + 0.76 \times (EXC_{m-1} - EXC_b)/EXC_b]$$

where:

$Tariff_m$ = Adjusted tariff for the month

$Tariff_b$ = Unadjusted tariff for the month calculated on Non-Fuel base rates.

EXC_b = Base Exchange rate for Jamaican Dollars into United States Dollars

EXC_{m-1} = Billing Exchange Rate

13. The <u>actual</u> Independent Power Producers (IPPs) costs shall be recovered as a pass-through on customers' bills by using the following methodology:

- Estimated base Non-Fuel IPP costs shall be embedded in the non-fuel charges. JPS shall submit its methodology for allocating IPP cost to the Office for approval.

- A computation shall be done on a monthly basis to determine whether the actual costs deviate from the estimated base costs.

- The surplus or deficit shall be returned or recovered over the kWhs billed. This surplus or deficit shall be included in the Fuel and IPP charge line item on the bill.

14. All low voltage customers above 25kVA shall be grouped together into a new Rate 40(all LV) grouping. All medium voltage customers above 25 kVA shall be grouped as Rate 50 (all MV). This will result in a simpler rate structure.

15. For the purposes of Time-of-Use billing, the following periods shall be used:

On Peak Period: Monday – Friday: 6:00 p.m. to 10:00 p.m.

Partial Peak Period: Monday – Friday: 6:00 a.m. to 6:00 p.m.

Weekends and public holidays: 6:00 p.m. to 10:00 p.m.

Off Peak Period: Monday – Friday: 10:00 p.m. to 6:00 a.m.
Weekends and public holidays (all hours except 6:00 p.m. to 10:00 p.m.)

16. The Time of Use (TOU) rate design shall be as follows:

    - The On Peak billing demand shall remain unchanged.

    - The partial peak billing demand shall be set as the maximum registered demand for the combined partial peak and on peak hours of that month, or 80% of the maximum demand for the partial and on peak hours during the five-month period immediately prior to the month in which the bill is rendered., whichever is higher, but not less than 25 kVA.

    - The off-peak billing demand shall be the maximum registered demand for that month, or 80% of the maximum demand for the five-month period immediately prior to the month in which the bill is rendered, whichever is higher, but not less than 25 kVA.

17. The reconnection fee applicable to all customers shall be $1,441 to reflect the actual cost incurred for each reconnection.

18. The under-mentioned five (5) new guaranteed standards become effective on September 1, 2004:

    - **EGS 7 - Frequency of Meter Reading** - JPS shall not render three (3) or more consecutive estimated bills (where it has access to the meter). JPS has committed to phase out estimated bills within two years. Effective September 2006 this Standard will be changed to not more than two (2) consecutive estimated bills.

    - **EGS 8 - Estimation of Consumption** - An estimated bill must be based on the average of the last three (3) actual readings (first 6 bills of a new account excepted).

    - **EGS 9 - Meter Replacement –** JPS shall replace a meter found to be faulty within 20 working days.

    - **EGS 10 - Billing Adjustments -** JPS shall adjust a customer's account within one billing period of identification of an error.

- **EGS 11 - Street Lighting Maintenance** - JPS shall repair each reported street light failure (as reported by the responsible local authority) within 14 days of receiving the report. [This standard will be implemented on September 1, 2004 on condition that the Office is satisfied that JPS and the local authorities have agreed on a protocol that will govern the arrangements between the parties. If asked, the Office would agree to broker the terms of such a protocol].

The full schedule of the Guaranteed Standards that will be in effect under this tariff is provided at Table D.2.

19. The under-mentioned four (4) new Overall Standards will become effective as indicated below:

    - **EOS4A – Customer Average Interruption Duration Index (CAIDI) -** average time to restore service to average customers per sustained interruption will be set June 1, 2005.

    - **EOS10 - Responsiveness of Call Centre Representatives** - 90% of phone calls to the call centre are to be answered within 15 seconds. This becomes effective on July 1, 2004.

    - **EOS11 - Effectiveness of Call Centre Representatives** - a target will be set on June 1, 2005 specifying the percentage of complaints registered through the Call Centre that should be resolved as the first point of contact. (Monitoring of this standard will commence as of June 2005).

    - **EOS12 - Effectiveness of Street Lighting Maintenance** - 99% of all street lighting complaints must be addressed and corrected within 14 days. This becomes effective July 1, 2004.

The full schedule of Overall Standards that will be in effect under this tariff is provided at Table D.3.

20. JPS shall complete the implementation of a policy over the next 24 months, i.e. by May 31, 2006, to return security deposits to good-paying customers. A good-paying customer is defined as one who has a record of paying electricity bills in full on every occasion that the bill is rendered on or before the due date for a continuous period of 24 months.

21. Compensation for breach of any of the guaranteed standards will be as follows:

Customer Class	Compensation
Domestic Rate 10 – Residential Service	$1,000
General Service Rate 20 – General service	$1,000
Power Service Rate 40 (all LV) – Power Service Rate 40A – Power Service Rate 50 (all MV)– Large Power	$8,400
Street Lighting Rate 60	$300 per lamp/month

The approved Non-Fuel base rates for 2004 are summarized at Table D.1

- **Table D.1:**
- **Approved Tariffs for 2004**

Rate Class		Rate Option	Customer Charge	Energy Charge (J$/kWh)	Demand-J$/KVA Std.	Off-Peak	Part Peak	On-Peak
Rate 10	LV	Lifeline	68	4.549	-	-	-	-
Rate 10	LV	Non Lifeline	68	8.008	-	-	-	-
Rate 20	LV		150	6.770	-	-	-	-
Rate 40A	LV	STD	2,100	4.250	276	-	-	-
Rate 40	LV	STD	2,100	1.728	707	-	-	-
Rate 40	LV	TOU	2,100	1.728	-	29	308	394
Rate 50	MV	STD	2,100	1.556	636	-	-	-
Rate 50	MV	TOU	2,100	1.556	-	26	277	355
Rate 60	LV	Street Lights(metered)	550	8.161	-	-	-	-
Rate 60	LV	Traffic lights	550	5.494				

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Table D2
Guaranteed Service Standards 2004 -2009

Code	Focus	Description	Performance Measure
EGS 1(a)	Access	Connection to Supply - New Installations	New service Installations within 5 working days.
EGS 1(b)	Access	Connection to Supply - Simple Connections	Connections within 4 working days where supply and meter already on premises
EGS 2(a)	Access	Complex Connection to supply	Between 30 and 100m of existing distribution line
			i- estimate within 10 working days
			ii- connection within 30 working days after payment
EGS 2(b)	Access	Complex Connection to supply	Between 101 and 250m of existing distribution line
			i- estimate within 15 working days
			ii- connection within 40 working days after payment
EGS 3	Response to Emergency	Response to Emergency	Response to Emergency calls within 6 hours
EGS 4	Billing Punctuality	Issue of First bill	Produce and dispatch first bill within 45 working days after service connection
EGS 5(a)	Complaints/Queries	Acknowledgements	Acknowledge written queries within 5 working days
EGS 5(b)	Complaints/Queries	Investigations	Complete investigation within 30 working days
EGS 5(c)	Complaints/Queries	Investigations involving 3rd party	Complete investigation within 60 working days if 3rd party involved
EGS 6(a)	Reconnection	Reconnection after Payments of Overdue amounts - urban areas	Urban reconnection within 1 day
EGS 6(b)	Reconnection	Reconnection after Payments of Overdue amounts - rural areas	Rural - reconnection within 2 days
EGS 7	Estimated Bills	Frequency of Meter reading	Should not be three (3) or more consecutive estimated bills (where company has access to meter). This changes to two (2) on September 1, 2006
EGS 8	Estimation of Consumption	Method of estimating consumption	An estimated bill should be based on the average of the last three (3) actual readings (first 6 bills of new accounts excepted)
EGS 9	Meter Replacement	Timeliness of Meter Replacement	Maximum of 20 business days to replace meter after detection of fault
EGS 10	Billing Adjustments	Timeliness of adjustment to customer's account	Where necessary, customer must be billed for adjustment within one (1) billing period of identification of error
EGS 11	Street Lighting Maintenance	Timeliness of repairs of street lights	Reported street lights failures must be repaired within 14 days. (Reports to be made by Local Authorities).
EGS12	Compensation	Making compensatory payments	Response to claim for compensation within 45 days of verification of breach

Table D3
Overall Standards (2004-2009)

Code	Standard	Units	Targets June 04 – May 09 (inclusive)
EOS1	Minimum of 48 hours prior notice of planned outages	Percentage of planned outages for which at least forty-eight hours advance notice is provided	100%
EOS2	Percentage of line faults repaired within a specified period of that fault being reported	Urban – 48 hrs Rural – 96 hrs	100% 100%
EOS3	System Average Interruption Frequency Index (SAIFI)	Frequency of interruptions in service	To be set June 2005
EOS4	System Average Interruption Duration Index (SAIDI)	Duration of interruptions in service	To be set June 2005
EOS4A	Customer Average Interruption Duration Index (CAIDI)	Average time to restore service to average customers per sustained interruption	To be set June 2005
EOS5	Total system losses (difference between net energy generated and billed energy)	System losses as a percentage of total energy delivered to customers	15.8%
EOS6	Frequency of meter reading	Percentage of meters read within time specified in the licensee's billing cycle (currently monthly for non-domestic customers and bi-monthly for domestic customers)	99%
EOS7 (a)	Frequency of meter testing	Percentage of rates 40 and 50 meter tested for accuracy annually	50%
EOS7 (b)	Frequency of meter testing	Percentage of other rate categories of customers meters tested for accuracy annually	7.5%
EOS8	Billing Punctuality	98% of all bills to be mailed within specified time after meter is read	5 working days
EOS9	Restoration of service after unplanned (forced) outages on the distribution system	Percentage of customer's supplies to be restored within 24 hours of forced outages in both Rural and Urban areas	98%
EOS10	Responsiveness of call center representatives	Percentage of calls answered within 20 seconds	90%
EOS11	Effectiveness of call center representatives	Percentage of complaints resolved at first point of contact	To be set June 2005
EOS 12	Effectiveness of street lighting repairs	Percentage of all street lighting complaints resolved within 14 days	99%

Table D4:
Estimated impact of OUR determined Non-Fuel Tariffs on customer bills based on March 2004 billing

Rate class	Current Rates (@ 11,600 kJ/kWh)	Proposed rates (@ 11,200 kJ/kWh)	Variance	Variance
Rate 10 Life Line customer (99kWh/month)	1,047	1,031	-16	-1.51%
Rate 10 typical customer (250kWh/month)	2,836	3,019	182	6.43%
Rate 10 typical (high energy) customer (750kWh/month)	8,769	9,613	844	9.62%
Rate 20 typical customer (1000kWh/month)	10,824	12,099	1,275	11.78%
Rate 40A average customer (10,933 kWh/month and 85 kVA/month)	119,633	129,127	9,494	7.94%
Rate 40 STD average customer ($)				
-40 LV (35,128 kWh/month and 114 kVA/month)	301,777	325,513	23,736	7.87%
-50 LV (264,172 kWh/month and 795 kVA/month)	2,261,141	2,388,687	127,547	5.64%
Rate 40 TOU average customer				
-40 LV (76,336 kWh/month and 193 kVA/month)	596,593	659,369	62,776	10.52%
-50 LV (181,811kWh/month and 586 kVA/month)	1,470,114	1,584,990	114,876	7.81%
Rate 50 STD average customer				
-40 MV (91,778 kWh/month and 322 kVA/month)	795,413	824,698	29,285	3.68%
-50 MV (493,323 kWh/month and 1,359 kVA/month)	4,064,386	4,188,427	124,041	3.05%
Rate 50 TOU average customer				
-40 MV (124,077 kWh/month and 365 kVA/month)	997,028	1,058,571	61,543	6.17%
-50 MV (462,001 kWh/month and 1,302 kVA/month)	3,723,760	3,880,576	156,815	4.21%

Chapter 1:

Introduction

1.0. Background

JPS is a vertically integrated company and operates generation, distribution, transmission facilities as well as the supply of light and power to various customer classes. The company was granted a new licence in 2001 – the All-Island Electric Licence, 2001. In addition to JPS, there are three Independent Power Producers (IPP's) which are contracted to supply capacity and energy to JPS under power purchase agreements. Under the Licence, JPS has exclusivity on transmission and distribution for a period of twenty years. However, after 31st March 2004 competition for generation has been be reintroduced.

1.1 JPS Rate Submission 2004

- On March 1 2004, JPS submitted its proposals for a tariff review in accordance with the Licence. The Licence stipulates that the current tariffs, which are fixed by the Office of Utilities Regulation (The Office), expire on May 31, 2004. JPS has proffered that its submission is based on three primary objectives: (i) the need to keep electricity costs down in the long-term; (ii) the need for continued improvement in the service provided; and (iii) the need to ensure continued viability of the company.
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- The tariff review will result in the introduction of a new regulatory framework and price control, effective June 1, 2004, which is aimed at securing greater efficiency in the electricity sector.

1.2 Regulatory Framework

The regulatory framework is described in the Licence.

The statutory framework within which the Office operates emphasises as broad objectives the importance of promoting efficiency, protecting the interests of customers and providing for the financial viability of the electricity service providers.
It is therefore the objective of the Office to ensure that the tariff determination will:

- further improve upon customer service and service reliability;
- provide the correct set of incentives for JPS to operate efficiently and to continue improving its productivity;
- provide a fair rate of return to investors; and
- ensure that, while the price cap regime imposes a constraint on the company to pass on excessive costs to customers, it does not

unfairly impose upon the company risks that are outside of managerial control.

In developing its approach, the Office has considered the lessons learnt during the period since the last review, together with the experience of other utility regulators and the evidence available from regulatory best practice.

1.3 Rate Making Conditions of Licence

Condition 15 (paragraph 2) of the Licence stipulates that the tariffs to be charged by JPS in respect of the supply of electricity shall be subjected to such limitations as may be imposed from time to time by the Office. It is also a requirement of the Licence that the Office impose a price cap on JPS tariffs from 2004 to 2009 and for every subsequent five year period.

Schedule 3, of the Licence describes the form of the price cap to be adopted. A central element of this price cap is the X-factor. The X-factor decreases the allowed tariff by a pre-defined percentage (per year) based on expected productivity gains. It is vital that the X-factor be properly established. If the X factor is set too high then the productivity gains required of JPS will be too onerous and may endanger the financial and operational viability of the company. Similarly, if it is set too low then JPS could earn excessive profits without any obligation to share those gains to consumers. Either outcome is to be avoided.

1.4 Purpose of this Document

This document sets out the reasons for the Office's Determination on JPS' application for tariff review which was submitted on March 1, 2004. The approach to the analysis has four elements – a cost-based assessment of opening prices, the annual price cap escalation factor, a tariff basket form of price control and tariff design.

1.5 Structure of this Document

Section 1 addresses the financial, economic and technical aspects of the rate review while Section 2 addresses the issues raised by and on behalf of customers and consumers.

SECTION 1

Chapter 2 provides a summary of JPS' proposal

Chapter 3 provides a description on tariff setting – Principles and Procedure

Chapter 4 discusses issues relating to the rate of return on investment including methodologies for deriving the cost of debt and cost of equity and the determination of the weighted Average Cost of Capital

Chapter 5 provides an analysis of and the determination on the valuation of JPS' Asset Base

Chapter 6 provides a detailed analysis of and the determination of JPS' Revenue Requirement

Chapter 7 discusses the methods used for the determination of "X" factor

Chapter 8 discusses the methodology used for the determination of the Q-factor.

Chapter 9 discusses the PBRM annual adjustment

Chapter 10 provides an analysis of the foreign exchange adjustment factor

Chapter 11 discusses performance improvements and reduction of operational losses.

Chapter 12 discusses the Pass-through of Independent Power Producers (IPP) costs

Chapter 13 provides a description of the tariff design.

Section II provides an analysis and discussion on consumer issues and quality of service standards

Chapter 2: Summary of JPS Proposal

2.0 The performance-based rate making (PBRM) mechanism

2.1 Global price cap system

- JPS proposes that the cap on annual adjustments made to the tariffs be applied to a tariff basket instead of individual tariffs. This would allow JPS to gradually rebalance tariffs to reflect costs. The OUR will retain the right to ensure that all adjustments within the basket are consistent with the cap on the total basket.

2.1.1 X-factor

- Schedule 3 Exhibit 1 of the Licence defines the X-factor as follows:
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    - "The X-factor is based on the expected productivity gains of the Licensed Business. The X-Factor is to be set to equal the difference in the expected total factor productivity growth of the Licensed Business and the general total factor productivity growth of firms whose price index of outputs reflect the price escalation measure "dI"."
-
- JPS commissioned a study (by Pacific Economics Group) to analyse the Total Factor Productivity (TFP) growth of JPS, the Jamaican economy and the US economy and based on the definition in the Licence and the results of the study, JPS has proposed an X-factor of –0.65%..

2.1.2 Q-factor

- Another element under the PBRM is the Q-factor, i.e., the allowed price adjustment to reflect changes in the quality of service provided to customers. JPS proposes the following:
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- The Q-factor should be based on two quality indices that measure the frequency and duration of outages, i.e., the system average interruption frequency index (SAIFI) and the system average interruption duration index (SAIDI).
- The targets would be set based on 2003 performance with built-in incentives for a 2% improvement each year within the price cap period.
- If JPS outperforms the target, then a bonus of 0.5% would be added to the annual tariff adjustment. If JPS performance falls short of a target, then a penalty of –0.5% would be applied to the annual adjustment.

2.1.3 The Z-factor

• As set out in the Schedule 3 (Exhibit 1) of the Licence, the Z-factor should cover any occurrence that affects JPS costs, are not due to managerial decisions and that are not captured by any other elements in the price cap mechanism. JPS further proposes that a *minimum* threshold of J$13 million, adjusted for inflation be set for adjustments under the Z-factor.

2.2 Modification of existing price adjustment factors

2.2.1 The foreign exchange adjustment factor

• JPS proposes the following modifications to the foreign exchange adjustment mechanism:

- Remove fuel costs from the current foreign exchange adjustment mechanism and calculate the fuel charge to be applied each month using the applicable billing exchange rate, instead of the Base Exchange rate. This will allow full foreign exchange rate-adjusted recovery of fuel costs.

- Apply the adjustment mechanism to non-fuel costs only and update the mechanism periodically to reflect current proportions of US dollar-related non-fuel costs relative to Jamaican dollar-related costs.

2.2.2 The annual inflation adjustment factor

• JPS proposes that the inflation adjustment formula be amended to correct for an error that it currently contains. In addition, the company proposes that the proportions of US dollar-related non-fuel costs, Jamaican dollar-related non-fuel costs and debt-financing costs be reset based on audited accounts for the financial year 2003. The higher the proportion of US dollar-related costs, the higher is the weight of US inflation in the calculation of the annual inflation adjustment.

2.3 Treatment of Independent Power Producers (IPP) costs

• JPS proposes to continue embedding base IPP non-fuel costs into the energy and demand charges. However, the company suggests that there is an inherent risk involved in keeping these costs static within the tariffs as there are components of the IPP costs that fluctuate in any given month that would not be reflected in the rates charged to customers. JPS therefore proposes to monitor the IPP costs and to make adjustments on a quarterly basis and if there are differences between the current base costs and base costs at March 1 2004, the difference will be passed on to the consumers. Inherently, this would be a symmetric adjustment applied as a surcharge (on a per kWh basis), i.e., there will a separate line item—credit or debit—on a customer's bill that is aimed at ensuring that JPS neither gains nor loses on its IPP non-fuel expense.

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- JPS proposes to pass through IPP costs calculated at base (contracted) capacity levels rather than actual dependable capacity. The company justifies this position by arguing that if and when IPP capacity falls below contracted levels, direct IPP costs (i.e., payments to the IPPs) fall accordingly. However, JPS incurs incremental indirect costs, as a result of the fall in IPP capacity. The company suggests that these incremental costs are a result of the following factors:
- more frequent servicing required for the generation units, which are run harder to make up for the loss in IPP capacity;
- higher operating costs as units lower down the dispatch hierarchy are run;
- potentially poorer heat rate performance; and
- Potential load shedding and the resultant loss in revenues as well as penalty under the Q-factor.
- JPS believes that these incremental costs outweigh the liquidated damages that the IPPs are obliged to pay, under the terms of the contract, when actual dependable capacity is below contracted level.

2.4 Fuel Efficiency Targets

2.4.1 Heat rate targets

- JPS proposes the following heat rate targets:
- 11,500 kJ/kWh in 2004; and
- 11,100 kJ/kWh when the generation expansion, as detailed in the Least Cost Expansion Model, is fully implemented. This is expected to take place in 2007. However, in order to retain the right incentives, JPS propose that the effective date of the new reduced target not be set now, but rather be dependent on the actual implementation date.
- This proposal reflects a reduction in the target from the current level of 11,600 kJ/kWh.

2.4.2 System losses targets

- JPS proposes that, over the 5-year price cap period the system losses target should be set as follows:

Year	2004	2005	2006	2007	2008	2009
System Losses targets (%)	18.0	17.7	17.4	17.1	16.8	16.5

- The proposal reflects the following:
-
- Reduction of technical losses from 9% — a level that is consistent with industry standards worldwide — to 8%.

- Reduction of operational commercial losses (e.g., those due to operational deficiencies such as billing errors and metering problems) from an estimated 2% to 1%.

- Stabilisation of social commercial losses (throw-ups and electricity theft) at the current level of 7.5%. Such losses are largely due to socio-economic factors, which are out of JPS' control and it would therefore be unfair and counter-productive to penalise JPS for such losses. JPS believes that this type of losses can only be reduced via a partnership between Government, civil society and the company. JPS would nonetheless continue to carry out best efforts—through raids, arrests and public education—to contain social losses.

2.5 Tariff Structure and Proposed rates

2.5.1 Rate class rationalisation

- JPS proposes to simplify the rate classes where all Low Voltage Customers above 25 KVA would be grouped into a new Rate 40 (LV) class, and all Medium Voltage Customers above 25 kVA would be classified as Rate 50 (MV). The minimum demand threshold for both classes would be set at 25kVA. This change excludes some customers currently in Rate 40A.

2.5.2 Modification to Time-of-Use (TOU) rates

- JPS proposes to modify the design of the TOU rates so as to provide stronger incentives for customers to shift their load to the off-peak period, as follows:
-
- calculating the partial-peak demand charge based on the maximum demand of the partial- and on-peak periods.

- introduction of a demand ratchet on partial-peak demand, in addition to the current ratchet on off-peak demand.

- increasing the on-peak charges by 5% above that implied by the loss of load probabilities to further encourage the shifting of load from the peak- to partial- or off-peak period.

2.6 Modification of calculation of street light billing

- JPS proposes to calculate street light bills on the assumption of 99% availability as against the 100% availability factor that is currently assumed.

2.7 Proposed tariffs

• Table 2 - 1 shows the non-fuel base tariffs that JPS proposes to take effect on June 1, 2004.

The major aspects of JPS tariff application are:

1. A real increase of 23% in non-fuel rate base tariff over (inflation adjusted) 2003 gazetted rates. The resulting proposed rates are outlined in table 2.1. The proposed non-fuel tariffs are expected to lead to average increases of between 11% to 18% in monthly customer bills, depending on the particular rate class.

Table 2.1

Rate Class		Rate Option	Customer Charge	Energy Charge (J$/kWh)	Demand-J$/KVA Standard	Off-Peak	Part Peak	On-Peak
Rate 10	**LV**	**Lifeline**	**87**	**6.127**	**-**	**-**	**-**	**-**
Rate 10	**LV**	**Non Lifeline**	**87**	**8.656**	**-**	**-**	**-**	**-**
Rate 20	**LV**		**816**	**6.433**	**-**	**-**	**-**	**-**
Rate 40A	**LV**	**Standard**	**2,497**	**3.882**	**417**	**-**	**-**	**-**
Rate 40	**LV**	**Standard**	**2,497**	**0.926**	**1,083**	**-**	**-**	**-**
Rate 40	**LV**	**TOU**	**2,497**	**0.926**	**-**	**45**	**469**	**600**
Rate 50	**MV**	**Standard**	**2,497**	**0.731**	**1,167**	**-**	**-**	**-**
Rate 50	**MV**	**TOU**	**2,497**	**0.731**	**-**	**49**	**513**	**664**
Rate 60	**LV**		**611**	**9.110**	**-**	**-**	**-**	**-**
Standby Tariff (Reserve Capacity Charge):					**60**			

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2. JPS proposed Revenue requirement of J$19.5 billion. This is the key driver to the requested tariff increase which JPS posited is driven by:

- the investment in additional generating capacity at Bogue, along with the corresponding return on investment, depreciation, O&M and tax costs; and

- imputed corporate taxes.

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• Table 2.2: Comparison of 2001 allowed revenue requirement and test year revenue requirement

	2001 allowed revenue adjusted for inflation and sales growth.(a)	Test year revenue requirement (b)	Change (c = b – a)
Bogue		**1,767,040**	**1,767,040**
GT11		**193,029**	**193,029**
Return on investment (excluding bogue and gt11)	**5,102,257**	**3,968,232**	**(1,134,025)**
Depreciation (excluding bogue and gt11)	**2,486,484**	**1,978,842**	**(507,642)**
Operations & maintenance	**10,238,981**	**10,443,791**	**204,810**
JPS O&M cost *(excluding our fees, bogue and gt11)*	5,968,428	6,730,801	762,373
IPP's Energy & Capacity payments	4,220,247	3,666,489	(553,757)
street light acceleration cost	-	-	-
Our licence fees	50,306	46,500	(3,806)
miscellaneous adjustments	**(906,183)**	**1,151,304**	**2,057,486**
-Taxes (excluding bogue and gt11)	-	1,483,368	1,483,368
-Other operating revenue	(632,517)	(121,597)	510,920
-Carib Cement revenue	(273,666)	(210,467)	63,199
non fuel revenue requirement	16,921,539	19,502,237	2,580,699

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2.8 Reconnection fees and Penalties under Guaranteed Standards

2.8.1 Reconnection Fees

• In a previous decision, the Office determined that , the reconnection fee is to be determined by June 30 each year and shall be based on the actual cost of undertaking reconnection in the preceding year plus a 10 percent service charge. The current 2003 gazetted reconnection fee is $1,325. Based on 2003 data, JPS estimates that the costs incurred for each reconnection is $1,310. Adding a 10% service charge yields in a reconnection fee of $1,441. JPS proposes that this fee be implemented for the year starting June 1, 2004.

2.8.2 Guaranteed Standards

• JPS proposes to jointly review with the OUR, the Guaranteed Service Standards that are currently in force. As part of that review JPS proposes to raise by 100% the level of compensation payments to customers for each breach of compliance as defined in Schedule 1 of the All-Island Electricity Licence 2001.

Chapter 3: Tariff Setting –Principles and Procedure

3.0 Introduction

JPS' tariffs have traditionally been set on the basis of two components – fuel and non-fuel. Fuel costs are passed through adjusted for efficiency factors set by the Office for systems loss and heat rate. The non-fuel component is subject to the price controls specified in the licence

3.1 Performance Based Rate – Making Mechanism (PBRM)

Internationally two methodologies have generally been adopted towards price control. The older of the two is termed "rate of return regulation" in which prices are fixed at a level which will provide the investor with a target rate of return on investment and adjusted up or down over time as the rate of return respectively falls below or rises above the target rate.

Price cap regulation is a form of PBRM which became popular, worldwide, after it was introduced in Britain in the 1980s.. In price cap regulation a formula is specified where the average price[4] is allowed to increase at a rate that is no more than the inflation rate, usually as measured by the consumer price index. Normally prices are required to increase slower than the rate of inflation because of expected efficiency improvements (i.e. real unit cost reductions). This approach is often referred to as CPI-X ("X" referring to the defined efficiency factor). Under certain circumstances, for example where considerable investment in infrastructure must be undertaken, the price increases permitted may exceed the rate of inflation (in which case the formula would be CPI+X). The tariff adjustment formula is reviewed by the regulator at fixed intervals, usually four to five years, primarily to determine the value of X, but also to adjust the structure of the price cap mechanism to changing circumstances.

If there were conditions of high inflation, the price cap formula would allow significant automatic increases in nominal prices (although, if the formula were CPI-X, there would be reductions in real prices, i.e. net of inflation). In this respect, however, the price cap would not necessarily differ materially from rate of return regulation. The inflation would lead to an increase in the utility's costs through higher operational expenses, such as labour costs, and higher capital costs, because of the revaluation of assets. In such circumstances the utility would be permitted price increases to maintain its rate of return.

Price cap regulation is, in reality, not the means by which prices are initially determined, but rather a methodology by which tariffs are adjusted over time from a previously accepted level. Therefore, the starting level of prices will be an issue to be addressed. If it is considered that the current level of prices is too low

[4] The weights to be used to compute the average price need to be defined (e.g. a common approach is for the weights to be the volume share of each service in the prior financial year).

to provide an adequate rate of return, the price cap could be used to smooth the transition to higher prices, e.g. by choosing a value of X below the expected real unit cost reductions.

Key issues in defining a price cap mechanism are how the rate of inflation is to be determined, the initial value of X (the factor by which increases in tariffs will lag inflation), the weights in the computation of the average price, and the frequency of tariff reviews.

One potential disadvantage of price caps is that the investor may feel exposed to greater "regulatory risk" than under rate of return regulation. This risk does not relate to the initial details of the price cap, such as the value of X, so long as these are pre-announced but investors may have a concern about factors such as how subsequent values of X will be set, who will be setting them, how much credibility that body has as an impartial regulator, what rights of appeal exist and how credible and impartial they are etc.

There are various advantages of price caps. First, price caps provide the utility operator with an incentive to improve efficiency. This is initially to the benefit of the investor, as lower costs feed through into higher profits (this is the source of the incentive). But, later on, at the periodic price control reviews, consumers obtain a share of these benefits through price adjustments or higher values of X. This is a tried and proven feature of price caps and it is often the case that the efficiency improvements achieved greatly exceed the initial expectations at the time of privatization.

Price caps also involve less intrusive regulation. Under price caps, the regulated company can choose the timing and frequency of price changes, and the structure of prices.[5] There may be restrictions to this flexibility, but they must be explicitly identified in the price cap formula. It also requires less direct supervision and intervention by the regulator.

3.2 Initial Price Cap Tariffs

With respect to initial set of prices which will be introduced on June 1, 2004, for the five year period, to May 31, 2009 the Office undertook a cost-based 'base year' adjustment of the weighted average tariffs that were in effect at the end of the 2001-2003 control period reflecting an updated "building blocks" analysis of the most recently available actual costs and revenue data. This will allow JPS the flexibility to align its price structures with the structure of its costs. The weighted average tariffs will be adjusted annually (i.e. years 2 through 4, i.e. June 1, 2005 – May 31, 2008 using the adjustment mechanism set out in equation 2 below.

Under the existing pricing arrangement, annual revenue requirements for each full year were estimated, based on a "building blocks" approach, using data for

[5] Structure here meaning differences in prices between customer groups, or geographically, or by time of day etc.

2000. Tariffs were then set at a level to allow the company to earn enough revenue to cover costs including a reasonable return on capital. Tariffs were then allowed to escalate based on movements in inflation and the foreign exchange rate without an off-set for efficiency.

With this background the Office took the decision, that as part of its assessment of the 2004-2009 proposals, it would re-examine JPS' current costs of operation to ensure the initial cost base from which a tariff basket will be developed reflects a reasonable balance between the commercial interests of the company and that of the consuming public. In carrying out this exercise the Office has shown regard to the efficient costs of providing the service and JPS' need for revenues that recover costs incurred.

In furtherance of these objectives the Office undertook a rigorous "building block" analysis to establish the level of efficient costs required by the company to provide the services required by the Licence.

International experience has been that price cap (and benchmark) approaches have been adopted by mature regulatory regimes where the existing price levels and initial cost base are 'about right'. In these circumstances, regulators can have more confidence that, in rolling forward a price cap, they are not compromising their primary objectives by compounding the extraction of monopoly rents or the under-recovery of efficient costs.

Schedule 3, Exhibit 1 of the Licence describes the form of the price cap formula as:

dPCI = dI ± X ± Q ±Z ……………………………………..equation (1),

where

dCPI = annual rate of change in non-fuel electricity prices;

dI = the annual growth rate in an inflation and devaluation measure;

X = the offset to inflation (annual real price increase or decrease) resulting from productivity changes in the electricity industry;

Q = allowed price adjustment to reflect changes in the quality of service provided to the customers; and

Z = the allowed rate of price adjustment for special reasons not captured by the other elements of the formula.

The base year adjustment is made to update the existing (i.e., 2003) tariffs, thereby deriving revised weighted average tariffs for 2004 ($ABNF_{\mathbf{2004}}$), as follows:

$$ABNF_{2004}) = ABNF_{2003} * (1 + A) \ldots \text{ Equation } \mathbf{(2)}$$

Where:

$ABNF_{2004}$ = the weighted average of approved tariffs being applied in 2004

and

A = a factor determined by the Office prior to commencement of the 2004 - 2009 regulatory control period which indicates the extent to which the weighted average tariffs applying in the 2001 -2003 regulatory control period requires adjustment in order to form an appropriate basis for tariffs in the 2004 -2009 regulatory control period.

By undertaking a base year cost analysis, the Office is able to explicitly incorporate updated asset values, WACC estimates and operating costs. The Office also examined the evidence submitted by the company to support assumptions on the relative efficiency of JPS. If, as the Office believes, there is an efficiency gap, the Office will make a decision to allocate a portion of that gap to the base year price adjustment (A) and the remainder to the escalation factor (X_2) incorporated into the price cap.

In its position papers, leading up to the tariff review JPS raised concerns regarding the extent to which special factors could distort the base year cost analysis.

The Office is alert to the possibility that, in undertaking the base year “building blocks” cost analysis, there may be factors relevant to that year that may distort the outcome of future indexation of prices.

3.3 Annual Adjustment in Tariffs

JPS is permitted to make adjustments to the non-fuel base rate for each customer class on the basis of the formulae at equation 3 below. The first annual adjustment shall take place on June 1, 2005.

$$\mathbf{ABNF_y = ABNF_{Y-1} * (1 + dPCI)} \ldots\ldots\ldots\ldots \text{equation (3)},$$

where

$ABNF_{Y-1}$ = the weighted average tariffs in the previous year (i.e. the year (y-1) preceding the year (y) for which new tariffs are being submitted by the Company for the Office’s approval and calculated in accordance with equation 3.

JPS will be required to develop tariff schedules annually, during the 2004 - 2009 regulatory control period in accordance with equation (3) but at the same time to satisfy the constraint at equation (1).

2.4 Approval of Annual Tariff Adjustments

Each year during the 2004 -2009 regulatory control period, the Office will consider approving the annual schedule of individual rate class tariffs submitted by JPS only if the weighted average of tariffs included in the schedule complies with the constraint in equation (3).

Under the price cap plan JPS will be free to make changes to the tariff *structure* of its tariffs, provided that:

(i) in conjunction with the submission of the schedule of annual tariffs for approval, JPS also provides the Office with a statement of reasons for any proposed modifications to the structure of the tariffs that is consistent with the approved Pricing Principles Statement and (with the Office only intervening where it considers that the proposed change in structure is not consistent with the approved Pricing Principles Statement); and

(ii) The resultant impact on individual customer bills, for the same level and type of consumption as applied in the previous year, will not produce rate shocks.

3.5 System Losses

System losses of JPS are abnormally high, mainly due to theft, and billing anomalies. This can only be curtailed and controlled, when JPS makes concerted efforts to deal with the problem but it is agreed that Government and perhaps political (at the level of Members of Parliament) support would greatly enhance the company's efforts The anticipated savings made through reduction of system losses and improvements made by JPS in its performance is accounted for in the determination of its expected revenue requirement.

Chapter 4: Weighted Average Cost of Capital

4.0 Introduction

The Weighted Average Cost of Capital (WACC) is defined as the financial cost incurred by a firm for funding the investment needed to produce a service or a basket of services. It is analogous to the economic concept of opportunity cost, i.e. the cost foregone for not investing in activities of similar risks. In short, WACC is the minimum return that an investor requires to make investing in a business worthwhile. It is the weighted average of the various elements of the firm's capital structure, namely, common equity (E) and debt (D). Under the Licence the level of return on investment for JPS is the WACC times the Non-fuel Rate Base. The latter should be based on data for the last audited financial period and may be modified to take account of changes that are known and measurable. In deriving the cost of capital consideration is usually given, at least to, the following factors:-

- cost must be commensurate with risk; and
- cost should be sufficient to allow an efficiently operated firm to sustain its financial integrity.

Determination of the weighted average cost of capital (WACC) requires three steps: (1) adoption of an appropriate capital structure; (2) determination of the cost rates for debt, preferred stock and equity, the three components of the capital structure; and (3) application of these rates to the adopted capital structure (gearing ratio). In this case, there is no disagreement between JPS and the Office with respect to the components used to calculate the WACC. However, it is the view of the Office that the appropriate capital structure, the cost of debt and the determination of the appropriate rate for common equity are to be determined based on credible methodologies.

Traditionally, the allowed rate of return in regulatory hearings is calculated as the *weighted average cost capital, (WACC),* that is, the individual component of the capital structure weighted by its book value. The algebraic expression for a firm's real cost of capital is the pre-tax nominal WACC *minus* inflation and is derived by way of the following formulae:-

$WACC = w_d*k_d + w_e* k_e,$
Where
W_d = the fraction of debt in the capital structure;
k_d = the forward looking cost of debt;
W_e = the fraction of equity in the capital structure, i.e. $1-W_d$;
k_e = the forward looking cost of equity

4.1 Capital Structure

Capital structure refers to the combination of different securities issued by the firm to fund capital projects and other aspects of its operation. In deriving the WACC the Office would accept the existing weights (i.e. W_e and W_d) of debt and equity as per JPS' annual statutory accounts. A drawback to this approach however is that due to the differential in the cost of equity and debt, there has to be a balancing of the interest of the consumer and the shareholders.

JPS proposes that the current gearing level of the company be used to compute the WACC. Based on JPS audited accounts for the test year, it has 43.3% of capital employed in the form of debt and 56.7% in the form of equity.

RATE BASE CAPITALIZATION	J$'000
Long term debt	15,204,146
Preferred stock	2,933
Equity	19,901,250
TOTAL CAPITALIZATION	35,105,396

Equity is generally a more costly method of financing than debt because common stock holders only receive a return on their investment after debt holders' claims on the assets of the company have been met. For this reason equity holders face greater risk than debt holders and because of this they need a higher level of return to entice them to forego consumption in favor of investment. Another reason why debt is less costly than equity is that interest charge on debt is tax deductible. Also, because increases in the level of gearing expose equity holders to greater risk (for example the risk of insolvency), equity holders in turn require much higher levels of return to compensate them for this higher risk which translates into a higher WACC. In light of this, as the share of debt relative to equity increases in a firm's capital structure, the weighted average cost of capital declines because the weight of debt (W_d) in the average increases. This may be especially relevant to JPS, which at the end of financial year 2003 had a capital structure make-up of 56.7% equity and 43.3% debt.

An alternative approach to utilising JPS' existing gearing is for the Office to identify an optimal capital structure and establish the cost of capital on that deemed combination of debt and equity.

Determination 4.1

The Office is of the view that a gearing of 48% is appropriate for JPS and therefore expects JPS to achieve this level by 2009. The Office also determines that the gearing to be used in this review is the actual gearing in the test year of 44%.

4.2 Cost of Debt

There are two ways to approach the recovery of debt costs. One is to use the incremental cost of new debt financing. The other is to allow JPS to recover the actual weighted costs of current outstanding debt. One approach to the calculation of the cost of debt is to utilize the Risk Premium Model (RPM). With this approach k_d is a combination of the risk free rate (R_f) and the firm's corporate risk premium (P). R_f can be measured by the rate of return on a GOJ fixed income security (for example treasury bill) or a security issued by say the US or the UK government. The firm's corporate risk premium is the difference between R_f and investors' expected return E(R) on the firm's current corporate bond. Added to this is the country risk premium (CRP). Algebraically, the formula is:-

$K_d = R_F + P + CRP$, where
K_d = cost of debt capital
R_f = real risk-free interest rate
P = company-specific risk surcharge or debt risk premium
CRP = Country Risk Premium

The assumption could be made that JPS' current actual cost of debt will remain the same during the life of the price cap. With this approach the selection of the appropriate risk free rate and estimating the size of the corporate risk premium is avoided. The major drawback is that the past may not be a good guide to the future. An alternate approach is to establish the cost of debt on the basis of international benchmarks.

The Office is of the view that regulatory arrangements which seek to underwrite the cost of debt on a company-specific basis can blunt incentives for JPS to source and manage its capital as efficiently as possible. However, if in the regulator's best judgement, the utility:

a) shows evidence that it is making every effort to minimize the costs of debt for given levels of risk, and

b) has no direct incentive to increase its debt cost because higher rates will result in lower sales; then the company's weighted cost of Outstanding Debt can reasonably be used to determine its WACC.

4.3 Incremental Cost of Debt

The cost of debt is made up of three components - **the risk free rate (R_F)**, a **country risk premium (CRP)** and a **company specific debt premium (P)**. The cost of debt proposed is calculated as the risk-free rate, using 10-year Treasury bonds yield in the United States as at July1 2003, plus the country risk, (that is, the difference between Jamaica Indexed-bond and U.S. Treasury bonds)[6], plus a risk premium for A-rated utility debt over US treasury bill. The real rate is then calculated based on the projected rate of inflation.

The cost of debt I is based on the risk-free rate plus a company risk premium and country risk.

$$Kd = R_F + P + CRP$$

Where

Kd = cost of debt
Rf = real risk-free interest rate
P = company-specific risk surcharge or debt risk premium
CRP = Country Risk Premium

Cost of Debt Calculation using Incremental debt cost Method (real, 2004)

Component	Calculation	Value	Source
(R_F)	(R_F)–US Inflation	2.27%	US.10-Year Treasury (4.77%at April 2004) Minus expected inflation (2.5%)
(CRP)		5.32%	Yield on GOJ 10-year US$ Index bond minus U.S Expected Inflation minus Real US risk free rate
(P)		2.0%	Risk premium for A-rated utility debt over US treasure bill
Total Cost of Debt	R_F + P+CRP	12.09% (nominal)	

[6] 10-year yield on Government of Jamaica US Index bond is estimated from a yield curve of various bind issue of varying duration. The yields on GOJ bonds implicitly reflect the real risk free rate, Country risk and inflation expectation in Jamaica.

4.3.1 Risk-Free Rate (R_F)

The goal of JPS should be to match debt tenure to its average asset life span. Given the types of assets that JPS invests in, this would lead to the decision to use mostly longer-term debt instruments to finance these investments. In light of this, the 10-year U.S. Treasury bond is an appropriate measure of a long-term risk-free rate of return. The information can be sourced from many public sources where it is presented in nominal terms. To adjust this to a real return the expected inflation rate is subtracted. The nominal risk-free rate of 4.77% is the latest US Treasury bond as at April 26, 2004. The expected U.S. inflation of 2.5% is subtracted leaving us with a 2.27% RFR.

4.3.2 Country Risk Premium (CRP)

The CRP represents the additional risk of investing in Jamaica US-Indexed Bond versus investing in U.S bonds with the same maturity. The CRP is estimated by estimating a 10-year yield curve for current Jamaica Index bond using April 21, 2004 average bid and ask yield rate, subtracting expected Jamaica Inflation and the real risk free rate on Treasury bonds. This estimate is 4.43% (9.20%-2.50%-2.27%) which represents the CRP specific to Jamaica. OUR estimated CRP using April 21, 2004 Jamaica Index Bond Yield Data is 4.43% while JPS proposed CRP using January 9, 2004, Jamaica Index Bond Yield Data is 6.77%. The Office is of the view that based on the methodologies adopted to estimate the CRP a range of values can be used. The Office has therefore determined that the applicable CRP is 5.31%.

4.3.3 Debt premium (P)

The Debt premium which lenders charge the company over and above the risk-free interest rate is known in the market as the credit spread. The size of the spread depends in practice on the company's credit rating and on the term of the loan in question. As a rule, the term taken for assessing the spread is one which corresponds to the term used for the risk-free interest rate. This is generally a period of 10 years. The Office analysis of risk premium for A-rated utility debt over US Treasury Bonds, analyzing monthly data covering the period 1977 to 2000 gives a value of 2.00%. The Office has set the expected debt premium for JPS at 2.00%. There is no reason at this time to anticipate that A-rated utility bond debt will become more risky relative to US treasury bonds.

4.4 Weighted Cost of JPS' Outstanding Debt

The alternative of using the rate paid by JPS for its existing debt was evaluated and the weighted cost of this debt, based on December 31 audited statements as well as subsequent submissions, established as outlined below.

JAMAICA PUBLIC SERVICE COMPANY LIMITED
SCHEDULE OF LONG TERM DEBT OBLIGATIONS
AS AT FEBRUARY 15, 2004 T0 MATURITY DATES OF LOAN

Institutions	Currency	JPS proposed Interest Rate	OUR determined Interest Rate	Balance @ 2/15/04	Weighted Interest Rate	
					JPS proposed	OUR determined
RBTT Merchant Bank	$US	11.90%	11.90%	80,000,000	3.75%	3.75%
RBTT Merchant Bank	$US	10.75%	10.75%	51,375,000	2.18%	2.18%
Republic Bank Loan	$US	12.35%	10.50%	2,262,873	0.11%	0.11%
Republic Bank Loan	$US	11.76%	10.00%	601,134	0.03%	0.03%
KFW Loan - DM 7M(a)	$US	7.00%	7.00%	4,235,000	0.12%	0.12%
KFW Loan - DM 14M(a)	$US	7.00%	7.00%	2,129,000	0.06%	0.06%
Republic Bank Loan(b)	$US	11.76%	10.00%	8,000,000	0.37%	0.37%
Dehring Bunting & Golding	$US	10.85%	10.85%	3,509,774	0.15%	0.15%
RBTT Merchant Bank	$US	14.12%	12.00%	26,785,714	1.49%	1.49%
RBTT Merchant Bank('c)	$US	14.12%	12.00%	30,000,000	1.67%	1.67%
Int'l Finance Corporation(d)	$US	12.38%	12.38%	45,000,000	2.19%	2.19%
Total long-term debt				253,898,495	12.18%	12.18%
Transaction cost					0.38%	0.38
Total Long-term debt					12.56%	12.56%

4.4.1 JPS' Proposal

JPS proposed cost of debt is 12.49% made up of the weighted interest rate of actual cost of outstanding debt principal of 12.11% plus existing transaction cost of 0.38%. JPS proposed that using the actual cost of debt should be conditional upon the following:

• Consideration be given to JPS' need to refinance a substantial portion of its loans—US$130 million—in 2006. JPS posited that if the loans are refinanced on different terms and conditions, the impact on the cost of debt and the WACC may be substantial. JPS further stated that the company's cost of debt has a floor that is set by market interest rates generally and the Government of Jamaica's cost of debt. If, for example, US Treasury bond rates were to rise or if sovereign risk were to rise—of which there is a real possibility—then JPS' cost of debt would also rise. JPS stated that both of these are real possibilities. JPS further proposed that interest rates in the US are currently at a historical low. Value Line, for example, forecasts a 2003 average rate for 3 month Treasury bills of 1.1% and 2.5% for 2004-06. The yield on ten-year Treasury notes is projected to rise from 4.0% this year to 5.5% for 2006-2008. JPS asserted that these data strongly indicate that the cost of capital will increase from current low levels. Further, the high debt burden of the Government of Jamaica makes it probable that the cost of sovereign debt of Jamaica will rise in the future. Hence, JPS agrees with using current cost of debt if, to the extent that JPS' cost of debt changes when the loans are refinanced, the OUR allows for an interim review under the Z-factor.

• The capital expenditure required for future generation expansion be treated separately outside of this rate review.

4.4.2 The Office's position on the cost of debt

The Office in making a determination on the cost of debt accepts JPS' proposal of using the actual cost of debt. The company has also satisfies us that the transaction costs have been amortized over the life of the loans. The cost of outstanding debt based on JPS' submission of outstanding loan principal is determined to be **12.56%.** The Office makes this determination without the conditions specified by JPS to reopen this during the price cap period. The Office is of the view that to subject this decision to the two conditions outlined in JPS' proposal, will likely blunt incentives for JPS to source and manage their capital as efficiently as possible. Moreover, the Office is of the view that given recent developments on the Jamaican economy the cost of sovereign debt will decrease in the future therefore neutralizing any impact the rise in ten-year Treasury notes may have. Within these market dynamics it is expected that JPS will have the incentive to manage its capital as efficiently as possible.

Determination 4.2

The Office has determined that the cost of debt is JPS' actual cost as per the test year's audited balance sheet. This cost of debt is 12.56%

4.5 Cost of Equity Capital

Of the two elements comprising WACC, the cost of equity has traditionally proven to be the most difficult to derive, and this is so even in countries with highly developed capital markets such as the USA and the United Kingdom. There are three main methods for estimating the cost of equity: (i) Comparable

Earnings, (ii) Gordon Dividend Growth Model, and (iii) Capital Asset Pricing Model (CAPM).

4.5.1 Comparable Earnings

With this technique the actual earnings of non-regulated firms are used as a benchmark to determine the regulated firm's cost of equity. This may involve either domestic comparison of similar firms or international comparisons. A drawback to this approach is that regulated and non-regulated firms operate in different sectors of the economy, overseas companies may face a very different environment and therefore each faces different risk. For this reason some adjustment is usually made to reflect the true risk facing the regulated firm. This adjustment can be sometimes arbitrary and has traditionally been a very contentious debate between regulators and regulated companies. Nevertheless, domestic and international comparisons can provide useful benchmarks to be used as a cross-check on the cost of equity derived using a different methodology.

Gordon Dividend Growth Model (DGM)

Underlying this approach is the idea that the regulated firm's share price equals the discounted present value of current and future dividend, and thus that the market discount rate (R_e) is a measure of shareholders required return on equity:-

$$P_0 = \sum D_t /(1+R_e)^t$$

where P_0 is the current price per share, D_t is the dividend per share in period t, t is the time period (for example the life of the price cap), and R_e is the discount rate. Assuming that D grows by a constant amount then the return on equity is a composite of the dividend yield and the rate of growth in dividend:

$$R_e = D_0 /P_0 + g$$

This approach is based on investors' expectations about the future performance of the regulated firm. The application of DGM is challenging even in settings where more highly developed capital markets exists. First, it would require information on market analysts' expectations about the future growth in dividend. This may be hard to come by and even when available there might be disagreement as to its accuracy. At the same time, the past might not be a reasonable measure of future movements in g[7]. Also, in Jamaica, there may be capital market distortions, thus the dividend yield (D_t/P_0) is unlikely to be a sound basis for measuring the cost of equity***.*** The P/E ratios of Jamaican companies demonstrate marked fluctuations over time.

[7] g represents dividend growth rate

4.5.2 Capital Asset Pricing Model

The CAPM is probably the most widely used method for estimating the cost of equity capital. It commands widespread respect in several regulatory jurisdictions (particularly in the UK), and is used almost universally in both corporate finance and regulatory applications in Australia. The algebraic model is outlined below:

$K_e = R_f + \beta(R_m - R_f)$, where:

K_e = Cost of equity

R_f = Risk-free interest rate

β = (equity) beta

$R_m - R_f$ = market (equity) risk premium

The expected equity risk premium for the Company, $\beta(R_m - R_f)$, is the additional return for making a risky investment in that Company rather than a safe one. The expected risk premium varies with the equity beta. Risks are of two types, diversifiable or market risk and non-diversifiable risk (systematic risk). An investor need not worry about diversifiable risk since by holding a diversified portfolio of various stocks he or she is able to minimize this type of risk. Non-diversifiable risk, varying from sector to sector, still exists even if the investor holds a well diversified portfolio of common stocks and the returns to the investor must compensate for this risk.

Jamaica is a developing country with a thin capital market. The majority of the shares (80%) of JPS are privately held by Mirant Corporation and the remainder (20%) is held by the Government of Jamaica. Ordinary shares are therefore not traded on the local stock exchange. It is therefore not possible to use stock market data to estimate the cost of capital as is traditionally done in developed countries with stable, broad and well diversified market. Given the global changes in the electric utility industry and, in particular, the privatisation to global investors, it is reasonable to estimate the risk of this industry and in particular JPS in a global setting and then make adjustments that focus on the risks specific to Jamaica.

4.5.3 Comparables

The methods of estimating the cost of equity in this determination use stock prices and other measures of investor expectations. Since JPS' stock is not traded, investor expectations that would affect the cost of equity for JPS cannot be measured directly. For this reason, groups of companies that are facing risks similar to those encountered by JPS in providing electricity service for which the cost of equity can be estimated is selected for comparison purposes. Risk is the uncertainty associated with the ability of an investment to generate the return expected by investors. Once the comparables are selected, their firm-specific data are applied to the cost-of-equity methodologies selected herein, and average or median returns for the surrogate group are calculated in order to determine a zone of reasonableness for cost of equity. The sample of surrogate companies and the criteria for selecting them and the DCF cost of equity are shown in **exhibit 1**.

4.6 Discounted Cash Flow (DCF)

Under the Discounted Cash Flow (DCF) methodology, a firm's cost of equity is calculated according to a formula involving the annual dividend and price of a share of its common stock, along with the estimated long-term dividend growth rate. The standard DCF formula is the annual dividend on common stock (Div) divided by the price (P) of a share of common stock (termed the "dividend yield") plus the long-term growth rate in dividends (g). The mathematical formula is expressed as follows:

$$k = Div_1/P + g$$

Determination 4.3

The Office has determined that the CAPM based on global operating firms is the preferred method used to estimate JPS' cost of equity.

As mentioned above, JPS is not a publicly traded company on the local stock exchange and hence the various parameters needed to estimate the cost of equity using this method will at best be a surrogate proxy using comparable companies.

There are no comparable companies to JPS in Jamaica to estimate the cost of capital. However, a sample of comparable companies from Investor Owned Utilities in the U.S was evaluated and an average cost of capital was estimated using the following criteria outlined below and as shown in exhibit 1.

Selection Criteria for Comparables

Beta < 1
Sales<$1000 million
Sales> $100 million
Net Plant< $1000 million
Net Plant >$100 million
Asset/Sales > 0.85

Except for the beta measure outlined above JPS' Financials as reported in the audited Financial Statements 2003 is comparable to the criteria outlined above. Twenty three (23) comparables were sampled from a population of 1773 companies. [8]Using data from Value Line Data Base (December 1, 2000), S&P Utility Compustat and Bloomberg- Zacks Earnings Estimates on the various DCF parameters, an average required return was estimated at 10.23 percent. In order to apply this estimate to JPS, the CRP of 4.43% as discussed in the previous section, is added to the DCF cost of equity. Hence the DCF cost of equity for JPS is **14.66%.**

4.7 Risk Premium

Risk premium methodologies can also be used to calculate the cost of equity. In this section we discuss two types of risk premium methodologies. The first is termed **traditional risk premium analysis.** The second type of risk premium analysis is the **Capital Asset Pricing Model ("CAPM").** These two methods share fundamental similarities in that they select a "risk free" investment such as long-term United States Treasury bonds and add a risk premium to return on that "risk free" investment to derive a cost-of-equity estimate. The differences between the two methods arise in the manner by which the risk premium is calculated. Under a more traditional risk premium methodology, the risk premium is typically estimated as the historical or estimated spread between equity security returns and bond yields. Under the CAPM methodology, the risk premium is formally quantified as a linear function of market risk (beta).

4.8 Traditional risk premium analyses

This methodology estimates the cost of equity as the current yield on a "risk free" investment, such as long-term U.S. Treasury bonds, plus country risk as described earlier, plus historical or expected equity risk premium..

4.9 CAPM Analysis.

Under the CAPM, the variance of the company's stock price is measured relative to the market as a whole to adjust the premium. Similar to traditional risk premium methodologies, the CAPM calculates a cost of equity equal to the sum of a risk-free rate and a risk premium. In the CAPM formula, however, the risk premium is proportional to the security's market risk, which in this case is the electric utility market risk, and the market price of the risk.

The OUR is of the view that the CAPM offers the best method of estimating the cost of Equity. CAPM is most widely used to estimate firms' cost of capital, notwithstanding the fact that there is considerable evidence of short comings in the CAPM. It must be emphasized however that its clear theoretical foundations and simplicity contribute to its continuing popularity.

The defining characteristic of the CAPM is that it expresses the systematic risk in terms of just one parameter: the beta (ß). This measures the risk of the

[8] This DCF analysis was done by FURC to determine Florida Power and Light required rate of return and the analysis is shown in exhibit 1

company's shares relative to the market as a whole. By definition, the beta of the market portfolio (the portfolio containing all shares) is 1. The risk premium for a share (that is, the expected real return minus the risk-free real interest rate R_f) with a systematic risk of ß is equal to ß times the risk premium for the systematic risk in the market portfolio.

When a global group of companies is used as a surrogate, the CAPM is restated for the cost of equity to be composed of the risk-free rate, plus market risk, plus company risk, plus county risk. The risk-free and country-risk rates were discussed in the previous section. The equation stating the return required by the JPS shareholders is:

$$Ke = R_f + CRP + \beta (R_m - R_f)$$

Where:

K_e	= Cost of equity
R_f	= Risk-free interest rate
CRP	= country Risk Premium
ß	= (equity) beta
$R_m - R_f$	= market (equity) risk premium

4.9.1 [9]Beta(ß) Estimation

There are several databases of asset betas for electricity companies. One in particular examines asset betas faced by companies under different regulatory regimes. Different regulatory regimes impose different degree of risk – for example under price cap risk to the company is greater than under rate of return regulation, therefore, all else equal, a higher beta may be expected. Alexander, Mayer and Woods (World Bank Working Paper #1698) report results from an international survey. They report an asset beta of 0.57 under high powered (price cap) regimes and of 0.41 under intermediate regimes (compare to about 0.35 under the lowest powered -- rate of return – regimes. JPS will face a price cap from 2004 and currently face a regime in which tariffs are reviewed every year but they are not guaranteed any specific rate of return. Therefore JPS will fall in between a high power rate of return and intermediate tariff regime. Since there is a considerable amount of pass through in the tariff structure and the OUR is specifically required to ensure JPS can fund future investment, the asset beta was weighted towards an intermediate level of risk. The final asset beta of 0.45 is based on a 75/25 weighting of the results from Alexander ***et al*** study (i.e. 75%x0.41 + 25%x0.57).

[9] See footnote on pg 74 of Jamaica Electricity Tariff Study, done by Power Planning Associates Ltd in Association with Frontier Economics

4.9.2 Market Risk Premium (R_m – R_f)

The Market Risk Premium, (R_m – R_f) is estimated from the difference between the risk of the market minus the Real Risk Free rate. OUR estimated the long run relationship between the yields of a basket of market shares and the risk free rate and this represents the estimate of market risk. The OUR assumes the U.S. Treasury bonds represents the risk free rate and the basket of shares must be the basket of U.S. shares. OUR adopted the Standard and Poor's 500 Index (S & P500 Index). Arithmetic averages of the difference between the risk-free rate and the S & P Index were computed for a range of time periods (see table below)

Market Risk Premium

Time period	Market Risk
1978 – 2001	5.81%
1983 – 2001	5.65%
1993 – 2001	5.06%
S&P 500 projected	8.20%

The values computed vary between a lower bound of 5.06% (the period 1993 – 2001) and a higher bound of 8.20% (considering all the data). Considering short periods such as 1998 – 2001 does not represent the risk associated with long run investment, such as those involve in electric utilities. Therefore, longer periods, of at least ten (10) to fifteen(15) years are considered by the Office and hence a "zone of reasonableness" is between 5.06% and 8.21%. The Office therefore determined that the intermediate market risk value of 8.20% as the most likely estimate representing a forward looking market risk premium. The Table Below shows the CAPM real Cost of Equity.

Indicative CAPM Risk Premium Cost Of Equity (Real)

R_f : 5 year moving average 10-Year US Real Treasury Bond Rate (Jan -04)	2.27%
Intermediate Price Cap Asset Beta	0.45
Real Market Risk Premium(R_m-R_f)	8.20%
deemed Gearing	48.00%
Derived Equity beta (Levered)	0.87
CAPM Risk Premium Cost of Equity	**9.37%**
Country Risk Premium (CRP)	4.43%
Real Cost of Equity adjusted for CRP	**13.80%**

4.10 JPS' PROPOSED CAPM

An analysis of JPS' proposed standard CAPM results indicate that overall, the cost of equity is in a range of 10.5% for DCF test results to 11.6% for CAPM test results before adjustment for significant risk differences between JPS and its comparable companies, and average 11.2%. JPS posited that these results are in line with the average approved return on equity by state utility commissions in the US, before adjusting for size, regulatory and country risk factors specific to JPS. JPS in its proposal identified four sources of risk:

- Differences in financial risk;
- The size premium effect
- The regulatory risk effect; and
- The country risk effect

Using comparable sales as a means of valuing a company has the same inherent flaw as rule-of-thumb formulas. Rarely, if ever, are two companies truly comparable. However, companies in the same industry do have some characteristics in common and a careful contrasting may allow a conclusion to be drawn about a range of values. The primary objective should be to find companies in the US and worldwide that are truly comparable with JPS. If this was not the case, any comparables could be chosen and adjustments made for identified sources of potential risk. Additionally, an important source of risk difference that JPS' proposal ignore is JPS' long term monopoly status with has more than half of its total costs subject to pass through in the tariff. It can be argued that *size premium risk* and *regulatory risk* will be more than compensated for by the tariff structure enjoyed by JPS vis-à-vis the comparables that it used. Also, the comparables are subject to various degree of regulation such as rate of return and price cap mechanism and as such the factoring of regulatory risk may have overstated the cost of equity.

JPS' proposed cost of equity of 12.2 % estimated from the CAPM and DCF methodology is given in nominal terms. JPS proposed expected inflation rate is given as 2.5% which implies forward looking real cost of equity of 9.7%. JPS' proposed average real cost of equity before adjusting for country risk is therefore 9.7%.

JPS' proposed a country risk premium (CRP) of 6.77%. The CRP is estimated from the yield curve regression equation on average bid and ask bond yield on Jamaica indexed bond using January 9, 2004 data.

JPS' real cost of equity = 9.70%+ 6.76% = 16.46%

4.11 Office Determined Cost of Equity

The difference between OUR CAPM cost of equity (13.80%) and JPS' proposed cost of equity (16.43%) is 2.34%. This difference is attributable to the different estimates of the CRP. OUR estimated CRP using April 21, 2004 Jamaica Index bond yield data is 4.43% while JPS proposed CRP using January 9, 2004 Jamaica Indexed Bond Yield data is 6.77%. The Office is of the view that based on the methodologies adopted to estimate the real cost of equity a range of values for CRP can be used. The Office has therefore determined that the applicable CRP is 5.315% and that the average of OUR and JPS' proposed real cost of equity of 9.37% and 9.70% respectively shall be adjusted by 5.315%. From these ranges of indicative values the Office is of the view that the real cost of equity for JPS is 14.85% (9.535%+5.315%) outlined in the tables below.

Average CAPM, DCF Real Cost of Equity		**JPS estimated CRP**	**OUR estimated CRP**	**Office determined CRP**
JPS	OUR	January 9,2004	April21,2004	
9.37%	9.70%	6.77%	4.43%	5.315%

Real Cost of Equity

JPS(real)	OUR (real)	Average real cost of Equity	Office determined CRP	Office determined real cost of Equity
9.37%	**9.70%**	**9.535%**	5.315%	**14.85%**

Determination 4.4

The Office has determined that JPS' real cost of equity is 14.85%

Computation of JPS post-tax WACC

$$\begin{aligned} WACC &= w_d{*}k_d{*}(1\text{-}T)+ w_e{*}\,k_e, \\ &= 44\%{*}12.56{*}(1\text{-}0.333)+ 56\%{*}\,14.85\% \\ &= 12\% \end{aligned}$$

Chapter 5: JPS' rate base

5.0 Introduction

The Rate Base is the investment base established by the regulatory authority upon which a utility is allowed to earn a fair return. In defining the Rate Base the Licence states in Schedule 3, Section 2:

> "Rate Base means the value of the net investment in the licensed business. The Rate Base shall be calculated on the net electric system investment made by the Licensee at the time the rates are being set and shall include net investment made by the Licensee in the generation, transmission and distribution and general plant assets. The Rate Base shall include appropriate rate-making adjustments to take into account known and measurable changes in the plant investment base and shall be increased or reduced by any positive or negative working capital requirement that may exist at such time. Working capital shall include, among other things, the cost of an appropriate level of fuel which is held in inventory, cost of appropriate levels of other inventories and an appropriate percentage of annual non-fuel operating expenses less any appropriate offsets."

5.1 Valuation of Assets

Valuation of assets of the utility is a major process in the determination of tariffs by the Office. The values of JPS' assets have to be established in the process of determination of the tariff under the PBR and RoR systems of costing. Any under-valuation or over assessment of the assets may lead to losses or undue enrichment of the utility.

There are various methodologies or basis for valuation of assets. The commonly used methodologies are:

1. **Original cost minus Depreciation**

The calculations take into account the book value of assets of the utility from which are deducted the depreciated value on the basis of the norms prevailing in the power sector at the relevant point of time. This method is still widely used because it lends itself to convenience of estimation based on documented records and also because it leaves some incentives for the utility to earn returns on the original investment. However, the results of valuations may be different due to the difference in the economic and the depreciated cost of assets.

2. **Current cost of assets less Depreciation**

Under this methodology, the present value of assets as reflected in reproduction costs (i.e. the cost of rehabilitating the same assets in the present time frame) or replacement costs i.e. the cost of procuring a new asset (based on current technology), needed for performing the same function, is calculated and depreciation at appropriate rates is deducted. In this approach the difficulties likely to be encountered are (i) difficulties in making a proper fixation of current costs, which are again subject to market forces and tend to display fluctuating tendencies, (ii) difficulty in selection of appropriate replacement items which may be taken as base for costing and (iii) the results produced by resorting to costing at current rates may lead to unduly high costs in comparison to marginal costing approach and may, thus, be detrimental to the interest of the consumer.

Valuation of assets by Independent Assessor

The utility has an option to appoint an independent assessor for valuation of assets based on market values or historical costs plus suitable adjustments to account for subsequent depreciation or appreciation. This method also has the same draw-back i.e. absence of standard parameters for assessment of market value for plants, equipments and systems which were purchased 30 to 40 years previously.

5.2 JPS' Method for revaluation of property plant and equipment

JPS revalues its specialized plants and equipment quarterly, on the replacement cost basis, using Handy Whitman[10] indices for equipment purchased abroad, adjusted for movements in the Jamaican dollar relative to the US dollar and adjusted where applicable for movements in inflation for local components. Land and buildings are stated at cost and are not revalued.

The methodology used for the revaluation of JPS' specialized plant and equipment is referred to as replacement cost of asset less depreciation. Under this methodology, the gross value of the plant and the accumulated depreciation are both revalued so that the remaining useful life of the asset does not change.

> **Determination 5.1**
>
> **The Office approves JPS' replacement cost valuation of its assets and as such the Office determines that a real cost of capital is to be applied to the asset base in the calculation of the revenue requirement**.

5.3 Allowed Rate of Return

PBR regulation of tariffs discussed herein requires choosing the appropriate rate of return on capital invested. This capital typically takes the form of a mix of debt and equity called WACC and is outlined in Chapter 4. The allowed WACC should reasonably generate enough resources to cover debt and equity payments, to enable the utility to attract the needed new capital.

The process of tariff review is based on fixation of a just and fair rate of return which may yield sufficient income to the utility on its capital base. This principle has been specified under the provisions of the Schedule 3 of the Licence.

The constituents of the Rate (Asset) Base as specified by the Licence are

[10] The Handy Whitman Indices are essentially a utility construction index and are published twice per year in the U.S

threefold:

1. ***Net investments***—which, for an electric utility such as JPS, comprises of generation, transmission, distribution and general fixed assets.

2. ***Working capital***—which is required for a business to maintain the operational supply inventories required to meet its prepayment obligations and to provide the cash needed to meet its operating expenses between the time it renders service and when it collects revenues for those services[11]. Working capital represents the net amount of capital employed in the firm, which is not invested in long-term assets or plant assets.

   The components of the working capital can be broken down into two major groups:

   – *Cash Working Capital*—which the utility must hold for the purpose of enabling it to satisfy ordinary requirements for minimum bank balances and to bridge the gap between the time the expenses of rendering utility service are paid and the time revenues derived from the sale of those services are collected.

   – *Non-Cash Working Capital*—which includes items such as materials, supplies and fuel that are needed to meet operating exigencies from time to time.

3) **Offsets**—the licence speaks to the exclusion of appropriate offsets from working capital. Such offsets would include items that derive from non-investor items that are 'cost-free' to the utility, i.e., they do not derive from either loans or equity capital, and they do not require a return. Since such capital is cost-free to the Utility then it is not reasonable and appropriate for the utility to earn a return on the components of the Rate Base that this capital supports.

Table 5.1: shows Office determined "Test Year" balance sheet compared with JPS

[11] Electricity Utility Cost Allocation Manual, NARUC (1992), PP29

Proposed “test year” and for the audited account for year ending December 31, 2004.

$’000

Items	2003 Audited	JPS Proposed Test Year	Office Determined Test Year
Gross fixed assets	79,885,634	83,178,789	79,885,634
Accumulated depreciation	49,169,076	51,678,463	49,169,076
Net fixed assets	30,716,558	31,500,326	30,716,558
Construction work in progress	1,781,458	1,541,834	1,653,458
Pension plan asset	900,900	1,069,798	900,900
Deferred expenditure	0	0	0
Capitalized redundancy costs	0	475,676	594,620
TOTAL LONG-TERM ASSETS	33,398,916	34,587,633	33, 865,536
CURRENT ASSETS	9,915,881	9,327,552	9, 170,761
Cash and short-term deposits	1,533,778	149,655	788,658
Receivables	6,909,150	7,594,914	6,909,150
Inventories	1,472,953	1,582,983	1,472,953
CURRENT LIABILITIES	5,688,013	3,355,164	3,302,193
Short-term loans	1,712,428	140,753	140,753
Payables	3,975,585	3,214,412	3,161,440
Related Companies balances			0
NET CURRENT ASSETS	**4,227,868**	**5,972,388**	**5,868,568**
TOTAL NET ASSETS	**37,626,784**	**40,560,021**	**39,734,104**
Financed by:			
SHAREHOLDERS’ EQUITY	19,709,238	19,901,250	19,581,238
Share capital		19,901,250	
LONG-TERM DEBT	13,034,737	15,204,146	15,420,557
CUSTOMER DEPOSITS	2,060,285	1,838,277	2,060,285
EMPLOYEE BENEFIT OBLIGATIONS	1,062,000	911,572	911,500
DEFERRED TAX LIABILITY	1,760,524	2,704,776	1,760,524
TOTAL NET ASSETS	**37,626,784**	**40,560,021**	**39,734,104**

Table 5.2: Known and Measurable changes to determine “test year” balance sheet

$’000s

Items	2003 Audited Financials	Known & measurable changes (1)	(2)	(3)	(4)	(5)	Test Year Restated Financials
Gross fixed assets	79,885,634						79,885,634
Accumulated depreciation	49,169,076						49,169,076
Net fixed assets	30,716,558	-	-	-	-		30,716,558
Construction work in progress	1,781,458					(128,000)	1,653,458
Pension plan asset	900,900						900,900
Deferred expenditure	0						-
Capitalized redundancy costs		594,620					594,620
TOTAL LONG-TERM ASSETS	33,398,916	594,620	-	-	-		33,865,536
CURRENT ASSETS	9,915,881	(594,620)	(150,500)	-	-		9,170,761
Cash and short-term deposits	1,533,778	(594,620)	(150,500)				788,658
Receivables	6,909,150						6,909,150
Inventories	1,472,953						1,472,953
CURRENT LIABILITIES	5,688,013	-	-	(557,164)	(1,828,656)		3,302,193
Short-term loans	1,012,036				(871,283)		140,753
Current portion of long-term liabilities	557,164			(557,164)			-
Due to related companies	143,228				(143,228)		-
Payables	3,975,585				(814,145)		3,161,440
NET CURRENT ASSETS	4,227,868	(594,620)	(150,500)	557,164	1,828,656		5,868,568
TOTAL NET ASSETS	37,626,784	-	(150,500)	557,164	1,828,656		39,734,104
Financed by:							
SHAREHOLDERS' EQUITY	19,709,238					(128,000)	19,581,238
LONG-TERM DEBT	13,034,737			557,164	1,828,656		15,420,557
CUSTOMER DEPOSITS	2,060,285						2,060,285
EMPLOYEE BENEFIT OBLIGATIONS	1,062,000		(150,500)				911,500
DEFERRED TAX LIABILITY	1,760,524						1,760,524
TOTAL NET ASSETS	37,626,784	0	(150,500)	557,164	1,828,656		39,734,104

As can be seen, the balance sheet items consist of the three categories of rate base items defined in the licence:

1. *Net investments*—i.e., total long term assets, which comprise of:
   - *Net plant in service*—JPS' net plant assets are revalued annually based on a formula that incorporates (a) the relevant industry indices for equipment purchased abroad (i.e., the Handy-Whitman index -a utility construction index), adjusted where applicable for movements in the Jamaican dollar relative to the US dollar; and (b) using relevant price indices for local costs (CPI). The split of assets between (a) and (b) is based on predetermined relationships for particular asset categories as determined by an independent Stone & Webster valuation. Consistent with the use of the test year sales, the Office is of the view that the test year fixed assets in service represents plant used and useful in generating that level of sales.

   - **The Office has determined that the net plant in service for the test year is J$30.72 billion.**

   - *Construction work in progress (CWIP)*—which represents the balance of funds invested in the utility plant under construction, but not yet placed in service. As and when the capital works are completed, the relevant amount is removed from the CWIP line and transferred into the net plant assets category. CWIP does not represent plant used and useful in the provision of the services of the licensed business so its inclusion in the rate is offset by the AFUDC being counted as income derived from the CWIP. One further adjustment needs to be made regarding the amount of AFUDC that is included in CWIP. This amount of $128 million is excluded from the rate base as including it would result providing a return on imputed returns on assets not yet in service.

   - **The Office has determined that CWIP for the test year is J$1.653 billion**

   - *Pension plan assets*—JPS operates a defined benefit pension plan. The annual net pension cost is actuarially determined using the projected unit credit method and is charged against the income statement. Additionally, the net present value of the pension obligation is compared to the fair value of the plan's assets, and a net asset or liability is reflected in the balance sheet, representing JPS' obligation to the fund.

   - **The Office has determined that the pension plan asset for the test year is J$900.9 million.**

2. *Working capital*—which is simply current assets less current liabilities. Current assets include cash, trade and other receivables (net of a provision for doubtful debts) and inventories (fuel, materials and supplies).

With regard to fuel inventory, it is JPS' policy to maintain at least ten days of fuel inventory. This comes against the background that this is an island utility which rules out the possibility of interconnectivity with other grids, should there be any crisis, which interrupts the importation of fuel.

Current liabilities take the form of short-term loans, trade payables and provisions, related company balances (in the case of JPS, Mirant) —which reflect transactions that are undertaken in the normal course of business and that comprise the provision of technical support and related professional services, as well as the acquisition of generation equipment and parts— and the current portion of long-term debt.

The Office has determined that working Capital for test year is J$5.868 billion.

3. *Appropriate offsets*—These, as described above would include cost-free capital, i.e., funds that JPS has access to, but was provided by externals sources outside of the funds normally accessed through capital financing i.e. long term loans or equity financing. JPS holds three types of cost-free capital, which would be offset against the other items above:

   – *Customer advances and deposits*—it should be noted that JPS incurs an interest charge on customer deposits held. If, customer deposits are considered as an offset, then JPS must recover elsewhere the interest costs incurred.

   – *Employee benefits*—a provision is made for the cost of unutilised vacation and sick leave in respect of services rendered by employees up to the balance sheet date, in accordance with their employee service contracts. Similarly, a provision is made in respect of post retirement benefits to be provided to employees upon retirement. The post retirement benefit obligation is actuarially determined at the balance sheet date on a basis similar to that used for the pension plan. This policy ensures proper recognition of employee service costs in the period when the service is actually provided.

   – *Deferred income tax*—this represents the provision for temporary differences arising between the tax bases of assets and liabilities and their book values in the financial statements, using current corporation tax rates. A deferred tax liability arises primarily in relation to the revaluation surplus on fixed assets, which exceeds the accumulated taxation losses of JPS. This change in accounting policy will allow proper recognition of JPS' tax expense in future years as JPS utilises its accumulated tax losses through taxable profits.

Table 5.3 shows the calculation of the Office's determined rate base, versus JPS proposed rate base following the definition in the Licence. As shown, the Office determined rate base for the test year period is $35.00 billion compared to $35.105 billion proposed by JPS.

Table 5.3:
Rate Base for Test Year Period (J$'000s)

	JPS	OUR
Total long-term assets	34,111,957	33,863,536
Net current assets	6,448,064	5,868,568
Total net assets	40,560,021	39,734,104
Customer deposits and construction advances	-1,838,277	-2,060,285
Employee benefit obligations	-911,572	-911,500
Deferred tax liability	-2,704,776	-1,760,524
Rate base	**35,105,396**	35,001,795
Long-term debt	15,204,146	15,420,557
Total shareholders' equity	19,901,250	19,581,238
Rate base	**35,105,396**	35,001,795

Determination 5.2

The Office has determined that the rate base for the test period is $35.002 billion

Table 5.4 shows the calculation of the return on investment (rate base).

Table 5.4: Return on Investment for Test Year Period (J$'000s)

		JPS	OUR
Pre-Tax Cost of Debt (%)	A	12.56	12.56
Return on Equity (%)	B	18.95	14.85
Tax Rate (%)	C	33 1/3	33 1/3
Gearing Ratio (%)	D=E/G	43.31	44
Long-Term Debt ($'000)	E	15,204,146	15,420,557
Shareholders' Equity ($'000)	F	19,901,250	19,581,238
Total Capitalization ($'000)	G=E+F	35,105,396	35,001,795
Cost of Debt ($'000)	H=A*(1-C)*E	1,273,094	1,291,215
Return on Equity ($'000)	I=B*F	3,771,287	2,907,814
Return on Investment ($'000)	J=H+I	5,044,381	4,199,028

Determination 5.3

The Office has determined that the return on investments for the test period is $4.199 billion

Chapter 6: Determination of Revenue Requirement

6.0 Introduction

The Regulatory process for tariff determination consists of two steps. The first step is the determination of revenue requirement of JPS. The second step is the design of the tariff elements which, when multiplied by sales, produce the allowed revenue that JPS can collect from customers. The allowed revenue should be equal to the revenue requirement to enable JPS to recover its costs. There are three general approaches for determining the revenue requirement:

a. Actual historic accounted for costs and sales volumes;

b. Estimated future costs and forecast loads; and

c. Estimated marginal costs(usual long-run incremental costs) and forecast loads

The main difference between these approaches is in the choice of a "test year," i.e., the period over which the utility's cost of supply and sales are measured.

6.1 HISTORIC TEST YEAR

Under the first approach, the Licence defines a specific 12-month period as the latest twelve month period for which audited financial statements are available as the historic test year, which may become the basis for assessing the costs of supply and sales of electricity. The costs and sales of the historic test year may be then adjusted for "known and measurable changes". Examples of known and measurable changes are an increase in power purchase cost due to a new PPA, a change in tax laws, or a decrease in load due to an exit from the system of a major industrial customer.

Schedule 3, section C of the Licence stipulates that the non-fuel revenue requirement shall be based on a test year in which the new rates will be in effect and shall include efficient non-fuel operating costs, depreciation expenses, taxes and a fair return on investment. It is sometimes referred to as cost-plus pricing because the regulated entity is able to collect all its cost, plus a regulated return on its investment from consumers. In general this method permits the total revenues allowed to the utility, under the following formula:

RR = [RB x RoR] + ED + EO&M + I + T

Where:

- RR = the total annual non-fuel revenue requirement of the utility
- RB = the rate base (required investment) of the utility
- RoR = the allowed rate of return (debt and equity) on investment
- ED = expense on annual depreciation
- EO&M = expense on non-fuel annual operation & maintenance (O&M)

- I = annual interest burden
- T = annual taxes, if any, paid by the utility

Under this general framework, JPS has the responsibility of proving to the Office's satisfaction that each proposed element of the revenue requirement is prudent.

JPS' proposed revenue requirement is based upon the values of the terms used in the formula during a "Test Year" and according to JPS adjusted for known and measurable changes in accounting principles as recommended by their independent auditors.

Table 6.1 shows the revenue requirement proposed by JPS for the test year period, broken down according to main categories.

Table 6.1 JPS' Proposed Revenue Requirement for Test Year

Component of Revenue Requirement	J$'000s
Operational Expenses	10,483,237
PPA	3,666,489
Maintenance	2,784,835
SG&A	4,021,598
Interest Income on short term debt	101,814
Interest Income on customer deposits	121,561
Interest Income	-107,597
AFUDC	-217,463
Other Income	-14000
Sinking (self –insurance) fund contribution	126,000
Depreciation & Amortisation	**2,299,443**
Depreciation	2,180,524
Amortization of redundancy costs	118,919
Return on Investment	**5,044,481**
Cost of Equity	3,771287
Cost of Long Term Debt	1,273,094
Taxation	1,885,643
Revenue Requirement	19,712,704
Caribbean Cement Company Revenue	210,467
Adjusted Revenue Requirement	19,502,237

The following table sets out the Office's analysis and determination on the various components.

Table 6.2: Office Determination of Revenue requirement

for Test Year Period

Components of Revenue requirement	J$ '000s
Operational Expenses	9,570,914
PPA	3,002,542
Maintenance	2,758,196
SG&A	3,886,384
Short Term Debt	76,814
Customer Deposits Interest expense	121,561
Interest Income	-121,561
AFUDC	-210,615
Other income	-44,407
Sinking fund contribution	122,000
Depreciation & Amortization	2,289,197
Depreciation	2,170,278
Amortization of Redundancy Costs	118,919
Return on Investment	4,199,029
Cost of Equity	2,907,814
Cost of Debt	1,291,215
Taxation	1,453,907
Revenue Requirement	17,513,047
CCC Revenue & Transformer Discount	214,785
Adjusted Revenue Requirement	**17,298,260**
Assumptions	
Exchange rate (May 31st. 2004) J$:US$	61.00: $1
Annual sales growth	4%

a. ***Purchase Power Agreement (PPA) costs***—JPS proposed an expected amount of $3.6 billion annually while **the Office has determined a prudent cost of $3.002 billion for the test year**.

Details of these costs are provided in table 6.3 below.

Reconciliation of 2003 IPP costs with test year

	2003 costs (J$)	JPS proposed 2004 cost (J$)	OUR adjusted test year cost (J$)
JPPC	1,769,989	1,803,512	1,500,379
JEP	1,592,455	1,549,894	1,260,111
Jamalco	125,394	81,135	70,252
Jamaica Boilers	(11,327)	(39,640)	(39,640)
Monroe	827	-	-
Wighton Wind Farm Project	-	209,474 -	209,474 -
Total	3,477,338	3,604,375	3,002,576

The difference in JPS' proposed cost and OUR determined cost is J$601,799 million. The Office's determination of IPP cost of J$3.002 billion is based on commitments of amount payable in 2004 under power purchase agreements, for energy capacity and certain operating charges as posited in JPS' 2003 audited accounts.

The Office has therefore determined that a prudent PPA test year cost is J$3.002 billion.

- ***Maintenance and selling, general and administration (SG&A) costs***

  JPS proposed a test year cost of $6.8 billion annually. The proposal by JPS was based on an exchange rate of J$63:US$1. The Base exchange rate for the new tariffs will be J$61:US$1 and since a foreign exchange adjustment clause is in place JPS' proposal would result in over recovery of costs. The Office adjusted this amount to $6.63 billion.

The Office has determined that the test year cost is J$6.63 billion.

- ***Interest expense on short-term debt***—which is the interest expense on current liabilities. Current liabilities, together with current assets, comprise working capital that is required for the day-to-day operations of the business. As current liabilities are deducted from the rate base such that JPS does not recover a WACC on them, it is appropriate for the interest expense incurred on them be included in the revenue requirement. JPS estimates this at J$101.2 million.

The Office has determined that a prudent expense is J$76.814 million.

- ***Interest expense on customer deposits***—which is the amount that JPS pays as interest to customers for holding their deposits. This expense item is included as part of the revenue requirement for two reasons:

- customer deposits are deducted from the rate base; and
- interest income from customer deposits and interest-earning assets are deducted from the revenue requirement.

- ***Interest income***—which is deducted from the revenue requirement. This includes interest earned on customer deposits and cash holdings. The exclusion of interest income from the revenue requirement is consistent with:

  - the inclusion of interest expense on customer deposits in the revenue requirement;
  - the inclusion of cash holdings in the rate base onto which the WACC is applied, for the calculation of the return on rate base; and
  - the inclusion of interest expense on short-term debt in the revenue requirement.

- ***Allowance for funds used during construction (AFUDC)***—which is capitalized interest incurred during the construction phase of a project. AFUDC is deducted from the revenue requirement as the equivalent item 'construction work in progress (CWIP)' is included in the rate base. The inclusion of both AFUDC and CWIP in the computation of the revenue requirement would lead to double counting. The inclusion of both would mean that JPS would be over-recovering on its financing costs incurred (interest expense on debt are incurred even during the construction phase and not only when the project is completed). Audited statements showed that AFUDC totaled J$285.1 million in 2003 and this amount is an increase of 13.5% over 2002. For the test year JPS has proposed AFUDC to be J$217.5 million. This was further amended to J$210.61 to account for the abnormal effects of the addition to the generating plant at Bogue during 2003.

  The Office has determined the test year AFUDC as J$210.61 million.

- ***Other income***—this refers to income generated from the rental of various properties owned by JPS as well as from pole attachments. This income arises from the use of assets for purposes other than the supply of electricity, Insurance proceeds, gain on sales of assets, pension gains and other income. The audited financial statements for 2003 and 2002 show other income moving from J$88.92 million to J$221 million. However, when 2003 figures are normalized by subtracting income from Port Authority Gains and Extra-ordinary fees, Other Income for 2003 totaled J$44.4 million, a significantly decreased amount when compared to J$88.6 million for the 2002 9-month period.

  The Office has determined this amount for other income to be $J44.4

million.

- **Contribution to the sinking (self-insurance) fund**—which is a proposed form of self-insurance for JPS' transmission and distribution assets.

The Office agrees with the principle of the self-insurance fund and has determined that provision for the sum of J$122 million is reasonable.

- **Depreciation**—which is calculated based on the depreciation rates in Schedule 4 of the Licence, totaled J$2.17 billion compared with J$2.18 proposed by JPS.

- **Amortization of redundancy costs**—in the first quarter of 2004, JPS undertook a voluntary redundancy programme so as to reduce labour costs and increase efficiency. The estimated savings from the redundancy programme is estimated to be $490 million annually The redundancy programme, however, has one-off costs in the form of redundancy payments. The capitalized redundancy cost is J$594.6million. The Office supports JPS' proposal that it is appropriate to spread (amortize) these costs over the five-year rate cap period. This has been done by capitalizing the redundancy costs (see rate base) and amortizing it.

  The Office has determined that the amortization of redundancy costs is J$118.92 million.

- *Return on investment*—which is calculated based on a post-tax WACC of 12% applied to the rate base outline in Table 5.1. The Office determination of JPS' rate base is detailed in table 5.1 And the return on investment is calculated on a Office determined post-tax WACC of 12% compared with 14.37% proposed by JPS. JPS has proposed that that the value of its return on investment is J$5.044 billion.

The Office has determined the value of the return on investment to be J$4.199 billion.

- *Taxation*—which is calculated using a 33 1/3% tax rate on pre-tax income. As stated in the Licence (Schedule 3 (2C)):

> "Taxes which are calculated based on the net income of the Licensee (Income Taxes) and payable to the Government of Jamaica shall be a component of the revenue requirement. Loss carry-forwards and any incentives to encourage capital investments are not included in the calculation of income taxes."

Determination 6.1

The Office has determined the Revenue Requirement to be J$17.298 billion.

Chapter 7: Determining JPS' Efficiency: the X-Factor

7.0 Introduction

The Licence stipulates that the X-factor is to be set to equal the difference in the expected Total Factor Productivity (TFP) growth of JPS and the general TFP growth of firms whose price index of output reflect the price escalation measure (dI) specified in equation 1

dPCI = dI ± X ± Q ±Z ……………………………………..equation (1),

where

dCPI = annual rate of change in non-fuel electricity prices;

dI = the annual growth rate in an inflation and devaluation measure;

X = the offset to inflation (annual real price increase or decrease) resulting from productivity changes in the electricity industry;

Q = allowed price adjustment to reflect changes in the quality of service provided to the customers; and

Z = the allowed rate of price adjustment for special reasons not captured by the other elements of the formula.

7.1 Productivity Analysis

The method that the Office has adopted splits the "X" factor into two components: X_1 and X_2. X_1 is an industry-wide performance benchmark to be designated by the Office, while X_2 is a company-specific 'stretch factor'. In determining the "X" factor the Office will be guided by "X" values typically used in other jurisdictions for newly privatized electricity companies, coupled with benchmarking derived from a Data Envelope Analysis (DEA) and the Total Factor Productivity (TFP) analysis study submitted by JPS. JPS has submitted the TFP study as part of the 2004 to 2009 Rate Submission and OUR analysis and review is outlined in this section.

The company-specific stretch factors have been widely used in other jurisdictions and in the case of Jamaica has been applied in the telecommunications sector. In general stretch factors are used where either an initial efficiency gap exists or circumstances are expected to be particularly favourable to the regulated business. In either case, there are grounds for arguing that customers should share in any additional profitability available from improved performance. In JPS' case, the Office considers that an initial efficiency gap exists that would cause an externally-determined efficiency factor to understate the gains available from an improvement in performance that could reasonably be expected to occur over the regulatory control period.

JPS in its proposed methodology for the “X” factor determination have made the claim that some regulators have recently moved away from DEA for benchmarking. This is true, however, all of this is not to conclude that DEA cannot be safely used, provided it is used with great care (like forms of statistical benchmarking).

The Office is of the view that techniques such as DEA will be useful as a basis for negotiation. JPS also proposed using an alternative benchmark, decisions on TFP growth in US regulated industries. This method is open to the obvious objection that the appropriate stretch factors for firms that have been subject to long-term regulation in the US will be lower than for more recently regulated (and privatised) firms such as JPS, assuming that the US regulators have been effective over the years and have eliminated most inefficiencies.

The objections raised to DEA are generally reasonable but some form of benchmarking is necessary as part of the regulatory process and DEA can be a useful input into this process, if used with care and recognition of its limitations.

In translating anticipated cost savings to the determination of an X factor, X_1 only involves account being taken of the future scope for productivity improvements in the regulated industry as a whole, whereas X_2 accounts for the scope for productivity improvements in the JPS relative to productivity growth in the regulated industry generally.

The X_1 factor is a pre-determined annual scalar applied to JPS’ forecast revenue without reference to its actual earned rate of return. It represents the percentage reduction in revenue JPS is deemed capable of achieving, taking account of efficiency improvements, without jeopardizing its financial integrity. If JPS can realise efficiency gains at a faster rate, it retains the resulting profits during the regulatory control period. If there is under performance, the company’s rate of return suffers.

The Office considers that it may be premature to use the total factor productivity (TFP) based approach alone given time constraints and the availability of relevant data to do a comprehensive TFP study, to determine the X_1 factor. Instead, the Office has chosen an X factor that encompasses best practice (i.e., efficient) electricity providers in other regions, DEA, the TFP study submitted by JPS, as well as advice from its own external consultants.

The value of the X factor is the amount by which tariffs (on average) are allowed to escalate relative to the rate of inflation as measured by movement in the consumer price index. X therefore determines the amount by which tariffs change in real terms. Because productivity (or cost per unit of output) is a primary driver of real price movements, X is often referred to as a productivity or efficiency factor.

There are two main approaches to setting the value of X. The first is on the basis of a “full building blocks” approach of projected required revenues for each year of the regulatory control period. This entails projecting system demand, capital expenditure and operating costs. Once required revenues have been projected, projected quantities of each tariff element are used to determine projected tariff revenues. The value of X is then determined so that the present value of tariff revenues equals the present value of required revenues. Because projected quantities are subject to forecast risk, and the rate of change in tariffs can influence quantities through the price elasticity of demand, scenario analysis is usually employed to estimate the likely range of X, before a final determination is made.

This is a complex and costly approach, but one which has been employed by network regulators in Victoria and New South Wales in their current and pending determinations. In each case, the analysis was undertaken over a period of 18 to 24months.

The alternative approach avoids detailed analysis of projected demand and costs specific to the network being regulated. Instead, X is based on a benchmark estimate of the trend for annual rate of productivity (or efficiency) performance for the industry. This then becomes the performance target that the regulated utility provider must equal to maintain its profitability. Performance which betters this target increases profit during the regulatory control period and provides the key incentive properties of the CPI-X form of regulation.

This is the approach favored in principle by the Office. It is a relatively common approach applied to networks (both electricity and telecommunications) and transport utilities in the United States. The method proposed effectively splits the conventional notion of X into two components – an industry-wide performance benchmark (which can be designates as X_1), and a network provider-specific ‘stretch factor’ (designated as X_2). The use of company-specific stretch factors has been developed by regulators in the United States to address cases where either an initial efficiency gap exists or circumstances are expected to be particularly favourable to the regulated business. In either case, there are grounds for arguing that customers should share in the available potential additional profitability from improved performance. For JPS, the Office considers that an initial efficiency gap exists that would cause a benchmark efficiency factor to understate the gains available from an improvement in performance that could reasonably be expected to occur.

The two primary objectives for regulators when capping prices or revenues are the prevention of monopoly rents – that is, the ability of network providers to charge prices that are above efficient costs – and providing the regulated business with a reasonable prospect of cost recovery. The benefit of the cost-based “building blocks” approach is that it allows the regulator to demonstrate that, on the basis of the best available information, forecasting and modeling techniques, these two objectives are met. This does not remove the risk that is inherent to the task of projecting outcomes over a five year period and second-guessing the relationships involved, but it gives the regulator the opportunity to demonstrate that what could be done has been done. Essentially, the detail required by the “building blocks” approach provides the regulator with a basis for decision-making that is robust – in many cases, this means robust to legal challenge. For many regulators, robustness of this kind is an attribute worth paying for. In the Office’s view, this is a reasonable position to take in the JPS context.

Aside from the considerations of cost and complexity, the chief criticism of the “building blocks” approach is that, on a purely objective basis, this robustness masks but does nothing to reduce the uncertainties inherent in the projections that form the basis for the “building blocks” approach. The building blocks approach has been further criticized for leading the regulator into a situation where it, de facto, micro-manages the regulated business by prescribing management responses to future developments. It relies heavily on regulatory judgments about the appropriateness of planned expenditure levels. For many critics, the intrusive nature of the “building blocks” approach is counter to the basic premise of incentive-based regulation.

Because the alternative benchmark approach is more light-handed and does not produce detailed projections of demand, costs and revenues, it cannot counter challenges that a particular future scenario may lead to stresses on the regulated business, or above normal profits. Given certain important provisions, however, it is widely accepted and demonstrable in theory that escalating average prices by general inflation less an empirically-based efficiency factor will provide a reasonable expectation of cost recovery for the business and avoidance of monopoly rents across a range of plausible scenarios over the regulatory control period.

7.1.1 Chief among the provisions is the requirement for opening prices that reflect efficient costs, which is the focus of the third element of the proposed approach. In practice, the Office proposes to adopt an X factor based on the assessment of -

- Benchmarking based on DEA
- X values typically used in other jurisdictions and
- a total factor productivity (TFP) analysis proposed by JPS.

7.2 JPS' Proposal for X-factor

7.2.1 Summary: Implications of TFP and benchmarking analysis for JPS' X-factor

JPS proposed that the X-Factor in the PBRM is to be equal to the difference in expected TFP growth for JPS and the general TFP growth of firms whose price index of outputs reflects the price escalation measure dI. Pacific Economic Group, PEG[12] estimates that TFP for JPS has historically grown at 0.15% per annum.

JPS further posited that since the inflation measure *dI* is based on economy-wide inflation trends in the US and Jamaica, the latter TFP growth rate is a weighted average of TFP growth trends for the US and Jamaican economies. The long-run TFP growth trends of the US and Jamaican economies are estimated to be 1.0% and 0.5% respectively. The weights specified in the PBRM for US and Jamaican inflation are 0.6 and 0.4, respectively. Overall TFP growth for firms whose output price indexes are reflected in the price escalation measure is therefore 0.8% (*i.e.* 0.6*1.0% + 0.4*0.5% = 0.8%).

The analysis also shows that JPS is an average non-fuel cost performer. JPS has therefore proposed that there is no evidence that a stretch factor should be further added to X. JPS posited the view that It is appropriate that the X-factor be set based on the definition in the Licence (see Schedule 3 Exhibit 1):

> "The X-Factor is to be set to equal the difference in the expected total factor productivity growth of the Licensed Business and the general total factor productivity growth of firms whose price index of outputs reflect the price escalation measure "dI"."
>
> X = 0.15% - (0.6*1.0% + 0.4*0.5%) = –0.65%
>
> Based on the Licence, therefore, JPS considers that an X-factor of –0.65% is appropriate for the PBRM.

7.3 Review of JPS' proposed X - factor

7.3.1 JPS' TFP GROWTH

The Licence sets out that the PBRM applies to Non-Fuel Base Rates. A separate Fuel Rate is adjusted monthly to take account of the cost of fuel and the fuel proportion of the cost of purchased power. Therefore, the TFP measure used to support JPS' PBRM proposal should exclude fuel costs and the fuel element of purchased power. JPS makes conflicting statements as to its treatment of fuel costs. On page 4, the PEG[13] study states, "All fuel and purchased power costs

[12] Pacific Economic Group, PEG is the consulting Group that JPS commissioned to do the TFP study
[13] Pacific Economics Group, X-factor Calibration for Jamaica Public Service, January 28 2004

were excluded from costs and inputs …". This contrasts with the statement on page 10 that "Electric O&M expenses are defined as the total O&M expenses of JPS less any expenses incurred for fuel, including the fuel costs in purchased power contracts". PEG should follow the methodology described on page 10, which is consistent with the Licence.

The choice of period used to estimate JPS' future TFP growth is crucial. According to JPS' calculations, the average annual TFP growth for JPS over the period 1991-2002 was 0.15%. However, TFP growth shows very high volatility. Analysis of JPS' data shows that annual average growth varies between 0.16% and 3.7% depending upon the period chosen. Table 7.1 below outlined JPS' TFP for various period and the corresponding input /output indices analysed from PEG data.

Table 7.1

Period	TFP	Output	Input
1991 - 2002	0.16%	6.02%	5.76%
1992 - 2002	0.94%	6.24%	5.09%
1993 - 2002	2.11%	6.63%	3.84%
1994 - 2002	1.37%	6.59%	4.79%
1995 - 2002	3.53%	6.89%	1.46%
1996 - 2002	3.08%	6.77%	2.08%
1997 - 2002	3.72%	6.88%	0.96%

A TFP growth of 0.15% appears very low when compared with other electricity utilities. While TFP growth is not directly comparable across different jurisdictions due to differences in the regulatory regimes and different constraints on companies' operations, the comparison can be informative. However in the last seven years JPS has shown growth of over 3%. This highlights the vulnerability of TFP studies to the choice of periods especially in predicting the expected TFP as required by the licence.

Meyrick and Associates[14] report the results of several TFP studies of electricity utilities. A 1994 study by San Diego Gas and Electric Company of power distribution found that TFP grew at 0.92% per annum. This is consistent with the reported results of a study by Kaufmann and Lowry (Price Cap Regulation of Power Distribution, 1999) that found TFP for the US distribution industry grew at 0.9% per annum for the 10 years to 1996. Meyrick reports that a study by Lawrence (The Australian Electricity Supply Industry's Productivity Performance, 2002) found that in Australia industry wide TFP grew at 3% per annum over the period 1976 to 2001. In the UK, Tilley and Weyman-Jones (Productivity Growth and Efficiency Change in Electricity Distribution, 1999) found that over the period 1991 to 1998 TFP for the UK distribution industry grew by 6.3% per annum.

[14] Meyrick and Associate, Regulation of Electricity Lines Businesses Resetting the Price Path THRESHOLD – Comparative option, 3 September 2003

Meyrick and Associates' own analysis shows that in New Zealand over the period 1996 to 2002, distribution TFP grew by 3.2% per annum and transmission TFP grew by 2.3% per annum. An Ontario Energy Board study into electricity distribution prior to the first performance based regulation determination found that TFP growth averaged 0.86% per annum over the period 1988 to 1997.7

7.3.2 Conclusions on JPS' TFP growth

It is possible that the capital investment in the early to mid 1990s facilitated stronger than average TFP growth in the late 1990s. Therefore, it is not clear that the trend of TFP growth during the late 1990s is a better predictor of future TFP growth than the trend over the period 1991-2002. However, it is apparent that there is significant uncertainty surrounding JPS' TFP growth estimate and it is noticeable that the JPS estimate is lower than TFP growth estimates for other electricity utilities. It seems likely that JPS has underestimated TFP growth by the order of 0.1% to 0.2% per annum as a result of bundling labour costs with O&M costs. Taking account of this adjustment, JPS' TFP growth would be in the order of 0.25% to 0.35% per annum. In addition if the more recent period is used TFP would be in the region of 3.08% to 3.72%.

7.4 US economy TFP Growth

The average annual TFP growth for the period over which data was examined, 1996 to 2001, is 0.86% per annum, which is 0.1% below JPS' estimate of 0.95%. In the 20-year period from 1981 to 2000, US TFP grew at an annual average rate of 0.85%.

7.5 Jamaican economy TFP Growth

The Office is of the view that the JPS estimate of 0.47% annual TFP growth over the period 1981 to 2002 seems reasonable and therefore finds little reason not to use this estimate.

7.6 OUR X-factor Determination

7.6.1 Historic basis

Using PEG's TFP growth for JPS of 0.15% per annum, TFP growth for the US economy of 0.95% per annum and TFP growth for Jamaica of 0.47% per annum, the implied X-factor based on historic data is –0.61% (i.e. 0.15% - [0.6x0.95% + 0.4 x 0.47%]), which is slightly greater than PEG's figure of –0.65%. Using the lower TFP growth rate for the US economy of 0.85% per annum, and the higher TFP growth rate for JPS of 3%, the implied X-factor would be 3.85%.

7.6.2 Stretch factor

JPS' All-Island Electricity Licence ("the Licence") states that the offset to inflation, X "is to be set to equal the difference in the expected total factor productivity growth of the Licensed Business and the general total factor productivity growth of firms whose price index of outputs reflect the price escalation measure dI."

JPS did an analysis of the difference between the historic TFP growth for JPS and a weighted average of the historic TFP growth for the US and Jamaican economies. This analysis requires adjustment to take account of the difference between historic and expected TFP growth. JPS refers to the adjustment to the historic TFP differential as a "stretch factor".

Regulators often include a stretch factor within the productivity offset in performance-based regulation ("PBR"). If the stretch factor is set at the start of the regulatory period and is not changed during the regulatory period it has little or no impact on the incentive of the firm to improve productivity. This is because the stretch factor does not affect the disconnect between prices and costs, provided that performance relative to target is not reflected in the next price control. Reasons for applying a stretch factor include:

- **Productivity catch-up**. If a firm is a long way from industry best practice, a stretch factor may be applied in recognition that the firm is likely to be able to improve efficiency more rapidly than the industry average. In future price controls, as the firm catches up with the average industry productivity, the stretch factor would diminish. PEG benchmarks JPS against US utilities in order to gauge whether JPS is close to industry best practice.
- Investments in electricity production are lumpy so the productivity gains increases in years after the investments are made. JPS has in the last year completed and commissioned into service a total of 140MW of new capacity. As these addition provide the capability for increased sales, in the future, average unit cost will decrease. This situation will continue into the future as new capacity will be added by way of Power Purchase Agreements and costs passed through to the customer. The years 1996 to 2002 are indicative of the JPS' TFP gains after new investments. These are in the order of 3%.

- **Regime change**. If there is a change in the regulatory regime, the historic productivity growth of the industry or company may not be representative of future productivity growth of the industry or company.

  Given the recent change in ownership of JPS and the regulatory regime change in Jamaica to a performance based regime, it is likely that JPS' TFP growth will accelerate and therefore a stretch factor should be added to the historic based X factor. A literature review by Europe Economics concludes: "several studies provided estimates of productivity growth achieved by firms since privatisation. These, on the whole, suggested that privatised industries have achieved productivity growth significantly faster than the economy as a whole, and generally faster than they managed before privatisation.[15] They state that the privatisation effect arises from a catch up of whole industries towards greater efficiency following privatisation and the introduction of

[15] Europe Economics, Scope for Efficiency Improvement in the water and Sewage Industries, March 2003

incentive regulation. JPS uses the results of the benchmarking study to conclude that JPS is an average industry performer. The company appears to use the rationale that the stretch factor should take account of regulatory regime change alone and not both the productivity catch up and regulatory regime change. JPS uses this argument to select the typical stretch factor for US PBRM of 0.5% as appropriate for JPS, resulting in a final X-factor of -0.15% (or -0.11% using JPS TFP results). JPS' benchmarking analysis leaves many areas of doubt and therefore it is uncertain whether JPS really is an average performer. The Office's intuition is that given JPS' low productivity growth compared with other utilities it is likely to be a below average performer. In particular, the fact that JPS appears to have lower TFP growth than US utilities throws doubt on the benchmarking analysis. This suggests that an above average stretch factor would be appropriate for JPS. The UK provides a useful example of the productivity improvements that can be achieved by an industry that is not at the efficiency frontier. The 12 regional electricity distributors in England & Wales were set soft price control targets in the first price control period (1990 – 1994) with X ranging between 0% and –2.5%. In the second price control (1995 – 2000) the regulator proposed a common X-factor of 2% and one-off price cuts (P_0 cuts) that ranged between 11 and 17% with an average of 14%. The next year, in response to criticism that his determination had been too lenient, the regulator introduced a second set of P_0 cuts for 1996 (average size 12%) and increased the X-factor for the remaining three years of the control (1997-1999) from 2% to 3%.

In 1999, the regulator introduced a further set of P_0 cuts for 2000 that averaged 17% along with an X-factor of 3%.

The average NPV-equivalent X-factors for the companies from 1995 to 2000 is 9% and 6% from 1995 to 2005. These are the adjusted X-factors that are equivalent, in the value of the revenue they remove from the companies, to annual X-factors over the period. Assuming that the regulator based the productivity offset for the first price control on historic TFP growth, the difference in the productivity offset for the period 1995 to 2005 and the productivity offset for the first price control (0 to –2.5%) provides some indication of the productivity acceleration with reform in the UK, i.e. an acceleration of as much as 6%.

Recalling that the TFP growth over the period 1991 to 1998 was estimated by Tilley and Weymen-Jones as 6.3% per year, costs appear to be falling broadly in line with prices. Average annual increases in TFP of 6% per year when sustained over a significant period suggest productivity growth well in excess of the productivity gains that could be attributed to technical progress.

Europe Economics also provide evidence of the effect of privatisation. They show that the real unit operating expenditure improvement of privatised infrastructure companies was 3% to 5% per annum. They also show that for water and sewerage companies this implies out performance of their long run efficiency trend of 1.25% to 3.5%.

7.6.3 Effect of IPP pass-through

In addition to the application of PBRM, there is an additional reason to suggest JPS' TFP growth may accelerate in future, namely that future generation capacity additions will be open to competitive procurement and costs will be passed through to consumers.

The result is that over time the net book value of generation assets to which the PBRM tariff applies will decline. The effect is that the quantities of capital input for a given quantity of output will decline thereby increasing TFP. This change should be reflected in tariffs.

The effect of this regime change can be broadly estimated. Assuming that JPS' existing generation plant is replaced over the next 25 years, the capital cost of replacement generation is not recovered through the PBRM, generation comprises approximately 40% of JPS' existing asset base, the regime change would reduce JPS quantity inputs by approximately 20% over 25 years.[16] This would be equivalent to a TFP increase of 25% over 25 years or 0.9% per annum (compounded). This estimate is approximate but is indicative of the magnitude of this particular rule change.
If the benchmarking results were discounted due to the uncertainty of the results and a judgment about productivity acceleration in JPS made from TFP growth in utilities elsewhere, one could probably conclude that JPS' TFP might accelerate by between 1% and 4% per year and perhaps, in the extreme, even as high as 6%. Setting aside the extremes of this range, this implies a stretch factor of between 2% and 4%, which is higher than the 0.5% proposed by PEG.

The change to the treatment of new generation costs would add a further 0.9% to this stretch factor.

7.7 Range for possible X factor

Combining the stretch factor with the historic basis suggests that the X-factor for JPS should be within the range of +1.5% to +4.5%. The Office has therefore determined that the expected productivity efficiency gains for JPS (X-factor) shall be 2.72% per year beginning 2006.

Determination 7.1

The X-factor for the annual adjustments for 2006 to 2008 is determined to be

[16] JPS weight O&M and Capital by approximately 50% each

2.72%

8.0 Introduction

The Office's consultants, PPA/Frontier Economics (PPA/FE), in their Electricity Tariff Study 2002, suggested two main ways that quality standards could be translated into an index that could be included within the electricity price cap—the "Relative Q" option and the "Absolute Q" option[17]

- "Relative Q" option—under this option, Q could be set based on the proportionate difference between pre-defined actual measures of quality and a target level of quality. PPA/Frontier suggested aspects of quality that include frequency of interruptions, duration of planned interruptions and duration of unplanned interruptions. Standards would be set for each and JPS' deviation from that standard would be calculated and a Q derived from the deviation and weighted importance. PPA/Frontier noted that the Office of the Regulator General in Victoria, Australia uses this form of index.

- "Absolute Q" option—under this option a starting absolute quality index is fixed. Quality indices could be weighted for perceived differences in value to customers. If JPS performs better than the fixed index then the calculated Q would be added to PCI, if JPS performs worse than the fixed index then the calculated Q would be subtracted from PCI. PPA/Frontier noted that the Office of Gas and Electricity Markets (OFGEM) in the UK use this form of index.

PPA/Frontier noted that both approaches require the OUR to assess the willingness of customers to pay for different levels of quality of supply in order to set a value of Q. Predicting the value that customers put on quality of supply is difficult, especially when dealing with several classes of customers and high-users and low-users within the same class.

The Office is of the view that the Q-factor should meet the following criteria:

- it provide the proper financial incentive to provide a level of service quality based on customers' view of the value of that service quality.

- measurement and calculation should be straightforward and transparent without undue cost of compliance.

- it should provide fair treatment for factors affecting performance that are outside of JPS' control, such as those due to disruptions by the independent power producers; natural disasters; and other Force Majeure events, as defined under the licence.

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[17] See PPA 2002 , opt.cit

- it should be symmetrical in application, as stipulated in the Licence, with appropriate caps or limits of effect on rates.

JPS proposes that the Q-factor be based on two quality indices:

- System average interruption frequency index (SAIFI)

$$\text{SAIFI} = \frac{\text{Total number of customer interruptions}}{\text{Total number of customer served}}$$

- System average interruption duration index (SAIDI)

$$\text{SAIDI} = \frac{(\quad \text{Customer interruption durations})}{\text{Total number of customer served}}$$

JPS, in their submission proposed a Q-factor of +0.5

The existing database that JPS used in the methodology, however, does not allow for the computation of SAIDI and SAIFI related to forced outages at the sub-feeder level. JPS therefore proposes that, during this upcoming price-cap period, the Q-factor be based on SAIDI and SAIFI that exclude forced outages at the sub-feeder level. This will ensure that the Q-factor is based upon comparing like with like. The OUR is of the view that the non-existence of data at the sub-feeder level will greatly compromise the value of the resultant indices and as such will not be a reasonable basis to establish a benchmark.

JPS proposes to put in place the required systems to collect all data required for the full computation of SAIDI and SAIFI for both planned and forced outages at both feeder and sub-feeder levels in the future. In the next rate review due in 2009, the OUR would have sufficient data to appropriately benchmark JPS' performance on SAIDI and SAIFI at both these levels. The value of Q will be based upon actual values of SAIDI and SAIFI for each year of the performance based rate making as compared to the benchmark. JPS proposes that the benchmarks be based on 2003 performance with built-in incentives for continuous improvement. Specifically, the proposed targets are shown in Table 8.1

Table 8.1
JPS' Proposed Targets for the Q-factor 2004 —2009

Year	Target SAIDI	Target SAIFI
2004	SAIDI2003	SAIFI2003
2005	SAIDI2003 (1 – 0.02)	SAIFI2003 (1 – 0.02)
2006	SAIDI2003 (1 – 0.04)	SAIFI2003 (1 – 0.04)
2007	SAIDI2003 (1 – 0.06)	SAIFI2003 (1 – 0.06)
2008	SAIDI2003 (1 – 0.08)	SAIFI2003 (1 – 0.08)

In each year JPS would be awarded quality points based on its performance in that year relative to the target, as shown in Table 2.

Table 8.2
Proposed categories and points for SAIDI and SAIFI

Band	SAIFI and SAIDI performance relative to target	Quality points
Excellent	Beating the target by 1.0%	2
Dead band	Beating the target by between 0% to 1.0%	1
Unsatisfactory	Worsening of performance	0

JPS further proposes that:

- If the sum of Quality Points for SAIFI and SAIDI is 4, then Q = +0.5%
- If the sum of Quality Points for SAIFI and SAIDI is 3, then Q = +0.5%
- If the sum of Quality Points for SAIFI and SAIDI is 2, then Q = +0.0%
- If the sum of Quality Points for SAIFI and SAIDI is 1, then Q = -0.5%
- If the sum of Quality Points for SAIFI and SAIDI is 0, then Q = -0.5%

The Office is extremely disappointed that adequate data is not available to properly assess the quality of service provided to customer after the long period of notice as to the requirements and is of the view that JPS has not treated with this issue as one of importance.

During previous discussions the Office proposed the use of the Customer Average Interruption Duration Index, CAIDI, as an input to the calculation of the Q factor. CAIDI is given as

$$\text{CAIDI} = \frac{(\quad \text{Customer interruption durations})}{\text{Total number of interruptions}}$$

JPS objected on the basis that since this was the ratio of SAIDI and SAIFI, the inclusion of this index would be double jeopardy. However while it is true that CAIDI can be derived from SAIDI and SAIFI, it brings a different dimension to the quality of service. SAIFI and SAIDI measure the capacity of the system to provide the required service while CAIDI indicates the responsiveness of the utility to problems with the system. There could be improvements in both SAIDI and SAIFI while there is a concurrent deterioration in CAIDI.

The Office of the view that in the absence of adequate data to establish a creditable benchmark for 2003 and to ensure that there is fairness to both consumer and the utility, the Q-factor should not be set until the relevant data becomes available. JPS in the meantime is required to put in place the required systems to collect all data required for the full computation of SAIDI, CAIDI and SAIFI for both planned and forced outages at both feeder and sub-feeder levels in the future. The Office requires that this data be available so that the Q factor can be implemented at the next adjustment date of June 2005. In the event that the data is not available, the Office will use international bench marks as the basis for determining appropriate values for SAIDI, CAIDI and SAIFI for the remainder of the tariff period.

Chapter 9: PBRM Annual Adjustment

9.0 Introduction

JPS is permitted to make adjustment to the non-fuel base rate for each customer class on the basis of the formulae at equation 3 below. The first annual adjustment shall become effective on June 1, 2005 and thereafter on June 1 each year

9.1 Price Cap Index (PCI)

dPCI = dI ± X ± Q ±Z ……………………………………..equation (1),

where

dCPI = annual rate of change in non-fuel electricity prices;

dI = the annual growth rate in an inflation and devaluation measure;

X = the offset to inflation (annual real price increase or decrease) resulting from productivity changes in the electricity industry;

Q = allowed price adjustment to reflect changes in the quality of service provided to the customers; and

Z = the allowed rate of price adjustment for special reasons not captured by the other elements of the formula.

$\mathbf{ABNF_y = ABNF_{Y-1} * (1 + dPCI)}$………..equation (3), where

$ABNF_{Y-1}$ = the weighted average non-fuel tariffs in the previous year (i.e. the year (y-1) preceding the year (y) for which new tariffs are being submitted by the Company for the Office's approval and calculated in accordance with equation 3.

JPS shall apply the following formula for setting the Price Cap Index

$\mathbf{PCI_0 = 1}$
$\mathbf{PCI_y = PCI_{y-1} (1 + dI \pm X \pm Q \pm Z), y>0}$

9.1.1 Weighted Average Actual Price Index (API)

The API is a weighted average price of the services making up the price cap basket. The basket will contain the following services. The weighted average tariffs already approved for the current year (or any previous years) (API_{y-1}) will be measured in index form as follows:

$API_0 = 1$

$API_{y-1} = API_{y-2}*[\quad_{i=1...n}[p^{I}_{y-1}*q^{I}_{y-2}] / \quad_{i=1...n}[p^{I}_{y-2}*q^{I}_{y-2}]]$ ……equation (4)

where:

p = approved price (or price component) for an individual tariff item;

q = quantity weight associated with the price (or price component) for the individual tariff item;

"i" = denotes an individual tariff item, or a component of an individual tariff item where a multi-part tariff is involved;

" " = denotes the summation of all relevant values

"y" = denotes a particular financial year, with y denoting the forthcoming year, y-1 the current year and y-2 the previous year; y=0 at the start of the price cap plan

One condition for approval of JPS' tariff filing is that for each annual filing PCI   API (Actual Price Index).

Quantity weights in the tariff basket will be determined as the amounts sold to customers in the most recent year for which actual figures are available. This will be done for each tariff component or rate class. Taking 2003 tariffs as an example, the quantity parameters for each tariff component are shown in Table 9.1

Table 9.1
Quantity and price parameters for the computation of API

	PRICE	QUANTITY per annum
Customer Charge		

Residential	$/Customer	Number of Customers
Rate 20	$/Customer	Number of Customers
Rate 40A	$/Customer	Number of Customers
Rate 40LV	$/Customer	Number of Customers
Rate 50 MV	$/Customer	Number of Customer
Monthly Energy Charge		
Residential	$/kWh	kWh sold
Rate 20	$/kWh	kWh sold
Rate 40A	$/kWh	kWh sold
Rate 40LV	$/kWh	kWh sold
Rate 50 MV		
Monthly Demand Charge	Peak/Partial/ Off	Peak/Partial /Off
Residential	$/kVA	kVA sold
Rate 20	$/kVA	kVA sold
Rate 40A	$/kVA	kVA sold
Rate 40LV	$/kVA	kVA sold
Rate 50 MV	$/kVA	kVA sold
		kVA sold

While a tariff basket form of control is in most respects relatively simple to implement and administer compared with other forms of price control, the introduction of new tariffs (and the removal of tariffs) requires rules and procedures for determining the quantity weights that should apply.

Because the tariff basket uses lagged quantity weights (for example, proposed tariffs for 2004 will use 2003 quantity weights), there will be a year's delay before data on actual sales for the new tariff (or tariff component) becomes available.

The Office will take an approach to the introduction of new tariffs or tariff components that would contain revenue risk within reasonable bounds.

In most cases, new tariffs or tariff components will have a readily identifiable parent tariff or tariff component. When introducing new tariffs or tariff components, the Office will require JPS to estimate the quantities that would have been sold had the tariff or tariff component been in place in the previous year. In effect, proxy quantities will be used. The Office will assess the reasonableness of these estimates and the supporting evidence, before determining the weights that will apply.

In particular, the Office will require:

a) JPS to nominate the 'parent tariff' category associated with the new tariff being introduced. This parent tariff category is the tariff category which currently applies to those customers who are expected to migrate to the new tariff category;

b) the value for the ‘current’ individual price of the new tariff (i.e., p_{y-1}) to be set equal to the current parent tariff;

c) JPS to submit a ‘reasonable estimate’ of the relevant quantities *that would have been sold* under the new tariff in year y-2, if the proposed new tariffs had been offered in that year. These estimates of q_{t-2} will be used in applying the tariff basket to the proposed new tariff; and

d) consistent with the estimate above, JPS to also submit a ‘reasonable estimate’ of the quantities *that would have been sold* under the existing parent tariff in year y-2 if the proposed new tariffs had also been offered in that year. This estimate of q_{y-2} will be used in applying the tariff basket to the parent tariff.

In the very limited situations where there is no existing parent tariff, the Office will consider any evidence presented by JPS to support the reasonableness of its estimates, and will take into account any particular difficulties arising in individual cases.

9.2 Approval of Annual Tariff Adjustments

Each year at May 1 within the 2004 -2009 regulatory control period JPS shall submit to the Office a new tariff schedule which will reflect any proposed changes based on the effects of the change in the Price cap index. The Office will review the schedule of individual rate class tariffs and will be disposed to approving such schedules only if the weighted average of tariffs included in the schedule complies with the constraint in equation (3).

Under the price cap plan JPS is free to make changes to the structure of its tariffs, provided that:

(i) JPS shall submit the proposed changes to the Office not less than 30 days prior to the proposed date of implementation

(II) in conjunction with the submission of the schedule of the annual tariffs JPS provides the Office with a statement of reasons for any proposed modifications to the structure of the tariffs demonstrating that proposed changes are consistent with the pricing principles established in this determination (the Office will only intervene where it considers the proposed change in structure is not consistent with the approved pricing principles); and

(iii) the resultant impact on individual customer bills, for the same level and type of consumption as applied in the previous year, does not result in rate shocks and breach some form of reasonable cap to be determined by the Office.

9.3 Headroom[18]

If JPS were to price below the cap, it would risk reducing revenues and would raise the actual price index the subsequent year even without an adjustment. Separate adjustments are required for June through January and February through May. Pricing below the cap in June through January affects revenues in the denominator of the API formula for the following price cap year. Pricing below the cap in February through May affects revenues in the denominator of the API formula for the price cap year two years ahead. The purpose of the headroom adjustment is to avoid penalizing JPS for pricing below the cap in any one year.

The headroom is calculated as follows:

$$H_t = \frac{PCI_y - API_y}{PCI} \text{; } \quad \text{where}$$

H_t = headroom at any particular time during price-cap year y and API and PCI are as defined above. For each Annual Performance-Based Rate-making Filing (PBRM), JPS must calculate the API, and the headroom associated with its proposed rates. Two conditions must be satisfied for JPS to remain compliance with the price cap regulation:

$$H_y > 0 \text{ and } API_y \quad PCI_y$$

With the headroom the API equation (3 above) becomes

$$\mathbf{API_{y-1} = \frac{{}_{i=1\ldots n}[p^{I}_{y-1} * q^{I}_{y-2}](1-8/12H_{y-2})}{{}_{i=1\ldots n}[pi_{y-2} * q^{I}_{y-2}]} \ldots\ldots y = 2 \text{ ,equation (4)}}$$

$$\mathbf{API_{y-1} = \frac{{}_{i=1\ldots n}[p^{I}_{y-1} * q^{I}_{y-2}](1-8/12H_{y-2} - 4/12 \quad {}_{y-3})}{{}_{i=1\ldots n}[pi_{y-2} * q^{I}_{y-2}]} \text{,y= 3,4.....equation (5)}}$$

H_y= the average headroom during the months of June through January of price cap year y. The average is weighted by the fraction of days (during the eight-month period) in which a particular headroom applied; and   = the average headroom during the months of February through May of price cap year y. The average is weighted by the fraction of days (during the four-month period) in which a particular headroom applied.

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[18] This method (Headroom)is adopted from Cable and Wireless Price Cap Plan Determination Notice, August 2001. The Headroom method allows JPS to accurately synchronize each annual Performance-Based Rate-Making Filing (PBRM) with the implementation date of the Tariff review price cap. The PBRM is 1st February and Tariff review price cap date is 1st June. The concept of the headroom method is to allow JPS to take advantage of unused cap while minimizing risk of revenue loss.

Chapter 10: Foreign Exchange Adjustment Factor

10.0 Introduction

JPS currently recovers its revenue through tariffs that are set on an assumed Base Exchange rate. This imposes a high currency risk as a significant share of JPS' costs is denominated in US currency. A foreign exchange adjustment factor is therefore applied to these base tariffs in the billing to customers, to offset any movement in the Jamaican currency relative to the US dollar.

The mechanism is set out in Exhibit 3 to the Licence. It states that the foreign exchange adjustment formula is applied to the total base tariff (which includes fuel and IPP costs) for all customer classes, on a monthly basis, using the following adjustment mechanism.

$Tariff_m = Tariff_b * [1 + 75.0 * (EXC_{m-1} - EXC_b) / EXC_b]$ …….10.1

where:

$Tariff_m$ = Adjusted tariff for the month

$Tariff_b$ = Unadjusted tariff for the month

EXC_b = Base Exchange rate for Jamaican Dollars into United States Dollars.

EXC_{m-1} = Billing Exchange Rate, defined as the daily weighted average for the last day of the month prior to the billing month

Equation 10.1 above shows a 75% foreign exchange adjustment factor. This implies that movements in the exchange rate will adjust the base tariffs by a factor of 0.75. The formulation was set in the Licence when, at the time, it was determined that approximately 75% of JPS' costs were foreign related.

At the time, the actual costs for 2000 were used to derive the foreign exchange adjustment factor. The foreign exchange adjustment factor was derived as a weighted average of the US component of fuel and non-fuel costs, that is:

Foreign exchange adjustment factor = (40% x 100%) + (60% x 60%) = 75%

Analysis of data submitted by JPS of the revenue stream since April 2001 has however revealed that the adjustment mechanism does not provide full recovery on foreign exchange movements. Specifically, the mechanism assumes that the cost structure of the JPS remains fixed in the proportion highlighted above and accordingly applies a 75% adjustment each month. This assumption, however, does not hold true for two reasons:

- The first is that fuel price volatility over the last two years has led to shifts in the proportion of fuel cost relative to non-fuel costs. As fuel costs are 100% US-dollar based, increases in the price of fuel would, all else equal, lead to an increase in JPS' US-dollar denominated costs as a proportion of total costs.

- Secondly, depreciation in the Jamaican dollar has led to an increase in the proportion of US$ related non-fuel costs relative to the local component.

Table 10.1 summarises the cost structure of JPS for the financial years ended December 2002 and December 2003. As can be seen, the weighted average of US$ related costs (non-fuel and fuel) increased to approximately 86% of total costs.

Table 10.1
Summary Analysis of Overseas and Local Costs

	Approve Allocations		Financial Year ended Dec 2002		Period ended Dec 2003	
	% of Total	% US Component of actual	% of Total	% US Component of actual	% of Total	% US Component of actual
Non-fuel expense (incl. IPP)	60%	60%	62%	76%	59%	76%
Fuel Expense (incl. IPP)	40%	100%	38%	100%	41%	100%
Total Expense	100%	75%	100%	85%	100%	86%

In an attempt to correct the inherent limitations of the current mechanism while maintaining cost reflective tariffs, JPS proposes the following modifications to the foreign exchange adjustment mechanism:

- Separate fuel and non-fuel foreign exchange adjustment mechanisms, which involve:

– Conversion of the fuel rates from US currency to Jamaican currency using the prevailing billing exchange rate; and

– Apply a foreign exchange adjustment formula to the **non-fuel** base tariffs only;

- Allowance for an annual review of the non-fuel adjustment factor to check the relative movements in JPS' domestic and foreign non-fuel costs.

10.1 Office Determination

The Office **accepts** JPS' proposal for the following modifications to the foreign exchange adjustment mechanism as follows:

- Conversion of the fuel rates from United States currency to Jamaican currency using prevailing billing exchange rate ; and
- Apply a foreign exchange formula to the Non-Fuel base tariff only, using –

$$Tariff_m = Tarriff_b \times [1 + 0.76 \times (EXC_{m-1} - EXC_b)/EXC_b]$$

where:

$Tariff_m$ = Adjusted tariff for the month

$Tariff_b$ = Unadjusted tariff for the month calculated on Non-Fuel base rates.

EXC_b = Base Exchange rate for Jamaican Dollars into United States Dollars

EXC_{m-1} = Billing Exchange Rate

However, the Office does not accept JPS' proposal for the allowance for an annual review of the non-fuel adjustment factor to check the relative movements in JPS' domestic and foreign non-fuel costs. The Office is of the view that to have an annual review will run contrary to the intent of the price cap regime. Keeping the modified foreign exchange mechanism fixed for the price cap period will encourage the utility the incentive to manage its expenses prudently.

10.1.1 Rationale for separate recovery of total fuel costs (including costs incurred due to foreign exchange movements)

Current procedure

Fuel costs are currently treated as a direct pass through to customers each month. The rates applied to customers' bills however do not capture any movement in the exchange rate over the month as these rates are converted from US dollars to Jamaican dollar terms using a fixed Base Exchange rate.

Any foreign exchange movement above or below the Base Exchange rate is dealt with by applying the foreign exchange adjustment clause. By so doing, JPS is assuming that the non-fuel to fuel ratio remains at the 60:40 level for that month and that the revenue from billing customers will capture 100% of fuel cost (and 60% of non-fuel costs).

Proposed procedure
With the implementation of the 2004 tariffs, the fuel rates should reflect the actual fuel costs for the particular month converted using the prevailing billing exchange rate instead of the fixed exchange rate as is currently done. There will consequently be no need to have a foreign exchange adjustment applied to fuel charges.

10.2 Implications for annual Inflation adjustment
Any amendment to the adjustment factor would also have implications for the Annual Inflation Adjustment Formula (dI in the PBRM mechanism). Specifically, the inflation formula also incorporates the relative proportion of foreign and local non-fuel costs (currently assumed to be 60% and 40% respectively).

The Office has determined that the inflation adjustment formula (dI) to be used during the 2004 -2009 tariff period, has been changed to more accurately reflect the inflation costs incurred on JPS. The base Non-Fuel tariffs shall be adjusted annually, as follows:

$b_1 = b_o [1 + dI]$

$dI = [\ 0.76^* \quad e + 0.76\ ^*0.922\ ^* \quad e^*i_{US} + 0.76^*0.922\ ^*i_{US} + 0.24^*\ i_j\ ]$

b_0 =Base non-fuel tariff at time period t = 0

b_1 = Base non-fuel tariff at time period t = 1

e = percentage change in the Base Exchange rate

i_{US} = US inflation rate (as defined in the licence)

i_j = Jamaican inflation rate (as defined in the licence)

f_{US} = US factor =0 .76

f_i = Local (Jamaica) factor = 0.24

Determination 10.1

The Office has determined that the annual inflation adjustment formula, dI, is given as
$dI = [\ 0.76^* \quad e + 0.76\ ^*0.922\ ^* \quad e^*i_{US} + 0.76^*0.922\ ^*i_{US} + 0.24^*\ i_j\ ]$

Chapter 11: Fuel Cost Adjustment Factors: Heat rate and System Losses

11.0 Introduction

Schedule 2 of the Licence authorizes the Office to specify a total system losses standard for JPS. The Licence defines total system losses as the difference between energy generated and the energy generated and energy for which revenue is received.

Further, according to Section 3(D) of Schedule 3 of the Licence

> "the Licensee shall apply the Fuel Rate Adjustment Mechanism that is in force on the date of this Licence. The Fuel Cost Mechanism that is in force on the date of this Licence is described in Exhibit 2."

The provisions of Exhibit 2 are that the total applicable energy cost for a given billing period includes:

> "The cost of fuel per kilo-watt hour (net of efficiencies) shall be calculated each month on the basis of the total fuel computed to have been consumed by the Licensee and Independent Power Producers (IPPs) in the production of electricity as well as the Licensee's generating heat rate as determined by the Office at the adjustment date and the IPPs generation heat rate as per contract with the IPPs and systems losses as determined by the Office at the adjustment date of total net generation (the Licensee and IPPs)"

It is clear that the Licence contemplates that under the price cap tariff period commencing June 2004, total system losses and heat rate will remain discrete indices of JPS' efficiency in fuel cost management. The Licence is however silent on the methodology to be applied in determining the target values for JPS or the terms and conditions of implementation of these efficiency measures. The treatment of the system losses target for calendar years 2002 and 2003 from Schedule 2, implied that the Licence has ceded discretion to the Office to make a determination on this process.

11.1 Heat Rate

The objective of setting a heat rate target for JPS is to assure customers of least cost unavoidable `fuel rates by providing an incentive for JPS to:

- improve its relative efficiency of converting chemical energy to electrical energy; and

- ensure the economic dispatch of all available generation sets.

Since April 1, 2003 JPS has operated with a total system heat rate target in the Fuel Clause of 11,600kJ/kWh. The deemed heat rate was set based on the Office's view at the time that there had been and it was expectant that there would be notable changes in the mix of the generating units since the target was established the previous year. These were:

- During September/October 2002, JPS commissioned into service two 40MW combustion turbines at Bogue Power Station

- During the second half of 2003, Heat Recovery Steam Generators (HRSGs) would have been coupled to these units together with a 40MW steam turbine and the plant operated in combined cycle mode with a total output of 120MW.

Subsequently, JPS has achieved a system annual heat rate of 11,554kJj/kWh for 2003. Table 11.1 shows the actual system heat rate achieved for the years 2002 to 2003 versus the targets.

Table 11.1:
System Annual Heat Rate (kJ/kWh)

Year	System Heat Rate	Target System Heat Rate
2002	11,888	11,900
2003	11,554	11,600

11.1.1 JPS Proposal

In its submission, JPS posited that based on the composition of the system's generation plant and the projected availability and dispatch, it proposed the following heat rate targets:

- 11,500kJ/kWh going forward from 2004; and
- 11, 100kJ/kWh when the generation expansion, is detailed in the LECP, is fully implemented. This is expected to take place in 2007. However, in order to retain the right incentive, JPS proposes that the effective date of the new reduced target not be set now, but rather be dependent on the actual implementation date. This would ensure that JPS does not, for example, face the incentive to bring on the new plant even if sales growth and other factors suggest that the implementation should be delayed. Such a perverse incentive would be ultimately detrimental to the customer.

- The heat rate target should continue to be a system heat rate target - as opposed to a JPS target - to encourage the correct dispatching of IPPs.

11.1.2 Office Determination

An analysis of the historical system heat rate and forecasted system heat rate has indicated that JPS is expected to achieve and maintain a system heat rate of 11,200 kJ/kWh for 2004. This heat rate is achievable based on the following assumptions:

- Plant Availability of 83% for JPS and 90 % for IPP plants with Equivalent Forced Outage Rate of 8% and 4% respectively.
- Deteriorating heat rate for 2004 relative to 2003 at respective power stations
- The full year effect of the availability of the Combined Cycle plant which was commissioned in October 2003.

The Office has determined that a projected system heat rate of 11,500 kJ/kWh is conservative:

- given the notable changes in the composition of the generation units and the attendant improvement in heat rate that should be derived from these additions and;
- given that there were significant improvements of over 300 kJ/kWh in 2003 over 2002 despite the fact that Bogue Combined Cycle Plant was not commissioned until the latter part of the year.

This being the case, the likely effect is the lowering of the system heat rate below 11,500 kJ/kWh, especially if the generation mix proposed is realised. A target heat rate of 11,200kJ/kWh is considered to be realistically sustainable.

In order to retain the right incentives, and while mindful of JPS' proposal to set the heat rate target for five years price cap period the Office has decided to fix the heat rate for five years to provide the company with the incentives to achieve and surpass the heat rate target on a sustained basis. New base load capacity expected to be added in 2008 just in time for heat rate review at the next tariff review in 2009.

Determination 11.1

The Office has determined that the applicable heat rate during the price cap period is 11,200 kJ/kWh.

11.3 System Losses

11.3.1 Background

In the 2003 Tariff adjustments review, JPS proposed that the losses target should be kept at the present level of 15.8% for the computation of the applicable fuel rate to be passed through to customers. Lower levels of losses indicate higher levels of efficiencies by JPS and result in lower fuel rate. The converse is also true.

In the 2003 tariff adjustment review, arising out of the JPS' status reports for January 2003, the Office reaffirmed its concerns about the effectiveness of company's efforts at controlling and reducing system losses. The Office notes, however, that the following actions taken by the company:

- The implementation of the upgrading of the Customer Information Systems (CIS). This will bring about greater control in the billing process.
- Installation of 78 km of insulated secondary conductors in areas prone to illegal connections
- Upgrading of seven feeders with an equivalent saving of 2,312 MWh of energy on an annualized basis

The Office in its decision at the time pointed out that it was mindful of the need to provide the utility with the incentive to reduce losses and consequently determined that the losses target will remain at 15.8% and that JPS may retain, in full, any gains that may accrue from surpassing this target.

11.3.2 JPS' Proposed System Losses

JPS' proposals regarding system losses are based on the following:

- Technical losses - As noted above, about nine percent (9%) of system loss is due to technical losses. This level of technical losses is not unreasonable in the context in which JPS operates.[19][32] Technical losses cannot be reduced via operational changes, but only through investment in new equipment such as transformers, conductor, insulators, etc. JPS would reduce technical losses by 1 percentage point if the OUR allowed

[19]See PPA (2002), *OUR Electricity Tariff Study*, July; in association with Frontier Economics, page 20.

for the recovery of these costs from the tariffs.

- Operational commercial losses - About two percent (2%) of system loss is due to 'operational commercial' losses. These losses can be reduced via operational improvements including meter-sealing, billing determinant audits, meter inspections, meter reader controls, internal controls, etc. Reduction of these operational commercial losses requires labour and diligence, but small amounts of capital expense. JPS has the expertise, tools and systems to reduce this type of loss and will continue to aggressively pursue this type of loss. This loss category can conceivably be reduced from its present level of 2.0% to about 1.0% notwithstanding prevailing economic conditions.

- Social commercial losses - About seven and a half percent (7.5%) of system loss is due to theft of electricity by residential users with no metering system or approved house wiring system. Such losses are predominantly due to socioeconomic factors that are largely outside of JPS' influence. JPS believes that this type of losses can only be reduced via a combined partnership between Government, civil society and the company. Reduction of these losses will require technical items such as proper/safe house wiring and metering, plus education, cultural change and enforcement. Reduction of these losses will not take place in a few years, but rather over a generation. In the short-term neither operational changes nor investment in new assets will reduce these type of losses. Persistent attention is, however, required to deter further expansion of the problem.

JPS is proposing that the target should adequately reflect the influence JPS can exercise towards reducing system losses. Specifically, while JPS feels that it is able to influence technical and some commercial losses, the most prevalent forms of commercial losses are beyond JPS' control. JPS therefore thinks that it would be unfair of the OUR to set targets for losses that penalize it in part for a loss that JPS cannot reduce on its own. A broader group of stakeholders, including the government and civil society should be involved in meeting the system loss target.

JPS therefore proposes that, over the five-year period, a target be set to reduce technical losses by one percent (1%) and 'operational commercial' losses by one percent (1.0%). Therefore, the correct system loss target should, over the five-year period, be 8.0+1.0+7.5 = 16.5%. The company's proposal is summarized in Table 11.2.

Table 11.2
JPS' Proposed schedule for Loss Reduction

Year	2004	2005	2006	2007	2008	2009

System losses (%)	18.0	17.7	17.4	17.1	16.8	16.5

11.4 Office Determination

JPS has categorized system losses into three groups:

- Technical losses;
- Operational commercial losses; and
- Social commercial losses or theft

JPS' technical loss spectrum and Commercial loss spectrum are outlined below

Table 11.3
JPS' Technical Losses

Generator Step Up Transformers	0.3%
Transmission Lines (138/69 kV)	1.5%
Substation Transformers	0.4%
Medium voltage Distribution (24/13.8 kV)	2.2%
Distribution Transformers	1.6%
Low Voltage Distribution	3.0%
Total	**9.0%**

Table 11.4
JPS' Commercial Losses

Causes	Losses
Operational commercial losses	
Defective equipment	**1.7**[20]
Incorrect Installations	**0.2**
Improper account set up	**0.1**
Sub total	**2.0**

[20] Defective equipment includes equipment which has failed as well as equipment which has been tampered with.

Social Commercial losses	
Throw-ups	**7.0**[21]
Other theft	**0.5**
Subtotal	**7.5**
Total	**9.5**

As can be seen from tables 11.4 and 11.3 JPS' non technical losses total 9.5% and technical losses total 9%. JPS argues that it is not unreasonable for technical losses to be 9% for the JPS system but suggests that it can be reduced further if investment is made. The Office is of the view that technical losses should be reduced to its minimum unless it can be shown that the investment needed would not be justified by commensurate benefits. JPS has argued that technical losses can be reduced to 8% if the Office would allow for the recovery of these costs from the tariffs. It is not necessary for JPS to seek permission or approval for investment to reduce technical losses. In any case it is expected that during the normal operation of the business JPS is responsible for its business plan and therefore its investment schedule. The reduction of technical losses from 9% to 8% is within the control and responsibility of JPS.

JPS further argued that Operational commercial losses can be reduced via operational improvements including meter-sealing, billing determinant audits, meter inspections, meter reader controls, internal controls, etc. Reduction of these operational commercial losses requires much labour and diligence, but small amounts of capital expense. JPS has the expertise, tools and systems to reduce this type of loss and should continue to aggressively pursue this type of loss. This loss spectrum can conceivably be reduced from its present level of 2.0% to about 1.0% notwithstanding prevailing economic conditions. The OUR is of the view that operational commercial losses as outlined above is within the control of JPS and therefore require action from JPS to be reduced.

JPS also argued that Social commercial losses, about 7.5% of system loss, is due to outright and blatant theft of electricity by residential users with no metering or approved house wiring system. JPS argues that such losses are predominantly due to socioeconomic factors that are largely outside the company's sphere of' influence. JPS believes that this type of losses can only be reduced via a combined partnership between Government, civil society and JPS. The Office is however of the view that JPS must bear some of the responsibility for reducing loss due to theft as not all of this type of loss occur in volatile communities where JPS is unable to act. The Office is therefore of the opinion that it is reasonable to hold JPS responsible for social commercial losses of 1.5%.

[21] Losses attributable to throw-ups based on average 189kWh/month energy consumption for inner city communities and 100kWh/month life line energy consumption for others.

Assuming that this is the case, the following scenario is evidenced;

Losses outside JPS' control		Losses within JPS' control	
Social Commercial	6%	Operational & social	3.5%
Technical	8%	Technical	1%

Assuming that social commercial losses of 6% is outside the control of JPS , the total losses that the consumer should be asked to pay for is 14% (6%+8%).

The Office is of the opinion that the target should adequately reflect the influence JPS can exercise towards reducing system losses and believes further that the company is able to influence technical and some commercial losses. The most prevalent forms of commercial losses that JPS posited are beyond JPS' control are already being borne by the consumer. Deemed losses at 15.8% implied that the consumer is totally absorbing the social responsibility of paying for the social commercial losses. It would be unreasonable of the Office to set target losses that penalize the consumer further for losses that JPS should reduce on its own. The more reasonable trend from the OUR's perspective is summarized in Table 11.5

Table 11.5
The Office's proposed schedule for loss reduction

Year	2004	2005	2006	2007	2008	2009
System losses (%)	15.8	15.3	15.0	14.7	14.2	14.0

However, the Office is mindful of the difficulties that the socio-economic condition of the country posed to the reduction of losses and the need to give JPS the incentive to reduce system losses. With this in mind the Office has determined that system losses shall remain at 15.8% over the price cap period. During this time JPS will have the incentive of reducing losses by a further 1.8% and keeping the revenue. At the beginning of the next review the Office will assess the overall losses with the aim of ensuring that the consumer is given back the benefit of the reduction in losses.

Determination 11.2

The Office has determined that the applicable systems loss for the price cap period is 15.8%

Treatment of systems losses in the tariffs

While JPS accepts that the fuel charge should be adjusted by a deemed sales figure based on the targeted system loss, it contends that the same should not be applied to the non-fuel charge because -

1. The level of losses do not affect fix costs

2. There is not a one to one correlation between the reduction in losses and the increase in sales

The Office is of the view that in the long run the level of losses does affect fixed costs as additional capacity has to be installed to compensate for the level of losses. In addition the difference between the deemed losses of 15.8% and the actual losses of 18.5% is within the commercial losses that are in the control of JPS. The Office is of the opinion that this difference can be recovered by increased sales as the major part of this difference is linked to existing customers of JPS.

Determination 11.3

The Office will calculate the base non-fuel rate at the actual test year sales plus 4%. If loss reduction efforts result in sales growth exceeding 4% in any year, the subsequent annual price adjustment will be modified by 60% of the revenues derived from a growth rate in excess of 4%.

Chapter 12: Treatment of IPP costs

12.0 Introduction

JPS has Independent Power Purchase (IPP) contracts with three private power generators—JPPC (60MW), JEP (74.1MW) and Jamalco (11MW).[22] The earliest of these contracts were agreed on in 1994 with JPPC and JEP. The contract with Jamalco followed in 2000. The then state-owned JPS entered into IPP arrangements in order to meet growing electricity demand through private investment. JPS at that point did not have the capital required to invest in generation capacity itself. All of the IPP contracts were for 20 years effective from the commercial operation date.

These companies supply power to the JPS under various purchasing arrangements. JPS is therefore faced with significant IPP costs that are governed by contract. These charges are intended to be fully recovered from customers. The Office recognized and accepted JPS position that with regard to the non-fuel costs, the tariff through which they are recovered are fixed, while the levels of some of these costs are variable to JPS as changes in costs incurred by the IPPs are passed through to JPS.

The IPP charges incurred by JPS are intended to be fully recovered from customers. However, while the fuel cost for the power purchased is passed through directly to the customers, the non-fuel costs are recovered through the tariffs. The tariffs in turn are set based on anticipated costs levels. In essence, apart from the inflation adjustment and foreign exchange adjustment the level of non-fuel costs that JPS can recover through the tariffs is a fixed amount per unit.

Presumably it was expected that such a mechanism would allow tariffs to appropriately reflect IPP costs incurred by JPS, if such costs are relatively fixed and predictable. This, however, has proven not to be the case. The levels of some variable IPP cost components passed through to JPS have changed while the tariffs recovered by JPS have not been correspondingly adjusted. In summary, there is incongruence between the IPP contracts to which JPS is obligated, and the manner in which the resulting costs are reflected in the tariff structure.

Additionally if sales volume differs from that which was used to calculate the base non-fuel rates then JPS could over or under recover IPP costs. Since sales tend to increase, JPS would more likely over recover these costs.

12.1 JPS' Proposal

JPS proposes a modification to the treatment of IPP costs in the tariff so as to ensure that JPS is revenue-neutral with respect to these costs—any increases or

[22] The contract with a fourth IPP, EAL/ERI, was terminated in December 2003

decreases in charges will be passed on to consumers.

The inconsistency between the structure of the inherited IPP contracts—under which several types of costs are passed through to JPS—and the way in which IPP costs are recovered through the tariffs, which are fixed in levels, means that JPS may not be revenue neutral with respect to IPP charges. Increases or decreases in these charges are not reflected in the tariffs.
The JPS proposal is to pass through IPP costs calculated at base (contracted) capacity levels rather than actual dependable capacity for the following reason. If and when IPP capacity falls below contracted levels, direct IPP costs (i.e., payments to the IPPs) fall accordingly. However, JPS incurs other indirect costs, as a result of the fall in IPP capacity, over and above the costs taken into consideration in the revenue requirement for the test year period. These incremental costs are a result of the following factors:

- more frequent servicing required for the generation units, which are run harder to make up for the loss in IPP capacity;
- higher operating costs as units lower down the dispatch hierarchy are run;
- higher operating costs as units lower down the dispatch hierarchy are run;
- potentially poorer heat rate performance; and
- potential load shedding and the resultant loss in revenues as well as penalty under the Q-factor.

JPS believes that these incremental costs outweighs the liquidated damages that the IPPs are obliged to pay under the terms of the contract, when actual dependable capacity is below contracted level.

12.2 Office Determination on IPP costs

The Office is of the view that the customers have to pay for the contracted capacity charges of the IPPs and failure to provide this capacity should result in a refund to the customers; therefore the actual value of capacity payment should be used. The Office is mindful that the non – fuel variable charge has never been quantified by JPS as over the years it has insisted that there are little or no variable costs apart from fuel. The actual capacity charges should be used to calculate the IPP charge

Determination 12.1

The Office has determined that:

The actual Independent Power Producers (IPPs) costs shall be recovered as a pass-through on customers' bills by using the following methodology:

- **Estimated base Non-Fuel IPP costs shall be embedded in the non-fuel charges. JPS shall submit its methodology for allocating IPP cost to the Office for approval.**

- **A computation shall be done on a monthly basis to determine whether the actual costs deviate from the estimated base costs.**

- **The surplus or deficit shall be returned or recovered over the total kWhs billed. This surplus or deficit shall be included in the Fuel and IPP charge line item on the bill.**

Chapter 13: Tariff Design

13.0 Allocated Cost of Service Study

13.1 Introduction

The Licence (Schedule 3, Section 2(B)) requires that JPS:

> "co-operates with *the Office* to conduct a cost of service study, the results of which will form the basis for rebalancing the tariffs in order to remove cross subsidies across rate classes."

The purpose of JPS' allocated cost-of-service study is to determine the cost to serve its individual customer rate classes, and to show the rate of return on investment and equity that the company currently earns from each rate class for the services rendered. This is accomplished by separating the revenues, investments, and expenses between the various rate classes based on an analysis of the causative nature of the costs incurred for the service provided. While certain costs are readily identifiable to a particular customer or customer class, many parts of an electric system are planned, designed, constructed, operated and maintained jointly to serve all customers. Costs incurred to serve all customers are referred to as joint or common cost and must be allocated to the customer rate classes based on the type or classes of customers, their load characteristics, their number, and various other implied customer-related investment and expense relationships.

13.2 Principles of a Cost-of-Service Study

In performing an allocated cost of service study, the overall objective is to allocate costs fairly and equitably to all customers. This objective is accomplished when the resulting allocated cost of service study reflects "cost causation". "Cost causation" is the fundamental and essential principle underlying the development of any cost-of-service study. "Cost causation" addresses the question as to which customers or groups of customers caused the Company to incur a particular type of cost, i.e., it establishes a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. "Cost causation" focuses upon the selection and development of an allocation methodology that recognizes the relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other.

"Cost causation" becomes intuitively obvious when a specific cost can be directly linked and specifically assigned to an individual customer, as in the case of plant and facilities related to the street lighting rate class (Rate 60). However, since a significant amount of JPS' costs are joint or common costs, and have been incurred to serve all customers, there are few opportunities to specifically assign costs.

13.3 Developing Allocated Cost-of-Service Study
Typically, there are three fundamental steps required to develop a cost-of-service study of any type. These are:

- functionalization;
- classification, and
- allocation.

13.3.1 Functionalization
This first step separates the investment and expenses of the Company into specific categories based upon utility operations involved in providing electric service. For JPS, the functional investment categories associated with providing electric service are production, transmission, distribution, and general plant. The functional expense categories include production, transmission, distribution, customer services, and administrative and general expenses.

13.3.2 Classification
The second step, classification, identifies the "cost causative" characteristics of the investment and expenses within each function. Typically, these "cost causative" characteristics are:

- *Energy-related* —those costs that vary with the customers' energy consumption; this generally refers to costs incurred by the utility that vary with the megawatt-hours (MWh) of energy consumed by the customer.
- *Demand-related*—those costs that are incurred as a consequence of the loads imposed on the system by all customers; this generally refers to costs incurred by the utility in order to provide the capacity necessary to serve the customers' maximum load throughout the year.
- *Customer-related*—those costs that vary with the number of customers; this generally refers to costs incurred by the utility just to connect a customer to the distribution system, and for customer metering, customer billing and administrative costs.

13.3.3 Allocation
The third and final step is the allocation of costs that have been functionalised and classified as previously described.

- *Energy costs*—energy costs are associated exclusively with fuel costs and the variable operations and maintenance expenses related to the production function. These costs are allocated based on the annual MWh consumed by the customers in the various rate classes, adjusted for losses.

- *Demand costs*—demand costs are associated with the production, transmission and distribution functions. Demand costs at each respective service level are allocated based on the MW demand imposed by the customers in the various rate classes, adjusted for losses.

- *Customer costs*—customer costs are associated with the customer component of certain distribution facilities along with the costs associated with the customer service function. The customer component of distribution facilities is that portion of costs that vary with the number of customers. Thus, the number of poles, conductors, transformers, service drops and meters are directly related to the number of customers on the JPS system. Customer service costs are also associated with meter reading, customer accounting, collections, uncollectible expenses, etc. Customer costs are analysed on an account-by-account basis to determine the rate classes that cause these costs to be incurred.

The functionalization, classification and allocation steps are necessary and essential to the preparation of any cost-of-service study, and the process is fundamentally the same whether analysing gross plant, accumulated provisions for depreciation, materials and supplies, other rate base items, revenues, operation and maintenance expenses, depreciation expenses, taxes, etc. Items that can be specifically identified with a particular customer class are so assigned, as in the case of rate revenues. All other costs are of a joint use nature and must be functionalized and classified in order to insure that the final allocation of costs reflect "cost causation."

13.4 Tariff Design

Currently, JPS has five standard rate classes:

- Rate 10 (residential service).

- Rate 20 (general service).

- Rate 40 (power service)—of which there are three subcategories:
  - Rate 40A;
  - Rate 40LV;
  - Rate 40MV.

- Rate 50 (large power service) — of which there are two subcategories

- Rate 50LV;
- Rate 50MV.

- Rate 60 (street lighting).

Customers in all rate classes incur the following charges:

- *Customer charge*—designed to recover investment and expenses incurred by the utility based on the number of customers served, independent of load;

- *Demand charge*—designed to recover investment and expenses incurred by the utility to provide readiness to serve expected load;

- *Energy charge*—designed to recover non-fuel costs that vary with the number of kWh supplied to the customer.

- *Fuel charge*—designed to recover the total cost of fuel which varies with cost of fuel and the number of kWh supplied to the customer

However, for Rates 10, 20 and 60, the demand charge is effectively rolled into the energy charge. These customers therefore incur only two categories of non-fuel charges—the customer and energy charges.
In addition, JPS offers special non-fuel tariffs to specific customer groups as outlined below:

- *Lifeline Rates*— in accordance with Condition 14 of the Licence and a long established social policy objective, JPS has a universal lifeline tariff structure within the rate 10 category, which allows all residential customers to get reduced energy charge for the first 100 kWh of electricity consumed, regardless of total consumption. Only the energy charge is discounted for the "lifeline" customer. That is, the customer charge and fuel charge is the same regardless of total consumption for the month.

- *Time-of-Use Rates*—these rates are an optional rate classification and are applicable to Rates 40 and 50 customers only. Time of Use (TOU) rates are designed to reflect the fact that JPS' cost to provide electricity to consumers varies according to the time of the day the electricity is produced. At the peak time, for instance, JPS incurs its highest costs since it is during this time that peaking plants, which operate at higher cost than the base load plants, are brought onto the system. Conversely, the company's cost is at its lowest during the "off-peak" hours when only the base load plants are in operation. A customer under this TOU option will have to demonstrate proper load management to effectively see savings on its bills relative to the standard (flat) rate option.

- *Standby Rates*—these rates were designed for those companies who own and operate generating equipment capable of meeting their own power requirement. These companies may at times find it necessary to take power from the JPS when demand exceeds their supply, including times of either planned or forced outages of their generating plant.

JPS has made proposals on the following:

- rationalization of rate classes;
- special tariffs, in particular, the lifeline rates, standby tariffs, TOU option and TOU rates;
- revision of assumptions on the calculation of street lighting bills;
- methodology for setting and realigning tariffs towards cost-reflectiveness; and
- design of the customer charge

13.4.1 Rate Class Rationalization

Customers are categorized into different rate classes on the basis of their demand profile and the voltage level at which they are connected to the JPS system. This is done against the background that customers with similar demand and voltage characteristics impose a similar cost on JPS and as such should bear the same charges. Additionally, amongst non-residential customers, the load demand profiles of the Rate 40LV and Rate 50 LV customers (Standard and TOU) are very similar; as are those of the Rate 40MV and Rate 50MV. OUR therefore agree with JPS' proposals to combine:

- Rate 40LV Standard and Rate 50LV Standard customers into a single LV Standard grouping;
- Rate 40LV TOU and Rate 50LV TOU customers into a single LV TOU grouping;
- Rate 40MV Standard and Rate 50MV Standard customers into a single MV Standard grouping;

- Rate 40MV TOU and Rate 50MV TOU customers into a single MV TOU grouping;

It should be noted that this proposal was also made by PPA/Frontier[23], with the exception that they recommended the inclusion of the Rate 20 class into the Rate 40LV and Rate 50LV grouping as well.[24] However, the Office, after consultation with JPS takes the view that the Rate 20 should be kept separately primarily because of the cost to initiate such a new structure as it would require the replacement of a large number of meters (about 40,000 meters at an average of US$425/meter) to facilitate the recording of demand. Also, the load for the majority of the customers in this category is minimal and therefore the benefits of measuring individual customer demand is likely to be outweighed by the high cost of meter replacement.

Table 12.1 below summarizes the results of the rate class rationalization proposals outlined above. A class that sees a decrease will, on average, see lower rates when combined with another rate class which would result in an average decrease in revenue recovered from that class. The converse occurs if a class experiences an increase. It is important to note however that the analysis does not examine the impact on individual customers, but instead focuses on the class totals.

- Alternate Rate 1: Combination of Rate 40 LV Standard / Rate 50 LV Standard;

- Alternate Rate 2: Combination of Rate 40 LV TOU / Rate 50 LV TOU

- Alternate Rate 3: Combination of Rate 40 MV Standard / Rate 50 MV Standard; and

- Alternate Rate 4: Combination of Rate 40 MV TOU / Rate 50 MV TOU

[23] See PPA (2002)
[24] Consultative Document done by Power Planning Associates Ltd and Frontier Economics for the Office of Utilities Regulation, Electricity Tariff Study; Final Report, July 2002

Table 13.1
Average Impact of Combining the Rate Classes

Current Rate Class	Alternate Rate 1	Alternate Rate 2	Alternate Rate 3	Alternate Rate 4
Rate 40 LV Standard	1.3%			
Rate 40 LV TOU		1.2%		
Rate 40 MV Standard			6.8%	
Rate 40 MV TOU				8.2%
Rate 50 LV Standard	-6.1%			
Rate 50 LV TOU		-4.9%		
Rate 50 MV Standard			-1.6%	
Rate 50 MV TOU				-0.5%

Note: These results are derived using 2002 billing determinants with the 2003 gazetted non-fuel tariffs.

Determination 13.1

The Office has determined that the former Rates 40LV and 50LV are to combined in a new Rate 40 (LV) and Rates 40MV and 50MV are to be combines in a new Rate 50 (MV)

The Rate 40A category was designed in 2001 as a temporary rate class to facilitate those Rate 40 LV customers with poor load factors who would have realized substantial rate shock if kept in the Rate 40LV class. The intent was that the rate class would have been phased out within the three-year period as these customers made their operations more efficient. However, at the end of the three years, there has been little change in the performance of these customers and so, any attempt to incorporate all 40A customers within a normal rate category would, on the average, result in severe rate shock. As a result, the 40A class will remain as a special rate category.

13.4.2 Lifeline Rates

It is common for utilities to include, in their rate design, a special rate that subsidizes low-income users. As currently applied, this rate may be described as a universal lifeline rate in the sense that all residential customers benefit from the subsidy up to a consumption of 100 kWh. In addition, it is an intra-class subsidy because above the subsidy ceiling (100 kWh) residential customers progressively pay the subsidy for the lifeline rate.

In assessing the effectiveness of lifeline rates two issues are key:

- *Are low-income consumers benefiting from the subsidy?* — Fundamental to the universal lifeline scheme is the assumption that low income consumers and low-consumption consumers of electricity are one and the same. However, while the assumption may hold in many cases it is not always true. Some low-income users are not low electricity consumers. For instance, a poor household with a large family might consume more electricity than a high-income household with a small family. On the other hand, some low users of electricity are not low-income consumers – an affluent consumer with a holiday cottage, that's only used on odd week ends. The typical bill for the cottage would be at the lifeline rate even though the consumer clearly belongs to a high-income group. It is evident that the existing scheme has the weakness of not being able to specifically identify and target true low-income users.

  Another drawback to the universal lifeline scheme is that it comes with considerable cost to other consumers. This approach to subsidisation is referred to as a restricted lifeline scheme and it results in a lower mark-up on rates since the subsidy is more targeted than it is under the universal scheme.

  However, despite all its shortcomings the universal lifeline has the advantage of being administratively easier to handle and present less of a public relations challenge when it comes to dealing with crossover increases between the subsidized and the non-subsidized rates. Tariff consultants, PPA/Frontier, in their *Jamaica Office of Utilities Regulation Electricity Study 2002* after examining the restricted and universal mechanisms recommended that the present scheme of subsidising all consumers below the lifeline ceiling be maintained.[25]

- *Is the level of subsidisation adequate?* —On the matter of the appropriate level of subsidization, PPA/FE examined this issue drawing on the Jamaica Survey of Living Condition 2000. In the end they concluded that the lifeline ceiling should be somewhere between 64 and 111 kWh and as such the current 100 kWh is about correct.

  Determination 13.2

[25] See PPA (2002) op. cit.

The Office has determined that the present lifeline mechanism and ceiling be maintained in the 2004 rate structure.

13.4.3 Standby tariffs

The standby tariff was designed for those companies who own and operate generating equipment capable of meeting their own power requirement. These companies may at times find it necessary to take power from the JPS when their demand exceeds their supply, including times of either planned or forced outages at their generating plant.

Whenever power is taken from JPS, the standby customer is billed according to voltage classification, using the applicable customer charge, energy charge and the time-of-use rates for demand and fuel. However, for those months during which the customer generates its own power, JPS bills it at a reserve capacity charge and a customer charge only. This reserve capacity charge is a fixed monthly charge that is applied to the contracted demand or the maximum demand in the customer's billed consumption

A standby customer that requires the reservation of a firm capacity for use at any given time places on the utility for the provision of plant than the normal customer. This is to be distinguished from a customer that will take power when it is needed if it is available. JPS would not necessarily have to plan for this capacity so a lower reserve capacity charge may be suitable.

Determination 13.3

The Office has determined that there shall be two categories of standby customers one for firm capacity and the other which takes power if available

13.4.4 Time of Use (TOU) option

Regardless of the overall load factor, the system peak is the determinant of the capacity that JPS requires to serve its customers. It is the fixed cost associated with this system capacity that is captured in the demand charge. Therefore, it seems only reasonable that the charge arising from demand during the system peak should be higher than those applicable at other times.

Fuel costs per kWh also vary, depending on the type of plants used in production. In the generation process, plants with the lowest variable cost (base load) are loaded first and those with highest variable cost (peaking plants) are reserved for peak load hour. Consequently, fuel cost per kWh generated during the off-peak is lower than it is during the peak. As a result, price signals differentiating the time of day that service is used is often reflected in the demand charge and fuel rates.

PPA/Frontier suggested that TOU rates should be offered to all consumers.[26] They noted that meter costs will typically outweigh TOU benefits for a residential customer, but if the customer agrees to pay increased meter cost, they should have the option of obtaining TOU rates. Although ideal from the perspective of sending price signals there are certain challenges associated with universal TOU rates:

- TOU metering costs are significantly higher than energy metering cost and if the meter cost is passed on to a residential customer it is very high relative their monthly usage.

- Residential customers who are the bulk of the utility's consumers prefer simpler bills to the more complex TOU representations.

Against this background, Office accepts JPS' recommendations of not offering TOU rates to either its residential (RT10) or small commercial (RT20) customers. Admittedly, a more complex bill should not cause too much of a problem to RT20 customers, but given relative low level of demand and the expected low acceptance of costs to change meters, the Office is of the view that the current rate structure for Rate classes 10 and 20 should continue.

With respect to the large commercial and industrial groups (RT40 and RT50), JPS also recommends that the current arrangement of a standard rate with optional TOU rates be kept intact. The Office agrees. The reason for this is that converting all standard customers to TOU billing presents a revenue recovery risk, since detailed billing data on demand patterns during the TOU periods is not available from the existing standard meters. What, however, is important is that consumers who identify an opportunity to derive costs savings are free to move to the optional TOU rates.

The Office also accepts JPS' recommendation that the present arrangement where off-peak rates apply over the entire weekend and on public holidays should be changed to partial-peak between 6:00pm and10:00 pm and off-peak at all other times. The historical trend has shown a significant growth in weekend demand during the 6:00pm – 10:00 pm period, which makes it more consistent with the partial-peak classification than with the present off-peak categorisation.

[26] See PPA (2002) op. cit.

13.4.5 Modifying the Time of Use (TOU) rates

Under the existing structure, all customers who take up the TOU option are billed under TOU rates for demand and fuel, based on the time of day that electricity is consumed. There are currently three TOU periods used for billing:

- On-peak period: Monday – Friday 6:00 pm to 10:00 pm;
- Partial-peak period: Monday – Friday 6:00 am to 6:00 pm; and
- Off-peak period: Monday – Friday 10:00 pm to 6:00 am; Weekends and Public Holidays.

The TOU rates are derived from the standard rates according to the loss of load probabilities, which vary according to the time of day. The loss of load probability associated with the on-peak period is the highest of the three periods, due to the increased likelihood of load shedding during this period. This is also the period in which JPS bears its highest generating costs. Consequently, the peak period has the highest TOU rates.

The load profile indicates that the partial peak is moving closer to the peak and therefore is becoming a driver for investment in capacity. For more efficient use of the plant it is necessary to provide incentives moving load to the off-peak hours.

Another feature of the current TOU design is that the billing demands for the on-peak and partial-peak periods are not ratcheted, but are the maximum registered demand for the respective on-peak and partial-peak hours of that month. The billing demand for the off-peak is, however, set as:

- the maximum demand for the month (regardless of the time of day it was registered in), or
- 80% of the highest maximum demand during the six-month period ending with the month for which the bill is rendered, whichever is higher.

That is, the off-peak period is the only time of day period for which the demand is set as the global maximum and for which the demand is ratcheted.

Determination 13.4

As indicated above the Office has accepted the proposal that the TOU billing periods will be:

On Peak Period: Monday – Friday: 6:00 p.m. to 10:00 p.m.

Partial Peak Period: Monday – Friday: 6:00 a.m. to 6:00 p.m.
Weekends and public holidays: 6:00 p.m. to 10:00 p.m.

Off Peak Period: Monday – Friday: 10:00 p.m. to 6:00 a.m.
Weekends and public holidays: all hours except 6:00 p.m. to 10:00 p.m.

13.4.6 Modification of demand ratchet and partial peak billing demand

The Office has determined that the Time of Use (TOU) rate design shall be as follows:

- The On Peak billing demand shall be the maximum registered demand for the Peak hours of that month.

- The partial peak billing demand shall be set as the maximum registered demand for the combined partial peak and on - peak hours of that month, or 80% of the maximum demand for the partial and on peak hours during the five-month period immediately prior to the month in which the bill is rendered., whichever is higher, but not less than 25 kVA.

- The off-peak billing demand shall be the maximum registered demand for that month, or 80% of the maximum demand for the five-month period immediately prior to the month in which the bill is rendered, whichever is higher, but not less than 25 kVA.

The rationale for redefining the partial-peak billing demands is to provide an additional incentive for customers to shift their load to the off-peak period. The current design is ineffective in this regard as a customer can realize savings without embracing effective load management once they move from standard to TOU option, thus defeating the whole objective of the TOU regime.

13.4.7 Increase in on-peak rates to encourage improvement in load profile

JPS proposes to increase the on-peak rates by 5% more than that implied by the loss of load probabilities. The TOU rates will therefore no longer sum to the standard rate and would further encourage the shifting of load from the peak- to partial- or off-peak period.

This is appropriate because these customers were getting an undue break due to the weakness in the previous rate design. The vast majority of these customers will still be paying less on this modified TOU rate than they would on the standard rate. Customers who have a majority of their usage in the off-peak period will be largely unaffected by these changes and will still receive significant rewards for consuming in the off-peak period. These rate modifications will also help to ensure that future migration to the TOU rate will only benefit customers who have load profiles consistent with the TOU rate concept. The Office would encourage JPS to accommodate those customers who are adversely affected by this change in the tariff design and wish to migrate to another appropriate tariff.

13.4.8 Calculation of street light bills

JPS currently calculates street lighting bills on the basis of the following two assumptions:

- Street lights function 100% of the time;
- Street lights consume energy for 12 hours each day (this is based on information on the number of hours between dusk and dawn from the Meteorological Office).

The assumption that street lights function 100% of the time is not realistic as there is always lapse between date of the failure of a lamp and the date of its repair.

Going forward, therefore, JPS proposes to modify this assumption to one that reflects an outage rate of 1%, i.e., street lights function 99% of the time. This is based on the following:

- An estimated average lifespan of street lights of four years; and
- An average time period of 14 days taken for JPS to repair the failed street lights.

The calculation of the 1% outage rate is shown in Table 13.2.

Table 13.2
Estimation of outage rate of street lights

Average Life of Street Light (a) Average Length of Outage (b)	4 years 14 days
Failures in one year (c = 1/a)	25%
Total yearly outage (d=c x b/365)	0.959% » 1%

The Ministry of Local Government in its response to consultations is challenging

JPS' claim that the outage rate is 1% and has provided data on actual outage experienced in one parish and a list of complaints from other parishes. The Office is minded to have regard to the issues raised by the Ministry of Local Government and has decided to set specific guaranteed and overall standards with view to securing some improvement in performance in this area of the company's operations. These are discussed in Section II of this document.

Determination 13.5

The Office has determined that the street lighting tariffs are to be calculated as if the streetlights were available 100% of the time. However, failure to repair, within 14 days, a streetlight reported by the local authority, will result in the breach of a guaranteed standard.

13.4.10 Realigning Tariffs towards being cost-reflective

The Office is of the view that the criteria of cost reflectiveness and economic price signaling are principles that should be a part of the rate setting exercise. From an economic perspective, marginal cost tariffs are ideal for sending price signals since, theoretically, decision makers tend to make optimal choices by focusing on the costs and benefits at the margin. On the other hand, it is the average tariff that allows the full recovery of the costs the firm faces. Therefore to narrowly insist on applying either the marginal cost tariff or the average tariff can lead to sub-optimal results in an economy. A combination of both approaches in the rate design exercise may be necessary to ensure that the utility remains viable whilst at the same time price signals are sent to enhance consumer welfare.

The PPA/Frontier study concluded among other things that:

- The Office is obliged to ensure that JPS recovers its embedded cost revenue requirement because these costs were incurred in the past in order to meet its responsibility to produce and deliver electricity.

- JPS' marginal cost tariff is lower than its embedded cost tariff, "because the cost of new capacity to meet incremental demand is lower than the embedded costs incurred to meet existing demand". Marginal cost pricing would therefore not lead to cost-reflective tariffs

- While the Ramsey pricing methodology is a possible approach to reconcile marginal cost tariff with embedded cost tariff, the Office is of the view that JPS should be allowed the latitude to take advantage of its comprehensive knowledge of the demand profile of its customers and set individual tariffs within the framework of the total allowed revenue requirement.

Applying the Ramsey pricing methodology suggested by PPA/Frontier[27] requires that rate design be predicated on the marginal tariffs, with any revenue difference between the marginal cost and embedded cost approaches being redistributed by an inverse price elasticity method. According to the Ramsey pricing principle, it is economically efficient to recover a relatively larger part of common costs from those customers whose demand is relatively more inelastic (i.e., less sensitive to price changes). In other words, under Ramsey pricing, costs would be allocated according to the customers' willingness to pay.[28] Strict application of this method is discriminatory and excludes social considerations that are very important in rate design. In addition, the Ramsey approach is not exactly straightforward and depends on the availability and accuracy of the elasticity estimates.

Another approach, which can be used to allocate the embedded costs across the different rate groups, is the equi-proportional mark-up (EPMU) method. Under this method, the embedded cost revenue is divided among rate classes in the same proportion as derived from the marginal cost tariff. The application of this method is simpler to apply than Ramsey pricing and may be considered a more equitable approach to the distribution of revenue.

The Office, therefore, supports retention of the current structure of its tariffs, which is reflective of marginal cost pricing. Annual adjustments will be made over the five-year term to align these tariffs in keeping with the Cost of Service study results. In addition, under the global price cap system JPS will have the latitude to fine tune the rates to minimise rate shocks.

13.4.11 Design of the Customer Charge

The customer charge is designed to recover costs other than those related to the production, transmission and distribution of electricity.. As such, it includes such costs as those related to metering, billing, collecting and providing service information and will vary between rate categories.

The existing differentiated approach used to derive the customer charges is cost reflective, with the exception of the residential class. The Office is of the view that this method be maintained.

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[27] See PPA (2002) op. cit.

[28] Put differently, the amount of revenue difference assigned to a rate class depends on its price elasticity.
Consequently, the more price-inelastic a rate class is, the higher the proportion of the revenue difference it bears.

13.4.12 Interruptible Tariffs

Although outside the scope of this review the Office will be requesting JPS to design a special regime of interruptible tariffs which it can apply to special customers under the provisions of section 14 of the OUR Act. These tariffs to become operational by January 1, 2005

13.5 Proposed tariffs based on revenue requirements

The approved Non-Fuel base rates for 2004 are summarized at Table 13.2

- **Table 13.2 Approved Tariffs for 2004**

					Demand-J$/KVA			
Rate Class		Rate Option	Customer Charge	Energy Charge (J$/kWh)	Std.	Off-Peak	Part Peak	On-Peak
Rate 10	LV	Lifeline	68	4.549	-	-	-	-
Rate 10	LV	Non Lifeline	68	8.008	-	-	-	-
Rate 20	LV		150	6.770	-	-	-	-
Rate 40A	LV	STD	2,100	4.250	276	-	-	-
Rate 40	LV	STD	2,100	1.728	707	-	-	-
Rate 40	LV	TOU	2,100	1.728	-	29	308	394
Rate 50	MV	STD	2,100	1.556	636	-	-	-
Rate 50	MV	TOU	2,100	1.556	-	26	277	355
Rate 60	LV	Street Lights(metered)	550	8.161	-	-	-	-
Rate 60	LV	Traffic lights	550	5.494				

13.6 Proposed Tariff Increase Relative to Current Tariff

The base gazetted tariffs set in April 2003 do not reflect the effects inflation and currency movements that have taken place since then. Rates are normally adjusted annually, using the inflation escalation factor as defined in the Licence, i.e.:

$$dI = [0.6 \quad e(1 + 6\ .\ 0\ i_{us}) + 4\ .\ 0\ i_j]$$

Where,

e ” = Change in the Base Exchange rate

i_{us} = ” US inflation rate (as defined in the licence)
i_j ” Jamaican inflation rate (as defined in the licence)

In order to derive the non fuel rates at March 31 2004 if an annual adjust had taken place, based on the escalation factor above, the Office estimates that an adjustment of 18.9% on the April 2003 base rates would have been required to reflect inflation levels and devaluation of the Jamaican currency. Table 13.3 shows the derivation of the inflation escalation factor. Of this 16.5% would have been made in the Foreign exchange adjustment clause leaving a further 2.4% of adjustment to be made. This compares to an 11% increase in non-fuel rates or 5% overall increase in tariffs with the new tariff schedule.

Table 13.3 Escalation Factor Computation

		Key	Notes/Formulas	**2001**	**2002**	**2003**	**2004**
Non-Fuel Base Rates	US c/kWh			9.24	9.27	9.33	9.10
Non-Fuel Base Rates	J$/kWh			4.06	4.36	4.67	5.55
JA inflation[29]	%	A	Point to Point inflation @		7.7%	5.8%	13.9%
US inflation[30]	%	B	October the previous year		2.1%	2.0%	2.0%
Present Base X Rate[31]	J$:US$	C	Used prior to Submission		44	47	50
Proposed Base X Rate[32]	J$:US$	D	Implemented upon Submission		47	50	61
Escalation Factor	%		[0.6*(D-C)/C*(1+0.6*B)]+0.4*A		**7.2%**	**6.2%**	**18.9%**

13.7 Reconnection Fees

JPS is required to reconnect a customer after full payment of the outstanding amounts and payment of the reconnection fee. A reconnection fee is applicable to all rate categories. The company currently charges a reconnection fee of $1,325 to reinstate service to customers, whose electricity supply had been disconnected because of non-payment of bills. This fee was based on a cost review carried out in 2002.

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[29] [1] Point-to-point inflation as from October the previous year
[30] This is the exchange rate used prior to the annual submission;
[31] This is the exchange rate implemented upon submission;
[32] This is calculated based on the formula in the licence, using the Jamaican and US inflation and foreign exchange movements.

The Office had previously made a determination in respect of reconnection fees which is repeated in the Rate Schedule 2003 as follows:

> "The reconnection fee shall be determined by June 30 each year and which shall be based on the actual cost of undertaking reconnection in the preceding year plus a 10 percent service charge PROVIDED THAT the said actual cost was incurred in the most cost efficient and cost effective manner".

The total cost associated with disconnection and reconnection in 2003 is estimated to be $94,829,709, based on the sum of the O&M costs, administrative costs and audit fees. The total number of reconnections in 2003 is 72,366. The cost per reconnection is estimated as follows:
Actual reconnection cost = Total cost / Total number of reconnections
As per Rate Schedule, a 10% of the actual reconnection cost is added as a service charge. Based on analysis the reconnection fee per activity should be set at $1,441. The derivation of this fee is summarized in Table 13.4

Table 13.4
Reconnection Cost Summary

Description	Costs ($)
Total reconnections for 2003 (a)	**72.366**
Contractor cost for 2003 (b)	**75,672,591**
Administrative cost for 2003 ©	**18,907,118**
Audit fees (d)	**250,000**
Total cost (e = b+c+d)	**94,829,709**
Actual reconnection unit cost for 2003 (f = e/a)	**1,310**
Plus 10% service charge (g = f* 10%)	**131**
Derived reconnection fee	**1,441**

SECTION II

Consumer Issues and Quality of Service Standards

1. Introduction

On March 31, 2004, the Jamaica Public Service Company (JPS) submitted a detailed Tariff Proposal, essentially seeking a 22.9% increase in base rates. The Office is duty bound to consult with the public as part of its review of the proposal.

To this end, the Office organized a number of Public hearings designed to canvass the views of a wide cross section of consumers and customers of the company. Firstly, a supplement summarizing the JPS Tariff Proposal was published in the Observer on Thursday March 18, 2004 and the public asked to submit written comments. Additionally, fourteen (14) parish meetings/hearings were organized and promoted extensively in the print and electronic media, including, the Gleaner, Observer, North Coast Times, Western Mirror, RJR, Irie FM , Power 106, Hot 102, Love 101 and so on. The meetings were attended by approximately three hundred (300) consumers and were held as follows:

Table 1: Venues – Public Consultation on JPS Tariff Review

Date	Parish	Venue
March 24, 2004	Westmoreland	St. Georges Anglican Church – Great Georges Street Savanna – La – Mar
March 25, 2004	Hanover	Lucea Parish Church Hall – Lucea, P.O, Lucea
March 26, 2004	St. James	Wexford Court Hotel - 39 Gloucester Avenue, Montego Bay
March 30, 2004	Portland	Old Marina, Port Antonio – West Palm Avenue
April 01, 2004	St. Catherine	Jose Marti Tech. High School Spanish Town – Twickenham Park
April 02, 2004	Clarendon	Hotel Versalles, Longbridge Avenue, May Pen
April 05, 2004	St. Elizabeth	Chariots Hotel – Leeds, Santa Cruz
April 06, 2004	Manchester	Golf View Hotel – 5 ½ Caledonia Road, Mandeville

Date	Parish	Venue
April 07, 2004	Kingston	PCJ Auditorium – 36 Trafalgar Road, Kingston 10
April 08, 2004	St. Catherine	Portmore Civic Centre - Portmore
April 13, 2004	St. Thomas	Morant Bay Parish Church – 1 East Street, Morant Bay
April 14, 2004	St. Mary	St. Mary's Civic Centre – Port Maria
April 15, 2004	St. Ann	St. Ann's Bay Parish Church Hall – Church Street
April 16, 2004	Trelawny	Trelawny Parish Council – 5 Rodney Street, Falmouth
May 3, 2004	Kingston	OUR Consumer Advisory Committee (OURCAC), OUR Conference Room, 36 Trafalgar Rd, Kgn 10

The Office presided over these hearings (with the exception of the OURCAC). At each meeting JPS made a presentation of its case for a rate increase, after which consumers had the opportunity to respond and to offer counter arguments to the JPS case.

Additionally, the Office met with the Jamaica Hotel and Tourist Association (JHTA) on March 22, 2004 and the Jamaica Manufacturers Association (JMA) on March 29, 2004. Two (2) written submissions were received from interested consumers. Efforts to convene a meeting with the Joint Confederation of Trade Unions (JCTU), signatories to the Memorandum of Understanding (MOU) with the Government, proved unsuccessful.

The proceedings were recorded and for the most part form the basis of the discussion in this section. The main issues identified by this process are summarised below.

2. Issues relevant to the Tariff Proposal raised during Consultation

2.1 Tariff Increase

Consumers have been generally strongly opposed to a tariff increase at this time citing a number of reasons, the most prevalent being the perceived inefficiency of JPS, poor customer service, prevailing economic conditions, the current Memorandum of Understanding (MOU) and the cost implications for commercial customers. It was felt that the JPS was not deserving of an increase at this time because of a perception that there are significant efficiency gains to be realised from the rationalising of its operations, especially relating to the reduction of system losses.

Consumers also expressed the view that a rate increase is not warranted as the current tariff automatically adjusts prices for inflation and movements in the exchange rates.

OUR Comments
The Office accepts the view that JPS can and must achieve significant efficiency gains, especially in the reduction of system losses. By and large, most of the general issues raised at the public hearings are addressed in the succeeding discussion.

2.2 System Losses (Technical and Non-Technical including theft)
At the tariff review in 2001, the Office allowed losses in the tariff at 15.8%, implying that the company would not be able to pass on any incremental losses above this value to consumers. However, since then losses have increased significantly and are currently at 18.5% with about 9% being of a technical nature, i.e. inherent in the generation, transmission, distribution and supply of electricity and the other 9.5% attributed to theft and other commercial practices.

While JPS argued that since 2001, despite its best efforts, which included a number of raids, removal of throw-ups, account investigations and arrests, losses have increased because the problem of electricity theft is mainly social in nature and requires a greater social partnership to be effectively dealt with it expressed the view that contributing factors such as the high unemployment rates, low penalties in the court system, and a general "freeness mentality" are mainly responsible for the high level of losses due to theft and that the company is ill-equipped to deal with problems of this nature. The company further suggested that while it does not have the expertise to design social programmes, it would contribute financially and otherwise to any structured programme designed to address the problems that contribute to electricity theft. Nevertheless, JPS committed to continue to improve its efforts to reduce electricity theft.

However, consumers were not convinced that JPS has done enough to reduce the level of losses due to electricity theft. Consumers felt it was unfair to allow the company to continue to charge paying customers for losses it sustained due to theft. Additionally customers felt that with the overt nature of the theft (throw-ups) in a lot of instances, JPS had not done enough to protect its service. Consumers were also concerned that the prevalence of throw ups affects the integrity of the service (i.e. voltage quality) inevitably leading to damage to customers equipment (see section 3.6 on Equipment damage). A number of suggestions to reduce theft were advanced by consumers including:

- Insulating secondary distribution wires to mitigate against throw-ups;

- Offer flat rates in certain “red” areas where there is a prevalence of electricity theft;
- Cooperation with community leaders to arrange for collection of revenues in “red” areas,

- Increased efforts to target theft in affluent areas,

- Educating consumers about the dangers of electricity theft.

OUR Comments
The Office has long maintained that the levels of system losses due to theft are unacceptable and has been engaging the JPS in dialogue aimed at identifying strategies for loss reduction. At every opportunity, the Office has not only publicly condemned the practice of electricity theft but also the tacit approval which society appears to give to it.

While it is accepts that electricity theft is a symptom of a greater social problem, the Office is not satisfied that the company has expended its best efforts at tackling the problems. The Office is of the view that a strategic approach to loss reduction has not evolved but that the “ad hoc” measures are taken from time to time is only a nominal response by the company. The Office would have expected the company to develop a comprehensive strategy and implementation plan to address the problem of electricity theft. The Office supports the approach of installing insulated secondary distribution wires in communities where there is a prevalence of illegal connections (throw-ups). Greater efforts also need to be expended by JPS in engaging the society on the matter of electricity theft as it not only affects the quality of their product, but ultimately the price which consumers pay for electricity.

2.3 Demand Charges
Commercial rate 40 and rate 50 customers expressed concern about the demand charge which they consider to be too high, especially the small hoteliers who make the argument that while they might experience full occupancy for one day of the year, they have to pay that demand charge or 80% of it for the succeeding six months. Consumers in this rate class propose that the demand charge be based on the peak for three months, instead of the current six months.

There is also the view that the demand charge acts as a disincentive for large users of electricity, in that in most other pricing regimes, consumers of large quantities of a commodity normally benefit from bulk discounts, and the demand charge instead imposes a penalty.

OUR Comments

The Office is cognizant of the concerns raised by customers in these rate classes about the perceived punitive nature of the demand charge. However this charge is necessary in that it compensates the company not only for making the capacity available to meet the customers' peak demand, but for having this capacity available on demand. In other words, if the investment had not been made, then the company would not have been able to meet the demand when required. However, the Office is examining the demand charge as part of the review of the current tariff.

2.4 Capital Projects – Extension of Service/Infrastructure Rehabilitation

During the consultation, JPS showed that it made significant investment in capital projects mainly to improve the reliability of the service. These capital projects included the addition of 140 MW of generating capacity at the Bogue plant in Montego Bay as well as implementing a programme for rehabilitation of the existing plants. The company showed that customer outages declined significantly (78% reduction in customer minutes lost since 2001) due to these investments. These investments in generating capacity were determined and agreed to be the priority as reliability of service was the main challenge facing the company in 2001 when Mirant Corporation assumed control of JPS.

While accepting that reliability has improved, consumers expressed concerns about the timeframe in which JPS proposes to recoup its investment. It was felt that JPS by applying for a rate increase is attempting to recover its investments in the assets in a much shorter timeframe than the actual life of the asset.

Additionally consumers feel that because these investments enhance the asset base of JPS, these would be naturally recovered over time as the increased reliability means that the company is generating greater revenue (due to less outages) and not through a rate/price increase. Increased investment should only result in a price increase only to the extent that this investment positively impacts the quality of the service hence the customer pays more for a better service.

There was also some concern about the technological efficacy of these investments in gas turbines which is a costly way of generating electricity.

OUR Comments

The Office is of the view that the accelerated investments in gas turbines were prudent due to the critical levels of reserve margin that was available in 2001. Combined cycle gas turbine technology was considered to be the least cost alternative for the addition of new capacity at that time. In any event, the expansion programme was one that was approved by the Office in order to meet the catastrophic shortfall in capacity which the country faced in 2001.

On the matter of JPS recovering its investment in the generating assets, the company is complying with its licence which allows for recovery of its capital over the life of the assets, 20 years in this case.

2.5 Fuel Diversity

Consumers were generally concerned about the dependence on fossil fuel (Number 2 - HFO and Number 6 diesel oil) for the generation of electricity. It was felt that JPS was not doing enough to diversify its generation due to the fact that it can directly pass on its fuel costs to the consumers. The company therefore has no incentive to minimise fuel costs. Alternate sources of power generation such as wind, thermal, natural gas, and especially solar (due to the fact that Jamaica is a tropical island) was suggested by consumers as ways to diversify and ultimately reduce costs.

OUR Comments

The issue of fuel diversity is of great national importance from a developmental point of view and is in fact a policy issue which is receiving government attention at the present time where the feasibility of a shift to Liquefied Natural Gas (LNG) as the primary fuel is actively being investigated. The company has recognized that the new regulatory regime, starting April 2004, will allow for competition in the generation of electricity (up to then JPS had sole right to add generating capacity) and suggested that this competitive environment should produce the least cost options for new capacity. The Office is of the view that special arrangements will have to be put in place to encourage the development of renewables and alternate energy sources. In any event the Office and JPS have to comply with Government's policy on fuel diversity, alternate energy etc but it must be acknowledged that renewable and alternate energy sources do not necessarily result in lower generating costs in the first instance. Decisions relating to generation, however, will be the subject of another decision which is being conducted concurrently with this tariff review.

2.6 Street Lighting

Throughout the consultative process JPS reported on improvements in the system for the management of street lighting including greater cooperation between the company and the local parish councils. As part of this improved system, consumers with complaints about non-functioning streetlights can make a report to either JPS or the appropriate parish council. Any request for the installation of new street lights, however must be made directly to the local council, who will then instruct the company accordingly. With respect to the process of installing street lights the company emphasised that in this case, the customer and therefore the entity that pays the bills is the parish council, hence the approval of the parish council is essential for any new street light to be installed. Under this arrangement, the company reported that for the period 2001-2003, it repaired over 50,000 streetlights and carried out 8,500 installations.

Additionally as part of the tariff application, the company has proposed to calculate street light bills on the assumption of 99% availability as against the 100% availability factor that is assumed in the current tariff.

On the other hand consumers complained about the tardiness of the company in repairing streetlights. Additionally, consumers were concerned that the street lighting is inadequate in many areas and requests for additional lights are not being satisfied. There was also come concern about the efficiency of a system which forces consumers to request streetlights through the parish councils. The Ministry of Local Government, Community Development and Sport also made a written submission on the matter of street lighting which essentially recommended the retention of the customer and energy charge at the current levels. Additionally, the Ministry proposed that the availability factor for the new tariff be set between 85-90%, as against the 99% suggested by JPS.

OUR Comments

On the matter of street lighting, the Office is satisfied with the current arrangement under which the parish council assume greater responsibility for the management of street lights in its local area. It is the local councils that are responsible for paying the JPS street lighting bills and as such must be responsible for monitoring the repair of street lights and instructing where new lights are to be installed.

Additionally, the Office will introduce the following guaranteed and overall standard respectively:

- **EGS 11 - Street Lighting Maintenance** - JPS shall repair each reported street light failure (as reported by the responsible local authority) within 14 days of receiving the report. [This standard will be implemented on September 1, 2004 on condition that the Office is satisfied that JPS and the local authorities have agreed on a protocol that will govern the arrangements between the parties. If asked, the Office would agree to broker the terms of such a protocol].

- **EOS12 - Effectiveness of Street Lighting Maintenance** - 99% of all street lighting complaints must be addressed and corrected within 14 days. This becomes effective July 1, 2004.

The Office is also reviewing the company's proposal on the availability factor in the calculation of the bill as part of this tariff review and will have regard to the views of all stakeholders.

3. Customer Service Issues

3.1 Simplified Bill

Consumers also indicated that they were unable to easily understand their electricity bills. They were concerned about not having a comparable fixed unit (kwh) charge per month on their bills and felt that they were too many variables. There is also some confusion as to the breakdown of the different components, as one customer puts it, “the current bill looks like JPS is charging for the ingredients as well as the electricity”.

OUR Comments

The Office was involved the development of the current bill and thought that it was important that consumers saw the impact of the different components (fuel, non-fuel and foreign exchange adjustments) on their statements. At the time, the Office viewed this current bill as an improvement on the previous one, in that it seems to be more user friendly and in particular shows a graph of the consumption history. It is noteworthy that even if the bill is restructured to show a single per kwh charge, i.e. to remove the fuel/non-fuel classifications, the unit kwh hour charge would vary each month. The Office had been of the view that a statement which showed a single unit charge that changes monthly would cause more customer dissatisfaction than presently obtains. The problem is that the volatility of fuel prices and to some extent the foreign exchange rate influences the monthly bills rendered by JPS. However based on the feedback from the public consultations the Office will engage the company in a review of the current bill format to see what improvements could reasonably be implemented.

3.2. Estimated Bills/Meter Reading

The matter of estimated billing was also of major concern to consumers who felt that the JPS should read the meter each month. It is unacceptable to them that for half of the year, they are asked to pay their bill based on estimates of consumption. Customers also felt that it was unfair to disconnect their service for non-payment of an estimated bill. There was also some concern about the methodology of estimation as they contend that the estimated bill is “always higher than the previous bill”.

During the consultative process, JPS committed to the phasing out of estimated bills over the next two years.

OUR comments

As part of this review, the Office intends to make the matter of estimated bills a guaranteed standard, breach of which will trigger a compensatory payment to the affected consumer (see section 6.3). The Office is supportive of the company’s objective to phase out estimated bills but cautions that the benefits must be positive in relation to the costs. At the same time, the Office must insist that consumers position their meters in locations that are easily accessible to JPS as per regulations and will support reasonable initiatives taken by the company to secure compliance to this requirement.

While the Office is mindful of the opinion that accounts should not be disconnected for non-payment of an estimated bill, the Office is of the view that the consumer does in fact consume the product during the period for which the estimated bill is rendered and is therefore liable for payment of that consumption. The problem is that the estimated bills do seem consistent with actual historical consumption. The Office would not at this stage insist that the company forebears in disconnection, but it will insist that the company review the algorithm to ensure that the last three (3) **actual** readings are used for calculating estimated bills.

The Office will introduce the following as a guaranteed standard:

- The company shall not render three (3) or more consecutive estimated bills,

- Estimates must be based on the last three (3) actual readings (first six bills of new accounts excepted).

Regarding the actual computation, an estimated bill must be based on the average of the last three (3) actual readings. One of the factors that influence the variation in kwh consumption in the monthly billing is the variability associated with the "number of days" in the billing cycle. The Office is of the view that the company should consider a reorganization of its billing procedures so as to generate monthly bills based on a fixed number of days.

3.3. Prepaid Meters

Some consumers expressed the view that JPS should consider the offering of a prepaid service where customers can control the amount of electricity they consume. This was also suggested as a means of reducing losses due to theft as well as the reduction of receivables.

OUR comments

This is a position that the Office has been encouraging JPS to take since 1998. While the Office is of the view that the prepaid option will allow consumers to manage their electricity budgets, it will not necessarily deter those persons who believe they have a right to free electricity service.

3.4. Disruptions in Service

There were concerns expressed about disruptions in service, both scheduled and unscheduled. While consumers accept that the reliability of the service has improved significantly since the crisis faced in 2001, there were concerns about the notification supplied by the company for planned outages. However, consumers were even more concerned about the timely restoration of service within the specified time. Customers indicated that often times JPS is tardy in restoring service after planned interruptions. There is also the concern about the quality of the voltage directly after an outage (see section 3.6 on Equipment Damage).

OUR comments
Interruptions in service will be addressed in the tariff by the Q-factor which will reward or punish the company depending on the achievement of certain targets. These targets will be based on the average frequency and duration of outages.

3.5. Customer Service

The company attempted to demonstrate that it had made significant improvements in the delivery of customer service in a number of areas including:

- A new Customer Information System (CIS) at a cost of US$5 million which allows for the faster turnaround time and the tracking of credit history of customers,

- Structured programme for the repair and installation of street lights by partnering with the relevant local authorities (parish councils etc),
- Increased convenience by allowing customers to pay bills at collection agencies,

- Improved call centre operations which allows its customers to carry out more transactions without having to physically attend the JPS office.

While accepting the improvements made by JPS, consumers are still dissatisfied with the level of customer service. There is concern that the reduction in the staffing has negatively impacted customer service, especially as it relates to the "personal" nature of its response. As one customer aptly puts it "we just want some one to help us with these problems".

OUR comments
The OUR is aware of the concerns regarding customer service as JPS has consistently been the most complained about utility company since 2001 (see section 5).

The Office is also of the view that the company needs to more effectively integrate the new CIS into its operations in order to leverage the benefits of the expenditure on the system as it feels that the customer is not fully benefiting from the level of investment in this system.

3.6. Equipment Damage/Voltage Quality

The single most contentious issue throughout the hearings was the matter of the quality of the voltage supplied by JPS and the resultant damage to consumers' equipment. Consumers complain that the voltage fluctuates considerably, especially when power is restored after an outage. This they contend invariably leads to equipment being damaged, report of which to JPS only leads to a standard company denial of liability. Customers contend that the company's denial of liability often times is not based on a comprehensive investigation, but almost a "knee jerk" response from the legal department at "head office". Customers also contend that the process for seeking redress for damaged equipment is complex, lengthy and sometimes drags on for months.

Commercial customers concerns are twofold relating to voltage quality. Firstly, there was concern about single phasing from the JPS system causing damage to sensitive equipment. The other concern expressed is that the single phasing condition drives up the demand charge in that the peak demand is higher due to the resultant instantaneous higher currents in the three phase supply. Imbalanced phase voltages were also one of the concerns raised by customers with three phase supply.

Overall customers think that the JPS should guarantee a certain quality of voltage and any fluctuation therefrom which leads to equipment damage should trigger some liability on the company's part. Customers further suggested that the company can protect itself and improve its customer service by providing some assistance/information to customers regarding proper surge protection for their equipment.

OUR Comments

The Office is on record about its dissatisfaction with the company's handling of equipment damage cases. JPS has to develop a more customer friendly policy which allows customers an objective consideration for any damage suffered due to operational incidents over which the company should reasonably be expected to have control. This policy must state the nature and scope of the investigations the company conducts to arrive at its decision. The company must also give commitments regarding the time within which it will complete its investigations and communicate its decision to the customer. There is also the need for the company to have information available in its offices about exactly what customers need to do in order to make a claim (e.g. a fact sheet showing date/time of incident, equipment damaged, electrician's report, repair estimates. etc).

While the matter of recommending technical specification for protection equipment should be a function of the Jamaica Bureau of Standards (JBS), the Office believes that JPS could engage the JBS in some joint effort to educate their consumers about the need for protection. The Office does not believe that the company should expose itself by explicitly recommending a particular brand or type of protective device.

3.7. Security Deposits

The practice of collecting security deposits on customer's accounts also came in for criticism by consumers who felt that it was unfair for the company to hold the deposits indefinitely and only pay interest once per annum on these sums. It was felt that the company had the opportunity to reap significant interest earnings on these deposits, especially those for good paying customers without having to share those earnings with customers.

OUR comments

The Office is concerned about the equity of the security deposit policy. While recognising the need for the company to reduce the risk of revenue fallout due to non payment of bills, the company must not be allowed to unduly benefit from funds that it holds on behalf of customers. Hence the Office is of the view that the company should return deposit to good paying accounts. Good paying accounts are those who for the previous twenty four (24) months have paid each bill in full on or before the due date.

4. Other Issues

4.1. Competition in the Generation/Net Metering

It was felt that there are opportunities to reduce prices and dependence on oil by allowing greater private sector involvement in the generation of electricity. Consumers feel that significant benefits could accrue to the country if there was the proper framework that allowed for private individuals to generate electricity to satisfy their own needs first and then any excess sold to the national grid. The view was expressed that this co-generation would reduce the capital requirements of JPS to add capacity.

OUR Comments

The new regulatory regime which will begin in April 2004 will allow for competition in the addition of new generating capacity. Hence interested parties will be invited to bid for the opportunity to add new capacity and the least cost option will be accepted.

On the matter of Net Metering and Co-Generation, the Office has undertaken to develop the regulatory framework by the end of the fiscal year 2004/05.

4.2. Memorandum of Understanding (MOU) between the Government and Public Sector Employees

Throughout the consultative process, the recently signed Memorandum of Understanding (MOU) between the Government of Jamaica and public sector employees was a major topic of discussion. There were concerns that any increase in electricity rates could undermine the agreement as wages were limited to 3% over the next three years. It was felt that the country is at a critical juncture and the emerging spirit of cooperation is very fragile. It was felt that this cooperative spirit could be irreparably damaged by any increase in electricity rates. Consumers contended that utility companies including JPS should be made to “hold strain” for the next three years to show solidarity with the workers.

OUR Comments

The Office views this concern as legitimate but contends that this falls outside its regulatory purview. The Office would have wished to discuss the issue in some detail with the unions, but efforts to convene a meeting with the Joint Confederation of Trade Unions (JCTU), signatories to the Memorandum of Understanding (MOU) with the Government proved unsuccessful. The Office is disappointed that it was unable to harness the views of this important stakeholder but has taken into consideration opinions reported in the press and otherwise informally.

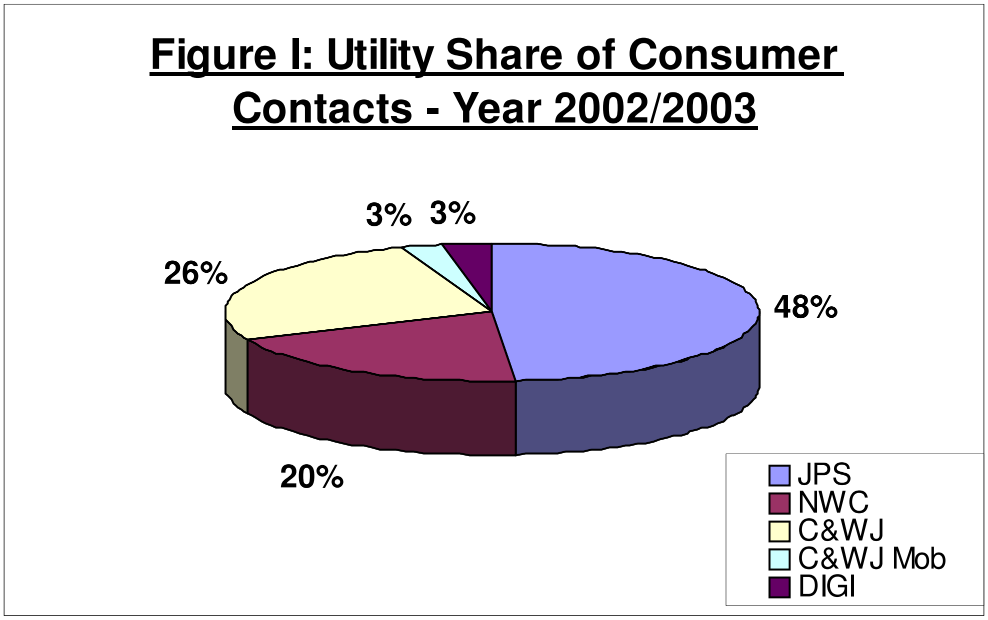
5. Customer service indicators - Comparative performance with other utilities

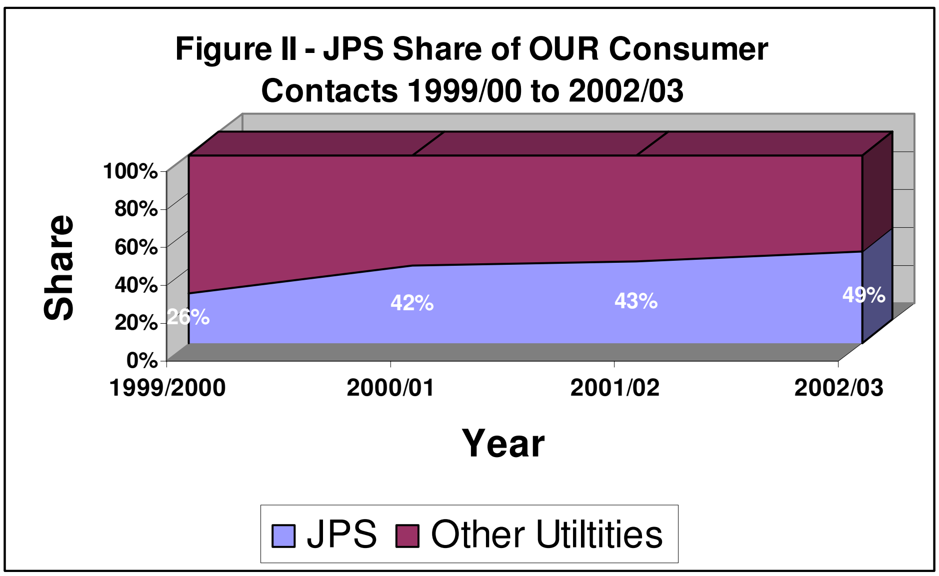
In addition to the views expressed during the public consultation regarding the tariff proposal, the performance of the JPS is also reviewed based on:

- Consumer contacts to the OUR and,
- OUR 2003 National Consumer Survey.

5.1. Consumer Contacts to the OUR

For the period January to December 2003, a total of 2,842 contacts were processed, which compares with a total of 2,656 for the similar period in 2002 and 1,833 handled in the 2001. JPS accounted for 48% of those contacts while in the previous year it accounted for 22%. Overall, since the 1999/2000, JPS share of contacts have consistently increased from 26% to 49% currently (*Refer to Figures I and II).*





In terms of the specific categories of complaints raised by consumers, a very high proportion of these continue to be about billing-related issues, the problem being of a greater significance for both JPS and NWC. Among the most frequently raised billing issues were high consumption, disputed charges and estimated billing.

Table 2: Contact Activity Summary (All Utilities)
January 2003 – December 2003

	DESCRIPTION	JPS	NWC	C&WJ	C&WJ Mobile	DIGI	GOTEL	TOTAL
A	Contacts for the Year:							
(i)	New Opinions	37	17	23	3	4	0	**84**
(ii)	New Referrals	1410	444	311	34	49	8	**2256**
(iii)	New Inquiries	76	26	43	0	7	1	**153**
(iv)	New Complaints	123	45	18	0	0	3	**189**
(v)	New Complaints - Pending Information	80	48	23	1	0	8	**160**
(vi)	New Complaints – Initiated by OUR	0	0	0	0	0	0	**0**
	Total contacts	**1726**	**580**	**418**	**38**	**60**	**20**	**2842**
B	Closure/Resolution of Complaints:							
(i)	Mutually Resolved	0	3	0	0	0	0	**3**
(ii)	Withdrawn by Customer	3	0	0	0	0	0	**3**
(iii)	Insufficient Information	43	32	15	1	0	14	**105**
(iv)	Outside of Jurisdiction	2	1	1	0	0	0	**4**
(v)	Resolved in Favour of Customer	21	14	9	0	0	1	**45**
(vi)	Resolved in Favour of Utility	40	33	7	0	0	0	**80**
	Total closures	**109**	**83**	**32**	**1**	**0**	**15**	**240**

Table 3: Distribution of Contacts by Utilities (January -December 2003)

Nature of Customer Concern	Utility						
	JPS	NWC	CWJ	CWJ Mobile	DIGI	GOTEL	Total
Billing Matters	1129	348	217	14	12	2	**1722**
Equipment Damage	143	0	1	0	0	0	**144**
Property Damage	16	3	0	0	0	0	**19**
Disconnection	67	30	17	0	2	1	**117**
Re-Connection	5	4	3	0	0	0	**12**
Redress Not Received	0	0	1	0	0	0	**1**
Irregular Supply	15	13	0	0	0	0	**28**
Unavailability of service	1	2	6	1	0	1	**11**
Payment Arrangement	19	1	4	0	0	0	**24**
Health and Safety	5	6	1	0	0	0	**12**
Poor Customer Service	17	3	5	2	5	0	**32**
Code of Practice	0	0	0	0	0	0	**0**
Unscheduled Interruption of Service	123	56	54	5	6	1	**245**
Metering	9	2	0	0	0	2	**13**
Service Connection	15	2	7	0	1	10	**35**
Guaranteed Standard	31	19	0	0	0	0	**50**
Community-wide	0	20	0	0	0	0	**20**

Security Deposit	16	2	30	0	0	0	**48**
Other	115	69	72	16	44	3	**319**
TOTAL	**1726**	**580**	**418**	**38**	**70**	**20**	**2852**

5.2. OUR 2003 National Consumer Survey

In November 2002 the OUR contracted the services of Market Research Services Ltd to conduct a survey among Jamaican consumers to assess among other things the performance of the OUR as well as the three regulated utility service providers. Data collection was done during February and March 2003. The sample included nine hundred and seventy (970) households and eighty two (82) commercial enterprises.

The survey attempted to measure the image of the three regulated utility service providers by asking consumers to indicate their agreement with a number of statements. While amongst households, NWC is considered to be the utility company that is *"doing a lot to help Jamaicans and Jamaica*", among commercial enterprise CWJ was selected. Similarly, when probed about which utility "*has been trying to improve quality of service*", more households indicated NWC, while more commercial enterprises indicated CWJ. On the matter of which utility is *"doing a lot to ensure customers have access to their services*", households felt JPS was doing the best job, while commercial enterprises indicated CWJ.

Table 4:
Consumers who are "Generally satisfied" with service:

	Rank		
Aspect of Service	**Satisfaction among Households**	**Satisfaction among Commercial enterprises**	**Overall**
Accuracy of bills	2nd	3rd	3rd
Timeliness of Bills	3rd	3rd	3rd
Professionalism of Staff	2nd	3rd	3rd
Reliability of Service	2nd	3rd	3rd
Knowledge of Staff	2nd	2nd	2nd
Speed in resolving problems	2nd	3rd	3rd
Ease of making	1st	2nd	2nd

contact by telephone			

* Extract from 2003 OUR National Consumer Survey

Satisfaction with various aspects of Service:
Consumers were asked to express their satisfaction with the various aspects of the service (see table 4) offered by the three main utility service providers. Based on the levels of satisfaction, the responses were then ranked in order of 1st being the utility customers were most satisfied with and 3rd being the utility with which customers were least satisfied. From table 4, of the three service providers, customers were least satisfied with the service of JPS, except for the "*knowledge of its staff*" and the "*ease of making contact by phone*".

Table 5:
Consumers who are "Generally satisfied" with service:

Utility	Satisfaction among Households	Satisfaction among Commercial Enterprises	*Average*
NWC	62%	56%	***59%***
JPS	46%	43%	***44%***
CWJ	36%	48%	***42%***

* Extract from 2003 OUR National Consumer Survey

Overall, of the three (3) regulated utility service providers, consumers were most satisfied with the service of NWC and least satisfied with the service of JPS (See Table 8).

5.2.1 Ranking of Areas which Utility Companies should Compensate Consumers For

As part of the survey, the standards for which customers may claim compensation, five (5) in total, were presented in a list to participants who were asked to rank each in order of importance and relevance to them. The standards evaluated included – no response to queries, no response to emergency calls, not carrying out repairs, disruptions in service without notification, no immediate reconnection after payment for outstanding bill made.

- The findings of this survey report "*disruptions in service without notification"* as the most frequently singled out as being the most important standard for compensation. 36% of consumers singled this standard out.

- The other two standards that make up the top three most important ones were *"no immediate reconnection after payment made"* – 21% and *"no response to emergency calls – 18%.*

Table 6:
Showing Importance Ranking of Standards for Compensation

Q. Please rank each of these in terms of their importance to you personally?

		1st	**2nd**	**3rd**	**4th**	**5th**
Disruptions without notification	%	**36**	17	16	19	12
No immediate reconnection after payment	%	**21**	20	15	16	29
No response to emergency calls	%	**18**	24	25	20	13
No response to queries	%	**14**	19	20	21	26
Not carrying out repairs	%	**11**	21	23	26	20

Note: where numbers do not add back to 100% this is due to rounding.

* Extract from 2003 OUR National Consumer Survey

5.2.2. Preferred Means for obtaining compensation under the "Claim Compensation" Program.

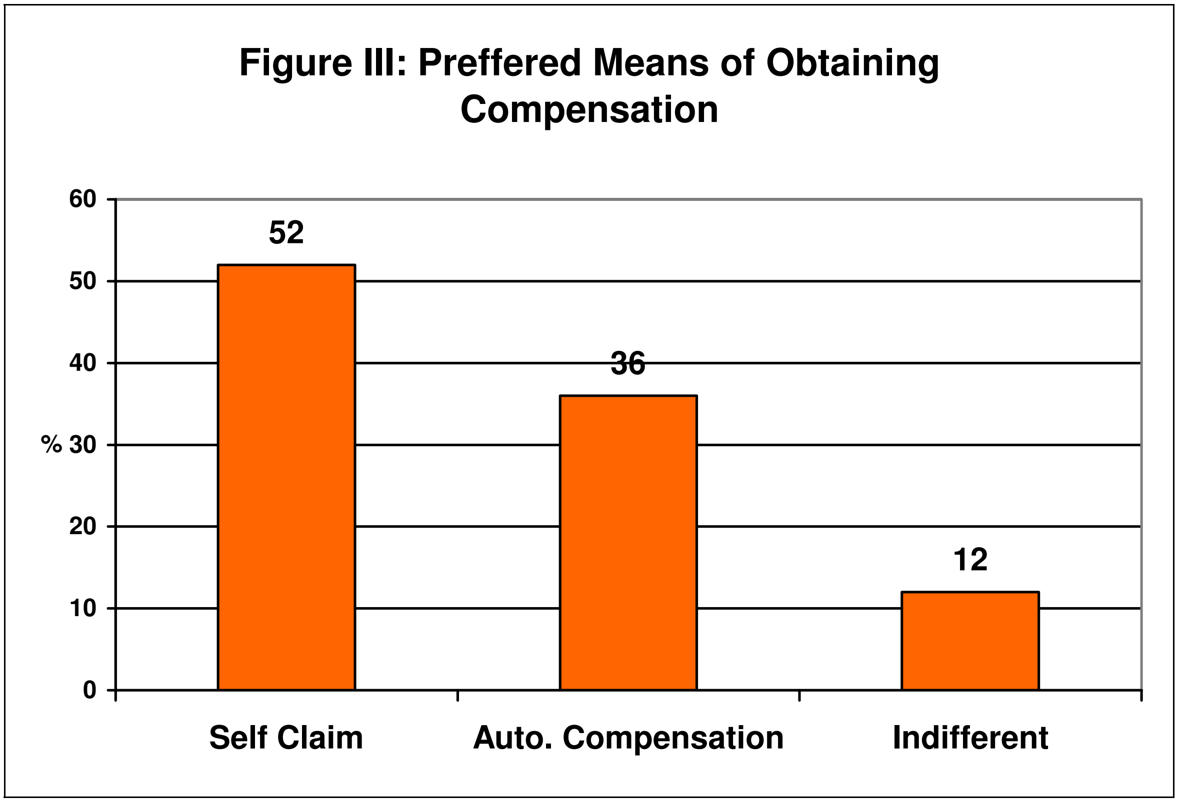
The survey also sought to determine whether or not consumers preferred to claim or be automatically compensated in the event a standard is breached.

- Fifty two percent (52%) of consumers say they would prefer to submit a claim for their compensation, under the Claim Compensation Program rather than be automatically compensated.

- While 36% would prefer an automatic compensation rather than having to submit a claim, 12% responded that they are indifferent.

- When the indifferent incidence is added to the 52% who would prefer to make the claim themselves, the survey suggest that 64% of Jamaicans could prefer to submit a claim under the Claim Compensation Program rather than be compensated automatically.

- Further, 48% could prefer an automatic system of compensation when the 12% indifferent are added to those who prefer to submit a claim.



* Extract from 2003 OUR National Consumer Survey

- When the idea that the amount of the compensation could be greater if the consumer submitted a claim directly instead of being compensated automatically was presented, the incidence that would prefer to submit the claim directly themselves rose to 71% from 52%. The incidence that would prefer an automatic compensation dropped from 36% to 24% while the incidence of indifference dropped from 12% to 4%.

6. Quality of Service Issues

6.1 Guaranteed Standards (2001-present)

In accordance with the requirements of the regulatory framework, JPS submits quarterly reports on its compliance to the guaranteed standards established in 1999. These reports have consistently been incomplete and as such there are limits as to the extent to which these reports represent the performance of the JPS. In tables 7 & 8, the figures for 2002 and 2003 do not include data for the second quarter (July – September 2002 & 2003).

JPS has not been reporting on what is considered to be one of the most important standard, EGS5 – Response to Customer Written Queries so there is no basis on which to judge its performance except that which can be garnered from contacts to the OUR and from the OUR 2003 National Consumer Survey (see section 5). In any event, a July 2003 audit of the JPS' system for the administration of the guaranteed standards suggest that there are weaknesses in the system as it relates to the completeness of the data collected. In other words, the audit suggested that the company is not capturing all the data regarding the standards in a systematic manner to allow for the generation of reports that are complete, accurate and reliable.

Notwithstanding, the data for 2001-2003 suggests that JPS has the most difficulty in meeting the standard for making complex connections to customers whose premises are further than 30 meters of an existing distribution line. The standard requires the preparation of estimates within 10-15 working days, which JPS achieves a 60% average compliance. The standard for actually making the connection within 30-40 working days after agreement with the customer, JPS averages 65% compliance. Over the period, JPS responded to 80% of emergency calls within the six (6) hour standard. With regard to compensatory payments, over the period customers have claimed a total of $1,350.00 of a possible $9,810,515.00 as compensation for breach of any standard.

Table 7
Compliance of JPS to Guaranteed Service Standards 2001-03 (JPS Reports)

Code	Focus	Description	Performance Measure	Compliance rate		
				2001	2002	2003
EGS 1(a)	Access	Connection to Supply - New Installations	New service Installations within 5 working days.	85%	90%	85%
EGS 1(b)	Access	Connection to Supply - Simple Connections	Connections within 4 working days where supply and meter already on premises	92%	86%	90%
EGS 2(a)	Access	Complex Connection to supply	Between 30 and 100m of existing distribution line			
			i- estimate within 10 working days	40%	56%	75%
			ii- connection within 30 working days after payment	63%	66%	78%
EGS 2(b)	Access	Complex Connection to supply	Between 101 and 250m of existing distribution line			
			i- estimate within 15 working days	55%	69%	66%
			ii- connection within 40 working days after payment	58%	71%	65%
EGS 3	Response to Emergency	Response to Emergency	Response to Emergency calls within 6 hours	77%	83%	81%
EGS 4	Billing Punctuality	Issue of First bill	Produce and dispatch first bill within 30 working days after service connection	87%	81%	86%
EGS 5(a)	Complaints/ Queries	Acknowledgements	acknowledge written queries within 5 working days	-	-	-
EGS 5(b)	Complaints/ Queries	Investigations	complete investigation within 30 working days	-	-	-
EGS 5(c)	Complaints/ Queries	Investigations involving 3rd party	complete investigation within 60 working days if 3rd party involved	-	-	-
EGS 6(a)	Reconnection	Reconnection after Payments of Overdue amounts - urban areas	Urban reconnection within 1 day	82%	78%	89%
EGS 6(b)	Reconnection	Reconnection after Payments of Overdue amounts - rural areas	Rural - reconnection within 2 days	-	-	-
EGS 7	Compensation	Making compensatory payments	Response to claim for compensation	-	-	-

Table 8
Potential compensatory payments of JPS under Guaranteed Service Standards 2001-03(JPS Reports)

Code	Focus	Description	Performance Measure	Potential Compensation payments 2001 ($)	2002 ($)	2003 ($)
EGS 1(a)	Access	Connection to Supply - New Installations	New service Installations within 5 working days.	609,300	292,950	112,750
EGS 1(b)	Access	Connection to Supply - Simple Connections	Connections within 4 working days where supply and meter already on premises	70,800	155,850	51,800
EGS 2(a)	Access	Complex Connection to supply	Between 30 and 100m of existing distribution line	534,600	216,900	32,100
EGS 2(b)	Access	Complex Connection to supply	Between 101 and 250m of existing distribution line	124,200	53,100	13,800
EGS 3	Response to Emergency	Response to Emergency	Response to Emergency calls within 6 hours	1,133,550	528,750	279,600
EGS 4	Billing Punctuality	Issue of First bill	Produce and dispatch first bill within 30 working days after service connection	1,364,715	1,622,600	397,600
EGS 6(a)	Reconnection	Reconnection after Payments of Overdue amounts - urban areas	Urban reconnection within 1 day Rural - reconnection within 2 days	1,053,450	1,026,300	135,800
Total				4,890,615	3,896,450	1,023,450

6.2. Overall Standards (2001-present)

Table 9
Target for Overall Standards (2001-present)

Code	Standard	Units	Targets Apr–Dec 2001 (inclusive)	Targets Jan-Dec 2002 (inclusive)
EOS1	Minimum of 48 hours prior notice of planned outages	Percentage of planned outages for which at least forty-eight hours advance notice is provided	100%	100%
EOS2	Percentage of line faults repaired within a specified period of that fault being reported	Urban – 48 hrs Rural – 96 hrs	100% 100%	100% 100%
+ EOS3	Number of complaints to JPS	Total telephone and written complaints per 10,000 customers per annum	245	230
EOS4	Average number of customer minutes lost	Average minutes lost per customer per annum	324	275
EOS5	Total number of customer minutes lost split into : - Generation - Transmission - Distribution	Total customer minutes lost per annum allocated between licensee's main areas of operation	29,872 61,109 70,563	To be adjusted at adjustment date
EOS6	Total system losses (difference between energy generated and energy for which revenue is received)	System losses as a percentage of total energy delivered to customers	15.8%	To be adjusted at adjustment date
EOS7	Frequency of meter reading	Percentage of meters read within time specified in the licensee's billing cycle (currently monthly for non-domestic customers and bi-monthly for domestic customers)	99%	99%
EOS8 (a)	Frequency of meter testing	Percentage of rates 40 and 50 meter tested for accuracy annually	50%	50%
EOS8 (b)	Frequency of meter testing	Percentage of other rate categories of customers meters tested for accuracy annually	20%	25%
EOS9	Billing Punctuality	98% of all bills to be mailed within specified time after meter is read	6 working days	5 working days
EOS10	Restoration of service after unplanned (forced) outages on the distribution system	Percentage of customer's supplies to be restored within 24 hours of forced outages in both Rural and Urban areas	98%	98%

6.3. Proposed Guaranteed Standards (2004-2009)

The Office intends to introduce new guaranteed standards for the duration of the tariff regime. To assure effective promotion, for the fist three years JPS will be required to:

- at least twice per year include in customers bills information on the guaranteed standards and how customers can claim for breach under these standards;
- at least once per quarter, include in the its regular weekly feature in the print media, information on the guaranteed standards;
- ensure that customer claim forms are readily available at JPS offices to facilitate consumers;
- make claim forms available to the OUR;
- adequately display the standards in all JPS customer service offices.

Table 10 – Proposed Guaranteed Service Standards 2004 -2009

Code	Focus	Description	Performance Measure
EGS 1(a)	Access	Connection to Supply - New Installations	New service Installations within 5 working days.
EGS 1(b)	Access	Connection to Supply - Simple Connections	Connections within 4 working days where supply and meter already on premises
EGS 2(a)	Access	Complex Connection to supply	Between 30 and 100m of existing distribution line
			i- estimate within 10 working days
			ii- connection within 30 working days after payment
EGS 2(b)	Access	Complex Connection to supply	Between 101 and 250m of existing distribution line
			i- estimate within 15 working days
			ii- connection within 40 working days after payment
EGS 3	Response to Emergency	Response to Emergency	Response to Emergency calls within 6 hours
EGS 4	Billing Punctuality	Issue of First bill	Produce and dispatch first bill within 45 working days after service connection
EGS 5(a)	Complaints/Queries	Acknowledgements	acknowledge written queries within 5 working days
EGS 5(b)	Complaints/Queries	Investigations	complete investigation within 30 working days
EGS 5(c)	Complaints/Queries	Investigations involving 3rd party	complete investigation within 60 working days if 3rd party involved
EGS 6(a)	Reconnection	Reconnection after Payments of Overdue amounts - urban areas	Urban reconnection within 1 day
EGS 6(b)	Reconnection	Reconnection after Payments of Overdue amounts - rural areas	Rural - reconnection within 2 days
EGS 7	Estimated Bills	Frequency of Meter reading	Should not be three (3) or more consecutive estimated bills (where company has access to meter). This changes to two (2) on September 1, 2006
EGS 8	Estimation of Consumption	Method of estimating consumption	An estimated bill should be based on the average of the last three (3) actual readings (first 6 bills of new accounts excepted)
EGS 9	Meter Replacement	Timeliness of Meter Replacement	Maximum of 20 business days to replace meter after detection of fault
EGS 10	Billing Adjustments	Timeliness of adjustment to customer's account	Where necessary, customer must be billed for adjustment within one (1) billing period of identification of error
EGS 11	Street Lighting Maintenance	Timeliness of repairs of street lights	Reported street lights failures must be repaired within 14 days. (Reports to be made by Local Authorities).

Code	Focus	Description	Performance Measure
EGS12	Compensation	Making compensatory payments	Response to claim for compensation within 45 days of verification of breach

6.3.1. Compensation for Breach of Guaranteed Standards

Compensation for breach of any of the guaranteed standards will be as follows:

Customer Class	Compensation
Domestic Rate 10 – Residential Service	$1,000
General Service Rate 20 – General service	$1,000
Power Service Rate 40 (all LV) – Power Service Rate 40A – Power Service Rate 50 (all MV)– Large Power	$8,400
Street Lighting Rate 60	$300 per lamp/month

Additionally, under the new tariff regime customers will still be required to submit a claim on the utility within thirty (30) working days of breach to be entitled to payments. All compensatory payments will be effected via a defined credit to customer's bill.

6.3.2. Reporting requirements for Guaranteed Standards

JPS will be required to submit quarterly reports to the OUR detailing its compliance to each standard, the resultant exposure due to non-compliance, compensation claims received and the actual compensation paid out to consumers. JPS shall also provide annual reports on its efforts to promote the guaranteed standards (i.e. bill stuffers, newspaper ads, etc).

6.4. Proposed Overall Standards

The Office is of the view that due to increased reliance on the call centre for customer service delivery, there must be standards regarding the quality of service offered by the call centre. These could include but not be limited to:

- all telephone calls that require a representative should be answered within 20 seconds,

- targets for the resolution of cases at the first point of contact ie all call centre representatives should be empowered to resolve the matter at that level,

- targets for the tracking of incomplete calls.

Table 11
Targets for Overall Standards (2004-2009)

Code	Standard	Units	Targets June 04 – May 09 (inclusive)
EOS1	Minimum of 48 hours prior notice of planned outages	Percentage of planned outages for which at least forty-eight hours advance notice is provided	100%
EOS2	Percentage of line faults repaired within a specified period of that fault being reported	Urban – 48 hrs Rural – 96 hrs	100% 100%
EOS3	System Average Interruption Frequency Index (SAIFI)	Frequency of interruptions in service	To be set June 2005
EOS4	System Average Interruption Duration Index (SAIDI)	Duration of interruptions in service	To be set June 2005
EOS4A	Customer Average Interruption Duration Index (CAIDI)	Average time to restore service to average customers per sustained interruption	To be set June 2005
EOS5	Total system losses (difference between net energy generated and billed energy)	System losses as a percentage of total energy delivered to customers	15.8%
EOS6	Frequency of meter reading	Percentage of meters read within time specified in the licensee's billing cycle (currently monthly for non-domestic customers and bi-monthly for domestic customers)	99%
EOS7 (a)	Frequency of meter testing	Percentage of rates 40 and 50 meter tested for accuracy annually	50%
EOS7 (b)	Frequency of meter testing	Percentage of other rate categories of customers meters tested for accuracy annually	7.5%
EOS8	Billing Punctuality	98% of all bills to be mailed within specified time after meter is read	5 working days
EOS9	Restoration of service after unplanned (forced) outages on the distribution system	Percentage of customer's supplies to be restored within 24 hours of forced outages in both Rural and Urban areas	98%
EOS10	Responsiveness of call center representatives	Percentage of calls answered within 20 seconds	90%
EOS11	Effectiveness of call center representatives	Percentage of complaints resolved at first point of contact	To be set June 2005

Code	Standard	Units	Targets June 04 – May 09 (inclusive)
EOS 12	Effectiveness of street lighting repairs	Percentage of all street lighting complaints resolved within 14 days	99%

6.4.1. Reporting Requirements for Overall Standards

JPS will be required to submit quarterly reports to the OUR detailing its performance relating to each standard. These targets will remain in force for the review period.

7. Conclusions

Since 2001, when the company was issued with a new Licence, there has been significant improvement in the reliability of service. One only has to reflect on the situation in 2001 and early 2002 where triple block load shedding was not an uncommon occurrence. However, the view is that this increased reliability might have been achieved at the expense of customer service and hence consumers are not receptive to the matter of an increase in rates at this time.

Consumers feel that the company is uncaring in its customer service efforts, especially as it relates to the handling of equipment damage claims due to poor voltage quality. Customers are also not confident in the accuracy of the bills produced by the company. Additionally, consumers feel that the company is still inefficient especially as it relates to dealing with losses due to theft. The consensus is that the company is not proactive in the reduction of these losses.

To this end conditions associated with the new tariff regime must address the matter of equipment damage, losses and meter reading. Incentive for customers to demand high quality service from the company ie Guaranteed Standards with the appropriate penalty must be provided.

In summary, the conclusions are as follows:

7.1. Electricity Theft

The levels of system losses due to theft are unacceptable. The Office condemns the practice of electricity theft and the tacit approval which society gives to it. While it is accepted that electricity theft is a symptom of a greater social problem, the Office is not satisfied that the company has expended its best efforts at tackling the problems. The Office is of the view that the strategic approach to loss reduction has not evolved to deal with the magnitude of the problem. The Office would urge the company to consider installing insulated secondary distribution wires in communities where there is a prevalence of illegal connections (throw-ups). Greater efforts also need to be expended by the JPS in engaging the society on the matter of electricity theft as it not only affects the quality of their product, but ultimately the price which consumers pay for electricity.

7.2. Meter Reading/Estimated Bills

While the Office is aware of the opinion that accounts should not be disconnected for non-payment of an estimated bill, it is of the view that the consumer does in fact consume the product and is liable to pay for that consumption. Although it seems that there is a lack of confidence in the reasonableness of estimated bills, the Office would not at this stage insist that the company forebears in disconnection for estimated bills, but it will insist that the company review the algorithm to ensure that the last three (3) **actual** readings are used. The company has to do what is necessary to foster customer confidence in the bill estimation process.

To this end, the OUR will introduce the guaranteed standards *EGS7 – Frequency of meter reading* and *EGS8 – Estimation of consumption* (see section 7.6 below)

The Office is supportive of the company's objective to phase out estimated bills but cautions that the benefits must be positive in relation to the costs. At the same time, the Office must insist that consumers provide for meters to be installed in locations that are easily accessible to JPS as per regulations and it will support reasonable initiatives taken by the company to secure compliance to this requirement.

Another factor that influences the variation in kwh consumption in the monthly billing is the variability associated with the "number of days" in the billing cycle. The Office is of the view that the company should consider a reorganization of its billing procedures so as to generate monthly bills based on a fixed number of days, perhaps 28 days.

7.3. Prepaid Meters

The offering of a prepaid option to customers is a position that the Office has been encouraging JPS to take since 1998. While the Office is of the view that the prepaid option will allow consumers to manage their electricity budgets, it will not necessarily deter those persons who believe they have a right to free electricity service.

7.4. Disruptions in Service

Interruptions in service will be addressed in the tariff by the Q-factor which will reward or punish the company depending on the achievement of certain targets. These targets will be based on the average frequency and duration of outages.

7.5. Customer Service

The OUR is aware of the concerns regarding customer service as JPS has consistently been the most complained about utility company since 2001 (see section 5). In an effort to address the customer service quality, the Office has proposed four (4) additional guaranteed standards. At the same time, the compensatory payment to be made to consumers upon verification of breach of the guaranteed standards has also been increased. Additionally, the Office proposes that due to increased reliance on the call centre for customer service delivery two new standards be added to the existing overall standards. (See section 7.6 & 7.7 below).

7.6. Guaranteed Standards

As a result of the consultative process, four (4) new guaranteed standards will be added while the compensation for breach increased to $1,000 for residential customers and four (4) times the applicable service charge for non-residential customers. Customers will be required to claim for compensation if they believe the company has breached a standard. Additionally, under the new tariff regime the company is expected to promote the standards extensively (see section 6.3). The four (4) new guaranteed standards (see table 10) are as follows:

- **EGS 7 - Frequency of Meter Reading** - JPS shall not render three (3) or more consecutive estimated bills (where it has access to the meter). JPS has committed to phase out estimated bills within two years. Effective September 2006 this Standard will be changed to not more than two (2) consecutive estimated bills.

- **EGS 8 - Estimation of Consumption** - An estimated bill must be based on the average of the last three (3) actual readings (first 6 bills of a new account excepted).

- **EGS 9 - Meter Replacement –** JPS shall replace a meter found to be faulty within 20 working days.

- **EGS 10 - Billing Adjustments -** JPS shall adjust a customer's account within one (1) billing period of identification of an error.

- **EGS 11 - Street Lighting Maintenance** - JPS shall repair each reported street light failure (as reported by the responsible local authority) within 14 days of receiving the report. [This standard will be implemented on September 1, 2004 on condition that the Office is satisfied that JPS and the local authorities have agreed on a protocol that will govern the arrangements between the parties. If asked, the Office would agree to broker the terms of such a protocol].

7.7. Overall Standards

For the most part, the overall standards remain unchanged except for some upward movement in the targets. In addition, four (4) new standards are added as follows (see table 11):

- **EOS4A – Customer Average Interruption Duration Index (CAIDI) -** average time to restore service to average customers per sustained interruption will be set June 1, 2005.

- **EOS10 - Responsiveness of Call Centre Representatives** - 90% of phone calls to the call centre are to be answered within 20 seconds. This becomes effective on July 1, 2004.
- **EOS11 - Effectiveness of Call Centre Representatives** - a target will be set on June 1, 2005 specifying the percentage of complaints registered

through the Call Centre that should be resolved as the first point of contact. (Monitoring of this standard will commence as of June 2005).

- **EOS12 - Effectiveness of Street Lighting Maintenance** - 99% of all street lighting complaints must be addressed and corrected within 14 days. This becomes effective July 1, 2004.

7.8. Security Deposits

The Office is of the view that the company should return deposits on good paying accounts. Good paying accounts are those whom the bills for the previous twenty four (24) months have been paid in full on or before the due date every time.

7.9. Equipment Damage

JPS has to develop a more customer friendly policy which allows customers an objective consideration for any damage suffered due to operational incidents over which the company should reasonably be expected to have control. This policy must state the nature and scope of the investigations the company conducts to arrive at its decision. The company must also give commitments regarding the time within which it will complete its investigations and communicate its decision to the customer. There is also the need for the company to have information available in its offices to consumers about exactly what they need to do in order to make a claim (e.g. a fact sheet showing date/time of incident, equipment damaged, electrician's report, repair estimates etc).

While the matter of recommending a technical specification for protection equipment should be a function of the Jamaica Bureau of Standards (JBS), the Office believes that JPS could engage the JBS in some joint effort to educate their consumers about the need for protection. The Office does not believe that the company should expose itself by explicitly recommending a particular brand or type of protective device.