Office of Utilities Regulation

Jamaica Public Service Company Limited Tariff Review for Period 2009-2014

Determination Notice

OFFICE OF UTILITIES REGULATION

September 18, 2009

DOCUMENT TITLE AND APPROVAL PAGE

DOCUMENT NUMBER: Ele 2009/04 : Det/03

1. DOCUMENT TITLE: Determination Notice- Tariff Review for period 2009 – 2014, Jamaica Public Service Company Limited (JPS)

2. PURPOSE OF DOCUMENT

This document sets out the Office's decisions regarding the rates and the mechanism for price control for electricity services provided by JPS, as well as performance and quality of service standards.

3. RECORD OF DOCUMENTS ON ISSUE

Document Number	Description	Date
Ele 2009/04 : Det/03	Decisions - JPS Tariff Review 2009-2014	September 18, 2009

4. APPROVAL

This document is approved by the Office of Utilities Regulation and the decisions therein become effective on October 1, 2009.

On behalf of the Office:

Ahmad Zia Mian
Director General

Date : September 18, 2009

Foreword

This document is in two parts. Part one presents the legal authority for the Office decision and sets out the specific determinations made by the Office in respect of its review of the Jamaica Public Service's (JPS) March 2009 tariff application. Part two summarizes the proposals made by JPS and outlines the Office's responses and the underlying rationale.

In arriving at it decision the Office has had extensive public consultation, engaged in ongoing discussions with JPS and where necessary and relevant has drawn heavily on best practices. The approach adopted reflects the objective of ensuring that the regime determined for the next five years provides incentives for the JPS to deliver real benefits to its customers through improved efficiency, better quality of service and expanded coverage.

The Office in its economic regulatory activities is committed to national development by creating an environment for the efficient delivery of reliable utility services to consumers while ensuring that service providers have the opportunity to make a reasonable return on investment.

DETERMINATION NOTICE

(Issued pursuant to Sections 11 and 12 of the Office of Utilities Regulation Act) as well as Condition 15 and Schedule 3 of the Jamaica Public Service Company Limited All Island Electric Licence 2001

IN THE MATTER OF THE OFFICE OF UTILITIES REGULATION'S REVIEW OF JPS TARIFF PROPOSAL OF MARCH 9, 2009

AND

IN THE MATTER OF JAMAICA PUBLIC SERVICE COMPANY LIMITED ALL ISLAND ELECTRIC LICENCE 2001

AND

IN THE MATTER OF THE OFFICE OF UTILITIES REGULATION ACT 1995 AS AMENDED BY THE OFFICE OF UTILITIES REGULATION AMENDMENT ACT 2000

TO: JAMAICA PUBLIC SERVICE COMPANY LIMITED
LICENCEE

WHEREAS the Minister in exercise of the powers conferred by Section 3 of the Electric Lighting Act and having regard to the recommendations of the Office of Utilities Regulation ("the Office") pursuant to Section 4 of the Office of Utilities Regulation Act 2000 as amended ("the Act") granted a Licence to Jamaica Public Service Company Limited ("JPS") entitled "Jamaica Public Service Company Limited All-Island Electricity Licence 2001" ("the Licence") authorizing JPS to generate, transmit, distribute and supply electricity for public and private purposes within Jamaica upon the terms and conditions set out in the said Licence. **AND**

WHEREAS Sections 11 and 12 of the Office of Utilities Regulation Act 1995 (as amended by the Office of Utilities Regulation Act 2000) provide as follows:

11. Power to fix rates.

11. (1) Subject to subsection (3), the Office may, either of its own motion or upon application made by a Licencee or specified organization (whether pursuant to subsection (1) of section 12 or not) or by any person, by order published in the *Gazette* prescribe the rates or fares to be charged by an approved organization in respect of its prescribed utility services.

(2) For the purposes of this section, the Office may conduct such negotiations as it considers desirable with a Licencee or specified organization, industrial, commercial or consumer interests, representatives of the Government and such other persons or organizations as the Office thinks fit.

(3) The provisions of subsections (1) and (2) shall not apply in any case where an enabling instrument specifies the manner in which rates may be fixed by a Licencee or specified organization.

12. Application by an approved organization to fix rates.

12. (1) Subject to subsection (2), an application may be made to the Office by a Licencee or specified organization by way of a proposed tariff specifying the rates or fares which the Licencee or specified organization proposes should be charged in respect of its prescribed utility services and the date (not being earlier than the expiration of thirty days after the making of the application) on which it is proposed that such rates should come into force (hereinafter referred to as the specified date).

(2) As respects a specified organization referred to in section 13 an application made under subsection (1) of this section shall take into account the provisions of section 13.

(3) Where an application by way of a proposed tariff is made under subsection (1) notice of such application and, if so required by the Office, a copy of such tariff shall be published in the *Gazette* and in such other manner as the Office may require.

(4) A notice under subsection (3) shall specify the time (not being less than fourteen days after the publication of the notice in the *Gazette*) within which objections may be made to the Office in respect of the proposed tariff to which the notice relates.

(5) Subject to the provisions of this Act, the Office may, after the expiration of the time specified in the notice under subsection (3), make an order either -

(a) confirming the proposed tariff without modifications or with such modifications as may be specified in the order; or

(b) rejecting the proposed tariff.

(6) If, after publication of the notice of an application in accordance with subsection (3), no order under subsection (5) has been made prior to the specified date, the proposed tariff shall come into force on the specified date.

(7) An order confirming a proposed tariff shall not bring into operation any rates or fares on a date prior to the date of such order." **AND**

WHEREAS Condition 2 paragraph 3 of the Licence provides as follows:

"Subject to the provisions of this Licence the Licencee shall provide an adequate, safe and efficient service based on modern standards, to all parts of the island of Jamaica at reasonable rates so as to meet the demands of the island and to contribute to economic development" **AND**

WHEREAS Condition 15 of the Licence provides as follows:

Condition 15: Price Controls

The Licencee is subject to the conditions in Schedule 3.

The prices to be charged by the Licencee in respect of the supply of electricity shall be subject to such limitation as may be imposed from time to time by *the Office*." **AND**

WHEREAS Schedule 3 Paragraph 2 (C) of the Licence provides as follows:

"…(C) **Rates Post May 31, 2004**

Non-Fuel Base Rate. The Licencee shall 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 revenue requirement shall be calculated using the following formula unless such formula is modified in accordance with the rules and regulations prescribed by *the Office*…." **AND**

WHEREAS the Test Year is defined in the said Schedule 3 of the Licence as comprising:

"… the latest twelve months of operation for which there are audited accounts and the results of the test year adjusted to reflect:

(i) Normal operational conditions, if necessary;

(ii) Such changes in revenues and costs as are known and measurable with reasonable accuracy at the time of filing and which will become effective within twelve months of the time of filing. Costs, as used in this paragraph, shall include depreciation in relation to plant in service during the last month of the test period at the rates of depreciation specified in the Schedule to this Licence. Extraordinary or Exceptional items as defined by The Institute of Chartered Accountants of Jamaica shall be apportioned over a reasonable number of years not exceeding five years; and

(iii) Such changes in accounting principles as may be recommended by the independent auditors of the Licencee…." **AND**

WHEREAS EXHIBIT 1 of Schedule 3 of the Licence provides as follows:

"The annual Performance-Based Rate-Making (PBRM) filing will follow the general framework where the annual rate of change in non-fuel electricity prices (dPCI) will be determined through the following formula:

dPCI = dI ± X ± Q ± Z

where:

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.'" **AND**

WHEREAS pursuant to the said Paragraph 2 (C) JPS submitted to the Office on March 9, 2009, an initial application for the recalculation of the Non-Fuel Base Rates. **AND**

WHEREAS the said application was not accompanied by the latest twelve months of operations for which there were audited accounts as JPS had requested an extension of time for the submission of the twelve month audited accounts ending December 2008, following its conversion from Jamaican currency denomination to US currency denomination. **AND**

WHEREAS in accordance with the powers vested in the Office by Sections 11 and 12 of the OUR Act as well as Condition 15 and Schedule 3 of the Licence, the Office hereby **MAKES THE FOLLOWING DETERMINATION which shall be applicable for the period October 1, 2009 to May 31, 2014**.

DETERMINATION

The Office has, in this determination, made adjustments to the non-fuel and fuel rates and incremental IPP rate charged by JPS. The overall effect on the customer's bill will therefore be the sum of the effects of the adjustments in these elements of the bill.

Allowed Non-Fuel Rates

With effect from October 1, 2009 the average Non-Fuel revenue to be recovered from customers by JPS shall be J$9.78 /kWh.

The average non-fuel tariff is derived from:

a. Two part tariff design using the marginal cost approach (Table 0-1 below shows the composition of this rate and the comparison between what currently obtains[1] and that determined by the Office.

b. The audited accounts for 2008 are determined as the 'test year'.

c. Non-Fuel Revenue requirement of J$ 31.86 billion to finance normal operational expenses, depreciation, taxation and amortization, to realize a reasonable return on investment for the 'test year" and special provision of J$1.13 billion to accelerate the loss reduction programme.

d. Billing determinant of 3,256 GWh. This includes 55% of the difference between the test year sales and the possible sales if the loss target was met. The "test year" sales were 3,179.7 GWh and energy loss is targeted at 19.5% for 2009/10.

e. A base Exchange Rate of US$1 = J$89

Table 0-1: The OUR Determined average Non-Fuel Rate

Rate	Description	Current IPP	Effective	Total	OUR	Non-

[1] Rates reflecting the annual adjustment clause in the Performance Based Rate-making Mechanism (PBRM)

		Increment (JMD/kWh)	Non-Fuel Rate (JMD/kWh)	Effective Non-Fuel Rate (JMD/kWh)	Determined Non-Fuel Rates (JMD/kWh)	Fuel Rate Increase
R10	Residential	0.22	10.22	10.44	11.87	13.7%
R20	General	0.22	11.41	11.63	13.52	16.2%
R40_STD	Power- Standard	0.22	6.87	7.09	7.91	11.6%
R40_TOU	Power - Time-of-Use	0.22	5.32	5.54	6.18	11.6%
R50_STD	Power - Standard	0.22	5.18	5.40	6.14	13.8%
R50_TOU	Power - Time-of-Use	0.22	5.62	5.84	6.64	13.7%
R60	Lighting	0.22	12.77	12.99	14.91	14.8%
JPS	**All customers**	0.22	8.43	8.65	9.78	13.1%

Note that Effective Rate includes adjustment from base tariff.

0.1.1. Rate Base and Weighted Average Cost of Capital

The OUR has determined that the rate base is J$49.29 Billion and that JPS' required return-on-investment (ROR) is 17.43%. The ROR is measured by the Pre-tax weighted average cost of capital (WACC) comprised of:

- Weighted Cost of Debt: 10.44%
- Nominal Cost of Equity: 16.00%
- Gearing: 48%
- Tax rate: 33 1/3%

Non-fuel Revenue Requirement

The OUR has determined the non fuel requirement to be $31.86 billion as provided in Table 0-2 below.

Table 0-2: Non –fuel Revenue Requirement (J$'000)

	JPS Proposed (J$'000)	OUR Determined (J$'000)
PPA Costs	5,740,899	6,011,059
Operating Expenses	13,693,013	12,154,180
Depreciation	4,219,529	3,631,289
Total Operational Expenses	**23,653,441**	**21,796,528**
Net finance costs (excl. long-term debt):		
Interest on short-term loans	179,690	364,746
Interest on customer deposits	77,372	179,032
Interest – other	12,396	
Int. Capitalised during construction (AFUDC)		237,274
Loan Finance Fees		130,673
Finance income	-269,658	-269,658
Total Other Expenses	**-200**	**642,067**
Other income	**-102,019**	**-102,019**
Self-insurance fund contribution	425,000	445,000
Gross up for taxes on SIF	212,500	222,500
Total Other Income	**637,500**	**667,500**
Return on Investment	**6,935,378**	**3,825,101**
Taxation	**3,467,689**	**1,912,550**
Long Term Interest Expenses	**3,047,058**	**2,304,027**
Revenue Requirement, net of credits	**37,638,847**	**31,045,755**
Less Carib Cement Revenue	-310,521	-310,521
Loss Reduction Fund		1,125,106
Adjusted Revenue Requirement	**37,328,326**	**31,860,340**

OUR Determined Non-Fuel Rate Schedule

The approved Non-Fuel base rates are shown in Table 0-3.

Table 0-3: Approved Tariffs for 2009

Rate Category		Customer Charge JMD/Month	Energy Charge JMD/kWh	Demand Charge JMD/kVA Standard and On-Peak	Demand Charge JMD/kVA Partial-Peak	Demand Charge JMD/kVA Off-Peak
	Residential					
R10_	First 100kWh	250.00	6.19			
R10_	Over 100 kWh	250.00	14.15			
R20_	**General Service**	550.00	11.99			
	Power Service					
RT40 (STD)	Standard Low Voltage	4,000	3.42	1,239.50		
RT40 (TOU)	Time of Use Low Voltage	4,000	3.42	697.87	545.38	52.61
RT50 (STD)	Standard Medium Voltage	4,000	3.24	1,115.55		
RT50 (TOU)	Time of Use Medium Voltage	4,000	3.24	619.75	483.41	49.48
RT60	**Street Lights & Traffic Signals**	1,500	14.83			

0.1.2. Global Price Cap for non-fuel tariffs

The price cap will be applied on a global basis. This means that the annual price adjustment factor will be applied to the tariff basket. The adjustment in each tariff will be weighted by an associated quantity for each element. The weighted average increase of the tariff basket should not exceed the annual price adjustment factor.

The base Non-Fuel tariffs shall be adjusted annually, as follows:

$b_1 = b_o [1 + dPCI]$

$dPCI = dI \pm X \pm Q \pm Z$

b_0 =Base non-fuel tariff at time period t = 0
b_1 = Base non-fuel tariff at time period t = 1

0.1.3. X-Factor

The productivity efficiency gain for JPS (X-factor) to be applied at the June, 2010 adjustment is 0%. The X-factor for the adjustment for June, 2011 and the adjustment for subsequent years shall be 2.72%.

0.1.4. Q-Factor

The Q-factor shall be zero at the June 2010 adjustment. Data on forced outages at both the feeder and sub-feeder levels shall be audited and analyzed in order to set baseline values for subsequent adjustments.

0.1.5. Z-Factor

A Z-Factor threshold of twenty million dollars ($20M) adjusted annually for Jamaican inflation shall apply.

0.1.6. Inflation Adjustment (dI)

The inflation adjustment formula (dI) to be used during the 2009 - 2014 tariff period shall remain.

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

Where:

Δe = 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

0.1.7. Fuel Cost Adjustment Mechanism

The actual fuel cost will be passed through as the fuel charge with efficiency modifications for heat rate and system losses. The efficiency factor to be applied to the fuel cost pass- through shall operate according to the following formula:

$$\textbf{Pass through fuel cost} = \textbf{Actual fuel cost} \times \frac{targeted\ heat\ rate}{actual\ heat\ rate} \times \frac{(1-actual\ losses)}{1-targeted\ losses)}$$

The OUR has determined that there shall be no cap on the fuel penalty / reward mechanism. The proposal of a one million US dollar (US$1M) cap on the fuel penalty/reward mechanism is therefore rejected.

0.1.7.1. Heat Rate

The billing heat rate target shall be set at 10,400 kJ/kWh for the price cap period but is subject to review and reset on the addition of new generation capacity to the grid during the price cap period.

0.1.7.2. Losses

The following are the OUR's determination on system losses:

- the new target for system losses is 19.5% to May 30, 2010 then 17.5% as of June 1, 2010 to May 30, 2011. Subsequent targets are to be determined at the Annual Tariff Adjustments exercise.

- the amount of 0.4 US c/kWh be set aside from the tariff for a special system losses fund that will be used specifically to implement Advanced Metering Infrastructure and other loss reduction technology.

- the rules for the administration of the system losses fund shall be determined by the OUR in consultation with the JPS. In addition, all withdrawals from the fund must be exclusively for system loss projects approved by the OUR.

- JPS shall be allowed to charge a rate equivalent to the prevailing interest rate on customer deposits on all sums associated with back-billing arising from the theft of electricity.

The system loss adjustment to be used in the derivation of fuel rates over the five-year period shall be $\{(1 - actual\ losses)/(1 - target\ losses)\}$.

0.1.7.3. Fuel charge

Table 0-4 Effect of new targets if applied to current fuel rate

	Fuel rate for September	Adjusted fuel rate for September Heat Rate @ 10,400 kJ/kWh and Target Losses @ 19.50%)	% change
Pure Fuel Charge (J$/kWh)	15.222	14.795	-2.80%
IPP surcharge (J$/kWh)	0.220	0.00	-100%
Fuel and IPP surcharge (J$/kWh	15.442	14.795	-4.19%

0.1.8. Overall effect of adjustments in tariffs

Rate	Description	Effective Rate (JMD/kWh)	OUR Determined Rate (JMD/kWh)	Increase %
R10	Residential	25.66	26.67	3.9%
R20	General	26.85	28.31	5.4%
R40_STD	Power- Standard	22.31	22.70	1.8%
R40_TOU	Power - Time-of-Use	20.76	20.98	1.1%
R50_STD	Power - Standard	20.62	20.94	1.6%
R50_TOU	Power - Time-of-Use	21.06	21.43	1.8%
R60	Lighting	28.21	29.71	5.3%
JPS	All Customers	23.87	24.58	3.0%

Note that effective rate includes adjustment from the base tariff and the current level of IPP surcharge. Due to the recalculation of the Non-Fuel rates the IPP surcharge that is currently included in the Fuel and IPP line on the bill will now be reset to zero.

0.1.9. Foreign Exchange Adjustment

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 monthly to the Non-Fuel base tariff only, using –
-

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

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} = monthly Billing Exchange Rate

0.1.10. Independent Power Producers' Non-Fuel Costs

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

a. Estimated base non-fuel IPP costs shall be embedded in the non-fuel charges.
b. Reconciliation shall be done monthly.
c. The surplus or deficit shall be returned or recovered over the kWh billed.

0.1.11. Time of Use (TOU)

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.)

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.

- The Office accepts the modification of the TOU by applying the weights of the respective TOU sale categories to the sales reported for these categories.

0.1.12. Reconnection Fee

The Office determines that the reconnection fee shall be increased from $1,441 to $1,500 with annual review for adjustments on 1st June based on the actual cost of undertaking reconnections in the preceding fiscal year.

Security Deposits

JPS shall continue the policy over this price cap period of returning 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.

Quality of Service Standards

The following Guaranteed Standards become effective on October 1, 2009:

Table 0-1: Guaranteed Standards

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 101m 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 5 hours –emergencies defined as broken wires, broken poles, fires
EGS 4	First Bill	Issue of First bill	Produce and dispatch first bill within 40 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	Reconnection	Reconnection after Payments of Overdue amounts	Reconnection within 24 hours **Attracts automatic compensation**
EGS 7	Estimated Bills	Frequency of Meter reading	Should NOT be more than two (2) consecutive estimated bills (where

Code	Focus	Description	Performance Measure
			company has access to meter).
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
EGS 9	Meter Replacement	Timeliness of Meter Replacement	Maximum of 20 working days to replace meter after detection of fault which is not due to tampering by the customer **Attracts automatic compensation**
EGS 10	Billing Adjustments	Timeliness of adjustment to customer's account	Where necessary, customer must be billed for adjustment within three (3) months of identification of error, or subsequent to replacement of faulty meter
EGS11	Disconnection	Wrongful Disconnection	Where the company disconnects a supply that has no overdue amount or is currently under investigation by the OUR or the company and only the disputed amount is in arrears. **Attracts automatic compensation**
EGS12	Reconnection	Reconnection after Wrongful disconnection	The company must restore a supply it wrongfully disconnects within 5 hours **Attracts automatic compensation**
EGS13	Meter	Meter change	JPS must ensure that a note is left at the premises and or utilize its text messaging service indicating the meter change including date of the change and meter readings at the time of change, reason for change and serial number of new meter
EGS14	Compensation	Making compensatory payments	Accounts should be credited within 45 days of verification of breach

0.1.13. Wrongful Disconnection

The standard is defined as follows:

- *The company commits a breach where it disconnects a customer's supply that has no overdue amount reflected on the associated account. This standard will also apply to accounts that are under investigation by the OUR or the company itself and on which the company is requested or has undertaken to place a hold on the disputed sum but disconnects the account prior to the OUR's or its own ruling on the matter and there were no outstanding sums owed beyond the disputed sum.*

0.1.14. Reconnection after Wrongful Disconnection

The standard is defined as follows:

- *A breach occurs where the company, after erroneously disconnecting a supply, fails to reconnect same within FIVE (5) hours of being notified or having itself detected the error.*

0.1.15. Changing Meters

The standard is defined as follows:

- *The company must provide customers with details of the date of change, reason for change, meter readings on the day and serial number of the new meter on the day of the meter being changed. This communication may be done via text message.*

0.1.16. Compensation

Compensation for breaches of the Guaranteed Standards shall be as follows:

General Compensation

1. For residential customers, a breach of a standard will result in compensation equal to the reconnection fee.

2. For commercial customers, the compensation will remain four times the customer charge**.**

3. Breaches will attract multiple payments up to four (4) periods.

Table 0-3 :
Compensation for Breach of Guaranteed Standards

Customer Class	Compensation
Domestic	
Rate 10 – Residential Service	$1,500
General Service	
Rate 20 – General service	$2,200
Power Service	
Rate 40 (all LV) – Power Service	
Rate 40A – Power Service	$16,000
Rate 50 (all MV)– Large Power	

Special Compensation

Wrongful Disconnection

1. ***Compensation for wrongful disconnection*** *will be TWO (2) times the reconnection fee for residential customers and FIVE (5) times the customer charge for Commercial customers.*

2. ***Reconnection after wrongful disconnection*** *standard when breached will attract compensation of TWO (2) times the reconnection fee for residential customers and FIVE (5) times the customer charge for commercial customers.*

Automatic compensation

The company will be required to automatically apply the necessary compensation to accounts for the following breaches:

- *Wrongful Disconnection*
- *Reconnection after Wrongful Disconnection*
- *Reconnection after Payment of Overdue Amounts*

- *Meter Replacement*

Automatic Compensation will be applicable where there is a breach which is brought to the attention of the company, as well as those breaches, which the company itself recognizes. Automatic compensation becomes effective January 4, 2010. Customers will be required to submit claims prior to the effective date.

- *Meter Replacement*

Automatic Compensation will be applicable where there is a breach which is brought to the attention of the company, as well as those breaches, which the company itself recognizes. Automatic compensation becomes effective January 4, 2010. Customers will be required to submit claims prior to the effective date.

0.1.17. Schedule of Overall Standards

For the under-mentioned three (3) Overall Standards the Office has determined that:

1. **GSO6** will not be merged with standard **OS2**

2. **OS7 -** The OUR/JPS and the Bureau of Standards Jamaica concluded Protocol, "Electricity Meter Testing in Jamaica". Benchmark target for testing be linked to the targets established in the protocol.

3. Momentary Average Interruptions Frequency Index (MAIFI) will not be included as an Overall Standard.

Table 0-2: Overall Standards (2004-2009)

Code	Standard	Units	Targets June 09 – May 2014
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 annually
EOS4	System Average Interruption Duration Index (SAIDI)	Duration of interruptions in service	To be set annually
EOS4A	Customer Average Interruption Duration Index (CAIDI)	Average time to restore service to average customers per sustained interruption	To be set annually
EOS6	Frequency of meter reading	Percentage of meters read within time specified in the Licencee'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
EOS 12	Effectiveness of street lighting repairs	Percentage of all street lighting complaints resolved within 14 days	99%

Reasons for Office Decision

&

Technical Analysis

Abstract

This determination of the Non-Fuel Rate Base (NFRB) for the Jamaica Public Service Company Limited (JPS) is made in accordance with the JPS All-Island Electricity Licence 2001 ("The Licence").

JPS is regulated by the OUR under an incentive-based regulatory framework, known as a price cap regime, introduced through the 2001 Licence.

Under the price cap mechanism, non-fuel base rates are set once every five (5) years. The Company is allowed to make annual rate adjustments between review periods for inflation and foreign exchange rate movements. Adjustments may also be allowed if events occur which are outside JPS' control and which affect the cost of operations.

The non-fuel base rate is used to recover costs associated with the operation and maintenance of the Company's regulated assets (the rate base) and its weighted average cost of capital. The price cap regime also includes a performance based rate adjustment mechanism (PBRM) in which non-fuel rates are adjusted annually based on a productivity offset for inflation and performance against quality of service targets set by the OUR.

The last non-fuel tariff rate adjustment was granted in 2004 for the period June 1, 2004 to May 31, 2009. To obtain new non-fuel tariff rates, the Licence stipulates that JPS is required to file a request with the OUR by the succeeding fifth anniversary of the last submission.

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Definitions

ABNF = Non-fuel base rate

ADC = Average Dependable Capacity

ADO = Automotive Diesel Oil

AMI = Advanced Metering Infrastructure

BAO = Best Alternative Option

CAPEX = Capital Expenditure

CAPM = Capital Asset Pricing Model

CIS = Customer Information System

CML = Customer Minutes Lost

CPI = Consumer Price Index

CRP = Country Risk Premium

CS = Consumer Surplus

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

HFO = Heavy fuel oil

IPP = Independent Power Purchase

IVR = Interactive Voice Response

IDT = Industrial Disputes Tribunal

J$ = Jamaican dollar

KVA = kilovolt-ampere

LCEP = Least Cost Expansion Plan

MAIFI = Momentary average interruption frequency index

MFP = Multifactor Productivity

MVA = Mega volt amperes

MW = Megawatts

MWh = MegaWatt-hours

NAC = Network Access Charge

NWC = National Water Commission

O & M = Operations and Maintenance

OCB = Oil circuit breakers

OPEX = Operating Expenditure

PEG = Pacific Economics Group, LLC

PPA = Power Purchase Agreements

PBRM = Performance Based Rate-making Mechanism

PRBO = Post Retirement Benefit Obligation

PT = Potential Transformer

RDC = Required Dependable Capacity

REP = Rural Electrification Programme Limited

ROE = Return on Equity

ROI = Return on Investment

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

SIF = Self-Insurance Fund

TFP = Total Factor Productivity

TOU = Time of Use

VAM = Volumetric Adjustment Mechanism

WACC = Weighted Average Cost of Capital

Chapter 1 Introduction

1.0 Background

JPS is a vertically integrated company and operates generation, distribution and 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 August 2007 Marubeni Caribbean Power Holdings acquired an 80% ownership stake and operating control of the company from Mirant Corporation. In February 2009, Marubeni announced that it had entered into an agreement with Abu Dhabi National Energy Company (TAQA) of the United Arab Emirates to transfer 50% of its equity stake in its Caribbean portfolio, which includes JPS. 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. Competition for generation was reintroduced after 31st March 2004.

1.1 JPS Rate Submission 2009

On March 9 2009, JPS submitted its proposals for a tariff review in accordance with the Licence. Delays in the presentation of the audited financials which are required to support the application, subsequent submissions and requests for extensions delayed the tariff review process. In the result, the new tariffs and regulatory framework, will take effect on October 1, 2009.

1.2 Regulatory Framework

The regulatory framework is described in the Licence.

The statutory framework within which the Office operates emphasises the importance of promoting efficiency, protecting the interests of customers and providing for the financial viability of the electricity service providers. The Office therefore has as its objectives that this 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 2009 to 2014 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

1.4 Purpose of this Document

This document details the analysis behind the Office's Determination on JPS' application for a tariff review. The approach to the analysis has four elements for the non-fuel prices – 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 details the analysis used to determine the financial, economic and technical aspects of the rate review. Section 2 summarises the issues raised by and on behalf of customers and consumers through the consultative process.

Section 1

- Chapter 2 provides a summary of JPS' proposal
- Chapter 3 provides a discussion 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 the "X" factor
- Chapter 8 discusses the methodology used for the determination of the Q-factor.
- Chapter 9 discusses the Fuel Cost Adjustment Factor –Heat Rate
- Chapter 10 discusses the Fuel Cost Adjustment Factor – System Losses
- Chapter 11 discusses the Pass-through of Independent Power Producers (IPP) costs
- Chapter 12 discusses Reconnection Fee
- Chapter 13 provides a description of the tariff design.
- Chapter 14 provides the structure of the tariffs to be charged

Section 2

- Chapter 15 provides an analysis and discussion on consumer issues and quality of service standards

Chapter 2 Summary of Proposals

2.1 Global Tariff Price Cap (Revenue Cap)

JPS proposed that the global tariff price cap be maintained allowing the Company the flexibility to rebalance tariff baskets at the annual adjustment.

2.2 Z- Factor Threshold

JPS proposed that the materiality threshold for the activation of the Z-Factor be set at $20 million representing the existing threshold of $13 million adjusted for inflation over the period 2004 – 9.

2.3 Tariff Design

JPS proposed a new tiered rate class structure for residential (rate10) and small commercial (rate 20) customers. Different service/ customer charges and energy charges would apply to the tiers. JPS posited that the redesign would be a more cost reflective tariff structure that applies a minimal increase to customers consuming at the lowest levels in rates 10 & 20. With this structure JPS argued that the company was attempting to keep electricity prices affordable to marginal and vulnerable customers. The new structure would introduce two tiers of service/customer charge for rate 10 customers and four tiers for rate 20 customers.

JPS proposed the following tiered rate structure:

- Rate 10 customer with consumption less than 100 kWh/month (1st tier)
- Rate 10 customer with consumption greater 100 kWh/month (2nd tier)
- Rate 20 customer with consumption less than 100 kWh/month (1st tier)
- Rate 20 customer with consumption of 101 – 1,000 kWh/month (2nd tier)
- Rate 20 customer with consumption of 1,001 – 2,000 kWh/month (3rd tier)
- Rate 20 customer with consumption above 2,000 kWh/ month (4th tier)

No change was proposed to the existing tariff design for Rate classes 40, 50 and 60

2.4 Cost of Capital

JPS proposed a pre-tax WACC of 23.08%. The ROE was calculated using the CAPM methodology and the long-term debt cost reflects the existing costs of debt for the utility plus the cost of acquiring an additional US$60M. A summary of how the pre-tax WACC of 23.08% was determined is provided below with a comparison to the adjusted pre-tax WACC for 2004.

PARAMETER	FORMULA	2004	2009
Cost of Debt	A	12.56%	11.47%
Rate of Return on Equity (ROE)	B	14.85%	21.63%
Tax Rate	C	33.33%	33.33%
Gearing Ratio	D=E/G	44%	44%
Long Term Debt (‘000)	E	15,420,557	26,537,000
Shareholder's Equity (‘000)	F	19,581,238	32,917,000
Total Capitalization (‘000)	G=E+F	35,001,795	59,454,000
Return on Equity	H=B*F	2,907,814	7,119,947
Taxation	I=H*0.5	1,453,907	3,559,974
Pre tax Return on Equity	J=H+I	4,361,721	10,679,921
Interest Expense	K=A*E	1,936,822	3,043,794
Post-tax WACC	L=D*(1-C)*E+(1-D)*B	12.00%	15.39%
Pre-tax WACC	M=D*E+(1-D)*B/(1-C)	18.00%	23.08%

2.5 Revenue Requirement

JPS proposed non-fuel revenue requirement of J$37.8B for the test year 2008. The revenue requirement included adjustments to reflect normal operating conditions. The table below provides a summary of the components of JPS’ proposed revenue requirement.

ITEM	VALUE (J$ '000)
PPA Costs	5,661,990
Operating Expenses	13,483,971
Depreciation	4,696,840
Total Operational Expenses	23,842,801
Net finance costs (excl. long-term debt):	(17,717)
Other income	(104,844)
Self-insurance fund contribution + taxes	637,500
Cost of Long Term Debt	3,043,794
Cost of Equity	7,167,966
Taxation	3,583,983
Revenue Requirement, net of credits	38,153,483
Less Carib Cement Revenue	(310,521)
Adjusted Revenue Requirement	37,842,962

Performance Based Rate Making Mechanism Components

2.5.1 X – Factor

3. Pursuant to the stipulations of the Licence, JPS submitted recommendations on an appropriate ***X***-factor. The Company retained the services of Pacific Economic Group (PEG) to undertake a total factor productivity (TFP) study to inform its recommendations.
4. The study calculated the expected TFP growth of JPS at 1.94% per annum based on the Company's average TFP growth since 2001. The TFP growth trend of the US economy at 1.53% and estimated the TFP growth for the Jamaican economy at zero using the weights specified in the PBRM for U.S. and Jamaican inflation of 0.76 and 0.24, respectively. The overall TFP growth for firms whose output price indexes are reflected in the price escalation measure was 1.16% (*i.e.* 0.76*1.53% + 0.24*0% = 1.16%).

Using these values as inputs in the formula stipulated by the Licence, JPS' proposed recommendation for the appropriate level of the ***X***-Factor was:

$X = 1.94 - (0.76*1.53+0.24*0) = 0.78\%$

Accordingly, JPS proposed an ***X*-**factor of 0.80% (0.78% rounded up) for the 2009 – 2014 price cap period.

2.5.2 Q-Factor

JPS proposed that the ***Q*-**factor should meet the following criteria:

- Provide the proper financial incentive to encourage JPS to continually improve service quality. It is important that random variations should not be the source of reward or punishment;
- Measurement and calculation of the ***Q***-factor should be accurate 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; and
- It should be symmetrical in application, as stipulated in the Licence.

JPS further proposed that Momentary Average Interruption Frequency Index (MAIFI) be excluded from the annual ***Q***-factor adjustment mechanism and that the OUR monitors MAIFI results during the period 2009 – 14. Additionally, JPS requested that Customer Average Interruption Frequency Index CAIDI be excluded from the ***Q***-factor measurement as of 2010 and that MAIFI be included in the Overall Standards.

2.5.3 Z- Factor Claims

JPS posited that it had made five Z-factor claims to date. These claims are listed in the table below:

Incident	Incident Date	Claim Date	Amount Claimed	OUR award Date	Amount Awarded
Hurricane Ivan Claim	Sep-04	Mar-05	$1.46B	Mar-05	$652.3M
2005 Tropical Storms	Jun - Nov-05	Mar-06	$193M	Jan-09	$90M
Hurricane Dean Claim	Aug-07	Mar-08	$1.21B	TBA	TBA
Tropical Storm Gustav	Aug-08	Dec-08	$256M	TBA	TBA
IDT Settlement (2008)	Jul-08	Mar-09	$3.5B	TBA	TBA

The Company highlighted its concerns about the risk it faces from hurricanes given the Determination of the OUR, which is under appeal.

JPS also highlighted the fact that in relation to the Industrial Disputes Tribunal (IDT) settlement made in 2008, the Company has made a separate **Z**-factor claim submission (March 2009). It underscored that while the current tariff submission does not specifically contemplate the impact of that separate claim it is relevant that the amount being claimed for recovery over the two-year period as a special **Z**-factor adjustment would amount to 6.75¢ per kWh. JPS has included this Z-factor amount in the overall analysis of the tariff impact. The tariff submission also assumes that the **Z**-factor charge in relation to Hurricane Ivan (currently 8.8¢ per kWh) comes to an end in June 2009.

JPS argues that, since the revenue requirement relates to normal operating expenses only, the **Z**-factor is designed conceptually to allow the Company to apply for the recovery of extra-ordinary costs that are legitimate operating expenses of the business, which were not contemplated in setting the tariffs.

Adjustments to the efficiency measures used in the fuel rate calculation

The mechanism used to calculate the fuel cost recovery on a monthly basis under the current tariff operates according to the following formula:

$$\text{Pass thru Fuel Cost} = \text{Fuel Cost Actual} * \frac{\text{Heat Rate Target}}{\text{Heat Rate Actual}} * \frac{(1 - \text{Losses Actual})}{(1 - \text{Losses Target})}$$

JPS proposed the introduction of a US$1 million cap on the fuel penalty/reward mechanism in conjunction with the application of the fuel efficiency measures, i.e. heat rate and system loss. Under this proposal there would be a symmetrical cap thereby reducing the upside or downside exposure of JPS in relation to fuel costs.

TOU

JPS proposed a modification to the derivation of the monthly fuel rate, to take account of the fact that Time of Use (TOU) customers are not billed at the standard fuel rate. The proposed modification would be done by applying the weights of the respective TOU sale categories to the sales reported for these categories. This would ensure that the standard rate is properly adjusted for the discount/premium charged to TOU customers and that the full cost of the applicable fuel amount is properly recovered through the energy sales in the subsequent month in conjunction with the use of the volumetric adjustment mechanism (VAM).

Heat Rate Target

JPS proposed that based on the planned mix of generating units, including IPPs, their projected availability and dispatch, and the possible variation in heat rate for reasons beyond JPS' control, a two stepped reduction (improvement) to the heat rate target for the period 2009 – 2014 be determined, as follows:

- An initial 3.1% reduction to 10,850 kJ/kWh for the period July 2009 – June 2010;
- A further 1.4% reduction to 10,700 kJ/kWh for the period July 2010 – June 2014 (contingent on the 60 MW JEP expansions).

The second step 150 kJ/kWh reduction in the heat rate target would be implemented only if the JEP 60 MW expansion was expected with certainty by August 2010. If not, it would be implemented in the month after the JEP 50 MW expansion is commissioned, or on a prorated basis for each 10 MW of capacity that is commissioned. So, if 30 MW were commissioned the target would be reduced by 30/60ths of 150 kJ/kWh or by 90 kJ/kWh.

JPS is further requesting that the heat rate target be set for the five-year tariff period. However, they would agree to the revision of the heat rate target if any major fuel diversification project (i.e. CNG or Petcoke) is commissioned into service during the price cap period.

System Losses Target

JPS promised to intensify its battle against losses on both the technical loss and commercial loss sides. They are proposing to reduce system losses from 22.9% (at the end of 2008) to 18.3% over the rate cap period primarily as a result of its ongoing loss reduction initiatives. This represents almost a 1% point reduction per annum for the next five years as the result of a cumulative CAPEX and O&M spend of approximately US$45M. JPS therefore proposes a reset of the system loss target with a reduction over the tariff period as in the schedule below. The proposal includes the application of a stretch target of 2% on the projected losses outturn.

Parameter	Actual	Forecast					
	Dec-08	**Jun-09**	**Jun-10**	**Jun-11**	**Jun-12**	**Jun-13**	**Jun-14**
Projected System losses	22.9%	22.5%	21.5%	20.5%	19.7%	18.9%	18.3%
Stretch target		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Proposed Losses Target		**20.5%**	**19.5%**	**18.5%**	**17.7%**	**16.9%**	**16.3%**

The breakdown of the targeted system losses is provided below:

Parameter	Actual	Forecast					
	Dec-08	**Jun-09**	**Jun-10**	**Jun-11**	**Jun-12**	**Jun-13**	**Jun-14**
Non-technical losses	13.0%	12.9%	12.2%	11.4%	10.8%	10.2%	9.8%
Technical losses	9.9%	9.6%	9.3%	9.1%	8.9%	8.7%	8.5%
Total losses	**22.9%**	**22.5%**	**21.5%**	**20.5%**	**19.7%**	**18.9%**	**18.3%**

Sales Forecast (See Annex D for complete details)

JPS forecasts sales growth for the tariff reset period (2009 – 2014) at 0.8% per annum. This forecast is marginally lower than the average growth rate of 1.1% for the period 2004 – 2008. This is a reflection of the negative economic outlook for the economy over the first half of the period.

Base Exchange Rate

JPS proposed a base-exchange rate of US$1 = J$85

FX Adjustment Factor

JPS proposed that the FX adjustment factor for the monthly FX billing adjustment and the annual FX/inflation adjustment factor be reset from 76% to 79%.

Depreciation

Based on a commissioned study, JPS is requesting adjustments specifically for assets that currently have a useful life that is 10 years (or more) over the sample mode of the Companies in the study.

A summary of the asset categories, the current useful lives in years, the mode of the sample and the excess are highlighted below.

Activity	Asset Category	JPS	Sample Mode	Difference
Generation	Hydro Production Plant	30	20	10
Distribution	Test Equipment	25	15	10
Distribution	Supervisory Control System	25	15	10
General Plant	Electronic Equipment	25	5	20
General Plant	Communication Equipment	15	5	10
General Plant	Computer Equipment	20	5	15
General Plant	Furniture & Office Equipment	20	10	10

Reconnection Fee

JPS is allowed to charge a reconnection fee to customers disconnected for non-payment based on the actual cost of reconnection activities plus a service charge. The fee currently being charged is $1441.

JPS calculated the unit costs of reconnections using 2008 data and proposes an increase in the reconnection fee to $2,036. JPS proposed that the revised fee be implemented on July 1, 2009 to coincide with the new tariffs.

Quality of Service Standards

The following modifications to the Guaranteed and Overall Standards were proposed:

1) GS02 - Complex Connections:

    a. Estimates within 15 days; connections within 35 working days after payment

    b. Estimates within 15 days; connections within 45 working days after payment

2) GS10 - Billing Adjustments

    "Billing Adjustments: Timeliness of adjustment to customer's account - where necessary, customer must be billed for adjustment within 2 billing periods after conclusion of investigation of billing error.

3) GS11 – Timeliness of repairs of streetlights

    GS11 measures the same performance target as Overall Standard OS11 is redundant and should be removed.

4) OS2 (a) & OS2(b)

    Similar to GSO6, JPS adopted a non-discriminatory policy in respect of OS2 (a) and (b) and configured our operations to comply with the more aggressive 48 hour restoration standard for all our customers. It is therefore proposed that this standard be united at 48 hours.

5) OS7 (b)

    In December 2005 the OUR/JPS and the Bureau of Standards Jamaica concluded a Protocol, "Electricity Meter Testing in Jamaica". The Protocol includes provision for the sample testing of meter lots and groups. It is proposed that the benchmark target for testing be linked to the targets established in the protocol.

6) MAIFI

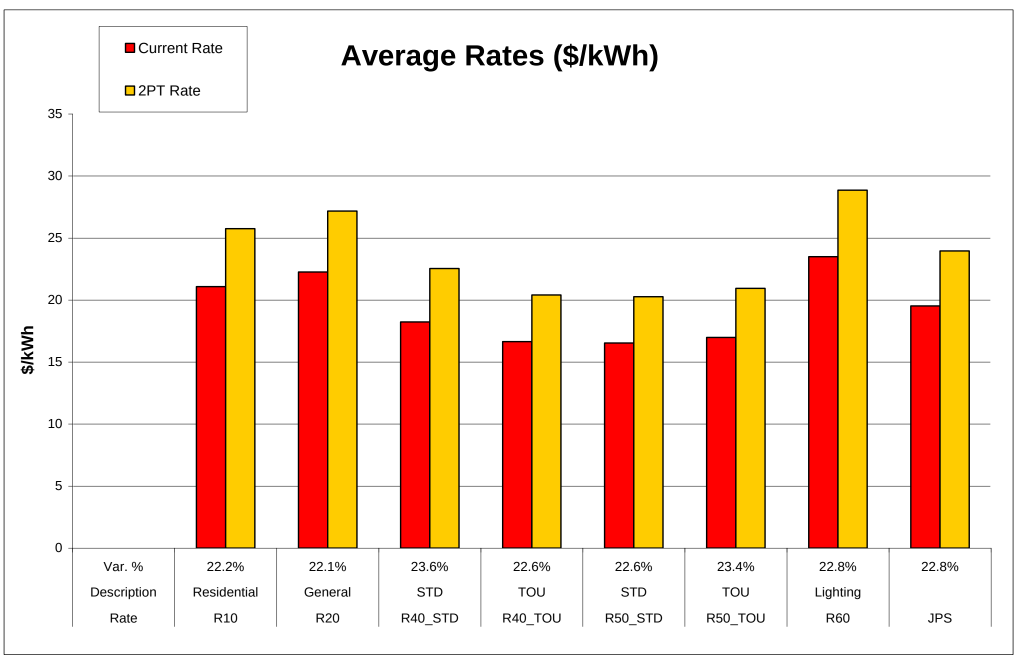
JPS proposed that Momentary Average Interruptions Frequency Index (MAIFI) be included as an Overall Standard.

Summary of JPS's Proposed New Tariff Rates

				Demand Charge $/kVA		
Rates	**Description**	Customer Charge $/Month	Energy Charge $/kWh	STD and On-Peak	Partial-Peak	Off-Peak
R10_1	0 - 100 kWh/month	190.00	6.20			
R10_2	100 - 500 kWh/month	475.00	17.65			
R10_3	> 500 kWh/month	475.00	17.65			
R20_1	0 - 100 kWh/month	475.00	8.38			
R20_2	100 - 1000 kWh/month	955.00	14.80			
R20_3	1000 - 3000 kWh/month	2,385.00	14.80			
R20_4	> 2000 kWh/month	4,775.00	14.80			
RT40 (STD)		10,956.03	5.23	1,444.91		
RT40 (TOU)		10,956.03	5.23	813.52	680.21	61.33
RT50 (STD)		10,956.03	4.94	1,369.44		
RT50 (TOU)		10,956.03	4.94	779.90	606.05	42.75
RT60	Streetlight	9,064.61	16.93			

Bill Impact

JPS proposed an overall tariff adjustment that would have an average bill impact of 22.8% on electricity rates as shown below.



This would result in an increase (total bill impact) from 4.3% for a tier 1 residential customer to 26.8% for a tier 4 commercial customer.

Chapter 3 Tariff Setting –Principles and Procedures

3.1 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 All-Island Electricity Licence, 2001.

3.2 General Principles

In power sector, tariff setting is a vital process of resource management for the utility's survival and growth and delivery of efficient service to consumers. An important factor, which has material bearing in pricing of electricity, is that it cannot be stored to meet fluctuations in demand. Additionally the service is intangible nature.

A utility is expected to pursue, besides profit, other objectives like consumer service, technological excellence, growth and human resources development. These multiple objectives are to be harmonized without affecting commercial viability. The choices thrown up while designing the tariff are difficult and costly to reverse and the decisions have far-reaching and long-term implications for a utility, consumers and the Country.

3.3 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[2] is allowed to increase at a rate that is no more than the inflation rate, usually as measured by the consumer price index.

[2] 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).

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 Office reviews the tariff adjustment formula every 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, 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.

Key issues in defining a price cap mechanism are how the rate of allowed inflationary movement 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 potential 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 can obtain a share of these benefits through price adjustments or higher values of X.

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.[3] 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.

3.4 Second Price Cap Tariffs

With respect to the set of prices now being introduced, the Office reviewed a 'Test year' comprising the latest twelve months of operation for which there are audited accounts and the results of the test year adjusted to reflect:

1. Normal operational conditions, if necessary
2. Such changes in revenues and costs as are known and measurable with reasonable accuracy at the time of filing and which will become effective within twelve months of the time of filing.
3. Such changes in accounting principles as may be recommended by the independent auditors of JPS

The existing pricing regime came into effect on June 01, 2004. Annual revenue requirements for the test year 2003 were estimated using a "building blocks" approach. Tariffs were set at a level to allow the company to earn enough revenue to cover costs including a reasonable return on capital. Tariffs are allowed to escalate based on movements in inflation and the foreign exchange rate with an off-set for efficiency.

In this review the Office examined JPS' current costs of operation to ensure that the initial cost base reflects a reasonable balance between the commercial interests of the company and that of the consuming public. In carrying out this exercise the Office focused on the efficient costs of providing the service and JPS' need for revenues that will recover the costs incurred.

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

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

$$\mathbf{dPCI = dI \pm X \pm Q \pm Z} \text{ ....equation (1),}$$

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

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., 2008) tariffs; thereby deriving revised weighted average tariffs for 2009 ($ABNF_{2009}$), as follows:

$$ABNF_{2009} = ABNF_{2008} * (1 + A) \ldots \text{Equation } \mathbf{(2)}$$

Where:

$ABNF_{2009}$ = the weighted average of approved tariffs being applied in 2009

And

A = a factor determined by the Office prior to commencement of the 2009 - 2014 regulatory control period which indicates the extent to which the current weighted average tariffs requires adjustment in order to form an appropriate basis for tariffs in the 2009 -2014 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).

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.

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

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 2009 - 2014 regulatory control period in accordance with equation (3) but at the same time to satisfy the constraint at equation (1).

Each year during the 2009 -2014 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 *structure* of its tariffs, provided that:

- 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.
- 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.

These changes should be consistent with the Pricing Principles outlined in Schedule 3 of the Licence. The Office will only intervene where it considers that the proposed change/s in structure is/are inconsistent with the approved Pricing Principles and Licence conditions and where in its judgment the proposed rates will result in rate shocks.

System Losses

JPS non-technical system losses are unacceptably high. These losses are mainly due to theft and billing anomalies. The Office is of the opinion that a major focus on this problem and the application of increased resources would result in gains for both the company and legitimate consumers. It is agreed that Government, and specifically Members of Parliament and Parish Councilors' support would greatly enhance the company's efforts. The anticipated savings/earnings from the reduction of system losses and performance improvements efforts of JPS are accounted for in the determination of the revenue requirement.

Chapter 4 Weighted Average Cost of Capital

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. The WACC is computed by finding the weighted average return on the 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.

In order to calculate the return on equity, the Office has used the Capital Asset Pricing Model (CAPM). The local capital market is fairly thin with only two utilities listed and therefore the approach used is to determine what a US investor would require in that market and adjust for the relative country risk of making the investment in Jamaica.

In deriving the cost of capital, consideration is given 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 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).

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

Capital Structure

The capital structure consists of the combination of different securities issued by the firm to fund capital projects and other aspects of its operation. In deriving the WACC the weights (i.e., W_d and W_e) of debt and equity are determined from the gearing ratio. The Office identifies an optimal capital structure from benchmarking comparable utility companies and establishes the cost of capital on that deemed combination of debt and equity.

In the 2004 Determination, the Office determined that a gearing of 48% is appropriate and JPS was expected to achieve this level by 2009. The Office now determines that the gearing to be used in this 2009 review is 48%.

Determination of the WACC Parameters

4.2.1 Risk Free Rate

The calculation of the cost of debt and the cost of equity both contain the estimate of the risk-free rate, i.e., the rate at which lenders would provide funds if there was no risk of default.

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 risk-free rate is estimated from the yield on government debt from a developed economy with well-established and liquid capital markets. Table 1 below provides an overview of nominal yields on 10-year government bonds for the USA. The OUR is of the view that the 10-year US Treasury bond is the appropriate measure of risk free rate to be used in the analysis of JPS WACC as its assets are valued in US dollars and its revenue stream is adjusted for foreign exchange movements against the US dollar.

Table 4. 1: Nominal government yields

	Past 12 months up to April 2009
USA Government Yield	3.36%

Source: Federal Reserve,

3.36% is the latest US Treasury bond yield as at April, 2009 and this represents the nominal risk free rate used in the derivation of the cost of equity. The Office determines that 3.36% is the value for the international nominal risk-free rate that is used to calculate the cost of equity.

A 10-year treasury bond is used as indicated. The time to maturity for these bonds is quite long, so the anticipated drop in yield as maturity is approached should not affect the results. Also the International bond market is accepted as having strong liquidity in any of these bonds.

4.2.2 Country Risk Premium (CRP)

There are numerous sources for data on the country risk premium (CRP). These sources of data are explored below.

4.2.3 Yield curve difference

The yield on Jamaican US$ denominated Treasury which are traded in Jamaica were sourced from the Bank of Jamaica. These yields can be compared to the USA Treasury bond data for US$ denominated bonds traded in the USA. The difference in the yields between these two sets of yield data is used to infer an estimate of the country risk. This is the premium expected by current investors for investing in Jamaica as opposed to investing in the USA. This premium known as Country Risk Premium (CRP) excludes a return to compensate for the exchange rate risk of converting Jamaican dollar to US$, because the bonds are both denominated in US$. The primary assumption is that the Jamaican US$ denominated bonds have sufficient liquidity.

The OUR is of the view that for the purpose of determining CRP, bond yields should be assessed over a period of time as opposed to a single instance as this method is more reasonable for setting return on equity. A statistical approach is used to estimate a series of monthly yield curves from the GOJ Global Bond yield rates for the period April 2008 to April 2009. The bond tickers are of varying maturity dates and differing coupon rate. The 10-year yields were derived from the series of yield curves estimated from the series of yield and maturity data. This 10-year yields were estimated from the yield curve since for the period there was no GOJ US$ denominated bond with 10-year maturity.

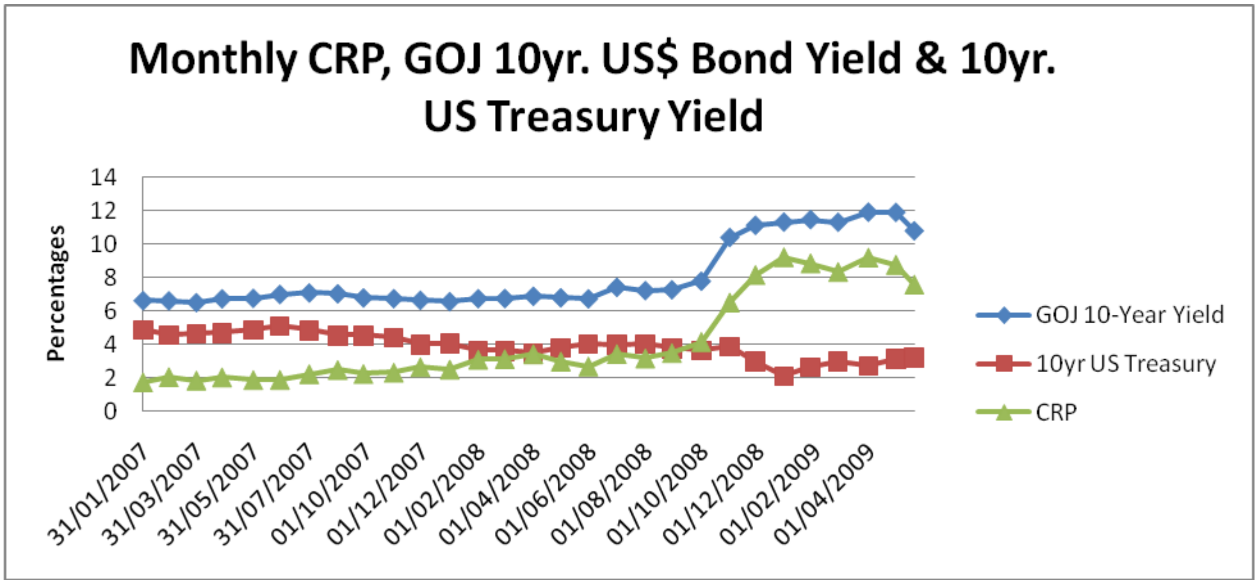
Table 4.2 shows the country risk premium which is the difference between yield to maturity of GOJ 10- year bonds estimated from the yield curves and 10 year US Treasury bonds.

Table 4.2 **Country Risk Premium**

Dates	GOJ 10-Year Yield	10yr US Treasury	CRP
30/04/2008	6.80	3.80	3.00
30/05/2008	6.74	4.03	2.71
30/06/2008	7.43	3.98	3.45
31/07/2008	7.23	4.04	3.19
29/08/2008	7.28	3.77	3.51
30/09/2008	7.79	3.62	4.17
31/10/2008	10.40	3.89	6.51
28/11/2008	11.13	2.98	8.15
29/12/2008	11.32	2.11	9.21
27/01/2009	11.47	2.62	8.85
26/02/2009	11.31	2.98	8.33
31/03/2009	11.91	2.72	9.19
30/04/2009	11.90	3.14	8.76
Average	**9.44**	**3.36**	**6.08**

Figure 4.3 shows the yield difference plotted against time to maturity. The average of the ten 10-year yield differences is 6.08%, which is the more representative estimate of the CRP for Jamaica as at the end of April 2009 for the ensuing five years.

Figure 4.3 Yield curves for 10 year bonds



4.2.4 Conclusion on CRP

The CRP represents the additional risk of investing in Jamaica US-Indexed Bond versus investing in US bonds with the same maturity. The CRP is derived by estimating a 10-year yield curve for current Jamaica US$ denominated Index bond using monthly data from March 2008 to April 2009 average bid and ask yield rate, and the yield on 10-year US Treasury bonds. This estimate is 6.08% i.e (9.44%-3.36%), which represents the CRP specific to Jamaica.

Return on Equity

The OUR is satisfied that for the 2009 review it should employ the most widely used methodology for estimating the cost of equity, which is the capital asset pricing model ("CAPM"). The CAPM is calculated from the following factors:

$$R_e \quad = \quad rf + \beta\ (rm - rf)$$

Where:

rf = the risk-free rate;

β = the measure of relative risk of the industry; and *rm* = is the expected return on the equity market. The difference between the market return and the risk-free rate is known as the equity or Market risk premium ("MRP").

This simplifies to:

$$R_e = rf + \beta\ MRP$$

The following sub-sections set out the Office's determination on each of these factors.

4.2.5 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 Marubeni 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 privatization 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.

The Market Risk Premium, $(R_m - R_f)$ is estimated from the difference between the risks of the market minus the Real Risk Free rate. The 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 Office has determined that the U.S. Treasury bonds represent the risk free rate and the basket of shares must be the basket of U.S. shares. The OUR adopted the Standard and Poor's 500 Index (S&P 500 Index). In the previous determination, the OUR used a forward-looking projection of the market risk premium (MRP). The projection for this parameter was set at 8.2% and was equal to the difference in the forecast growth in the S&P 500 Index and the US 10-year Treasury bond yield in 2004.

In light of the structural changes that the World and the US economy are undergoing, analysts have revised their projections with respect to the share prices. Recent research and analysis (see table below) have indicated the long-term peak-to-peak annualized earnings growth rate for the S&P 500 is approximately 10.9%, Thus, Office has determined a mean earnings growth rate of 10.9%, with a standard deviation of 2.5%, The table below outlined the expected 10-Year return on the S&P 500 and the probability distribution.

Intrinsic Value and Expected Return Deciles for the S&P 500		
Decile	S&P 500 Intrinsic Value	10-year E[Return]
0%	210	-4.40%
10%	450	3.00%
20%	565	5.40%
30%	660	6.90%
40%	740	8.10%
50%	830	9.00%
60%	900	9.90%
70%	985	11.00%
80%	1090	12.10%
90%	1230	13.50%
100%	1700	17.10%

Source: John P. Hussman, Ph.D(http://seekingalpha.com/article/125278-estimating-the-intrinsic-value-distribution-of-the-S&P 500, March 11, 2009

The Market Risk Premium, (R_m – R_f) of 7.54% is estimated from the difference between the risks of the market using the S&P expected return minus the nominal Risk Free rate, that is, (10.90% -3.36%)

4.2.6 [4] Equity Beta (β_{Ei}) Estimation

The OUR adopted the methodology of Alexander, Mayer and Woods (World Bank Working Paper #1698). They reported results from an international survey. Asset beta of 0.57 was reported for companies under high powered (price cap) regimes and 0.41 under intermediate regimes. This compares to about 0.35 under the lowest powered -- rate of return – regimes.

JPS is currently in a price cap regime for non-fuel tariffs in which tariffs are adjusted every year but they are not guaranteed any specific rate of return. Fuel costs and Independent Power Producers (IPPs) costs are passed through subject to efficiency adjustments. JPS falls in between a high power rate of return and intermediate tariff regime. There is a considerable amount of pass through in the tariff structure and the OUR is specifically required to ensure that JPS can fund future investments.

Average asset beta values by regulatory regime and electricity sector

	Average beta
High-powered	0.57
Intermediate	0.41
Low-powered	0.35

Source: World Bank Policy Research Working Paper 1698

Asset beta was calculated based on a weighting of 75:25 for intermediate to low-powered firms. This weighting estimate asset beta is to be used for JPS cost of equity at 45% (i.e. 75%*0.41 + 25%*0.57).

The reasons are:

- The fact that the revenue allowance is determined based on an assessment of the costs actually incurred by JPS, subject to an X- factor for efficiency improvement.
- The regulatory regime already allows certain costs to be automatically passed through to customers. Such pass-through structures will reduce the risk faced by the utility.

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

Asset beta values can be calculated as follows:

$$\beta_{Ai} = \beta_{Ei}(1\text{-}G_i) + G_i\ \beta_{Di}$$

Where:	β_{Ai}	=	asset beta for security *i*
	β_{Ei}	=	equity beta for security *i*
	G_i	=	gearing ratio for security *i*
	β_{Di}	=	debt beta for security *i*

A general assumption that is applied is that $\beta_{Di} = 0$; this simplifies the calculation of the amount to:

$$\beta_{Ai} = \beta_{Ei}(1\text{-}G_i)$$

The deemed gearing ratio for JPS is 0.48 which therefore gives us an **equity beta of 0.865** [i.e. 0.45/ (1-0.48)]

The Office determines that the equity beta for the cost of equity is 0.87.

4.2.7 Return on Equity

The OUR has determined that the regulatory return on equity for JPS be set as follows:

$$\mathbf{K_e = R_f + CRP + \beta_E\,[R_m - R_f\,]}$$

$\mathbf{K_e}$ **= Return on Equity**

$\mathbf{K_e}$ = 3.36 +6.08+ 0.87(7.54) = 16.00%

The OUR determines the following values for the parameters of the CAPM formula:

Risk free rate of return	3.36%
Equity beta	0.87
Market risk premium	7.54%
Nominal cost of equity before CRP	9.92%
Country risk premium	6.08%
Total Nominal cost of equity	16.00%

The Office has determined a nominal cost of equity for JPS equal to 16.00%,

CONCLUSION

The OUR's estimate of the JPS cost of equity over this period is 16.00%. This determination is based on the framework that the OUR established in its 2004 rate determination, but updated to take account of the most recently available information in 2009. The OUR conclusions on each of the CAPM parameters are broadly similar to the OUR's previous findings. The recommended cost of equity is in nominal terms whereas the previously-approved 14.85% represented the real cost of equity. The nominal cost of equity is applied since JPS' functional currency is now the US dollar and the company is reporting historical cost. The new cost of equity of 16.00% and the previously approved 14.84 % are similar for three reasons.

- The OUR has determined an equity beta of 0.87, the same as previously determined in 2004. The OUR is of the view that this is reasonable since the regulatory regime already allows certain costs to be automatically passed through to customers. Such pass-through structures will reduce the risk faced by the utility.
- The OUR also determines a similar MRP to the value approved in 2004. This is reasonable in part because world equity markets have performed better than expected in recent years and the recent stock market declines occasioned by the subprime meltdown mean that investors are likely to be more risk averse. Additionally, the OUR is of the view that it is likely that equity markets will recover much slower during the five years of the PBRM since earnings and balance sheets for most corporations have generally remained weak.
- Third, the OUR has determined a CRP that is reflective of a broader time horizon rather than reflecting a snap shot in time. This is warranted in light of the current volatility of financial market conditions.

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. The OUR has used the latter approach.

4.2.8 The Office's position on the cost of debt

The OUR accepts JPS' proposal of using the actual cost of debt in computing its revenue requirement. However, the OUR considers transaction costs of acquiring debt as onetime expenses and therefore has adjusted the cost of debt accordingly. Additionally, the OUR is of the view that the estimated US$ 60 million loan at 13.50% to increase the capital structure does not represent investment in assets to be used in the provision of services but merely represent an artificial increase in working capital in order to achieve the targeted gearing. The Office had envisioned a gradual substitution of debt for equity over the previous period in order to achieve the target.

The cost of outstanding debt based on JPS' submission of outstanding loan principal is determined to be **10.44%.** Given recent developments in 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 in the current market situation. Within these market dynamics it is expected that JPS will have the incentive to manage its capital as efficiently as possible.

The following table shows JPS outstanding debts and costs of debts.

Table 4.4 OUR analysis of JPS outstanding debt as at December 31, 2008

Institutions	Currency	JPS proposed Interest Rate	OUR determined Interest Rate	Balance @31/12/2008	**Weighted Interest Rate**	
					JPS proposed	**OUR determined**
KFW Loan-DM 14M	US$	7.45%	7.00%	422,000	0.01%	0.01%
KFW Loan-DM 7M	US$	7.45%	7.00%	5,029,000	0.12%	0.14%
Int'l Finance Corporation	US$	9.87%	9.12%	35,000,000	1.09%	1.24%
AIC Merchant Bank	US$	9.25%	8.75%	1,627,000	0.05%	0.06%
Credit Suisse	US$	11.45%	11.00%	180,000,000	6.50%	7.70%
FCIB Syndicated	US$	10.46%	9.46%	35,000,000	1.15%	1.29%
Additional Borrowing	US$	13.5%	-	60,000,000	2.55%	-
Total long-term debt					11.47%	**10.44%**

Weighted Average Cost of Capital

There are a number of valid ways to present the average cost of capital (WACC). These include:

- Post–tax real and nominal;
- Pre-tax real and nominal

Table 4.5 provides a summary of the WACC estimates given the different parameters proposed by JPS and those determined by the Office.

Computation of JPS Weighted Average Cost of Capital

Table 4.5 JPS Weighted Average Cost of Capital

	2004 -2009 Determination	JPS Proposed 2009	2009 -2014 Determination
Cost of Debt	12.56%	11.47%	10.44%
Rate of Return on Equity (ROE)	14.85%	21.63%	16.00%
Tax Rate	33.33%	33.33%	33.33%
Gearing Ratio	44%	45%	48%
Post-tax WACC	12.02%	15.41%	11.68%
Pre-tax WACC	18.00%	22.99%	**17.43%**

Chapter 5 JPS' Rate Base

5.1. 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 determining the Rate Base three categories of the company's assets need to be examined; net fixed assets, appropriate offsets and working capital.

5.2. Net Fixed Assets

The two main balance sheet items included in the Net Fixed Assets component of the rate base are:

1. *Property, Plant and Equipment*—which refers to the utility's total long term physical assets used directly to generate, transmit and distribute electricity as well as to provide customer service.
2. *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 Licenced business so the inclusion in the rate will not be fair to the consumer. JPS has argued that since the OUR had included CWIP in the rate base at the last tariff review it would be inconsistent to do otherwise in the current determination. The default position of the majority of regulators is to exclude CWIP from the rate base; however there may be deviation from this at times if there is need to achieve a specific level of revenue requirement or for specific assets that may have a large impact on the operations. With any inclusion there should be an analysis of the likely effects on revenues and costs. It would be unreasonable to include these assets without accounting for the benefits that would be derived from their use. In addition JPS has been successful in its bid to install additional generating capacity and the cost of these assets, inclusive of preliminary engineering, will be treated in similar fashion to those of IPPs and allowed as a pass through after commissioning. In any event the Office takes the view that it is not estopped from varying from a position adopted in a previous decision where there are cogent reasons to do so.

3. ***Allowance for funds used during construction (AFUDC)*** – which is capitalized interest incurred during the construction phase of a project. AFUDC is included in the revenue requirement as the equivalent item CWIP is e*xc*luded 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 is incurred even during the construction phase and not only when the project is completed). Audited statements showed that AFUDC totaled J$237 million in 2008 and this amount is an increase of 103% over 2007.

The methodology used for the revaluation of JPS' specialized plant and equipment is predicated on the historical cost accounting. JPS reporting requirement to their shareholders is the US$ functional currency and hence for the 2008 audited accounts all asset values were denominated in US$ using 1992 as the base year. Under this methodology, the gross value of the plant and the accumulated depreciation are reported at historical cost. However, Land and Buildings were revalued last year at current costs. In determining the allowed return on asset the OUR has determined that the nominal cost of equity be applied except for the Land and Property which was revalued in 2007 at current exchange. In order not to double count the return on assets to JPS the OUR has to make adjustment on the return attributable to Land and Property to account for the fair return required as opposed to an inflated return from applying the nominal rate to the revalued cost of Land and Property.

The OUR in arriving at the value of JPS' Net Fixed Assets has therefore recognized the historical costs denominated in US$ for specialized Plant and Equipment and the current cost of Land and Property which is revalued at current cost.

The Office has determined that the net plant in service for the test year using 2008 audited statements is J$50.9 billion.

5.3. Off-Sets

Offset is comprised of cost-free capital, i.e., funds that JPS has access to, but which 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:

a. *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.

b. *Employee benefits*—a provision is made for the cost of unutilized 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.

c. *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.

5.4. Working Capital

Working capital is the 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—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 the test year is J$7.915billion.

5.5. The Rate Base

Table 5.1 shows the calculation of the Office's determined rate base, following the definition in the Licence. As shown, the Office determined rate base for the test year period is $49.29 billion of which J$45.61 billion is related to specialized Plant and Equipment and J$3.68 billion is related to Land and Property revalued at current cost

Table 5.1 Rate Base for Test Year 2008 US$1:J$89

Items	US$'000	J$'000
Property Plant and Equipment	623,439	55,486,071
Intangible assets	4,007	356,623
Rural Electrification Program assets (REP)	1,097	97,638
Construction work in progress (CWIP)	(56,616)	(5,038,824)
Net fixed assets	**571,927**	**50,901,508**
Off-Sets		
Customer Deposits	-30,078	-2,676,942
Employee benefits obligations	-17,706	-1,575,834
Deferred expenditure (Tax)	-59,252	-5,273,428
Total Long Term Assets	**464,891**	**41,375,304**
Cash and short-term deposits	7,208	641,512
Repurchase agreements	8,139	724,371
Receivables	172,428	15,346,092
Tax recoverable	2,420	215,380
Inventories	43,929	3,909,681
Current Assets	**234,124**	**20,837,036**
Bank Overdraft	775	68,975
Short-term loans + Current port. Long Term	66,002	5,874,178
Payables	78,254	6,964,606
Related Companies balances	161	14,329
Current Liabilities	**145,192**	**12,922,088**
Net Current Assets(Working Capital)	**88,932**	7,914,948
TOTAL NET ASSETS(Rate Base)	**553,823**	**49,290,252**

5.6. Return on Investment

Schedule 3 paragraph 2(c) of the Licence provides that the return on investment is the component of the tariff *"calculated based on the approved Rate Base of the Licencee and the required rate-of-return which allows the Licencee the opportunity to* *earn a return sufficient to provide for requirements of consumers and acquire new investments at competitive costs"*[5]

The rate of investment for JPS is the Company's Weighted Average Cost of Capital (WACC) which rewards the components of capital in relation to their relative importance in the utility's capital structure. As the Licence provides, it *"will balance the interests of both consumers and investors and be commensurate with returns in other enterprises having corresponding risks which will assure confidence in the financial integrity of the enterprise so as to maintain its credit and attract capital."*[6]

Table 5.2 Calculation of the Return on Investment

		J$'M **2009 JPS**	J$'M **2009 Determination**
Cost of Debt	A	11.47%	10.44%
Rate of Return on Equity (ROE)	B	21.63%	16.00%
Tax Rate	C	33.33%	33.33%
Gearing Ratio	D	45%	48%
Rate Base	E	58,629	49,290
Post-tax WACC	L=D*(1-C)*A+ (1-D)*B	15.29%	11.68%
Pre-tax WACC	M=D*A+(1-D)*B/(1-C)	22.94%	17.43%
Return on Equity		**6,935**	**3,825,101**
Taxation		**3,468**	**1,912,550**
Return on Investment		**10,403**	**5,737,651**[7]
Interest Expenses		**3,047**	**2,304,027**

Determination

The Office has determined that the return on investments for the test period is $5.737 billion

[5] See Schedule 3 of the **All-Island Electricity Licence 2001**

[6] Ibid

[7] Pre-Tax WACC of 17.43% was applied to historical cost asset base of $45.6 and the re-valued Land and Property of $3.68 billion was assessed to have 10% of its value deserving of a nominal return for JPS shareholders and for inclusion in the Revenue requirement.

Chapter 6 Determination of Revenue Requirement

6.1. Introduction

The Regulatory process for tariff determination consists of two steps. The first step is the determination of the revenue requirement of the 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. In arriving at the revenue requirement the OUR employed the historic cost approach.

6.2. Historical Test Year

Under this approach, the historic test year is critical in assessing the costs of supply and sales of electricity. The 'test-year' period as defined by the Licence is the latest twelve month period for which audited financial statements are available. The costs and sales of the historic test year may then be adjusted for "known and measurable changes". Examples of known and measurable changes would include an increase in power purchase costs 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.

The test-year was deemed to be 2008 based on the JPS' Audited financial statements as prepared by the auditing firm, Ernst & Young.

6.3. Revenue Requirement

Schedule 3, section C of the Licence stipulates that the non-fuel revenue requirement for the initial tariffs shall be based on a test year 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 costs, plus a regulated return on its investment from consumers. In general this method permits the total revenues allowed to JPS, under the following formula:

$$RR = [RB \times WACC] + ED + EO\&M + T$$

Where:

RR = the total annual non-fuel revenue requirement of the utility

RB = the rate base (required investment) of the utility

WACC = the allowed rate of return (WACC) on investment , "K%".

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

Table 6.1 Revenue Requirements

	JPS Proposed (J$'000)	OUR Determined (J$'000)
PPA Costs	5,740,899	6,011,059
Operating Expenses	13,693,013	12,154,180
Depreciation	4,219,529	3,631,289
Total Operational Expenses	**23,653,441**	**21,796,528**
Net finance costs (excl. long-term debt):		
Interest on short-term loans	179,690	364,746
Interest on customer deposits	77,372	179,032
Interest – other	12,396	
Int. Capitalised during construction (AFUDC)		237,274
Loan Finance Fees		130,673
Finance income	-269,658	-269,658
Total Other Expenses	**-200**	**642,067**
Other income	**-102,019**	**-102,019**
Self-insurance fund contribution	425,000	445,000
Gross up for taxes on SIF	212,500	222,500
Total Other Income	**637,500**	**667,500**
Return on Investment	**6,935,378**	**3,825,101**
Taxation	**3,467,689**	**1,912,550**
Long Term Interest Expenses	**3,047,058**	**2,304,027**
Revenue Requirement, net of credits	**37,638,847**	**31,045,755**
Less Carib Cement Revenue	-310,521	-310,521
Loss Reduction Fund		1,125,106
Adjusted Revenue Requirement	**37,328,326**	**31,860,340**

***Note**: The Base Exchange Rate for JPS Proposed are US$1 = J$85.00 and US$1 = J$89.00 respectively*

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.

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

6.4. Power Purchase Costs

JPS proposed Purchase Power costs of $5.74 billion annually. However, the Office has determined a prudent cost of $6.01 billion for the test year.

There is no real difference in JPS' proposed costs and the OUR determined costs. The Office's determination of IPP costs of J$5.66 billion is based on commitments of amount payable in 2008 of J$4.89 per KWh under power purchase agreements, for energy capacity and certain operating charges. An adjustment of J$775.4 million was made to account for the Base Exchange rate of US$1 = J$89 for the test year as opposed to an exchange rate of US$1 = J$85 as proposed by JPS.

The Office has therefore determined that a prudent PPA test year cost is J$6.01 billion.

6.5 Operating Expenses

JPS proposed operating expenses totaling $13.69 billion. The proposal by JPS was based on an exchange rate of J$85: US$1. Analysis of the Operating Expenses is outlined below.

The OUR is of the view that Salaries and Expenses are strictly the purview of the management of JPS and as such it is a management decision that will ultimately determine the level of salaries and related expenses to be paid to the employees. The Management may choose to adjust salaries based on the company's capacity to recover those costs. JPS costs are adjusted for the rate of inflation on an annual basis and as such management may choose to adjust salaries to reflect the inflation adjustment or not.

The Office is of the view that it should not appear to be setting the level of salaries and expenses for JPS employees when this management decision should be between the management and the Trade Unions.

Table 6.3 JPS proposed Salaries and Related Expenses

J$'000s	2008	CPI - 2008	1/2 CPI - 2009	2008 ADJUSTED
Unionized employee costs	4,909,198	799,781	332,438	6,041,417
Non-unionized employee costs	586,928	-	34,008	620,936
TOTAL	5,496,126	799,781	366,446	6,662,353

JPS proposed an increase of $799,781,000 and inflation adjustments of $366,446,000 for the years 2008 and 2009 respectively on the total salaries and related expenses for the year ending 2008. The OUR is of the view that the proposed sum should be adjusted as follows:

- Year 2009 unionized employee and non-unionized employee costs to be disallowed given that there are no known and measurable and reasonable changes in salary agreement between the company and the trade unions.
- Year 2008 unionized employee costs to be adjusted for inflation adjustments for the months of January and February 2009. Inflation adjustments for March 2009 to February 2010 will be captured in the annual rate adjustment in 2010. Annual inflation rate of 12% is applied.

Table 6.4 OUR adjusted Salaries and related expenses

Payroll, benefits & training J$'000						
	Actual Costs	Rate Increase	J$ Costs	Exclusion	Infl. Adj.	Adjusted Cost
JPS Proposed	5,496,126	799,781	6,295,907	0	366,446	6,662,353
OUR Allowed	5,496,126	0	5,496,126	36,706	109,923	5,569,343

The Office has determined that the test year employee cost is J$5.57 billion

6.6 Payroll, benefits & training

6.6.1 Thirty One (31) Day Billing Directive

In order to meet the thirty one (31) day maximum number of days in each bill, as directed by the Office, JPS requested an increase in Meter Reading Costs of $50.86 million. Extract from Sheet No. 205 of JPS standard terms and conditions reads "The word 'month' as used herein and in the rates is hereby defined to be the elapsed time of approximately thirty (30) days. In the July 2008 to August 2008 billing period JPS was found to be in breach of this condition and consequently condition 13 (10) (ii) of the Licence. The Office hereby reiterates its directives effected 13th October 2008, which states that "JPS shall ensure that at least 99% of bills based on actual reading issued to customers reflect usage no greater than a billing period of 31 days". This directive is for JPS to conform to a long established standard and is nothing new. Hence, there is no justifiable basis on which to approve an increase in meter reading costs and as such the company should find an efficient alternative to executing its responsibilities. In any case, the Office has approved the creation of a fund for introducing new metering technology which will improve the efficiency of meter reading. The Office has determined that this item will not be allowed.

The Office has determined that Overtime cost of $56,130,223 should be disallowed.

6.7. Third Party Services

The proposed third party cost was adjusted as follows:

- Photographic services amount of $2,012,000 is assessed to be a non-recurring expenditure and therefore is not prudent to be included in the total amount in the revenue requirement. Although such expenditure is non-recurring the company may require such services again over the price cap period. The OUR therefore believes that the amount of $1,500,000 is a reasonable exclusion from the revenue requirement.

- Disconnection/Reconnection Charges of $158,259,000 representing payments to contractors should not be allowed in the revenue requirement since this is collected directly from the consumer as disconnection/reconnection fee

- Related Party fees are reduced by $31,000,000. The amount represents 2007 Expatriate Taxes charged to the expense account in 2008. The allowed amount is $124,922,000.

Third Party Services	Actual Costs	US$ Costs	J$ Costs	F/X Adjustment	Inflation Adjustment
JPS Proposed	1,669,868	583,890	1,085,978	96,811	65,125
OUR Allowed	1,479,097	517,684	961,413	110,368	19,228

Third party services should therefore be reduced from $1,669,868,000 to $1,479,097,000 a reduction of $190,771,000 .

Known and Measurable Changes

JPS requested an adjustment for foreign exchange movement from J$73.36: US$1 being the average exchange rate for 2008 to J$85.0: US$1 the base foreign exchange rate for 2009. Additionally, they requested inflation adjustments of 6% for half of 2009.

The OUR is of the view that the foreign exchange adjustment base rate should be adjusted from J$73.36: US$1 being the average exchange rate for 2008 to J$89.0: US$1 instead of the J$85 proposed by JPS. Additionally, instead of adjusting the actual Jamaican costs components by the 6% for half of 2009, the expenses should be adjusted by the movement of the Jamaican CPI for the period February 2008 to February 2009 prorated for two months, January and February. That is, annual Jamaican CPI of 12.84% prorated two months. Inflation adjustments from March 2009 to February 2010 will be done in the 2010 annual rate adjustment. The OUR's analysis of JPS' operating expenses adjusted for known and measurable is outlined in Table 6.5.

Table 6.5 JPS Adjusted Known and Measurable Operating Expenses

{All amounts in J$'000s}	Actual Costs	Additions/ Exclusions	Rate Increase	FX	CPI	Interest Rates	Bad Debt	Cost of Capital	Adjusted Costs
Purchased Power	4,925,090			815,809					5,740,899
Operating Expenses:									
Payroll, benefits & training	5,496,126		799,781		366,446				6,662,353
Payroll, benefits & training	-		56,130						56,130
Third party services	1,669,868			96,811	65,125				1,831,804
Materials & equipment	833,549			138,072					971,621
Office & Other expenses	1,036,995			137,417	12,444				1,186,856
Transportation expenses	742,034			109,736	4,773				856,543
Insurance expense	547,629		151,708	-	-				699,337
Bad debt write-off	1,161,689			-	-		266,680		1,428,369
	11,487,890		1,007,619	482,036	448,788	-	266,680		13,693,013
Depreciation & Amortization	3,033,618		615,102	570,809					4,219,529
Net finance costs:									
Foreign exchange losses	1,092,633	(1,092,633)							-
Interest on long-term loans	1,872,659							1,174,399	3,047,058
Interest on short-term loans	364,746					(185,056)			179,690
Loan finance fees	130,673	(130,673)							
Interest on customer deposits	133,152					(55,780)			77,372
Interest - other	12,396								12,396
Finance income	(269,658)								(269,658)
	3,336,601	(1,223,306)	-	-	-	(240,836)	-	1,174,399	3,046,858
Other income	(368,829)	266,810							(102,019)
Other expenses	1,196,690	(1,196,690)							-
	827,861	(929,880)	-	-	-	-	-	-	(102,019)
TOTAL NON-FUEL EXPENSES	**23,611,060**	**(2,153,186)**	**1622,721**	**1,868,654**	**448,788**	**(240,836)**	**266,680**	**1,174,399**	**26,598,280**

Table 6.6 OUR Determined Known and Measurable Operating Expenses

{All amounts in J$'000s}	Actual Costs	Additions/ Exclusions	Rate Increase	FX	CPI	Interest Rates	Bad Debt	Cost of Capital	Adjusted Costs
Purchased Power	4,925,090			1,085,969					6,011,059
Operating Expenses:									
Payroll, benefits & training	5,496,126	-36,706	-		109,923				5,569,343
Payroll, benefits & training	-								-
Third party services	1,669,868	-190,771		110,368	19,228				1,608,693
Materials & equipment	833,549			177,709					1,011,258
Office & Other expenses	1,036,995			176,866	4,148				1,218,009
Transportation expenses	742,034			140,290	1,680				884,004
Insurance expense	547,629		153,555	-	-				701,184
Bad debt write-off	1,161,689			-	-				1,161,689
Total Operating Expenses	11,487,890	-227,477	153,555	605,233	134,979	-	-		12,154,180
Depreciation & Amortization	3,033,618			597,671					3,631,289
Net finance costs:									
Foreign exchange losses	1,092,633	-1,092,633							-
Interest on long-term loans	1,872,659							597,374	2,470,033
Interest on short-term loans	364,746								364,746
Loan finance fees	130,673								130,673
Interest on customer deposits	133,152	45,880							179,032
Interest - other	12,396	-12,396							
Finance income	-269,658								-269,658
	3,336,601	-1,059,149	-	-	-		-	597,374	2,874,826
Other income	-368,829	266,810							-102,019
Other expenses	1,196,690	-1,196,690							-
	827,861	-929,880	-	-	-	-	-	-	-102,019
TOTAL NON-FUEL EXPENSES	**23,611,060**	**-2,216,506**	**153,555**	**2,288,873**	**134,979**		**-**	**597,374**	**24,569,335**

Table 6.7 OUR adjusted Insurance Expense

	2008 Actual US$ Premium	2009 US$ Increase	2008 Actual J$ Premium	2008 J$ Increase	J$ Equivalent at base FX rate
	('000s)	('000s)	('000s)	('000s)	('000s)
Property damage (all risk)	5,305	796			542,989
Public/Employer's liability	612				54,468
Excess liability	297				26,433
Motor contingent liability	0		55,280		55,280
Group Life & Personal accident	0		15,413	0	15,413
Other miscellaneous	0		6,601		6,601
	6,214	796	77,294	0	701,184

6.8 Bad Debt Expense

Table 6.8 Billings to Collections Ratio

J$ Millions	2004	2005	2006	2007	2008	Total
Billings	30,435	38,676	47,436	52,169	71,318	240,034
Collections	29,274	37,851	46,638	50,220	70,965	234,948
Collections ratio	96.2%	97.9%	98.3%	96.3%	99.5%	97.9%

JPS contends that the collections ratio of 99.5% in 2008 includes arrears and an unusually high amount of back billing related to theft recovery. The company therefore requested an adjustment in bad debt expense to cover the short fall in collection ratio of 2%. The OUR takes the view that if this is done JPS would have no incentive to improve their collections effort given the fact that they would be fully covered from any such losses and might even benefit from a surplus should their collections continue on this positive trend. In making the adjustment for back billing of $750 million the collections ratio for year 2008 would be 98.5%. The table above shows that the company's collections efforts have improved steadily over the years with the exception of year 2007. The OUR commends the company on its debt recovery efforts and encourages it to maintain this thrust.

The OUR is of the view that increasing the bad debt expense ratio from 1.1% to 2% will place unreasonable costs on consumers at this time.

The Office has determined that the test year Operating Expenses is J$12.15 billion at the base exchange rate of US$1:J$89.

6.9. Interest Expense on Short Term Debt

This refers to the interest expense on current liabilities. Since current liabilities are not included in the rate base it is appropriate for the associated interest expense be included in the revenue requirement. JPS estimates this at J$179.7 million. The OUR does not accept the proposed US$60M long term refinancing at the expensive rate of 13.5%. The test year actual short term interest expense of $364,746,000 is therefore allowed in the revenue requirement.

The Office has determined that the allowed interest on short term debt is J$364.7 million for the test year.

6.10. Interest on Customer Deposits

JPS proposed that if any interest is to be paid on customers' deposits, it should be based on the BOJ average domestic savings rate and not the Treasury Bill rate as now obtains. The JPS argued that the use of the average savings rates for commercial banks would be more reflective of the economic benefit to the Company and the economic cost of capital to the customer.

JPS further states that "if they did not require a customer deposit, it would simple require additional debt funding to fill the working capital requirement." On the other hand it requested that it be allowed to pay interest on customers' deposits at the domestic savings rate. The OUR is of the view that interest should be paid on customers' deposits and at the Treasury Bill rate and an allowed handling charge of 2%. The OUR is of the view that this represents the true/fair opportunity cost of capital to the consumer.

6.11. Interest Income

Interest income is deducted from the revenue requirement since it does not represent a revenue inflow from the utility core business. 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.

6.12. Allowance for Funds Used During Construction (AFUDC)

Allowance for funds used during construction (AFUDC) refers to capitalized interest incurred during the construction phase of a project. AFUDC is included in the revenue requirement as the equivalent item 'construction work in progress (CWIP)' is excluded in the rate base. As previously indicated the inclusion of both AFUDC and CWIP in the computation of the revenue requirement would lead to double counting. Audited statements showed that AFUDC totaled J$237.2 million in 2008 and this amount is an increase of 103% over 2007.

The Office has determined the test year AFUDC as J$237.2 million.

6.13. Other Income

Other income refers to income generated from other activities outside of the company's core business, such as the rental of JPS owned properties and income from the use of the utility's poles for attachments by telecom firms.

The Office has determined that test year other income is $102 million.

6.14. Self Insurance Fund Contribution

Self Insurance Fund Contribution is the fund established since 2004 to provide coverage for the company's T&D assets in the absence of conventional insurance coverage at reasonable premiums.

The Office agrees with the principle of the self-insurance fund and has determined that provision for the sum of J$445 million is reasonable.

6.15. Depreciation

Depreciation which is calculated based on the rates specified in Schedule 4 of the Licence, totaled J$3.63 billion compared with J$4.219 billion proposed by JPS. The allowed amount represents the test year actual cost of depreciation and amortization.

The Office has determined that depreciation should be the actual test year cost of$3.63 billion

6.16. Taxation

Taxation is calculated using a 33 1/3% tax rate on pre-tax income. As stated in Schedule 3 paragraph 2(c) of the Licence;

Determination

The Office has therefore determined the value of the Taxation to be J$1.91 billion.

The Office has determined that based on test year adjustments the Revenue Requirement allowed is J$31.86 billion.

7. Determining JPS' Efficiency: the X-Factor

7.1 Introduction

The X-factor is the efficiency component in the price cap mechanism as stated in the equation below.

$$dPCI = dI \pm X \pm Q \pm Z$$

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	=	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 Licence stipulates that the X-factor is to be set equal the difference in the expected Total Factor Productivity (TFP) growth of JPS and the general TFP growth of firms.

7.2 JPS' Proposal for X-factor

Pursuant to the stipulations of the Licence, JPS provided recommendations on an appropriate ***X***-factor, derived from a total factor productivity (TFP) study undertaken by PEG. The following are the findings of the study:

- the derived expected TFP growth of JPS at 1.94% per annum. This was based on the Company's average TFP growth since 2001.
- the TFP growth trend of the US economy at 1.53% and the estimated TFP growth for the Jamaican economy at zero.

- Overall TFP growth for firms whose output price indexes are reflected in the price escalation measure is proposed to be 1.16%

As such, using these values as inputs in the productivity methodology stipulated by the Licence, PEG recommended ***X*-**Factor of 0.78%[8] . Against this background JPS rounded the calculation upwards and proposes a ***X*-**factor of 0.80% for the 2009 – 14 price cap period.

JPS citing PEG's research argued:

- It has made substantial improvements in its non-fuel cost performance in recent years and has a limited ability to make incremental TFP gains.
- When setting X factors, regulators often add "stretch factors" to historical TFP differentials in the expectation that productivity growth will accelerate when companies become subject to stronger performance incentives under PBR.
- that the average stretch factor in North American index-based PBR plans is 0.5%.

In this context, JPS posited that a stretch factor value between 0 and 0.5% would be reasonable for the next PBRM. As such, when this stretch factor band is added to the estimated TFP differential, this leads to an X factor ranging between approximately 0.8% and 1.3%.

7.3 Review of JPS' proposed X - factor

7.3.1 JPS' TFP GROWTH

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 1990-2007 was at an average rate of 0.74% per annum. 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 periods and the corresponding input /output indices analysed from PEG data.

Table 7. 1: TFP Results

[8] X = 1.94 - (0.76*1.53+0.24*0) = 0.78%

Year	TFP	Output	Input
1991	1.000	1.000	1.000
1992	0.932	1.038	1.114
1993	0.828	1.065	1.286
1994	0.900	1.135	1.262
1995	0.764	1.180	1.544
1996	0.834	1.256	1.507
1997	0.834	1.318	1.581
1998	0.833	1.408	1.690
1999	0.907	1.487	1.640
2000	0.909	1.551	1.707
2001	1.001	1.622	1.620
2002	1.013	1.662	1.641
2003	0.998	1.743	1.745
2004	1.022	1.772	1.734
2005	1.096	1.808	1.649
2006	1.105	1.861	1.685
2007	1.132	1.881	1.661
Average Annual Growth Rate:			
1990 - 2007	0.74%	3.77%	3.03%
1990 – 2001	0.12%	4.62%	4.50%
2001 – 2007	1.94%	2.15%	0.21%

A TFP growth of 0.12% 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. In the last seven years JPS has shown growth of 1.94%. This highlights the fact that the choice of period for the study can introduce biases in the prediction of the expected TFP.

A review of the literature on the experience with TFP methods as it relates to regulation of North American electric utilities[9] reveal that TFP for utilities in California, Ontario, Maine and Massachusetts average 1.5% to 2.57%.

Meyrick[10] 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. 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.

7.3.2 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. Additionally, reduce input cost as evident from the table 7.1 results in the higher TFP for the period 2001 – 2007. 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 1991-2007. 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. Given this evidence of weak TFP growth for the Jamaican economy, and the OUR's view that it is not reasonable to expect TFP to decline indefinitely, the OUR concurs with PEG and is of the view that the best estimate of Jamaica's TFP growth during the term of the PBRM is 0.52 % percent, reflecting the more recent trend of the 2000 – 2002 period.

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[9] A presentation to Australian Energy Market Commission by A.J. Golding, President London Economics International, November 18, 2008

[10] Lawrence, D. (2002), "The Australian Electricity Supply Industry's Productivity Performance," Appendix 2 in COAG Energy Market Reforms, Report prepared by ACIL Tasman for the COAG Energy Market Review Panel (Paper Review), Canberra

7.4 OUR X-factor Determination

7.4.1 Historic basis

Using PEG's TFP growth for JPS of 1.94% per annum, TFP growth for the US economy of 1.53% per annum and TFP growth for Jamaica of 0.52% per annum, the implied X-factor based on historic data is 0.65%[11]. This is slightly less than PEG's figure of 0.78%. However, 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 3.77%.

7.4.2 Stretch factor

In determining the stretch factor it is important to take account of the difference between historic and expected TFP growth. The methods of estimating the stretch factor are outlined here-under:

- **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 benchmarked 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 increase in the years after the investments are made. As these additions provide the capability for increased sales, in the future, average unit costs 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.
- **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. A stretch factor should therefore be added to the historic based X factor. A literature review by Europe Economics concludes: "several studies

[11] X= 1.94% - [0.76x1.53% + 0.24 x 0.52%]

provided estimates of productivity growth achieved by firms since privatization. These, on the whole, suggest that privatized industries have achieved productivity growth significantly faster than the economy as a whole. Also, these industries generally grow faster than they managed before privatization.[12] They state that the privatization effect arises from a catch up of whole industries towards greater efficiency following privatization and the introduction of incentive regulation.

JPS used 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% to 0.5% as appropriate for JPS, resulting in a final X-factor of 1.18% (or 1.30% using JPS TFP results). However, it may be argued that given JPS' low productivity growth compared with other utilities it is likely to be a below average performer.

The fact that JPS appears to have similar TFP growth as 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

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12 Europe Economics, Scope for Efficiency Improvement in the water and Sewage Industries, March 2003

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 privatization. They show that the real unit operating expenditure improvement of privatized 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%.

7.4.3 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 15 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 15 years.[13] This would be equivalent to a TFP increase of 20% over 15 years or 1.33% 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 judgement 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

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

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 JPS and PEG.

The change to the treatment of new generation costs would add a further 1.33% to this stretch factor.

7.4.4 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 +5.3%. The Office has therefore determined that the expected productivity efficiency gains for JPS (X-factor) shall remain at 2.72% per year.

Determination

The productivity efficiency gain for JPS (X-factor) to be applied at the June, 2010 adjustment is 0%. The X-factor for the adjustment for June, 2011 and the adjustment for subsequent years shall be 2.72%.

8. The Q-factor (Service Quality)

8.1 Introduction

The PBRM as expressed in the price-cap formula below includes a price adjustment component, Q, which captures the changes in the quality of service provided to customers by JPS.

$$dPCI = dI \pm X \pm Q \pm Z$$

It has been established that in principle that the Q-factor should meet the following criteria:

- It should provide the proper financial incentive to encourage JPS to continually improve service quality. It is important that random variations should not be the source of reward or punishment;
- It should be accurate and transparent without undue cost of compliance;
- It should provide a 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; and
- It should be symmetrical in application, of rewards and penalties as stipulated in the Licence.

In the 2004 Tariff Review Determination the OUR stipulated that the Q-factor should be based on three quality indices:

- SAIFI—this index is designed to give information about the average frequency of sustained interruptions per customer over a predefined area. It is expressed in number of interruptions per year

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

- SAIDI – this index is commonly referred to as customer minutes of interruption and is designed to provide information about the average time that customers are interrupted. It is expressed in minutes.

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

- CAIDI – this index represents the average time required to restore service to the average customer per sustained interruption. It is the result of dividing the duration of the average customer's sustained outages (SAIDI) by the frequency of outages for that average customer (SAIFI). It is expressed in minutes per interruption.

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

8.2 The Benchmark SAIDI, SAIFI and CAIDI

In its 2004 decision the OUR made the determination that until the next price review, the verified set of SAIFI, SAIDI and CAIDI indices for 2005 and subsequent years will be used as the baseline quality level. Furthermore, the OUR determined that SAIFI, SAIDI and CAIDI should be improving by 2% in 2005 relative to the 2004 performance level and by 3%, relative to the 2005 performance level, in each subsequent year until 2009. Accordingly, the target set by the OUR is shown in the **Table 8.1** below.

Table 8.0-1: The OUR Targets for the Q-factor 2006 – 2009

Year	Target SAIDI	Target SAIFI	Target CAIDI
2006	$SAIDI_{2005}$	$SAIFI_{2005}$	$CAIDI_{2005}$
2007	$SAIDI_{2005}$*(1 – 0.02)	$SAIFI_{2005}$*(1 – 0.02)	$CAIDI_{2005}$*(1–0.02)
2008	$SAIDI_{2005}$*(1 – 0.05)	$SAIFI_{2005}$*(1 – 0.05)	$CAIDI_{2005}$*(1– .05)
2009	$SAIDI_{2005}$*(1 – 0.08)	$SAIFI_{2005}$*(1 – 0.08)	$CAIDI_{2005}$*(1– .08)

The OUR is of the view that, generally in PBRM, penalties are increased as performance worsens and are capped when a maximum penalty is reached and further, that, rewards for good reliability can be implemented in a similar manner. The OUR is of the view that this would provide an incentive for JPS to enact reliability improvement measures even after they have surpassed the poor reliability threshold for a year, before the year comes to an end provided the data used to calculate the indices are properly captured, verified and audited.

The OUR has determined that once its satisfied that the calculation of the quality of service indices meet all the criteria of properly captured, verified and audited, the quality of service performance should be classified into three categories, with the following point system:

- Above Average Performance (greater than 10% above benchmark) - would be worth 3 Quality Points on either SAIFI, SAIDI, or CAIDI;
- Dead Band Performance (+ or – 10%) - would be worth 0 Quality Points on either SAIFI, SAIDI, or CAIDI; and
- Below Average Performance (more than 10% below target) - would be worth -3 Quality Points on SAIFI, SAIDI, or CAIDI.

The OUR further stated, that, if the sum of Quality Points for:

- SAIFI, SAIDI, and CAIDI is 9, then Q = +0.50%
- SAIFI, SAIDI, and CAIDI is 6, then Q = +0.40%
- SAIFI, SAIDI, and CAIDI is 3, then Q = +0.25%
- SAIFI, SAIDI, and CAIDI is 0, then Q = 0.00%
- SAIFI, SAIDI, and CAIDI is -3, then Q = -0.25%
- SAIFI, SAIDI, and CAIDI is -6 then Q = -0.40%
- SAIFI, SAIDI, and CAIDI is -9 then Q = -0.50%

Since the performance in each of the three performance measures can either be above target, below target or on target (dead band) the Total Factor Adjustment may vary between a minimum of -0.5% and a maximum of +0.5%.

This design of the Q-factor adjustment as a component of the PBRM is symmetrical and all possible outcomes are properly defined based on the PBRM point system. The design is balanced as it provides equal opportunity for either a positive or negative adjustment to the PBRM as stipulated by the Licence.

8.3 2008 SAIDI, SAIFI and CAIDI Performance

The **Table 8.3** below outlines JPS' stated performance for 2008 and the OUR's analysis of JPS' submitted outage data in the three main quality of service measures: SAIDI, SAIFI and CAIDI. JPS indicated that the data submitted was for the complete system performance and includes interruptions due to generation, transmission and distribution outages. Additionally, JPS posited that the distribution interruptions included both feeder level and sub-feeder level outages. All the computations are based on the 2007 customer base of 581,056, as previously provided in the annual tariff adjustment submission for 2008. It shows a peak in all three indices in January, which is the month when JPS experienced a total system shutdown. Additionally, the **Table 8.4** below compares JPS' performance for 2008 and OUR analysis of JPS submitted outage data in the three main quality of service measures. In addition Table 8.4 highlighted the mean and standard deviations of the service measure data derived from the outage data submitted by JPS. OUR analysis of JPS outage data for the period revealed slight variation in the monthly SAIFI, CAIDI and SAIDI indices for JPS. The values are different because of differences in the number of customer count attributed to a particular outage and the duration of the outage. The differences are not significant, but they underscore the need for an audit of the process of capturing outage data.

Table 8.3 : 2008 JPS Outage Data

Month/ year	JPS SAIFI	OUR SAIFI	JPS SAIDI	OUR SAIDI	JPS CAIDI	OUR CAIDI
Jan-08	2.38	2.38	326.04	326.04	136.99	137.03
Feb-08	1.41	1.40	98.18	98.12	69.63	70.31
Mar-08	1.56	1.54	130.18	128.84	83.45	83.82
Apr-08	2.25	2.24	214.46	213.03	95.32	94.95
May-08	1.28	1.27	171.15	169.12	133.71	132.81
Jun-08	3.21	3.18	230.50	226.53	71.81	71.33
Jul-08	3.19	3.18	272.04	269.52	85.28	84.72
Aug-08	2.51	2.52	310.44	306.53	123.68	121.77
Sep-08	2.20	2.18	263.00	259.08	119.55	118.67
Oct-08	1.60	1.59	162.38	160.17	98.27	100.77
Nov-08	1.87	1.86	228.11	225.47	101.49	121.10
Dec-08	0.99	1.01	111.10	123.74	87.57	122.79
TOTAL	**24.45**	**24.35**	**2518**	**2506.19**	**102.97**	**102.94**

Table 8.4: 2008 JPS Outage Data variability

Variability of Monthly Indices						
Month/ year	**JPS SAIFI**	**OUR SAIFI**	**JPS SAIDI**	**OUR SAIDI**	**JPS CAIDI**	**OUR CAIDI**
Jan-08	2.38	2.38	326.04	326.04	136.99	137.03
Feb-08	1.41	1.40	98.18	98.12	69.63	70.31
Mar-08	1.56	1.54	130.18	128.84	83.45	83.82
Apr-08	2.25	2.24	214.46	213.03	95.32	94.95
May-08	1.28	1.27	171.15	169.12	133.71	132.81
Jun-08	3.21	3.18	230.50	226.53	71.81	71.33
Jul-08	3.19	3.18	272.04	269.52	85.28	84.72
Aug-08	2.51	2.52	310.44	306.53	123.68	121.77
Sep-08	2.20	2.18	263.00	259.08	119.55	118.67
Oct-08	1.60	1.59	162.38	160.17	101.49	100.77
Nov-08	1.87	1.86	228.11	225.47	121.98	121.10
Dec-08	0.99	1.01	111.10	123.74	112.22	122.79
MEAN	**2.04**		**210**		**104.59**	
STD	**0.72**		**75.93**		**23.47**	

The 2008 target is based on data supplied in the 2008 Annual tariff submission, which was 3,257 for SAIDI; 34.82 for SAIFI; and 88.84 for CAIDI.

8.4 Comments on the Benchmark SAIDI, SAIFI and CAIDI

In reality, the five year baseline data currently available is not sufficient and may undermine the penalty and reward system that seeks to incentivize JPS to provide quality electricity service. The current baseline data proposed by JPS represents data that is reflective of a period when there were a number of countervailing factors[14] militating against adequate reliability and consequently there is high variability in the monthly indices. The OUR is of the view that the data presented over the last four years is not sufficient and for that matter may not be representative enough to ensure the optimum baseline for a robust Q-factor. However, the OUR is of the view that in order to minimize the risk of a lower than optimum baseline for the measurement of subsequent Q-factors, the

[14] The countervailing factors are bad weather in 2004 and 2005, system shutdown in 2007 and 2008 and data collection issues relating to the integrity of the system

dead-band performance[15] target should be sufficiently large to take into account the variability of the current data. In addition, the OUR will have to direct the utility to provide an audit of the collection and measurements of the outage data to verify its representativeness and validity. This will ensure that the utility will have to bring material improvements to the quality of service to score quality points exceeding the dead band of zero.

Furthermore until a reasonable trend and consistent quality in the Q data set can be observed the OUR will be constrained in establishing a fair baseline. The OUR has observed that in other jurisdictions such data is typically collected for a three to ten year period. Additionally, given the proposed continuous improvement to the accuracy of the data, and the knowledge that the target is derived from base line data with some known imperfections, and given the proposed improvement to the data collection process, the Office is of the view that setting the penalty/reward targets relative to the Quality points for each of the indices above is premature and fraught with risk.

JPS has proposed that the company performance in 2008 would be classified into the above average performance range when compared to the 2008 benchmark target, as noted in the **Table 8.5** below:

Table 8.5 : Actual 2008 Q-Factor Performance vs. the 2008 Target

SAIDI was 24% better than target	3	Quality
SAIFI was 30% better than target	3	Quality
CAIDI was 16% worse than target	3	Quality

Since the sum of the quality points on SAIDI, SAIFI and CAIDI is 3, then Q would have been equal to 3 if the Company had a 2009 annual tariff adjustment. This would have resulted in an overall 0.25% positive adjustment to the annual tariff reset, reflecting the fact that JPS' performance was overall better than the target.

However, the following observations are noteworthy;

[15] Actual performance within a certain variance sufficiently large to ensure that the utility will have to improve quality of service to score quality points exceeding zero.

- Examination of the 2008 data revealed that the system experienced over 400 more outages than the previous year indicating a worse performance overall.

- JPS has indicated that there has been a marked improvement in system reliability performance as dictated by the reliability indices. However, a review of the 2008 data shows that there are several incidences of repeated outages on a particular feeder. Further, there are approximately 100 instances where outage duration exceeded 24 hours before customers' supply was restored.

- For example, on August 29, 2008 the **TWICKENHAM G/DALE FDR 6-410** went out of service for over 95 hours with 118 customers connected (FROM: 29/8/2009, 8:37PM TO 2/9/2009, 8:15PM) and there are many more instances of similar occurrences. This does not demonstrate the type of improvement in reliability JPS is declaring.

- The 2008 outage data also contains an element of inconsistency which could possibly lead to incorrect measurement of a particular index.

  Typical example is the data capture (number customers connected, duration of outage etc) for the January 9, 2008 all Island system shutdown. JPS records for January 2008 show the number of customers on the system for December 2007 stood at approximately 581,500, however following the sequence of events from 6:12PM on January 9, 2008 (start of blackout) to 10:36PM when the system was fully restored the total number of customers accounted for was only 562,805. This indicates that the number of customers on a particular feeder may not be precisely known or some of the data is missing. Inconsistencies of this nature will definitely have implications for the derivation of the reliability indices.

The OUR is of the view that a determination based on the current baseline data is risky as there is need for the auditing of the data collection procedure and processes along with further analysis on the variability of the performance of the indices overtime.

8.3.1 Data Collection Methods

The calculation of SAIDI, SAIFI and CAIDI indices requires key information to be collected. Namely:

- Outage starts and end times;
- System total number of customers; and
- Number of customers affected by each outage.

In 2004 it was agreed that the following methods be used to capture the above-mentioned data.

8.3.2 Outages Start and End Times

Feeder level outage

At the feeder level, all planned and forced outages were to be collected and stored in a Microsoft Access-based outage-logging database (developed in-house) located at its System Control Centre. This information would contain all the start and end times associated with the individual outages. These outage times were to be derived from the SCADA system and in the event of communication failure the outage start times be derived from the customer call log, when the first affected customer called.

Sub feeder level outages

- Planned outages—for planned outages at the sub-feeder level, data was to be made available primarily from the Outage Log Database at the System Control Centre. The outage times were to be derived from actual switching times logged by the System Control Engineer.
- Forced outages—the central call centre logs would be used to provide outage start times. The start time would be derived from the time the first affected customer called. The outage end time would be determined by the recloser or switch closing time as reported to the system control engineer or dispatch technician by the field personnel and also recorded in the call centre log.

8.3.3 Number of Customers Interrupted

Feeder Level Outages

JPS has submitted that to determine the customer count per feeder, an extensive customer to feeder GPS mapping exercise was completed in 2006 where 95% of all customers were mapped with their GPS coordinate to respective feeders island-wide. The remaining 5% were assigned to feeders based on their address and meter reading route. This more accurate and reliable method to determine the number of customers at the feeder level was introduced in 2007.

Where outages (planned and forced) are concerned at the feeder level, it was therefore accepted that the estimated number of customers on each feeder be determined from this derived customer count listing. This list was updated at the end of the tariff year and used in the following year's calculations.

Sub-feeder level outages

JPS did not have customer count data at the sub-feeder level so therefore, a method of utilizing the fuse sizes and derived average customer demand per feeder was used to approximate the number of customers interrupted. This method is shown below;

$$\textit{Average customer utilization (MW/customer)} = \frac{\textit{feeder peak loading per month}}{\textit{Number of customers on the feeder}}$$

The number of customers interrupted was to be computed as follows:

$$\textit{Number of customers to be interrupted} = \frac{\textit{Estimated load (kW) interrupted}}{\textit{Average Customer Utilization (kW/Customer) for that feeder}}$$

Where neither the kW loading nor customer utilization was provided JPS posited that the discounted rating of the isolating fuse (amperes) to be opened was used as a proxy to estimate the load on the line section. The fuse rating was discounted using the transformer utilization factor to approximate the typical peak load on the section.

- Load on branch = transformer utilization x fuse factor x branch kVA
- Where branch kVA = fuse size (amperes) x phase voltage
- fuse factor = feeder connected kVA / total main branch fuse kVA

JPS has since used a discount factor of fifty (50) percent to determine the load and the number of customers interrupted for outages at the sub-feeder level.

8.3.4 Improvements in Data Collection

JPS has posited that consistent with the Company's commitment to improve the accuracy and reliability of the customer count, significant investment and efforts were expended in 2007/8 to achieve this objective. This included the following:

- Staffing – 1 GIS Administrator and 3 GIS Technicians
- Data Infrastructure – Acquire ESRI Arc Server and Desktop v9.3
- GPS Mapping and Field Data Capture of asset attributes
    - 280,000 poles
    - 31,000 transformer locations
    - 10,500 switch location
    - 8,000 km of secondary circuits to which customers are connected.
- Established Geometric Network – Mechanism used to develop and maintain the connectivity of 580,000 customers to transformer locations to line switches and to feeder reclosers.

The Geometric Network was completed on a phase-by-phase basis as outlined below.

1. Phase I – Map All Customer Meters
2. Phase II – Map All Line Switches (Isolating and Interrupting Device) Locations
3. Phase III – Map All Transformer Locations Including Secondary Dead-End Points

With the geometric network completed, each switching device currently has a unique Name/Identifier and attributes data, which includes the number of customers served via the switch. Whenever a switch operates, this unique identifier is captured as a part of the outage information, which now results in each outage being assigned to a unique switch identifier, and in turn an accurate customer count.

Feeder Level Outages

These outages will continue to be captured at the System Control Centre outage-logging database and will be time-stamped using the data provided by the SCADA system. As indicated earlier the revised mapped customer count data has been implemented and tied to the individual feeder recloser providing accurate registering of customers affected.

Sub-Feeder Level Outage

- Planned outages—for planned outages at the sub-feeder level, all outages are currently tied to a switching point, which in turn is mapped to a customer count. The start and end times are recorded and captured in the Outage Log Database at the System Control Centre.

- Forced outages— for forced outages JPS will continue using the start time of outages as that reported by the first customer and the end time as that determined by the recloser or switch closing time.

8.3.5 JPS Data Capture Proposal

JPS intends to utilize the improved data capture mechanism with actual customer count to compute system reliability indices for 2009. After preliminary comparisons between both methods of estimating customer counts it was observed that on average the customer counts using the information from the GIS database was 70% higher than that using the fuse method of calculation. Further research revealed that according to an EEI survey conducted in 2005 among 24 utilities, 17 of the 24 utilities recorded an increase in outage statistics after improvements in data gathering techniques. It can therefore be concluded that a transition between customer estimation methods will inevitably result in increases in SAIDI, SAIFI and CAIDI levels.

In order to track and quantify this possible increase, JPS proposes to continue calculating the reliability indices using both techniques (use of fuse size data and the use of GIS data) for the remainder of 2009. After this point a comparison can be made between both methods to establish a benchmark performance for setting reliability targets for 2010 and beyond.

8.3.6 Future Data Collection Improvements

With the completion of the geometric network JPS has undertaken the task of procuring/building an Outage Management System. At present there are several different types of software that capture outage data for reporting purposes. These applications will be replaced with a single solution that will log and record, outage start and end times, interrupting devices, fuse sizes, customer information on all feeder and sub feeder outages.

JPS is currently embarking on the implementation of AMI meters in residential communities. These meters will be outfitted with communication capabilities and will report kWh readings, tamper flags as well as outages to a central database. With the implementation of this technology JPS will use the data from these meters to accurately define the outage start and end times.

With almost real time graphical monitoring of system outages and modifications, a proposal will be made to move from a static feeder count system to a dynamic count to facilitate system reconfigurations including partial load transfers between feeders.

JPS has indicated that the company is investing a significant amount of resources in its efforts to improve its data collection capabilities. JPS posited that the combined spend on the GIS project, along with the acquisition of additional SCADA and communication system upgrades to ensure proper monitoring of all substations, is approximately US$3 million. Additionally, JPS' total expenditure between 2007 – 09 on the installation of smart meters (AMI) at 5,000 plus commercial and industrial customer locations to augment its ability to detect outages at the sub-feeder level on some secondary circuits will total US$6 million upon completion later this year.

8.4 OUR position on the proposed Q-Factor

The current baseline data proposed by JPS represents data that is reflective of a period when there were a number of countervailing factors[16] militating against adequate reliability and consequently there is high variability in the monthly indices.

Additionally, the initial baseline data used to derive the indices are unreliable and there was always the need to improve data collection as being demonstrated in the discourse outlined above. The OUR is of the view that the data presented over the last four years is neither sufficient nor representative enough to ensure the optimum baseline for a robust Q-factor. However, the OUR is of the view that in order to minimize the risk of a lower than optimum baseline for the measurement of a subsequent Q-factor, the dead-band performance[17] target should be sufficiently large to take into account the variability of the current data. In addition, the OUR will direct the utility to provide an audit of the collection and measurements of the outage data to verify its representativeness and validity. This will ensure that the utility will have to bring material improvements to the quality of service to score quality points exceeding the dead band of zero

Furthermore until a reasonable trend and consistent quality in the Q data set can be observed the OUR will be constraied in establishing a fair baseline. OUR has observed that in other jurisdictions that such data is typically collected for a three to ten year period. Additionally, given the proposed continuous improvement to the target data, and the knowledge that the target is derived from base line data

[16] The countervailing factors are hurricanes in 2004 and 2005, system shutdown in 2007 and 2008 and data collection issues relating to the integrity of the system

[17] Actual performance within a certain variance sufficiently large to ensure that the utility will have to improve quality of service to score quality points exceeding zero.

with some known imperfections, and given the proposed improvement to the data collection process in future the Office is of the view that setting the penalty/reward targets relative to the Quality points for each of the indices above is premature and fraught with risk. The Office is of the view that the Q-factor should continue with a dead band with zero points until the integrity of the data and the data collection procedures are fully implemented and audited.

JPS is proposing that there should be a discontinuance of the use of CAIDI as a benchmark, while upholding the use of SAIDI and SAIFI.

The reasons for CAIDI exclusion are outlined as:

1. " The metric is redundant when SAIDI and SAIFI are already included in the metrics"
2. "It can be demonstrated mathematically that SAIDI and SAIFI are ultimately what matters to customers"; and
3. "Using SAIDI, SAIFI and CAIDI to measure quality can lead to anomalous and unwarranted penalties or rewards in a service quality mechanism" [18]

8.4.1 Definition of MAIFI as a Reliability Index

MAIFI—this index is designed to give information about the frequency of momentary outages (those of durations of 5 minutes or less) per customer over a predefined area.

$$MAIFI = \frac{\text{Total number of customer interruptions (for durations of 5 minutes or less)}}{\text{Total number of customers served}}$$

(expressed in number of interruptions per year)

Momentary interruptions are defined in IEEE Std. 1366 as those that result from each single operation of an interrupting device such as a recloser. MAIFI measures data on momentary interruptions that result in a zero voltage. For example, two circuit-breaker open operations are equivalent to two momentary interruptions.

[18] Please see Appendix three of the *X factor and Q factor recommendations for JPS, October 2008*, for mathematical proof of what matters to customers.

8.4.2 JPS Operations and Momentary Interruptions

JPS' posited that the distribution network comprises 110 feeders, predominantly overhead lines, which emanate radially from 52 substations. The major drivers of momentary interruptions on any exposed outdoor distribution system include lightning strikes or other weather related effects, lines making contact, tree interaction with lines as well as animal and bird contact with lines.

In the JPS system, the feeder protection systems are managed through substation reclosers working in tandem with fuses at the feeder laterals. The general philosophy of operation is to have one fast and two slow operations of a substation feeder recloser upon the event of a fault along the feeder.

The first fast operation (instantaneous) of the recloser prevents unnecessary fuse blowing (fuse saver scheme) and strives to minimize sustained interruptions by opening and reclosing immediately to give an opportunity for a temporary fault to clear. On the first slow operation of the breaker, if the fault still persists, this will allow enough time for the fuse required to isolate the fault to blow. Should the fault still persist after the second closing of the breaker, then a third breaker opening will cause a lockout (remain open) of the breaker and no supply to the feeder.

On the event of a lockout, field personnel will be dispatched to find the source of the fault and effect isolation and repairs. The unaffected parts of the feeder will be returned to service when isolation is effected by closing back the breaker. Each incident of a breaker lockout will almost always exceed the five minute threshold for MAIFI and will thus be captured in SAIFI and SAIDI. In instances when the source of the fault is not permanent (e.g. lightning strikes), there can be one or two cycles of the feeder not leading to a lockout. These instances would be captured in MAIFI.

Based on the configuration of JPS' distribution system, section outages would not normally fall in the category of momentary interruptions and can be ignored for MAIFI calculations since operations on a feeder beyond the recloser are predominantly manual. Likewise, JPS has stated that it does not now have the capability to measure momentary outages at an individual customer level.

8.4.3 Current Data Collection Systems for MAIFI

JPS collects data on all sustained interruptions due to permanent trips in the Outage Database at the System Control Centre. These include interruptions due to under-frequency, planned and forced transmission and distribution outages.

JPS also stores on the SCADA historian server, all the recloser cycling for substations that are monitored. However, not all the substations are monitored by SCADA and, therefore for recloser cycling, data from such substations will not be available for MAIFI computation. Similarly, whenever there is a break in communication to a substation's Remote Terminal Unit (RTU) the recloser cycling operation is not captured.

8.4.4 Guiding Principles for calculating MAIFI

Given the various scenarios that can lead to momentary interruptions, JPS is of the view that the target set for MAIFI, as is the case with the other reliability indices, should provide fair treatment for factors affecting performance that are outside of JPS' control. Thus, the baseline data used to set MAIFI targets must be confined to instances initiated by JPS controllable factors. In that respect, it is JPS' view that the following incidences should be excluded:

- Normal switching activities required during maintenance, load transfers, fault isolation or post fault restoration etc., that may cause momentary interruptions to customers;
- Under-frequency operations which act to protect the system from collapse;
- Cycling operations which eventually lead to a lockout of the recloser and hence restoration times exceeding five minutes since this incident will already be accounted for in SAIFI;
- Third party initiated incidences which cause momentary interruptions to customers where such third party is not acting as an agent of JPS; and
- Acts of GOD (i.e. lightning or other weather related effects, natural disasters etc.) or other force majeure provisions presently applied to the other indices (SAIDI, SAIFI and CAIDI) under the current Q-Factor mechanism.

The remaining incidences will be driven by factors that JPS is either directly responsible for or has some means of controlling or mitigating. This will ensure that the Q-factor is satisfying the criteria of providing the proper financial incentive to encourage JPS to continually improve service quality.

8.4.5 2006 – 2008 MAIFI Data Analysis and Q Factor Proposal

JPS submitted the number of breaker cycling data required for the calculation of MAIFI for the JPS system for the period 2007 – 2008. JPS posited that research on the use of MAIFI as an index for reliability measure has shown that this index has waned in popularity over the years. Oftentimes utilities have found it difficult to extract the information to calculate this index accurately and have abandoned the measure in preference to SAIDI and SAIFI.

JPS has also posited that the company had significant difficulty in extracting the information solely related to the calculation of MAIFI. The old SCADA system (ABB Ranger) along with the limitations of other database management and communications systems provided significant challenges to extracting incidences less than five minutes in duration and consistently classifying them as MAIFI related according to the principles outlined above. This is not uncommon to many utilities across the world. Consequently, the MAIFI data presented for 2007 to 2008 has not been cleaned of all the momentary outages caused by the above-mentioned factors which are outside of JPS' control.

Nevertheless, the Company has used its best efforts to provide a breakdown of the 2008 MAIFI related outage data. This should provide some high level guide to the breakout of the effects of the causative factors. Statistically, the 2008 breakout data indicates that 9,643 pairs of breaker open and close operations were recorded by the SCADA system. Of that amount, 695 were found to have associated outages whose duration would result in them being classified under SAIFI. The remaining 8,948 breaker operations include 1,044 with duration between 6 seconds and five minutes. These 1,044 breaker operations would for sure include the majority of under-frequency operations, switching operations, operations caused by weather related factors and other factors mentioned before. The 7,904 breaker operations left include all cycling operations of less than 6 seconds duration caused either by JPS controlled (planned maintenance or forced events), acts of God and weather related factors, third party incidences, etc. Using the non-SAIFI related breaker operations (8,948) to calculate MAIFI gives a result of 117.29 minutes.

JPS is also proposing that to effectively, accurately and consistently measure and report MAIFI will require vast improvement in its data capture, reliability and verification capabilities. JPS stated that the company is currently improving its communications infrastructure as well as implementing a new SCADA system with improved data capture and processing capabilities. While some of the MAIFI causative factors (maintenance, switching, under-frequency etc.) can be possibly be tracked and eventually extracted, the tracking of many of the main MAIFI drivers (acts of GOD and weather related causes etc.) require infrastructure and systems that JPS currently does not have.

Importantly, given the current configuration of the T&D network and the lack of inter-connectivity, particularly in many rural areas, it would require significant capital investment to implement redundant systems and automatic switching equipment to enable the Company to be able to control or improve MAIFI

As a result of all of the above factors JPS proposes that MAIFI not be included as part of the annual Q-factor adjustment mechanism but rather that the OUR monitors the MAIFI results during the period 2009 – 14. JPS further states the following in their submission:

- there are significant uncertainties regarding an appropriate benchmark for MAIFI.
- JPS recommends that MAIFI simply be monitored, rather than subject to explicit penalties or rewards, in the next PBRM.
- JPS also believes more attention should be devoted to understanding customers' willingness to pay for quality improvements, including the willingness to pay for reductions in MAIFI.
- JPS proposes that MAIFI be included as a part of the overall standards and be monitored on an annual basis.

Conclusion

The OUR agrees that more knowledge of customer preferences can help JPS make appropriate investments and ensure that any quality improvements actually improve customer welfare.

Notwithstanding, the OUR is of the view that JPS should continue to improve its systems to refine the data required for the assessment of momentary interruptions consistent with the principles outlined in this submission to facilitate the inclusion of an appropriate index in the determination of service quality.

The OUR will facilitate a continuous dialogue with the JPS on the inclusion of MAIFI as part of the Q-factor determination while the Company improves its monitoring capabilities, attempts to better understand and categorize the data with respect to the causative factors and further analyze the relative performance of some feeders vs. others.

Determination

The Office has determined that once the base-line data is deemed reliable for SAIDI and SAIFI and CAIDI on the improved basis that the targets and penalty/reward scoring system be revised during the 2009-2014 annual adjustment submissions. The Q-factor adjustment for 2009 will therefore remain within the dead band and therefore zero. The Office further determines that it will include MAIFI as part of the Q-factor adjustment mechanism going forward as of 2010, but given the significant challenges and concerns highlighted by JPS, the weighting of MAIFI in the point score system

will be assessed for its resultant tariff impact and for further decision by the Office.

Additionally, the Office has determined that Generation outages caused from IPP plants should be excluded from the Q-factor calculations.

9. Fuel Cost Adjustment Factors - Heat rate

9.1 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 energy for which revenue is received.

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

"the Licencee 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 Licencee and Independent Power Producers (IPPs) in the production of electricity as well as the Licencee'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 Licencee and IPPs)"

It is clear that the Licence contemplated that under the price cap tariff period commencing June 2004, total system losses and heat rate would 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.

9.2 Heat Rate

9.2.1 JPS' Stated Objectives and Principles for Heat Rate

The OUR is of the view that the objective for setting the heat rate target for the generation system is to ensure that customers are provided with fair and reasonable fuel rates by having a regulatory environment that provides JPS with the incentives to:

- Improve the relative efficiency of converting chemical energy to electrical energy; and
- Ensure economic dispatch of all available generation units.

The OUR is of the view that the following principles should be applied in setting the heat rate target:

- target should hold JPS accountable for the factors which are under its direct control;
- The target should adequately and realistically reflect the available and future (within the rate-cap period) generating fleet's capabilities and legitimate constraints;

9.3 Generation Dispatch

The dispatch of the generating plants in Jamaica's electricity system has considerable implications for the system's fuel bill, and consequently, for the fuel based tariff to customers. The main objective of the generation dispatch process should be to minimize the system's production (variable) cost, subject to the overriding considerations of safety, system security and reliability. The process of minimizing the system's variable cost, which is predominantly composed of fuel expenses, is termed "Economic Dispatch."

9.3.1 Economic Dispatch

In this document, the term Economic Dispatch is used to collectively represent the economic optimisation processes that determine:

- the combination of generating plants which should be turned on (committed) and made available to serve the system load (referred to as Unit Commitment).
- the levels of electricity output from the committed generating plants (usually called Economic Dispatch)

Classical economic dispatch theory indicates that the production cost optimisation is achieved when the dispatch is based on the equal incremental cost principle whereby the generators online in the system are loaded to points of equal incremental cost. The generating plant that can increase its output at the least incremental cost then supplies the next increment of load on the system. There are many methods for determining how to commit units to the power grid. It is internationally accepted that the most efficient method is the Priority Based or Merit Order Listing, which is the approach prescribed by the All Island Electricity Licence of 2001. The term "Merit Order" refers to the procedure whereby the generating units with the lowest variable costs are committed first for operation, moving from the least expensive unit to progressively expensive units as the demand increases during the day. Conversely, as the demand falls the higher costs generators are taken out of use first.

9.3.2 Security Constraint Economic Dispatch (SCED)

An overriding condition to the cost optimization process is the need to ensure safety, the preservation of the system security and an adequate level of service reliability. In this regard, from time to time JPS will not be able to dispatch the generating plants strictly on the basis of economics, as operating limitations in the power network may constrain the dispatch (for example, under certain transmission line outage contingencies). Security constraint economic dispatch (SCED) is the term used to refer to the process of minimizing the system's production cost subject to security constraints on the system. Under SCED, generating plants may be required to be committed outside of their original merit order (out-of-merit).

9.3.3 JPS' Obligation to Perform Economic Dispatch

The All Island Electricity Licence (2001) Condition 23 sets out the requirement for JPS to perform its generation dispatch function in accordance with a merit order system. This system is based on "Equal Incremental Cost" principles. This implies that JPS has a legal obligation to perform economic dispatch of the generating plants in its system, subject to safety, system security constraints and reliability considerations.

9.3.4 Business Incentive

The Licence prescribes for actual fuel cost passed on to rate payers to be modified by targets for system losses and the system heat rate, which measures the efficiency of the conversion of fuel to electricity. If the company betters these targets it will make a gain and conversely if it does not meet the targets it will suffer a loss. Whatever efficiencies the company gains are expected to be clawed back at the end of the 5-year tariff period when the tariff is reset. This regulatory arrangement provides JPS with a financial incentive to legitimately minimize its system heat rate (i.e. to maximize the system's fuel conversion efficiency)[19] and its system losses. The incentive, which is designed to allow JPS to recover a component of the system fuel expenses if it outperforms specified system heat rate and system losses targets, can be depicted by the following equation:

[19] The fuel conversion efficiency (η) is inversely proportional to the heat rate (HR). Mathematically, this is represented as $\eta = \frac{3600}{HR}$, if HR is in kilojoules per kilo-watt-hour.

$$JPS \quad Monthly \quad Gain = \left[\left(\frac{HR_{PERMITTED}}{HR_{ACTUAL}} \times \frac{1 - Loss_{ACTUAL}}{1 - Loss_{PERMITTED}} \right) - 1 \right] \times FC_{ACTUAL} \quad \ldots(1)$$

Where:

$HR_{PERMITTED}$ is the target system heat rate allowed in JPS' tariff;

HR_{ACTUAL} is the actual system heat rate achieved by the system in a given month;

$Loss_{PERMITTED}$ is the target system losses allowed in JPS' tariff;

$Loss_{ACTUAL}$ is the actual system losses achieved by the system in a given month;

FC_{ACTUAL} is the actual system fuel cost in a given month;

It is possible that the incentive to minimize the system heat rate (HR_{ACTUAL}) could be pursued to the detriment of economic dispatch. This may seem counterintuitive given that minimizing the system heat rate implies maximizing the system's fuel conversion efficiency. However, maximizing the system's fuel conversion efficiency will not necessarily lead to minimizing the fuel cost – the most significant component of the production cost, since the generating plants in the system operate on two different types of fuel oil which have different unit prices.[20]

On examining equation 1, one may conclude that higher system fuel costs (FC_{ACTUAL}) should actually suit JPS financially if the company is able to achieve actual system heat rate (HR_{ACTUAL}) and system losses ($LOSS_{ACTUAL}$) such that

$$\left(\frac{HR_{PERMITTED}}{HR_{ACTUAL}} \times \frac{1 - Loss_{ACTUAL}}{1 - Loss_{PERMITTED}} \right) > 1.$$

[20] Note that the fuel cost of a generating plant (US$) is the product of its heat rate (kJ/kWh), the unit price of the fuel it burns (US$/kJ), and the plant's electricity generation (kWh).

There is however, a relationship between higher fuel costsand system losses and demand which must be understood in order to fully appreciate the nature of the situation. Fuel cost can increase based on a number of factors including an increase in baseline fuel prices, worsening conversion efficiency, or sub-optimal dispatch. Whatever the reason, it is generally accepted that consumers will react to higher costs. Higher fuel cost generally leads to an increase in losses, and stagnation or reduction in demand, which are not in JPS' interest.

Once $\left(\frac{HR_{PERMITTED}}{HR_{ACTUAL}} \times \frac{1 - Loss_{ACTUAL}}{1 - Loss_{PERMITTED}} \right) < 1$, it would appear that it is in JPS' best interest to minimize the system fuel cost (FC_{ACTUAL}). However, this is not necessarily true, since the system fuel cost is a function of the system heat rate. Even while $\left(\frac{HR_{PERMITTED}}{HR_{ACTUAL}} \times \frac{1 - Loss_{ACTUAL}}{1 - Loss_{PERMITTED}} \right) < 1$, it may be possible for JPS to adjust its system heat rate (HR_{ACTUAL}) such that the system fuel cost (FC_{ACTUAL}) is higher than the optimum value, while JPS monthly gain (loss) works out higher (lower) than the case of optimum dispatch. To give an illustration, consider the concocted, yet realistic, system parameters given in Table 9.1 below:

System Parameters	Case A (Optimal Dispatch)	Case B	Case C
Target System Heat Rate ($HR_{PERMITTED}$) (kJ/kWh)	11,200	11,200	11,200
Actual System Heat Rate (HR_{ACTUAL}) (kJ/kWh)	10,450	10,275	10,275
Target System Loss ($LOSS_{PERMITTED}$) (%)	15.8%	15.8%	15.80%
Actual System Loss ($LOSS_{PERMITTED}$) (%)	23.0%	23.00%	25.00%
System Fuel Charge (FC_{ACTUAL}) (J$k)	3,215,000	3,450,000	3,450,000
$\left(\frac{HR_{PERMITTED}}{HR_{ACTUAL}} \times \frac{1 - Loss_{ACTUAL}}{1 - Loss_{PERMITTED}} \right)$	0.9801	0.9968	0.9709
JPS Net Gain (J$k)	(63,906)	(10,968)	(100,311)

Table 9.1: Illustration of JPS Business Incentive

Case B in Table 9.1 illustrates that it may be possible for JPS' financial situation to be improved by performing sub-optimal generation dispatch, with the assumption that heat rate improves and losses are not affected.

To be objective, it is important to point out that there is a feedback mechanism in which a sub-optimal dispatch could eventually lead to a negative impact on JPS' financial position. This arises due to the fact that sub-optimal dispatch implies higher fuel prices and consequently higher fuel base tariff, which in turn can influence the upward movement of the system losses. Case C represents this scenario and shows that sub-optimal dispatching could eventually worsen JPS' financial situation.

During the year 2007 JPS made a net loss on fuel amounting to J$1.27 billion, while for the period January 2008 to August 2008 JPS made a net gain of J$67.66 million on fuel.

9.3.5 JPS Proposal

The JPS made reference to Schedule 3, Exhibit 2 paragraph 1 which it quotes verbatim. In summary this clause states the following:

- *The cost of fuel per kWh (net of efficiencies) shall be calculated each month on the basis of:*
    - *Total fuel computed to have been consumed by JPS and IPPs*
    - *Licencee's generating heat rate as determined by the Office*
    - *IPPs generating heat rate as per contract with IPPs*
    - *System losses as determined by the Office*
    - *Total net generation*

JPS stated that the Clause is silent on exactly how the fuel rate is to be calculated.

The Licence does describe a methodology for calculation of the monthly fuel rate which in summary is as follows:

Fuel cost portion of monthly bill is given by:

F = *Fm/Sm*

F = *Monthly adjusted fuel rate in J$/kWh applicable to bills rendered during the current Billing Period.*

Sm = *kWh Sales in the Billing Period*

which is the actual kWh sales occurring during the billing period which ended one month prior to the first day of the applicable billing period.

Fm = *Total Applicable Energy Cost which is:*

- *Cost of fuel adjusted for determined heat rate and system losses*

  PLUS

- *Fuel portion of the cost of purchased power adjusted for determined losses*

  PLUS

- *An amount to correct for under- or over-recovery of total reasonable and prudent fuel cost which is*

- *Fuel costs billed using estimated fuel costs*

  LESS

- *Actual reasonable and prudent fuel costs incurred during the month which ended one month prior to the first day of the billing period.*

The Licence therefore does provide a mechanism for calculation of the fuel rate but the mechanism specified does lack details on:

- How to adjust the cost of fuel for determined heat rate and system losses
- How to adjust the fuel portion of the cost of purchased power for losses
- How to make the correction for under or over recovery.

There is in fact a detailed mechanism which JPS and the OUR have been using to determine the monthly fuel cost. The mechanism currently being used involves the following formula:

$$\textbf{Pass through fuel cost} = \textbf{Actual fuel cost} \times \frac{\textit{targeted heat rate}}{\textit{actual heat rate}} \times \frac{(1-\textit{actual losses})}{1-\textit{targeted losses})}$$

JPS proposed that the heat rate target should continue to be based on the total generating units throughout the system (both JPS and IPPs), since fuel optimization through economic dispatch seeks to optimize overall system variable cost.

JPS proposed that this is similar to the approach used in setting the 2004 – 2008 heat rate target where average performance was considered indicative of future performance subject to the addition of new capacity or the retirement of existing ones.

There are a few issues regarding the mechanism being used in practice. Issues raised by JPS include the following:

1. JPS is concerned about the TOU discount/premium can lead to under- or over-recovery of fuel cost.
2. JPs is "fundamentally concerned" about the impact that fuel prices and IPP availability/reliability can have on system dispatch and overall costs and by extension the system heat rate and the resultant determination of recoverable fuel cost.
3. JPS states that since IPP costs and performance funds (i.e. liquidated damages) are included in the fuel rate calculation, when IPP performance

is below expectation, JPS is effectively penalized by the resulting deterioration in the system heat rate. JPS has stated that this is a great concern to them since:

4. The IPP performance is entirely outside their control;
5. IPPs make up a significant portion of the total fuel costs and will increase their proportion in the future;
6. The current fuel cost penalty also applies to the IPP fuel cost.

There appears to be some validity to issue number 1 and the OUR is of the view that with the correct design of the TOU rates the problem can be rectified.

Issues 2 and 3 are also valid and are assessed by the OUR. There are two options which can be considered fair. They are as follows:

1. JPS continues to be penalized for IPP performance but gets to keep the liquidated damages collected from IPPs for said non-performance.
2. JPS passes through the liquidated damages from the IPPs but appropriate adjustments are made such that JPS is not penalized for the IPPs non-performance.
    - This option will be more complicated and difficult to monitor and manage;
    - JPS seems to prefer this option and has proposed that the heat rate target be adjusted to neutralize any fuel and/or IPP impact on the system heat rate.
    - Given that liquidated damages are now being passed through to customers this is the preferred option to the OUR as well.
    - Given the above, practical mechanisms need to be considered to ensure that JPS is not punished for factors outside its control but at the same time is not able to benefit unfairly from the system.

9.4 Heat Rate Target

9.4.1 General

Heat rate for a generating unit or system is a reflection of the efficiency with which chemical energy in the fuel used is converted to electrical energy. The unit typically used is Btu/kWh or kJ/kWh.

The JPS system average net heat rate for a given time period can be determined by dividing the total amount of energy contained in the fuel burned by the net amount of energy produced during the same time period.

9.4.2 Objective

The objectives of the heat rate target should be the following:

- Ensure that customer tariffs reflect a fair charge for the cost of fuel based on efficient operation of generating units in the system.
- Provide an incentive for JPS to improve the fuel conversion efficiency of its generating units and its economic dispatching activities.

9.4.3 Application of Heat Rate Target

The OUR traditionally establishes a heat rate target for each tariff period at the time of the tariff review. There are some issues with how the target is applied and these will be discussed separately. In this section the proposed methodology for establishing the target will be discussed.

9.4.4 Guiding Principles for Setting the Heat Rate Target

JPS proposed a policy guideline as well as a number of key factors that should be taken into account in establishing the system heat rate target. The JPS proposals are reasonable but could be more comprehensive. JPS' proposals were taken into account in coming up with the following guidelines.

The OUR's view is that the guiding principles for the establishment of the heat rate target are as follows:

- The overall objective shall be the provision of a reliable electricity supply to consumers at the lowest possible cost.
- The establishment of the heat rate target shall be in accordance with the applicable provisions of the Licence.
- JPS shall be held accountable for factors affecting system heat rate which are under its control.
- The change interval should give JPS the opportunity to reap gains from investments in meeting and exceeding the target.
- The target should reflect the guaranteed capabilities of different generating units including heat rate, availability, capacity rating. These capabilities should be guaranteed by the respective owners of the units.
- The target should reflect legitimate system constraints provided that JPS is taking all reasonable action to mitigate these constraints. The constraints should be the subject of independent verification.
- The target should take into account changes in generating plant in the system including planned additions and retirements. These should be based on a generation system least cost expansion plan.
- All other major factors that impact the target should be taken into account including:
- The requirement for procuring fuel at the best price possible.
- The requirement for economic dispatching of generating units.

Given the uncertainties regarding some of the above factors, the target should be revisited more frequently than at five year intervals.

Ideally, a software program capable of taking into account the information specified above and having the capability to economically dispatch the generating units should be used to determine the expected heat rate which could then inform the target to be set. The WASP software currently used by the OUR for generation planning, with some creativity, could be used for this purpose supported by calculations with the economic dispatching software currently being used by the JPS.

9.4.5 Adequacy of the Heat Rate Target

Economic dispatching is aimed at minimizing the overall cost of electricity to consumers. This is consistent with the OUR's objective of ensuring a reliable supply of electricity to consumers at least cost.

Plant heat rate is only one of the factors that affect economic dispatching and therefore focus on this by itself does not guarantee economic dispatching.It is therefore not sufficient to ensure that the OUR's objective is met.

Factors affecting economic dispatch include:

- Generating plant capability, availability and reliability;
- Network constraints;
- Spinning reserve policy;
- Improvements to existing units;
- Plant additions and/or retirements;
- Fuel price;
- Performance of IPPs;
- Non-fuel variable operating and maintenance costs.

The use of the system heat rate target does provide some incentive for JPS to improve on some of these factors but not necessarily to the extent consistent with the overall objective of reliable power at least cost.

To the extent that the heat rate target does not provide the motivation for improvement in these other factors, the OUR will ensure that other mechanisms afforded by the Licence are brought to bear.

9.4.6 NETWORK CONSTRAINTS

- o JPS has claimed that network constraints have forced it to dispatch plants out of merit and that these constraints need to be taken into account in setting heat rate targets.
- o In particular, as indicated elsewhere, JPS may have an incentive to dispatch the combined cycle plant at Bogue out of merit and in fact appears to have been doing so with the explanation that this is due to network constraints.

- After several longstanding requests, the JPS is yet to provide details of the reported constraints.
- If the network constraints are due to temporary line outages, JPS has an incentive to minimize these and thus the OUR is of the view that this should not be included in setting the heat rate targets.
- If there are fundamental issues with the capability of the network that require time to correct, the OUR is of the view that JPS should implement measures to address these concerns over the medium term and the OUR expects this to be reflected in the heat rate targets.

9.4.7 SPINNING RESERVE POLICY

- In order to ensure system security and quality of supply, JPS needs to operate the system with an appropriate level of spinning reserve.
- Since JPS is penalized for poor quality of supply under the Q-Factor, JPS does have an incentive to strike the right balance between economic dispatching and security of supply by operating with appropriate spinning reserves.
- The OUR should ensure that the incentives / penalties for quality of supply and cost of supply are adequately balanced based on implications for JPS by way of the Q-Factor and the heat rate target.

9.4.8 IMPROVEMENTS TO EXISTING UNITS

- Changes in the capabilities of existing units in terms of capacity, availability and operating efficiency are encouraged by the heat rate target.
- To the extent that JPS seeks to recover investment in existing units, the benefits from these investments should be justified to the OUR and factored into the performance targets.
- Significant changes such as the introduction of new fuel types should be subject to evaluation based on the LCEP and should demonstrate net benefits to consumers before being factored into the targets set by the OUR.
- JPS should be encouraged to seek innovative means of improving the existing units to the extent that these improvements are consistent with the LCEP by allowing the company to share in the gains.

9.4.9 NEW GENERATION

- The most significant impact on the overall cost of electricity production will result from the introduction of new generating plants.
- Since the OUR is now responsible for planning for and procurement of new capacity, JPS should not be penalized or rewarded for introduction of such new capacity, unless JPS is the agency specified by the OUR to implement such new capacity.
- Heat rate and other performance targets should reflect any new plant that is added to the system or old plant retired from the system.
- Future targets could be set based on simulations WASP and the economic dispatch program, with adjustments made if projects are not implemented or do not perform as planned.
- Alternatively, the targets should be adjusted after a new plant is commissioned and expected performance is confirmed.

9.4.10 FUEL PRICE

- Fuel accounts for a significant cost of power generation and this cost is a reflection of fuel conversion efficiency as well as the price paid.
- The heat rate target does not take into account the price of fuel even though this is required to be taken into account in the economic dispatching of generating units.
- The heat rate incentive therefore may not be completely aligned with economic dispatching of units and JPS, in its efforts to meet the heat rate target could be tempted to dispatch plants out of merit.
- The combined cycle unit at Bogue is an example of a situation where, all other things being equal, JPS may wish to dispatch out of merit due to its low heat rate, even though it burns a more expensive fuel.
- In order to address this potential breakdown in the incentive scheme, the OUR will need to utilize its powers under the Licence to:
    - Ensure that JPS is procuring fuel at the least cost at all times based on the requirement of the Licence for JPS to procure goods and services in the most economic manner;

- Ensure that JPS is dispatching all generating units based on merit by enforcing the sections of the Licence which require JPS to do this.
- Ensure that JPS does not discriminate against IPPs.

9.4.11 VARIABLE O&M COSTS

- The heat rate target does not take into account variable O&M costs which must be taken into account in economic dispatch.
- This deficiency again may lead to JPS dispatching units out of merit in order to meet heat rate targets.
- In order to address this potential breakdown in the incentive scheme, the OUR will need to utilize its powers under the Licence to:
    - Ensure that JPS takes variable O&M costs into account in dispatching generating units.
    - Ensure that JPS is dispatching all generating units based on merit by enforcing the sections of the Licence which require JPS to do this.
    - Ensure that JPS does not discriminate in the dispatching of IPPs.

9.4.12 IPP PERFORMANCE

- Since the heat rates of IPPs are guaranteed, their actual heat rate performance does not affect the cost to JPS.
- The performance of IPPs in terms of availability and reliability will affect the overall system heat rate. However, there are performance guarantees with respect to these parameters which have associated liquidated damages.
- If JPS is to be held responsible for the performance of the IPPs then JPS should be entitled to keep the liquidated damages collected from IPPs.
- If JPS is not to be held responsible for the performance of IPPs then the liquidated damages should be passed on to consumers by setting them off against the monthly fuel and IPP charge.

9.4.13 SYSTEM HEAT RATE TARGET FOR 2004 - 2008

1. The OUR established a target heat rate for the entire tariff period 2004-2008 with no interim adjustments.
2. The target heat rate established by the OUR was 11,200 kJ/kWh
3. JPS proposed to relate the average system heat rate targets to the historical average for the preceding five years. The average JPS system heat rate for the five years preceding the tariff determination for 2004 were as follows:

System Annual Heat Rate: 1999 – 2003

Year	System Heat Rate (KJ/kWh)
1999	12,872
2000	13,234
2001	13,384
2002	11,888
2003	11,554

4. If the OUR had used the latest average heat rate as a guide, the initial target heat rate should have been set at about 10,824 kJ/kWh.
5. If the five year average was being used, the target would have been set at about 12,586 kJ/kWh. However, because the combined cycle was completed in 2003, the target heat rate would need to take this into account and therefore would more likely be closer to the actual figure for 2003 which is reported to be 11,554 kJ/kWh.
6. If simulations were done using WASP and or the economic dispatch program, the target would have been expected to be close to the above 2003 system heat rate.
7. The target heat rate was not adjusted after the introduction of the new JEP 50 MW plant in 2006 which would have resulted in significant improvements to the overall system heat rate.
8. The target heat rate did not take into account other changes to the existing generating units.
9. The heat rate performance reported by JPS for the period 2004 to 2008 was as follows:

- 2004 - 10,832 kJ/kWh
- 2005 - 10,985 kJ/kWh
- 2006 - 10,174 kJ/kWh
- 2007 - 10,627 kJ/kWh
- 2008 - 10,215 kJ/kWh

10. The reduction in 2006 was apparently due to the completion of the combined cycle plant at Bogue. It is not clear what the expected rate should be with the inclusion of this plant.
11. It is not yet clear what caused the increase in 2007, however, the rate returned to close to the 2006 figure in 2008.
12. For this review the performance of the JPS and IPP plants have been taken into account by the OUR to see how they compared with expected/guaranteed levels.
13. Based on the above, the average system heat rate over the period 2004 to 2008 was 10,567 kJ/kWh. The calculated weighted average reported elsewhere was 10,561 kJ/kWh.
14. This means that the target heat rate was 6.0% higher than the actual outturn for that period. This is very significant given the cost of fuel.
15. JPS has indicated that for every 100 kJ/kWh difference in heat rate, the benefit using 2008 fuel prices would be US$4.5 M per annum.
16. Based on this, the net benefit to JPS in 2008 was in excess of US$44 Million or J$ 4 Billion.
17. The fact that JPS was making a significant profit on fuel used would mean that, all other things being equal:
    - Consumers were paying more than they should have;
    - JPS had an incentive to purchase fuel at the highest price possible rather than at the lowest price possible.

It should be noted that JPS was losing on the losses target and therefore the final analysis must also take this into account. However, given the high cost of fuel, the above demonstrates the importance of the OUR establishing appropriate targets for JPS.

9.4.14 METHODOLOGY & DATA USED BY JPS

The methodology and data used by JPS in arriving at its proposed heat rate targets whilst reasonable are questionable. The OUR evaluated JPS' heat rate model using generation data produced by WASP. The WASP simulation was done using the existing system for the period 2009 – 2014 taking into account knownno addition to the system over the period.

9.4.15 JPS PROPOSED NEW HEAT RATE TARGETS

JPS proposes the following heat rate targets:

1. July 2009 to June 2010 - 10,850
2. July 2010 to June 2014 - 10,700 (contingent on new 60 MW plant)

9.4.16 Comment on Results

The projected heat rates calculated by JPS are shown below in comparison to the targets being proposed by JPS and that simulated by the OUR using the energy output simulated from WASP. The WASP software currently used by the OUR for generation planning, with some creativity, could be used for this purpose supported by calculations with the economic dispatching software currently being used by JPS.

Year	JPS Projected Heat Rate	JPS Proposed Target	Our Projected Heat Rate
2009	10,380	10,850	9,208
2010	10,209	10,850 & 10,700 from July	9,341
2011	10,073	10,700	8932
2012	10,073	10,700	9,058
2013	10,120	10,700	9,317
2014	10,280	10,700	9,363

As can be seen, JPS is proposing heat rate targets that are significantly above even their own projected targets. Additionally, the OUR's projected heat rate is below JPS' projected heat rate. Both methods of projecting heat rates have their drawbacks mainly because the OUR's estimates are not supported by calculations with the economic dispatching software currently being used by JPS, and JPS projections lack the WASP simulation. It is the view of the OUR that given the three scenarios outlined in table above JPS projected heat rate should form the cap in setting the heat rate target for 2009.

9.5 CONCLUSIONS

- The best set of tools for setting heat rate targets for the short to medium term are the economic dispatch program currently being used by JPS and the WASP generation planning program being used by JPS and the OUR for generation planning.
- The OUR will seek to have greater oversight and access to JPS economic dispatch program which, in combination with the WASP program can be used to establish the system heat rate targets.
- The economic dispatch program could also be used to assist with the monthly checks of dispatch and fuel cost information submitted by JPS.
- The OUR will monitor and enforce the requirements for JPS to dispatch generating plants based on merit and procure fuel (and other goods and services) in an efficient manner.
- The OUR will generate its own projected system heat rates based on expected demand and required plant performances for both IPP and JPS owned generating units.

- Targets to be set by the OUR for heat rate will not be significantly higher than the projected heat rate figures.
- The heat rate target will be updated annually and when there is any significant change in the generation mix as approved by the OUR.

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 10,400 kJ/kWh. 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.

In order to retain the right incentives, and while mindful of JPS' proposal to set the heat rate target for the five year price cap period, the Office has decided to review the heat rate target annually as it is expected that new capacity for addition and replacement are likely to be added to the system over the price cap period and this will allow the OUR to take into account the expected improvements. The target will ensure that JPS has an incentive to improve the average heat rate of its own plants.

Determination

The Office has determined that the applicable heat rate for 2009/2010 is 10,400 kJ/kWh. Furthermore the Office has determined that the heat rate target will be reviewed and reset whenever there are new capacity additions to the national grid.

10. Fuel Cost Adjustment Factors – Losses

10.1 System Losses

10.1.1 Background

In the 2004 Tariff adjustments review, JPS proposed that the losses target should be kept at a 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 a lower fuel rate. The converse is also true.

Additionally, in the 2004 tariff adjustment review, the Office restated its concerns with regards to the company's effectiveness in controlling and reducing system losses. The Office noted, however, that the following actions had been taken by the company:

- the implementation of the upgrading of the Customer Information Systems (CIS). This was expected to bring about greater control in the billing process.

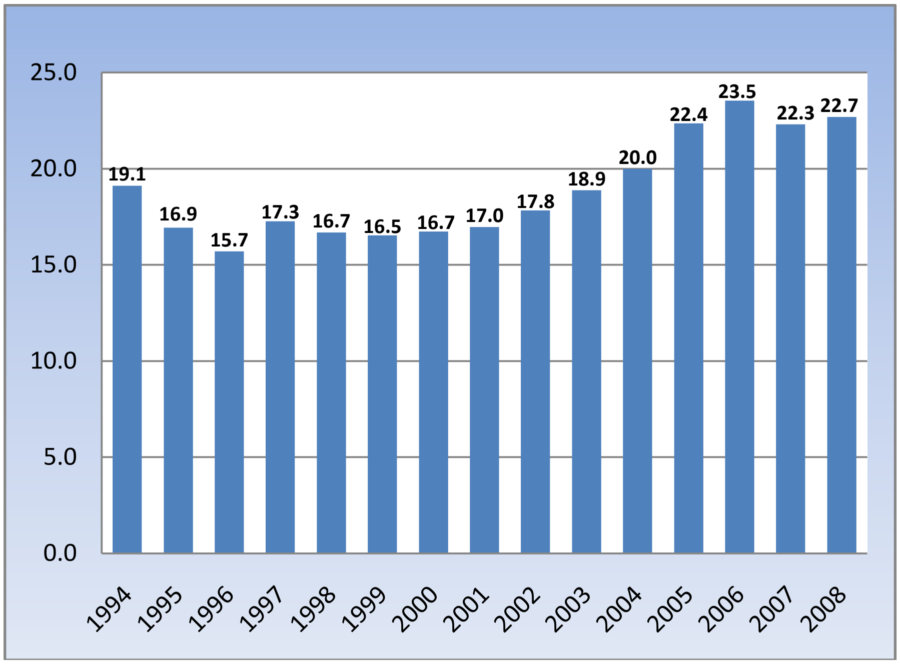
- the installation of 78 km of insulated secondary conductors in areas prone to illegal connections

- the 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 would remain at 15.8% and that JPS may retain, in full, any gains that may accrue from bettering this target.

Over the period 2001-08 however, JPS system losses increased from 17% to 22.7% of net generation and purchases. Apart from 2007, where system losses dipped by 0.8 percentage points relative to the 23.5% level registered in 2006, system losses have progressively increased since 2001.

Fig. 10.1 JPS % System Losses (1994 -2008)



The greater portion of the system losses experienced has its origins in non-technical sources. Based on the company's analysis of its system loss spectrum, technical losses[21] currently account for 9.6 -10% of overall losses. The other approximately 12.9% is attributable to losses of a non-technical nature.

10.2 JPS' Proposed System Losses – 2004 and 2009 comparison

As is the case in the JPS 2009 tariff submission, a declining system losses target regime was proposed in 2004. Comparisons of the two proposed sets of targets are show in the table below:

[21] Losses associated with the movement of electricity from the generating plants to end users

Table 10.2

JPS' Proposed schedule for System Loss Reduction, 2004 & 2009

	2004 -2009 Target (%)	2009 -2014 Target (%)
Base Year	18.0	20.5
Year -1	17.7	19.5
Year -2	17.4	18.5
Year -3	17.1	17.7
Year -4	16.8	16.9
Year -5	16.5	16.3

10.2.1 2009 -2014 System Loss Proposal

JPS plans to spend US$44.9 million during the next price-cap regime with the aim of reducing losses to 18.3% by June of 2014. Of this planned expenditure US$28.3 million will be devoted to capital and the remainder of US$16.6 million is to go towards Operating & Maintenance costs (see Table 3).

Table 10.3 JPS Planned System Loss Expenditure (2009-14)

Type of Loss	Planned Programme	Cost (US$ Million)
Technical	Energy Balance Project	7.0
	VAR Management	1.0
	Primary Upgrade	5.0
	Transformer Replacement	2.0
Non-Technical	AMI Metering	12.9
	Customer Audits	2.0
	Theft Resistance/Smart Meters	6.0
Total		**44.9**

In keeping with its planned expenditure JPS estimates that over the five-year period technical and non-technical losses will be reduced from 9.9% to 8.5% and 13.0% to 9.8% respectively.

Table 10.4 Proposed System Loss Target (2009-14)

	System Loss Performance			Proposed Target	
	Technical	Non-Technical	Total	Stretch	System Loss
Dec -2008	9.9%	13.0%	22.9%	-	15.8%
2009	9.6%	12.9%	22.5%	2.0%	20.5%
2010	9.3%	12.2%	21.5%	2.0%	19.5%
2011	9.1%	11.4%	20.5%	2.0%	18.5%
2012	8.9%	10.8%	19.7%	2.0%	17.7%
2013	8.7%	10.2%	18.9%	2.0%	16.9%
2014	8.5%	9.8%	18.3%	2.0%	16.3%

For the 2009 review JPS is proposing the following system losses targets for the next price-cap period:

- A ***Declining System Loss Target Regime:*** to replace the existing fixed system loss target of 15.8%. This proposed target is derived from its projected performance and a stretch target of 2 percentage points. The proposed system loss regime would require a reduction in the target from 20.5% in mid 2009 to 16.3% at the end of the next price-cap regime in 2015 (see Table 10. 4).

- *A* ***Non-technical Loss Penalty Clause:*** that would allow the company to impose a monetary penalty on illegal consumers of electricity with consumption levels in excess of 200 kWh. The proposed 200 kWh threshold is to target illegal consumption by high-income households and JPS has suggested that the penalty be set at 30% of the total amount billed for illegal consumption.

  JPS contends that at present back billing of customers does not take into account the opportunity cost of money since customers are simply charged the nominal value of the bill and no adjustments are made for interest payments. In addition, arrangements are often made for the payment of the amount back-billed over a 6-month period, and this represents an interest free loan to illegal consumers. JPS has indicated that a similar penalty (set at 20%) exists in the Dominican Republic.

It is further proposed that half of the proceeds from the Non-technical Loss Penalty be remitted to the OUR or its designee to be *"utilized for increased monitoring of losses, for infrastructure development, or for house-wiring projects in poor communities"*[22]

- ***Financial charges on illegal Consumption***: to capture the implicit costs associated with the back-billing of illegal consumption. JPS contends that given the volatility of the domestic currency, energy consumption back-billed at the time the electricity was used does not accurately mirror the present foreign exchange rate. In addition, merely billing for the nominal value of past consumption overlooks the opportunity cost of capital. As such interest expense and foreign exchange adjustment charges should be applied to bills of electricity customers caught stealing.

- ***Direct demand management of high loss communities:*** because it is more expensive to run Gas Turbines (GTs) to meet peak demand, the company proposes that peak shaving may be achieved during the day and evening peak hours by shedding power in high loss areas. Its proposal is based on the fact that:

    - Less than 2% of consumers in the 12 communities (see Table 10.5) identified for this programme are legal customers
    - It would result in substantial reduction in the fuel bill
    - a similar programme is currently being used in the Dominican Republic

Table 10.5 Communities Proposed for Direct Demand Management

[22] Ibid, p.188

	Location	Parish	Feeder
1	Seaview	KSAS	D&G 310
2	Jones Town	KSAS	Greenwich Rd 310
3	Torrington	KSAS	Greenwich Rd 311
4	Harbour Heights	KSAS	Cane River 410
5	Rose Heights	St. James	Queens Drive 710
6	Retirement	St. James	Bogue 310
7	Canterbury	St. James	Queens Drive 810
8	Central Village	St. Catherine	Twickenham 210
9	Maxfield Park	KSAS	Hunts Bay 810
10	August Town	KSAN	Hope 510
11	New Haven	KSAN	Duhaney 310
12	Arnett Gardens	KSAS	Hunts Bay 810

10.3 System Loss Activities 2004 -09

By its own account during the first two years (2004 & 2005) of the current price-cap regime[23] the company's system loss endeavors were focused primarily on 'locating and removing illegal connections and prosecuting offenders'. In addition, some attention was given to annual meter audits of major customers and selective audits of small customers. While the strategy resulted in approximately 700 arrests for electricity theft, the programme proved ineffective in arresting or reversing the upwards climb of losses.

It was not until 2006 that the company embarked on a comprehensive review of its loss reduction programme. Arising from the review, several organizational changes were initiated and a number of strategies were introduced. These include:

- the re-establishment of a Loss Reduction Management Unit
- an increase in the workforce of the Revenue Protection Department and Large Account Audit Unit

[23] The current price-cap regime spans 2004 -09

- the development of an Amnesty Programme
- the implementation of a Targeted Feeder Energy Loss Reduction Programme

The evidence suggests that it was out of this new loss reduction thrust that losses were brought below 23% in 2007 and 2008. A similar but a larger thrust was introduced during the period 1995 – 2000 which resulted in a reduction in losses from 19.1 % to 16.5%.

10.4 JPS Reasons for System Loss Increase

Against the background of the steady increase in system losses over the period 2001 - 2007, invariably the question that arises is "what are the factors that explain this development?"

JPS posits that the "One main reason for this is that the problem of electricity theft is socio-economic which like other crimes thrives in a society where the economic conditions are less than desirable."[24] In addition JPS asserts that "unfortunately, it appears as if this crime has become ingrained in the culture of the society. This is evidenced by how prolific the illegal abstraction of electricity has become. The problem has become endemic and pervasive, from deep rural communities to inner city communities to well-known businesses."[25]

In support of this position JPS made reference to a study which external consultants were engaged to conduct. The study which is predicated on econometric modeling and employs a sample of 63 utilities attributes non-technical system losses in a country to three variables:

- the level of poverty
- the average residential bill to Per Capita GDP ratio
- the level of violence

10.4.1 System Losses and the Crime Rate

The OUR shares the view that the socio-economic conditions in a country appears to have an impact on the levels of non-technical system losses. However,

[24] Tariff Review Application 2009 – 2014, p.49

[25] Ibid, p.49

the interpretation proffered by JPS in some parts of the submission that system loss is a function of crime is dubious[26]. Here a distinction must be drawn between causation and correlation. It does not follow logically that more persons will steal electricity in country because the murder rate is increasing. It is possible that both system losses and crime are explained in the same variable, poverty, and as such system losses and crime would naturally move in the same direction. Hence, it may well be that crime is correlated and not an explanatory variable.

If, however, as obliquely suggested in another part of the submission[27] that the crime rate might be a proxy for the efficiency of the justice system this then would be somewhat more plausible. Arguably, the efficiency of the justice system has implications for the protection of property rights which includes preventing the diversion of energy from JPS power lines. Therefore, deterioration in the protection of property rights could translate to greater system losses.

10.4.2 System Losses and deteriorating Economic Conditions

While economic conditions apparently impact the demand for electricity and the propensity to divert energy illegally from the power grid, JPS clearly overstated the case in its attempt to explain the increase in system losses since 2001.

Firstly, it argues that "*economic conditions have deteriorated significantly since 2001*". This statement is false. Certainly, the rate of economic growth over the period 2001 to 2007 was not spectacular. However, cumulatively the economy grew more over that seven years than it did in the previous seven (see Table 10.6).

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26 Ibid, p.49

27 Ibid, p.168

Table 10.6 System Loss, Real GDP Growth & Oil Prices (1994 - 2004)

	System Loss	Real GDP Growth	Crude Oil Price (US$/Bbl)
1994	19.1%	1.0%	15.66
1995	16.9%	0.7%	16.75
1996	15.7%	-1.0%	20.46
1997	17.3%	-1.7%	18.64
1998	16.7%	-0.3%	11.91
1999	16.5%	-0.4%	16.56
2000	16.7%	0.8%	27.39
2001	17.0%	1.5%	23.00
2002	17.8%	1.1%	22.81
2003	18.9%	2.3%	27.69
2004	20.0%	1.2%	37.66
2005	22.4%	1.5%	50.04
2006	23.5%	2.5%	58.30
2007	22.3%	1.1%	99.65
2008	22.7%	-0.6%	64.20

Secondly, it asserts that the price of electricity *'has increased four-fold for customers in J$ terms which undoubtedly would have some impact on non-technical losses'*. If JPS had correctly used **real J$**[28] instead of nominal J$ the increase in the actual increase reflected would have been 50% instead of 400%. Evidently, this unreasonably exaggerates the economic situation in the country.

10.4.3 Management Responsibility

It is interesting to note that since 1997 there were two distinct periods (1997-2000 and 2006-08) during which the JPS saw a decline in system losses. During the first period (1997-2000) the economy saw three years of negative economic growth (see Fig. 2).

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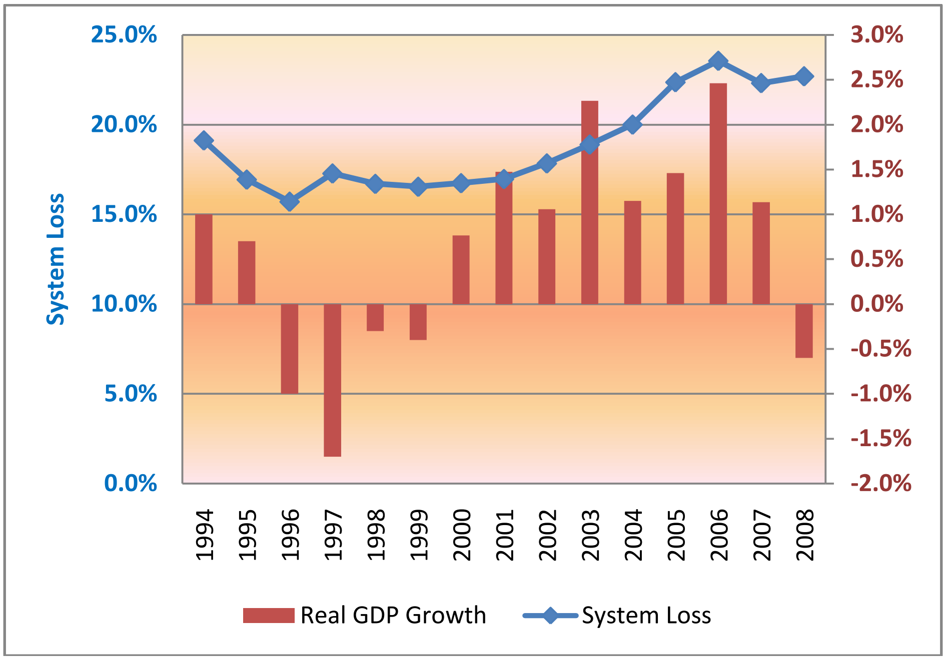
[28] The CPI at 2006 prices at May 2009 and May 2001 were 140 and 57.4 respectively.

During the second period (2006 -2008) the average price of crude oil soared from US$50.30 per barrel in 2005 to US$99.65 in 2007, yet the company saw a decline in system losses (see Table 6).

Fig.2 System Losses & Economic Growth (1994 -2008)



The factor common to these two periods, to which JPS failed to give due recognition in its submission, was the strong organizational focus and strategic emphasis given to loss reduction.

The OUR is of the view that escalation in the level of system losses over the period 2001-2006 at JPS was primarily the result of the tepid approach to tackling the problem by management. JPS should therefore accept responsibility for the upward system loss trajectory over the last eight years.

10.4.4 Declining System Loss Target

JPS proposed that the system loss target be increased from its current level of 15.8% to 20.5% in 2009 and gradually reduced to 16.3% in 2014. It is important to note that this proposed target is higher than actual system losses of 17% registered by the company in 2001. Interestingly, the proposed target at the end of the price-cap regime would be higher than the existing system target.

In addition, if it is assumed that fuel prices were maintained at the 2008 level and generating plants performance remained unchanged, then customers would immediately see an increase of 1.2 US c/kWh in their fuel rate with the implementation of the new price-cap regime.

Furthermore, if JPS had reduced system losses over the last eight (8) years by half of what it proposes to do in the next five (5) then system losses would have already been below the existing target of 15.8% and both customers and the company would have benefited from the reduction.

Notwithstanding, the Office is of the view that if the system loss target is increased and a portion of improved revenues accruing from the changes to the fuel efficiency targets is used specifically to address system losses the reduction rate could be accelerated. As such the Office approves an increase in the system loss target initially to 19.5% and 17.5% in 2011. The Office also directs JPS to establish a fund to finance OUR endorsed system loss projects.

Against this background the OUR determines that:

1. **the system losses target be increased from 15.8% to 19.5% in 2009/10 then to 17.5% in 2011/12. Subsequent targets are to be determined during the Annual Tariff Adjustments exercise.**
2. **The amount of 0.4 US c/kWh be set aside from the tariff for a special system losses fund that will be used specifically to implement Advanced Metering Infrastructure and other anti-theft technology.**

It is projected that the fund will accrue at a rate of approximately US$13 million annually. The rules of the fund shall be determined by the OUR in consultation with JPS. The withdrawals from the fund must be in relation to system loss projects that are approved by the OUR.

10.5 System Loss Penalty & Financial Charges

The notion that there are implicit costs associated with back billing of illicit electricity consumption that need to be taken into account is true. Notwithstanding, there are certain problems associated with the Penalty Clause and the Financial Charges JPS proposed in its submission:

- the Penalty Clause which is to be applied to illegal consumption of over 200 kWh per month is based on the idea that it will penalize high income consumers engaged in theft. Currently, the average residential consumption is 164 kWh per month. However, no consideration is given to household size in the proposed scheme and this is critical to the analysis. For instance, a poor family of six could easily consume 210 kWh per month while a household with a single high income earner may be hard pressed to consume 190kWh per month. The Penalty Clause, as proposed, therefore would not necessarily achieve the objective of penalizing high-income illegal consumers.

- no rationale was given for setting the proposed penalty at 30%.
- the proposal for remitting half of the proceeds from the penalty to the OUR or an organization designated by the regulator reflects in our view an inclination on the part of JPS to dodge the socio-economic reality integral to loss reduction. It is important that JPS recognizes that a "total approach" to the problem of system losses is crucial to its success.
- the proposed Penalty Clause and the introduction of financial charges were not presented as alternative approaches, even though the argument used in their support were similar.
- the introduction of financial charges for illegal consumption, as pointed out in the proposal, may require changes in the legal framework under which JPS now operates which may be time consuming.

The OUR believes that there is merit in the argument that the implicit costs associated with back billing are not being recouped. As such it will support the introduction of a Penalty Clause equivalent to the existing rate paid to customers on their deposit. This rate would be reset at the beginning of each new price-cap regime.

The OUR is of the view that the use of the proceeds from the Penalty Clause to assist in addressing socio-economic issues associated with system losses is worthwhile pursuing. However, JPS should take responsibility for such a programme rather than trying to pass the task on to the regulator. JPS stands to gain much, in terms of its image and revenues, from a well designed socio-economic programme that addresses house wiring and other infrastructural issues that promotes legitimate energy consumption.

10.5.1 Direct demand management of high loss communities

Direct demand in high loss communities offers the prospect of lowering the overall fuel rate for paying customers, reducing the national bill for fuel importation and reducing the consumption of free-loaders on the national grid. However, it raises some difficult questions in relation to equity and justice.

While there may be only a few paying customers in a high loss community it is inequitable for these customers to be paying the same price for electricity as all other electricity users, yet they are deliberately given a second class service. Moreover the proposal raises issues of discrimination that may be actionable.

Given the fact that the JPS' five-year planned expenditure of approximately US$45 million is less than its current annual revenue losses from system loss, there are technological solutions (with high pay-back ratios) that may be used to achieve the same goal that accords with the principle of allocative efficiency. The OUR rejects the proposed Direct Demand Management in high loss communities.

10.5.2 Treatment of systems losses in the tariffs

While JPS accepts that the fuel charge should be adjusted by a derived 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 fixed costs
2. Energy associated with loss reduction does not translate to an equivalent 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 22.5% 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

The following are the Office's determinations on system losses:

1. **the system losses target be increased from 15.8% to 19.5% in 2009/10 then to 17.5% in 2011/12. Subsequent targets are to be determined during the Annual Tariff Adjustments exercise.**
2. **the amount of 0.4 US c/kWh be set aside from the tariff for a special system losses fund that will be used specifically to implement Advanced Metering Infrastructure and other anti-theft technology.**
3. **the rules for the administration of the system losses fund shall be determined by the OUR in consultation with JPS. In addition, all withdrawals from the fund must be exclusively for system loss projects approved by the OUR.**
4. **JPS shall be allowed to charge a rate equivalent to the prevailing interest rate on customers' deposits on all sums associated with back-billing arising from the theft of electricity.**

11. Treatment of IPP costs

11.1. Introduction

JPS has Independent Power Purchase (IPP) contracts with three private power generators—JPPC (60MW), JEP (124.1MW) and Jamalco (11MW)

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 recognizes and accepts 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.

11.2. IPP costs

The Office is of the view that customers have to pay for the contracted capacity charges of the IPPs. Failure to provide this capacity should result in a refund to the customers. The Office is mindful that the non – fuel variable charge has never been quantified by JPS. JPS has always contended that there are little or no variable costs apart from fuel. The Office has determined that actual capacity charges should be used to calculate the IPP charge

Determination

The Office has determined that:

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.**

12. Reconnection Fee

12.1. Introduction

As outlined in the Jamaica Public Service Company Limited (JPS) rate schedules, *reconnection fee* is charged to customers of all rate categories on requesting reconnection after being disconnected for non-payment of past due bills. The reconnection fee shall be determined by June 30 each year and shall be based on the actual cost of undertaking reconnections in the preceding fiscal year plus a ten percent (10%) service charge PROVIDED THAT the said actual cost was incurred in the most cost efficient and cost effective manner. JPS currently charges a fee of $1,441 which was determined by the OUR in the 2004 rate case.

JPS had the opportunity to seek annual increases in this fee. However, since the last review in 2004 they chose not to have done so. They are now requesting an increase of the reconnection fee from $1,441 to $2,200, which represents an increase of approximately 7% per annum since 2004 or 41% increase over the 2004 fee.

12.2 Methodology

Reconnection fee is computed based on the total cost incurred in the disconnection/ reconnection process. This total cost is the sum of the *operations and maintenance costs* incurred to disconnect and reconnect the account, the *administrative expenses* incurred by the collections staff of JPS and *external audit fees*. The fee is calculated by dividing the total actual annual cost for a specific base year by the number of reconnections during that period to obtain a reconnection fee per unit to which a ten percent service fee is added.

12.3 Operations and Maintenance Costs

The disconnection/reconnection activities of JPS are outsourced to third party contractors. The operating and maintenance costs associated with this activity consist mainly of third party contractor costs. The rates charged by contractors have been held constant by JPS since 2004 but have recently been revised upwards by 40% through a tender process. The new rates became effective on

February 1, 2009. JPS has also agreed with the contractors to adjust these rates annually based on local inflation.

JPS has advised that third party costs for disconnection/reconnection activity for a 12 month period July 07 to June 08 totaled $143,914,894. They also estimated operations and maintenance costs of $205,800,000 when the 40% increase in contractor rates is applied. Table 11.1 below lists the amount charged monthly.

Table 11.1

Contractor Costs	Amount ($)
Jul-07	13,625,861
Aug-07	14,247,101
Sep-07	4,796,185
Oct-07	7,161,148
Nov-07	12,233,806
Dec-07	11,483,586
Jan-08	10,837,028
Feb-08	13,819,900
Mar-08	13,607,783
Apr-08	12,746,359
May-08	15,090,877
Jun-08	14,265,260
Total 2007/2008	**143,914,894**

The Office accepts the contractor cost of $143,914,894 as the average cost for disconnection/reconnection activities. The 40% increase agreed by JPS with the contractors should however result in the new cost of $201,480,852 and not $205,800,000 as stated by JPS.

JPS is also requesting an amount of $700 per audit representing auditing of customers who have been disconnected but who have not come back for reconnection during the year. JPS estimates that some 3,100 audits are required monthly resulting in an additional annual cost of $26 million. These audits are said to be carried out by third party contractors. The Office is not of the view that these costs should be borne by legitimate customers who were disconnected for the late payment of bills. These costs should be considered a part of JPS' loss reduction plan.

12.4 Administrative Costs

The administrative costs associated with the disconnection/reconnection process are carried out by the collections department of JPS. JPS assumes an increase in total employee cost of 16.87% resulting in an estimate of $42,900,000 for total administrative cost for 2008. The Office accepts the amount of $36,705,978 as the prudent amount that should be allowed in the computation of reconnection fee. This is the stated actual test year cost and is also based on the average disconnections of 18,500 per month pre-text messaging. The Office has not allowed the adjustment of 16.87%. Additionally, revenue requirement is reduced by the said amount of $36,705,975. The affected line item is payroll, benefits and training.

12.5 Audit Fees

An independent review of reconnection costs is commissioned by JPS which is estimated to attract an audit fee of J$1,000,000. The fee allowed in 2004 was $250,000. The OUR does not agree with the 300% increase requested. A fee of $500,000 is being allowed for this review period.

12.6 Service Charge

A 10% administrative fee/service charge is added to the per unit reconnection cost charged to customers. JPS states that this charge represents the opportunity cost of capital on trade receivables specifically arrears associated with late paying customers. The company is seeking an increase in the service charge from 10% to 15% in recognition of a claimed significant increase in trade receivables.

Table 11.2

JPS Total Sales & Receivables J$'000			
Year	Sales (a)	Receivables (b)	(b) as % of (a)
2004	30,398,917	6,866,491	22.59%
2005	40,253,133	9,180,085	22.81%
2006	48,145,435	10,571,792	21.96%
2007	54,194,466	14,408,639	26.59%
2008	71,418,435	13,875,505	19.43%

The table above shows the total sales, trade receivables and the ratio of trade receivables to total sales for the years 2004 to 2008. The results of the ratio of trade receivables to total sales do not indicate a significant increase in trade receivables. Trade receivables have been relatively constant over the period under review with the exception of the year 2007 when the ratio was increased to 26.59% over the year 2006 ratio of 21.96%. Year 2008 however showed positive signs with a reduction in ratio to 19.43% the lowest level for the period 2004 to 2008.

On this basis the Office is of the view that the service charge should remain at 10% and not 15% as requested by JPS.

12.7 Reconnection Fee Calculation

JPS is requesting an increase in reconnection fee from $1,441 to $2,037. The contractor rates were agreed on by JPS through a tender process and new rates became effective on February 1, 2009. Total contractor costs of J$143,914,894 for the 12 month period July 07 to June 08 was advised by JPS. Applying the negotiated increase of 40% results in an estimated O&M cost of $201,480,852.

In addition to the adjustments outlined in the foregoing sections, further adjustments were made to the reconnection fee request based on additional information received from JPS.

JPS has introduced a text messaging system of advising customers of possible disconnections for failure to pay their due bills. Prior to the introduction of this system JPS advised that an average of 18,500 disconnections were done per month. With the introduction of text messaging in year 2008, disconnections increased to an average of 25,000 per month. For the period July 07 to June 08 contractor costs were $143,914,894. For the same period OUR estimated that average reconnection was 199,800. This estimate was calculated using 90% of the monthly average disconnections of 18,500. The total number of reconnections should therefore be increased from JPS' understated amount of 177,243 to 199,800.

Table 11.4 below gives the details of the OUR's computation of the reconnection fee.

Table 11.4

Reconnection Cost Summary	
Description	**OUR Determined**
Number of reconnections for 2007/8	147,243
Expected increase in the number of reconnections	52557
Total number of reconnections	199800
Estimated Contractor Cost for normal disco/recon activity	201,480,852
GCT on discon/recon activity @ 16.5%	33,244,341
Estimated Contractor cost for audit of non-reconnected accounts	0
GCT on audit of non-reconnected accounts @ 16.5%	0
Administrative Cost for 2008	36,705,978
Audit Fees	500,000
Total Cost	271,931,170
Per Unit discon/recon cost for 2008	1361
Plus 10% Service Charge	136
Final per unit cost for discon/recon	**1497**

Determination

The Office determines that reconnection fee is $1,500 subject to annual review.

13. Tariff Design and Rates

13.1. Allocated Cost of Service Study

13.1.1. 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
- to show the rate of return on investment and equity currently earned from each rate class for services rendered.

This is accomplished by separating the revenues, investments, and expenses between the various rate classes. Separation is 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 costs. These costs must be allocated to the customer rate classes based on the type or classes of customers, load characteristics, number of customers and various other customer-related investment and expense relationships.

In order to design tariffs based on unbundled costs, these costs need to be identified, categorized and allocated, using justifiable segmentation in a cost-of-supply study. It is important that costs should be allocated appropriately into justifiable cost categories, as all costs do not have the same cost driver. It is expected that JPS should use the FERC accounting method as the framework for its cost-of-supply studies, but can expand its model to allow for more sophisticated allocation of costs.

13.2. Balancing Of Stakeholder Needs and Drivers For Change

There are different stakeholders whose needs provide the drivers for tariff changes and must therefore be considered in determining tariffs. These stakeholders are the government, the business needs and the customers. The biggest challenge is to balance the needs of one stakeholder against the needs of another stakeholder and still achieve the pricing objectives.

13.3. JPS Business Needs

JPS' business needs should be guided by the shareholder, regulatory rules and the requirements of good corporate governance. A fundamental principle in designing tariff structures is that JPS should not incur unacceptable business risk as determined by the OUR, and that these tariff structures should promote the sustainability and viability of the business as well as the electricity industry.

13.4. Customer Needs

The customers' goal is to obtain the best value for their money. For commodities such as electricity, that often means purchasing electricity as cheaply as possible. It is therefore important for individual customer needs to be fairly balanced against the needs of all customers. It is important to understand customer needs and the impact of proposed changes on the customer. The following have been identified by customers as important factors and need to be considered among the drivers for change:

1. Non-cost-reflective tariffs, surcharges and subsidies
2. Charging on a time-of-use basis
3. The appropriateness of the current voltage categories
4. Fixed charges due to operation of their businesses
5. The need for more tariff options.

Based on all these factors, this section outlines the OUR pricing objectives.

13.5. 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" 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" 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.

13.6. 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:

- functionalisation;
- classification, and
- allocation.

13.6.1 Functionalisation

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

13.6.2 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* —this generally refers to costs incurred by the utility that vary with the megawatt-hours (MWh) of energy consumed by the customer.
- *Demand-related*— 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*—generally refers to costs incurred by the utility to connect a customer to the distribution system and for customer metering, billing and administrative costs.

13.6.3 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. Fuel is treated separately in the present tariff regime.
- *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 analyzed on an account-by-account basis to determine the rate classes that cause these costs to be incurred.

The functionalisation, classification and allocation steps are necessary and essential to the preparation of any cost-of-service study. The process is fundamentally the same whether analysing gross plant, accumulated provisions for depreciation, materials and supplies and other rate base items. 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 ensure that the final allocation of costs reflect "cost causation."

13.7 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 a 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 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, Not only are the operating costs higher at the peak periods but it is also the demand at peak that drives the installation of additional capacity. 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 bills relative to the standard (flat) rate option.

13.8. Tariff Design Approaches

Failure to reflect cost causation in the tariff structure would result in cross-subsidies, whereby some customers would subsidize other customers.

Different cost allocation criteria have been proposed and implemented in different parts of the world, not only within the utilities.

Some of the more important or well-known approaches are:

a. Average Costs

b. Marginal Costs (in its various forms)

- Ramsey
- Equi-proportional Mark Up
- Two Part Tariff

One of the most important concepts in rate design is cost causality. That is, if a new customer is incorporated into the company, that customer is required to cover any additional costs the company incurs in providing services to him. If this customer is willing to pay for those costs (marginal costs) and along with some additional amount (large or small) then the rest of the consumers would be happy to bring this consumer on board since his additional contribution will reduce the burden on them. This in essence is the core of the marginal cost-pricing concept.

13.8.2. Marginal Costs

Marginal cost approaches are aimed at determining the incremental costs caused by the consumption of additional units by the customers. Customers are then asked to pay this charge for each unit of the product they consume. In monopolistic industries, such as electricity markets, these costs are typically smaller than the average cost of producing the requisite level of production. Therefore, if marginal cost pricing is used exclusively this will result in revenue inadequacy. To ensure the company has sufficient revenues, a complementary mechanism would have to be put in place to ensure that the remaining revenue requirement is recovered. There are different methods that deal with this issue of revenue adequacy, each having advantages and drawbacks.

When tariffs are based on marginal costs, customers are better off since this approach attempts to provide rates that are affordable, reflective of caused cost and forward looking[29]. It is expected that under this methodology more customers will find it attractive to consume the Company's services and this will result in a bigger customer base to pay for its fixed infrastructure, reducing the unitary impact.

13.9. Cost Allocation Criteria

The first step in cost allocation is to separate customer service costs from the other costs. These costs are simply to allocate on a per customer basis. These costs are related to the commercial cycle: reading, billing and collecting.

[29] represent the least cost which would be incurred in providing the requisite level of service over the relevant period

Customer service costs also include telephone customer service costs and costs of capital for meters and dedicated services.

For the remaining costs and regardless of the approach, average or marginal, there is some allocation criterion that is required. Average costs allocations will affect the whole revenue requirement while marginal costs allocations will only impact the incremental costs. The remainder of the costs (shared costs) will be recovered from consumers based on other criteria different to cost allocation. At this stage responsibility factors will be required.

13.10. Network Costs: Responsibility Factors

The ideal situation occurs when each customer pays the costs he causes, but unfortunately in real life applications constraints make it very difficult to achieve this goal. The generation facilities, the transmission facilities, the primary line extension and sometimes the secondary line extension are assets shared by many users, making it very difficult or impossible to link each asset or portion of each asset to each customer in an accurate way. For this reason it is important to calculate responsibility factors for each customer class to help determine the contribution of each class to the cost of the shared facilities.

14. Results from Two-Part Tariff Approach

The Two-Part tariff approach proposed by JPS is adopted by the OUR. Essentially the Two-Part structure involved starting from the long-run marginal costs calculated for each activity and voltage level and multiplied by the responsibility factors of each category of user. The revenue gap resulted had to be recovered through a network access charge (NAC).

The long-run marginal cost of each voltage level was calculated by applying the Average Incremental Cost formula to the Total Cost variations due to the demand growth.

The output by category is as follows:

Table 14. 1: Marginal Rates

				Demand Charge JMD/kVA		
		Customer Charge JMD/Month	Energy Charge JMD/kWh	STD and On-Peak	Partial-Peak	Off-Peak
R10_1	0 - 100 kWh/month	109.88	5.17			
R10_2	100 - 500 kWh/month	109.88	5.17			
R10_3	> 500 kWh/month	109.88	5.17			
R20_1	0 - 100 kWh/month	109.88	5.01			
R20_2	100 - 1000 kWh/month	109.88	5.01			
R20_3	1000 - 3000 kWh/month	109.88	5.01			
R20_4	> 2000 kWh/month	109.88	5.01			
RT40 (STD)		109.88	0.06	1,321.06		
RT40 (TOU)		109.88	0.06	813.52	641.60	61.33
RT50 (STD)		109.88	0.06	1,315.24		
RT50 (TOU)		109.88	0.06	779.90	520.38	42.75
RT60	Streetlight	109.88	6.66			

For RT10, RT20 and RT60, marginal capacity costs have been energized.

The total revenue (J$ 000) obtained through the application of charges based exclusively in marginal costs is $15,219,266 as shown below

Table 14 2: Marginal Revenue

		Customer Charge JMD/Month	Energy Charge JMD/kWh	Demand Charge STD and On-Peak	Demand Charge Partial-Peak	Demand Charge Off-Peak
R10_1	0 - 100 kWh/month	269 073	617 656			
R10_2	100 - 500 kWh/month	404 173	3 706 519			
R10_3	> 500 kWh/month	22 461	1 011 130			
R20_1	0 - 100 kWh/month	24 707	41 720			
R20_2	100 - 1000 kWh/month	41 947	641 884			
R20_3	1000 - 3000 kWh/month	6 851	426 380			
R20_4	> 2000 kWh/month	7 246	1 323 575			
RT40 (STD)		1 933	40 313	3 255 836		
RT40 (TOU)		550	17 675	459 278	464 843	40 637
RT50 (STD)		124	22 604	1 327 241		
RT50 (TOU)		36	8 541	280 097	268 627	22 872
RT60	Streetlight	460	462 277			
Total JPS		**779 561**	**8 320 273**	**5 322 453**	**733 469**	**63 509**
				15 219 266		

This revenue represents ***50***% of the total non-fuel revenue requirement. The revenue gap was met allocating costs looking at the demand side, hence, taking into consideration aspects such as:

(a) Economic and social environment

(b) Non technical losses recovery

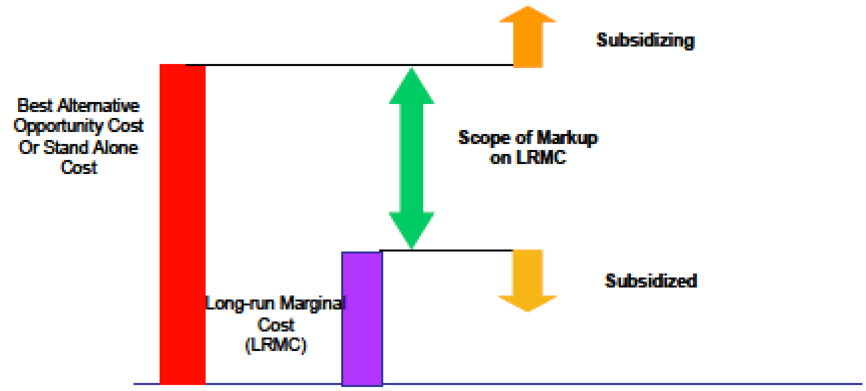
(c) Willingness to pay by category or by tiers within the categories

(d) Risk of losing large customers who for the time being absorb part of the cost of service

Within this approach special attention must be paid to giving the market the correct price signals and avoiding cross subsidization: the existence of subsidized or subsidizer customers.

From the economic standpoint, a customer is subsidized when the price paid is lower than the marginal cost being generated, and is a subsidizer when the price paid is above the cost of its best alternative opportunity (stand-alone cost).

Figure 0-1: Subsidized and Subsidizing Customers



Based on this definition, the minimum charges the customers must pay are those, which reflect marginal costs. Then, each category charge is calculated considering the constraint that it must be lower than the difference between the cost of the best alternative to network electricity and the marginal cost. This charge is called Net Access Charge (NAC). To get the final NAC by category, customer surplus has to be calculated.

The surplus of each category is the result of multiplying the individual surplus by the number of users in each category. Adding up the surpluses of all categories, we obtain the total surplus of the market.

Consequently, NAC must be equal to the deficit generated by the difference between the revenue requirement and the income derived from the application of the long-run marginal costs.

From the known revenue gap and the total surplus of the market, a factor called ***alpha*** is calculated indicating the percentage of the total surplus of consumers who should be transferred to the Company so that it is sustainable over time, that is recovering its long-run average costs.

The following table provides a summary of:

- Non fuel revenue requirement
- Revenues at marginal costs
- Revenue Gap (Deficit)
- Total estimated market surplus
- Alpha
- Total NAC (equal Revenue Gap)

Table 14. 3: Alpha Calculation

	Income (JMD 000)	
	Revenue Requirement	Marginal Costs
Total	31,860,340	15,906,319
Deficit		15,954,021
Total Surplus		111,555,625
Alfa		**14.30%**
NAC		15,954,021
Difference (Deficit - NAC)		0

As can be observed, a total customer surplus of 14.3% is necessary to meet the revenue gap.

Accordingly the OUR is not of the opinion that the nature of the NAC should be a fixed charge per customer. There are variable and fixed components attributable to each customer group. A detailed cost of service study and functionalisation can determine the proportion of fixed charges and variable energy charges. Acknowledging the existence of customers with very different consumption in all categories, a major portion of this cost was allocated to energy. In conclusion, the NAC that could not remain as a fixed charge was allocated to become part of the energy charge ($/kWh) and just a little part (in the case of RT40 and RT50) went to the demand charge to equalize charges between RT40 and RT50 and between the Standard and TOU options.

Table 14. 4: OUR determined Rate Schedule with NAC Explicit

2PT Rates							Network Access Charge				
				Demand Charge JMD/kVA							
		Customer Charge JMD/Month	Energy Charge JMD/kWh	STD and On-Peak	Partial-Peak	Off-Peak	Customer Charge JMD/Month	Energy Charge JMD/kWh	Demand Charge JMD/kVA	Partial-Peak	Off-Peak
R10_1	0 - 100 kWh/month	109.88	5.17				140.12	1.02			
R10_2	100 - 500 kWh/month	109.88	5.17				140.12	8.98			
R10_3	> 500 kWh/month	109.88	5.17				140.12	8.98			
R20_1	0 - 100 kWh/month	109.88	5.01				440.12	6.99			
R20_2	100 - 1000 kWh/month	109.88	5.01				440.12	6.98			
R20_3	1000 - 3000 kWh/month	109.88	5.01				440.12	6.98			
R20_4	> 2000 kWh/month	109.88	5.01				440.12	6.98			
RT40 (STD)		109.88	0.06	1,321.06			3,890.12	3.35	-81.56		
RT40 (TOU)		109.88	0.06	813.52	641.60	61.33	3,890.12	3.35	-115.65	-96.22	-8.72
RT50 (STD)		109.88	0.06	1,315.24			3,890.12	3.18	-199.69		
RT50 (TOU)		109.88	0.06	779.90	520.38	42.75	3,890.12	3.18	-160.15	-36.98	6.83
RT60	Streetlight	109.88	6.66				1,390.12	8.16			

14.1 Fixed charges revenues versus Fixed Costs

Comparison between costs and revenues for the OUR determined Rate Charges by category are presented in the following tables:

Table 14. 5: Rate Schedule Determination

Rate Category		Customer Charge JMD/Month	Energy Charge JMD/kWh	Demand Charge JMD/kVA		
				Standard and On-Peak	Partial-Peak	Off-Peak
	Residential					
R10_1	First 100kWh	250.00	6.19			
R10_2	100 - 500 kWh	250.00	14.15			
R10_3	Over 500 kWh	250.00	14.15			
	General Service					
R20_1	First 100kWh	550.00	11.99			
R20_2	100 - 1000 kWh	550.00	11.99			
R20_3	1000 - 2000kWh	550.00	11.99			
R20_4	Over 2000 kWh	550.00	11.99			
	Power Service					
RT40 (STD)	Standard Low Voltage	4,000.00	3.42	1,239.50		
RT40 (TOU)	Time of Use Low Voltage	4,000.00	3.42	697.87	545.38	52.61
RT50 (STD)	Standard Medium Voltage	4,000.00	3.24	1,115.55		
RT50 (TOU)	Time of Use Medium Voltage	4,000.00	3.24	619.75	483.41	49.58
RT60	Street Lights & Traffic Signals	1,500.00	14.83			

Table 14. 6: Revenues by Category

	Customers	Total or On-Peak block Energy (JMD 000)	Partial-Peak block Energy (JMD 000)	Off-Peak block Energy (JMD 000)	Sum. Max. Demand or On-Peak (JMD 000)	Sum. Partial-Peak Demand (JMD 000)	Sum. Off-Peak Demand (JMD 000)	
R10_1	612,205	800,239						
R10_2	919,590	8,053,026						
R10_3	51,104	2,832,795						
R20_1	123,674	108,201						
R20_2	209,965	1,664,197						
R20_3	34,293	1,105,364						
R20_4	36,271	3,431,216						
RT40 (STD)	70,356	2,374,766			3,054,831			
RT40 (TOU)	20,004	128,747	457,446	454,999	393,987	395,128	34,860	
RT50 (STD)	4,520	1,264,967			1,125,727			
RT50 (TOU)	1,312	59,106	210,007	208,883	222,579	249,538	26,526	
RT60	6,282	1,113,632						
	2,089,576	**22,936,253**	**667,453**	**663,882**	**4,797,125**	**644,666**	**61,385**	**31,860,340**

The distribution of Revenue expected to come from the customer charge and the demand charges are group together while the revenue derived from the energy charges are separated and highlighted in Table 7 as fixed and variable Revenues:

Table 14. 7: Fixed Revenues vs. Variable Revenues

	Revenues (JMD 000)			% of total Revenues	
	Customer and Demand Charge (JMD 000)	Energy Charge (JMD 000)	Total	Fixed	Variable
RT 10 LV Residential Service	1,582,899	11,686,060	13,268,958	12%	88%
RT 20 LV General Service	404,203	6,308,977	6,713,181	6%	94%
RT 40 LV Power Service (Std)	3,125,187	2,374,766	5,499,952	57%	43%
RT 40 LV Power Service (ToU)	843,979	1,041,192	1,885,171	45%	55%
RT 50 MV Power Service (Std)	1,130,247	1,264,967	2,395,214	47%	53%
RT 50 MV Power Service (ToU)	499,956	477,995	977,951	51%	49%
RT 60 LV Street Lighting	6,282	1,113,632	1,119,914	1%	99%
	7,592,752	**24,267,588**	**31,860,340**	**24%**	**76%**

Fixed costs represent ***76%*** of JPS total non-fuel costs, but the company is allowed to recover only ***24%*** of the total revenue requirement through fixed charges.

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.

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.

The proposed tariff structure has tariff charges derived from marginal costs, to which a fixed and energised monthly charge per customer is added, the NAC. This mechanism ensures that the different types of users pay according to their willingness to pay. This way the lower income sectors will pay a lower rate because they have a lower NAC. The OUR is of the view that instead of recovering the NAC through a fixed charge per customer, part of it can be recovered through another type of charge (energy or demand charge). The fixed and variable proportion can be determined by doing a cost functionalisation and causality analysis.

The OUR is of the view that the Two Part Tariff design is a useful structure that will help JPS tackle the non-technical losses issue and ensures JPS revenue equal to the revenue requirement while mitigating the customers' loss of welfare. However, in order to properly identify NAC fixed and variable (energy) cost for each category of customers the OUR is of the view that a cost functionalisation and causality analysis should be done by JPS for OUR review before the next annual adjustment period

14.3 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.

14.4. 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 are to become operational by January 1, 2010.

Non-Fuel Charges per Category Relative to Current Tariff

In this section charges to recover Non-Fuel Costs per category are presented:

14.5.1 Residential Customers - RT10

Tariff designs based on the Two-Part Marginal Cost and NAC tariff approach enable a better organization of the customers, taking advantage of their different willingness to pay for the service and at the same time minimizing billing shocks for customers when they move from one tier to another. However, for this determination the OUR has rejected the tier structure and will maintain the current structure of a life line rate and a single tier customer charge. JPS can seek to rebalance it tariff structure over the Price Cap period based on the tier structures the company proposed for this rate review.

The OUR will evaluate such proposals on their merit at the time of filing taking all regulatory impact assessments into consideration.

14.5.2 Small Commercial Customers - RT20

JPS proposed introducing 4 different fixed charges and 2 energy charges. However, for this determination the OUR has rejected the tier structure and will maintain the current structure of a single tier customer charge. JPS can seek to rebalance its tariff structure over the Price Cap period based on the tier structures the company proposed for this rate review. The OUR will evaluate such proposals on their merit at the time of filing taking all regulatory impact assessments into consideration.

14.5.3 Street Lights and Traffic Lights - RT60

The Street lighting category remains with the actual tariff structure which has:

- Customer charge: the customer charge is applicable whether or not there is any consumption. It covers the customer service marginal costs and a portion of non-fuel costs that are part of the gap between marginal cost and average cost of service.

- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the revenue gap.

14.5.4 Large Commercial Customers who do not own Transformer - RT40

The Power Service Low Voltage category keeps the actual tariff structure.

- Customer charge: the customer charge is applicable whether or not there is any consumption and irrespective of the level of consumption. It covers the customer service marginal costs and a portion of non-fuel costs that are part of the gap between marginal cost and average cost of service.
- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the revenue gap.
- Demand charge
- Standard Option:
- One demand charge applicable on each kVA billing demand
- Billing demand: The kilovolt-ampere (kVA) Billing Demand for each month shall be the maximum demand for that month, or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes
- TOU Option:

1. One demand charge applies on each kVA billing demand per hour block.
2. On-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the On-Peak hours of that month. The minimum 25 kilovolt amperes (kVA) does not apply.
3. Partial-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the on-peak and partial-peak hours of that month, or 80% of the maximum demand for the on-peak and partial-peak hours during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes.
4. Off-Peak Period Billing Demand: The billing demand in this period shall be the maximum demand for that month (regardless of the time of use period it was registered in), or 80% of the maximum demand during the five -month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes kVA).

14.5.5 Large Commercial Customers who own transformer - RT50

The Power Service Medium Voltage category keeps the actual tariff structure.

- Customer charge: the customer charge is applicable whether or not there is any consumption and irrespective of the level of consumption. It covers the customer service marginal costs and a portion of non-fuel costs that are part of the gap between marginal cost and average cost of service.
- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the revenue gap.
- Demand charge
- Standard Option:
- One demand charge applicable on each kVA billing demand
- Billing demand: The kilovolt-ampere (kVA) Billing Demand for each month shall be the maximum demand for that month, or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes
- TOU Option:
    - One demand charge applies on each kVA billing demand per hour block.
    - On-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the On-Peak hours of that month. The minimum 25 kilovolt amperes (kVA) does not apply.
    - Partial-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the on-peak and partial-peak hours of that month, or 80% of the maximum demand for the on-peak and partial-peak hours during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes
    - Off-Peak Period Billing Demand: The billing demand in this period shall be the maximum demand for that month (regardless of the time of use period it was registered in), or 80% of the maximum demand during the five -month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes kVA).

14.6. Allowed Non-Fuel Rates

The tariff design with the Non-Fuel Rate Schedule and the NAC with the correspondent charges are outlined in Tables 14.8 and 14.9 respectively as follows:

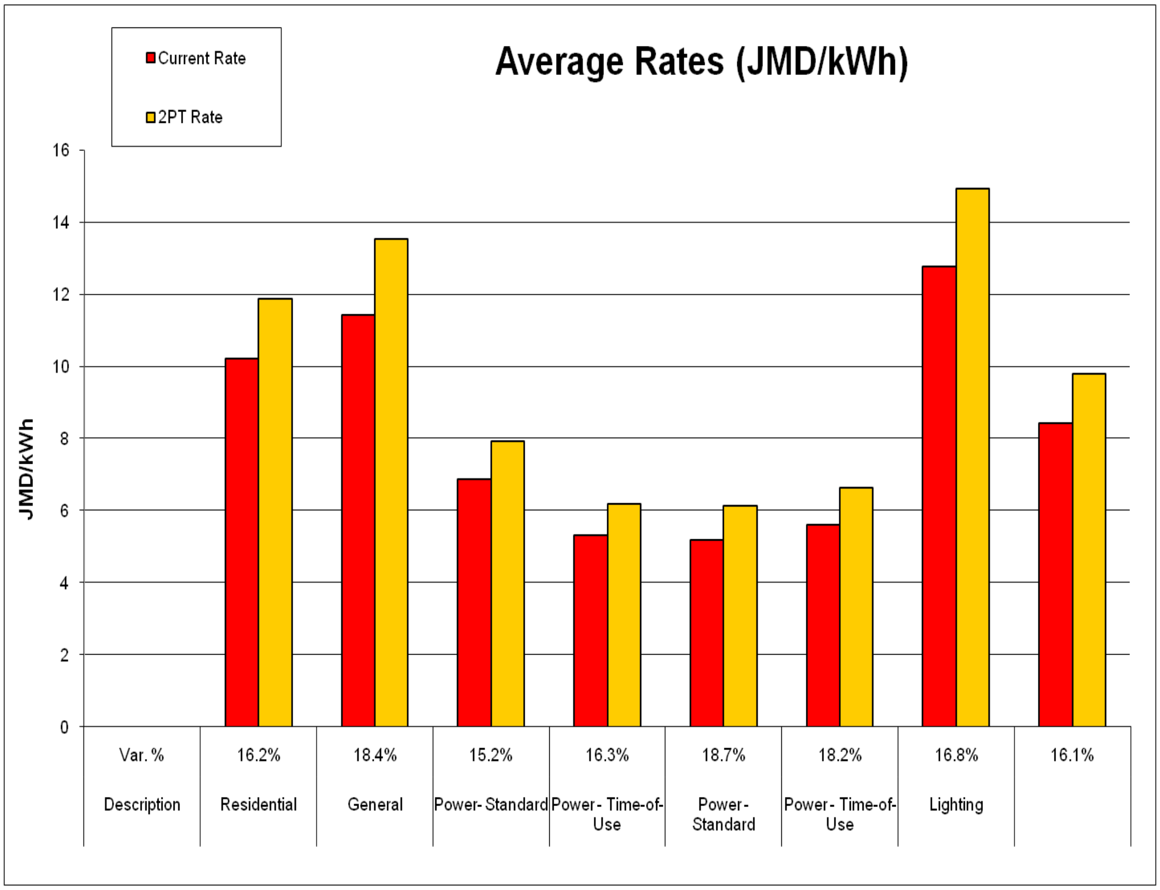
Table 14.8: Non-Fuel Final Rate Schedule

Rate Category		Customer Charge JMD/Month	Energy Charge JMD/kWh	Demand Charge JMD/kVA Standard and On-Peak	Demand Charge JMD/kVA Partial-Peak	Demand Charge JMD/kVA Off-Peak
	Residential					
R10_	First 100kWh	250.00	6.19			
R10_	Over 100 kWh	250.00	14.15			
R20_	**General Service**	550.00	11.99			
	Power Service					
RT40 (STD)	Standard Low Voltage	4,000	3.42	1,239.50		
RT40 (TOU)	Time of Use Low Voltage	4,000	3.42	697.87	545.38	52.61
RT50 (STD)	Standard Medium Voltage	4,000	3.24	1,115.55		
RT50 (TOU)	Time of Use Medium Voltage	4,000	3.24	619.75	483.41	49.48
RT60	**Street Lights & Traffic Signals**	1,500	14.83			

14.6.1 Histogram of Impact

The rates determined applied to the Test Year determinants yield the average tariff per category that is presented in Table 13.9. A comparison with the actual rates in force is also shown.

Figure 6: Average Tariff by Customer Category



The OUR is of the view that the two part tariff design approach allows the Office to distribute the increase within each category, taking into account the socio-economic conditions of the users depending on the established correlation between family income and electricity consumption. Customers will pay above their marginal cost - there are no subsidized customers.

Table 14.09: The OUR Determined average Non-Fuel Rate versus Current Effective Non-Fuel Rates

Rate	Description	Current IPP Increment (JMD/kWh)	Effective Non-Fuel Rate (JMD/kWh)	Total Effective Non-Fuel Rate (JMD/kWh)	OUR Determined Non-Fuel Rates (JMD/KwH)	Non-Fuel Rate Increase
R10	Residential	0.22	10.22	10.44	11.87	13.7%
R20	General	0.22	11.41	11.63	13.52	16.2%
R40_STD	Power-Standard	0.22	6.87	7.09	7.91	11.6%
R40_TOU	Power - Time-of-Use	0.22	5.32	5.54	6.18	11.6%
R50_STD	Power - Standard	0.22	5.18	5.40	6.14	13.8%
R50_TOU	Power - Time-of-Use	0.22	5.62	5.84	6.64	13.7%
R60	Lighting	0.22	12.77	12.99	14.91	14.8%
JPS	**All customers**	0.22	8.43	8.65	9.78	13.1%

Note that Effective Rate includes adjustment from base tariff.

Table 14.10: Overall effect of adjustments in tariffs

Rate	Description	Effective Rate (JMD/kWh)	OUR Determined Rate (JMD/kWh)	Var. %
R10	Residential	25.66	26.67	3.9%
R20	General	26.85	28.31	5.4%
R40_STD	Power- Standard	22.31	22.70	1.8%
R40_TOU	Power - Time-of-Use	20.76	20.98	1.1%
R50_STD	Power - Standard	20.62	20.94	1.6%
R50_TOU	Power - Time-of-Use	21.06	21.43	1.8%
R60	Lighting	28.21	29.71	5.3%
JPS	All Customers	23.87	24.58	3.0%

Note that effective rate includes adjustment from the base tariff and the current level of IPP surcharge. Due to the recalculation of the Non-Fuel rates the IPP surcharge that is currently included in the Fuel and IPP line on the bill will now be reset to zero.

Residential Customer

Table 14.11: shows RT10 allowed charges.

Rate Category	R10			
Description	Customer Charge JMD/Month		Energy Charge JMD/kWh	
	Current	2PT	Current	2PT
First 100 kWh	108.01	250.00	6.90	6.19
100 - 500 kWh	108.01	250.00	12.08	14.15
Over 500 kWh	108.01	250.00	12.08	14.15

As can be observed there are two columns per charge. Adjusted actual charges are in the first column and two-part tariff approach rates are in the second one.

Table 14.12 presents the billing impacts on the non-fuel portion of the bill for typical customers in each consumption interval

Table 14.12: Non-fuel Bill Impact on Rate 10 Typical Customers

Description	Average consumption kWh/month	Monthly Bill Including IPP Increment for September JMD/Month		Impact on Consumers JMD/Month	%
		Current	OUR Determined	OUR Determined	OUR Determined
First 100 kWh	100	820	869	49	6.0%
100 - 500 kWh	200	2,050	2,283	233	11.4%
Over 500 kWh	1,000	11,892	13,599	1,707	14.4%

As can be observed, while the Residential category has an average increase of 16%, the first tier that includes mainly families with low income will receive an average increase of 5.9% mainly due to the customer charge as the energy rate is less than the current charges. The number of residential customers that have this increase is about 200,000 customers representing 40% of the residential category. Customers whose consumption is within the second tier will see an average increase of 11.2%, a value which is below the average increase required by the Company. Finally, customers with consumption over 500 kWh / month are those with 14.2% increase within this category.

Table 14.13: **Overall effect of adjustments of efficiency factors on Rte 10 customers**

Description	Average consumption kWh/month	Monthly Bill Including Fuel charge JMD/Month		Impact on Consumers JMD/Month	%
		Current	**OUR Determined**	**OUR Determined**	**OUR Determined**
First 100 kWh	100	2,342	2,348	6	0.3%
100 - 500 kWh	200	5,094	5,242	148	2.9%
Over 500 kWh	1,000	27,112	28,394	1,282	4.7%

Table 14.14 summarizes the residential energy sales and customer structure for the Test Year.

Table 14.14: Rate 10 Customer Structure

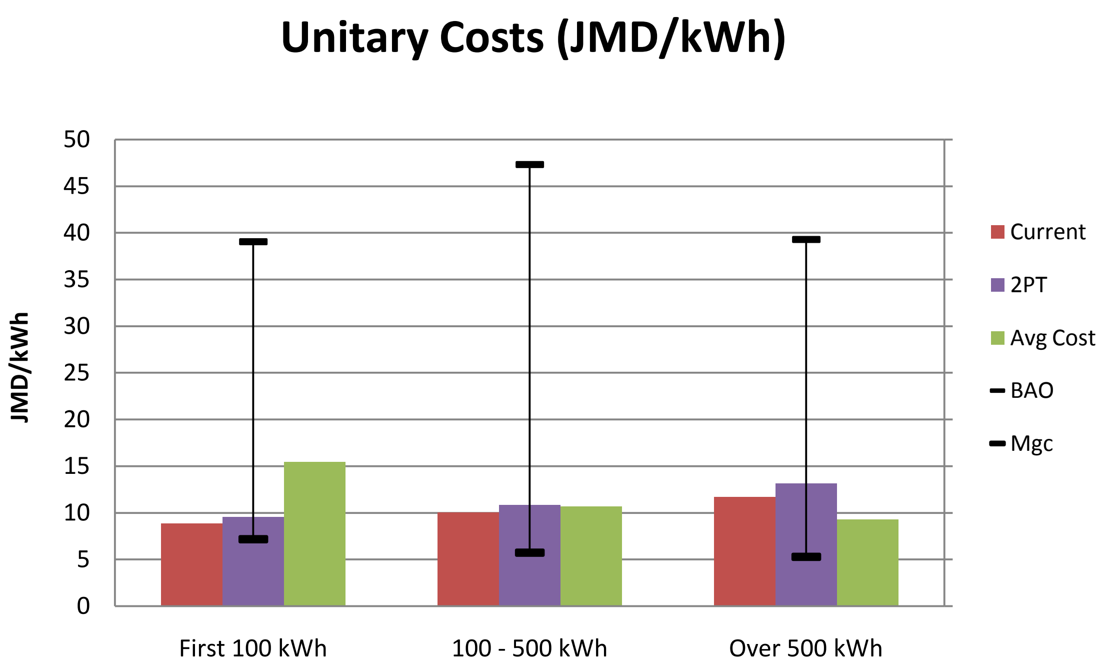
Rates	Description	Customers	% / Category	Energy Sales MWh	% / Category
R10_1	0 - 100 kWh/month	204,069	39%	119,493	12%
R10_2	100 - 500 kWh/month	306,530	58%	717,073	69%
R10_3	> 500 kWh/month	17,035	3%	195,616	19%
		527,634	**100%**	**1,032,182**	**100%**

Figure 0-2 below shows important data which not only has to do with the histogram of impact but to validate the tariff design. The graph shows the following data for typical customers per consumption interval:

- Current average rate
- Proposed average rate
- Its marginal cost
- Cost of his best alternative opportunity.

The latter two data sets represent the limits within which the tariff should be determined. As previously indicated, if the price is below marginal cost that customer is being subsidized while if the rate is above the cost of the best alternative opportunity there is a risk that the customer will disconnect from the network, to the detriment of all other customers who would have to bear a higher cost for energy.

Figure 7: Unitary Costs by Consumption Levels



14.7. Small Commercial Customer R 20

Table 14.15 shows the proposed RT20 charges.

Table 14.15: Rate 20 Charges

Rate Category	R20			
Description	Customer Charge JMD/Month		Energy Charge JMD/kWh	
	Current	OUR Determined	Current	OUR Determined
First 100 kWh	248.43	550.00	10.72	11.99
100 - 1000 kWh	248.43	550.00	10.72	11.99
1000 - 2000 kWh	248.43	550.00	10.72	11.99
Over 2000 kWh	248.43	550.00	10.72	11.99

As can be observed there are two columns per charge. Adjusted actual charges are in the first column, and two-part tariff rates are in the second.

Table 14.16 presents the billing impacts for typical customers in each consumption interval.

Table 14.16: Non-Fuel Bill Impact on Rate 20 Typical Customers

Description	Average consumption kWh/month	Monthly Bill Including IPP Increment for September JMD/Month		Impact on Consumers JMD/Month	Impact on Consumers %
		Current	OUR Determined	Current	OUR Determined
First 100 kWh	100	1,343	1,749	407	30.3%
100 - 1000 kWh	400	4,625	5,345	720	15.6%
1000 - 2000 kWh	1,400	15,567	17,331	1,764	11.3%
Over 2000 kWh	3,500	38,545	42,502	3,957	10.3%

It is to be noted that while the General Service category has an average increase of 18%, the first consumption interval that includes mainly small commercial users will receive in the case of the typical consumer an increase of 30.3%. Customers whose consumption is within the second interval will see an average increase of 15.6%. Customers with consumption over 1,000 kWh / month (Interval 3 and 4) are those who will experience an increase of 11.3% and 10.3% respectively.

Table 14.17 summarizes the general service energy sales and customers structure for the Test Year.

Table 14.17: **Overall Bill Impact of Tariff decisions on Rate 20 customers**

Description	Average consumption	Monthly Bill Including Fuel charge for September		Impact on Consumers	
	kWh/month	JMD/Month		JMD/Month	%
		Current	**OUR 2PT**	**OUR 2PT / Current**	**OUR 2PT / Current**
100 - 1000 kWh	400	10,713	11,263	550	5.1%
1000 - 2000 kWh	1,400	36,875	38,044	1,169	3.2%
Over 2000 kWh	3,500	91,815	94,284	2,469	2.7%

Table 14.18: Rate 20 Customer Structure

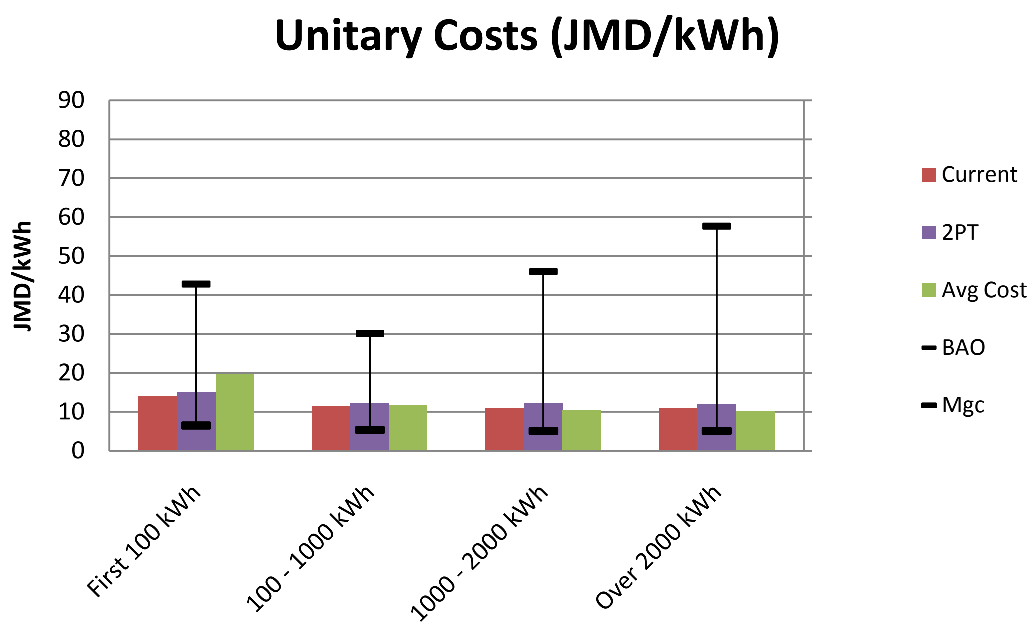
Rates	Description	Customers	% / Category	Energy Sales MWh	% / Category
R20_1	0 - 100 kWh/month	18,738	31%	8,335	2%
R20_2	100 - 1000 kWh/month	31,813	52%	128,238	26%
R20_3	1000 - 3000 kWh/month	5,196	8%	85,184	18%
R20_4	> 2000 kWh/month	5,496	9%	264,429	54%
		61,243	**100%**	**486,186**	**100%**

Figure 8 validates the tariff design. The graph shows the following data for typical customers per tier of consumption:

- Current average rate
- Proposed average rate
- Its marginal cost
- Cost of his best alternative opportunity.

The price is above marginal cost and below the best alternative opportunity. This is indicating that the tariff design for this category is good for all consumers and JPS. There is no risk that the customer will disconnect from the network, to the detriment of all other customers who would have to bear a higher cost for energy.

Figure 8: Unitary Costs by Rate 20 Consumption Levels



14.8 Large Industrial Customer Non-Fuel Tariff

Table 14.19 shows the Power Service's charges for large commercial customers.

Table 14.19: Rate 40 & 50 Charges

Description	Customer Charge JMD/Month		Energy Charge JMD/kWh		Demand Charge JMD/kVA	
	Current	**Proposal**	**Current**	**Proposal**	**Current**	**Proposal**
RT40 (STD)	3,446	4,000	2.89	3.42	1,097	1,240
RT40 (TOU)	3,446	4,000	2.89	3.42	612	698
RT50 (STD)	3,446	4,000	2.61	3.24	987	1,116
RT50 (TOU)	3,446	4,000	2.61	3.24	551	620

As can be observed there are two columns per charge. Adjusted actual charges are in the first column and the OUR determined rates are in the second one.

Table 14.20 presents the billing impacts for typical customers for each category and option.

Table 14.20: Non-Fuel Bill Impact on Rate 40 and Rate 50 Typical Customers

	Average consumption	Load Factor	Demand (kVA)			Energy (kWh)			Bill		Impact on Consumers	
	kWh/month	%	STD and On-Peak	Partial-Peak	Off-Peak	STD and On-Peak	Partial-Peak	Off-Peak	000 JMD/Month		000 JMD/Month	%
									Current	**Proposal**		
RT40 (STD)	39,536	40%	134						274	305	32	11.5%
RT40 (TOU)	60,966	59%	113	145	132	7,539	26,785	26,642	338	377	39	11.7%
RT50 (STD)	345,069	55%	852						1,822	2,074	252	13.8%
RT50 (TOU)	449,127	56%	1,095	1,574	1,631	55,536	197,323	196,268	2,622	2,981	359	13.7%

The figure below shows important data which not only has to do with the histogram of impact, but validates the tariff design. The graph shows for typical customers per category and option the following data:

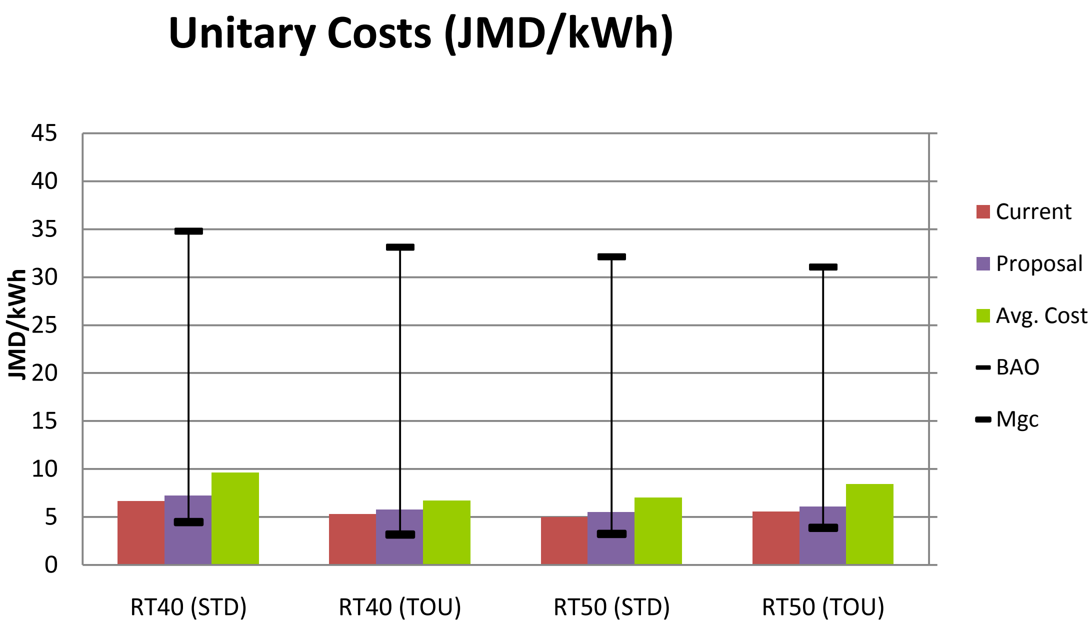
- Current average rate
- Proposed average rate
- Its marginal cost
- Cost of his best alternative opportunity.

The price is above marginal cost and below the best alternative opportunity. This is indicating that the tariff design for this category is good for all consumers and JPS. There is no risk that the customer will disconnect from the network, to the detriment of all other customers who would have to bear a higher cost for energy.

14.21 Overall Bill Impact of OUR determined Tariff on Rate 40 & 50 customers

	Average consumption	Load Factor	Demand (kVA)			Energy (kWh)			Monthly Bill		Impact on Consumers	
			STD and On-Peak	Partial-Peak	Off-Peak	STD and On-Peak	Partial-Peak	Off-Peak	000 JMD/Month			
	kWh/month	%							**Current**	**Proposal**	000 JMD/Month	%
RT40 (STD)	39,536	40%	134						876	890	15	1.7%
RT40 (TOU)	60,966	59%	113	145	132	7,539	26,785	26,642	1,266	1,279	13	1.1%
RT50 (STD)	345,069	55%	852						7,074	7,180	105	1.5%
RT50 (TOU)	449,127	56%	1,095	1,574	1,631	55,536	197,323	196,268	9,458	9,626	168	1.8%

Figure 9: Unitary Costs by Rate 40 & 50 Consumption Levels



Customers in these categories represent less than 0.5% of the total customer base but account for 45% of all energy consumed. For this reason it is very important to set rates that encourage the Rate 40 and 50 customers to stay on the system. This is the reason why the OUR reduced the NAC for these categories while at the same time keeping the energy charges unchanged from the current rates. This is despite the existence of a greater willingness to pay by this group, given the cost of the best alternative opportunity that exists for this group, as demonstrated by Figure 9.

Comparison of OUR Determined Non-Fuel Rates with JPS Proposed Non-Fuel Rates

14.22 JPS Proposed Non-Fuel Rates

Rate	Description	Current Non-Fuel Rate (JMD/kWh)	Current Non-Fuel Rate including current IPP Increment 0.22$/kWh	JPS Proposed Rate (JMD/kWh)	Increase %
R10	Residential	10.04	10.26	14.46	40.9%
R20	General	11.27	11.49	18.38	60.0%
R40_STD	Power- Standard	7.09	7.31	11.77	61.0%
R40_TOU	Power - Time-of-Use	5.45	5.67	6.98	23.1%
R50_STD	Power - Standard	5.32	5.54	9.40	69.7%
R50_TOU	Power - Time-of-Use	5.79	6.01	7.71	28.3%
R60	Lighting	12.54	12.76	17.41	36.4%
JPS	**All customers**	**8.43**	**8.65**	**12.56**	45.2%

14.23 OUR Determined Non-Fuel Rates

Rate	Description	Current Rate (JMD/kWh)	Current Non-Fuel Rate including current IPP Increment 0.22$/kWh	OUR Determined Rate (JMD/kWh	Increase %
R10	Residential	10.22	10.44	11.86	13.6%
R20	General	11.41	11.63	13.5	16.1%
R40_STD	Power- Standard	6.87	7.09	7.98	12.6%
R40_TOU	Power - Time-of-Use	5.32	5.54	6.21	12.1%
R50_STD	Power - Standard	5.18	5.4	6.09	12.8%
R50_TOU	Power - Time-of-Use	5.62	5.84	6.58	12.7%
R60	Lighting	12.77	12.99	14.89	14.6%
JPS	**All customers**	**8.43**	**8.65**	**9.78**	13.1%

Comparison of OUR Determined Overall Average Tariff with JPS Proposed Overall Average Tariff

14.24 JPS Proposed Overall Average Rates

Rate	Description	Current Rate (JMD/kWh)	JPS Proposed 2PT Rate (JMD/kWh)	Increase(%)
R10	Residential	25.48	30.25	18.8%
R20	General	26.71	28.98	8.5%
R40_STD	Power- Standard	22.53	26.69	18.5%
R40_TOU	Power - Time-of-Use	20.88	25.99	24.5%
R50_STD	Power - Standard	20.76	24.40	17.5%
R50_TOU	Power - Time-of-Use	21.22	26.40	24.4%
R60	Lighting	27.98	33.56	19.9%
JPS	**All Customers**	**23.87**	**28.00**	**17.3%**

14.25 OUR Determined Overall Average Rates for September 2009

Rate	Description	Effective Rate (JMD/kWh)	OUR Determined Rate (JMD/kWh)	Increase %
R10	Residential	25.66	26.67	3.9%
R20	General	26.85	28.31	5.4%
R40_STD	Power- Standard	22.31	22.70	1.8%
R40_TOU	Power -Time-of-Use	20.76	20.98	1.1%
R50_STD	Power - Standard	20.62	20.94	1.6%
R50_TOU	Power - Time-of-Use	21.06	21.43	1.8%
R60	Lighting	28.21	29.71	5.3%
JPS	All Customers	23.87	24.58	3.0%

SECTION II

15. Consumer Issues and Quality of Service Standards

15.1. Public Consultations

Section 11 (2) of the OUR Act states that the OUR may consult with stakeholders on rates or fares to be charged by a Licencee. Acknowledging the importance of public participation in the review process, the OUR convened five public consultation meetings across the island to hear the views of stakeholders on the submission by the Jamaica Public Service Co. (JPS) to the OUR for a 23.08% increase in its existing non - fuel rates. The consultations also served as a forum which allowed JPS to present to consumers the company's reasons for the requested increase as well as to respond to questions regarding its application.

The rate application document that was submitted by JPS was placed on the OUR's website and a summary prepared and published in the daily newspapers, to provide stakeholders an opportunity to examine the details of the company's request, and by so doing, facilitate pertinent questions at the consultations. Consumers would also have the opportunity at the meetings to convey to the OUR and the JPS, quality of service issues that affect them.

The consultation meetings were widely publicized through a variety of media and were held in strategic locations across the island to ensure extensive participation by the public. Consumers were also encouraged to make written submissions to the OUR.

15.2 Format of the Consultations

The Office – represented by the Director General, presided over most of the meetings. The JPS made an approximate 35 minute presentation on its submission after which consumers were given the opportunity to engage representatives of the company and the OUR.

15.3 Views on the proposed Tariff Increase

It was the consensus at the meetings as well as through written submissions received by the OUR that the company was unreasonable in its request for an increase. This perceived unreasonableness of the company came against the background of the current global economic crisis which has resulted in many persons becoming unemployed while the salaries of others remain stagnant.

Some consumers although acknowledging the company's objective to make a return on investment, however felt strongly that no benefit could be derived by the company if customers are unable to pay their bills due to a further increase in rates. Additionally, there was the expressed concern that consumers' inability to cope with further increases in electricity rates may unfortunately result in increased incidences of electricity theft.

15.4 Inefficiencies

It was largely the view that JPS' submission for an increase was fuelled by its own inefficiencies. It was the opinion of many consumers that JPS' inefficient operation of its generation and distribution systems is a likely contributing factor to losses. Consumers felt that if the company addressed its internal inefficiencies, it would have no need for an increase. The company's seemingly inability to effectively address the issue of electricity theft was also highlighted as an area in which the company needs to be more responsive.

15.5 Proposed Rate Tiers

Customers are of the view that they should not be subsidizing the lifeline consumers. The view was expressed that the tiered rate design proposed by JPS was inequitable and would only make worse what is perceived to be an already complicated bill.

15.6 Small Businesses and Hoteliers

Some business customers lamented that any increase in rates granted would only serve to cripple the already ailing small business and manufacturing sectors. They felt that enough is not being done to promote net metering which would provide incentives for private businesses and householders to invest in alternative renewable energy. It was their opinion that any increase granted must hold JPS to this possibility.

15.7 Quality of Service Issues Highlighted

Some quality of service issues highlighted by customers at the consultation meetings included:

- Billing system integrity – customers expressed little confidence in the company's ability to give them a proper monthly bill after approximately 40,000 customers in 2008 received bills reflecting over 35 days usage.

- There was also the issue of seemingly inexplicable spikes in consumption which fuelled concerns about the integrity of the billing system.

- Poor voltage quality - resulting in equipment damage for which JPS maintains that the company is not liable

    - outages – Customers were of the view that this was a direct result of inadequate maintenance

15.8 Quality of Service

Section 4(5) (b) of the Office of Utilities Regulation Act empowers the Office to *"….prescribe standards for the measurements of quantity, quality or other conditions relating to prescribed utility services"*. The OUR therefore has the responsibility of ensuring that the utility companies deliver to customers a certain level of service.

In order to fulfill this mandate, the OUR developed Guaranteed and Overall Standards for the Jamaica Public Service Company and the National Water Commission. The standards reflected what the Office perceived as reasonable levels of service delivery that consumers value. The areas of focus were technical quality, reliability and service quality.

15.9 The Guaranteed Standards Scheme

The Guaranteed Standards for JPS were implemented in the year 2000 and were borne out of consultations with stakeholders on the service issues that affected them. The Office took the decision to review the standards every 5 years during the review of the company's rates.

The OUR in the last tariff review for the company in 2004, implemented 5 new standards. The Office's decision to introduce the new standards was guided by concerns communicated by consumers to the OUR's Consumer Relations Unit (CRU) regarding the company's service delivery, as well as the results of a national consumer survey that was conducted. The new standards were as follows:

- Frequency of meter reading
- Estimation of consumption
- Meter Replacement

- Billing adjustments
- Street lighting maintenance

The compensation for breach of a standard was also increased to $1000 for residential and rate 20 customers (small commercial) and $8400 for larger commercial customers.

Subsequent to the inclusion of the new standards in 2004, the OUR, in particular the CRU, continued to monitor the standards through quarterly compliance reports submitted by JPS, consumer contacts and two national consumer surveys that were conducted in 2006 and one recently concluded in 2009.

15.9.1 Concerns Regarding the Scheme

The following concerns were communicated to the OUR by consumers regarding the Guaranteed Standards Scheme:

- Some of the performance targets being measured do not meet consumers' expectation of quality of service
- The existing standards do not reflect current consumer issues and experiences with the company
    - The compensation is too low
    - Claim mechanism ineffective
    - Review period too long [every 5 years]

15.9.2 Breaches of the Guaranteed Standards - JPS Compliance Report

The quarterly submissions by JPS on its compliance with the standards indicate that on a quarterly basis the company commits on average 16,000 breaches attracting potential compensation of over $50,000,000. Consumers have however been reluctant to claim citing that the cost associated with submitting a claim outweighed the benefit, as it is the view of most consumers that the current compensation for breach of a standard is too low. Consequently on average less than $250,000 is paid out by the company on a quarterly basis based on claims received.

15.9.3 JPS' Submission on the Guaranteed Standards – 2009 Tariff Application

In its rate application submission JPS has recommended the following changes to the Guaranteed Standards:

- *GS2– Complex Connections:*

- GS2a – Estimates within 15 days; connections within 35 working days after payment
- GS2b – Estimates within 15 days; connections within 45 working days after payment

According to the company the modified timeline would be more realistic given various constraints associated with executing such projects.

- *EGS6 – Reconnection after payment of overdue amounts:*
    - JPS proposes that this standard be revised to 24 hours to reconnect customers after payment of overdue amounts irrespective of the customer's location.

- *EGS8 – Estimation of Consumption:*
    - JPS proposes that this standard be converted into an overall standard.

- *EGS10 – Billing Adjustments:*
    - JPS proposes that this standard be modified to allow for as many as two billing periods for adjustments.

- *EGS11 – Timeliness of repairs of streetlights*
    - JPS proposes that this standard be removed as it is already measured as an Overall Standard.

15.9.4 Review of the Existing Guaranteed Standards JPS' recommendations to have some standards modified as well as concerns and proposals conveyed by consumers regarding the scheme were taken into consideration in the review of the standards undertaken as follows:

- **EGS1 (a) – Connection to Supply (Simple) – New Installations**

Performance Measure – *JPS must install new service within 5 days*

Office's Comment & Determination:

The Office has decided to maintain this standard at the current level as it deems the timeliness for a new connection as reflected in the standard to be reasonable.

- **EGS1 (b) – Connection to Supply – Simple Connections**

Performance Measure – *Connection within 4 working days where supply and meter are already on premises*

Office's Comment & Determination:

There will be no change to this standard except that JPS must ensure that the meter has not been tampered with before the contract with the new customer commences.
It should be noted that when a customer commences a relationship with the utility company there is a justified presumption that they have received a meter that is in good working condition. It is felt therefore that the company has an obligation to ensure that these conditions exist on commencement of the relationship. Accordingly, JPS will be required to provide the customer with a report which indicates the condition of the meter and the meter reading on installation and commencement of a contract.

- **EGS2 (a) – Connection to Supply – Complex**

Performance Measure – *Estimate within 10 working days; Connection within 30 working days after payment*

- **EGS2 (b) – Connection to Supply – Complex**

Performance Measure – *Estimate within 15 working days; Connection within 40 working days after payment*

Office's Comment & Determination:

JPS proposes that the timeframe for connection under EGS2 (a) & (b) be increased to reflect current construction constraints. The Office is however of the view that the company has not adequately demonstrated its position in this regard and as such, the existing performance targets will be maintained. Notwithstanding, the Office will make allowance for special circumstances, provided that the company makes a commitment in writing to the applicant indicating the reasons [inclusive of the scope of work to be undertaken] it will be unable to provide the connection within the time stipulated by the Guaranteed Standard. The applicant should also receive a new connection date

in writing which is reflective of the work to be done, and which will be the new standard that the company must guarantee.

- **EGS3 – Response to Emergency [localized situations such as blown fuses, fire on pole, etc.]**

Performance Measure – *Respond to emergency within 6 hours*

Office's Comment & Determination:

The Office is of the view that the Company must endeavour to respond promptly to emergencies to preserve life and property. Accordingly, in an attempt to safeguard against any unfortunate occurrences, the current performance measure is revised to encourage the company to promptly attend to reported emergencies.

The standard will therefore be revised to: RESPOND TO EMERGENCIES WITHIN FIVE (5) HOURS. These emergencies are defined as broken wires, fires and broken poles.

- **EGS4 – Issue of First Bill**

Performance Measure – *Produce and dispatch bill within 45 working days after service connection.*

Office's Comment & Determination:

The Office is mindful of the impact a customer's first bill can have on his/her cash flow in the absence of a consumption pattern to gauge monthly electricity usage. Accordingly it is desirous that a customer's first bill does not reflect extended billing days.

To reduce the likelihood of such an occurrence, the existing standard is revised to 'First bill dispatched within FORTY DAYS after service connection'. There is a directive that precludes JPS from billing for any period exceeding 31 days for which a customer's first bill is excepted.

- **EGS5 (a) – Acknowledgement**

Performance Measure – *Acknowledge written queries within 5 days*

- **EGS5 (b) – Investigations**

Performance Measure – *Complete Investigations within 30 working days*

- **EGS5 (c) – Investigations involving 3rd party**

Performance Measure – *Complete investigations within 60 working days if 3rd party involved*

Office's Comment & Determination:

The Office is of the view that the company has reasonable control over the duration of investigations under EGS5 (b) given that it houses all information pertaining to the customer's account. However, as the Office wishes to ensure that complaints are thoroughly investigated, the existing standards will be maintained.

- **EGS6 (a) – Reconnection After Payment of Overdue Amounts**

Performance Measure – *Reconnection within 24 hours for urban areas*

- **EGS6 (b) – Reconnection After Payment of Overdue Amounts**

Performance Measure – *Reconnection within 48 hours – rural areas*

Office's Comment & Determination:

The Office is of the view that a customer, after clearing arrears [and paying reconnection fee] which led to the disruption of the supply, should have the service restored promptly, irrespective of location. Consequently, this standard is revised to reflect a standard 24 HOUR RECONNECTION after arrears are settled with the company or arrangements agreed for settlement.

- **EGS7 – Frequency of Meter Reading**

Performance Measure – *Should not be more than two (2) consecutive estimated bills where the company has access to the meter*

Office's Comment & Determination:

Although there is a prescribed methodology for the calculation of estimated bills, consumers have expressed a lack of confidence in estimated bills rendered by the company. It is their view that where the meter is accessible to the company, bills should reflect actual meter readings. Notwithstanding the foregoing, the Office recognizes the company's efforts over the past year to

read meters on a monthly basis. Additionally, the reports submitted by JPS indicate 97% compliance in this area of service delivery.

Having noted the customers' concerns and the company's efforts in this area, the Office has decided that the current standard will be maintained. However, the company will be expected to maintain 99% compliance with this standard.

- **EGS8 – Method of Estimating Consumption**

Performance Measure – *An estimated bill should be based on the average of the last three actual readings – First 6 bills of new accounts excepted.*

Office's Comment & Determination:

JPS proposes in its submission that this standard be converted to an Overall Standard as the methodology for estimating consumption is hard coded in its billing system. Despite this proposal and proclamation by the company, it has been the OUR's experience [through bills submitted by customers] where estimates applied are not always in keeping with the estimation methodology. Additionally, as this standard has a direct impact on the consumption billed, the Office has decided that it will remain a Guaranteed Standard.

- **EGS9 – Timeliness of Meter Replacement**

Performance Measure – *maximum of 20 working days to replace meter after detection of fault*

Office's Comment & Determination:

Given the thrust to ensure that bills rendered to customers are based on meter readings, thereby reducing estimated billings, the Office has decided that this standard will remain at 20 working days. This standard will however not apply where a meter becomes defective as a result of tampering by the customer.

- **EGS10 – Timeliness of Adjustment to Customer's account**

Performance Measure -	*Where necessary, customer must be billed for adjustment within one billing period of identification of error*

Office's Comment & Determination:

Similar to the company's concerns, the Office has seen where it is necessary to extend the timeframe for adjustment to ensure that the company establishes a proper consumption pattern for the customer in instances where same is necessary for adjustments. In an effort to meet the existing standard, the company currently uses the consumption over a short period – usually 7 days - to inform the adjusted amount. In most instances, the average consumption derived over this period does not accurately reflect the customer's monthly usage. The Office has therefore concluded that a month's consumption would be more reasonable in terms of establishing the customer's usage pattern. The Office will therefore revise the standard to allow for adjustments within three months.

- **EGS12 – Compensation**

Performance Measure –	*Response to claim for compensation within 45 days of verification of breach*

Office's Comment & Determination:

The Office is of the view that one billing period should provide sufficient time for the company to verify and process claims received, however the existing standard will be maintained until the mid tariff review.

Additionally, the customer will be given 132 working days or 180 days within which to submit a claim for any breach of the Guaranteed Standards. This will allow persons to claim for a breach after the quarterly publication of the compliance report as well as be consistent with the back billing policy of six months (180 days – 48 for weekends = 132 days).

The Implementation of New Standards

In response to the public's concern that the existing scheme does not address current quality of service issues, the Office sees it as necessary to introduce four (4) new Guaranteed Standards. These standards are reflective of growing trends in service delivery that were communicated to the OUR by affected customers. They were also reiterated at the public consultations.

The new standards are as follows:

1. Wrongful Disconnection

There was strong advocacy throughout the consultation for the inclusion of 'wrongful disconnection' as a standard. Over the last three years, the OUR's Consumer Relations Unit has processed numerous contacts regarding electricity supply that was inadvertently disconnected by JPS. Customers, in addition to the inconvenience and embarrassment so caused, were left disgruntled having been informed that there was no provision in the existing scheme to treat with such an action by the company.

The standard will be defined as follows:

- The company commits a breach where it disconnects a customer's supply that has no overdue amount reflected on the associated account. This standard will also apply to accounts that are under investigation by the OUR or the company itself and on which the company is requested or has undertaken to place a hold on the disputed sum but disconnects the account prior to the OUR's or its own ruling on the matter and there were no outstanding sums owed beyond the disputed sum.

2. Reconnection After Wrongful Disconnection

Having suffered the inconvenience of an unwarranted disruption in supply, it is the Office's view that the company should endeavour to restore same within the shortest possible time, and as such, should be treated in a manner separate from the timeframe for reconnecting a supply that was disconnected as a result of arrears. The timeframe for this standard will be linked to the company's response to an emergency call.

The standard is defined as follows:

– Where the company after erroneously disconnecting a supply, fails to reconnect same within FIVE (5) hours of being notified or having itself detected the error.

3. Changing Meters

The Office continues to receive complaints from customers regarding meters that are changed due to defects without any communication from the outset by the company. In some instances, customers are only made aware that there was a problem when they receive a letter with their electricity bill which indicates an adjustment to the account due to a faulty meter that was replaced. The Office finds this level of communication insufficient and is of the view that the company should ensure that its customers are provided with the necessary information that will impact future billing.

The standard is defined as follows:

– The company must provide customers with details of the date of change, reason for change, meter readings on the day and serial number of the new meter on the day of the meter being changed. This communication may be done via text message.

15.9.5 Compensation

Consumers have generally felt that the resultant compensation for breach of a standard is low and therefore provides no incentive for the customer to submit a claim. The Office maintains the view that the objective of the scheme is to encourage the company to consistently provide a prescribed minimum level of service to its customers. Any significant 'drop off' in this level of service would impact the company financially through the aggregate of claims submitted by affected customers. It is anticipated that such a financial impact would generate a more responsive approach by the company to service delivery. The Office recognizes that the compensation payment should be revised; however, its revision will be in keeping with the objectives of the scheme.

General Compensation – *This does not include compensation for wrongful disconnection*

1. ***For residential customers, a breach of a standard will result in compensation equal to the reconnection fee.***
2. ***For commercial customers, the compensation will remain four times the customer charge.***

Compensation for Wrongful Disconnection

1. ***Compensation for wrongful disconnection will be TWO (2) times the reconnection fee for residential customers and FIVE (5) times the customer charge for Commercial customers.***

2. ***Reconnection after wrongful disconnection' standard when breached will attract compensation of TWO (2) times the reconnection fee for residential customers and FIVE (5) times the customer charge for commercial customers.***

15.9.6 Automatic versus Claim

The claim mechanism associated with the compensation aspect of the scheme has resulted in significantly low payments by the company as a direct result of very few claims submitted by customers. Customers have indicated to the OUR that the cost to submit a claim outweighed the benefit - given the low compensation. It is the expressed view of many that the company should be directed to automatically credit accounts with the requisite compensation when it breaches a standard.

The Office has noted the concerns expressed but is of the view that the customer should not be absolved of the responsibility of engaging the company in dialogue of some form regarding service delivery. The Office will however introduce automatic compensation in specific areas under the scheme to impel the company to be more responsive in some areas and in others as a consequence of a specific action by the company.

Accordingly, the company will be required to automatically apply the necessary compensation to accounts for the following breaches:

1. **Wrongful Disconnection**
2. **Reconnection after Wrongful Disconnection**
3. **Reconnection after Payment of Overdue Amounts**
4. **Meter Replacement**

For clarity, Automatic Compensation is defined as both a breach which is brought to the attention of the company and those breaches which the company itself recognizes have occurred.

The Office recognizes that the company may need to implement the necessary systems to address breaches requiring automatic compensation. As such, the automatic payments will be enforced effective January 4, 2010. Customers will therefore be requested to submit claims for these breaches prior to the date specified.

15.9.7 Timeframe for Review of Standards

Although the JPS Licence provides for the revision of the Guaranteed Standards between tariff reviews, the practice of the Office has been to review the standards during a tariff review. The Office however recognizes that the practice of reviewing the standards every five years is neither beneficial to the customer nor the company as important service issues would not be addressed in a timely manner. Additionally, periodic reviews of the standard will assist in assessing their effectiveness and relevance.

Given the foregoing concerns, the Guaranteed Standards will now be reviewed every 2 years. However recognizing the implications for the company's revenues, this mid tariff review will not seek to introduce additional automatic standards nor will it increase the penalties. However new standards may be introduced and existing performance measures modified.

15.9.8 Reporting Requirement for the Guaranteed Standards

The Office will require JPS to submit quarterly reports indicating its compliance to each of the standards. The report will now include an appendix which provides details on automatic credits such as the number of breaches, the affected accounts and the credits applied.

The company must be applauded for its efforts to promote the standards and will be required to continue these efforts through the use of bill stuffers, newspaper ads, on its website and in its commercial offices.

The Guaranteed Standards are summarized in the table below

JAMAICA PUBLIC SERVICE CO LTD

Guaranteed Service Standards 2009 - 2011

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 5 hours –emergencies defined broken wires, broken poles, fires
EGS 4	First Bill	Issue of First bill	Produce and dispatch first bill within 40 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	Reconnection	Reconnection after Payments of Overdue amounts	reconnection within 24 hours **Attracts automatic compensation**
	Estimated Bills	Frequency of Meter reading	Should NOT be more than two (2)

Code	Focus	Description	Performance Measure
EGS 7			consecutive estimated bills (where company has access to meter).
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.
EGS 9	Meter Replacement	Timeliness of Meter Replacement	Maximum of 20 working days to replace meter after detection of fault which is not due to tampering by the customer **Attracts automatic compensation**
EGS 10	Billing Adjustments	Timeliness of adjustment to customer's account	Where necessary, customer must be billed for adjustment within three (3) months of identification of error, or subsequent to replacement of faulty meter
EGS11	Disconnection	Wrongful Disconnection	Where the company disconnects a supply that has no overdue amount or is currently under investigation by the OUR or the company and only the disputed amount is in arrears. **Attracts automatic compensation**
EGS12	Reconnection	Reconnection after Wrongful disconnection	The company must restore a supply it wrongfully disconnects within 5 hours **Attracts automatic compensation**
EGS13	Meter	Meter change	JPS must ensure that a note is left at the premises and or utilize its text messaging service indicating the meter change including date of the change and meter reading at the time of change and serial number of new meter
EGS14	Compensation	Making compensatory payments	Response to claim for compensation within 45 days of verification of breach

Customers should submit claims within 180 days or 132 working days after the occurrence of the breach. Breaches will attract multiple payments up to four (4) periods.

15.10 Additional Quality of Service Issues

The Office is aware of additional quality of service issues that need to be addressed. Some of the service concerns will require the JPS to implement the appropriate protocols and procedures. Accordingly, JPS will be instructed to implement protocols within a timeframe to be specified after these determinations. Some of the issues reported that are of concern to the Office are outlined below:

15.10.1 Outages

The Office continues to receive numerous complaints from customers regarding the frequent power outages across the island. While the level of outages in general is of concern to the Office, there are specific areas that JPS will be required to conduct an extensive assessment to ascertain the cause of prolonged and frequent outages in these areas. The company will be required to ensure that the necessary rehabilitation work is executed within a timely manner in the affected areas. These areas include sections of Portland, the King Weston area of Lawrence Tavern St. Andrew and the King Street area of Montego Bay.

15.10.2 T & D Line Maintenance Report

The Office recognizes that an appropriate maintenance schedule directly impacts outages – both planned and unplanned. To closely monitor the company's maintenance activities, JPS will be requested to submit on a quarterly basis, a report indicating its schedule maintenance activity inclusive of work conducted, the type of work carried out, work to be conducted and the respective area/location. The cost associated with each piece of work undertaken should be included as well as works that were scheduled but were not undertaken, as well as the reason (s) same were not done.

15.10.3 Bill Notification/Reminder

Customers have communicated to the Office, the need for the company to be more customer oriented as it relates to pre- disconnection reminders. The Office has been made aware of issues regarding billing punctuality and in some cases non receipt of bills. Whilst this is not necessarily a failure on the part of the company to render same – as it could possibly be associated with problems at post offices, the Office is of the view that JPS can provide more options to customers to inform bill balances/charges. The Office notes that JPS, in its tariff application, has reported that it currently has a database of numbers for 62% of its customers to facilitate text message notification of overdue amounts. The Office commends the company for its initiative in this regard but now requires the company to use all reasonable means of increasing customer awareness of such a database to improve on the current 62% of customer for whom contact details are available. Such method of awareness include but is not limited to the company leaving a card at the customer's premises at the time of every disconnection requesting mobile information for bill alerts and for payments at the JPS offices there should be a request for mobile numbers.

15.10.4 Protocols and Procedures

Since the last tariff review, consumers have contacted the Office of Utilities Regulation regarding issues with JPS that they perceive require the implementation of clear polices. Some of these issues include:

- Metering – inspections, removal, replacement
- Procedures for dealing with illegal connections
- Billing Issues – Abnormally high readings, methodology for billing adjustments
- Equipment Damage – company's refusal to honour claims

The JPS will be requested through guidance from the Office to implement the appropriate protocols and procedures to deal with these issues within three months of the Office's determination on the tariff for the company.

This will likely include a revision of the high-low criteria which places accounts on the exceptions list and direction as to how to verify the bills generated.

ANNEX A: JPS Known and Measurable Changes (US$) Converted Tables

Table 5.20 Reconciliation of Test Year Expenses

85.0
72.9211

{All amounts in J$'000s}	Adjustment Section	Actual Costs	Exclusions	Rate Increase	FX	CPI	Interest rates	Bad debt	Cost of Capital	Adjusted Costs
Purchased power	5.2.9	4,925,090			815,809					5,740,899
Operating expenses:										
Payroll, benefits & training	5.2.1	5,496,126		799,781		366,446				6,662,353
Payroll, benefits & training	5.2.7	-		56,130						56,130
Third party services	5.2.9	1,669,868			96,811	65,125				1,831,804
Materials & equipment	5.2.9	833,549			138,072	-				971,621
Office & Other expenses	5.2.9	1,036,995			137,417	12,444				1,186,856
Transportation expenses	5.2.9	742,034			109,736	4,773				856,543
Insurance expense	5.2.2	547,629		151,708	-	-				699,337
Bad debt write-off	5.2.5	1,161,689			-	-		266,680		1,428,369
		11,487,890	-	1,007,619	482,036	448,788	-	266,680		13,693,013
Depreciation & amortisation	5.2.9	3,033,618		615,102	570,809					4,219,529
Net finance costs:										
Foreign exchange losses		1,092,633	(1,092,633)							-
Interest on long-term loans		1,872,659							1,174,399	3,047,058
Interest on short-term loans	5.2.4	364,746					(185,056)			179,690
Loan finance fees		130,673	(130,673)							-
Interest on customer deposits	5.2.4	133,152					(55,780)			77,372
Interest - other		12,396								12,396
Finance income		(269,658)								(269,658)
		3,336,601	(1,223,306)	-	-	-	(240,836)	-	1,174,399	3,046,858
Other income	5.2.6	(368,829)	266,810							(102,019)
Other expenses	5.2.6	1,196,690	(1,196,690)							-
		827,861	(929,880)	-	-	-	-	-	-	(102,019)
TOTAL NON-FUEL EXPENSES		23,611,060	(2,153,186)	1,622,721	1,868,654	448,788	(240,836)	266,680	1,174,399	26,598,280

Table 5.21

REVENUE REQUIREMENT	
PPA	5,740,899
O&M	13,693,013
Dep'n	4,219,529
	23,653,441
NFC, excl. LTD	**(200)**
Other Income	**(102,019)**
	23,551,222
SIF	**637,500**
ROE	**6,935,378**
Taxes	**3,467,689**
Interest	**3,047,058**
RR	**37,638,847**
CCC	(310,521)
RR, excl. CCC	37,328,326

Table 5.4 & 5.19

J$'000s	Audited 2008	Reclass-ification	Add'l Debt @85:1	2008 (Adjusted)
Cash	1,304,495		425,000	1,729,495
Receivables	14,656,380			14,656,380
Inventories	3,733,965			3,733,965
Other	205,700			205,700
Current Assets	19,900,540	-	425,000	20,325,540
Accounts Payable	(6,651,590)		680,000	(5,971,590)
Bank overdraft	(65,875)			(65,875)
Short-term loans	(4,526,250)	(522,000)	3,145,000	(1,903,250)
Current maturity	(1,083,920)	1,083,920		-
Other liabilities	(13,685)			(13,685)
Current Liabilities	(12,341,320)	561,920	3,825,000	(7,954,400)
Net current assets	7,559,220	561,920	4,250,000	12,371,140
PP&E	52,992,315			52,992,315
Other non-Current Assets	2,363,765			2,363,765
Other Long-term Liabilitie:	(9,098,060)			(9,098,060)
	53,817,240	561,920	4,250,000	58,629,160
Shareholder's equity	32,913,700		(850,000)	32,063,700
Long-term Loans	20,903,540	561,920	5,100,000	26,565,460
	53,817,240	561,920	4,250,000	58,629,160

		J$'000s	J$'000s
		Table 4.4	
		2004	**2009**
Cost of Debt	A	12.56%	11.47%
Rate of Return on Equity (ROE)	B	14.85%	21.63%
Tax Rate	C	33.33%	33.33%
Gearing Ratio	D=E/G	44.1%	45.3%
Long-term Debt ('000)	E	15,420,557	26,565,460
Shareholder's Equity ('000)	F	19,581,238	32,063,700
Total Capitalization ('000)	G=E+F	35,001,795	58,629,160
Return on Equity	H=B*F	2,907,814	6,935,378
Taxation	I	1,453,907	3,467,689
Return on Investment	J=H+I	6,298,543	10,403,067
Interest Expense	K=A*E	1,936,822	3,047,058
Post-tax WACC	L=D*(1-C)*E+(1-D)*B	12.00%	15.29%
Pre-tax WACC	M=D*A+(1-D)*B/(1-C)	17.99%	22.94%

M=D*E+(1-D)*B/(1-C)

Table 5.1 Analysis of Employee Costs

J$'000s	2008	CPI - 2008	1/2 CPI - 2009	2008 ADJUSTED
Unionized employee costs	4,740,847	799,781	332,438	5,873,066
Pension cost	188,479			
Non-unionized employee costs	566,800	-	34,008	600,808
TOTAL	5,496,126	799,781	366,446	6,473,874

Table 5.13

J$'000s	Contract	Permanent	TOTAL
Number of meter readers	101	22	123
Approximate daily cost	4,500	6,700	
Saturday over-time multiple	1.5	1.5	
Sunday over-time multiple	2	2	
No. of Saturdays required for meter reading	43	43	
No. of Sundays required for meter reading	10	10	
Estimated overtime cost at 2008 Costs	38,405,250	12,455,300	50,860,550
Adjustment for 2008 Salary increase	1.00	1.168	
Adjustment for 2009 CPI/Salary increase	1.06	1.06	
Estimated overtime cost at 2009 Costs	40,709,565	15,420,658	56,130,223

J$'000s	Contract
Number of meter readers	20
Approximate daily cost	4,500
No. of Workdays required for meter reading	260
Estimated cost at 2008 Costs	23,400,000
Adjustment for 2008 Salary increase	1.00
Adjustment for 2009 CPI/Salary increase	1.00
Estimated cost at 2009 Costs	23,400,000
Redundancy cost assuming 1.5 years pay	57,486,000
Redundancy cost annualized over 5 years	11,497,200
Total annual cost	34,897,200

Table 5.17: US$ vs. J$ Cost Components

{All amounts in J$'000s}	Actual Costs	Cost component US$ Costs	Cost component J$ Costs	% of cost US$	% of cost J$
Purchased power (excluding fuel)	4,925,090	4,925,090	-	100%	0%
Operating expenses:					
Payroll, benefits & training	5,496,126	-	5,496,126	0%	100%
Third party services	1,669,868	584,454	1,085,414	35%	65%
Materials & equipment	833,549	833,549	-	100%	0%
Office & Other expenses	1,036,995	829,596	207,399	80%	20%
Transportation expenses	742,034	662,485	79,549	89%	11%
Insurance expense	547,629	518,878	28,751	95%	5%
Bad debt write-off	1,161,689	-	1,161,689	0%	100%
	11,487,890	3,428,962	8,058,928	30%	70%
Depreciation and amortisation	3,033,618	3,033,618	-	100%	0%
	19,446,598	11,387,670	8,058,928	59%	41%

Table 5.18

{All amounts in J$'000s}	1/2 CPI or FX Adjustment US$	J$
Purchased power (excluding fuel)	815,809	-
Operating expenses:		
Payroll, benefits & training	N/A	N/A
Third party services	96,811	65,125
Materials & equipment	138,072	-
Office & Other expenses	137,417	12,444
Transportation expenses	109,736	4,773
Insurance expense	N/A	N/A
Bad debt write-off	N/A	N/A

	482,036	82,342
Depreciation and amortisation	N/A	-

Table 5.11: Adjustment to bad debt ex

(2008 Actual)	Adjustment	(2008 Adjusted)
1.63%		2%
1,161,689	266,680	1,428,369

Table 5.14: Full Yr Dep'n based on PIS at Dec-31-08

J$'000s	Dec'08 (1 month)	Annualized Amount	Year-end FX Rate	Base FX Rate	Adusted Amount
Depreciation	284,361	3,412,332	80.47	85.00	3,604,427

Table 5.15: Asset Lives Comparison

Activity	Asset Category	JPS	Sample Mode	Differ-ence	Requested Amount
Generation	Hydro Production Plant	35	20	15	20
Distribution	Test Equipment	25	15	10	15
Distribution	Supervisory Control System	25	15	10	10
General Plant	Electronic Equipment	25	5	20	10
General Plant	Communication Equipment	15	5	10	10
General Plant	Computer Equipment	20	5	15	5
General Plant	Furniture & Office Equipment	20	10	10	10

Table 5.16: Additional Dep'n due to Asset Life Adj

Activity	Asset Category	Book Value @ $80.47	Book Value @ $85	Additional Dep'n Charge
		J$'000s	J$'000s	J$'000s
Generation	Hydro Production Plant	2,531,506	2,674,015	57,300
Distribution	Test Equipment	664,763	702,185	18,725
General Plant	Communication Equipment	4,434,605	4,684,248	156,142
General Plant	Computer Equipment	2,098,819	2,216,970	332,546
General Plant	Furniture & Office Equipment	954,076	1,007,785	50,389
		10,683,769	11,285,203	615,102

4,219,529

Table 5.5

Interest Expense	US$'000s	FX Rate	J$'000s
Interest on long-term loans	25,681	72.92	1,872,659
Interest on short-term loans	5,002	72.92	364,746
Loan finance fees	1,792	72.92	130,673
Interest on customer deposit:	1,826	72.92	133,152
Interest - other	170	72.92	12,396
	34,471		2,513,626

Year end FX Rate 80.4713

Table 5.6

	_____Loan Balance_____	___Interest Exps___		
	US$000s	Rate	US$000s	J$000s
Adjusted Short-term loan balance	22,391	9.44%	2,114	179,690

J$'000s	2008 (Actual)	Actual Interest rate	Revised Interest rate	2008 (Restated)
Customer deposits	133,152	8.88%	11.93%	178,886
Customer deposits	133,152	8.88%	5.16%	77,372

Table 5.2: Analysis of Test Year Insurance Exps

	Expriry date	2008 Actual US$ Premium	2008 Actual J$ Premium	J$ Equivalent Exps in 2008
		('000s)	('000s)	('000s)
Property damage (all risk)	31-May-09	5,305	-	429,412
Public/Employer's liability	30-Apr-09	612	-	44,124
Excess liability	31-Jul-09	297	-	21,495
Motor contingent liability	30-Jun-09	-	55,280	31,903
Group Life & Personal accident	31-Jan-09	-	15,413	14,072
Other miscellaneous		-	6,601	6,601
		6,214	77,294	547,607

Table 5.3: Insurance Exps adj

	2008 Actual US$ Premium	2009 US$ Increase	2008 Actual J$ Premium	2008 J$ Increase	J$ Equivalent at base FX rate
	('000s)	('000s)	('000s)	('000s)	('000s)
Property damage (all risk)	5,305	1,061			541,110
Public/Employer's liability	612				52,020
Excess liability	297				25,245
Motor contingent liability	0		55,280		55,280
Group Life & Personal accident	0		15,413	3,668	19,081
Other miscellaneous	0		6,601		6,601
	6.214	1.061	77.294	3.668	699.337

Table 5.12

Miscellaneous Income/ (Expenses)

	US$000s	J$000's @ 73.36		
		2008 (actual)	Adjustments	2008 (Adjusted)
Post retirement benefit obligation - write-back	-	-	-	-
Rental Income	611	44,823		44,823
Cable & Pole attachment fees	810	59,422		59,422
Insurance Proceeds & other miscellaneous	3,637	266,810	(266,810)	-
	5,058	**371,055**	**(266,810)**	**104,245**
IDT Job Reclassification	14,577	1,069,369	(1,069,369)	-
Tropical storm restoration costs	1,791	131,388	(131,388)	-
Tropical storm restoration costs	43	3,154	(3,154)	-
	16,411	**1,203,911**	**(1,203,911)**	**-**

Table 4.2: JPS Actual Cost of Debt

Long term loans Lender	Cur'y	Org. Curr '000	US$ Equiv	Int. Rate	Issuance Cost	All-in rate	WACC	Issue Date	Maturity Date
KFW Loan	**EUR**	**3,879**	**5,451**	7.00%	0.45%	7.45%	0.13%	31-Mar-02	30-Dec-30
Int'l Finance Corporation	**$US**	**35,000**	**35,000**	9.1163%	0.75%	9.87%	1.09%	16-May-03	30-Aug-15
AIC Merchant Bank	**$US**	**1,627**	**1,627**	8.75%	0.65%	9.40%	0.05%	08-Oct-04	08-Oct-09
Credit Suisse	**$US**	**180,000**	**180,000**	11.00%	0.45%	11.45%	6.50%	06-Jul-06	06-Jul-16
FCIB Syndicated - US$	**$US**	**35,000**	**35,000**	9.46%	1.00%	10.46%	1.15%	01-Dec-08	01-Jun-11
Additional Borrowing	**$US**	60,000	60,000	13.00%	0.5%	13.50%	2.55%		
			317,078				**11.47%**		

Short term loans Lender	Cur'y	Org. Prin. '000	Int. Rate	Issuance Cost	All-in Rate	WACC	Issue Date	Maturity Date
First Global Fin. Services	**$US**	**25,000**	8.50%	1.00%	9.50%	4.46%	27-Mar-08	27-Mar-09
Citibank N.A.	**$US**	**15,000**	9.17%	1.00%	10.17%	2.86%	31-Oct-08	29-Jan-09
Peninsula Corporation	**$US**	**5,250**	8.50%	1.00%	9.50%	0.94%	01-Oct-08	30-Mar-09
Republic Bank Limted	**$US**	**8,000**	6.82%	1.00%	7.82%	1.17%	04-Nov-08	01-May-09
		53,250				**9.43%**		