Office of Utilities Regulation

Jamaica Public Service Company Limited
Annual Review 2018 & Extraordinary Rate Review

Determination Notice

OFFICE OF UTILITIES REGULATION

2018 October 1

DOCUMENT TITLE AND APPROVAL PAGE

1. DOCUMENT NUMBER: 2018/ELE/018/DET.004

2. DOCUMENT TITLE: Jamaica Public Service Company Limited Annual Review 2018 & Extraordinary Rate Review: Determination Notice

3. PURPOSE OF DOCUMENT:

This document sets out the Office's decisions on (i) issues related to the fourth annual rate adjustment for the Jamaica Public Service Company Limited's Tariff Review Period 2014 – 2019, the third such under the Revenue Cap regime established pursuant to the Electricity Licence, 2016.

4. ANTECEDENT DOCUMENTS:

2014/ELE/008/DET.004	Jamaica Public Service Company Limited Tariff Review for Period 2014 - 2019: Determination Notice	2015 January 07
2015/ELE/003/ADM.001	Jamaica Public Service Company Limited Tariff Review for Period 2014 - 2019: Determination Notice – Addendum 1	2015 February 27
Ele 2015/ELE/007DET.001	Jamaica Public Service Company Limited Annual Tariff Adjustment 2015 – Determination Notice	2015 September 03
Ele 2016/ELE/004DET.001	Jamaica Public Service Company Limited Annual Tariff Adjustment 2016 - Determination Notice	2016 July 04
2017/ELE/001/DET.001	Jamaica Public Service Company Limited Extraordinary Rate Review 2017 Determination Notice	2017 February 01
2017/ELE/006/DET.003	Jamaica Public Service Company Limited Annual Review 2017 & Extraordinary Rate Review – CPLTD: Determination Notice	2017 August 31

APPROVAL:

This document is approved by the Office of Utilities Regulation and this Determination becomes effective as of 2018 October 01.

On behalf of the Office:

Ansord E. Hewitt
Director General

2018 October 1

Abstract

On 2018 May 2, Jamaica Public Service Company Limited (JPS) submitted a request to the Office of Utilities Regulation (OUR/Office) for its Annual Rate Review. Included also in the same submission was a request for an Extraordinary Rate Review in relation to debt cost financing recovery.

The OUR reviewed JPS' Annual Review and Extraordinary Rate Review submission and took the view that given the gravity and complexity of the issues involved, three (3) months would not be adequate to arrive at a determination. In response JPS agreed to a four (4) month review period. Notwithstanding, the agreed review period was further extended, at JPS' requests, to allow for clarifications in relation to several components of the Draft Determination Notice which was shared with the company.

This Determination Notice reflects, among other things, the Offices decisions in relation JPS' 2017-2018 performance with respect to the revenue true-up mechanism delineated in the Electricity Licence, 2016; the treatment of accelerated depreciation and separation cost associated with the scheduled retirement of its baseload plant in 2020; and the introduction of an Accelerated Loss Reduction Mechanism (ALRIM) to incentivize JPS in its effort to reduce losses. The impact of revenue adjustment approved by the Office translates to a 2.8% increase in the average non-fuel tariff and an increase of 0.4% in the overall tariff.

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Definitions, Acronyms and Abbreviations

2014-2019 Determination Notice	-	Jamaica Public Service Company Limited Tariff Review for Period 2014 -2019 Determination Notice, Document No. 2014/ELE/008/DET.004
2015 Annual Tariff Adjustment Determination Notice	-	Jamaica Public Service Company Limited Annual Tariff Adjustment 2015 – Determination Notice, Document No. Ele 2015/ELE/007DET.001
2016 Annual Tariff Adjustment Determination Notice	-	Jamaica Public Service Company Limited Annual Tariff Adjustment 2016 - Determination Notice, Document No. Ele 2016/ELE/004DET.001
2017 Extraordinary Rate Review Determination	-	Jamaica Public Service Company Limited Extraordinary Rate Review 2017 Determination Notice, Document No. 2017/ELE/001/DET.001
2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice	-	Jamaica Public Service Company Limited Annual Review 2017 & Extraordinary Rate Review – CPLTD: Determination Notice, Document No. 2017/ELE/006/DET.003
ABNF	-	Adjusted Base-rate Non-Fuel
Addendum 1	-	Jamaica Public Service Company Limited Tariff Review for the Period 2014 – 2019: Determination Notice – Addendum 1, Document No. 2015/ELE/003/ADM.001
Annual Review Submission 2017	-	Jamaica Public Service Company Limited Annual Tariff Adjustment Submission for 2017 & Extraordinary Rate Review dated 2017 May 05
CAIDI	-	Customer Average Interruption Duration Index
CCGT	-	Combined Cycle Gas Turbine
CIS	-	Customer Information System

COD	-	Commercial Operations Date
CPLTD	-	Current Portion of Long Term Debt
CPI	-	Consumer Price Index
CRR	-	Community Renewal Rate
CT	-	Current Transformer
dPCI	-	Annual rate of change in non-fuel Revenue Target as defined in Exhibit 1 of the Licence
dI	-	The annual growth rate in an inflation and devaluation measure
EEIF	-	Electricity Efficiency Improvement Fund
EGS	-	Electricity Guaranteed Standard
ELS	-	Energy Loss Spectrum
EOS	-	Electricity Overall Standard
ESET	-	The Electricity Sector Enterprise Team
FCAM	-	Fuel Cost Adjustment Mechanism
GCT	-	General Consumption Tax
GDP	-	Gross Domestic Product
GNTL	-	Non-technical losses that are not totally within the control of JPS – designated by JPS as general non-technical losses
GoJ	-	Government of Jamaica
GIS	-	Geographic Information System
HB	-	Hunts Bay

HESS	-	Hybrid Energy Storage System
HPS	-	High Pressure Sodium
IAS	-	International Accounting Standards
IFRS	-	International Financial Reporting Standards
IPP	-	Independent Power Producer
IRP	-	Integrated Resource Plan being prepared pursuant to section 7 of the Electricity Act, 2015
JEP	-	Jamaica Energy Partners Limited
JMD	-	Jamaican Dollars
JNTL	-	Non-technical losses that are within JPS' control
JPS/Licensee	-	Jamaica Public Service Company Limited
KVA	-	Kilo Volt Amperes
KWh	-	Kilowatt-hours
Licence 2016	-	The Electricity Licence, 2016
LED	-	Light-emitting Diode
MAIFI	-	Momentary Average Interruption Frequency Index
MED	-	Major Event Day/s
MSET	-	Ministry of Science Energy and Technology
MV	-	Mercury Vapour
MVA	-	Mega Volt Amperes
MW	-	Megawatt

MWh	-	Megawatt-hours
NBV	-	Net Book Value
NFE	-	New Fortress Energy
NPV	-	Net Present Value
NTL	-	Non-technical losses
O&M	-	Operating and Maintenance
OCC	-	Opportunity Cost of Capital
Office/OUR	-	Office of Utilities Regulation
OH	-	Old Harbour
OUR/Office	-	The Office of Utilities Regulation
OUR Act	-	The Office of Utilities Regulation Act
PATH	-	Programme of Advancement Through Health and Education
PAYG	-	Pay As You Go
PBRM	-	Performance Based Rate-Making Mechanism
PCI	-	Non-fuel Electricity Pricing Index
PPA	-	Power Purchase Agreement
RE	-	Renewable Energy
ROFR	-	JPS's Right of First Refusal exercisable in accordance with the Electricity Act, 2015
SAIDI	-	System Average Interruption Duration Index
SAIFI	-	System Average Interruption Frequency Index

SBF	-	System Benefit Fund
SJPC	-	South Jamaica Power Company Limited
SSP	-	Smart Streetlight Programme
System	-	Refers to the physically connected generation, transmission and distribution network of JPS
T&D	-	Transmission & Distribution
TFP	-	Total Factor Productivity
TL	-	Technical losses
TOU	-	Time of Use
USD	-	United States Dollars
WKPP	-	West Kingston Power Plant
WT	-	Wholesale Tariff
YTD	-	Year to date

1.0 Executive Summary

1.1 The JPS's Tariff Proposal

1.1.1 JPS in its 2018 Annual Review & Extraordinary Rate Review submission to the Office of Utilities Regulation (OUR/Office) made the following requests:

1. Its 2018 Annual Revenue Target (ART2018) be set at $48,777,311,955. $48,097,375,950 of which is associated with its Annual Review submission and the remaining $679,936,000 arises from its Extraordinary Rate Review application. This request translates to an increase of:

   a) 2.4% on the non-fuel tariff
   b) 1.1% on the overall tariff

2. The components of JPS's non-fuel rate reflect:

   a) An increase in the Growth Rate in Inflation/Exchange Rate Factor (dI) and Growth Rate Factor (dPCI) by 19.28% and 23.99% respectively. The 4.71% difference between these two factors is explained by a request for a Z-Factor increase in relation to the retirement of JPS's old baseload plants.

   b) A revenue true-up adjustment amounting to:

      - A decrease of $1,847.2M before the Weighted Average Cost of Capital (WACC) is applied
      - A decrease of $2,091.4M after the application of WACC

   [The largest element of the true-up is associated with system losses ($971.0M before WACC)]

   c) A Z-Factor adjustment with respect to the retirement of the Old Harbour and Hunts Bay baseload plants by 2020 which includes a claim of:

      - $1,640.5M for accelerated depreciation; and
      - $242.4M for separation costs

   d) The recovery of $633.4M in relation to the return on investment for the current portion of long term debt (CPLTD). This principle was approved in the 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice.

   e) A tariff adjustment by way of an Extraordinary Rate Review based on a proposal for the refinancing of a US$179.1M bond. The proposal is premised on a request for:

- Customers to pay the net upfront refinancing fee (after deductions for the benefit) of US$5.31M (or J$679.9M) in 2018-2019; and
- Customers be allowed to reap the benefit of US$5.37M annually from the refinancing over the next two (2) ensuing years.

3. The losses penalty ($TUVol_{2017}$) be reduced to allow the company to pursue the installation of smart meters at a more aggressive pace. According to JPS, this would allow the company to double its installation of smart meters, from 100,000 to 200,000. This, it argues, would be a major boost to its system losses reduction strategy.

4. JPS has proposed that its expenditure on its Smart Street Light Programme (SSP) to date, including planned expenditure on the project up to 2019, be set off directly against its liability to the Electricity Efficiency Improvement Fund (EEIF). The residual balance is estimated at US$14.4M as at the end of 2017 December. JPS expects that its cumulative SSP spending will be $14.5M and $38.9M at the end of 2018 and 2019 respectively.

5. The current heat rate target be raised from 11,450 kJ/kWh to 11,482 kJ/kWh. JPS contends that the request is not unreasonable given its plans for major maintenance of the Bogue Combined Cycle plant in the first quarter (Q1) of 2019.

1.2 Procedural Assessment of the Proposal

1.2.1 After assessing the procedural issues arising from the various requests in JPS's submission, the OUR took the view that:

a) Three (3) months was too short a time to complete the Annual and Extraordinary Rate Reviews requested, especially given the weight and complexity of the issues involved. JPS agreed to a four (4) month review period after the OUR indicated that this was desirable.

b) JPS's debt refinancing proposal did not qualify for an Extraordinary Rate Review since the circumstances of the financial market trends which gave rise to the proposal were not deemed to be the extraordinary circumstances contemplated and required by the Licence 2016 provisions relating to Extraordinary Rate Review. However, the proposal is not without merit since both JPS and its customers could benefit from the savings that would accrue by way of a lower interest rate on JPS's debt. Consequently, the proposal could best be accommodated under a "Refinancing Incentive Mechanism".

c) The Z-Factor claim for accelerated depreciation and separation cost ought to be correctly treated as a Z-Factor adjustment for the component that involves impairment cost, and as an Extraordinary Rate Review for the forward-looking portion of the claim.

d) Even though it was not a part of JPS's submission, the Determination Notice should also address other issues that would have a rate impact such as JPS's recovery of costs for fuel additive expenses in 2015, the recovery of revenue by JPS arising from an adjustment to be made to the billing determinants used in the 2014-2019 Determination Notice, and the reimbursement by JPS to customers of foreign exchange adjustment on fuel during the 2013 March to December period.

1.3 The Analysis of the Proposal

1. The OUR was able to confirm the correctness of JPS's Growth Rate in Inflation/Exchange Rate (***dI***) of 19.28%. However, because the OUR has shifted most of the company's Z-Factor claim to an Extraordinary Rate Review, the Z-Factor was assigned a value of 0.49%. Hence, the OUR's derived value for the Rate of Change (dPCI) is 19.77% versus the 23.99% requested (see Table 1.1 below).

2. The OUR agreed with all the elements of JPS's revenue true-up calculations except its system losses computation. While JPS's calculation shows -\$971.0M, the OUR's derivation of the system losses surcharge was -\$2,043.5M (see Table 1.2 below); bringing the total of the OUR's revenue true-up calculation to -\$2,919.7M compared with JPS's -\$1,847.2. This is explained by the fact that JPS presented actual non-technical losses figures as follows:

   - Non-technical losses completely within JPS's control (JNTL):3.85%
   - Non-technical losses not completely within JPS's control (GNTL):14.01%

   However, the OUR's analysis indicates that JPS's non-technical losses allocation should be:

   - Non-technical losses completely within JPS's control (JNTL):6.63%
   - Non-technical losses not completely within JPS's control (GNTL):11.22%

Table 1.1- Growth Rate in Inf/Fx (dI) & Rate of Change (dPCI)

Annual Adjustment Clause Calculation			
Line	**Description**	**JPS Proposed**	**OUR Approved**
L1	Base Exchange Rate	112.00	112.00
L2	Proposed Base Exchange Rate	128.00	128.00
L3	Jamaican Inflation Index		
L4	CPI @ Mar 2018	248.1	248.1
L5	CPI @ Mar 2014	214.2	214.2
L6	US Inflation Index		
L7	CPI @ Mar 2018	249.6	249.6
L8	CPI @ Mar 2014	236.3	236.3
L9	Exchange Rate Factor	14.29%	14.29%
L10	Jamaican Inflation Factor	15.83%	15.83%
L11	US Inflation Factor	5.61%	5.61%
L12	**Growth Rate in Infl./Exch. Rate (dl)**	**19.28%**	**19.28%**
L13	**Q-Factor**	**0.00%**	**0.00%**
L14	**Z-Factor**	**4.71%**	**0.49%**
L15	**Rate of Change (dPCI)**	**23.99%**	**19.77%**

Table 1.2: JPS's Revenue True-Up Performance vs the OUR's Calculation

Performance Adjustments	**JPS' Proposal ($'000)**	**OUR's Calculation ($'000)**
Foreign Exchange Surcharge	(253,628)	(253,628)
Interest Surcharge	(90,632)	(90,632)
Volumetric kWh	(362,935)	(362,958)
Volumetric kVa	(71,505)	(71,505)
Customer Charge	(97,512)	(97,512)
System Losses	(971,004)	(2,043,456)
Total	**(1,847,216)**	**(2,919,691)**

3. The OUR established that JPS's proposed 2018 returns on CPLTD of $633.6M is correct (allowing for rounding off errors) and is therefore recoverable through the tariff.

4. Even though the OUR considers the debt refinancing proposal of $179.2M ineligible for treatment under an Extraordinary Rate Review application, its analysis indicates that it

would be beneficial to customers and JPS. According to the proposal customers would pay the net refinancing fees of US$5.31M in 2018-2019 and reap an estimated US$5.37M per annum in the next two (2) ensuing years.

The OUR's review of the debt refinancing proposal through a net present value analysis reveals that the total net benefit would be:

a) ***Option A:*** US$2.0M with a one-time payment of refinancing cost
b) ***Option B:*** US$10.7M with the amortization of the refinancing cost

In light of this, the OUR is willing to approve the refinancing initiative under a "Refinancing Initiative Mechanism". Under this mechanism, JPS will be given US$2.66M or half of the amount requested in its proposal, with the expectation that it pursues its refinancing plan (preferably under Option B). This initiative will benefit customers in that there should be a lowering of JPS's annual revenue target in the next two (2) annual review periods (i.e. 2019-2020 and 2020-2021), by at least US$3.36M per annum.

4. According to JPS, the accelerated depreciation and separation costs in relation to the retirement of two of its baseload plants by 2020 translates, in the 2018 -2019 review period, to the recovery of:

    a) $1,640.5M of accelerated depreciation; and
    b) $242.4M of separation costs

    The OUR's analysis revealed that certain planned capital expenditures were included in JPS' proposed accelerated depreciation expense. Furthermore, $195.1M of the accelerated depreciation cost was incurred in 2017 and merited Z-Factor classification since it was a retrospective expense. Consequently, the Office approved $195.1M of accelerated expense as a Z-Factor adjustment and another $822.0M as an extraordinary adjustment.

    With respect to the separation cost, JPS included employee costs that should already have been accrued in their financial statements. Hence, the total figure had to be adjusted downwards. However, even though JPS had requested that one-third of the total separation cost be passed through in 2018-2019, the Office considered it prudent to pass though one-half since the baseload plants should be retired in the next two (2) years. Consequently, the Office has approved $296.7M of separation cost in the 2018-2019 review period.

5. Even though the OUR rejects JPS's proposal of reducing or removing the system losses target, it recognises the importance of reducing losses. In this regard, the OUR has established a fund called the 'Accelerated Losses Reduction Incentive Mechanism' (ALRIM), which will allows JPS to select one of two (2) options:

    - *ALRIM-1:* will provide JPS with funds to acquire an additional 50,000 smart meters annually over the next two (2) years at a cost of US$9.5M (after tax) each year; or

- *ALRIM-2:* will provide JPS with funds to acquire an additional 50,000 smart meters in 2018-2019 and the amount US$9.5M (before tax) in 2019-2020 to be used in loss reduction activities.

Under any of the selected option JPS will be required to achieve a minimum loss reduction target of 1.2 percentage point by the end of the 2019-2020 review period. Further, if JPS achieves or surpasses the loss reduction target it will be given the opportunity to request the transfer of the smart meters to the regulatory asset base at a discounted price in consideration of a commensurate reduction in revenues. This the OUR hopes will incentivise JPS in its loss reduction drive.

6. The OUR has accepted JPS's proposal for setting-off capital expenditures incurred under its SSP against its EEIF liabilities. In this regard, approval is granted for the US$16.1M to be set-off against JPS's liabilities to the EEIF. This US$16.1M set-off will cover all of JPS' SSP capital expenditure since its inception to the end of 2018. In addition, JPS will be required to provide the OUR with additional information to facilitate a precise determination of its residual liability to the EEIF. Further, JPS will be required to conduct an audit of its SSP expenditure in order to validate the US$16.1M set-off.

7. The OUR has assessed JPS's proposed heat rate target of 11,482 kJ/. Given that the heat rate performance for the 2017-2018 period was 11,325 kJ/kWh, there is a high likelihood of JPS again outperforming its proposed target, as well as the 2017 target of 11,450kJ/kWh. Notwithstanding, the OUR recognizes that there are risks of breakdowns given the age of JPS's base load plants and its maintenance plan for the Bogue Combined Cycle plant. In this regard, the OUR takes the view that the heat rate should be kept at its existing level, i.e. 11,450kJ/kWh.

Other Revenue Adjustments

8. The matters of the Foreign Exchange Adjustment charges which JPS had appealed before the Electricity Appeal Tribunal and the reimbursement of costs incurred by JPS in 2013 for fuel additives were considered by the OUR. Also, during the period under review, JPS requested a reconsideration of the OUR's decision relating to billing determinants arising from an audit of JPS's metering and customer information systems.

   Following the OUR's review, the claim relating to fuel additives and the billing determinant reconsideration were allowed and the directive to JPS to repay the foreign exchange adjustment charges was reinstated. Consequently, JPS is required to return to customers a net amount of $691.6M or US$5.4M (inclusive of opportunity cost). The associated revenue adjustment is to be treated in JPS' tariff as follows:

   - The sum of J$433,899,700 shall be recovered in the non-fuel tariff; and
   - A revenue reduction of $1,125,538,895 is to be applied to the fuel rate mechanism over the 2018-2019 period.

9. Based on the foregoing, JPS would see a 2.8% increase in its non-fuel tariff and a 0.4% increase in its overall tariff (see Table 1.3 below).

Table 1.3 - Comparative Tariff Analysis

	JPS Submission	OUR's Approved
2018 Annual Revenue Target -ART_y (J$'000) @J$128:US$1	**48,777,312**	**48,863,084**
2018 Annual Revenue Target -ARTy (J$'000) @J$131:US$1	**49,743,425**	**49,856,782**
Non-Fuel Rate Impact	2.5%	2.8%
FX -fuel Adj. Settlement (Overall)	0.0%	-1.0%
Fuel (Heat Rate) Impact of Changing from 11,450	0.2%	0.0%
Over-all Impact	1.4%	0.4%
Avg. Non-fuel Tariff 2018 (J$)	15.67	15.69
Avg. Non-fuel Tariff 2018 (US c/kWh)	12.24	12.26
Avg.Fuel Tariff 2018 (J$) @ 131	20.57	19.57
Avg.Fuel Tariff 2018 (US $/kWh)	0.157	0.1494

2.0 Introduction

2.0.1 In keeping with the procedure delineated in Schedule 3 of the Electricity Licence, 2016 (Licence 2016), the Jamaica Public Service Company Limited (JPS) applied for its Annual Review of rates on 2018 May 3. In addition to the Annual Review application, the company also made a request for an Extraordinary Rate Review.

2.0.2 The Licence 2016 prescribes sixty (60) day periods for the completion of the Annual Rate Review and the Extraordinary Rate Review respectively. However, in the Licence 2016, both review timeframes are stated independently of each other and there are no specific guidelines for the period for conducting both reviews simultaneously. Consequently, and in light of the complexity and gravity of the issues involved in both reviews, the OUR on 2018 May 17 requested JPS's agreement to a ninety (90) day review period. By way of letter dated 2018 May 21, JPS acceded to the OUR's request. Notwithstanding, the agreed review period was further extended, at JPS' requests, to allow for clarifications in relation several components of the Draft Determination Notice which was shared with the company.

2.1 JPS Annual Review Submission

2.1.1 JPS has submitted a request that its 2018 Annual Revenue Target (ART_{2018}) be set at $48,777,311,955. As shown in Table 2.1 below, $48,097,375,950 is associated with the 2018 Annual Review submission and the remaining $679,936,000 arises from its Extraordinary Rate Review application.

2.1.2 According to JPS, the objectives of its 2018 Annual Review submission are[1]:

- *Securing sufficient revenues to support the continued investment in the systems including reducing system losses;*
- *Managing rate impacts to customers; and*
- *Resolving outstanding matters with the OUR and move forward collaboratively to work on key items including Losses interface.*

<u>Adjusted Revenue Cap</u>

2.1.3 In keeping with the methodology established in the Jamaica Public Service Company Limited Annual Tariff Adjustment 2016 – Determination Notice, Document No. Ele 2016/ELE/004DET.001 (2016 Annual Tariff Adjustment Determination Notice), JPS has proposed that the **revenue cap for 2018 be set at $39,965,567,027**. This was computed by adjusting the 2014 -2019 revenue requirement (revised in 2017) of $41,773,495,042 by a productivity improvement factor (X)[2].

[1] See JPS Annual Tariff Adjustment Submission for 2018 & Extraordinary Rate Review (p. 3-4)

[2] RC_{2018} = Revenue Requirement for the 2014 – 2019 Rate Review period revised in 2017 × (1 – X) 4

2.1.4 JPS posits that the rate of change (dPCI) applicable to its basic **revenue cap for 2018** is 24.0%. It was derived by inputting the relevant United States and Jamaican inflation data along with exchange rate information and the Z-Factor percentage into the rate of change equation specified in JPS's performance –based ratemaking mechanism.

2.1.5 The application of JPS's derived rate of change (dPCI) to its proposed 2018 revenue cap of $39,965,567,027 results in an **adjusted revenue cap (Adjusted RC_{2018}) of $49,555,339,962 for 2018.**

Revenue True-Up

2.1.6 JPS's revenue surcharge has three components: (1) the true-up for volume adjustments; (2) the true-up for system losses; and (3) the true-up for foreign exchange gains/ losses, net of interest and late-payment penalties levied on customers. These true-ups reconcile JPS's actual performance during 2017 against the targets set for that year. Based on its performance during 2017, JPS proposes the following revenue surcharge adjustments for 2018:

- Volume adjustment true-up: -$531,951,610 (reduction)
- System losses adjustment true-up: -$971,004,027 (reduction)
- Foreign exchange – interest expense true-up: -$344,260,408 (reduction)

2.1.7 Consequently, the basic revenue surcharge derived from adjusting the three (3) true-up components proposed by JPS is -$1,847,216,045. However, the application of the pre-tax WACC of 13.22% to account for the opportunity cost of the revenue surcharge, results in a proposed downward adjustment of the revenue cap by $2,091,418,006.

2.1.8 JPS explains the reduction of $2,091,418,006 to the adjusted revenue cap as follows[3]:

a) Actual sales exceeding targets established in the 2017 Annual Filing Determination have resulted in adjustments for energy, demand and customer charges;

b) Not achieving the aggressive system losses target in 2017 has resulted in adjustments to the system losses surcharge;

c) The foreign exchange gain returned during the period has resulted in a refund to customers; and

d) Greater interest income from commercial and government accounts in 2017 has resulted in adjustments to the interest surcharge (lion share of interest has not been collected).

[3] See JPS Annual Tariff Adjustment Submission for 2018 & Extraordinary Rate Review (p.7)

Pre-Approval

2.1.9 In its 2018 Annual Review submission, JPS included **a claim for $633,454,362 in relation to the current portion of long-term debt (CPLTD)**. This reflects an approval provided by the OUR in the Jamaica Public Service Company Limited Annual Review 2017 & Extraordinary Rate Review – CPLTD: Determination Notice Document No. 2017/ELE/006/DET.003 (2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice) for the company to pass on such costs to customers. The 2017 Extraordinary Rate Review Determination is in keeping with the Licence 2016 which, unlike JPS's two licences immediately preceding the Licence 2016, explicitly identifies CPLTD as a cost to be captured in the tariff.

Table 2.1 – Components of JPS' Proposed Actual Revenue Target 2018

REVENUE COMPONENT	(J$'000)
Revenue Cap 2014 -2019 (Revised in 2017)	41,773,495
Revenue Cap 2018 (basic)	39,965,567
Adjusted Revenue Cap 2018 (@ dCPI = 24%)	**49,555,340**
Revenue True-Up	
- Volumetric	(531,952)
- System Losses	(971,004)
- Foreign Exch. -Interest Expense	(344,260)
	(1,847,216)
Adjusted Revenue True-Up (@WACC =13.22%)	**(2,091,418)**
Pre-approved Ajustment - CPLTD	**633,454**
Z-Factor Adustment (of 4.71% included in dCPI)	
- Accelerated Depreciation	1,640,529
- Separation Cost	242,432
	1,882,961
Extraordinary Rate Review	
- Refinancing cost (net)	**679,936**
Annual Revenue Requirement (@ J$128:US$1)	**48,777,312**
Non-fuel Bill Impact (@ J$131:US$1)	2.40%

Z-Factor

2.1.10 In anticipation of the decommissioning of its Old Harbour and Hunts Bay base load plants by 2020 December, JPS has submitted a Z-Factor claim in relation to the capital and labour components attached to such decommissioning.

2.1.11 In addressing the capital side of the decommissioning programme, JPS argues that the earlier than planned retirement of the plants will require the acceleration of their depreciation rates. Consequently, this would result in an increase in depreciation expenses amounting to $1,640,529,000 (US$12.82M) over the period 2018-2020.

2.1.12 With respect to the labour component of JPS's claim, it is seeking to recover in the 2018 Annual Review a total of $242,432,000 (US$1.89M) in staff separation costs which it expects to incur over the same period.

2.1.13 Consequently, **JPS proposes an overall Z-Factor recovery of $1,882,961,000 (US$14.71M) which translates to 4.71% in the rate of change (dPCI) factor.**

2.2 JPS's Extraordinary Rate Review Claim

2.2.1 With interest rates on Government of Jamaica (GoJ) bonds trending downwards in recent years, JPS posits that the company is likely to refinance its outstanding bonds at interest rates at or below 8%. JPS contends that the achievement of an 8% coupon could translate *to "annual savings in excess of US$5M ($640M)"* and reduce average electricity rates by 1.2%. JPS has indicated that it is prepared to pass on the savings to customers, however it is proposing that the net debt refinancing cost of $679,936,000 (US$5.3M) be included in the revenue it recovers in the 2018- 2019 regulatory period. This, it argues, would require an Extraordinary Rate Review.

2.2.2 In this regard, JPS proposed an **annual non-fuel revenue target for 2018 of $48,777,311,955 at a Base Exchange rate of J$128.00: US$1** (see Table 2.1 above), which reflects the summation of:

- The Adjusted Revenue Cap 2018
- The Revenue Surcharge (inclusive of WACC)
- The pre-approved adjustment for CPLTD; and
- The Debt Refinancing cost (net)

2.3 Proposed 2018 Tariff Basket and Rates

2.3.1 JPS's proposed non-fuel annual revenue target represents an increase for 2018 of 0.53% relative to 2017. This proposed annual revenue target would translate to an increase in the average non-fuel rate of 2.4%.

2.3.2 In keeping with the annual non-fuel revenue target for 2018 of $48,777,311,955, JPS posits that its revenue distribution among its rate classes and between its tariff charges should be as shown in Table 2.2 below.

2.3.3 Even though JPS contends that the proposed revenue target will not afford it the opportunity to generate a reasonable rate of return, it acknowledges that a substantial increase in tariffs will present a challenge for customers. As such, JPS proposes a "saw-off", or a cap, on the increase in the tariffs at 2% on the non-fuel component of the tariff to be applied during the 2018/2019 tariff year. This, JPS states, would accord with a greater level of acceptance of any increase among customers while permitting the company to pursue the investments the sector requires.

Table 2.2 –JPS's Proposed Actual Revenue Target 2018 by Rate Class & Tariff Charge

CLASS	BLOCK	VOLATGE LEVEL	TOTAL REVENUE	CUSTOMER	ENERGY	DEMAND
			($)	($)	($)	($)
RT10	≤100 kWh	LV	6,336,124,221	1,236,328,658	5,099,795,563	
RT10	>100 kWh	LV	13,938,503,759	1,813,016,097	12,125,487,662	
RT20		LV	12,589,833,379	780,550,999	11,809,282,380	
RT40-Std		LV	8,010,772,832	142,208,689	3,857,547,534	4,011,016,610
RT40-TOU		LV	1,157,430,678	9,539,664	653,673,358	494,217,655
RT50-Std		MV	2,258,080,291	9,728,085	1,125,890,362	1,122,461,844
RT50-TOU		MV	557,775,323	1,960,970	290,245,100	265,569,253
RT70-Std		MV	1,925,839,544	1,591,107	949,369,308	974,879,129
RT70-TOU		MV	338,860,171	314,034	162,013,694	176,532,443
RT60		LV	1,664,092,119	14,528,334	1,649,563,785	-
Total			**48,777,312,317**	**4,009,766,637**	**37,722,868,746**	**7,044,676,934**

2.3.4 Table 2.3 below shows JPS's proposed tariff by rate classes and tariff charges based on the 2.4% increase in the average non-fuel rate.

Table 2.3 –JPS's Proposed Tariff for 2018 by Rate Class & Tariff Charge

Class	Voltage Level	Block	Customer Charge	Energy Charge	Demand Charge			
					Std.	Off-Peak	Part Peak	On-Peak
			$/Month	$/kWh	$/kVA	$/kVA	$/kVA	$/kVA
Rate 10	LV	"≤ 100	444.61	9.64	-	-	-	-
Rate 10	LV	> 100	444.61	22.45	-	-	-	-
Rate 20	LV		990.50	18.52	-	-	-	-
Rate 40-Std	LV		6,978.54	5.76	1,786.91	-	-	-
Rate 40-TOU	LV		6,978.54	5.76	–	75.36	786.25	1,006.71
Rate 50-Std	MV		6,978.54	5.56	1,600.54	-	-	-
Rate 50-TOU	MV		6,978.54	5.56	-	71.39	696.58	893.73
Rate 70-Std	MV		6,978.54	3.70	1,523.62	-	-	-
Rate 70-TOU	MV		6,978.54	3.70	-	68.21	671.60	862.81
Rate 60	LV		2,813.93	24.15	-	-	-	-

2.3.5 Further, JPS has indicated that if current fuel prices are held constant, then the overall bill impact on average would be an increase of 1.1%. This increase would range from a high of 1.2% for residential customers to a low of 0.8% for large industrial customers (Rate 70).

2.4 Pre-paid Rates

Rate 10 Prepaid Rates

2.4.1 JPS has proposed a two-tiered tariff structure for the pre-paid Rate 10 customer category pending the 2019 Rate Review. According to JPS, at that time, the cost of service study will allow it to separate the revenue requirement of its post-paid customers from its prepaid customers.

2.4.2 The proposed non-fuel tariff for the Rate 10 prepaid customers are as follows:

- $15.3579/kWh for the first 118kWh in a 30 day cycle
- $22.4491/kWh for every kWh above 118kWh in a 30 day cycle

Rate 20 Prepaid Rates

2.4.3 JPS's proposal for the non-fuel tariffs for the Rate 20 prepaid customers are as follows:

- $117.5791/kWh for the first 10kWh in a 30 day cycle
- $18.5189/kWh for every kWh above 10kWh in a 30 day cycle

2.5 Forward-looking Rates

2.5.1 As an alternative to the rates proposed in Sections 2.3 and 2.4 above, JPS is requesting that consideration be given to rates predicated on a forward-looking model.

2.5.2 JPS states that due to the implementation of the SSP, the streetlight customer category (rate 60) has seen a 14% YTD reduction in consumption as a result of the LED lamp replacements. In light of this, it has proposed that the non-fuel revenue target for 2018 be increased by 0.78%, instead of 0.53% (relative to 2017) under its forward-looking model. The proposed rates arising for post-paid customers for 2018-2019 based on JPS's forward-looking approach are shown in Table 2.4 below.

Rate 10 Prepaid Rates (Forward-looking Model)

2.5.3 JPS proposes that the non-fuel tariff for the Rate 10 prepaid customers based on its forward-looking model, should be as follows:

- $15.3488/kWh for the first 117kWh in a 30 day cycle
- $22.496/kWh for every kWh above 117kWh in a 30 day cycle

Table 2.4 –JPS's Proposed Tariff for 2018 by Rate Class & Tariff Charge

Class	Voltage Level	Block	Customer Charge	Energy Charge	Demand Charge			
					Std.	Off-Peak	Part Peak	On-Peak
			$/Month	$/kWh	$/kVA	$/kVA	$/kVA	$/kVA
Rate 10	LV	"≤100	445.74	9.67	-	-	-	-
Rate 10	LV	> 100	445.74	22.50	-	-	-	-
Rate 20	LV		993.01	18.56	-	-	-	-
Rate 40-Std	LV		6,996.23	5.77	1,791.44	-	-	-
Rate 40-TOU	LV		6,996.23	5.77	-	75.55	788.24	1,009.26
Rate 50-Std	MV		6,996.23	5.57	1,604.90	-	-	-
Rate 50-TOU	MV		6,996.23	5.57	-	71.57	698.35	896.00
Rate 70-Std	MV		6,996.23	3.71	1,527.49	-	-	-
Rate 70-TOU	MV		6,996.23	3.71	-	68.38	673.31	865.00
Rate 60	LV		2,821.06	24.21	-	-	-	-

Rate 20 Prepaid Rates (Forward-looking Model)

2.5.4 JPS proposes that the non-fuel tariff for the Rate 20 prepaid customers based on its forward-looking model, should be as follows:

- $117.873/kWh for the first 10kWh in a 30 day cycle
- $18.5592/kWh for every kWh above 10kWh in a 30 day cycle

2.6 Community Renewal Rate (CRR)

2.6.1 As part of a community renewal effort, the OUR in 2017 approved the implementation of a Community Renewal Rate (CRR) by JPS. Eligibility for the CRR is based on whether the applicant is a PATH beneficiary.

2.6.2 JPS states that it is collaborating with PATH to implement the programme. It has also indicated that it will rely on PATH to validate all applicants for the programme.

2.6.3 Additionally, JPS is proposing that the CRR for the 2018-2019 period for both post-paid and pre-paid customers be $9.64/kWh (9.67/kWh using the forward looking model) for up to 150kWh of consumption per month. The proposed CRR is completely variable and does not attract a customer charge or any other charges provided that consumption remains below 150kWh in a billing cycle.

2.7 Quality of Service – The Q-Factor

2.7.1 Since the inception of the performance-based price mechanism as a part of JPS's tariff mechanism, the Q-factor has been set at zero owing primarily to data quality and measurement reliability issues. In its 2018 Annual Review submission, JPS claimed that it has invested a total of $49M in improving the reliability performance, with $26M allocated to T&D initiatives and $23M to Generation.

2.7.2 Given the advances it has made towards establishing credible Q-Factor statistics, the company is proposing that the 2016-2018 dataset be used to establish a baseline for the 2019-2024 Q-Factor targets.

2.7.3 Further, JPS has proposed that the Q-Factor be kept at zero for the 2018-2019 review period.

2.8 Reconciliation of the Electricity Efficiency Improvement Fund (EEIF) Residual Balance

2.8.1 In keeping with an agreement between JPS and the GoJ, the company has embarked on the SSP which, over the next two (2) to three (3) years, will see the replacement of High Pressure Sodium (HPS) and Mercury Vapour (MV) street lamps with LED lamps.

2.8.2 Following the termination of the EEIF by the OUR[4] in 2017, there is a residual amount owing to the Fund by JPS. In light of this, JPS is proposing a direct set-off of the total

[4] See 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice

capital expenditure cost of the SSP against its determined present and future liability to the EEIF.

2.9 Proposed Heat Rate Target

2.9.1 JPS has proposed a heat rate target of 11,482 kJ/kWh for the 2018-2019 review period. This target is higher than the previous target of 11,450 kJ/kWh. According to JPS, the proposed target is derived from a weighted average of best case (25%) and worst case (75%) forecasts. JPS argues that the proposed heat rate target of 11,482 kJ/kWh is reasonable, considering the scheduled major overhaul maintenance on the Bogue Combined Cycle plant in the first quarter (Q1) of 2019. JPS posits that its proposal would mitigate against the negative impact of fuel cost recovery that may arise from the failure of any of the company's critical generating plants, lasting for at least a month.

3.0 Legal Framework

3.1 The Office/OUR is a multi-sector regulator established pursuant to the Office of Utilities Regulation Act, (the "OUR Act"), to regulate the provision of prescribed utility services in Jamaica. Under Section 4(1)(a) of the OUR Act, the Office has regulatory authority over, inter alia, the generation, transmission, distribution and supply of electricity.

3.2 Pursuant to Condition 2, paragraphs (2) and (3) of the Licence 2016, JPS is authorized to *"generate, transmit, distribute and supply electricity for public and private purposes in all parts of the Island of Jamaica"*, and is obligated to *"...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."*

3.3 In the exercise of its powers and functions, section 4(3) of the OUR Act mandates the OUR to,

> *"...undertake such measures as it considers necessary or desirable to -*
> *(a) encourage competition in the provision of prescribed utility services;*
> *(b) protect the interests of consumers in relation to the supply of a prescribed utility service;*
> *(c) encourage the development and use of indigenous resources; and*
> *(d) promote and encourage the development of modern and efficient utility services..."*

3.4 Among the various powers and functions of the OUR set out in section 4 of the OUR Act, is a power to determine rates in respect of the generation, transmission, distribution and supply of electricity. A portion of section 4(4A) of the OUR Act directs that:

> *"(4A) The rates determined by the Office in respect of prescribed utility services for the generation, transmission, distribution and supply of electricity shall –*
> *(a) be in accordance with -*
>
> ...
>
> *(iv) the tariff provisions set out in all licences and enabling instruments with respect thereto;"...*
>
> *(b) take into account –*
>
> *(i) the interest of consumers in respect of matters, including the cost, safety and quality of the services;...*

3.5 In the case of JPS, Condition 15 and Schedule 3 of the Licence 2016 makes provision for the determination of its rates. Paragraph 2 of Condition 15 and paragraph 5 of Schedule 3 specify respectively that:

> Condition 15:
> *"2. The rates to be charged by the Licensee in respect of the Supply of electricity shall be subject to such limitation as may be imposed from time to time by the Office.*
> ...
>
> *Schedule 3:*
> *"5. All rates shall be determined by the Office."*

3.6 Schedule 3 of the Licence 2016, outlines the procedures for determination and review of JPS's electricity tariff. This Schedule provides for three (3) instances in which the OUR may be requested to review and determine rates which may result in revisions or adjustments to JPS's non-fuel rates based on a revenue cap methodology, viz:

1. **Five-Year Rate Reviews (paragraphs 6- 41):** As the name suggests, these reviews are scheduled at five-year intervals. The five-year rate review involves an exhaustive examination of all aspects of the revenue requirement, including rate base, return on investment, operating and maintenance cost, depreciation, as well as, efficiency targets and incentive mechanisms. The date for the next such review is 2019 April.

2. **Extraordinary Rate Reviews (paragraphs 59-61):** These reviews may be done between five-year rate reviews, and are occasioned by the impact of exceptional circumstances on the electricity sector and/or JPS. Such a review is only permissible where the impact is significant, and where the circumstances did not comprise factors that were considered or known when the last rate review was undertaken. Rate reviews of this type are done at the request of either the Minister or JPS. The prescribed time period for such a review is sixty (60) days, unless the OUR and JPS otherwise agree, and the scope of the review is limited to the impact of the exceptional circumstances.

3. **Annual Review or Annual Rate Adjustment (paragraphs 42-56):** The Licence 2016 details the formula to be employed for an annual adjustment to the revenue target, the annual adjustment date (beginning 2016 July 1) and the time period for conducting the adjustment (sixty (60) days). Notably the formula specifically assumes, inter alia, that tariffs based on the revenue-cap regime are already in place. Therefore, changes are only required to the superstructure and not the substructure of the tariff.

Exhibit 1 of Schedule 3 of the Licence 2016 specification of the Annual Review formula is as follows:

$$\mathbf{ART_y = RC_y(1 + (dI + Q \pm Z)) + (RS_{y-1} + SFX_{y-1} - SIC_{y-1}) * (1 + WACC)}$$

Where:

$\mathrm{ART}_y = \textit{Allowed Revenue Target for current year} (i.e., y)$
$\mathrm{RC}_{y-1} = \textit{the Approved Revenue Cap for previous year} (i.e., y-1)$
$\mathrm{dI} = \textit{change in inflation}$
$\mathrm{Q} = \textit{the quality of service improvement factor}$
$\mathrm{Z} = \textit{the exogenous factor}$
$\mathrm{RS}_{y-1} = \textit{Adjustment for previous year Revenue under/over} - \textit{recovery}$
$\mathrm{SFX}_{y-1} = \textit{Adjustment for previous year Net Foreign Exchange Losses}$
$\mathrm{SIC}_{y-1} = \textit{Adjustment for Net Interest Income on unpaid Customer bills}$
$\mathrm{WACC} = \textit{the Weighted Cost of Capital}$

3.7 Within the framework of Annual Rate Adjustments, provision is made for alterations to the tariff using the Z-factor mechanism. The application of the Z- factor is triggered by special circumstances that materially affect, inter alia, JPS's non-fuel costs, for which the recovery of such costs is done through an allowed percentage increase in the revenue cap. The provisions governing the Z-Factor mechanism that are most relevant to JPS's submission are that set out in paragraph 46.d.(i) of Schedule 3 of the Licence 2016, which states in part:

"d....The Z factor is the allowed percentage increase in the Revenue Cap due to any of the following special circumstances:

(i) Any special circumstances that satisfy all of the following:

a) affect the Licensee's costs or the recovery of such costs, including asset impairment adjustments;

b) are not due to the Licensee's managerial decisions;

c) have an aggregate impact on the Licensed Business of more than $50 million in any given year; and

d) are not captured by the other elements of the revenue cap mechanism"

3.8 The Licence 2016 therefore makes provision for the treatment of exceptional and defined special circumstances affecting the tariff in between Five Year Rate Reviews, by way of two channels: (1) the Z-factor adjustment mechanism specified under the Annual Review, and (2) Extraordinary Rate Review utilizing the rate review mechanism applicable to the Five Year Rate Review (i.e. an adjustment to the base revenue requirement).

3.9 In accordance with Sections 4(4) and 4(4A) of the OUR Act, as well as Condition 15 and Schedule 3 of the Licence, the Office makes the **DETERMINATIONS** set out below.

4.0 OUR's Analysis of the Proposal

4.1 Computation of the Annual Rate of Change (dPCI)

Background

4.1.1 Schedule 3 of the Licence 2016 defines the annual rate of change (dPCI) as follows:

$$\boxed{dPCI = dI \pm Q \pm Z}$$

Where:

dI = the growth rate in the inflation and JMD to USD exchange rate measures

Q = the Q-Factor (*i.e. the allowed price adjustment to reflect changes in the quality of service provided to the customers versus the target for the prior year*)

Z = the Z-factor (*i.e. the allowed rate of price adjustment for special reasons, not under the control of the Licensee and not captured by the other elements of the formulae*)

4.1.2 It further defines the growth rate inflation and exchange rate (dI) as:

$$\boxed{dI = (EX_n - EX_b)/EX_b\{USP_b + INF_{US}(USP_b - USDS_b)\} + INF_{us}(USP_b - USDS_b) + (1 - USP_b)INF_J}$$

Where:

EXb = Base US exchange rate at the start of the Rate Review period.

EX_n = Applicable US exchange rate at Adjustment Date.

INF_{US} = Change in the agreed US inflation index as at 60 days prior to the Adjustment Date and the US inflation index at the start of the Rate Review period.

INF_J = Change in the agreed Jamaican inflation index as at 60 days prior to the Adjustment Date and the Jamaican inflation index at the start of the Rate Review period.

USP_b = US portion of the total non-fuel expenses as determined from the Base Year.

4.1.3 Conceptually, the purpose of the Rate of Change factor (dPCI) is to ensure that the revenue cap for the current year is kept constant in real terms. Consequently, the basic revenue cap (RC_Y) is adjusted to include the effect of **dPCI** and this results in what is referred to in this Determination Notice as the **Adjusted Revenue Cap**. The Adjusted Revenue Cap, as shown below, captures the effect of inflation and exchange rate movement over the previous year.

$$\boxed{\textbf{Adjusted Revenue Cap} = \textbf{RCy (1 + dPCI)}}$$

JPS's Rate of Change Proposal

4.1.4 In its submission, JPS requested that the growth rate inflation and exchange rate (dI) and the rate of change (dPCI) for the 2018 review be set at 19.28% and 23.99%. As shown in Table 4.1, the request is predicated on the following factors:

- Jamaican point-to-point inflation[5] (INF_J) of 15.83% for the period 2014 March - 2018 March;
- U.S. point-to-point inflation rate[6] (INF_{US}) of 5.61% for the period 2014 March - 2018 March;
- A 14.29% increase in the Base Exchange Rate which moved from J$112: US$1 to J$128.00: US$1;
- A Q-Factor of zero; and
- A Z-Factor adjustment of 4.71% based on the company's computation of its accelerated depreciation of assets and separation costs claim.

The OUR's Position

4.1.5 The OUR in its analysis has confirmed that all the inflation and exchange parameters inputted into the Growth Rate in Inflation and Exchange Rate (dI) equation are correct.

4.1.6 In addition, the OUR accepts JPS's proposed Base Exchange Rate of J$128.00: US$1.00 since it reasonably reflects the actual exchange rate at the time of the submission. The OUR has also observed that since the time of the submission the exchange rate has depreciated somewhat, however, there is no need to shift from the proposed Base Exchange Rate since ultimately it will not affect the final amount billed to customers. In this regard, the Office approves dI to be 19.28% as shown in Table 4.1 below.

4.1.7 With regards to JPS's Z-Factor claim of 4.71 percentage points, the OUR has disallowed it from being incorporated in the Rate of Change factor (dPCI). Consistent with the position taken in the Jamaica Public Service Company Limited Extraordinary Rate Review 2017 Determination Notice (2017 Extraordinary Rate Review Determination)[7] the Office maintains that the Z-Factor should correctly capture costs that have already been incurred, while an Extraordinary Rate Review ought to address forward-looking costs that impact the tariff base. Accordingly, the Office has treated the 2017 accelerated depreciation component of JPS' claim as a Z-Factor adjustment and all the other components including

[5] Derived from the CPI data published by the Statistical Institute of Jamaica.

[6] Obtained from U.S. Bureau of Labor Statistics website, http://data.bls.gov/cgi-bin/surveymost

[7] Document No.: 2017/ELE/001/DET.001

separation costs, which are forward-looking, as an Extraordinary Rate Review. Consequently, the Z-Factor is computed to be 0.49 percentage point.

4.1.8 Therefore having previously established that the Q-Factor in this review would be zero[8], as shown in Table 4.1 below, the Office approves a Rate of Growth factor of 19.77%.

Table 4.1 –Proposed & Approved Rate of Growth (dPCI) Factor

Annual Adjustment Clause Calculation

Line	Description	Formula	JPS Proposed	OUR Approved
L1	Base Exchange Rate		112.00	112.00
L2	Proposed Base Exchange Rate		128.00	128.00
L3	Jamaican Inflation Index			
L4	CPI @ Mar 2018		248.1	248.1
L5	CPI @ Mar 2014		214.2	214.2
L6	US Inflation Index			
L7	CPI @ Mar 2018		249.6	249.6
L8	CPI @ Mar 2014		236.3	236.3
L9	Exchange Rate Factor	(L2-L1)/L1	14.29%	14.29%
L10	Jamaican Inflation Factor	(L4-L5)/L5	15.83%	15.83%
L11	US Inflation Factor	(L7-L8)/L8	5.61%	5.61%
L12	**Growth Rate in Infl./Exch. Rate (dI)**	**L9*{0.8+(0.8-0.0688)*L11}+(0.8-0.0688)*L11+(1-0.8)*L10**	**19.28%**	**19.28%**
L13	**Q-Factor**		**0.00%**	**0.00%**
L14	**Z-Factor**		**4.71%**	**0.49%**
L13	**Rate of Change (dPCI)**	**dI ± Q ± Z**	**23.99%**	**19.77%**

Determination 1:

Having verified the accuracy of the parameters in JPS's Rate of Growth equation, the Office approves:

- A Growth Rate of Inflation and Exchange Rate (dI) of 19.28%
- A Rate of Growth factor (dPCI) of 19.77%

[8] See 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice (p.50)

4.2 Q-Factor Component of the PBRM

Background

4.2.1 As one of the key components of the Performance Based Rate-making Mechanism (PBRM) defined in Schedule 3 of the Licence 2016, the OUR is required to evaluate the quality of electricity service provided to customers by JPS each year and determine a Q-Factor for annual adjustment of the annual revenue target. However, since the introduction of the PBRM in 2001 the Q-Factor has been set at zero primarily because of measurement and data correlation issues.

4.2.2 Notwithstanding, the OUR has worked with JPS to resolve the gaps in its Q-Factor data capture, and in the 2017 Annual Review noted *"that the company has made considerable progress towards ensuring that a robust outage data set is in place to set a Q-Factor baseline."*

4.2.3 The OUR further pointed out that "there are still outstanding issues that need to be resolved before this objective can be achieved". Consequently, after making an assessment of the progress made and JPS's Q-Factor plan, the OUR signaled to JPS in the 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice that *"subject to the relevant regulatory requirements, the OUR intends to continue its consultations with JPS, on this issue with the aim of establishing the Q-factor baseline by the end of 2018 to facilitate the implementation of the Q-Factor incentive scheme at the 2019-2024 rate review."*

4.2.4 Implicit in the OUR's 2017 Annual Review assessment was an understanding, that given the baseline data capture status at the time, the Q-Factor would have to be set at zero in the 2018 Annual Review.

JPS's Q-Factor Proposal

4.2.5 In the 2018 Annual Review submission, JPS reported that in 2017 the company invested US$49M in improving the system's reliability performance, with US$26M allocated to T&D initiatives and US$23M to Generation. The 2017 reliability performance improvement strategy encompassed the following:

1) Deployment of an automated grid management system in the T&D network.
2) Traditional/routine activities involving lightning mitigation, structural integrity checks, routine inspections and the application of the appropriate solutions to problem areas.
3) Intensifying outage management processes and improving outage data quality.

4.2.6 JPS indicated that the company will continue its reliability improvement strategy in 2018, by undertaking, among other things, the following initiatives:

- Continuation of lifecycle data management for the Outage Management System (OMS);
- Increased use of automated technologies to improve system reliability performance; and
- Integrated Vegetation Management Framework.

4.2.7 JPS noted that the increased penetration of variable RE generation in the system, has adversely impacted system reliability, resulting in increased electricity supply interruptions. To address this situation, JPS has invested in a 24.5MW Hybrid Energy Storage System (HESS), which is expected to be commissioned into service by 2019 April.

4.2.8 JPS also indicated that its 5-year Year Reliability Improvement Plan (2019-2024), is being developed, and will provide a comprehensive outlook of all reliability initiatives being considered, and will be aligned with the various system improvement plans (such as the IRP) being developed for Jamaica.

4.2.9 In the 2018 Annual Review submission, JPS included its 2017 outage dataset as the supporting schedule for its 2017 quality indices. The company indicated that its continued engagement with the OUR has helped in resolving concerns raised since the OMS was implemented, and helped to improve the quality of the data and key outage processes.

4.2.10 JPS proposes that the 2016 – 2018 dataset be used to establish a baseline for the 2019 – 2024 Q-Factor targets and the 2018 Q-Factor value be set at zero.

The OUR's Position

4.2.11 In its 2018 Annual Review submission, JPS highlighted that system reliability performance for 2017 in terms of SAIDI and SAIFI were as follows:

- 2017 SAIDI was 3% better than 2016 SAIDI
- 2017 SAIFI was 4% worse than 2016 SAIFI.

Table 4.2 – JPS's Q-Factor Reliability Indices

RELIABILITY INDICES			
Year	SAIDI	SAIFI	MAIFI
2014	2,404.4	21.8	34.0
2015	1,983.7	18.9	24.1
2016	1,774.3	15.7	25.6
2017	1,755.5	16.4	32.9
Change in Index (2017/2016)	-1%	4%	29%

4.2.12 Despite JPS's declaration that the Q-Factor improved by 3% in 2017 relative to 2016, the data presented by JPS in the submission (see Table 4.2 above[9]) actually reflects a 1% improvement.

4.2.13 The OUR's analysis suggests that the improvement in the average duration of interruption captured by SAIDI was a direct result of the strategies and initiatives undertaken by the company during the year. However, the decline in SAIFI, which relates to the frequency of service interruptions in 2017, was mainly due to the abnormal (rainy) weather events experienced during the year, which impacted the grid negatively.

4.2.14 The OUR notes that even though the company claims to have invested US$49M in improving the system's reliability performance, the evidence of the reported expenditures, capital investment schedule and the commensurate reliability impact was not provided.

4.2.15 In addition, JPS indicated in its submission that US$17.3M was invested in the rehabilitation and reinforcement of the T&D network during 2017. However, the connection between this expenditure and the $26M allocated to T&D initiatives, is not clear.

4.2.16 Admittedly, JPS has made progress towards the establishment of a plausible Q-Factor mechanism, nevertheless, the company still has some challenges in relation to the development of a reliable and credible baseline from which to measure changes in quality of service (see the *OUR's 2018 Q-Factor Report* in **Annex 5**). The OUR continues to have concerns with regard to:

- Outage Data Related Issues
- Reliability Measurement and Indicators
- System Reliability Performance Improvement

4.2.17 It is therefore evident that the achievement of a satisfactory Q-Factor mechanism in the short term will require continued consultation between the OUR and JPS on this issue, up to the 2019-2024 Rate Review.

4.2.18 Based on the Q-Factor evaluation and consideration of related issues, the Office determines that no Q-Factor adjustment will be allowed in the PBRM for the 2018-2019 review period. Accordingly, the Q-Factor shall remain in the dead band range (i.e. Q = 0).

[9] MAFI is the Momentary Average Interruption Frequency Index, JPS included information on this index even though it is not one of the indices in the Q-Factor metric.

Determination 2:

Consistent with the OUR's assessment of the state of readiness with regard to a proper functioning Q-Factor Mechanism, the Office:

(i) Approves a Q-Factor of zero for the 2018-2019 review period

(ii) Requires that JPS observes the Q-Factor positions set out by the OUR and take actions where applicable.

4.3 Revenue True-Up Mechanism

Background

4.3.1 The PBRM allows for adjustments to the Actual Revenue Target (ART_y) for the current year based on JPS's performance against targets approved by the OUR in the previous Annual Review.

4.3.2 The revenue true-up mechanism may be broken down into four main components:

1. *Revenue Surcharge* (RS_{y-1}):which is comprised of:
    a. The Volumetric Adjuster ($TUVol_{y-1}$)
    b. The System Losses Adjuster ($TULos_{y-1}$)
2. *Foreign Exchange (FX) Surcharge* (SFX_{y-1})
3. *Interest Expense Surcharge* (SIC_{y-1}); and
4. *Opportunity cost adjuster* (1+WACC)

Taken all together, the revenue true-up component of the PBRM may be expressed as:

$$\boxed{Revenue\ True\ Up = \left(\mathrm{RS_{y-1}} + \mathrm{SFX_{y-1}} - \mathrm{SIC_{y-1}}\right) * (1 + \mathrm{WACC})}$$

Where, $\mathrm{RS_{y-1}} = TUVol_{y-1} + TULos_{y-1}$

4.3.3 For the Volumetric Adjuster ($\mathrm{RS_{y-1}}$) the true-up is based on JPS's performance in the previous year against energy (kWh), demand (kVA) and no. of customer. In this regard:

$$\mathbf{RS_{y-1} = Energy\ True\text{-}up + Demand\ True\text{-}up + Customer\ True\text{-}up}$$

Where:

$$\boldsymbol{Energy\ True\ Up} = \left(\frac{kWh\ Target_{y-1} - kWh\ Sold_{y-1}}{kWh\ Target_{y-1}}\right) * Non\ Fuel\ Rev\ Target\ for\ Energy$$

$$\textbf{\textit{Demand True Up}} = \left(\frac{kVA\ Target_{y-1} - kVA\ Sold_{y-1}}{kVA\ Target_{y-1}}\right) * Non\ Fuel\ Rev\ Target\ for\ Demand$$

$$\textbf{\textit{Customer True Up}} = \left(\frac{Cust.Ch.Target_{y-1} - Cust.Billed_{y-1}}{Target_{y-1}}\right) * Non\ Fuel\ Rev\ Target\ for\ Cust.Ch.$$

4.3.4 It was established in transitioning from the price-cap regime to the revenue-cap mechanism in the 2016 Annual Tariff Adjustment Determination Notice that the current year target for each billing determinant would be the actual billing determinant in the previous year. Hence the billing targets for 2017 are given as follows:

$kWhTarget_{2017} = kWhSold_{2016}$
$kVATarget_{2017} = kVASold_{2016}$
$\#\ Customers\ ChargesTarget_{2017} = \#\ Customers\ ChargesBilled_{2016}$

JPS's Revenue True-Up Proposal

4.3.5 JPS's proposal with respect to its actual performance in 2017 versus the targets established in 2017 are shown in Table 4.3 below.

4.3.6 While the 2018 Annual Review submission included JPS's target for the 2018-2019 review period, the company expressed the view that there is no need for target setting. JPS argues that since there will be no annual filing in 2019, being the year of the Five (5) Year Rate Review, then its stands to reason that target setting is redundant as the Five (5) Year Review allows *"for the establishment for the first time of a 'Base Year' to support the fixing of a Revenue Cap in keeping with the terms of the Licence."*

Table 4.3: JPS's Revenue Proposal vs. the OUR's Calculation

Performance Adjustments	JPS' Proposal ($'000)	OUR's Calculation ($'000)
Foreign Exchange Surcharge	(253,628)	(253,628)
Interest Surcharge	(90,632)	(90,632)
Volumetric kWh	(362,935)	(362,958)
Volumetric kVa	(71,505)	(71,505)
Customer Charge	(97,512)	(97,512)
System Losses	(971,004)	(2,043,456)
Total	**(1,847,216)**	**(2,919,691)**

The OUR's Position

4.3.7 The Office accepts all of the targets and actual performance statistics in JPS's 2018 Annual Review submission except the actual data presented for system losses.

4.3.8 JPS presented actual non-technical losses figures as follows:

- Non-technical losses completely within JPS's control (JNTL): 3.85%
- Non-technical losses not completely in JPS's control (GNTL):14.01%

4.3.9 Based on the OUR's assessment of the losses spectrum, JPS's allotment of system losses deviates from the criteria established. It is clear from the assessment that JPS has redistributed overall non-technical losses in a way that shifts more of the losses deemed to be directly under its control (JNTL) to the basket for which JPS is not completely responsible. Hence, JPS's proposed system losses adjustment is -$971,004,027.

4.3.10 The OUR's analysis indicates that JPS's non-technical losses allocation should be:

- Non-technical losses completely within JPS's control (JNTL): 6.63%
- Non-technical losses not completely within JPS's control (GNTL):11.22%

4.3.11 Accordingly, as shown in Table 4.4 above, the OUR's calculation shows that the System Losses adjustment ($TULos_{y-1}$) for 2017 should be -$2,043,455,898 instead of -$971,004,027.

4.3.12 Consequently, as shown in Table 4.4 above, the Revenue True Up for 2018, before the application of opportunity cost is -$2,919,690,980, and -$3,305,674,128 inclusive of opportunity cost.

4.3.13 With regard to the use of targets for the next annual review period, the Office is of the view that the PBRM construct does not contemplate having a year in which there should be no performance targets established. On the contrary, the fact that there is a Five (5) Year Rate Review at the end of the tariff period provides an opportunity to be compensated for its positive performance and penalized for under-achievement. Consequently, the revenue true-up in the final year would be a component of the Five (5) Year Rate Review.

4.3.10 The OUR's analysis indicates that JPS's non-technical losses allocation should be:

- Non-technical losses completely within JPS's control (JNTL): 6.63%
- Non-technical losses not completely within JPS's control (GNTL):11.22%

4.3.11 Accordingly, as shown in Table 4.4 below, the OUR's calculation shows that the System Losses adjustment ($TULos_{y-1}$) for 2017 should be -$2,043,455,898 instead of -$971,004,027.

Table 4.4: OUR's Revenue True-Up: FX, Interest & Revenue Surcharges 2017

FX, Interest and Revenue Surcharges for 2017 (SFX_{2017} - SIC_{2017} + RS_{2017})				
Line	**Description**	**Amount**	**Formula**	**Value (J$)**
	FX Surcharge			
L1	TFX			
L2	AFX_{2017}			(253,628,288)
L3	**SFX_{2017}**		**L2-L1**	**(253,628,288)**
	Interest Surcharge			
L4	Actual net interest expense/(income) in relation to interest charged to customers for 2017			16,929,720
L5	Actual Net Late Payment Fees for 2017			73,702,400
L6	AIC_{2017}		L4+L5	90,632,120
L7	TIC_{2017}			-
L8	**SIC_{2017}**		**L6-L7**	**90,632,120**
L9	**SFX_{2017} - SIC_{2017}**		**L3-L8**	**(344,260,408)**
	Revenue Surcharge (RS_{2016})			
L10	kWh $Target_{2017}$	3,083,667,744		
L11	kWh $Sold_{2017}$	3,113,504,786		
L12	Non Fuel Revenue Target for Energy Rev_{2017}	37,511,772,576		
L13			(L10 - L11)/L10 x L12	(362,957,509)
L14	kVA $Target_{2017}$	5,233,851		
L15	kVA $Sold_{2017}$	5,288,413		
L16	Non Fuel Revenue Target for Demand Rev_{2017}	6,859,084,134		
L17			(L14 - L15)/L14 x L16	(71,505,212)
L18	# of Customer charges billed $Target_{2017}$	623,982		
L19	# of Customer charges billed Act_{2017}	639,615		
L20	Non Fuel Rev Target for Customer Charges Rev_{2017}	3,892,154,588		
L21			(L18 - L19)/L18 x L20	(97,511,954)
L22	**$TUVol_{2016}$**		**L13 + L17 + L21**	**(531,974,674)**
L23	Target System Loss "Technical Losses" $(\%)_{2017}$	8.00%		
L24	Actual System Loss "Technical Losses" $(\%)_{2017}$	8.60%		
L25			L23 - L24	-0.60%
L26	Target System Loss "Portion of Non-technical losses which is completely within JPS' control" $(\%)_{2017}$	3.30%		
L27	Actual System Loss "Portion of Non-technical losses which is completely within JPS' control" $(\%)_{2017}$	6.63%		
L28			L26 - L27	-3.33%
L29	Target System Loss "Portion of Non-technical losses which is not completely within JPS' control" $(\%)_{2017}$	9.70%		
L30	Actual System Loss "Portion of Non-technical losses which is not completely within JPS' control" $(\%)_{2017}$	11.22%		
L31	RF-Responsibility Factor determined by the Office (%)	20.0%		
L32			(L29 - L30) x L31	-0.30%
L33	Y_{2017} System Losses		L25 + L28 + L32	-4.23%
L34	ART_{2017}			48,263,011,298
L35	**$TULos_{2017}$**		**L33 x L34**	**(2,043,455,898)**
L36	**RS_{2017} = $TUVol_{2017}$ + $TULos_{2017}$**		**L22 + L35**	**(2,575,430,573)**
L37	**SFX_{2017} - SIC_{2017} + RS_{2017}**		**L9 + L36**	**(2,919,690,980)**

4.3.12 Consequently, as shown in Table 4.4 above, the Revenue True Up for 2018, before the application of opportunity cost is -$2,919,690,980, and -$3,305,674,128 inclusive of opportunity cost.

4.3.13 With regard to the use of targets for the next annual review period, the Office is of the view that the PBRM construct does not contemplate having a year in which there should be no performance targets established. On the contrary, the fact that there is a Five (5) Year Rate Review at the end of the tariff period provides an opportunity to be compensated for its positive performance and penalized for under-achievement. Consequently, the revenue true-up in the final year would be a component of the Five (5) Year Rate Review.

Determination 3:

Consistent with the methodology outlined in the Licence 2016, the Office has determined that JPS's Revenue True-up for 2018 shall be:

(i) -$2,919,690,980 before the application of the opportunity cost (or WACC)
(ii) -$3,305,674,128 inclusive of the opportunity cost (or WACC)

Consequently, the 2017 Revenue True-up will result in **a reduction of $3,305,674,128 in JPS's Annual Revenue Target for 2018.**

4.4 System Losses Review

Background

4.4.1 The 2016 Annual Tariff Adjustment Determination Notice signaled a departure from the approach used to quantify system losses that was established in the 2014-2019 Determination Notice. In the 2014 -2019 Determination Notice, the system losses target was broken down into a technical target and a non-technical target. In keeping with Schedule 3 of the Licence 2016, system losses have been disaggregated into three components:

a) Technical losses (Ya), designated TL;
b) Non-technical losses totally under JPS's control (Yb), designated JNTL; and
c) Non-technical losses not totally under JPS's control (Yc), designated GNTL

4.4.2 For the component which is defined to be partially under JPS's control, a Responsibility Factor (RF) now applies. This is critical to the determination of the portion of NTL defined as Yc as shown in the equations below. The total system losses for which JPS is held accountable, is computed based on the formulae below:

$$Y_{y-1} = Y_{ay-1} + Y_{by-1} + Y_{cy-1}$$

Where

$$Y_{ay-1} = \text{Target System Loss "a" Rate\%y} - 1 - \text{Actual System Loss "a" Rate\%y} - 1$$
$$Y_{by-1} = \text{Target System Loss "b" Rate\%y} - 1 - \text{Actual System Loss "b" Rate\%y} - 1$$
$$Y_{cy-1} = \text{Target System Loss "c" Rate\%y} - 1 - \text{Actual System Loss "c" Rate\%y} - 1$$

Where: Ya = TL; Yb = NTL totally within JPS's control; Yc = NTL not totally within JPS's control; and RF is a percentage from 0% to 100%, which is determined by the Office.

4.4.3 In translating system losses to a monetary value, the total system losses differential (Y_{y-1}) must be multiplied by the Actual Revenue Target in the previous year (ARTy-1) which may be expressed as:

$$TULos_{y-1} = Y_{y-1} * ART_{y-1}$$

JPS's System Losses Proposal

4.4.4 In the 2018 Annual Review submission, JPS proposed:

- no TL target, stating that it is in the process of remodeling its network and no new information is available to inform a target for the 2018-2019 regulatory period;
- a total NTL target of 16.55% - 16.75%, stating that a short to medium term target setting process (2019-2020) that is aligned with the loss reduction strategy, resource alignment and expected results, was necessary; and
- Responsibility factor be reduced from 20% to 10%

Table 4.5: JPS's System Losses Target & Actual for 2018-2019 and Proposed Target for 2019-2020

Component	Symbol	2018-2019		2019-2020
		Target	Actual	Proposed Target
JPS TL	Ya	8.00%	8.60%	No Proposal
JPS NTL (Total) - JNTL	Yb	3.30%	6.63%	Proposal for total NTL of 16.55% - 16.75%
JPS NTL (Partial) - GNTL	Yc	9.70%	11.22%	
Responsibility Factor	RF	20%	20%	10%

4.4.5 The system losses target & actual level for the 2018-2019 adjustment and the proposed targets for 2019-2020, are shown in Table 4.5 above.

The OUR's Position on System Losses

4.4.6 It worth mentioning that it was established in the 2014 Rate Review that the Electricity Losses Spectrum (ELS) at the December of subsequent years will be the foundational basis for assessment of the losses. This position was maintained even after the Licence 2016 became effective. It therefore holds that the evaluation of the losses at this 2018 Annual Review will be based on 2017 December ELS. In keeping with the reporting practice, JPS submitted its 2017 December ELS via email on 2018 February 8 (see Figure 4.1 below).

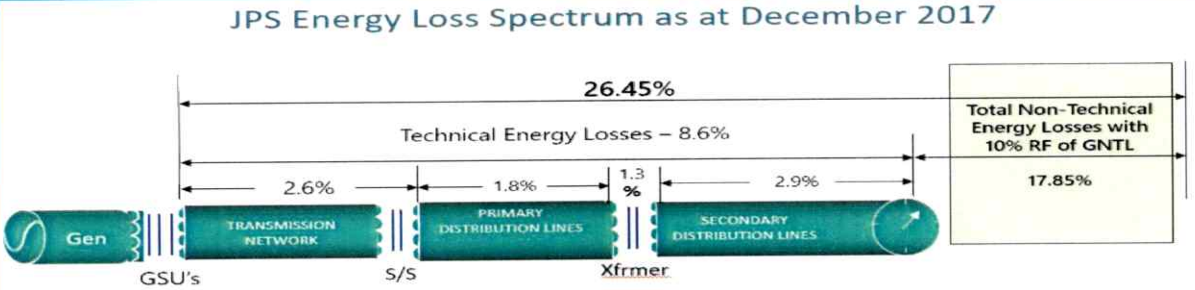
4.4.7 However, after submitting the 2017 December ELS to the OUR, JPS subsequently altered the allocations to JNTL and GNTL shown in Table 4.6 below, without consultation with the OUR. Notably the overall NTL remained constant, but its allocation was changed shifting more of the losses away from the category that JPS is totally responsible for (JNTL) to the category for which it has partial responsibility (GNTL).

4.4.8 For the purpose of clarity, it should be pointed out that essentially JNTL and GNTL are not standard ELS components of the total losses spectrum. Essentially, they represent an energy loss allocation construct derived from the provisions of the Licence 2016. Consequently, once the basis on which the JNTL-GNTL classification has been established they cannot be changed unilaterally by JPS without proper regulatory consultation. Furthermore, the JNTL-GNTL allocation proposed by JPS in its Annual Review Submission represents a significant departure from how losses have been treated since the establishment of this mechanism in 2016. The OUR therefore rejects the spectrum proposed by JPS in its 2018 Annual Review submission and has used the 2017 December ELS provided by the company on 2018 February 8 as the guide to the analysis.

4.4.9 In response to the Draft Annual Review 2018 & Extraordinary Rate Review Determination Notice shared with JPS, the company argued that:

"Total system losses for 2016 was 26.75%. The OUR set a combined target (TL & NTL) of 21% for 2017, effectively expecting a reduction of 5.75% within a period of less than 12 months. This expectation clearly could not meet the standard of reasonable or achievable, as it has no basis, either in historical performance or any expansion in agreed resources that could give rise to such an accelerated annual loss reduction expectation. This is true for all three elements of the losses targets – technical losses, JNTL or GNTL. An annual loss reduction expectation of that magnitude was not supported by any historical, empirical or practical consideration and therefore pre-disposed JPS to incurring the associated level of penalty without the reasonable ability to effect meaningful mitigation through its effort."

Figure 4.1: JPS December 2017 ELS



Description/Category		No. of Customers	Bill Sales (MWh)	Energy Loss (MWh)	% Loss	JNTL	GNTL
Billed Customers	Streetlight/Stoplight/Interchange (R60)	432	110,577	3,903	0.09%	0.09%	0.00%
	Large C&I (Rate 40, 50 & 70)	1,973	1,432,744	32,435	0.74%	0.74%	0.00%
	Medium C&I (rate 20)	5,738	257,825	11,890	0.27%	0.27%	0.00%
	Small C&I (rate 20)	59,670	338,459	14,622	0.34%	0.29%	0.05%
	Residential (rate 10)	569,488	1,069,344	261,224	5.99%	4.79%	1.20%
Sub-Total		637,302	3,208,949	324,073	7.43%	6.18%	1.25%
Unquantified				47,110	1.08%	1.08%	0.00%
Illegal users (non-customers)		180,000		407,722	9.34%	0.00%	9.34%
TOTAL		817,302	3,208,949	776,611	17.85%	7.26%	10.59%

Table 4.6: JPS Adjusted JNTL and GNTL

Description	Average Monthly Users	Billed Energy (MWh)	Energy Loss (MWh)	Energy Loss %	JNTL %	GNTL %
Billed Customers						
Streetlight, Stoplight, Interchange (RT60)	432	110,577	3,903	0.09%	0.09%	0.00%
Large Commercial (RT40&50)	1,973	1,432,744	32,435	0.74%	0.74%	0.00%
Medium Commercial (RT20)	5,738	257,825	11,890	0.27%	0.27%	0.00%
Small Commercial (RT20)	59,670	338,459	14,622	0.34%	0.13%	0.21%
Residential (RT10)	569,488	1,069,344	261,224	5.99%	1.53%	4.45%
Subtotal	637,302	3,208,949	324,073	7.43%	2.77%	4.66%
Internal Losses	N/A	N/A	47,110	1.08%	1.08%	0.00%
Illegal Consumers	180,000	N/A	407,722	9.34%	0.00%	9.34%
Grand Total	817,302	3,208,949	778,905	17.85%	3.85%	14.01%

4.4.10 JPS' argument that the OUR's loss reduction expectation is without "*historical, empirical or practical consideration*" is weak and appears to have been informed by too narrow a time window. In this regard, JPS' analysis should take the following factors into account:

- The 12-month rolling average performance was reported at 16.58% of net generation as at year-end 2001. However, over the years it has increased, peaking at 27% in 2015 and dipping slightly to 26.45% at the end of 2017.

- In the 2009-2014 Determination Notice, the OUR recognizing the challenges that JPS was facing in dealing with system losses increased the overall target initially from 15.8% to 19.5% for 2009/2010 and set it at 17.5% for the rest of the Rate Review period.

4.4.11 It is therefore evident that the current overall system losses target of 21% exceeds JPS' actual performance of 16.8% in 2001. This demonstrates that collectively, customers have been paying more for system losses over time because JPS has failed to put a lid on the expanding degradation.

4.4.12 Additionally, the OUR's setting of the system losses targets has not been without practical consideration, even though by itself, the financial incentive to reduce losses on the company's part is high. For instance, at the 2013-2014 Annual Tariff Adjustment, the OUR in response to financial sustainability concerns from JPS, provided additional relief to the company by way of a Fuel Cost Recovery Adjustment (FCRA), which allowed JPS to recover approximately US$30.33 Million up to 2014 December, with conditions for a certain level of reduction in system losses.

4.4.13 Furthermore, the OUR has also sought over the years to mobilize customer funds to provide additional resources to combat system losses. In the 2009-2014 Tariff Determination Notice, the OUR established the EEIF, a US$13 million per annum fund to support JPS' capital expenditure programme aimed at reducing losses. The EEIF programme spanned the period 2009 -2017.

4.4.14 Nevertheless, even after interventions such as FCRA and EEIF, losses increased from 23.0% in 2009 to 27% in 2015.

4.4.15 In its 2018 Annual Review Submission, JPS made reference to a 2013 study on system losses by consultants, Quantum Consulting (Quantum). JPS points out that the *"report concluded that about 90% of the variation in system losses is explained by the poverty level, murder rate and the relative cost of electricity"*. However, while a study of that sort cannot be overlooked, its applicability in the Jamaican context is questionable for a number of reasons.

4.4.16 Firstly, the poverty level in Jamaica has declined since 2001 and cost of electricity over shorter timeframe has declined, yet there has been no visible positive impact on system losses.

4.4.17 Secondly, the claim that there is a causation between the murder rate and system losses appears dubious. In fact, it might very well be merely a case of a correlation between the two variables rather than a cause and effect relationship. Consequently, the Quantum study on its own without further empirical corroboration, might not necessarily explain the sources of losses in Jamaica.

4.4.18 The OUR is cognizant of its responsibility to balance the objectives of the customer against those of the utility. In this regard, it would be unreasonable to increase the burden of higher system losses to the ratepayer without assigning a fair degree of responsibility to the utility, for whom the financial incentive of reducing losses is great. Therefore, the argument of history, empiricism and practicality appears to be flawed.

The OUR's Position: Technical Losses

4.4.19 Following a comprehensive review and evaluation of JPS's TL losses, the OUR determined JPS's TL target as prescribed by the Licence 2016 (see the details of the analysis in the *OUR's 2018 System Losses Report* in Annex 6). In determining the target, the OUR took into consideration, among other things, the following factors:

- The level of TL reduction expected in 2017 based on previously approved loss reduction plans;
- JPS's TL reduction initiatives for 2018;
- The evaluation of transmission losses based on power flow simulations; and
- JPS's overall strategy to address TL since 2014.

4.4.20 As determined by the Office, the technical losses target to be applied in JPS's annual revenue adjustment mechanism for the 2019-2020 adjustment period shall be **8.0%** of net generation. This is set out in Table 4.7 below.

Table 4.7 JPS's TL Target Determined by OUR

OUR's Determination: JPS's Technical Losses Target for 2019-2020 Adjustment Period				
	[2018-2018] Adjustment	**[2018-2019] Adjustment**	**[2019-2020] Adjustment**	**[2018-2019] Adjustment**
ASPECT OF SYSTEM LOSSES [% of Net Generation]	JPS PROPOSED TARGET	OUR's APPROVED TARGET	NO TARGET PROPOSED	OUR DETERMINED TL TARGET
TECHNICAL LOSSES (TL)	8.4%	8.0%	-	**8.0%**

The OUR's Position: Non-Technical Losses

4.4.21 Based on the analysis presented by JPS in its 2018 Annual Review submission based on the 2017 system losses performance, the company's disaggregation of the total NTL into JNTL and GNTL is shown in Table 4.8 below.

4.4.22 For the reasons set out in detail in the *OUR's 2018 System Losses Report* in Annex 6, JPS adjusted JNTL and GNTL of **3.85%** and **14.01%** respectively. However, having considered JPS's allocation, the OUR does not accept such an allocation in this Annual Review exercise, since it does not accord with the criteria established when the targets were being set.

Table 4.8: JPS Allocation of Non-Technical Losses

JPS's Allocation of NTL							
Loss Category	Components	2017 DECEMBER ELS			JPS 2018-2019 Annual Review Filing (Adjusted Values)	
		NTL	JNTL	GNTL	JNTL	GNTL
Non-Technical Losses (NTL)	Streetlight/Stoplight (R 60)	0.09%	0.09%	0.00%	0.09%	0.00%
	Large C&I (Rate 40&50)	0.74%	0.74%	0.00%	0.74%	0.00%
	Medium C&I (Rate 20)	0.27%	0.27%	0.00%	0.27%	0.00%
	Small C&I (Rate 20)	0.38%	0.29%	0.05%	0.13%	0.21%
	Residential (Rate 10)	5.99%	4.79%	1.20%	1.53%	4.45%
	Internal/Unquantified	1.08%	1.08%	0.00%	1.08%	0.00%
	Illegal Users	9.34%	0.00%	9.34%	0.00%	9.34%
	Total Non-Technical Losses	**18.11%**	**7.26%**	**10.59%**	**3.85%**	**14.01%**

Table 4.9: OUR's Distribution of JPS's NTL

OUR's Distribution of JPS's NTL					
Loss Category	Components	JPS NTL (2016 Dec ELS)	JPS NTL (2017 Dec ELS)	JNTL OUR Determined	GNTL OUR Determined
Non-Technical Losses (NTL)	Streetlight/Stoplight (R 60)	0.09%	0.09%	0.09%	0.00%
	Large C&I (Rate 40&50)	0.45%	0.74%	0.74%	0.00%
	Medium C&I (Rate 20)	0.38%	0.27%	0.27%	0.00%
	Small C&I (Rate 20)	0.27%	0.38%	0.25%	0.09%
	Residential (Rate 10)	7.48%	5.99%	4.19%	1.80%
	Internal Bleeds/Unquantified	0.14%	1.08%	1.08%	0.00%
	Un-metered Households	9.30%	9.34%	0.00%	9.34%
	Total Non-Technical Losses	**18.11%**	**17.85%**	**6.63%**	**11.22%**

4.4.23 Based on the evaluation of the system losses data, related issues and considerations, the OUR has apportioned the total NTL into JNTL and GNTL as shown in Table 4.9 above. JNTL and GNTL were estimated at 6.63% and 11.22% of net generation respectively. These NTL components and the system losses target determined by the OUR for application at this 2018 Annual Review, were used in the revenue surcharge for adjustment to annual revenue.

The OUR's Position: Responsibility Factor

4.4.24 In its 2018 Annual Review submission, JPS proposed the responsibility factor (RF) should be set at 10%. The company relied on a report (dated 2013 October) of a study conducted by Quantum, which concluded that about 90% of the variation in system losses is explained by the poverty level, murder rate and the relative cost of electricity. According to JPS, these are all factors that are largely outside JPS's control.

4.4.25 In determining the RF, the OUR considered, among other things, the following:

- The findings of the OUR's evaluation of JPS's NTL losses up to 2017 December, including their orientation, causes, distribution, and allocations;
- Actual loss reduction activities undertaken by JPS during the 2017-2018 rate adjustment period;
- Reports from JPS that provide information on the responsibility assigned to the relevant aspects of NTL;
- JPS's proposed loss reduction programmes and initiatives, including funding for the 2018-2019 adjustment period.

4.4.26 Accordingly, the OUR determined that the RF for NTL that are not totally within the control of JPS shall be **20%** for application at the 2019-2020 rate adjustment.

Determination 4:

Based on its analysis of system losses and JPS's performance against the target over the 2017-2018 period the Office has determined that:

Technical Losses

The Technical Losses (TL) Target to be applied by JPS at the 2019-2020 rate adjustment, shall be **8.00%** of net generation.

Non-Technical Losses

Target for Non-Technical Losses (NTL) that are within the control of JPS, to be applied at the 2019-2020 rate adjustment, shall be **3.60%** of net generation.

The Target for NTL that are not totally within the control of JPS, to be applied at the 2019-2020 rate adjustment, shall be **9.70%** of net generation.

Responsibility Factor (RF) for Non-Technical Losses

RF applicable to JPS's NTL that are not totally within its control, to be applied at the 2019 Rate Review Adjustment shall be **20%.**

These system losses targets for the 2019-2020 Adjustment are deemed indicative and may be considered for review subject to improvement the system losses data quality and convergence on the measurement methodology, on a forward-looking basis.

4.5 Current Portion of Long-term Debt (CPLTD)

Background

4.5.1 In the 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice[10] the Office determined that JPS should be allowed to recover J$636.7M in respect of the returns on investments associated with the CPLTD.

4.5.2 JPS's application in relation to its CPLTD claim in 2017 came as a result of the introduction of provisions in the Licence 2016 which prescribes the recovery of CPLTD in the revenue recovery equation. Specifically, paragraph 29 of Schedule 3 of the Licence 2016 states *"For the avoidance of doubt, the current portion of long term debt should not be an off-set, since this is part of the long term funding of the Licensee"*.

4.5.3 In this regard, JPS is correctly entitled to claim a return on investment for CPLTD.

JPS's CPLTD Proposal

4.5.4 JPS, in its 2018 Annual Review submission, included a sum of J$633.5M as the total returns to be recovered on the CPLTD for 2018. JPS specified that its request is founded on the prior approval given by the OUR in the 2017 Annual Review and Extraordinary Rate Review. However, apart from a footnote on the formula used on page 45 of its submission, JPS provided no further input into the calculation of the specified amount.

The OUR's Position

4.5.5 The OUR examined the accuracy of JPS's claim by way of the computation of return on the CPLTD for 2018 based on the following formula:

$$ROI_{2018} = ROI_{2013} * (1 + dI_{2018})^4$$

Where,

ROI	=	the return on the investment (CPLTD)
dI	=	the growth rate in the inflation and JMD to USD exchange rate
X	=	the productivity efficiency improvement factor

4.5.6 Table 4.10 below shows the computation of the 2018 returns on CPLTD recoverable by JPS. Hence, the amount recoverable is $633,601,604.

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[10] Document No.: 2017/ELE/006/DET.003

Table 4.10: OUR's Computation of the 2018 ROI for the CPLTD

Calculation Block	Calculation Item	
Components of WACC	Cost of Debt	8.07%
	Rate of Return on Equity(ROE)	12.25%
	Tax Rate	33.33%
	Gearing Ratio (Deemed)	50.00%
	Post-tax WACC	8.81%
	Pre-tax WACC	13.22%
Return on 2013 CPLTD Derivation		**US$'000**
	Rate Base	37,492.00
	Return on Equity	2,295.91
	Taxation (Gross Up)	1,147.96
	Long Term Interest Expenses	15,132.31
	Returns on CPLTD in 2013	**US$4,9576.15**
Return on 2018 CPLTD Derivation	dI_{2018}	19.28%
	X	1.10%
	EX_b	J$112:US$1
	Returns to be Recovery in 2018	**J$633,601,604**

Determination 5:

Consistent with the decision taken in the JPS Annual Review 2017 & Extraordinary Rate Review – CPLTD: Determination Notice, the Office approves the recovery of $633,601,604 for returns on the Current Portion of Long Term Debt.

4.6 Extraordinary Rate Review: Debt Refinancing Cost Recovery

Background

4.6.1 JPS, in its application for an Extraordinary Rate Review, has requested approval for the recovery of US$5.312M which represents net refinancing costs for a bond it intends to secure to replace long term debt in its portfolio of US179.19M. This debt has an expiration date of 2021 July 06.

4.6.2 JPS postulates that the circumstance surrounding the request satisfies the provisions under which the company is allowed to file an Extraordinary Rate Review. These provisions are outlined in paragraph 59 of the Licence 2016 which states that the application is valid if it arises out of "*exceptional circumstances that have a significant impact on the electricity sector and/or the Licensee, but were not factors considered or known when the Rate Review was undertaken*".

4.6.3 Furthermore, in carrying out the Extraordinary Rate Review, paragraph 61 of the Licence 2016 instructs that:

> "*Where possible, the scope of such extraordinary Rate Review will be limited to the impact of the exceptional circumstances and therefore the review process is expected to be completed within a 60 day period, unless the Office and the Licensee agree otherwise.*"

JPS's Debt Refinancing Proposal

4.6.4 JPS's 2018 Extraordinary Rate Review submission is for the recovery of refinancing costs associated with the bond. The costs comprises the breakage fee of US$3.299M, the embedded unamortized financing cost for the existing bond of US$2.436M and the estimated financing cost for the new US$180M bond, which JPS estimates at 2.75% or US$4.95M. This is summarized in Table 4.11 below.

4.6.5 JPS has sought to make a case for the recovery of refinancing costs associated with a 10-year, US$179.18M bond with an attendant coupon rate of 11%. The company stated that it will be able to access the local market and refinance the bond at an interest rate lower than 8%, despite increases in the US Treasury rates in the last eighteen (18) months (and projections for further increases in 2018) and a 200 basis points increase in the LIBOR over the last two (2) years.

4.6.6 JPS further reasons that ten (10) year bonds issued by the GoJ have remained stable. This stability in GoJ's bond prices, JPS argues, is primarily attributed to the confidence that investors have placed in the Jamaican market given the discipline displayed by the GoJ in meeting and exceeding the targets established under the IMF Stand-by Agreement over the past six (6) years.

4.6.7 In justifying its conclusion that it would be able to refinance the outstanding bonds at coupon rates that are at or lower than 8%, JPS states that as at 2018 April 27, the 2028 and 2045 GoJ bonds are trading at a yield of 5.38% and 6.46% respectively. JPS further states that Latin American Corporates are achieving coupon rates of 1% to 2% above the sovereign rate. However, the company sought to qualify its proposal by pointing out that confidence currently placed on the Jamaican market is susceptible to a number of unforeseen events.

Table 4.11: JPS's Debt Refinance Costs

	US$'000
Make Whole/Breakage Fee	3,299
Embedded Unamortized Financing Costs	2,463
New Financing Costs	4,950
Total	**10,712**
Offset Interest Rate Savings	(5,400)
Total Refinancing Cost	**5,312**

4.6.8 According to JPS, the benefits to the company and their customers to be derived from the 300 basis points reduction in the coupon rate on the bonds, will translate into a saving of approximately US$5.4M per annum for the remaining three (3) years of the life of the bond or US$16.11M in total.

4.6.9 JPS further proposed that the annual interest rate savings of approximately US$5.4M would be used to offset the total upfront fees totaling US$10.712M in the first year. Thus, the net amount being requested is US$5.312M.

<u>The OUR's Position on the Extraordinary Rate Review Submission</u>

4.6.10 While the Office is cognizant of the benefits that would accrue to both JPS and its customers by the refinancing of the debt, it does not agree that the refinancing plan outlined qualifies for an Extraordinary Rate Review.

4.6.11 Firstly, the tariff contains a component in the rate of return formulation for market risks which encompasses non-fuel inputs, market demand, as well as variation in financial markets. In this regard, the market risk premium in the rate of return on equity anticipates that markets in general will move up and down forcing firms to adjust, but more importantly the market risk premium seeks to compensate firms for downside risk. The circumstances outlined by JPS in support of its Extraordinary Rate Review application is therefore not considered "exceptional" in the context of the provisions in the Licence 2016.

4.6.12 Secondly, at the time of the last Five (5) Year Rate Review in 2014, all the macroeconomic indicators were pointing to improvement in the economy. Even though there are always risks involved in such forecast, it cannot be said that these "*were not factors considered or known when the Rate Review was undertaken*".

4.6.13 Consequently, the Office is of the view that the trend in interest rates in this instance, favourable though it may be, does not constitute a trigger for an Extraordinary Rate Review.

4.7 Refinancing Incentive Mechanism

4.7.1 Notwithstanding the Office's position with regard to the validity of JPS's Extraordinary Rate Review application, the Office is of the view that any plausible plan that will lower cost and yield savings to customers should be encouraged. As such, while not examining the proposal as an Extraordinary Rate Review, the Office has taken the decision that it should be treated and assessed as a '**Refinancing Incentive Mechanism**' for which the net benefits are shared between JPS and its customers.

Analysis of the Incentive Proposal

4.7.2 JPS has suggested that the reduction in coupon rate on the bond by 3% would translate to a savings of US$5.37M per annum to customers for the remaining three (3) years of the life of the bond or US$16.11M in total. The OUR's evaluation is that this assessment appears to be overstated.

4.7.3 Normally, the benefits of an interest rate reduction would only pass through to the customers when the tariffs are reset during a Five (5) Year Rate Review. Prior to the reset, JPS would have been allowed to keep the benefits of an interest rate reduction. In its submission, JPS is proposing to pass on the full US$5.37M of interest reduction to its customers in the 2018/2019 period. However, the customers would not experience the benefit of this reduction, as JPS's proposal is also to pass on the full cost of refinancing the debt to the customers in one year, an amount which outweighs the interest expense reduction by US$5.3M. Thus, in the first year, customers would have to pay more for the cost of refinancing than any benefit that would accrue to them.

4.7.4 Based on the current tariff structure, all other things being equal, in 2019/2020 and 2020/2021, the benefits of an interest rate reduction will accrue to customers as a decrease in the revenue requirement via a reduction in the returns associated with the rate base.

4.7.5 In addition, the cost of capital and the value of the rate base are likely to change at the time of the 2019 – 2024 Rate Review. However, since these are not yet known, the OUR's analysis will be based on the values established during the 2014 – 2019 Rate Review Determination Notice. At that time, the OUR approved an interest rate of 8.07% for JPS's debts which was based on the weighted average interest rates on debts outstanding as of 2013 December 31. The reduction of the coupon rate on the US$179.1M bond would have reduced the average cost of debt to 6.75%.

4.7.6 Therefore as shown in Table 4.12 below, using the cost of debt as 6.75% as opposed to 8.07%, the returns associated with the rate base would be reduced by US$3.37M and not US$5.37M per annum as stated by JPS.

4.7.7 It is important to note that the OUR's analysis has revealed that based on JPS proposal US$5.37M would be reflected as an interest expense reduction on JPS's income statement, but customers would only see an impact of US$3.37M in rates, which translates to an average rate reduction of less than 0.001US$/kWh. All things being equal, customers would see a cumulative benefit of US$6.74M over the 2019/2020 and 2020/21 period.

4.7.8 In response to the OUR's request for additional information to support the Extraordinary Rate Review application, JPS submitted data from which the OUR observed that JPS is currently paying additional annual financing fees, other than the amortized financing costs, on the US$179.1M bond. In certain loan financing arrangements, annual maintenance fees are required in addition to the upfront financing costs. These fees usually cover the cost of administration required to monitor the debt. This fee, in the case of the US$179.1M bond, is very small, less than 0.01% of the principal. JPS did not provide an estimate of the recurring maintenance fees for the new bond and thus, the OUR is unable to determine what the final impact of the refinancing will be.

Table 4.12 – Variance in Long Term Debt Expenses due to Coupon Rate Reduction

Cost of Debt	ROI (exc. Financing Cost)	ROI (inc. Financing Cost)	Variance
Cost of Debt	6.75%	8.07%	
Rate of Return on Equity(ROE)	12.25%	12.25%	
Tax Rate	33.33%	33.33%	
Gearing Ratio (Deemed)	50%	50%	
Post-tax WACC	7.94%	8.81%	
Pre-tax WACC	11.91%	13.22%	
	US$'000	**US$'000**	
Rate Base	**510,000**	**510,000**	
Return on Equity	**31,238**	**31,238**	
Taxation (Gross Up)	**15,619**	**15,619**	
Long Term Interest Expenses	**17,213**	**20,579**	
Total	**64,069**	**67,435**	**3,366**

4.7.9 The OUR accepts that the make whole/breakage fee and embedded amortized financing costs for the existing loan is likely to be an upfront fee that JPS would have to pay at the time of settling the bond. Data submitted by JPS after its 2018 Annual Review submission reveal that the breakage fee would depend on the timing of the refinancing (see Table 4.13 below).

Table 4.13 – JPS's Breakage Fee for the Debt (2016-2019)

Year	Breakage Fee (%)	Breakage Fee US$'000
2016	5.50%	9,855.40
2017	3.67%	6,570.86
2018	1.83%	3,284.53
2019	0%	0

4.7.10 However, the OUR is of the view that if it is at all possible, JPS should seek to amortize the breakage fee and the embedded unamortized financing costs over a longer period by including these as part of the proposed bond arrangement. For new bond issues, it is typical for financing fees to be amortized over the period of the debt and as such, the OUR takes the view that JPS should explore the option of amortizing the new financing cost of US$4.95M rather than treating it as a one-time upfront cost.

4.7.11 The 3.04% financing fees for the existing US$179.1M bond was amortized over a ten-year period as indicated in the data obtained from JPS. The data indicates that JPS paid an amortized amount of US$578,466 to cover the financing costs for the debt in 2017. It is therefore fair to assume that JPS will be able to amortize the US$4.95M over the 10-year life of the new bond. The OUR however believes that the 2.75% financing fee for the new bond is reasonable given the financing fees that JPS is currently paying on its existing debts.

4.7.12 Accordingly, the OUR carried out an evaluation of the JPS's proposal based on five (5) refinancing options to determine which would be most favourable to JPS and its customers. The five (5) options that were evaluated are:

- *Option 1 (Base Case)* - Do nothing – wait until the bond matures in 2021 to refinance and refinance as per JPS's usual practice;
- Option 2a – Refinance the bond in 2018 and pay all refinancing fees as a one-time payment in 2018;
- *Option 2b* – Refinance the bond in 2018 and amortize the payment of refinancing fees over the bond's tenure;
- *Option 3a* – Refinance the bond in 2019 and pay all refinancing fees as a one-time payment in 2019; and
- *Option 3b* – Refinance the bond in 2019 and amortize the payment of refinancing fees over the bond's tenure.

4.7.13 For each option, the associated net present value (NPV) of payments between 2018 and 2021 were determined. The assumptions that were made in doing the evaluation are detailed as follows:

- The discount rate is JPS's approved WACC which is currently 13.22%
- Interest payment on bonds are made semi-annually
- Payments in 2018 commence from July 2018
- Only payments up to June 2021 are included in 2021
- Original bond principal is US$179.189M with an attendant interest rate of 11%
- Financing cost for original bond is 3.04% of the principal or US$5.45M
- The proposed new bond principal is US$180 with an attendant interest rate of 8%
- Financing cost for the proposed new bond is 2.75% of principal or US$4.95M
- Bond refinancing in 2018 will be completed in December 2018
- Bond refinancing in 2019 will be completed in July 2019
- The repayment of the bond principal would be done via the acquisition of the new bond

4.7.14 Tables 4.14 to 4.18 show the NPV of the costs for options 1 (base case), 2a, 2b, 3a and 3b respectively. The loan maintenance fee was ignored from the analysis as it is negligible and JPS did not provide an estimate of this for the proposed new bond.

Table 4.14: NPV of Option 1 – Base Case Option

Option 1: Refinance at bond expiration in 2021						
		2018	2019	2020	2021	Total
Annual Interest Payments	US$	9,855,395	19,710,790	19,710,790	9,855,395	59,132,370
Amortized Financing Cost	US$	332,567	723,702	809,469	440,028	2,305,765
PV Annual Interest Payments & Financing Expenses	US$	10,187,962	18,048,482	16,007,980	7,093,731	51,338,155
NPV of loan expenses						51,338,155

Table 4.15: NPV of Option 2a – Refinance in 2018, one-time refinancing fee payment

Option 2a: Refinance by Dec 31, 2018						
		2018	2019	2020	2021	Total
Breakage Fee	US$	3,299,000				
Unamortized Financing Costs	US$	2,305,626				
New Financing Costs	US$	4,950,000				
Annual Interest Payments	US$	9,855,395	14,400,000	14,400,000	7,200,000	45,855,395
PV Annual Interest Payments	US$	9,855,395	12,718,601	11,233,528	4,960,929	38,768,454
PV Annual Fees, Penalties	US$	**10,554,626**				10,554,626
Total PV Option 2	US$					49,323,080
NPV of Option 2a						49,323,080
Benefits relative to Base Case (NPV Option 2a - NPV Option 1)						(2,015,076)

Table 4.16: NPV of Option 2b – Refinance in 2018, amortize refinancing fees

Option 2b: Refinance in 2018 and amortize refinancing fees						
Refinancing Date July 2019		2018	2019	2020	2021	Total
Breakage Fee	US$	-	-			
Unamortized Financial Costs	US$	332,567				
New Financing Costs	US$		701,371	765,266	408,393	1,875,030
Annual Interest Payments	US$	9,855,395	14,400,000	14,400,000	7,200,000	45,855,395
Annual Interest Payments +Financing Fees	US$	10,187,962	15,101,371	15,165,266	7,608,393	48,062,992
PV Annual Interest Payments	US$	10,187,962	13,338,077	11,830,517	5,242,319	40,598,876
PV Annual Fees, Penalties	US$					
NPV of Option 2b						40,598,876
Benefits relative to Base Case (NPV Option 2b - NPV Option 1)						(10,739,280)

Table 4.17: NPV of Option 3a – Refinance in 2019, one-time refinancing fees payment

Option 3a: Refinance by July 2019						
Refinancing Date July 2019		2018	2019	2020	2021	Total
Breakage Fee	US$	-	-			
Unamortized Financial Costs	US$	332,567	1,621,476			
New Financing Costs	US$	-	4,950,000			
Annual Interest Payments	US$	9,855,395	17,055,395	14,400,000	7,200,000	
Annual Interest Payments + Fees	US$	10,187,962	23,626,871	14,400,000	7,200,000	55,414,833
PV Annual Interest Payments	US$	10,187,962	20,868,108	11,233,528	4,960,929	47,250,527
NPV of Option 3a						47,250,527
Benefits relative to Base Case (NPV Option 3a - NPV Option 1)						(4,087,628)

Table 4.18: NPV of Option 3b – Refinance in 2019 and amortize refinancing fees

Option 3b: Refinance in 2019 and amortize refinancing fees						
Refinancing Date July 2019		2018	2019	2020	2021	Total
Breakage Fee	US$	-	-			
Unamortized Financial Costs	US$	332,567	351,722			
New Financing Costs	US$		214,453	456,803	243,151	914,406
Annual Interest Payments	US$	9,855,395	17,055,395	14,400,000	7,200,000	48,510,790
Annual Interest Payments +Financing Fees	US$	10,187,962	17,621,570	14,856,803	7,443,151	50,109,485
PV Annual Interest Payments	US$	10,187,962	15,564,008	11,589,883	5,128,464	42,470,317
PV Annual Fees, Penalties	US$					
NPV of Option 3b						42,470,317
Benefits relative to Base Case (NPV Option 3b - NPV Option 1)						(8,867,838)

4.7.15 An analysis of the impact of interest rate rise from 2018 to 2019 was also conducted. Table 4.19 below shows that if JPS pursued the option of a one-time payment for the refinancing fees and interest rates were to rise by more than 70 basis points (0.7%) in 2019, refinancing in 2018 would be the more favourable option.

Table 4.19: Interest Rate Increase that equates Option 2a with Option 3a

Option 3: Refinance by July 2019 (70 bips Interest Rate Increase)						
Refinancing Date July 2019		2018	2019	2020	2021	Total
Breakage Fee	US$	-	-			
Unamortized Financial Costs	US$	332,567	1,621,476			
New Financing Costs	US$	-	4,950,000			
Annual Interest Payments	US$	9,855,395	17,717,031	15,723,272	7,861,636	
Annual Interest Payments +Refinancing Fee	US$	10,187,962	24,288,507	15,723,272	7,861,636	58,061,377
PV Annual Interest Payments	US$	10,187,962	21,452,488	12,265,821	5,416,808	49,323,080
PV Annual Fees, Penalties	US$					
NPV of Option 3	US$					49,323,080
NPV of Option 3 - NPV of Option 1	US$					(2,035,139)
NPV of Option 3 - NPV of Option 2	US$					-

4.7.16 Table 4.20 below summarizes the results of the NPV analysis for the five (5) options that were evaluated. It shows the benefits/savings of refinancing the loan relative to the base option. The results in Table 4.19 highlight the following:

- JPS should clearly refinance the bond prior to maturity in 2021, if JPS's assumption that it can access the market at 8% or below holds true.
- If JPS chooses to pay its refinancing fees as a one-time payment, then it is preferable for the company to refinance the bond in 2019 when it does not have to pay breakage (prepayment) fees. There is a risk that interest rates could rise and wipe out the benefit of delaying refinancing. The rate rise would have to be more than 0.7%.
- If JPS chooses to amortize the refinancing fees over the tenure of the proposed new bond, then it would be preferable to refinance in 2018 rather than wait until 2019. From the data provided by JPS, it is normal practice for financing fees to be amortized over the life of the debt.

Table 4.20: Benefits between July 2018 and July 2021 for Refinancing Options

Option	Option a One-time Payment of Refinancing Costs	Option b Amortization of Refinancing Costs
Base Case - Refinance in 2021	-	
Option 2 - Refinance in 2018	2,015,076	10,739,280
Option 2 - Refinance in 2019	4,087,628	8,867,838

4.7.17 It is also important to note that in the 2014-2019 Determination Notice, the OUR approved US$3.202M of debt issuance cost and expenses in JPS's revenue requirement (see Table 6.81 in the 2014-2019 Determination Notice). This amount was the average of the debt issuance costs between 2009 and 2013. This covered the amortized value of financing fees for JPS's long term debt instruments, including the amortized financing fees for the US$179.1M, which payments commenced in 2011.

4.7.18 The OUR also approved interest charges on short term loans and bank overdrafts of US$2.8M in JPS's revenue requirement. Thus, the total allowance for debt issuance costs and short term debt costs that was included in JPS's revenue requirement in the 2014-2019 Determination Notice was US$6M. JPS's 2017 Audited Financial Statements indicated that amortization of debt issuance cost in 2017 was US$3.44M, while short term loans and bank overdraft costs were US$90,000 and US$636,000 respectively. JPS's total debt issuance and short term debt costs in 2017 was therefore US$4.16M; significantly less than the amount that is embedded in JPS's revenue requirement for such costs.

4.7.19 Based on the foregoing, the OUR is of the view that if JPS's debt refinancing is pursued on the basis highlighted in Option 2b of the OUR's evaluation, there is much more to be gained from such an approach.

The OUR's Position: Refinancing Mechanism

4.7.20 From the preceding analysis, refinancing in 2018 appears to be the best option if JPS amortizes the financing costs over the tenure of the bond. However, arising from the OUR's discussions with JPS, the company has indicated that the OUR's recommended option will not be feasible.

4.7.21 The OUR is of the view that the refinancing of JPS's debt refinancing proposal, even without pursuing the OUR's preferred approach, would lead to a lower tariff trajectory in 2019 and 2020.

4.7.22 Further as indicated above, a provision was made for debt issuance costs and short term debt costs equivalent to US$6M per annum in JPS's revenue requirement in the 2014-2019 Determination Notice. Consequently, while the OUR recognizes that JPS is likely to face other debt issuance costs, given that a provision was made for this kind of expense, it seems only reasonable that at least a part of the net expense (i.e. US$5.312M) associated with this refinancing initiative should come from the US$6M provision in the revenue requirement.

4.7.23 In this regard, the Office is willing to allow JPS to pass-through 50% of the proposed net refinancing cost of $5.312M to customers in the 2018-2019 review period. All other things being equal, this should result in an annual reduction in the tariff of at least US$3.36M in 2019 and 2020.

Determination 6:

The Office has concluded that JPS's refinancing proposal does not qualify for an Extraordinary Rate Review. However, it has been determined that the proposal has merits and has therefore been accepted under a Refinancing Incentive Mechanism that will result in the refinancing benefits flowing to customers in 2019 and 2020. Consequently, under this mechanism:

(i) JPS shall receive US$2.66M (or J$340M) in its tariff over the 2018-2019 period.

(ii) JPS shall provide evidence of the loan agreement to the OUR within ten (10) working days of finalizing the transaction.

(iii) Should JPS fail to refinance its debts as stated in its proposal, on or before 2019 March 31, the company shall be required to return the amount of US$2.66M (along with the computed opportunity cost) to its customers through its rates during the 2019-2020 Rate Review period.

(iv) The OUR shall use JPS' weight average cost of debt that results from the debt refinancing under this mechanism to compute the company's weight average cost of capital (WACC) in the 2019 – 2024 Rate Review exercise.

5.0 Z-Factor Adjustment & Extraordinary Review: Accelerated Depreciation & Separation Cost

5.0.1 JPS has indicated that the construction of the South Jamaica Power Company Limited (SJPC) 190MW Combined Cycle Gas Turbine (CCGT) plant (SJPC plant) is expected to be completed by 2019 July, while the New Fortress Energy (NFE) cogeneration facility is scheduled for completion in 2020 July. JPS submitted that within twelve (12) months of commercial operations date (COD) of the SJPC plant, the Old Harbour (OH) generating units will be retired and decommissioning activities will commence. Similar activities are expected to commence at Hunts Bay (HB) Unit#6 within six (6) months after COD of the NFE cogeneration facility.

5.1 Background

5.1.1 In 2014 June, the Electricity Sector Enterprise Team (ESET) was established by the Cabinet of Jamaica to urgently procure base-load capacity to replace approximately 292MW of existing oil-fired steam generation capacity owned by JPS at its HB and OH power stations, which are due to be retired from service.

5.1.2 By Gazette published 2014 July 10, the JPS Amended and Restated All-Island Electric Licence, 2011, was amended (Amended Licence) to grant JPS the right of first refusal (ROFR) to replace its obsolete generating capacity. By letter dated 2015 January 15, JPS indicated to ESET its interest in exercising its ROFR, pursuant to Condition 6(5) of the Amended Licence, to construct a 190MW, Natural Gas (NG)-fired generating capacity, based on CCGT technology at its Old Harbour premises. By letter dated 2015 March 10, ESET confirmed its agreement with the exercise of JPS's ROFR and JPS's commitment to proceed with steps in the design, planning, permitting, financing and construction of the 190MW plant, subject to various conditions.

5.1.3 The 190MW generation facility was structured as an IPP pursuant to section 20 (8) of the Electricity Act, 2015 (EA), and was to be owned and operated by SJPC. Approval was subsequently granted to NFE to replace the remaining portion of the 292MW of steam generating capacity. This is being developed as a 100MW co-generation facility, with net export of 94MW to the system with the remainder supplied to Jamalco's alumina operations as equivalent thermal energy.

5.1.4 JPS has executed power purchase agreements (PPAs) with SJPC and NFE to supply power to the System from their new power generation facilities, projected to be completed in 2019 July and 2020 June respectively. After these plants are commissioned into service, it is anticipated that the JPS OH Units #2, #3 & #4 and HB Unit #6, will be completely displaced from the schedule of active generation and retired. These generating units have far exceeded their initially estimated technical and economic useful lives and over the time, have required considerable capital and operating expenditure to maintain their operations on an ongoing basis. A description of the units is provided in Table 5.1 below.

Table 5.1: Description of the JPS OH and HB Oil-Fired Steam Generating Units

Capabilities and Performance Characteristics of the JPS OH and HB Oil-Fired Steam Generating Units										
UNIT	Description	Fuel Type	Gross Capacity (MW)	Station Service (%)	Net Capacity (MW)	Minimum Operating Level (MW)	2017 Avg. Heat Rate (kJ/kWh)	Approximate Availability (%)	C.O.D	Age (years)
OH Unit #2	Oil-Fired Steam	HFO	60.0	5.0%	57.42	35.6	14,571	89%	1970	48
OH Unit #3	Oil-Fired Steam	HFO	65.0	5.0%	62.48	34.4	12,980	80%	1972	46
OH Unit #4	Oil-Fired Steam	HFO	68.5	5.0%	64.59	35.5	12,769	62%	1973	45
HB Unit #6	Oil-Fired Steam	HFO	68.5	5.0%	64.36	35.4	12,545	91%	1976	42

5.2 JPS Plant Decommissioning Costs Proposal

5.2.1 In its 2018 Annual Review submission, JPS proposed a Z-Factor adjustment to address issues associated with the pending decommissioning of the existing OH and HB steam generating units. JPS argued that since these generating units will be retired by 2020 December as indicated above, depreciation/impairment of these plant assets will need to be completed by the time of the commissioning of the new generation plants. This is to ensure that these assets are retired before the replacement capacity is commissioned in order to minimize the impact on retail tariffs. JPS posited that accelerating this depreciation expense will advance depreciation costs totaling US$12.8M (J$1,638M).

5.2.2 In addition, JPS proposed a Z-Factor adjustment for separation costs of US$1.89M (J$242.4M) which it attributes to the expected retrenchment of staff working at the two (2) plants.

5.2.3 On reviewing JPS's submission, the OUR concluded that given the forward looking nature of the revenue cap mechanism prescribed in the Licence 2016, the tariff adjustments requested could not be treated precisely in the manner requested. The submission appears to assume that a rate revision (i.e. an adjustment to the base revenue requirement) was applicable both to the asset impairments which occurred in 2017 and the projected increase in depreciation and separation cost. However, similar to the position that was taken in the 2017 Extraordinary Rate Review Determination Notice, the OUR takes the view that the retrospective nature of the asset impairment occurring in 2017 due to the accelerated depreciation of the OH and HB plant assets warrants a Z-Factor compensation treatment, while the projected costs arising from the accelerated depreciation and separation costs up to 2020 should be correctly treated as an Extraordinary Rate Review issue.

5.2.4 Accordingly, the OUR has treated some components of JPS's decommissioning request as a Z-Factor adjustment, and other components as an Extraordinary Rate Review claim.

5.3 Analysis: OH and HB Steam Production Plant Asset Value

5.3.1 As at 2017 June, the "carrying value" of the OH and HB steam production plant assets were approximately US$24.5M and US$4.5M respectively. Based on International Accounting Standard (IAS) 16, the depreciable amount of an asset is determined after deducting its residual value. This means that for the plants in question, their depreciable amount will be equivalent to their depreciated cost (or carrying value) less any estimated residual value recoverable from their disposal at retirement. With respect to residual asset value, JPS has indicated that a market assessment done on the two (2) plants revealed that the most favourable recoverable value of the plants would be realizable through the sale of the remaining metal components, as no secondary market for these plant models were identified.

5.3.2 Based on market information, scrap values for metals will depend on market price at the time of disposal. JPS estimates that a residual value in the range of US$1.4M to US$2M may be possible. With reference to its 2014-2019 Rate Review submission, JPS noted that there are significant costs associated with decommissioning of these plants, which were forecasted at US$10.4M excluding severance costs of potentially US$9M. JPS submitted that based on the significance of these costs, the company proposes a deferral of the application of the residual value at this 2018 Annual Review to the 2019-2024 Rate Review. JPS added that a more reliable estimate of the residual asset value could be obtained by 2019, which would be applied as an offset to the decommissioning costs.

5.3.3 Based on the factors outlined above, JPS asserted that in order to satisfy the relevant requirements of the Licence 2016 and International Financial Reporting Standards (IFRS), and in order to achieve a full write-off of their carrying values over the period to their projected retirement dates, depreciation rates applicable to OH and HB steam production plant assets will need to be adjusted. According to JPS, this accounting treatment would result in the acceleration of the applicable depreciation charges, commencing 2017 June, the actual date JPS was notified of the activities influencing the increase in the rate of depreciation. The effect of the accelerated depreciation has resulted in incremental charges of US$9,156,904, over the period 2017 to 2020, for both generation facilities as presented in Table 5.2 below.

Table 5.2: JPS's Incremental Depreciation Charges due to Accelerated Depreciation (2017-2020)

INCREMENTAL DEPRECIATION RELATED TO JPS HB AND OH STEAM UNITS					
Plant Asset	2017 Dec 31	2018 Dec 31	2019 Dec 31	2020 Dec 31	TOTAL
	US$	US$	US$	US$	US$
HB [Unit #6]	187,658	375,317	375,317	375,317	1,313,609
OH [Unit #2, #3 and #4]	1,568,659	3,137,318	3,137,318	-	7,843,295
TOTAL	1,756,318	3,512,635	3,512,635	375,317	9,156,904

5.3.4 Given that US$1,756,318 of the depreciation expense was incurred in 2017, and the Licence 2016 expressly permits recovery of asset impairment adjustments under the Z-Factor mechanism (see Schedule 3, paragraph 46.d(i)), this component of JPS's submission will be treated in the rate review exercise as a Z-Factor adjustment.

5.3.4 However, the balance of US$7,400,587 programmed to be incurred over the 2018-2020 period has been classified as an extraordinary rate adjustment. The circumstances giving rise to this component of the claim (i.e. the decommissioning of the OH and HB Unit#6 power stations occasioned by the impending commissioning of NG-fired replacement capacity by 2019 and 2020, which replacement capacity was initiated by the GoJ as part of its fuel diversification strategy for Jamaica's energy sector) are deemed to be exceptional, are acknowledged to have a significant impact on JPS, and were factors not taken into account at the time of the last Five (5) Year Rate Review (i.e. 2014-2019 Determination Notice). These satisfy the conditions in the Licence 2016 for examination under an Extraordinary Rate Review.

5.4 Analysis: JPS's Ongoing Maintenance Expenditure

5.4.1 JPS argues that the OH and HB steam generating units represent a critical component of the extant generation fleet, therefore the company has an obligation to ensure that they continue to operate in a reliable manner until the replacement generation is fully commissioned.

5.4.2 This obligation will necessitate additional capital expenditure in the interest of undertaking significant preventative maintenance and overhaul activities, which will be required prior to retirement. JPS contends that depreciation of these capital expenditures will also need to be accelerated so that they may likewise be written-off by the retirement date of the plants.

5.4.3 In its 2018 Annual Review submission, JPS has indicated that the total expenditure to perform the stated maintenance activities over the period 2018-2020, is estimated at US$13.2M, with US$6.0M already incurred in 2017 and a further US$7.2M planned for 2018-2020. These costs were not included in the incremental depreciation charges described above and will have the effect of increasing the annual depreciation charges as represented in Table 5.3 below. As proposed by JPS, these expenditures will be depreciated over calendar years 2018-2020 resulting in depreciation charges of US$2.6M, US$6.3M and US$4.2M in each year, respectively.

Table 5.3: JPS's Incremental Depreciation related to Future Maintenance Expenditure

JPS's PROJECTED MAINTENANCE EXPENDITURE FOR ACCELERATED DEPRECIATION					
Plant Asset	2017 Dec 31	2018 Dec 31	2019 Dec 31	2020 Dec 31	TOTAL
	US$	US$	US$	US$	US$
Forecasted Expenditure	6,030,200	4,078,938	2,053,267	937,153	13,099,558
RELATED DEPRECIATION					
HB [Unit #6]	-	237,496	1,248,077	2,399,052	9,359,699
OH [Unit #2, #3 and #4]	-	2,399,406	5,060,848	1,899,445	3,824,626
Additional Depreciation	-	2,636,902	6,308,925	4,298,497	13,184,325

5.5 Analysis: Proposed Recovery of Total Incremental Depreciation Charges

5.5.1 Overall, JPS proposes the adjustment of the non-fuel rates in 2018 to permit the recovery of the accelerated depreciation costs for the 2017, 2018 and half of the 2019 allocation, totaling US$12.8M **[US$1.7M + US$6.1M+ US$4.9M (0.5 x $9.8M)]**, as shown in Table 5.4 below.

5.5.2 JPS argues that whilst it is an unusual request for an Annual Review, the company believes the timing is appropriate for several reasons outlined under section 3.1.6 of its 2018 Annual Review submission. On that basis, JPS proposes to recover the total incremental depreciation of US$12.8M through the Z-Factor clause in this 2018 Annual Review, translating to a Z-Factor adjustment of 4.10%. JPS is of the view that its proposal is prudent, reasonable and justifiable.

Table 5.4: Total Incremental Depreciation Charges

JPS's TOTAL INCREMENTAL DEPRECIATION CHARGES					
Plant Asset	2017 Dec 31	2018 Dec 31	2019 Dec 31	2020 Dec 31	TOTAL
	US$	US$	US$	US$	US$
HB [Unit#6] - Existing	187,658	375,317	375,317	375,317	1,313,609
OH - Existing	1,568,659	3,137,318	3,137,318	-	7,843,295
Sub-Total	1,756,318	3,512,635	3,512,635	375,317	9,156,904
HB [Unit#6] - Additional	-	237,496	1,248,077	2,399,052	9,359,699
OH - Additional	-	2,399,406	5,060,848	1,899,445	3,824,626
Sub-Total		2,636,902	6,308,925	4,298,497	13,184,325
TOTAL	1,756,318	6,149,537	9,821,560	4,673,814	22,341,229

5.6 Analysis: Return on Investment

5.6.1 By dint of the fact that depreciation occurs at an accelerated rate, the rate base upon which return on investment is computed, would also reduce at a faster rate. In this regard, even though JPS had not submitted any calculation for rate of return on investment adjustment, the OUR considers it an important element of the review exercise.

5.6.2 Table 5.5 below shows the required reduction in the return on investment associated with the accelerated depreciation over the period 2017-2020.

Table 5.5: Return on Investment Adjustment on Accelerated Depreciation

	Z-Factor	Extraordinary Review				TOTAL
	2017	2018	2019	2020	Total	
Cost of Debt	8.07%	8.07%	8.07%	8.07%		
Rate of Return on Equity (ROE)	12.25%	12.25%	12.25%	12.25%		
Tax Rate	33.33%	33.33%	33.33%	33.33%		
Gearing Ratio (Deemed)	50.00%	50.00%	50.00%	50.00%		
Post-tax WACC	8.81%	8.81%	8.81%	8.81%		
Pre-tax WACC	13.22%	13.22%	13.22%	13.22%		
	US$	**US$**	**US$**	**US$**	**US$**	**US$**
Change in Rate Base	1,756,318	3,512,635	3,512,635	375,317	7,400,587	9,156,905
Return on Equity	107,574	215,149	215,149	22,988	453,286	560,860
Taxation (Gross up)	53,779	107,558	107,558	11,492	226,609	280,388
Long Term Interest Expenses	70,867	141,735	141,735	15,144	298,614	369,481
Reduction in Return on Investment	**232,221**	**464,442**	**464,442**	**49,625**	**978,509**	**1,210,730**
Allowed Adjustment	**1,524,097**	**3,048,193**	**3,048,193**	**325,692**	**6,422,078**	**7,946,175**

5.7 OUR's Position on JPS's Accelerated Depreciation Claim

5.7.1 Based on the review of JPS's proposed incremental depreciation and supporting schedules, applicable regulatory requirements and relevant accounting standards, the OUR's position on the Z-Factor request is outlined below:

<u>JPS's Incremental Depreciation Charges</u>

1) Based on IAS 16, the depreciable amount of an asset is determined after deducting its residual value. JPS has presented a residual value estimate of US$1.4M-US$2.0M, which may not be reliable, given the uncertainties surrounding the mode of disposal. On that basis, JPS proposes to defer the application of the residual value to the 2019-2020 Rate Review. By such time it could be better estimated and applied as an offset to the impending decommissioning costs. The OUR is of the view that

the proposal is not unreasonable and therefore has no objection to the proposed approach;

2) This accelerated depreciation treatment attempts to align cost recovery with cost factors to ensure overall price stability. The early recovery of the relevant depreciation costs could serve to negate the impact of the impending decommission cost on rates;

3) The schedules and calculations supporting the proposed incremental depreciation charges were thoroughly examined and evaluated. It was validated that the computed charges were reasonable and reflective;

4) The OUR believes that under the circumstances, the accelerated depreciation of plant assets was reasonable and justified, on the basis that they will not be required after the scheduled retirement dates, are unlikely to re-enter service, and will not have any impact on rates and revenue in the future;

5) In reviewing JPS's asset register and schedule of depreciation charges and calculations, it was observed that cost items such as major maintenance activities are being added to the carrying value of the assets, without regulatory review of the projects and associated budget of expenditure. Although the IFRS dictates that these costs should be capitalized when incurred, for price control purposes, the OUR will effect greater monitoring of the asset register and regulatory asset base. This may involve a year-by-year tracking approach, which examines capital expenditure with the various asset categories. In that regard, JPS shall submit its complete and updated asset register and depreciation calculation schedule for each calendar year to the OUR for review;

6) The incremental depreciation charges of **US$9,156,904**, resulting from accelerated depreciation of OH and HB plant assets are approved. However, the amount of US$1,756,318 which was incurred in 2017 is approved for Z-Factor adjustment. On the other hand, the amount of US$7,400,587 that will be incurred over the 2018 to 2019 period, is to be treated as an extraordinary rate adjustment.

JPS's Incremental Depreciation related to Future Maintenance Expenditure

7) JPS had knowledge of the replacement of its OH and HB base-load capacity replacement and the associated reliability considerations from at least 2015. However, the company did not present a credible capital expenditure programme to the OUR to ensure that the OH and HB plants would be available and functional during the 2018-2020 time frame;

8) Periodic (normally at five (5) year intervals) major overhaul/maintenance activities are critical to ensuring that the generation plants remain useful and reliable. JPS's asset register and depreciation calculations schedule, show that OH Unit#3 was

overhauled in 2015 (overhaul cost - US$9.8M) and OH Unit#2 in 2016 at a cost of US$4.5M. During these major maintenance activities, all critical plant equipment and systems are inspected, repaired and replaced as necessary. However, JPS in its 2018 Annual Review submission, has forecasted significant capital expenditures for maintenance activities on these units that would consequently improve their useful lives by at least five (5) years, while the same plants are due for retirement just over a year from present. This is questionable and raises concerns of prudence in relation to JPS's generation operations and maintenance practices.

9) The forecasted capital expenditures (2018-2020) appear to contain unjustifiable costs, including cost of small parts/items that should be captured in the company's annual maintenance routine. It is important to note that the costs associated with this mode of maintenance are already reflected in the non-fuel rates. Therefore, the capitalization and addition of those forecasted costs to "PPE" would result in double counting;

10) There are observed inconsistencies with projected capital expenditures included in the 2018 Annual Review submission and those provided in the supporting schedule. For example, US$4,078,938 was projected for 2018 but US$4,968,148 was indicated in the supporting schedule;

11) Based on IAS 16, the forecasted capital expenditure (US$13.2M) for maintenance activities over the 2018-2020 period, cannot be recognized as assets until they are incurred. This means that depreciation charges cannot be applied. Nevertheless, necessary plant maintenance expenditure incurred by JPS in the future that is determined to be reasonable and prudent will be considered for recovery;

12) The proposed additional depreciation charges of US$13,244,324 does NOT satisfy the applicable Z-Factor conditions, on the basis that they are largely not incurred and in some cases not justified. As such, they were NOT allowed in the Z-Factor adjustment to the annual non-fuel revenue requirement. Furthermore, given the questions concerning some of these charges, the OUR is of the view that they should not be captured at this point in its extraordinary rate adjustment; and

13) Consistent with the OUR's position in the 2014-2019 Determination Notice, JPS, prior to undertaking any major overhaul/maintenance of its generation plants, shall submit the planned project scope and schedule, including budget (estimated cost), to the OUR for review.

JPS's Incremental Depreciation related to Future Maintenance Expenditure

14) Given the fact that JPS's rate base is being reduced at a faster rate because of the acceleration of depreciation, then the Z-Factor and Extraordinary Rate Review adjustments to the tariff must give due recognition to the impact of the incremental adjustment in the rate base on the return on investment. Accordingly, the approved:

- Z-Factor amount of US$1,756,318 for 2017 has been adjusted downward by US$232,221 to capture the rate of return effect; and
- Extraordinary Rate Review amount of US$7,400,587 for the 2018-2020 period has been reduced by US$978,509 to reflect the impact of the return on investment.

Determination 7:

The Office has determined that some components of JPS's accelerated depreciation cost claim qualifies for treatment under the Z-Factor mechanism, while other components qualify for treatment under the Extraordinary Rate Review mechanism. After conducting its assessment of the claim, the Office has concluded that over the 2018-2019 Annual Review period:

(i) JPS shall receive US$1,524,097 (or J$224.8M) as Z-Factor compensation for accelerated depreciation costs incurred in 2017.

(ii) JPS shall receive US$6,422,078 (or J$882.M) under an Extraordinary Rate Review for accelerated depreciation costs that will be incurred over the period 2018-2020.

5.8 Extraordinary Rate Review: Separation Cost

Background

5.8.1 In its 2018 Annual Review submission, JPS indicated that the retirement of the OH and HB steam generating units will also result in staff separation. As previously indicated, OH power station will be the first to be retired in 2019 June, while the HB Unit#6 will be decommissioned starting 2020 July.

Old Harbour Power Station

5.8.2 Regarding the OH power station, JPS noted that based on its assessment of staffing requirements up to 2019 December (decommissioning commencement date), it is appropriate to initiate the cost-recovery process in 2018. According to JPS, the company expects to separate staff employed to the OH power station progressively over twelve (12) months starting 2019 June and proposes to recover US$1.89M (J$242M) through the 2018 Annual Review.

5.8.3 JPS believes that including these costs in the 2018 Annual Review will help mitigate anticipated rate increases in 2019, taking into consideration unavoidable decommissioning expenses. JPS indicated that having assessed the financial implications from the winding down operations at the OH power station, the company thinks it is prudent at this time to request recovery of the related costs it expects to incur within the 2018-2019 regulatory period. JPS, taking a strategic view of the rates over the next three (3) years, also believes that this proposal will redound to the benefit of customers.

5.9 Separation Cost Proposed by JPS due to Generation Units Retirement

HB Unit #6:

5.9.1 With respect to HB Unit #B6, a total of US$3.3M (J$422.4M) was estimated by JPS for staff separation costs, which the company proposes to recover during the 2019-2024 regulatory period.

OH Power Station:

5.9.2 JPS submitted that a schedule has been developed and the company expects to separate sixty-eight (68) persons employed at the OH power station by 2019 June at a total cost of US$5.579M (J$714.196M). JPS posited that based on the certainty of the retirement proceedings, the company proposes to recover a third (1/3) of the separation cost, which translates to US$1.894M (J$242.432M) through this 2018 Annual Review, and the remaining US$3.7 million (J$471.764M) during the 2019-2024 regulatory period.

5.10 JPS's Proposed Recovery of System Separation Cost

5.10.1 JPS's request for the recovery of a third (1/3) of the total separation cost, associated with the OH power station, during the 2018-2019 regulatory period was made via a Z-Factor application. JPS contends that the decision to retire the relevant plant assets was not a decision of JPS's management but one that originated in the Ministry with responsibility for energy, as part of its fuel diversification strategy involving the addition of Natural Gas (NG) to the energy matrix. According to JPS, the Z-Factor adjustment associated with the request for the recovery of the US$1.894M will be 0.61%.

5.11 OUR's Review of JPS's OH Power Station Separation Cost Proposal

5.11.1 In keeping with the principle established in the 2017 Extraordinary Rate Review Determination Notice, the OUR maintains that costs not yet been incurred by the company, where they satisfy the conditions set out in the Licence 2016, should be recovered in the tariff under an Extraordinary Rate Review. The circumstances which gave rise to the accelerated depreciation claim in respect of OH power station, and which qualified that component of JPS's submission for treatment under an Extraordinary Rate Review, also apply to JPS's claim in respect of the projected separation costs to be incurred during the 2018-2019 regulatory period. Consequently, the recovery of those elements of JPS's separation cost which are forward looking, was done as part of an Extraordinary Rate Review exercise.

5.11.2 The OUR's initial examination of the OH power station staff separation cost proposal revealed the following issues:

- The total separation cost of J$714.196M (US$5.579M) stated in JPS's submission, was not representative of the actual staffing structure;
- There were discrepancies in the computation of the total separation costs; and
- The employee benefits obligations specified as accumulated sick and vacation pay were included in the schedule for compensation to employees, although not directly included in the separation cost connected to salaries.

5.11.3 Based on these observations, the OUR requested clarification and additional information from JPS in order to facilitate a complete review of the proposal. Updated cost data and staff information were submitted to the OUR on 2018 July 6. The updated information indicates the following:

- The OH power station has an establishment of seventy-seven (77) positions, comprised of seventy-five (75) staff sixty-eight (68) permanent and seven (7) contract) with two (2) vacancies. All seventy-seven (77) positions are expected to be made redundant by the time the plant ceases operation in 2019;

- No redundancy costs are associated with the contract staff and there are no planned internal transfers of the displaced staff within JPS; and

- The total redundancy cost for the sixty-eight (68) permanent staff to be separated has been revised to **J$593.373M (US$4.64M),** reflecting a reduction of J$120.823M.

5.11.4 According to JPS, this revised staff separation cost of J$593.373M (US$4.64M), is for redundancy costs only and is based on the final list and the OH power station's staff chart provided by JPS.

5.12 The OUR's Position on the Recovery of Separation Cost

5.12.1 Based on the review of JPS's proposed staff separation costs at the OH power station, supporting schedules and relevant Licence 2016 requirements, the OUR's position on the Extraordinary Rate Review is outlined below:

1) The total separation costs were examined and verified and found to be consistent with the staffing structure, staff classification and the sixty eight (68) employees to be separated;

2) **US$2.318M** (representing one half (1/2) of the revised total separation cost associated with the OH power station) is approved for extraordinary rate adjustment to the annual non-fuel revenue requirement. While this amount is 22% higher than the US$1.894M

that was initially proposed, the OUR takes the view that given that plant is expected be taken out of service in the next two (2) years it would be reasonable to spread the separation cost over an equivalent period;

3) The OUR supports JPS's view that recovery of a half (1/2) of the separation cost in the 2018-2019 rate adjustment period will provide a stream of revenue to allow JPS to cost-effectively fund the redundancy exercise, while minimizing the overall tariff impact on customers; and

4) Employee benefits obligations referenced above are not included in the separation cost, as they are accrued and carried in JPS's financial accounts, according to the audited financial statements.

Determination 8:

The Office has determined that an Extraordinary Rate Review is more appropriate for JPS's separation cost claim because of the forward looking nature of expenses. Accordingly, it has concluded that the company shall recover **US$2.318M or J$296.7M (representing one-half (1/2) of the revised total separation cost associated with the OH power station)** over the 2018-2019 Annual Review period.

6.0 Other Revenue Adjustments

6.0.1 There are a few issues that do not form a part of JPS's 2018 Annual Review submission, and which are not a part of the Annual Review exercise. These relate to a previous claim by JPS for reimbursement of costs for fuel additives incurred in 2015 March to 2015 December and a directive issued by OUR to JPS to reimburse customers for foreign exchange adjustment charges placed on fuel rates during the period 2013 March to December. Another issue relates to a request by JPS for the OUR to reconsider its decision regarding the data used to determine the billing determinants arising from an audit of JPS's metering and customer information systems.

6.0.2 The OUR's resolution of each of these matters, which are discussed further below, will result in both a reimbursement to JPS and a reimbursement to its customers. The OUR is of the view that it would be prudent to effect these reimbursements through the fuel rate mechanism or non-fuel electricity rates depending on the nature of the cost/revenue involved. The circumstances of the current Annual Review provides a convenient opportunity to address these payments in the rates to be approved for the 2018-2019 regulatory period. Inclusion of these reimbursements in the annual rate adjustment for the ensuing period will allow for the spreading of the payments across the regulatory period, which is advantageous because it avoids multiple changes to the tariff during the regulatory period, and smooths out the adjustments to JPS's revenue over the tariff period which reduces the potential for rate shock.

6.1 Fuel Additives Costs and Foreign Exchange (Fuel) Adjustment Charges

Fuel Additives Costs

6.1.1 In the 2014-2019 Determination Notice[11], the OUR directed JPS to cease including the cost of fuel additives in the monthly fuel rate calculations. JPS did so in 2015 March. However, while these costs are recognized by the OUR as legitimate expenses, they were not included in the non-fuel component of the tariff approved in the 2014-2019 Determination Notice. In light of this, JPS argued that it should be allowed to recover the amount of J$53,489,985 (i.e. US$453,837) for the cost of fuel additive used in the generation process over the period 2015 March – December.

6.1.2 The OUR acknowledges that JPS is entitled to recover the cost of the fuel additives amounting to J$53,489,985 (i.e. US$453,837) for the period 2015 March to December, as they represent legitimate and recoverable expenses incurred in the generation process. Further, given the time that has elapsed since these costs were incurred, the opportunity cost associated with these expenditures has to be taken into account in any reimbursement.

[11] See p. 226-227 "Jamaica Public Service Company Limited Tariff Review for Period 2014-2019: Determination Notice", (Document No. 2014/ELE/008/DET.004)

Hence, the amount recoverable through its fuel rate mechanism after the application of an opportunity cost[12] is J$65,448,663 (i.e. US$555,309).

<u>FX (Fuel) Adjustment Charges</u>

6.1.3 By Directive dated 2015 February 13[13] the OUR directed JPS:

> *"TO REFUND to its customers the sum of J$973,372,164.14 being amounts unilaterally imposed as Foreign Exchange Adjustments on fuel supplied by Petrojam Limited during the period March 2013 to December 2013 in contravention of Exhibit 2, Schedule 3 of the Licence."*

6.1.4 The sum was passed on by JPS to its customers through its fuel rate mechanism over the period 2013 March to December. According to JPS, the pass-through was attributable to unrecovered US dollars in fuel expenses which resulted from the depreciation in the domestic currency between the time the company was billed by its fuel supplier and the time when the associated revenues were recouped from customers. Consequently, the Jamaican dollars recouped was insufficient to pay the company's fuel bill from its supplier, quoted in US dollars.

6.1.5 After its investigation of the matter, the OUR determined that JPS had no legal authority under the existing regulatory framework to unilaterally impose these additional costs on customers, and so it issued the Directive.

6.1.6 In accordance with the provisions of its licence, JPS appealed the Directive to the Electricity Appeal Tribunal in 2015 February. The Directive was therefore stayed pending the determination of the appeal. Without any admission of any wrongdoing, JPS has now agreed to withdraw the appeal and comply with the Directive to refund the amounts to its customers. Consequently, the amount deemed owing by JPS to its customers is J$973,372,164 (or US$7,487,478), plus opportunity cost of $217,615,394 (or US$1,700,120), equaling a total sum owed of J$1,190,987,558 (or US$9,161,443). The OUR has in turn agreed that the sum due to customers will be recovered as indicated in paragraph 6.1.7 below.

<u>The Net Effect</u>

6.1.7 Given that both the fuel additives costs payable to JPS and the FX (Fuel) adjustment charges reimbursement to JPS's customers pertain to items that flow through the fuel adjustment mechanism, the Office takes the view that they ought to be paid through the

[12] The opportunity cost is based on the cost of debt (8.08%) for 2015-2016 and the WACC (i.e. 13.22%) for 2016-2017. It is important to note that prior to the issuance of Licence 2016, the cost of debt is applicable and the use of the WACC thereafter is as explicitly stated in the Licence 2016.

[13] Directive to Jamaica Public Service Company Limited (JPS) for the repayment of Foreign Exchange Adjustment Charges on Fuel supplied by Petrojam Limited during the Period March 2013 to December 2013, (Document No. 2015/ELE/002/DIR.001

fuel rate mechanism. In this regard, the net effect of the fuel additives costs and the FX (Fuel) adjustment charges reimbursement is -J$1,125,538,895 (or -US$8,793,273).

Determination 9

a) JPS shall be allowed to pass through to its customers the sum of J$65,448,663 (or US$555,309) for its fuel additive expenses in the fuel rate mechanism.

b) JPS will also be required to reimburse to its customers the sum of $1,190,987,558 (or US$9,161,443) by way of a surcharge on the fuel rate.

c) In light of (a) and (b) above, JPS shall adjust its fuel rate over the 2018-2019 review period to allow the net amount of J$1,125,538,895 (or US$8,793,273) from the fuel additives costs and the FX (Fuel) adjustment charges reimbursement to be passed on to customers.

6.2 Billing Determinants Reconsideration

6.2.1 After the OUR issued the 2014 – 2019 Determination Notice, JPS stated that there was *"an error in the computation of the energy revenue for Rate 10 customers and that, based on this error, the OUR's determined tariffs would not allow JPS the opportunity to recover the determined revenue requirement[14] of J$41,570,355,652."* JPS then followed up this claim by submitting, on 2015 January 29, a revised billing determinants data set **(2015 January 29 Data set)**.

6.2.2 At the OUR's request, on 2015 February 11, JPS uploaded an Auditor Certified version of its billing determinant data **(2015 February 11 Data set)** as a replacement for the data it had submitted in its 2014 Tariff Review application. Arising from the OUR's analysis of the **2015 February 11 Data set**, it concluded that the Rate 10 billing determinants matched the revised data that was in JPS's **2015 January 29 Data Set**. Accordingly, the OUR accepted JPS's proposed Rate 10 billing determinants and approved a revision to the rates by way of the publication of an addendum[15] to the 2014 – 2019 Determination Notice on 2015 February 27 (Addendum 1). Nonetheless, the OUR, in Addendum 1, stated that it "*will conduct an audit of the energy demand data and the OUR reserves the right to adjust the non-fuel rates in the event that there is a material difference between the audit results and the revised data*".

[14] Excluding the inflows to the Electricity Efficiency Improvement Fund (EEIF)

[15] Jamaica Public Service Company Limited Tariff Review for the Period 2014 – 2019: Determination Notice – Addendum 1 (Document No. 2015/ELE/003/ADM.001)

6.2.3 On 2015 April 1, JPS reported that the billed consumption data for rate classes 20 and 50 in the **2015 February 11 Data set** (i.e. the Auditor Source-Certified billed consumption data) was materially different from the original consumption data submitted in JPS's 2014 -2019 tariff submission and therefore a further revision of these billing determinants was warranted.

6.2.4 In keeping with its stance on the matter, the OUR in 2016 July commissioned an audit (the Audit) of JPS's metering and customer information systems (CIS). After reviewing the auditors' report, the OUR issued a determination notice (Jamaica Public Service Company Limited Metering and Customer Information Systems Audit – Determination Notice Document No. 2018/ELE/001/DET.001) dated 2018 January 11 (Metering and CIS Determination Notice) by which, among other things, it determined at Determination 4 that it would not use the 2015 February 11 Data Set to adjust the billing determinants, as requested by JPS, and that the electricity rates approved in the 2014 – 2019 Determination Notice and Addendum 1 would remain unaltered.

6.2.5 After receipt of the Metering and CIS Determination Notice, JPS requested a reconsideration of the Office's position regarding, among other things, its decision in Determination 4 relating to the 2015 February Data Set (Auditor Source-Certified data).

6.2.6 Acting in accordance with regulatory prudence, the OUR engaged an independent consultant to provide an assessment of, and advice on the results of the Audit and to evaluate the appropriateness of its position on the data sets. The consultant advised that:

- The **2014 April 4 Data Set** used in the JPS 2014-2019 Rate submission is unreliable and irreconcilable.

- The **2015 February 11 Data set** provides an accurate record of the 2013 energy demand consumption data in the Banner Database.

6.2.7 In light of the consultant's advice and based on its assessment of all the circumstances, the OUR has reconsidered its position and will rely on the **2015 February 11 Data Set** (Auditor Source-Certified data) as the appropriate basis of the billing determinants for the 2014-2019 regulatory period. A formal reconsideration decision will be subsequently issued in this regard. The application of the revised data as the basis for the billing determinants will result in JPS under-recovering revenue during the rate period, which under-recovery should be compensated as detailed in the analysis below.

Analysis of Revenue Adjustment:

6.2.8 Given the timing of the implementation of the 2014 – 2019 Determination Notice [16] and the point at which the tariff regime under the Licence 2016 changed from a price cap to revenue cap methodology, JPS's billing determinants revenue loss ought to be computed

[16] See the 2014 – 2019 Determination Notice

over the period 2015 April – 2016 July. This period may further be broken down into two (2) sub-periods to reflect changes in the electricity rates arising from the 2016 Annual Review. In this respect, the first sub-period is 2015 April to September, and the second is 2015 September to 2016 July. The total revenue under-recovery for the 2015 April – 2016 July is J$419.7M, and when decomposed into sub-periods, it is as follows:

- **2015 April – September**: J$155.2M
- **2015 September – 2016 July**: J$264.5M

6.2.9 In addition, JPS ought to be paid the opportunity cost associated with the revenue it was denied over the period. In keeping with the methodology delineated in the performance-based rate mechanism (PBRM) in Schedule 3 of the Licence 2016, the Office takes the view that the opportunity cost should be equivalent to the WACC determined at the last Five (5) Year Rate Review. As such, the applicable opportunity cost is 13.22%.

6.2.10 It is worth noting, in addition to checking for the revenue gap associated with billing errors in its 2014- 2019 tariff submission, JPS also performed a billing determinant analysis of its revenues over the period 2010-2013. The result of this analysis revealed that in 2015 JPS had registered an over-recovery of $89.8M.

6.2.11 After adjusting all of JPS's under- and over-recovered billing determinant revenues to account for WACC, the OUR has computed that JPS should correctly receive an additional J$433.9M in revenues (see Table 6.1 below), with J$329.8M attributable to billing determinant adjustments and J$104.1M arising from compensation for the opportunity cost of the revenue previously denied.

Table 6.1 Billing Determinant Reconsideration

Billing Period	JPS's Claim		JPS's Claim +WACC		OUR Allowed	
	J$	US$	J$	US$	J$	US$
2015 Apr – Sep	155,154,174	1,193,494	225,181,608	1,732,166	225,181,608	1,732,166
2015 Sep – 2016 Jul	264,537,867	2,034,907	339,104,965	2,608,500	339,104,965	2,608,500
2010 - 2013	-89,838,898	-691,068	-130,386,872	-1,002,976	-130,386,872	-1,002,976
JPS Total Claim	**329,853,143**	**2,537,332**	**433,899,700**	**3,337,690**	**433,899,700**	**3,337,690**

Determination 10

The Office has reconsidered Determination 4 of the Jamaica Public Service Company Limited Metering and Customer Information Systems Audit – Determination Notice (Document No. 2018/ELE/001/DET.001), and has determined that JPS will be allowed to recover J$433,899,700 (or US$3,337,690) in respect of billing determinant errors that resulted in unrecovered revenues over the period 2010 to 2016. This sum of J$433,899,700 shall be recovered in JPS's non-fuel tariff.

7.0 Smart Meter Losses Incentive Mechanism

7.1 Background

7.1.1 In its 2018 Annual Review submission, JPS proposed to the OUR that the losses penalty ($TUVol_{2017}$) be reduced to allow the company to pursue the installation of smart meters at a more aggressive pace. This JPS argues, is a key component of its strategy to reduce system losses.

7.2 The OUR's Analysis

7.2.1 JPS indicated that it has budgeted for the installation of 100,000 smart meters in 2019, but believes that it could achieve more reduction with 200,000 smart meters. A reduction in the losses penalty would enable it to achieve this aim. Following a further request for information made by the OUR, JPS provided details on the outcomes that could be achieved for rollout of smart meters under three (3) scenarios:

1. Rollout of 100K smart meters per year
2. Rollout of 150K smart meters per year
3. Rollout of 200K smart meters per year

7.2.2 Table 7.1 below shows the expected outcomes for the three (3) scenarios in terms of MWh and percentage point reduction.

Table 7.1: Loss Reduction Projections for Smart Meter Installation

	Base 100K per year			150K per year			200K per year		
Year\Period	1st half	2nd half	Full year	1st	2nd	Full year	1st	2nd	Full year
2018		757	757		757	757		757	757
2019	8,376	15,555	23,932	8,945	16,611	25,556	9,513	17,667	27,180
2020	9,500	13,119	22,618	10,351	14,294	24,646	12,054	16,646	28,701
Total (MWh)	17,876	29,431	47,307	19,296	31,663	50,959	21,567	35,070	56,638
Max %	0.38%	0.62%	1.00%	0.41%	0.67%	1.08%	0.46%	0.74%	1.20%
Min %	0.26%	0.44%	0.70%	0.29%	0.47%	0.75%	0.32%	0.52%	0.84%

7.2.3 The OUR's computation shows that the loss reduction penalty for 2018 based on its actual performance in the previous year is J$2.043Billion. This is significant and the OUR is mindful that this may be an obstacle to JPS's undertaking the necessary capital investments to accelerate the pace of system losses reduction. Reducing or removing the losses penalty is however inconsistent with the principles on which the losses incentive/penalty mechanism embedded in the annual tariff adjustment formula was established in the Licence 2016 and thus, the OUR does not approve any such action.

7.3 The OUR's Position

7.3.1 Even though the OUR takes the view that there is the need for a paradigm shift with respect to how JPS deals with loss reduction, it is not unaware of the impact the current level of system losses has on the company's profitability. In this regard, the OUR is prepared to conduct a comprehensive review of the targets, spectrum and the treatment of the classification delineated in the Licence 2016 with a view of facilitating a reversal of the adverse losses trend and thereafter rapid reduction in losses.

7.3.2 Notwithstanding, the OUR considers that the thrust to install smart meters as a strategy in the loss reduction programme should be supported. Hence the OUR has devised a special loss reduction initiative called "Accelerated Loss Reduction Mechanism" (ALRIM) that allows for the funding of capital investment in smart meters and provides an incentive for JPS to effectively use the smart meters to reduce losses and rewards the company for positive results. ALRIM is programmed to span a two (2) year period.

7.3.3 The ALRIM provides JPS with one of two (2) options:

a) ***ALRIM-1:*** under this option, JPS would be allowed additional revenues amounting to US$13.87M annually before tax (US$9.25M net of tax) for 2018-2019 and 2019-2020 review periods. This is to facilitate the procurement and installation of 50,000 additional smart meters per annum. JPS's JNTL is set at 3.60% considering the projected impact of the smart meters; or

b) ***ALRIM-2:*** under this option, JPS would be allowed additional revenues amounting to US$13.87M annually before tax (US$9.25M net of tax) for 2018-2019 for the procurement of 50,000 smart meters. However for 2019-2020, JPS could chose to spend the additional revenues in whatever way it deems fit in its loss reduction drive and not necessarily on smart meters. In consideration of the imperative to lower system losses and for flexibility of the company to focus its attention on loss reduction, the 2018-2019 JPS's JNTL system losses target, exclusively under this incentive mechanism, would be increased from 3.60% to 5.75%. This adjustment to the allowed target under ALRIM-2 shall be independent of any future system losses target and shall not be construed as a normal component of the system losses target process. Based on JPS's performance in in 2017-2018, all other things remaining constant, the revenues effect, in this case, translates to US$9.25M before tax.

7.3.4 Given that these revenues are deemed to be the customers' contribution to loss reduction, the assets procured under ALRIM would not be included in the regulatory rate base, even though they would be captured in the company's asset base. As such, JPS would not be allowed to earn a rate of return on these assets.

7.3.5 In order to incentivize JPS in its loss reduction effort, the company would be given the opportunity to have these meters transferred to the regulatory rate base at the end of 2020 in return for a reduction in its revenue requirement provided it achieves an approved system losses reduction threshold of 1.2 percentage points. This means that given that the overall system losses at the end of 2017 was 26.45%, JPS should register a maximum actual overall system losses of 25.25% at the end of 2020 to qualify for the incentive. This target is common to both ALRIM options.

7.3.6 A critical component of the mechanism is tied to the principle that the reduction in the revenue requirement arising from the transfer would be equivalent to a "discount" on the book value of the meters transferred to the regulatory rate base. Further, the extent of the discount would be directly related to the degree to which JPS achieves and surpasses the system losses reduction target established by the OUR under the smart meter programme over the two (2) years, 2019 and 2020. The assessment of JPS's performance under the ALRIM shall be done at the 2020/2021 Annual Review.

7.3.7 Should JPS fail to meet the minimum loss reduction target of 1.2% at the end of 2020 Annual Review period, it will be given chance to have the smart meter assets acquired under ALRIM transferred to the regulatory asset base at their net book value for a commensurate reduction in the tariff.

7.3.8 The ALRIM represents a strong package of incentives that focuses on system losses. The mechanism has the following advantages:

- It provides additional funds to augment the company's resources in its drive to reduce system losses;
- It will include in its design, timely regulatory evaluations to keep JPS focused on its targets;
- It will allow JPS to transfer the smart meters acquired under the programme to the regulatory rate base and earn a rate of return on these assets.

7.3.9 Furthermore, the installation of smart meters come with other benefits that can contribute to JPS' efficiency and management of demand, these include:

- Reduction in meter reading cost with remote readings
- The capacity to disconnect and reconnect customers remotely
- The capacity to quickly monitor the electricity system
- The capability of introducing time-of-use rates to residential customers

7.3.10 However, the OUR takes the view that the effectiveness of JPS's system losses strategy goes beyond the simple installation of hi-tech meters. It also requires the use of appropriate data analytics to surgically identify and deal with the problems, as well as the strategic mobilization and deployment of resources across the island. Consequently, the OUR in its oversight of JPS' system losses programme, will be emphasizing these dimension of the strategy.

7.3.11 The OUR intends, in the short term, to work out in greater detail the elements of the ALRIM and will engage JPS after the publication of this Determination Notice.

Determination 11

(i) The Office approves funding to reinforce and incentivize JPS's loss reduction efforts under the Accelerated Loss Reduction Incentive Mechanism (ALRIM). Under ALRIM, JPS shall identify within one (1) month of the effective date of this Determination Notice, which of the two (1) options of ALRIM it has selected. The options offered are:

a. ***ALRIM-1:*** under this option, JPS would be allowed additional revenues amounting to US$13.87M annually before tax (US$9.25M net of tax) for 2018-2019 and 2019-2020 review periods. This is to facilitate the procurement and installation 50,000 additional smart meters per annum. JNTL target for 2019 -2020 is 3.60% bearing in mind the projected impact of the smart meter programme.

b. ***ALRIM-2:*** under this option, JPS would be allowed additional revenues amounting to US$13.87M annually before tax (US$9.25M net of tax) for 2018-2019 for the procurement of 50,000 smart meters. However for 2019-2020, JPS could chose to spend this additional revenue in whatever way it deems fit in its loss reduction drive and not necessarily on smart meters. In consideration of the imperative to lower system losses and allowances made for the flexibility of the company to focus its attention on loss reduction, the 2019-2020 JNTL target would be increased from 3.60% to 5.75%. All other things remaining constant, the revenues in this case translates to US$9.25M before tax.

Determination 11 (Continuation)

(ii) The Office shall, at JPS's request, transfer the smart meters assets acquired under ALRIM to the regulatory rate base consistent with the asset discount system established **provided that** the company achieves the system losses target established by the OUR under ALRIM over the 2018-2019 and 2019-2020 period.

(iii) The Office shall, at JPS's request, transfer of smart meters assets acquired under ALRIM to the regulatory rate base at their net book values if the company fails to achieve the system losses target established by the OUR under ALRIM over the 2018-2019 and 2019-2020 period.

(iv) The Office shall, on transferring the smart meter assets to the regulatory rate base, reduce JPS revenue requirement by an amount equivalent to the value of the transferred assets plus a discount that reflects the incentive scheme established under ALRIM **provided that** the system losses target established by the OUR is achieved. However, should JPS fail to achieve the minimum system losses target, then JPS' revenue requirement shall be reduced by the net book value of the assets.

(v) Should JPS opt to take ALRIM-1, then the targets established in Determination 4 would apply. However, should JPS take the ALRIM-2 option then the following targets are applicable for the 2018-2019 Annual Review period:

- Technical Losses (TL) Target: **8.00%**
- Non-Technical Losses within the control of JPS (JNTL) Target: **5.75%**
- Non-Technical Losses not fully within the control of JPS (GNTL)Target: **9.70%**
- Responsibility Factor (RF) for Non-Technical Losses to JPS's NTL that are not totally within its control: **20%**.

8.0 Tariff Design

8.1 JPS's Forward Looking Proposal

Background

8.1.1 Since making the transition to the revenue cap tariff regime in 2016, the OUR has approved the billing determinants for the current period on the basis that it should be equivalent to the actual in the previous period. In other words, the approved billing determinants for 2018 would be equal to the 2017 actuals.

8.1.2 Under the revenue cap, the revenue target set in any given year must be recovered. Consequently, if there is an over-recovery in any given year then the excess is programmed into the revenue true-up calculation by way of a lower revenue target the following year. Likewise, if there is an under-recovery in one year, the deficit is recovered in the ensuing year by way of an increase in the annual revenue target.

8.1.3 In this respect, the billing determinants do not affect the overall revenue that ultimately is recovered, but it does impact the rate of revenue recovery since it impacts the price level. Consequently, having a realistic billing determinant is important.

JPS's Forward-Looking Billing Determinant Proposal

8.1.4 JPS in its 2018 Annual Review submission argues that due to the implementation of the SSP, there has been a 14% year-to-date reduction in electricity consumption as a result of the use of LED streetlights. In light of this, the company is proposing what it describes as a forward-looking mechanism to reduce the Rate 60 consumption in the rate design for 2018.

The OUR's Position

8.1.5 JPS, it its 2014 -2019 tariff submission, proposed total energy sales of 3,085.6GWh for the test year 2013. The energy demand for the 2013 test year is shown in Table 8.1 below. JPS then proposed to reduce the demand for street lighting by the amount of 28,312MWh. JPS's proposal was based on the assumption that Rate 60 energy sales would be reduced as a result of a planned LED retrofit.

8.1.6 As shown in Table 8.1 below, the energy consumption for Rate 60 sales in 2013 was 73,027MWh, which, based on JPS's request, should have been adjusted downward to 44,715 MWh by 2018.

8.1.7 On the basis of the planned LED retrofit for street lighting, the Office approved a reduction in the energy sales billing determinant in the Rate 60 category. Rate 60 energy sales was adjusted downwards from 73,027MWh to 57,101MWh as shown in Table 8.2 below. This adjustment resulted in the Office approving a test year energy sales billing determinant of 2,979.8GWh.

8.1.8 In this regard, the existing tariff has already accounted for the projected reduction in streetlight sales attributable to the LED retrofit by JPS. Further, JPS has not provided any compelling reasons beyond those already factored into the existing billing determinants for the change.

Table 8.1: JPS's 2014 Proposed Street Lighting Replacement with LED

Street Lighting	Test Year	2014	2015	2016	2017	2018	Average
Level of replacement		25%	50%	75%	100%	100%	
Projected demand (MWh)	73,027	62,916	52,804	42,692	32,580	32,580	44,715

Table 8.2: OUR's Approved 2013 Test Year Billing Determinants

Customer Class	Customers	Energy (MWh)
RT 10 LV Res. Service ≤ 100 kWh	222,531	118,508
RT 10 LV Res. Service 101-500 kWh	301,954	710,037
RT 10 LV Res. Service > 500 kWh	14,116	157,095
RT 20 LV Gen. Service ≤ 100 kWh	24,842	11,145
RT 20 LV Gen. Service 101-1000 kWh	28,235	135,779
RT 20 LV Gen. Service 1001-7500 kWh	8,588	304,169
RT 20 LV Gen. Service > 7500 kWh	992	201,647
RT 60 LV Street Lighting	236	**57,101**
RT 40 LV Power Service (Std)	1,601	645,804
RT 40 LV Power Service (TOU)	121	121,303
RT 50 MV Power Service (Std)	104	411,322
RT 50 MV Power Service (TOU	27	105,893
Total	**603,346**	**2,979,803**

8.1.9 In addition, under the existing revenue cap regime there has been the decoupling of JPS's revenue requirement from its energy sales. Consequently, as alluded to earlier, if energy sales were to increase or decrease, JPS's revenues for any given tariff period would be capped/protected. This protection is carried out through the volumetric true-up mechanism that is now applicable in setting the rates.

8.1.10 Therefore, even though the OUR will revisit the impact of the LED technology on streetlight energy, the OUR is less than convinced that any change in the energy target is required at this time.

Determination 12

The Office rejects JPS's request for an adjustment to the non-fuel revenue change under the forward-looking model approach.

8.2 Pre-Paid Rates: Residential Customers (Rate 10)

8.2.1 JPS, in its submission, states that the company will continue to use the two-tiered tariff structure until the 2019-2024 Rate Review, when cost of service study will be presented. JPS intends to use the cost of service study to aid the company in delinking the revenue requirement of its post-paid customers from that of its pre-paid customers.

8.2.2 Based on JPS's forward-looking model approach and the rate design, which is dependent on the post-paid tariff, JPS's proposal for Rate 10 pre-paid rates are as follows:

- J$15.3488/kWh for the first 117 kWh within a thirty (30) day consumption cycle
- J$22.496/kWh for each additional kWh above 117kWh in a thirty (30)-day consumption cycle.

8.2.3 Table 8.3 below sets out JPS's position on pre-paid rates. Using JPS's proposed tariffs, and assuming that all residential customers migrate from post-paid to PAYG metering, JPS would be revenue-neutral for customers with consumption levels above 100kWh. However, for consumption levels below 100kWh, pre-paid customers would benefit in the amount of J$26.6 million/month using the two-tiered structure.

Table 8.3: Comparison of Pre and Post-paid Non-fuel Bills for average consumption in intervals (JPS) – Two-Tiered

Customer Bands	Customer Count	Test Year Demand (MWh)	Average Consumption (kWh/month)	Post-paid Rate	Pre-paid Rate	Monthly Post-paid Revenue	Monthly Pre-paid Revenue	Monthly Variance	Annual Variance
0-50 kWh	82,440	23,081	23.33	28.78	15.35	55,353,299.26	29,523,041.82	(25,830,257.44)	(309,963,089.28)
50-100 kWh	111,262	103,177	77.28	15.44	15.35	132,758,174.44	131,984,324.98	(773,849.46)	(9,286,193.52)
100-200 kWh	203,929	354,278	144.77	16.72	16.72	493,621,238.24	493,621,238.24	-	-
200-300 kWh	80,328	232,621	241.32	19.03	19.03	368,891,848.83	368,891,848.83	-	-
300-400 kWh	27,945	114,811	342.37	20.05	20.05	191,828,969.48	191,828,969.48	-	-
400-500 kWh	11,225	59,760	443.67	20.61	20.61	102,637,262.39	102,637,262.39	-	-
500- 1000 kWh	12,396	97,893	658.10	21.23	21.23	173,190,255.35	173,190,255.35	-	-
>1000 kWh	3,540	86,835	2,044.14	22.09	22.09	159,848,886.20	159,848,886.20	-	-
Total						1,622,776,635	1,622,002,785	(26,604,107)	(319,249,283)

8.2.4 The OUR-approved rates set out in Table 8.4 below shows the revenue comparisons of the pre-paid and post-paid rates using the assumption that all post-paid customers migrate to pre-paid metering. For consumption levels below 114kWh, pre-paid customers would benefit in the amount of J$28.6 million/month, using the two-tiered structure.

Table 8.4: Comparison of pre-paid and post-paid non-fuel bills for average consumption in intervals (OUR) – Two-Tiered

Customer Bands	Customer Count	Test Year Demand (MWh)	Average Consumption (kWh/month)	Post-paid Rate	Pre-paid Rate	Monthly Post-paid Revenue	Monthly Pre-paid Revenue	Monthly Variance (Pre - Postpaid)	Annual Variance
0-50 kWh	82,440	23,081	23.33	28.75	15.14	55,293,721	29,120,919	-26,172,803	-314,073,631
51-100 kWh	111,262	103,177	77.28	15.42	15.14	132,592,476	130,176,727	-2,415,749	-28,988,990
101-200 kWh	203,929	354,278	144.77	16.70	16.70	493,093,314	493,093,314	0	0
201-300 kWh	80,328	232,621	241.32	19.02	19.02	368,640,592	368,640,592	0	0
301-400 kWh	27,945	114,811	342.37	20.04	20.04	191,744,906	191,744,906	0	0
401-500 kWh	11,225	59,760	443.67	20.60	20.60	102,586,421	102,586,421	0	0
501- 1000 kWh	12,396	97,893	658.10	21.21	21.21	173,065,016	173,065,016	0	0
>1000 kWh	3,540	86,835	2,044.14	22.08	22.08	159,760,504	159,760,504	0	0
Total	533,065					1,621,483,230	1,619,067,480	-28,588,552	-343,062,622

8.2.5 The benefit of the lifeline rate is maintained with the pre-paid metering service. A typical customer consuming 82kWh for the month would pay approximately J$1,237.32 (non-fuel) using the post-paid service and J$1,241.50 (non-fuel) using the pre-paid service.

Determination 13

The approved non-fuel pre-paid rates are as follows:

(i) J$15.1402/kWh for the first 114kWh within a thirty (30)-day consumption cycle.

(ii) J$22.4876/kWh for each additional kWh thereafter within that thirty (30)-day consumption cycle.

The pre-paid rates shall be reviewed at the next Rate Review.

8.3 Pre-Paid Rates: Small Commercial Customers (Rate 20)

8.3.1 The pre-paid tariff for small commercial customers (Rate 20) was approved in the Jamaica Public Service Company Limited Annual Tariff Adjustment 2015 – Determination Notice Document No. Ele 2015/ELE/007DET.001 ("2015 Annual Tariff Adjustment Determination Notice"). JPS has not requested any change to the design of this tariff.

8.3.2 The JPS's proposed rates based on the forward-looking model are as follows:

- First 10kWh J$117.873/kWh
- Additional kWhs J$18.5592/kWh

8.3.3 The non-fuel tariff to be charged for this service shall remain revenue-neutral when compared to existing post-paid rates for Rate 20 customers. The approved non-fuel rate for Rate 20 post-paid customers was used to compute the pre-paid rates.

8.3.4 The rates to be charged are as follows:

- First 10kWh J$117.774/kWh
- Additional kWhs J$18.550/kWh

8.3.5 The analysis of the approved rates showing revenue neutrality is illustrated in Table 8.5 below.

Table 8.5: Comparison of prepaid and post-paid non-fuel bills for average consumption in intervals – Rate 20 Customers

Customer Bands	Customer Count	Test Year Demand (MWh)	Average Consumption (kWh/month)	Post-paid Rate	Pre-paid Rate	Monthly Post-paid Revenue	Monthly Pre-paid Revenue	Monthly Variance	Annual Variance
(0-50] kWh	10,940	2,778	21.16	65.44	65.44	15,149,448	15,149,448	-	-
(50-100] kWh	7,781	6,982	74.78	31.82	31.82	18,513,628	18,513,628	-	-
(100-1000] kWh	30,850	128,470	347.03	21.41	21.41	229,203,567	229,203,567	-	-
(1000-7500] kWh	9,482	283,614	2,492.56	18.95	18.95	447,827,725	447,827,725	-	-
>7500 kWh	1,002	218,449	18,172.28	18.60	18.60	338,679,193	338,679,193	-	-
Total						**1,049,373,560**	**1,049,373,560**	-	-

Determination 14

The approved non-fuel tariff to be charged for Rate 20 pre-paid service in comparison to the existing post-paid rates shall be revenue-neutral and shall be applied as follows:

First 10kWh J$117.774/kWh

Each additional kWh J$18.550/kWh

The pre-paid rates shall be reviewed at the next Rate Review

8.4 Revenue Basket Compliance

8.4.1 The requested annual adjustment resulting from changes in the inflation offset index, including efficiency gains and changes in the quality of service, are to be applied to the base-year revenue requirement. JPS is allowed to adjust the tariffs for each rate class on the basis that the percentage change does not result in an increase of the annual rate of change in non-fuel electricity revenues (dPCI) that is approved by the Office. The adjusted tariffs should also accord with the 2014-2019 Determination Notice and Addendum 1, whereby JPS is allowed to recover its revenue requirement by 23% fixed charges and 77% variable charges. The effective change in the non-fuel revenue is the dPCI offset by surcharges, less the cumulative movements due to foreign exchange rate changes.

8.4.2 The annual adjustment factor for the non-fuel base revenue of 19.772%[17] is adjusted to take account of revenue surcharge (RS_{2017}), foreign exchange surcharge (SFX_{2017}) and net

[17] Derived from dPCI = (dI = 19.284%) ± (Q = 0%) ± (Z = 0.488%)

interest expense/ (income) surcharge (SIC_{2017}). The cumulative change of 11.43% due to foreign exchange rate movements (Base Exchange $Rate_{2014}$ – US$1: J$112; Adjusted Billing Exchange $Rate_{2017}$ – US$1: J$128.00) is accounted for in customers' bills on a monthly basis. The effective increase in non-fuel rates is 0.71%. See Tables 8.6 and 8.7 below.

Table 8.6: Details of Annual Inflation Adjustments: 2018

Annual Non-Fuel Revenue Adjustment 2018	
Growth Rate in Inflation and Exchange Rate (dI) for 2017	19.28%
Z-Factor	0.49%
dI adjustment and Z-Factor	**19.77%**
Net change in Base Revenue Cap attributed to: Surcharge adjustment, Refinacing and Settlement, CPLTD, Smart Meter Expense & Extraordinary Review.	2.38%
Change attributed to Actual Non Fuel Revenue for 2017 (Already accounted for in customers' bills)	16.15%
Effective Change in Annual Non-Fuel Revenue for 2018	**0.71%**

Table 8.7: Details of Revenue Adjustments: 2018

Annual Non-Fuel Revenue Adjustment 2018 (J$)	
Base $Year_{2014}$ Non-Fuel Revenue Adjusted with X-Factor of 1.10% (RC_{2018})	**41,512,909,469**
Foreign Exchange, Interest and Non-Fuel Revenue Surcharges (SFX_{2017} - SIC_{2017} + RS_{2017})	(2,919,690,980)
Refinancing & Settlement Decision	773,867,700
CPLTD Adjustments (2018)	633,601,604
Smart Meter Expense	1,775,112,444
Extraordinary Rate Review	1,118,712,779
Adjustments to 2014 Rate Base (2017 Depreciation)	**260,585,618**
Annual Non-Fuel Revenue Target for 2018 (ART_{2018})	48,863,083,638
Actual Non-Fuel Revenue for 2017	48,520,723,317
Effective Change in Annual Non-Fuel Revenue for 2018	**342,360,321**

8.4.3 Table 8.8 below shows the OUR-approved annual adjustment factor of 0.71% that is applied to each revenue component in the revenue basket for the 2018-2019 regulatory period.

Table 8.8: Annual Non-Fuel Adjustment per Revenue Component: 2018-2019

Class		Block/Rate Option	Customer Charge	Energy Charge	Demand-J$/KVA Std.	Off-Peak	Part Peak	On-Peak
Rate 10	LV	–100	0.71%	0.71%				
Rate 10	LV	> 100	0.71%	0.71%				
Rate 20	LV		0.71%	0.71%				
Rate 40A	LV							
Rate 40	LV - Std		0.71%	0.71%	0.71%			
Rate 40	LV - TOU		0.71%	0.71%		0.71%	0.71%	0.71%
Rate 50	MV - Std		0.71%	0.71%	0.71%			
Rate 50	MV - TOU		0.71%	0.71%		0.71%	0.71%	0.71%
Rate 70	MV -STD		0.71%	0.71%	0.71%			
Rate 70	MV -TOU		0.71%	0.71%		0.71%	0.71%	0.71%
Rate 60	LV		0.71%	0.71%				

8.4.4 The adjustment to each revenue item in the revenue basket is weighted such that the sum of the weights does not exceed the total effective change of 0.71% as shown in the revenue basket of weights in Table 8.9 below.

Table 8.9: Annual Non-Fuel Adjustment per Revenue Component: 2017-2018

		Block/Rate Option	Customer Charge	Energy Charge	Demand-J$/KVA Std.	Off-Peak	Part Peak	On-Peak	
			Weighted increase						TOTAL
Rate 10	LV	–100	0.018%	0.074%	0.000%	0.000%	0.000%	0.000%	0.092%
Rate 10	LV	> 100	0.026%	0.175%	0.000%	0.000%	0.000%	0.000%	0.202%
Rate 20	LV		0.011%	0.171%	0.000%	0.000%	0.000%	0.000%	0.182%
Rate 40	LV - Std		0.002%	0.056%	0.058%	0.000%	0.000%	0.000%	0.116%
Rate 40	LV - TOU		0.000%	0.009%	0.000%	0.000%	0.003%	0.003%	0.017%
Rate 50	MV - Std		0.000%	0.016%	0.016%	0.000%	0.000%	0.000%	0.033%
Rate 50	MV - TOU		0.000%	0.004%	0.000%	0.000%	0.002%	0.002%	0.008%
Rate 70	MV -STD		0.000%	0.014%	0.014%	0.000%	0.000%	0.000%	0.028%
Rate 70	MV -TOU		0.000%	0.002%	0.000%	0.000%	0.001%	0.001%	0.005%
Rate 60	LV		0.000%	0.024%	0.000%	0.000%	0.000%	0.000%	0.024%
TOTAL			0.058%	0.546%	0.088%	0.001%	0.006%	0.006%	0.71%

8.4.5 Table 8.10 below shows the base year non-fuel basket of revenues that was approved by the Office in the 2014 – 2019 Determination Notice.

Table 8.10: Non-Fuel Base Year$_{2014}$ Revenue Basket

		Block/ Rate Option (kWh)	12 Months Test Year Customer Revenue (J$)	Energy Revenue (J$)	Demand (KVA) revenue (J$) Std.	Off-Peak	Part Peak	On-Peak	Total Demand Revenue (J$)	Total Revenue (J$)
Rate 10	LV	≤ 100	1,054,796,940	4,191,406,198	-	-	-	-		5,246,203,138
Rate 10	LV	>100	1,498,171,800	9,561,808,060	-	-	-	-		11,059,979,860
Rate 20	LV		661,657,920	10,600,519,280	-	-	-	-		11,262,177,200
Rate 40	LV - Std		119,114,400	3,267,765,943	3,624,517,296	-	-	-	3,624,517,296	7,011,397,639
Rate 40	LV - TOU		9,002,400	613,795,614	-	24,907,919	248,664,055	255,306,166	528,878,140	1,151,676,154
Rate 50	MV - Std		7,737,600	2,007,252,136	1,215,921,562	-	-	-	1,215,921,562	3,230,911,298
Rate 50	MV - TOU		2,008,800	516,756,352	-	38,607,274	366,976,668	391,469,455	797,053,397	1,315,818,549
Rate 60	LV		7,080,000	1,227,665,631	-	-	-	-		1,234,745,631
TOTAL			**3,359,569,860**	**31,986,969,214**	**4,840,438,858**	**63,515,193**	**615,640,723**	**646,775,621**	**6,166,370,395**	**41,512,909,469**

8.4.6 The Licence 2016 stipulates that for each year of the rate review period, the revenue cap parameter (RC_y) will be established without factoring inflation. During the annual adjustments, the inflation between the base year and the current adjustment period would be factored in through the dI parameter.

8.4.7 The approved revenue cap for 2018 (RC_{2018}) is derived as follows:

$$RC_{2018} = (\text{Approved Rev. Requirement 2014–2019 Determination Notice}) \times (1 - X)^4$$

Where: X represents the productivity efficiency factor

8.4.8 In the 2014 – 2019 Determination Notice, the productivity efficiency factor (X-Factor) was set at 1.10%. The factor (1-X) is cubed to account for the three adjustment periods from the establishment of the revenue cap (that is, for the periods: 2015-2016, 2016-2017, 2017-2018 and 2018-2019 adjustment periods).

Hence,

$$RC_{2018} = \$41{,}773{,}495{,}087.12^{18} \text{ x } 0.95672 = \$39{,}965{,}567{,}070.24$$

8.4.9 Table 8.11 below shows the actual basket of revenues that was collected by JPS for 2017 on which the annual adjustment rate of 0.56% is applied.

Table 8.11: Actual Revenues Collected: 2017

Class		Block/Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA				Total Revenue
					Std.	Off-Peak	Part Peak	On-Peak	
Rate 10	LV	--100	1,229,825,054	5,072,968,512	0	0	0	0	6,302,793,566
Rate 10	LV	> 100	1,803,478,876	12,061,702,541	0	0	0	0	13,865,181,417
Rate 20	LV		776,444,976	11,747,160,631	-	-	-	-	12,523,605,606
Rate 40	LV - Std		141,460,612	3,837,255,225	3,989,916,990	-	-	-	7,968,632,827
Rate 40	LV - TOU		9,489,482	650,234,764	-	22,875,864	233,261,961	235,480,039	1,151,342,110
Rate 50	MV - Std		9,676,911	1,119,967,709	1,116,557,227	-	-	-	2,246,201,847
Rate 50	MV - TOU		1,950,654	288,718,290	-	14,124,417	128,278,041	121,769,790	554,841,192
Rate 70	MV -STD		1,582,737	944,375,230	969,750,858	-	-	-	1,915,708,825
Rate 70	MV -TOU		312,382	161,161,434	-	8,253,871	79,971,186	87,378,752	337,077,626
Rate 60	LV		14,451,908	1,640,886,392	-	-	-	-	1,655,338,300
TOTAL			3,988,673,592	37,524,430,728	6,076,225,075	45,254,152	441,511,188	444,628,582	48,520,723,317

[18] Accelerated depreciation amounting to J$260,585,618 was approved by the Office in the 2017 Tariff Determination Notice as an addition to the 2014 revenue cap of J$41,512,909,469. Therefore, J$41,512,909,469 + J$260,585,618 = J$41,773,495,087.

8.4.10 Table 8.12 below shows the approved annual revenue target for 2018 after applying the effective increase of 0.71% on actual revenues collected for 2017.

Table 8.12: Approved Annual Revenue Target: 2018

Class		Block/Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA Std.	Demand-J$/KVA Off-Peak	Demand-J$/KVA Part Peak	Demand-J$/KVA On-Peak	Total Revenue
									0
Rate 10	LV	–100	1,238,502,651	5,108,763,179	0	0	0	0	6,347,265,830
Rate 10	LV	> 100	1,816,204,152	12,146,809,442	0	0	0	0	13,963,013,594
Rate 20	LV		781,923,541	11,830,048,136	-	-	-	-	12,611,971,677
Rate 40A			-	-	-	-	-	-	-
Rate 40	LV - Std		142,458,752	3,864,330,748	4,018,069,688	-	-	-	8,024,859,188
Rate 40	LV - TOU		9,556,439	654,822,795	-	23,037,275	234,907,848	237,141,577	1,159,465,935
Rate 50	MV - Std		9,745,191	1,127,870,157	1,124,435,611	-	-	-	2,262,050,959
Rate 50	MV - TOU		1,964,418	290,755,475	-	14,224,078	129,183,166	122,628,993	558,756,130
Rate 70	MV -STD		1,593,905	951,038,704	976,593,382	-	-	-	1,929,225,991
Rate 70	MV -TOU		314,587	162,298,583	-	8,312,110	80,535,459	87,995,293	339,456,032
Rate 60	LV		14,553,880	1,652,464,422	-	-	-	-	1,667,018,302
TOTAL			**4,016,817,517**	**37,789,201,640**	**6,119,098,681**	**45,573,463**	**444,626,474**	**447,765,863**	**48,863,083,638**

8.4.11 Table 8.13 below shows the actual 2017 billing determinants (extracted from JPS's CIS) as presented by JPS. These billing determinants were accepted and approved by the OUR to be the target billing determinants for 2018. The billing determinants were applied to the approved revenue requirement to derive the tariffs for the 2018-2019 period.

Table 8.13: Actual Billing Determinants: 2017

Class		Block/ Rate Option	Average 2017 Customer	Energy kWh Std.	Demand-KVA Std.	Demand-KVA Off-Peak	Demand-KVA Part Peak	Demand-KVA On-Peak
Rate 10	LV	<100	231,726	528,985,246	-	-	-	-
Rate 10	LV	>100	339,815	540,156,854	-	-	-	-
Rate 20	LV		65,670	637,739,448	-	-	-	-
Rate 40	LV - STD		1,698	669,678,050	2,244,666	-	-	-
Rate 40	LV - TOU		114	113,479,016	-	305,174	298,247	235,148
Rate 50	MV -STD		116	202,525,806	701,170	-	-	-
Rate 50	MV -TOU		23	52,209,456	-	198,907	185,127	136,969
Rate 70	MV -STD		19	256,623,704	639,842			
Rate 70	MV -TOU		4	43,793,868		121,649	119,705	101,808
Rate 60	STREETLIGHTS		430	68,313,339	-	-	-	-
TOTAL			**639,615**	**3,113,504,786**	**3,585,678**	**625,731**	**603,079**	**473,926**

8.4.12 Table 8.14 below shows the approved non-fuel tariffs 2018-2019 for each rate category. These rates were derived by applying the billing determinants in Table 8.13 above to the approved revenue target of J$48,863,083,638 which is reported in Table 8.12 above.

Table 8.14: Approved Non-Fuel Tariffs: 2018-2019

Class		Energy-J$/kWh Block Rate Option	Energy-J$/kWh Customer Charge J$/Mth	Energy-J$/kWh Energy Charge J$/kWh	Demand-J$/KVA Std.	Demand-J$/KVA Off-Peak	Demand-J$/KVA Part Peak	Demand-J$/KVA On-Peak
Rate 10	LV	–100	445.39	9.66	-	-	-	-
Rate 10	LV	> 100	445.39	22.49	-	-	-	-
Rate 20	LV		992.24	18.55	-	-	-	-
Rate 40	LV - Std		6,990.81	5.77	1,790.05	-	-	-
Rate 40	LV - TOU		6,990.81	5.77	-	75.49	787.63	1,008.48
Rate 50	MV - Std		6,990.81	5.57	1,603.66	-	-	-
Rate 50	MV - TOU		6,990.81	5.57	-	71.51	697.81	895.30
Rate 70	MV -STD		6,990.81	3.71	1,526.30	-	-	-
Rate 70	MV -TOU		6,990.81	3.71	-	68.33	672.78	864.33
Rate 60	LV		2,818.88	24.19	-	-	-	-

8.4.13 Tables 8.15 and 8.16 below show the overall estimated bill impact[19] of the combination of the non-fuel tariff adjustment and the revised fuel rate (adjusted for full pass-through of system losses and the revised heat rate target). The impact was estimated with the use of data that was implemented in the 2018 June billing.

8.4.14 With the OUR-determined rates, the typical residential and small commercial customers (Rate 10 and Rate 20) would have seen an increase of 0.30% on average in the total balance on their bills, while the typical large commercial customers (Rate 40, Rate 50 and Rate 70) would have seen a reduction of 0.40%. On the other hand, with the JPS-proposed rates, residential and small commercial customers would have seen on the average a 1.4% increase, while the typical larger commercial customers would have seen a 1.0 % increase in the total balance on their bills.

Table 8.15: Estimated Bill Impact of OUR's Determined Annual Tariff Adjustment

Customer Class	Overall Bill Impact of the OUR Approved Rates			
	Typical Usage (kWh)	Demand (kVA)	Total Bill Impact (%)	Average Change (%)
RT 10 LV Res. Service < 100 kWh	90	n/a	0.0%	0.2%
RT 10 LV Res. Service 101-150 kWh	150	n/a	0.2%	
RT 10 LV Res. Service > 150 kWh	200	n/a	0.3%	
RT 20 LV Gen. Service < 100 kWh	90	n/a	0.8%	0.4%
RT 20 LV Gen. Service 100-1000 kWh	1,000	n/a	0.3%	
RT 20 LV Gen. Service 1000-7500 kWh	5,000	n/a	0.3%	
RT 20 LV Gen. Service > 7500 kWh	8,000	n/a	0.3%	
RT 40 LV Power Service (Std)	35,000	100	-0.2%	-0.4%
RT 50 MV Power Service (Std)	500,000	1,500	-0.3%	
RT 50 MV Power Service (TOU-Partial Peak)	500,000	1,500	-0.6%	
RT 70 Power Service (Std)	500,000	2,000	-0.4%	-0.5%
RT 70 Power Service (TOU-Partial Peak)	500,000	2,000	-0.7%	
Efficiency Targets:	**System Losses Target**		**JPS Thermal Heat Rate Target**	
	Full Pass Through on Fuel		11,450 kJ/kWh	

[19] The bill impact was estimated on data received from JPS for May 2018 billing for electricity consumed in April 2018.

Table 8.16: Estimated Bill Impact of JPS's Proposed Annual Tariff Adjustment

Customer Class	Overall Bill Impact of the JPS Proposal			
	Typical Usage (kWh)	Demand (kVA)	Total Bill Impact (%)	Average Change (%)
RT 10 LV Res. Service < 100 kWh	90	n/a	1.2%	1.3%
RT 10 LV Res. Service 101-150 kWh	150	n/a	1.3%	
RT 10 LV Res. Service > 150 kWh	200	n/a	1.3%	
RT 20 LV Gen. Service < 100 kWh	90	n/a	1.6%	1.4%
RT 20 LV Gen. Service 100-1000 kWh	1,000	n/a	1.4%	
RT 20 LV Gen. Service 1000-7500 kWh	5,000	n/a	1.4%	
RT 20 LV Gen. Service > 7500 kWh	8,000	n/a	1.4%	
RT 40 LV Power Service (Std)	35,000	100	1.1%	1.0%
RT 50 MV Power Service (Std)	500,000	1,500	1.0%	
RT 50 MV Power Service (Std)	500,000	1,500	0.9%	
RT 70 Power Service (Std)	500,000	2,000	1.0%	0.9%
RT 70 Power Service (TOU-Partial Peak)	500,000	2,000	0.8%	
Efficiency Targets:	System Losses Target		JPS Thermal Heat Rate Target	
	Full Pass Through on Fuel		11,482 kJ/kWh	

8.5 Community Renewal Programme (CRP)

8.5.1 The Office, in its 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice, gave approval to JPS to extend the community renewal tariff to beneficiaries of the PATH programme. JPS states that the company has since been working with the administrators of the PATH programme to implement the rate.

<u>Community Renewal Rate</u>

8.5.2 The community renewal rate, which was introduced by JPS, was approved by the Office in the 2015 Annual Tariff Adjustment Determination Notice. The rate has been in effect since then and JPS is now requesting an approval of the amount of $9.67/kWh, for both post-paid and pre-paid customers, based on assumptions in its forward-looking model submission.

8.5.3 The approved rate for the 2018-2019 regulatory period is J$9.66/kWh for consumption up to 150kWh for both the post-paid and pre-paid customers. No customer charge will be applied to bills less than 150kWh.

8.5.4 Customers consuming more than 150kWh per month will pay the regular pre-paid or post-paid rate, whichever is applicable for the incremental consumption above 150kWh per month.

8.5.5 JPS is being reminded that the rate to be charged should accord with Condition 14(1) of the Licence 2016 that is, "Charges and Terms and Conditions for the Supply of Electricity", which states that:

"The Licensee shall, save where it enters into special contracts with customers for the Supply of electricity pursuant to section 14 of the OUR Act, charge its customers for such a Supply according to published rates, approved by the Office, as updated from time to time. Such published rates shall be cost-reflective, unless otherwise directed by the Office. Each rate category will apply uniformly across the Island and there will be no discrimination to customers on the rate charged based on location."

8.5.6 The OUR maintains that there should be no discrimination in the tariff charged in each rate category.

Determination 15

The approved Community Renewal Rate to be charged for Rate 10 service is a flat rate of J$9.66/kWh for consumption up to 150kWh for both the post-paid and pre-paid customers. No customer charge will be applied to bills less than 150kWh.

Customers consuming more than 150kWh per month will pay the regular pre-paid or post-paid rate, whichever is applicable for the incremental consumption above 150kWh per month.

9.0 Fuel Cost Adjustment Mechanism - Heat Rate

9.1 Fuel Efficiency Adjustment

9.1.1 A significant portion of JPS's monthly operating expenses is related to the cost of fuel consumed by both JPS's and IPPs' thermal generating plants, which are used to produce the electrical energy required to supply aggregate System demand.

9.1.2 For a given billing period, the total fuel cost (US$) incurred, is largely dependent on the following factors:

1) The price and quantity of fuel consumed by JPS's and IPPs' generating plants;
2) The fuel conversion efficiencies (Heat Rates) of JPS's and IPPs' thermal generating plants;
3) The system total net generation (kWh) for the billing period;
4) The utilization level of each available generating unit in the dispatch process; and
5) The fuel supply mix and the contribution of each generating unit to System total net generation.

9.1.3 It therefore follows that the total fuel cost in each billing period (monthly) will likely differ, given the propensity for changes to one or more of the above factors.

9.1.4 Based on the current price control regime, each month the total fuel cost for the System is recovered through the monthly Fuel Rate (J$/kWh), calculated in accordance with the Fuel Cost Adjustment Mechanism (FCAM) defined under Schedule 3 of the Licence 2016. That is, for a given billing month, JPS is required to calculate the applicable Fuel Rate based on the System's total fuel cost, relevant energy quantities and efficiency adjustment parameters. Importantly, these Fuel Rate calculations are subject to the review and validation of the OUR as part of its regulatory monitoring framework. JPS then uses the applicable Fuel Rate to bill consumption (kWh) across its customer base, in order to recover the total fuel cost incurred.

9.1.5 As reflected in Exhibit 2 of Schedule 3 of the Licence 2016, JPS is allowed to recover its monthly fuel costs through the monthly Fuel Rate, derived in accordance with the defined FCAM, which has been in effect since 2016 July 1, and represented mathematically in the formula below.

$$\textit{Pass Through Cost} = \left[\textit{IPPs Fuel Cost (subject to PPAs)} + \left(\textit{JPS Fuel Cost} \times \left(\frac{\textit{JPS Heat Rate Target}}{\textit{JPS Heat Rate Actual}}\right)\right)\right]$$

9.1.6 According to the FCAM, the monthly Fuel Rates are derived from the monthly total fuel costs (IPPs and JPS), net of efficiency adjustment.

9.1.7 ***Efficiency Adjustment to IPPs' Fuel Cost:*** For cost recovery, the IPPs' component of the monthly total fuel costs reflects the cost adjusted by the IPPs' contracted Heat Rates as per their respective power purchase agreements (PPAs). As such, no Heat Rate targets are required to be determined for the IPPs.

9.1.8 ***Efficiency Adjustment to JPS's Fuel Cost:*** Based on the FCAM, JPS's portion of the monthly total fuel cost is subject to adjustment by a fuel conversion efficiency factor. That is the ratio of the OUR's determined Heat Rate target to the JPS generating Heat Rate. This efficiency adjustment approach is an implicit incentive scheme designed to encourage JPS to improve its operational efficiency as well as to optimize its generation dispatch operations. The embedded incentive mechanism innately delivers financial benefits or penalties to the extent that there is any over-achievement or under-achievement of the determined Heat Rate target. The rates are also adjusted to account for movements in the exchange rate between the United States dollar (US$) and the Jamaican dollar (J$).

9.2 The Heat Rate Target

Background

9.2.1 The Heat Rate target focuses on the System's generation operations and benchmarks how efficiently generating units owned and operated by JPS and IPPs convert input fuel (kJ or BTU) into electrical energy (kWh). The Heat Rate target for the 2017-2018 regulatory period was set at **11,450 kJ/kWh**. In this regard, to the extent that the monthly Heat Rate exceeds this ceiling, JPS is prevented from passing through costs related to fuel penalties as a consequence of its failure to meet the Heat Rate target, to customers. Conversely, to the extent that the monthly Heat Rate surpasses the target, then the JPS is permitted to pass through its fuel costs to customers on a dollar-for-dollar basis plus the additional revenues applied as a reward for over-achievement of the target.

JPS's Heat Rate Proposal

9.2.2 For the 2018-2019 regulatory period, JPS proposed a Heat Rate target of **11,482 kJ/kWh**. To justify this proposal, JPS argued that although the overall heat rate performance has improved, the 2018-2019 adjustment period will see JPS having to dispatch a thermal fleet which is a year older amongst aging IPP units as well. According to JPS, the proposed Heat Rate is needed to assist JPS to at least partially mitigate negative impacts to JPS's thermal assets; to mitigate any hindrance to JPS's ability to fully recover on its fuel costs, and ultimately its ability to serve its customers.

Assessment of JPS's 2017-2018 Heat Rate Performance

9.2.3 At the 2017 Annual Review, the OUR adjusted JPS's Heat Rate target downward from 11,620 kJ/kWh to 11,450 kJ/kWh. This target was considered to be reasonable and achievable based on the technical configuration and operational capability of the generation system.

9.2.4 Given the reported Heat Rate outcomes, the OUR is of the view that the approach employed for setting the Heat Rate targets is prudent and reasonable and consistent with good regulatory practice. Additionally, the performance levels being achieved indicate that the Heat Rate targets have been effective in incentivizing JPS to improve the overall fuel conversion efficiency of its thermal generating plants.

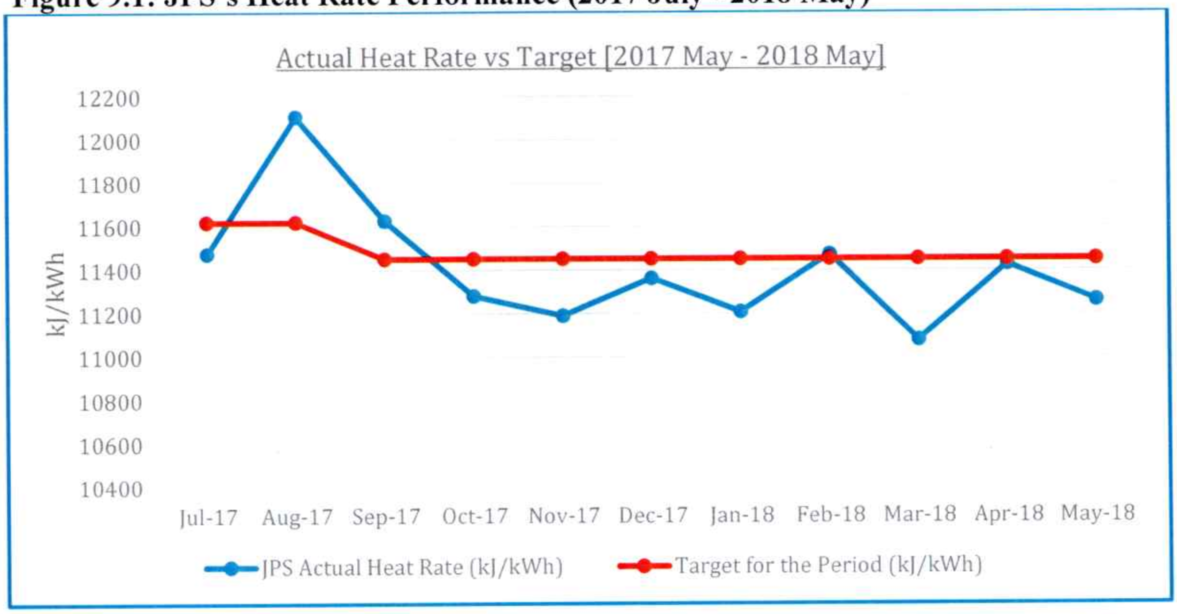
9.2.5 Based on JPS's performance data, the monthly Heat Rate (thermal plants) recorded for the 2017-2018 regulatory period to date, is provided in Table 9.1 and Figure 9.1 below.

Table 9.1: JPS's Thermal Generating Plants Heat Rate (2017 July - 2018 May)

JPS's Thermal Generating Plants Heat Rate Performance (2017-2018)													
(kJ/kWh)	2017 JUL	2017 AUG	2017 SEP	2017 OCT	2017 NOV	2017 DEC	2018 JAN	2018 FEB	2018 MAR	2018 APR	2018 MAY	2018 JUN	AVE
Heat Rate	11,415	12,109	11,628	11,281	11,191	11,360	11,208	11,472	11,079	11,425	11,261	-	11,401
Target	11,620	11,620	11,450	11,450	11,450	11,450	11,450	11,450	11,450	11,450	11,450	11,450	11,467
Variance	-205	489	178	-169	-259	-90	-242	22	-371	-25	-189	-	-66

9.2.6 As shown in Table 9.1 above, the actual monthly Heat Rates ranged between 11,079 kJ/kWh to 12,109 kJ/kWh (spread of 1,050 kJ/kWh), yielding an average monthly Heat Rate of 11,401 kJ/kWh. This is within 1% of the target and translates to an over-achievement of 66 kJ/kWh on average each month, in favour of JPS (see Annex 7 for details of the fuel rate assessment).

Figure 9.1: JPS's Heat Rate Performance (2017 July - 2018 May)



The OUR's Position

9.2.7 Based on the Licence 2016 requirements as referenced in the relevant sections above, and consistent with the 2016 Annual Tariff Adjustment Determination Notice and 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice, the OUR has determined that:

- The Heat Rate (actual) to be used by JPS in the defined FCAM for efficiency adjustment each month shall be in relation to JPS's thermal generating plants.
- The target for the Heat Rate target shall continue to be based on JPS's thermal generating plants.

9.2.8 Having reviewed JPS's Heat Rate proposal, the proposed Heat Rate target of 11,482 kJ/kWh is not approved on the basis that:

- It is not corroborated by a Heat Rate Model submitted by JPS.
- Elements of the 2018-2019 Heat Rate projections appear to be inconsistent with the technical configuration and operational capability of JPS's thermal generating system.
- Improvement in the generation dispatch operations could realize higher efficiencies.

9.2.9 Based on OUR's Heat Rate evaluation and giving due consideration to risks of breakdowns given the age of its base load plants and its maintenance plan for the Bogue Combined Cycle plant, the Office has determined that the Heat Rate target for JPS's thermal generating system for the 2018-2019 regulatory period should be kept at the existing level of **11,450 kJ/kWh.**

Determination 16

The Office has assessed JPS's heat rate proposal for the 2018-2019 review period and has determined that the company's heat rate for the 2018-2019 period shall be **11,450 kJ/kWh**.

10.0 The SSP, the EEIF and SBF

10.0.1 In its 2018 Annual Review submission, JPS proposed that the OUR approve a direct set-off of the total capital expenditure cost of the SSP against the determined present and future liability to the EEIF.

10.1 The Smart Street Light Programme (SSP)

10.1.1 The SSP is the name given by JPS for the installation of LED streetlights enabled with smart technology to replace the existing 105,000 mostly HPS lamps. Condition 28 of the Licence 2016 mandated JPS to commence the programme by 2016. The Licence 2016 also directs the OUR to utilise "a Fund or the System Benefit Fund (as defined in the EA)," as the mechanism for JPS to recover the cost of the SSP.

10.2 The Energy Efficiency Improvement Fund (EEIF)

10.2.1 The EEIF was a customer-contributed fund which was introduced by the OUR in 2009 for the primary purpose of augmenting JPS's capital expenditure on system losses initiatives with the objective of accelerating loss reduction. The EEIF was established with an initial annual revenue intake of US$13,000,000 and was financed by way of an incremental rate of 0.4 US₵/kWh on JPS's customers' bills. The final rules of operation of the EEIF was established by the OUR in 2011.

10.2.2 According to JPS in its 2018 Annual Review submission, by 2016 December, the EEIF had funded assets totaling US$60.6M.

10.3 The System Benefit Fund (SBF)

10.3.1 Section 50 of the Electricity Act, 2015 establishes the SBF, and specifies that it should be administered and controlled by the Office. Subsections (2) and (3) of section 50 of Electricity Act, 2015 prescribes the sources of financing and the permitted usage of the SBF as follows:

2) "The System Benefit Fund shall be financed from -
- *a) tariffs, as the Office may direct;*
- *b) fines collected pursuant to this Act;*
- *c) monies from the Consolidated Fund;*
- *d) any other source.*

3) The resources of the System Benefit Fund shall be utilized –
- *a) to increase the penetration of renewable energy or energy security;*
- *b) for the promotion of energy conservation;*
- *c) for the purpose of providing electricity to rural areas; and*

d) *for any other purpose that the Minister may prescribe by Order published in the Gazette."*

10.4 Relationship between the EEIF, SBF and SSP

10.4.1 In its 2016 Annual Tariff Adjustment Determination Notice, the OUR reduced the intake of revenues into the EEIF by 50% based on evidence that the system losses initiatives funded by the EEIF had not been effective in achieving the established system losses reduction objectives. JPS in its 2017 Annual Review and Extraordinary Rate Review submission proposed that the EEIF be discontinued and the SBF be initiated instead. Subsequent to JPS's submission, and prior to the Office issuing its 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice, the Ministry of Science, Energy and Technology (MSET) requested that the OUR replace the EEIF with the SBF, which was to be funded with an initial annual amount of US$5M and indicated that the proceeds of the SBF be used to allow JPS to recover the cost of implementing its SSP under the Licence 2016. The Ministry's request was later gazetted in the Electricity Act (System Benefit Fund) Order, 2017 dated 2017 August 16.

10.4.2 The OUR approved the discontinuation of the EEIF and established the SBF in the 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice. The evidence from a preliminary audit commissioned by the OUR and calculations done by JPS had suggested that:

a) At the end of 2016, JPS owed the EEIF US$17.4 million by way of cumulative capital allowance tax benefits since its introduction in 2009;
b) Additional tax benefits would be due to the EEIF in 2017 and beyond;
c) There was the need for a reconciliation of the EEIF expenditures against the revenue inflows to determine the residual sum to be transferred from the EEIF to the SBF.

10.4.3 Therefore, the OUR determined that the initial source of funding of the SBF was to be a transfer of residual funds and any obligations outstanding from the EEIF to the SBF. The OUR also determined that JPS was to make initial payments of US$500,000 per month for ten (10) months, commencing 2017 September, for an accumulated total of US$5M by 2018 June. However, following a request made by JPS, the OUR approved the delay of the commencement of the payments to SBF to 2018 January 2018 at an accelerated funding rate that would still achieve the US$5M total by 2018 June.

10.4.4 The OUR then directed JPS to engage an auditor to determine the outstanding amount due to the EEIF as at 2018 June 30, and any further amounts due from the capital tax allowances extending into future years. JPS engaged KPMG to conduct this exercise and presented the results of the audit to the OUR on 2018 July 13. The results of the audit are discussed below.

10.5 OUR's Assessment of JPS's SSP Proposal

10.5.1 JPS indicated in its 2018 Annual Review submission that the SSP commenced on schedule in 2016 December and at year end 2017, 36,440 lamps were installed, exceeding the 35,000 year-end target by 4.1%. JPS stated that phase II of the SSP project was scheduled to commence in 2018 June following a second round of procurement to ensure the programme and customers continue to reap gains from a beneficial cost curve for LED luminaires. The programme targets and planned capital expenditure schedule are shown in Table 10.1 below.

Table 10.1: SSP Installation Schedule and Capital Expenditure

	Unit	2017	2018	2019	Total
Installations	*No.*	*36,440*	*5,000*	*63,560*	***105,000***
Contract and Services	S$'000	1,327	374	4,752	**6,453**
Material Cost	S$'000	8,485	1,327	17,852	**27,664**
Other	US$'000	2,185	822	1,726	**4,733**
Total	**US$'000**	**11,997**	**2,523**	**24,330**	**38,850**

10.5.2 Table 10.1 shows that JPS spent US$11,997,000 in 2017 and is projected to spend an additional US$2,523,000 on the SSP, thus, JPS is projected to spend a total of US$14,520,000 by the end of 2018. According to JPS, it has utilized its own capital to operationalize the SSP to meet the mandated Licence 2016 implementation schedule.

10.5.3 The OUR agrees with JPS that provided in the Licence 2016, the financing of the SSP should be from a fund which could either be the SBF or another fund. Under powers conferred in the Electricity Act, 2015, the Minister has, by Order authorized the financing of the SSP from the SBF which, as of 2018 June, would have had an accumulated intake of US$5M from JPS. The OUR is however in the process of establishing the Rules of the SBF and in addition, has not yet determined what other projects, if any, is to be funded by the SBF in 2018. At this stage therefore, it is premature for the OUR to allocate the monies from the SBF to the SSP without proper regard to the rules of operationalization and other financing needs.

10.5.4 The OUR is of the view that the residual funds owing to the EEIF, representing capital allowance tax benefits, is a viable alternative for financing the SSP. As suggested by JPS in its submission, the direct set-off of the total capital expenditure cost of the SSP against the determined present and future liability to the EEIF obviates the immediate need to adjust tariffs for customers to fund the SBF to the level that is required to support the SSP. Financing the SSP from the funds owed by JPS to the EEIF is also not inconsistent with the funding mechanism prescribed in Condition 28 of the Licence 2016, which permits the Office to either utilize the SBF or some other "Fund" to allow JPS to recover the costs of implementing the SSP.

10.5.5 The audit conducted by KPMG on behalf of JPS reviewed and re-computed the capital allowances to determine the accuracy of the calculation of the tax benefits due to the EEIF covering the period 2009 January – 2017 December. In addition, KPMG calculated the future tax benefits for all qualifying assets from 2018 January 1, up to the point where the assets are fully written down for tax purposes.

10.5.6 The results of KPMG's assessment indicated that the preliminary assessment of the residual credits was imprecise, because its calculation was more general and did not focus on the specific assets involved. Table 10.2 below shows the tax benefits from 2009 to 2017 and the projected benefit to the end of 2018. This may be summarized as follows:

- The total amount due to the EEIF up to 2017 December is US$14.4M and is projected to be US$16.2M up to the end of 2018.
- The future benefits beyond 2018 amount to US$12.3M.

10.5.7 In keeping with the consultation process, the OUR shared its Draft Annual Review 2018 & Extraordinary Rate Review Determination Notice (Draft Determination Notice) with JPS to which JPS provided feedback. In its response to the Draft Determination Notice, JPS indicated that its management had determined that only 76% of the amount calculated by KPMG was owing to the EEIF as JPS had contributed fund to investments in losses reduction assets. JPS further indicated that KPMG's report confirmed (via the investment allowance) that up to the end of 2017, a cumulative total of US$83.6M of investments were made for loss reduction assets while the amount contributed by the EEIF was $63.6M, thus, only 76% of the capital allowances are due to the EEIF.

10.5.8 The OUR does not dispute that the cumulative investments from the EEIF up to the end of 2018 was U$63.6M dollars and accepts the KPMG's results which shows that investment allowances between 2009 and 2017 was US$16.7M implying that cumulative investments up to the end of 2017 was US$83.6M. JPS had suggested in its feedback to the Draft Determination Notice that the 76% allocation could be used uniformly to determine the proportion of the tax allowances that were outstanding to the EEIF as shown in Table 10.3 which shows JPS' management calculations.

Table 10.2: JPS' Management Calculation of the amount Liabilities to the EEIF

	2009 US$	2010 US$	2011 US$	2012 US$	2013 US$	2014 US$	2015 US$	2016 US$	2017 US$	Projected 2018 US$	Total US$
Tax Impact: Capital Allowance (US$)	33,713	1,044,984	694,759	1,784,812	2,902,496	1,344,515	1,479,963	1,888,173	3,214,447	1,856,963	
Proportion of EEIF funding to total asset cost	76%	76%	76%	76%	76%	76%	76%	76%	76%	76%	
Tax Impact: Capital Allowance (US$) - Customer funded	**25,678**	**795,940**	**529,182**	**1,359,450**	**2,210,763**	**1,024,086**	**1,127,253**	**1,438,177**	**2,448,369**	**1,414,405**	**12,373,304**

10.5.9The OUR disagrees with the approach suggested by JPS in Table 10.2 as it does not factor annual variations in the proportion of investments made by the EEIF versus JPS' contribution. Further, when the costs are brought to present value using the opportunity cost as the discount rate, these variations will become meaningful. The OUR is also unable to determine these annual variations as the KPMG's report did not shed light on this. As such, the OUR is unable to determine the exact amount owing to the EEIF without conducting a further audit of the EEIF.

10.5.10 The OUR will in the interim allow JPS to set-off the SSP costs against the EEIF liabilities up to the end of 2018. JPS will be compensated for the use of its own capital in 2017 by allowing it to recover the opportunity cost for that year. This opportunity cost amount and the total amount of capital expenditure recoverable by JPS are calculated as shown in Table 10.3 below.

Table 10.3: Capital Expenditure recoverable by JPS

	Unit	Value
Capital Spend on SSP in 2017	US$	11,997,000
WACC	%	13.22%
Opportunity Cost	US$	1,586,003
Total Amt. due to JPS for 2017 expenditure	US$	13,583,003
Total Amount projected for 2018	US$	2,523,000
Total Amount of set-off required	**US$**	**16,106,003**

10.5.11The OUR will allow JPS to immediately set-off the SSP costs incurred in 2017 and the cost to be incurred on the programme by the end of 2018 (which totals US$16.6M). The reconciliation of the amounts owing to the EEIF will be done at the 2019 – 2024 Rate Review by which time the OUR expects to determine annual inflows and outflows from the fund to make a final determination on the amount of liability.

10.5.12JPS, in its response to the Draft Determination Notice, indicated that in the calculation of the total amount owing to the EEIF, the WACC should be excluded. JPS argued that the price cap mechanism that existed prior to 2016 did not enable it to earn a return on investments made since 2014 and that in addition, its actual rate of return is an average 6.2% and not what was approved by OUR in 2015. JPS also surmised that the high level of GoJ receivables did not allow it to obtain a cash benefit from the capital tax allowance.

10.5.13 The Licence 2016 explicitly provides an opportunity cost mechanism in the annual revenue target adjustment formula to allow JPS to recover opportunity cost at the rate of the WACC on revenues forgone and other expenses such as FX losses. Since 2016, JPS has also made submissions to the OUR requesting the recovery of opportunity costs for monies being claimed. The regulatory precedent for including opportunity cost using the WACC has therefore been established by the Licence 2016 and the claims that JPS has since made for the recovery of opportunity cost.

10.5.12 The OUR accepts that prior to 2016, no formal mechanism for the recovery of opportunity cost was embedded in the tariff mechanism, however, precedent for the treatment of opportunity cost was established by a Tribunal Decision in 2012. JPS had appealed the OUR's decision not to award opportunity cost at the WACC for expenses made in response to JPS' Hurricane Ivan recovery effort. The OUR had argued that the cost of debt was the more appropriate opportunity cost to apply and the Tribunal had agreed with the OUR's arguments. JPS' was allowed to recover opportunity cost losses using the cost of debt as the appropriate rate. Prior to the Licence 2016, the cost of debt was the mechanism used to compensate JPS for opportunity cost, if such costs were claimed. The OUR therefore considers it reasonable that the opportunity cost should be calculated using the cost of debt between 2009 and 2015 while the WACC shall be applied between 2016 and 2018.

10.5.11 In addition, in keeping with good regulatory practice, the OUR will require that a special audit be done of JPS's SSP expenditures for 2017 and 2018. This is to ensure that there is no under- or over-recovery of any legitimate costs incurred in the roll-out of the SSP.

Determination 17

The Office has determined that:

(i) JPS shall set-off US$16,106,003 of capital expenditure for the Smart Streetlight Programme (inclusive of the opportunity cost) up to 2018 December against the residual amounts owing to the EEIF.

(ii) JPS shall be required to submit to the OUR, the result of independent audit of its Smart Streetlight Programme expenditures for 2018 and 2019 before the end of the 1st quarter, 2019.

(iii) The OUR will determine the future payments into the SBF from any residual amounts owing to the EEIF in the 2019 – 2024 Rate Review.

ANNEXES

ANNEX 1: US and Jamaican Inflation Consumer Price Indices

1.1 U.S. Consumer Price Index

U.S. Consumer Price Index - All Urban Consumers

Series Id: CUUR0000SA0
Not Seasonally Adjusted
Area: U.S. city average
Item: All items
Base Period: 1982-84=100

The Consumer Price Index (CPI-U) is compiled by the Bureau of Labor Statistics and is based upon a 1982 Base of 100. A Consumer Price Index of 168 indicates 68% inflation since 1982. The commonly quoted inflation rate of say 3% is actually the change in the Consumer Price Index from a year earlier.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual	HALF1	HALF2
2000	168.8	169.8	171.2	171.3	171.5	172.4	172.8	172.8	173.7	174.0	174.1	174.0	172.2	170.8	173.6
2001	175.1	175.8	176.2	176.9	177.7	178.0	177.5	177.5	178.3	177.7	177.4	176.7	177.1	176.6	177.5
2002	177.1	177.8	178.8	179.8	179.8	179.9	180.1	180.7	181.0	181.3	181.3	180.9	179.9	178.9	180.9
2003	181.7	183.1	184.2	183.8	183.5	183.7	183.9	184.6	185.2	185.0	184.5	184.3	184.0	183.3	184.6
2004	185.2	186.2	187.4	188.0	189.1	189.7	189.4	189.5	189.9	190.9	191.0	190.3	188.9	187.6	190.2
2005	190.7	191.8	193.3	194.6	194.4	194.5	195.4	196.4	198.8	199.2	197.6	196.8	195.3	193.2	197.4
2006	198.3	198.7	199.8	201.5	202.5	202.9	203.5	203.9	202.9	201.8	201.5	201.8	201.6	200.6	202.6
2007	202.4	203.5	205.4	206.7	207.9	208.4	208.3	207.9	208.5	208.9	210.2	210.0	207.3	205.7	209.0
2008	211.1	211.7	213.5	214.8	216.6	218.8	220.0	219.1	218.8	216.6	212.4	210.2	215.3	214.4	216.2
2009	211.1	212.2	212.7	213.2	213.9	215.7	215.4	215.8	216.0	216.2	216.3	215.9	214.5	213.1	215.9
2010	216.7	216.7	217.6	218.0	218.2	218.0	218.0	218.3	218.4	218.7	218.8	219.2	218.1	217.5	218.6
2011	220.2	221.3	223.5	224.9	226.0	225.7	225.9	226.5	226.9	226.4	226.2	225.7	224.9	223.6	226.3
2012	226.7	227.7	229.4	230.1	229.8	229.5	229.1	230.4	231.4	231.3	230.2	229.6	229.6	228.8	230.3
2013	230.3	232.2	232.8	232.5	232.9	233.5	233.6	233.9	234.1	233.5	233.1	233.0	233.0	232.4	233.5
2014	233.9	234.8	**236.3**	237.1	237.9	238.3	238.3	237.9	238.0	237.4	236.2	234.8	236.7	236.4	237.1
2015	233.7	234.7	236.1	236.6	237.8	238.6	238.7	238.3	237.9	237.8	237.3	236.5	237.0	236.3	237.8
2016	236.9	237.1	238.1	239.3	240.2	241.0	240.6	240.9	241.4	241.7	241.4	241.4	240.0	238.8	241.2
2017	242.8	243.6	243.8	244.5	244.7	245.0	244.8	245.5	246.8	246.7	246.7	246.5	245.1	244.1	246.2
2018	247.9	249.0	**249.6**												

Source: United States Department of Labour Bureau of Labor Statistics Bureau of Labor Statistics Data

1.2 Jamaican Consumer Price Index

Ja. Consumer Price Index

The Index numbers listed in the table: Consumer Price Index for 2007-2011, are based on the revised calculations using the new series that have been derived by using data from the HES conducted between June 2004 and March 2005. For the years prior to 2007 the data is linked to the 1988 series of the CPI using a link factor.

These index numbers provide an historical series of the CPI on a monthly basis. The monthly indexes are given for the 12 months of the calendar year while the arithmetic mean of the data for the 12 months is used to arrive at an annual average index. The Percentage Changes calculated from these averages represent average annual changes for the year.

Consumer Price Index for 2003-2018

Month	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
January	64.80	74.60	84.10	94.70	101.00	119.40	136.00	152.60	167.80	178.90	193.80	211.80	223.00	231.30	237.30	248.60
February	64.40	75.00	84.50	94.80	101.30	121.50	137.10	155.90	167.10	180.30	195.00	211.90	221.50	229.60	237.80	248.30
March	64.70	75.40	85.30	94.90	102.50	122.90	138.20	156.60	168.90	181.20	197.70	**214.20**	222.70	229.30	238.70	**248.10**
April	65.70	75.70	86.90	96.00	102.90	124.80	138.80	158.70	169.70	181.90	198.50	213.60	223.10	228.40	239.40	
May	66.80	76.20	88.70	96.30	104.30	127.80	140.00	159.70	171.00	182.80	199.60	215.70	224.20	229.00	239.60	
June	68.50	76.80	90.00	97.60	105.10	130.30	142.00	160.70	172.30	183.80	199.90	215.90	225.30	231.00	241.20	
July	69.50	77.60	91.40	98.90	106.10	134.00	143.30	161.30	173.60	183.20	200.90	218.90	227.20	232.10	242.70	
August	70.40	78.60	91.50	99.20	107.20	135.60	143.90	162.00	174.60	184.10	201.60	221.30	229.00	233.10	243.40	
September	71.50	79.00	93.80	99.90	108.90	136.50	146.30	162.80	175.91	187.60	207.20	225.90	230.00	234.20	245.00	
October	72.70	81.60	94.30	99.80	110.40	136.90	147.50	164.00	176.70	189.40	209.00	226.10	230.70	234.80	245.80	
November	73.40	83.60	94.60	99.60	114.00	136.40	148.70	165.70	177.50	190.60	209.50	224.90	231.80	235.60	247.30	
December	73.90	84.10	94.60	100.00	116.80	136.50	150.40	168.10	178.20	192.50	210.70	224.10	232.30	236.30	248.70	
Annual Average	**68.90**	**78.20**	**90.00**	**97.60**	**106.70**	**130.20**	**142.70**	**160.68**	**172.78**	**184.69**	**201.95**	**218.69**	**226.73**	**232.06**	**242.24**	
Annual Inflation Rate	**13.80**	**13.70**	**12.60**	**5.70**	**16.80**	**16.80**	**10.20**	**11.80**	**6.00**	**8.00**	**9.45**	**6.36**	**3.66**	**5.44**	**7.06**	

The Consumer Price Index (CPI) is one in a series of economic indicators produced by the Statistical Institute of Jamaica as part of its objective to provide an integrated set of statistical information on the social and economic conditions of the people of Jamaica.

Source: http://statinja.gov.jm/Trade-Econ%20Statistics/CPI/NewCPI.aspx

ANNEX 2: Estimated Bill Impact of OUR's Approved Annual Tariff Adjustment

2.1 Bill Comparison for a Typical Rate 10 Consumer with consumption < 100 kW

Usage 90 kWh

Rate 10	June 2018 Bill - Before				June 2018 Bill - After					
Below 100kWh	2017 - 2018 Rates J$				2018 - 2019 Rates J$				Change	
Description	Base F/X Rate	Billing F/X Rate			Base F/X Rate	Billing F/X Rate			J$	%
	131.00	127.90			128.00	127.90				
	Usage kWh	Rate (J$)			Usage kWh	Rate (J$)				
Energy 1st	90	9.59		863.10	90	9.66		869.19	6.09	0.71%
Energy 2nd	0	22.33		-	0	22.49		-	-	
Customer Charge				442.27				445.39	3.12	0.71%
Sub Total				**1,305.37**				**1,314.58**	**9.21**	**0.71%**
SBF formerly EEIF	90	0		**0.00**	90			-		
F/E Adjust		-0.019	-	24.69		-0.001	-	0.80		
Fuel & IPP	90	19.815		1,783.32	90	19.451		1,750.63	- **32.69**	**-1.83%**
Bill Total			**J$**	**3,064.00**			**J$**	**3,064.41**	**0.41**	**0.01%**

2.2 Bill Comparison for a Typical Rate 10 Consumer with consumption 101kWh </= 150kWh

Usage 150 kWh

Rate 10	June 2018 Bill - Before				June 2018 Bill - After					
101 < /=150kWh	2017 - 2018 Rates J$				2018 - 2019 Rates J$				Change	
Description	Base F/X Rate	Billing F/X Rate			Base F/X Rate	Billing F/X Rate			J$	%
	131.00	127.90			128.00	127.90				
	Usage kWh	Rate (J$)			Usage kWh	Rate (J$)				
Energy 1st	100	9.59		959.00	100	9.66		965.77	6.77	0.71%
Energy 2nd	50	22.33		1,116.50	50	22.49		1,124.38	7.88	0.71%
Customer Charge				442.27				445.39	3.12	0.71%
Sub Total				**2,517.77**				**2,535.54**	**17.77**	**0.71%**
SBF formerly EEIF	150	0		-	150	0		-		
F/E Adjust		-0.019	-	47.63		-0.001	-	1.55		
Fuel & IPP	150	19.815		2,972.20	150	19.451		2,917.71	- **54.49**	**-1.83%**
Bill Total			**J$**	**5,442.34**			**J$**	**5,451.70**	**9.36**	**0.17%**

2.3 Bill Comparison for a Typical Rate 10 Consumer with consumption 150kWh and above

Usage 200 kWh

Rate 10	June 2018 Bill - Before			June 2018 Bill - After				
Above 150kWh	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	9.59	959.00	100	9.66	965.77	6.77	0.71%
Energy 2nd	100	22.33	2,233.00	100	22.49	2,248.76	15.76	0.71%
Customer Charge			442.27			445.39	3.12	0.71%
Sub Total			**3,634.27**			**3,659.91**	**25.64**	**0.71%**
SBF formerly EEIF	200	0	-	200	0	-		
F/E Adjust		-0.019 -	68.75		-0.001 -	2.23		
Fuel & IPP	200	19.815	3,962.93	200	19.451	3,890.28		
Bill Sub-Total			**7,528.46**	**Bill Sub-Total**		**7,547.97**		
GCT @16.5%		0.165	344.21		0.165	345.88	**1.67**	**0.49%**
Bill Total		J$	**7,872.66**		J$	**7,893.85**	**21.19**	**0.27%**

2.4 Bill Comparison for a Typical Rate 20 Consumer with consumption ≤ 100 kWh

Usage 90 kWh

Rate 20	June 2018 Bill - Before			June 2018 Bill - After				
Below 100kWh	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	90	18.42	1,657.80	90	18.55	1,669.50	11.70	0.71%
Customer Charge			985.29			992.24	6.95	0.71%
Sub Total			**2,643.09**			**2,661.74**	**18.65**	**0.71%**
SBF formerly EEIF		0	-	90	0	-		
F/E Adjust		-0.019 -	50.00		-0.001 -	1.62		
Fuel & IPP	90	19.815	1,783.32	90	19.451	1,750.63	- **32.69**	**-1.83%**
Bill Sub-Total			**4,376.41**			**4,410.74**	**34.33**	**0.78%**
GCT @16.5%		0.165	722.11		0.165	727.77		
Bill Total		J$	**5,098.52**		J$	**5,138.52**	**40.00**	**0.78%**

2.5 Bill Comparison for a Typical Rate 20 Consumer with consumption 101kWh - 1000kWh

Usage 1000 kWh

Rate 20	June 2018 Bill - Before			June 2018 Bill - After				
101 - 1000kWh	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	1000	18.42	18,420.00	1000	18.55	18,549.97	129.97	0.71%
Customer Charge			985.29			992.24	6.95	0.71%
Sub Total			**19,405.29**			**19,542.21**	**136.92**	**0.71%**
SBF formerly EEIF		0	-	1000	0	-		
F/E Adjust		-0.019	- 367.07		-0.001	- 11.91		
Fuel & IPP	1000	19.815	19,814.66	1000	19.451	19,451.41	- 363.24	-1.83%
Bill Sub-Total			**38,852.87**			**38,981.72**	**128.84**	**0.33%**
GCT @16.5%		0.165	6,410.72		0.165	6,431.98	21.26	0.33%
Bill Total		J$	**45,263.60**		J$	**45,413.70**	**150.10**	**0.33%**

2.6 Bill Comparison for a Typical Rate 20 Consumer with consumption 1001kWh - 7500kWh

Usage 5000 kWh

Rate 20	June 2018 Bill - Before			June 2018 Bill - After				
1001 - 7500kWh	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	5000	18.42	92,100.00	5000	18.55	92,749.85	649.85	0.71%
Customer Charge			985.29			992.24	6.95	0.71%
Sub Total			**93,085.29**			**93,742.10**	**656.81**	**0.71%**
SBF formerly EEIF		0	-	5000	0	-		
F/E Adjust		-0.019	- 1,760.80		-0.001	- 57.12		
Fuel & IPP	5000	19.815	99,073.28	5000	19.451	97,257.06	- 1,816.22	-1.83%
Bill Sub-Total			**190,397.76**			**190,942.03**	**544.27**	**0.29%**
GCT @16.5%		0.165	31,415.63		0.165	31,505.44	89.80	0.29%
Bill Total		J$	**221,813.39**		J$	**222,447.47**	**634.08**	**0.29%**

2.7 Bill Comparison for a Typical Rate 20 Consumer with consumption above 7500kWh

Usage above 7500 kWh

Rate 20	June 2018 Bill - Before			June 2018 Bill - After				
Above 7500kWh	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	8000	18.42	147,360.00	8000	18.55	148,399.77	1,039.77	0.71%
Customer Charge			985.29			992.24	6.95	0.71%
Sub Total			**148,345.29**			**149,392.01**	**1,046.72**	**0.71%**
SBF formerly EEIF		0	-	8000	0	-		
F/E Adjust		-0.019 -	2,806.10		-0.001 -	91.04		
Fuel & IPP	8000	19.815	158,517.24	8000	19.451	155,611.30	- 2,905.94	-1.83%
Bill Sub-Total			**304,056.43**			**304,912.27**	**855.84**	**0.28%**
GCT @16.5%		0.165	50,169.31		0.165	50,310.52	141.21	0.28%
Bill Total		J$	**354,225.74**		J$	**355,222.80**	**997.06**	**0.28%**

2.8 Bill Comparison for a Typical Rate 40 Consumer

Usage 35,000 kWh

Demand 100 kVA

Rate 40	June 2018 Bill - Before			June 2018 Bill - After				
Standard	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	35000	5.73	200,550.00	35000	5.77	201,965.07	1,415.07	0.71%
Demand kVA	100	1777.51	177,751.00	100	1790.05	179,005.20	1,254.20	
Customer Charge			6,941.83			6,990.81	48.98	0.71%
Sub Total			**385,242.83**			**387,961.09**	**2,718.26**	**0.71%**
SBF formerly EEIF		0	-	35000	0	-		
F/E Adjust		-0.019 -	7,287.27		-0.001 -	236.41		
Fuel & IPP	35000	19.022	665,772.42	35000	18.673	653,567.45	- 12,204.97	-1.83%
Bill Sub-Total			**1,043,727.98**			**1,041,292.12**	**- 2,435.86**	**-0.23%**
GCT @16.5%		0.165	172,215.12		0.165	171,813.20	- 401.92	-0.23%
Bill Total		J$	**1,215,943.10**		J$	**1,213,105.32**	**- 2,837.78**	**-0.23%**

2.9 Bill Comparison for a Typical Rate 50 Customer

Usage 500,000 kWh

Demand 1,500 kVA

Rate 50	June 2018 Bill - Before			June 2018 Bill - After				
Standard	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	5.53	2,765,000.00	500000	5.57	2,784,509.73	19,509.73	0.71%
Demand kVA	1500	1592.42	2,388,630.00	1500	1603.66	2,405,484.08	16,854.08	0.71%
Customer Charge			6,941.83			6,990.81	48.98	0.71%
Sub Total			**5,160,571.83**			**5,196,984.62**	**36,412.79**	**0.71%**
SBF formerly EEIF		0	-	500000	0	-		
F/E Adjust		-0.019	- 97,617.53		-0.001	- 3,166.91		
Fuel & IPP	500000	19.022	9,511,034.54	500000	18.673	9,336,677.86	- 174,356.69	-1.83%
Bill Sub-Total			**14,573,988.84**			**14,530,495.57**	- **43,493.27**	**-0.30%**
GCT @16.5%		0.165	2,404,708.16		0.165	2,397,531.77	- 7,176.39	-0.30%
Bill Total			**J$ 16,978,697.00**			**J$ 16,928,027.33**	- **50,669.66**	**-0.30%**

2.10 Bill Comparison for a Typical Rate 50 TOU Customer (Partial Peak)

Usage 500,000 kWh

Demand 1,500 kVA

Rate 50	June 2018 Bill - Before			June 2018 Bill - After				
TOU (Partial Peak)	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	5.53	2,765,000.00	500000	5.57	2,784,509.73	19,509.73	0.71%
Demand kVA	1500	692.92	1,039,380.00	1500	697.81	1,046,713.82	7,333.82	0.71%
Customer Charge			6,941.83			6,990.81	48.98	0.71%
Sub Total			**3,811,321.83**			**3,838,214.37**	**26,892.54**	**0.71%**
SBF formerly EEIF		0	-	500000	0	-		
F/E Adjust		-0.019	- 72,095.08		-0.001	- 2,338.91		
Fuel & IPP	500000	18.273	9,136,562.20	500000	17.938	8,969,070.35	- 167,491.85	-1.83%
Bill Sub-Total			**12,875,788.95**			**12,804,945.81**	- **70,843.14**	**-0.55%**
GCT @16.5%		0.165	2,124,505.18		0.165	2,112,816.06	- 11,689.12	-0.55%
Bill Total			**J$ 15,000,294.12**			**J$ 14,917,761.86**	- **82,532.26**	**-0.55%**

2.11 Bill Comparison for a Typical Rate 70 Customer

Usage 500,000 kWh

Demand 2,000 kVA

Rate 70	June 2018 Bill - Before			June 2018 Bill - After				
Standard	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	3.68	1,840,000.00	500000	3.71	1,852,982.97	12,982.97	0.71%
Demand kVA	2000	1515.61	3,031,220.00	2000	1526.30	3,052,608.17	21,388.17	0.71%
Customer Charge			6,941.83			6,990.81	48.98	0.71%
Sub Total			**4,878,161.83**			**4,912,581.95**	**34,420.12**	**0.71%**
EEIF		0	-	500000	0	-		
F/E Adjust		-0.019	- 92,275.46		-0.001	- 2,993.60		
Fuel & IPP	500000	19.022	9,511,034.54	500000	18.673	9,336,677.86	- 174,356.69	-1.83%
Bill Sub-Total			**14,296,920.92**			**14,246,266.20**	- **50,654.72**	**-0.35%**
GCT @16.5%		0.165	2,358,991.95		0.165	2,350,633.92	- 8,358.03	-0.35%
Bill Total			**J$ 16,655,912.87**			**J$ 16,596,900.12**	- **59,012.74**	**-0.35%**

2.12 Bill Comparison for a Typical Rate 70 TOU Customer (Partial Peak)

Usage 500,000 kWh

Demand 2,000 kVA

Rate 70	June 2018 Bill - Before			June 2018 Bill - After				
TOU (Partial Peak)	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	3.68	1,840,000.00	500000	3.71	1,852,982.97	12,982.97	0.71%
Demand kVA	2000	668.07	1,336,140.00	2000	672.78	1,345,567.75	9,427.75	0.71%
Customer Charge			6,941.83			6,990.81	48.98	0.71%
Sub Total			**3,183,081.83**			**3,205,541.53**	**22,459.70**	**0.71%**
SBF formerly EEIF		0	-	500000	0	-		
F/E Adjust		-0.019	- 60,211.27		-0.001	- 1,953.38		
Fuel & IPP	500000	18.273	9,136,562.20	500000	17.938	8,969,070.35	- 167,491.85	-1.83%
Bill Sub-Total			**12,259,432.75**			**12,172,658.50**	- **86,774.25**	**-0.71%**
GCT @16.5%		0.165	2,022,806.40		0.165	2,008,488.65	- 14,317.75	-0.71%
Bill Total			**J$ 14,282,239.16**			**J$ 14,181,147.16**	- **101,092.00**	**-0.71%**

ANNEX 3: **Estimated Bill Impact** of JPS Proposed Annual Tariff Adjustment

3.1 Bill Comparison for a Typical Rate 10 Consumer with consumption < 100 kWh

Usage 90 kWh

Rate 10	June 2018 Bill - Before			June 2018 Bill - After				
Below 100kWh	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	90	9.59	863.10	90	9.67	869.86	6.76	0.78%
Energy 2nd	0	22.33	-	0	22.50	-	-	
Customer Charge			442.27			445.74	3.47	0.78%
Sub Total			**1,305.37**			**1,315.60**	**10.23**	**0.78%**
F/E Adjust		-0.019 -	24.69		-0.001 -	0.80		
Fuel & IPP	90	19.815	1,783.32	90	19.845	1,786.08		
Bill Total		**J$**	**3,064.00**		**J$**	**3,100.88**	**36.88**	**1.20%**

3.2 Bill Comparison for a Typical Rate 10 Consumer with consumption 101kWh </= 150kWh

Usage 150 kWh

Rate 10	June 2018 Bill - Before			June 2018 Bill - After				
101 < /=150kWh	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	9.59	959.00	100	9.67	966.51	7.51	0.78%
Energy 2nd	50	22.33	1,116.50	50	22.50	1,125.25	8.75	0.78%
Customer Charge			442.27			445.74	3.47	0.78%
Sub Total			**2,517.77**			**2,537.50**	**19.73**	**0.78%**
F/E Adjust		-0.019 -	47.63		-0.001 -	1.55		
Fuel & IPP	150	19.815	2,972.20	150	19.845	2,976.80		
Bill Total		**J$**	**5,442.34**		**J$**	**5,512.76**	**70.41**	**1.29%**

3.3 Bill Comparison for a Typical Rate 10 Consumer with consumption 350kWh and above

Usage 150 kWh

Rate 10	June 2018 Bill - Before			June 2018 Bill - After				
Above 150kWh	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	9.59	959.00	100	9.67	966.51	7.51	0.78%
Energy 2nd	100	22.33	2,233.00	100	22.50	2,250.50	17.50	0.78%
Customer Charge			442.27			445.74	3.47	0.78%
Sub Total			**3,634.27**			**3,662.75**	**28.48**	**0.78%**
F/E Adjust		-0.019 -	68.75		-0.001 -	2.23		
Fuel & IPP	200	19.815	3,962.93	200	19.845	3,969.07		
Bill Sub-Total			**7,528.46**	**Bill Sub-Total**		**7,629.59**		
GCT @16.5%		0.165	344.21	GCT @16.5%	0.165	349.28		
Bill Total		**J$**	**7,872.66**		**J$**	**7,978.86**	**106.20**	**1.35%**

3.4 Bill Comparison for a Typical Rate 20 Consumer with consumption ≤ 100 kWh

Usage 90 kWh

Rate 20	June 2018 Bill - Before			June 2018 Bill - After				
Below 100kWh	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	90	18.42	1,657.80	90	18.56	1,670.79	12.99	0.78%
Customer Charge			985.29			993.01	7.72	0.78%
Sub Total			**2,643.09**			**2,663.80**	**20.71**	**0.78%**
F/E Adjust		-0.019 -	50.00		-0.001 -	1.62		
Fuel & IPP	90	19.815	1,783.32	90	19.845	1,786.08		
Bill Sub-Total			**4,376.41**			**4,448.26**	**71.85**	**1.64%**
GCT @16.5%		0.165	722.11		0.165	733.96		
Bill Total		**J$**	**5,098.52**		**J$**	**5,182.22**	**83.70**	**1.64%**

3.5 Bill Comparison for a Typical Rate 20 Consumer with consumption 101kWh - 1000kWh

Usage 1000 kWh

Rate 20	June 2018 Bill - Before			June 2018 Bill - After			Change	
101 - 1000kWh	2017 - 2018 Rates J$			2018 - 2019 Rates J$				
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	1000	18.42	18,420.00	1000	18.56	18,564.34	144.34	0.78%
Customer Charge			985.29			993.01	7.72	0.78%
Sub Total			**19,405.29**			**19,557.35**	**152.06**	**0.78%**
F/E Adjust		-0.019 -	367.07		-0.001 -	11.92	355.15	
Fuel & IPP	1000	19.815	19,814.66	1000	19.845	19,845.35	30.70	0.15%
Bill Sub-Total			**38,852.87**			**39,390.79**	**537.91**	**1.38%**
GCT @16.5%		0.165	6,410.72		0.165	6,499.48	88.76	1.38%
Bill Total		**J$**	**45,263.60**		**J$**	**45,890.27**	**626.67**	**1.38%**

3.6 Bill Comparison for a Typical Rate 20 Consumer with consumption 1001kWh - 7500kWh

Usage 5000 kWh

Rate 20	June 2018 Bill - Before			June 2018 Bill - After			Change	
1001 - 7500kWh	2017 - 2018 Rates J$			2018 - 2019 Rates J$				
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	5000	18.42	92,100.00	5000	18.56	92,821.72	721.72	0.78%
Customer Charge			985.29			993.01	7.72	0.78%
Sub Total			**93,085.29**			**93,814.73**	**729.44**	**0.78%**
F/E Adjust		-0.019 -	1,760.80		-0.001 -	57.17	1,703.64	
Fuel & IPP	5000	19.815	99,073.28	5000	19.845	99,226.76	153.48	0.15%
Bill Sub-Total			**190,397.76**			**192,984.32**	**2,586.56**	**1.36%**
GCT @16.5%		0.165	31,415.63		0.165	31,842.41	426.78	1.36%
Bill Total		**J$**	**221,813.39**		**J$**	**224,826.73**	**3,013.34**	**1.36%**

3.7 Bill Comparison for a Typical Rate 20 Consumer with consumption above 7500kWh

Usage above 7500 kWh

Rate 20	June 2018 Bill - Before			June 2018 Bill - After				
Above 7500kWh	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	8000	18.42	147,360.00	8000	18.56	148,514.75	1,154.75	0.78%
Customer Charge			985.29			993.01	7.72	0.78%
Sub Total			**148,345.29**			**149,507.76**	**1,162.47**	**0.78%**
F/E Adjust		-0.019 -	2,806.10		-0.001 -	91.11	2,715.00	
Fuel & IPP	8000	19.815	158,517.24	8000	19.845	158,762.82	245.57	0.15%
Bill Sub-Total			**304,056.43**			**308,179.47**	**4,123.04**	**1.36%**
GCT @16.5%		0.165	50,169.31		0.165	50,849.61	680.30	1.36%
Bill Total		J$	**354,225.74**		J$	**359,029.08**	**4,803.34**	**1.36%**

3.8 Bill Comparison for a Typical Rate 40 Consumer

Usage 35,000 kWh

Demand 100 kVA

Rate 40	June 2018 Bill - Before			June 2018 Bill - After				
Standard	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	35000	5.73	200,550.00	35000	5.77	202,121.55	1,571.55	0.78%
Demand kVA	100	1777.51	177,751.00	100	1791.44	179,143.90	1,392.90	
Customer Charge			6,941.83			6,996.23	54.40	0.78%
Sub Total			**385,242.83**			**388,261.68**	**3,018.85**	**0.78%**
F/E Adjust		-0.019 -	7,287.27		-0.001 -	236.60	7,050.67	
Fuel & IPP	35000	19.022	665,772.42	35000	19.052	666,803.82	1,031.41	0.15%
Bill Sub-Total			**1,043,727.98**			**1,054,828.91**	**11,100.92**	**1.06%**
GCT @16.5%		0.165	172,215.12		0.165	174,046.77	1,831.65	1.06%
Bill Total		J$	**1,215,943.10**		J$	**1,228,875.67**	**12,932.57**	**1.06%**

3.9 Bill Comparison for a Typical Rate 50 Customer

Usage 500,000 kWh

Demand 1,500 kVA

Rate 50	June 2018 Bill - Before			June 2018 Bill - After				
Standard	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	5.53	2,765,000.00	500000	5.57	2,786,667.16	21,667.16	0.78%
Demand kVA	1500	1592.42	2,388,630.00	1500	1604.90	2,407,347.84	18,717.84	0.78%
Customer Charge			6,941.83			6,996.23	54.40	0.78%
Sub Total			**5,160,571.83**			**5,201,011.22**	**40,439.39**	**0.78%**
F/E Adjust		-0.019 -	97,617.53		-0.001 -	3,169.37	94,448.17	
Fuel & IPP	500000	19.022	9,511,034.54	500000	19.052	9,525,768.91	14,734.37	0.15%
Bill Sub-Total			**14,573,988.84**			**14,723,610.77**	**149,621.93**	**1.03%**
GCT @16.5%		0.165	2,404,708.16		0.165	2,429,395.78	24,687.62	1.03%
Bill Total		**J$**	**16,978,697.00**		**J$**	**17,153,006.54**	**174,309.54**	**1.03%**

3.10 Bill Comparison for a Typical Rate 50 TOU Customer (Partial Peak)

Usage 500,000 kWh

Demand 1,500 kVA

Rate 50	June 2018 Bill - Before			June 2018 Bill - After				
TOU (Partial Peak)	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	5.53	2,765,000.00	500000	5.57	2,786,667.16	21,667.16	0.78%
Demand kVA	1500	692.92	1,039,380.00	1500	698.35	1,047,524.81	8,144.81	0.78%
Customer Charge			6,941.83			6,996.23	54.40	0.78%
Sub Total			**3,811,321.83**			**3,841,188.20**	**29,866.37**	**0.78%**
F/E Adjust		-0.019 -	72,095.08		-0.001 -	2,340.72	69,754.36	
Fuel & IPP	500000	18.273	9,136,562.20	500000	18.301	9,150,716.44	14,154.24	0.15%
Bill Sub-Total			**12,875,788.95**			**12,989,563.91**	**113,774.96**	**0.88%**
GCT @16.5%		0.165	2,124,505.18		0.165	2,143,278.04	18,772.87	0.88%
Bill Total		**J$**	**15,000,294.12**		**J$**	**15,132,841.95**	**132,547.83**	**0.88%**

3.11 Bill Comparison for a Typical Rate 70 Customer (NEW)

Usage 500,000 kWh
Demand 2,000 kVA

Rate 70	June 2018 Bill - Before			June 2018 Bill - After				
Standard	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	3.68	1,840,000.00	500000	3.71	1,854,418.65	14,418.65	0.78%
Demand kVA	2000	1515.61	3,031,220.00	2000	1527.49	3,054,973.31	23,753.31	0.78%
Customer Charge			6,941.83			6,996.23	54.40	0.78%
Sub Total			**4,878,161.83**			**4,916,388.19**	**38,226.36**	**0.78%**
F/E Adjust		-0.019 -	92,275.46		-0.001 -	2,995.92	89,279.53	
Fuel & IPP	500000	19.022	9,511,034.54	500000	19.052	9,525,768.91	14,734.37	0.15%
Bill Sub-Total			**14,296,920.92**			**14,439,161.18**	**142,240.26**	**0.99%**
GCT @16.5%		0.165	2,358,991.95		0.165	2,382,461.59	23,469.64	0.99%
Bill Total			**J$ 16,655,912.87**			**J$ 16,821,622.77**	**165,709.91**	**0.99%**

3.12 Bill Comparison for a Typical Rate 50 TOU Customer (Partial Peak) (New)

Usage 500,000 kWh
Demand 2,000 kVA

Rate 70	June 2018 Bill - Before			June 2018 Bill - After				
TOU (Partial Peak)	2017 - 2018 Rates J$			2018 - 2019 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	131.00	127.90		128.00	127.90			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	3.68	1,840,000.00	500000	3.71	1,854,418.65	14,418.65	0.78%
Demand kVA	2000	668.07	1,336,140.00	2000	673.31	1,346,610.29	10,470.29	0.78%
Customer Charge			6,941.83			6,996.23	54.40	0.78%
Sub Total			**3,183,081.83**			**3,208,025.17**	**24,943.34**	**0.78%**
F/E Adjust		-0.019 -	60,211.27		-0.001 -	1,954.89	58,256.38	
Fuel & IPP	500000	18.273	9,136,562.20	500000	18.301	9,150,716.44	14,154.24	0.15%
Bill Sub-Total			**12,259,432.75**			**12,356,786.71**	**97,353.96**	**0.79%**
GCT @16.5%		0.165	2,022,806.40		0.165	2,038,869.81	16,063.40	0.79%
Bill Total			**J$ 14,282,239.16**			**J$ 14,395,656.52**	**113,417.36**	**0.79%**

ANNEX 4: Fuel Weights

4.1 Existing Weights

FUEL & IPP RATE SUMMARY - May 2018

(To be implemented June 2018)

BILLING EXCHANGE RATE J$127.9025 = US$1.00

Fuel Weights Applicable

Class	Std.	Off Peak	Partial Peak	On Peak
Rate 10				
1st. 100 kWh	1.000			
Over 100 kWh	1.000			
Rate 20	1.000			
Rate 40 LV	0.960	0.800	1.044	1.302
Rate 40A LV	0.960			
Rate 50 MV	0.960	0.800	1.044	1.302
Rate 60	0.960			
Rate 70	0.960	0.800	1.044	1.302
Traffic Signal	0.960			

Actual Fuel & IPP Rate for May 2018 [USc/kWh]	15.492
Billing Exchange Rate for May 2018	127.90

Fuel & IPP Rates for May 2018

Class	Std.	Off Peak	Partial Peak	On Peak
Rate 10				
1st. 100 kWh	19.815			
Over 100 kWh	19.815			
Rate 20	19.815			
Rate 40 LV	19.022	15.852	20.695	25.791
Rate 40A LV	19.022			
Rate 50 MV	19.022	15.852	20.695	25.791
Rate 60	19.022			
Rate 70	19.022	15.852	20.695	25.791
Traffic Signal	19.022			

4.2 Approved Weights

FUEL & IPP RATE SUMMARY - May 2018

(To be implemented June 2018)

BILLING EXCHANGE RATE J$127.9025 = US$1.00

Fuel Weights Applicable

Class	Std.	Off Peak	Partial Peak	On Peak
Rate 10				
1st. 100 kWh	1.000			
Over 100 kWh	1.000			
Rate 20	1.000			
Rate 40 LV	0.960	0.800	1.044	1.302
Rate 40A LV	0.960			
Rate 50 MV	0.960	0.800	1.044	1.302
Rate 60	0.960			
Rate 70	0.960	0.800	1.044	1.302
Traffic Signal	0.960			

Actual Fuel & IPP Rate for May 2018 [USc/kWh]	15.208
Billing Exchange Rate for May 2018	127.90

Fuel & IPP Rates for May 2018

Class	Std.	Off Peak	Partial Peak	On Peak
Rate 10				
1st. 100 kWh	19.451			
Over 100 kWh	19.451			
Rate 20	19.451			
Rate 40 LV	18.673	15.561	20.315	25.318
Rate 40A LV	18.673			
Rate 50 MV	18.673	15.561	20.315	25.318
Rate 60	18.673			
Rate 70	18.673	15.561	20.315	25.318
Traffic Signal	18.673			

ANNEX 5: THE OUR'S 2018 Q-FACTOR REPORT

BACKGROUND

As part of the Performance Based Rate-making Mechanism (PBRM) incorporated in JPS's price control regime, defined under Schedule 3, Exhibit 1 of the Licence 2016, the OUR is required to evaluate the quality of electricity service provided to customers by JPS each year, and determine a Q-Factor for annual adjustment of the annual revenue target.

ASPECTS OF QUALITY OF SERVICE

Quality of service requirements usually encompass three (3) main aspects:

- Commercial quality – speed and accuracy with which customer requests and complaints are handled by the electric utility. This aspect is addressed in JPS's Guaranteed Standards (GS) and Overall Standards (OS);

- Power quality – primarily voltage quality. This is covered in the relevant Electricity Sector Codes but no punitive measures to discourage violation are included; and

- Reliability of supply – the level of continuity of electricity supply to customers. This is in the Q-Factor requirements set out under Schedule 3 of the Licence 2016.

Under the existing legal and regulatory framework, JPS is designated the Single Buyer/System Operator with the obligation to provide an adequate, safe and efficient electricity service throughout the country, subject to specific technical/operational standards, codes, regulations, relevant legislation, prudent utility practice and international best practices. These requirements serve to ensure that electricity is supplied to customers at an acceptable level of reliability and quality.

PURPOSE

The OUR's evaluation of JPS's Q-Factor at this 2018 Annual Review, focuses on the following:

- The reliability performance in terms of power outages in the various segments of the system, resulting in supply interruptions to customers;
- The nature and causes of the supply interruptions and their impact on customers;
- Derivation of the quality of service (reliability) indicators prescribed by the Licence 2016; and
- Issues relating to the collection and accuracy of JPS' system outage data required for the computation of the reliability indicators to establish the Q-Factor baseline needed for the implementation of the Q-Factor incentive scheme.

MEASUREMENT OF RELIABILITY

To effectively manage system reliability, the utility must be able to properly measure and monitor it. To achieve this objective, reliability performance metrics become applicable. Additionally, reliability measurements are necessary to support utility regulators' efforts to monitor performance improvements and to establish performance benchmarks and incentive mechanisms.

LICENCE REQUIREMENTS FOR Q-FACTOR

Regarding the application of the Q-Factor to the annual PBRM, Schedule 3, paragraph 46 of the Licence 2016, provides as follows:

> *"a. The Q-Factor, which is the annual allowed price adjustment to reflect changes in the quality of service provided by the Licensee to its customers. The Office shall measure the quality of service versus the annual target set in the 5 year rate review determination."*

Regarding the Q-Factor adjustment system, Exhibit 1, Schedule 3 of the Licence 2016 states that:

> *"The Q-factor should be based on three quality indices until revised by the Office and agreed between the Office and the Licensee:*
>
> *SAIFI–this index is designed to give information about the average frequency of sustained interruptions per customer over a predefined area*

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

(Expressed in number of interruptions (Duration > 5 minutes per year)

> *SAIDI–this index is referred to as customer minutes of interruption and is designed to provide information about the average time that customers are interrupted*

$$SAIDI = \frac{Customers\ interruption\ durations}{Total\ number\ of\ customers\ served}$$

(Expressed in minutes)

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

$$CAIDI = \frac{Customers\ interruption\ durations\ or\ SAIDI}{Total\ number\ of\ interruptions\ or\ SAIFI}$$

(Expressed in minutes per interruption (Duration > 5 minutes)

Until revision by the Office, the quality of service performance should be classified into three categories, with the following point system:

- *Above Average Performance (greater than 10% below target) — would be worth 3 Quality Points on either SAIFI, SAIDI or CAIDI;*

- *Dead Band Performance (+ or – 10% of target) — would be worth 0 Quality Points on either SAIFI, SAIDI or CAIDI; and*

- *Below Average Performance (Greater than 10% above target) — would be worth -3 Quality Points on SAIFI, SAIDI or CAIDI.*

Until the revision by the Office, the adjustment factors that would be assigned to cumulative quality points scores for the three reliability indices as follows: If the sum of the 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%"*

Exhibit 1, Schedule 3 of the Licence 2016 also indicates that the annual PBRM filing should follow the general framework where the rate of change in the Revenue Cap will be determined through the following formula: $dPCI = dI \pm Q \pm Z$, where Q represents the Q-Factor defined under Schedule 3, paragraph 46 of the Licence.

Exhibit 1 also stipulates that the Q-Factor should be based on three (3) quality indices until revised by the Office and agreed between the Office and JPS. The three (3) quality indices prescribed in the Licence 2016 are SAIFI, SAIDI and CAIDI. The definitions of these indices, as stated in the Licence 2016 are consistent with the IEEE Standard 1366 – 2012, the IEEE Guide for Electric Power Distribution Reliability Indices.

While the effects of momentary interruptions can be severe, Momentary Average Interruption Frequency Index (MAIFI) was not prescribed by the Licence to be included in the Q-Factor. MAIFI provides information about the average frequency of momentary interruptions per customer. Momentary interruptions occur when there is a brief (<= five minutes) loss of power supply to one or more customers, caused by the operation of an interrupting device (circuit breaker or recloser). From a regulatory monitoring perspective, JPS is still required to record momentary interruption events, derived from the MAIFI indicator, and then submit them to the OUR as part of the regulatory reporting framework, for review and analysis.

REGULATORY PRINCIPLES FOR IMPLEMENTATION OF Q-FACTOR

For proper implementation of the Q-Factor, the OUR and JPS have established that, in principle, the Q-Factor should satisfy the following criteria:

1. Provide proper financial incentive to deliver a level of service quality based on customers' view of the value of that service quality;
2. Measurement and calculation should be accurate and transparent without undue cost of compliance;
3. There should be fair treatment for factors affecting performance that are outside of JPS' control, such as IPP forced outages, natural disasters, and other Force Majeure events, as defined under the Licence; and
4. It should be symmetrical in application, as stipulated in the Licence with appropriate caps or limits of effects on rates.

Based on the reliability and quality of service requirements of the Licence, the Q-Factor should be determined based on the average reliability performance across the entire system. This means that all the customers in the system should necessarily receive the same level of reliability irrespective of their individual preferences. However, given the topology and geographical orientation of the system and load density, among other things, this expectation is often not realized.

JPS OUTAGE DATA ISSUES AND IMPROVEMENT STRATEGY

One of the prevailing challenges in the process of implementing the Q-Factor mechanism has been the establishment of a reliable and credible baseline from which to measure changes in quality of service. From the perspective of the utility, the baseline is considered crucial to its expected annual revenue. As such, they would want to ensure that such baseline is reasonable, based on historical quality of service performance, and is aligned to its quality of service projections presented in its five (5)-year Business Plan, at each Five (5)-Year Rate Review, as required by the Licence 2016. While a Q-Factor adjustment to the non-fuel rate is required as part of the PBRM at each annual review, ongoing system outage data integrity concerns have hindered the establishment of a credible baseline. Credible system outage data is very essential to the derivation of the prescribed quality indices necessary for the establishment of the Q-Factor baseline and related incentive scheme.

Since 2009 significant efforts have been employed to address JPS's outage data issues, including those that were identified during an independent Q-Factor audit commissioned by the OUR in 2012. In response to the recommendations of the audit, JPS deployed an Outage Management System (OMS) in 2013 December, to enable accurate collection and recording of system outage data.

Despite this initiative, OUR's review of JPS's 2014, 2015 and 2016 outage data sets revealed a number of lingering issues affecting the outage data collection and data management processes.

Since the 2017 Annual Review, JPS has reportedly taken action to address the identified issues and improve the outage data quality. While there is evidence of incremental improvements, recurring defects in conjunction with iterative responses have resulted in extended delays in establishing a credible Q-Factor baseline.

JPS's 2017 RELIABILITY PERFORMANCE

In the 2018 Annual Review submission, JPS highlighted that system reliability performance for 2017 in terms of SAIDI and SAIFI is as follows:

- 2017 SAIDI was 3% better than 2016 SAIDI
- 2017 SAIFI was 4% worse than 2016 SAIFI.

Table QF1: Reliability Indices Presented by JPS for 2014 - 2017

RELIABILITY INDICES PRESENTED BY JPS FOR 2014 - 2017			
Year	SAIDI	SAIFI	MAIFI
2014	2404.4	21.8	34.0
2015	1,983.7	18.9	24.1
2016	1,774.3	15.7	25.6
2017	1,755.5	16.4	32.9

However, the Q-Factor data presented by JPS as shown in Table QF1 does not validate a 3% improvement in SAIDI for 2017 relative to 2016.

According to JPS, the improvement in SAIDI was a direct result of the strategies and initiatives undertaken by the company during the year. However, the decline in SAIFI in 2017 was mainly due to the abnormal weather events experienced during the year, which impacted the grid negatively.

JPS's 2017- 2018 RELIABILITY PERFORMANCE IMPROVEMENT STRATEGY

In the 2018 Annual Review submission, JPS reported that in 2017 the company invested US$49M in improving the system's reliability performance, with US$26M allocated to T&D initiatives and US$23M to Generation. The 2017 reliability performance improvement strategy encompassed the following:

1) Deployment of automated grid management system in the T&D network.
2) Traditional/routine activities, involving lightning mitigation, structural integrity, routine inspections and the application of the appropriate solutions to problem areas.
3) Intensifying outage management processes and improving outage data quality.

However, evidence of the reported expenditures, capital investment schedule and the commensurate reliability impact was not provided.

On page 90 of JPS's submission, JPS also indicates that US$17.3M was invested in the rehabilitation and reinforcement of the T&D network during 2017. However, the connection between this expenditure and the $26M indicated above, is not clear.

JPS's 2018 RELIABILITY IMPROVEMENT PLAN

JPS indicated that the company will continue its reliability improvement strategy in 2018 by undertaking, among other things, the following initiatives:

- Continuation of lifecycle data management for the OMS;
- Increased use of automated technologies to improve system reliability performance; and
- Integrated Vegetation Management Framework.

JPS noted that the increased penetration of variable RE generation in the system, has adversely impacted system reliability, resulting in increased electricity supply interruptions. To address this situation, JPS has invested in a 24.5MW Hybrid Energy Storage System (HESS), which is expected to be commissioned into service by 2019 April.

JPS also indicated that its 5-Year Reliability Improvement Plan (2019-2024), is being developed, and will provide a comprehensive outlook of all reliability initiatives being considered, and will be aligned with the various system improvement plans (IRP, PSP, etc.) being developed for Jamaica.

JPS's 2018 SYSTEM RELIABILITY OBJECTIVES ARE AS FOLLOWS

Reduction in SAIFI

- Reduction in the number of outages through technology and cost-effective approaches.
- Reduction in the number of outages through an Asset Management Approach to our maintenance practices (Enterprise Asset Management).
- Minimization of the impact of outages (No. of customers affected per outage), through technological approaches.

Reduction in CAIDI

- Maximize use of OMS - quicker response to outages;
- Increased outage detection through Smart Meters;
- Faster outage trouble-shooting;
- Implementing automatic call-out of crews/trouble-shooters for faster outage restoration;
- Increasing crew availability and hours of coverage; and
- Institutionalizing a culture of "restore before repair".

Q-FACTOR BASELINE

In the 2018 Annual Review submission, JPS included its 2017 outage dataset as the supporting schedule for its 2017 quality indices. The company indicated that its continued engagement with the OUR has helped in resolving concerns raised since the OMS was implemented, and helped to improve the quality of the data and key outage processes.

JPS proposes that the 2016-2018 dataset be used to establish a baseline for the 2019-2024 Q-Factor targets.

REGULATORY REVIEW OF JPS's 2017 QUALITY OF SERVICE PERFORMANCE

REVIEW OF JPS 2017 Q-FACTOR DATA

JPS's 2017 outage dataset included in the 2018 Annual Review Submission was used as the basis for the review of the Q-Factor by the OUR. This was submitted as a supporting schedule in the 2018 Annual Review submission. This outage dataset was presented in Microsoft (MS) Excel format under the filename "*Reliability 2018 dataset.xlsx*". It includes six (6) worksheets, which contain the data captured in JPS's OMS system and calculations to determine the 2017 quality indices (SAIFI, SAIDI and CAIDI). The 2017 outage dataset is presented based on the matrix shown in Table QF2.

Table QF2: Arrangement of 2017 Outage Data

Arrangement of 2017 Outage Data		
Index	**Data Location**	**Data Description**
1	ANNEX A	Raw Dataset
2	ANNEX B	Calibrated Dataset
3	ANNEX C	Summary Table
4	ANNEX D	Major Event Day Calculations
5	ANNEX E	2014 – 2017 Monthly Trends Comparison
6	ANNEX F	Major Event Days and Force Majeure Events

The 2017 outage data contained in the named document was reviewed by the OUR to determine any glaring discrepancies, omissions, errors or misrepresentations in the underlying data used and the scope and scale of any adjustments made by JPS to the raw outage data prior to the calculation of the reliability indices. The OUR's review includes checks for outages with negative duration, checks for duplicate outage event records, events incorrectly classified as momentary or sustained outage events (subject to the relevant requirements of the Licence 2016), among other things. These checks were considered necessary considering that similar problems have been identified in previous outage datasets submitted by JPS. Based on the definitions and mathematical representations of the quality indices prescribed by the Licence 2016, discrepancies or errors in the outage dataset can adversely impact the accuracy of the calculated values which are crucial constituents of future Q-Factor baseline.

Description of the 2017 Dataset

Table QF3 below provides a summary of some of the main aspects of the outage dataset, including details of service interruptions occurring on each of the 365 days covering the period 2017 January 1 to December 31.

Table QF3: Summary Characteristics of the 2017 Outage Data

TOTAL NUMBER of OUTAGE EVENTS	
Annex	Events
A	85,282
B	85,282
F	2,797

NUMBER of REPORTABLE vs NON-REPORTABLE OUTAGE EVENTS		
Annex	Reportable	Non-Reportable
A	79,574	5,708
B	79,574	5,708
F	2,797	0

NUMBER of OUTAGE EVENTS by CLASSIFICATION			
Annex	Generation	Transmission	Distribution
A	1,932	957	82,229
B	1,932	957	82,229
F	4	27	2,766

NUMBER OF MOMENTARY vs. SUSTAINED OUTAGES		
Annex	Momentary	Sustained
A	7,854	77,428
B	8,602	76,680
F	0	2,797

NUMBER of FORCED vs. PLANNED OUTAGES		
Annex	Forced	Planned
A	82,289	2,993
B	82,289	2,993
F	2,797	0

RANGE OF CUSTOMERS AFFECTED DURING OUTAGE EVENTS		
Annex	Minimum	Maximum
A	0	37,499
B	0	37,499
F	0	20,153

RANGE OF OUTAGE DURATIONS (minutes)		
Annex	Minimum	Maximum
A	0.0	146,254.8
B	0.0	146,254.8
F	5.0	37,347.0

RANGE OF CUSTOMER MINUTES LOST		
Annex	Minimum	Maximum
A	0.0	225,278,085.5
B	0.0	225,278,085.5
F	0.0	11,064,110.2

SUMMARY OF DAILY CUSTOMER COUNT DATA				
Avg.	Max	Min	Max Daily Δ	@ End of Period
611,219	619,811	590,949	6,408	590,949

For the purpose of clarification, JPS indicates that it classifies an outage event as being "Non-Reportable" when clear errors are identified in the information related to the outage event. JPS further indicates that these classifications are based on a "rules base data dictionary". Only outage events classified as "Reportable" are considered when calculating reliability indices. In addition, outage events or interruptions, classified as "Sustained", are defined as those with a duration of greater than five (5) minutes, while outage events classified as "Momentary" have an outage duration of five (5) minutes or less.

Discrepancies and Modifications Observed in Dataset

As shown in Table QF4, OUR's review of the 2017 system outage dataset revealed that the dataset did not contain outage events with negative duration; duplicate outage events; or outage events incorrectly classified as momentary or sustained. However, a considerable number of outage event records denoted as "NULL" (approximately 1% of the data) were identified. Additionally, an outage event was included in the raw outage dataset that did not appear in the calibrated dataset for no indicated reason. These observations were raised with JPS during the review process, but a response was not provided.

Table QF4: Summary of Observed Discrepancies and Anomalies

CHECKS	ANNEX A	ANNEX B	ANNEX F
Outage Events with Negative Duration	0	0	0
Duplicate Outage Events	0	0	0
Incorrect Classification as Momentary or Sustained	0	0	0
Events with "NULL" Data Points	824	834	23

Review of Daily System Customer Count Records

System customer counts are important inputs for the calculation of the quality indices designated for the Q-Factor incentive scheme. As such, the accuracy of the customer counts used in calculating reliability indices is crucial, and the use of incorrect customer information will likely lead to inaccurate results.

For the submission of the 2016 OMS data, JPS incorporated daily customer counts into the calculation of the reliability indices, moving away from the previous approach of using annual customer counts. This represented a significant improvement, as variation in customer count values can have a significant effect on annual reliability indices. There were, however, issues with JPS's use of daily customer counts, as observations indicated instances of very large variations in customer count from one day to the next (up to 4.4% of the average customer count), greater than what could be reasonably expected. Additionally, it was observed that customer counts given as part of the 2016 OMS data submission did not align with other customer count values reported by JPS, introducing uncertainty into the calculated indices.

A summary of the 2017 customer count records obtained from the JPS's OMS is shown in Table QF5 below.

Table QF5: Summary of Daily Customer Count Data

SUMMARY OF DAILY CUSTOMER COUNT DATA PRESENTED IN 2017 OUTAGE DATASET				
Avg.	Max.	Min.	Max. Daily Change	Customer Count @ End of 2017
611,219	619,811	590,949	6,408	590,949

As represented in Table QF5 above, the daily customer count values indicate a maximum single-day variation in the total number of customers on JPS's system of 6,408 customers (about 1.1% of the average customer count for the year). This maximum single-day variation in customer count values and variations in customer count overall is significantly less than daily variations exhibited for the 2016 outage dataset which was presented by JPS as part of their 2017 Annual Review submission. However, as was the case with the 2016 outage dataset, the 2017 customer count values do not appear to align with customer count records included by JPS in other regulatory reports submitted to the OUR in 2017. This is a repeated matter, and needs to be urgently rectified by JPS.

Adjustment/Calibration of Outage Data Prior to Calculation of Reliability Indices

Based on OUR's review, the 2017 reliability indices presented by JPS were not calculated from the raw OMS outage data, but from calibrated outage data included in the 2017 outage dataset. JPS stated in section 7.4 of the 2018 Annual Review submission that data calibration is done when outage characteristics are abnormal and such calibration exercise is performed via application of a "Rules Base Data Dictionary", developed by JPS and reviewed by the OUR.

During the OUR's review, the data calibration carried out by JPS was examined for reasonableness. Some of the OUR's observations are presented in Table QF6 below.

Table QF6: Breakdown of Amendments to Outage Data

CATEGORY	NUMBER OF DATA CHANGES	REMARKS
"Sustained"	60	This would indicate a reclassification of the outage event from Sustained to Momentary or vice versa and would result from a change in the outage duration due to a change in the start or restoration time.
"EventDay"	7	These would be a result of a change in the outage start time such that the date to which an outage is attributed to would change.
"TimeStarted"	80	Changes in the outage start time appear to be a result of actions taken following a recognition of Condition 3 under Rule 1 of JPS' "Rules Base Data Dictionary".
"TimeRestored"	3,211	Changes in the outage restoration time appear to be a result of actions taken following a recognition of Condition 4 under Rule 1 of JPS' "Rules Base Data Dictionary".
"DurationMins"	3,291	Changes to the outage duration would be a result of changes made to the outage start or restoration time or both.
"CustomersAffected"	2,691	Changes to the number of customers affected by an outage event appear to be a result of actions taken following a recognition of Condition 1 or 2 under Rule 1 of JPS' "Rules Base Data Dictionary".
"CML"	5,845	Changes to CML would be a result of changes to the duration of an outage event or changes to the number of customers affected by an outage event.
"TimeStartedBy"	3,184	This would be a result of amendments to the data source for the outage start time.
"TimeRestoredBy"	6,524	This would be a result of amendments to the data source for the outage restoration time.

Additional Observations

- The JPS calibrated data contained additional "primary" data elements for each outage record including the name of feeder to which each outage event was assigned, and the system customer count; as well as derived data such as the event SAIDI and the event SAIFI.
- There was evidence that important records were removed from the calibrated dataset (Record ID: 472270001) without any justification. JPS needs to provide explanation.

Classification and Normalization of Outage Data

To verify the reliability indices calculated by JPS, the OUR performed corresponding calculations based on the same 2017 system outage data, taking into account necessary and relevant modifications to the data. To avoid distortion in the calculations, the 834 outage events with data points denoted as "NULL" were removed prior to calculation of the quality indices. A summary of the modified outage data used to calculate the indices is presented in Table QF7 below.

Table QF7: Normalization of Outage Data

OUR MODIFIED DATA							
CUSTOMER COUNT					REPORTABLE vs. NON-REPORTABLE OUTAGE EVENTS		
Avg.	Max	Min	Max Daily Δ	@ End of Period	Reportable	Non-Reportable	Total
611,219	619,811	590,949	6,408	590,949	79,575	5,708	85,283

FORCED vs. PLANNED OUTAGE EVENTS		MOMENTARY vs. SUSTAINED FORCED OUTAGES	
Forced	Planned	Momentary	Sustained
82,290	2,993	8,603	76,680

ADJUSTED DATA - REMOVAL OF "NULL" ELEMENTS [85,283 – 834 = 84,449]							
CUSTOMER COUNT					REPORTABLE vs. NON-REPORTABLE OUTAGE EVENTS		
Avg.	Max	Min	Max Daily Δ	@ End of Period	Reportable	Non-Reportable	Total
611,219	619,811	590,949	6,408	590,949	78,794	5,655	84,449

FORCED vs. PLANNED REPORTABLE OUTAGE EVENTS		MOMENTARY vs. SUSTAINED REPORTABLE FORCED OUTAGE EVENTS	
Forced	Planned	Momentary	Sustained
76,042	2,752	6,816	69,226

Outage Analysis

After the disaggregation of the outage data as shown in Table QF7 above, a total of 76,042 forced outage events were categorized and analyzed as shown in Table QF8 below.

Table QF8: Monthly Reportable Forced Outages Shown by Class

MONTHLY REPORTABLE FORCED OUTAGES SHOWN BY CLASS										
	Generation			Transmission			Distribution			TOTAL
2017	Momentary	Sustained	Total	Momentary	Sustained	Total	Momentary	Sustained	Total	
Jan	38	30	68	16	55	71	355	5,615	5,970	**6,109**
Feb	41	30	71	0	21	21	160	2,954	3,114	**3,206**
Mar	42	64	106	11	45	56	325	4,574	4,899	**5,061**
Apr	52	60	112	10	26	36	491	4,756	5,247	**5,395**
May	138	206	344	16	33	49	620	6,968	7,588	**7,981**
Jun	72	110	182	12	28	40	545	5,567	6,112	**6,334**
Jul	53	17	70	4	9	13	366	4,958	5,324	**5,407**
Aug	93	76	169	8	22	30	470	6,239	6,709	**6,908**
Sep	124	196	320	15	15	30	796	8,283	9,079	**9,429**
Oct	192	70	262	31	34	65	683	6,903	7,586	**7,913**
Nov	68	5	73	17	28	45	426	5,769	6,195	**6,313**
Dec	71	24	95	19	37	56	436	5,399	5,835	**5,986**
Total	**984**	**888**	**1,872**	**159**	**353**	**512**	**5,673**	**67,985**	**73,658**	**76,042**

The variations in the indicated outage categories throughout 2017 are provided in Figures QF1 and QF2 below.

Figure QF1: Variation of Reportable Forced Outage Events Occurring in 2017

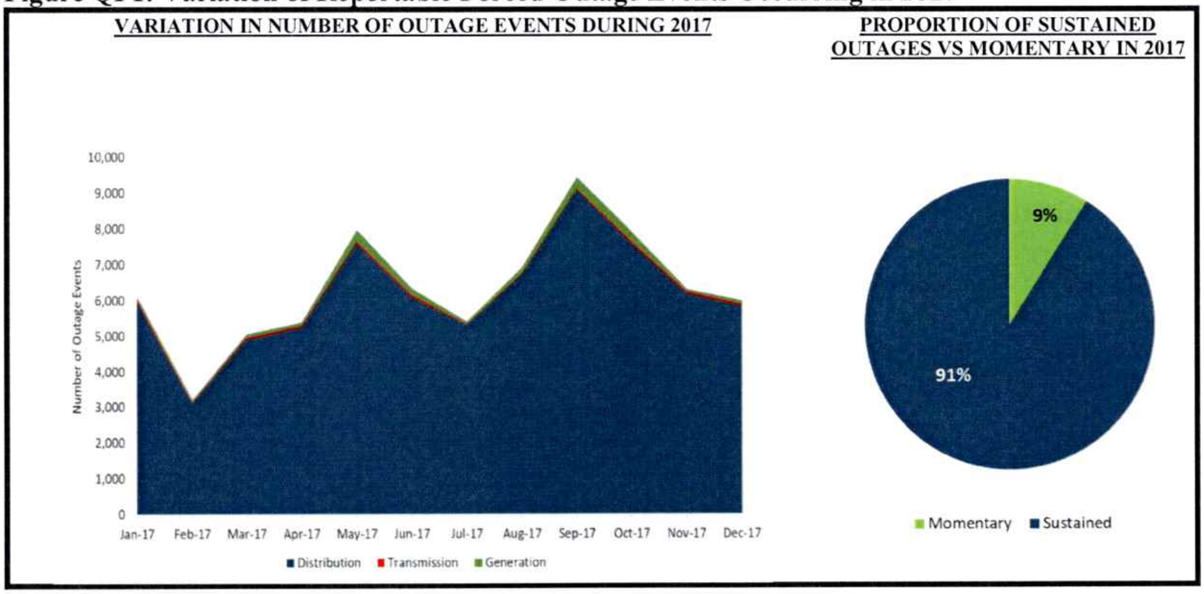
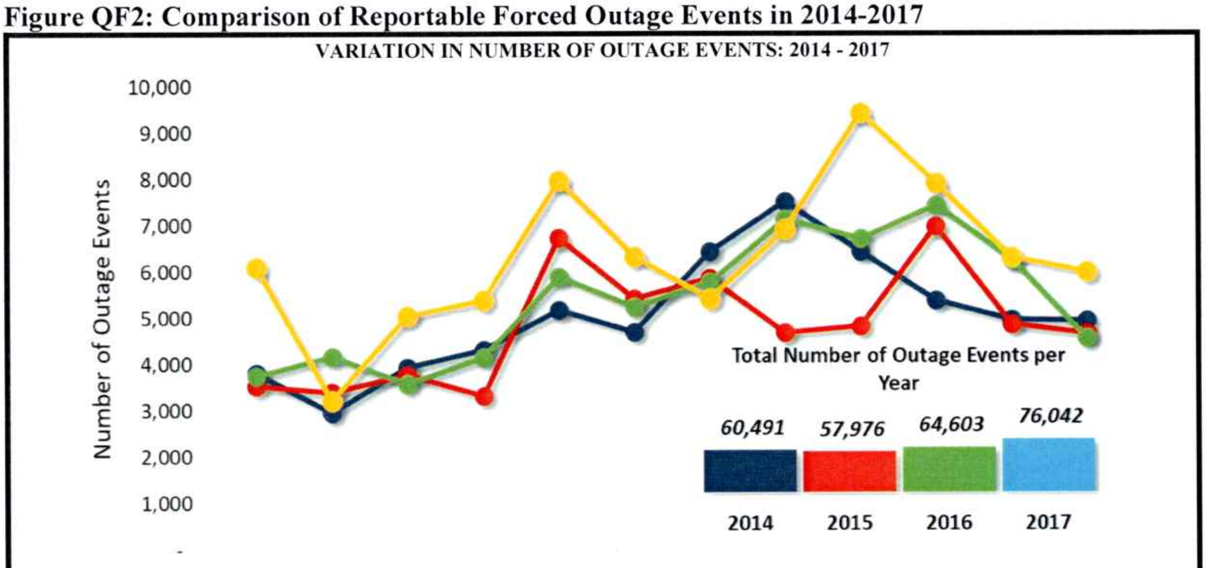


Figure QF2: Comparison of Reportable Forced Outage Events in 2014-2017



As shown, in 2017, there were variations in the number of outage events reported for each month with the highest number of 9,429 reported for 2017 September, a level which was much higher (49%) than the monthly average throughout the year. This appears to be abnormal, which needs to be further investigated by JPS. As shown in Table QF8 most of the reported forced outages were linked to the distribution system, which is expected. This tends to occur because most of the customers are connected to this part of the system, which is predominantly an exposed overhead network with inherent vulnerabilities. Outage events occurring in 2017, identified as sustained events and momentary events, were found to have a distribution of 91% and 9% respectively. These proportions were largely similar to those for the 2014, 2015 and 2016 reporting periods, indicating that annual distribution of sustained and momentary interruptions have largely remained constant. However, it is not clear as to the specific factors influencing this distribution.

A comparison of the total number of outages occurring in each year from 2014 to 2017 shows a significant increase in the number of outage events occurring in 2017 compared to the other years. The OUR's analysis also reveals that, for the four (4) years under observation, there has been an apparent increase in the number of outage events towards the middle of the year, with a reduction (fairly sharp in some instances) as the year comes to a close. This behaviour seems to coincide with the hurricane season but no major hurricanes have affected the island during these years. Therefore, further investigation may be necessary to clearly ascertain the reason for such noticeable increases in the number of outage events during this period.

Movement in JPS's Calculated Quality Indices

While the number of forced outages in 2017 have shown a sharp increase relative to the preceding three (3) years, the calculated quality indices for 2014-2017, as shown in Table QF1, indicates that:

- The average duration of unplanned interruptions have decreased since 2014;
- The frequency of unplanned interruptions have declined since 2014, despite an increase in the 2017 level relative to 2016; and
- The frequency of momentary interruptions in 2017 has shown a reversal to near the 2014 level, despite a marked decrease in the intervening years.

OUR's Calculation of the Reliability Indices

Taking into consideration the data treatment outlined above, the OUR computed the relevant quality indices for 2017, as shown in Table QF10 and Table QF11 below.

Table QF10: OUR Computed 2017 Reliability Indices

2017	RELIABILITY INDICES											
	Generation			Transmission			Distribution			Aggregate		
	SAIDI	SAIFI	MAIFI	SAIDI	SAIFI	MAIFI	SAIDI	SAIFI	MAIFI	SAIDI	SAIFI	MAIFI
Jan	4.043	0.391	0.708	14.722	0.138	0.064	210.968	0.904	2.941	229.732	1.432	3.713
Feb	5.569	0.205	0.813	8.382	0.076	0.000	89.123	0.443	0.699	103.074	0.725	1.512
Mar	9.785	0.608	0.662	15.425	0.134	0.101	136.675	0.842	1.254	161.885	1.583	2.017
Apr	3.851	0.426	0.515	12.929	0.121	0.106	122.637	0.800	2.351	139.417	1.347	2.973
May	27.870	1.347	1.133	9.473	0.155	0.189	234.997	1.086	2.087	272.341	2.588	3.410
Jun	7.050	0.732	0.615	27.372	0.116	0.091	159.615	0.800	1.683	194.037	1.648	2.390
Jul	3.935	0.193	0.544	3.240	0.045	0.022	107.495	0.724	1.395	114.670	0.962	1.961
Aug	10.284	0.566	0.830	9.987	0.119	0.051	122.846	0.854	2.069	143.116	1.538	2.950
Sep	31.913	1.104	1.058	2.978	0.022	0.138	190.240	1.203	3.102	225.131	2.329	4.298
Oct	3.872	0.386	1.759	3.073	0.054	0.063	184.583	0.766	2.469	191.527	1.205	4.292
Nov	0.149	0.020	0.683	11.466	0.180	0.059	120.077	0.635	1.442	131.692	0.835	2.184
Dec	1.812	0.221	0.665	1.595	0.041	0.137	149.517	1.017	1.572	152.924	1.280	2.374
TOTAL	**110.135**	**6.198**	**9.986**	**120.640**	**1.200**	**1.023**	**1,828.772**	**10.073**	**23.064**	**2,059.546**	**17.471**	**34.074**
CAIDI	*17.770*			*100.541*			*181.543*			*117.881*		

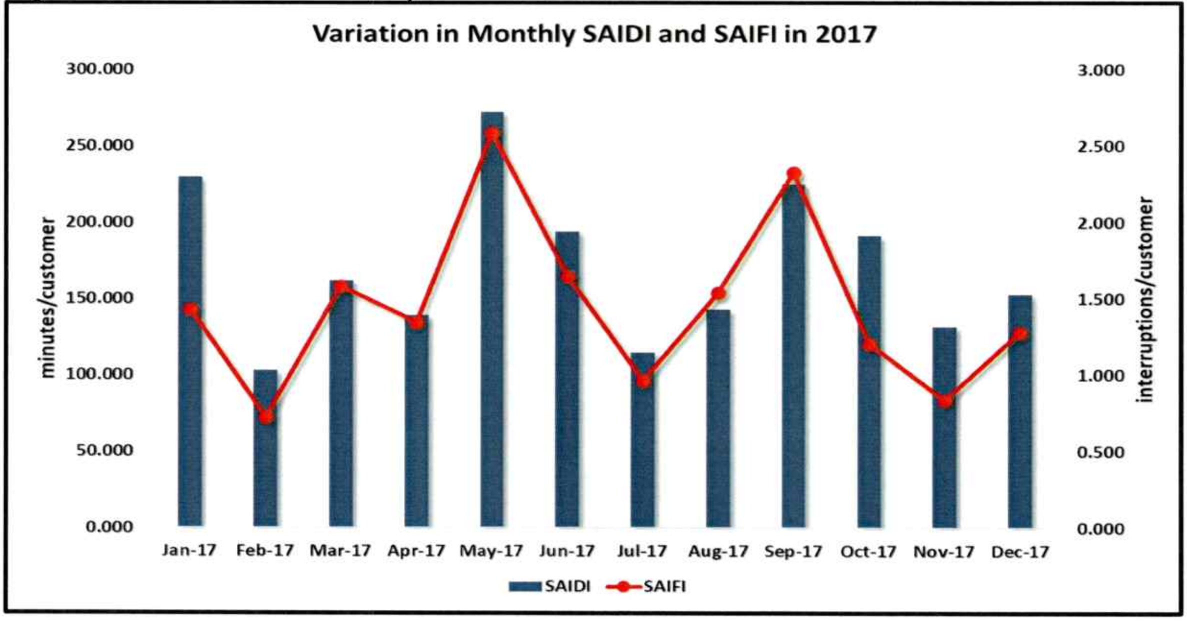
The average value of each quality index for 2017 is obtained by aggregating the calculated values of the respective quality index for each segment of the system, as given in Table QF10 above. These are presented in Table QF11 below.

Table QF11: 2017 Quality Indices Calculated by OUR

INDICATOR	UNIT	JPS CALCULATED INDICES	OUR CALCULATED INDICES (Including MED Events)	PERCENTAGE DEVIATION
SAIDI	minutes/customer	1,755.514	**2,059.546**	17.32%
SAIFI	interruptions/customer	16.447	**17.471**	6.23%
CAIDI	minutes/customer	106.740	**117.881**	10.44%
MAIFI	interruptions/customer	32.894	**34.074**	3.59%

For comparison, the 2017 quality indices derived by OUR and those by JPS are presented in Table QF11 above. As shown, all indices calculated by the OUR showed significant differences to those calculated by JPS, with the largest variations attributed to the duration indices (SAIDI and CAIDI). These deviations are largely due to the exclusion of certain outage events from JPS's calculations, as discussed above. This is a matter which will have to be addressed going forward. The variations in the quality indices, SAIDI and SAIFI is illustrated in Figure QF3 below.

Figure QF3: Variation in Monthly SAIDI and SAIFI in 2017



Geographical Representation of Outage Data

An apparent shortcoming of the Q-Factor scheme is that the relevant quality indices represent System-wide average reliability performance across the entire island of Jamaica. This, in principle, suggests similar service levels to all customers. However, in practice, due to the topographical layout and orientation of power system, it is likely that there will be wide variation in supply reliability across the service areas, that is, some areas may experience exceptionally good reliability, while others suffer with disproportionately poor reliability. To investigate this situation, the OUR assessed the reliability performance across the different parishes and major service areas across the country, using indicators derived from the 2017 system outage dataset, as shown in Table QF12.

Table QF12: Number of Outages & Reliability Indices for Each Parish/Region

NUMBER OF OUTAGES & RELIABILITY INDICES FOR EACH PARISH/REGION							
Parish/Region	Number of Outages			Reliability Indices			
	Momentary	Sustained	Total Outages	SAIDI (min/customer)	SAIFI (interruptions/customer)	CAIDI (min/customer)	MAIFI (interruptions/customer)
Clarendon	418	5,161	5,579	2,217.79	11.79	188.14	31.61
Hanover	681	3,360	4,041	4,856.69	68.63	70.77	152.23
KSAN	666	9,297	9,963	1,548.62	10.71	144.66	8.09
KSAS	480	4,102	4,582	747.94	13.32	56.17	14.45
Manchester	946	4,622	5,568	1,266.51	17.17	73.75	68.99
Portland	94	1,959	2,053	1,365.99	11.74	116.32	4.15
Portmore	162	3,086	3,248	1,280.63	12.53	102.20	18.37
St. Ann	645	4,730	5,375	2,294.85	13.55	169.38	55.15
St. Catherine	601	7,720	8,321	1,701.24	10.87	156.57	26.35
St. Elizabeth	469	3,363	3,832	2,611.03	55.99	46.64	108.38
St. James	531	8,519	9,050	2,547.43	19.85	128.34	16.42
St. Mary	595	4,393	4,988	3,574.53	15.63	228.66	25.47
St. Thomas	118	3,135	3,253	5,817.35	21.06	276.20	18.53
Trelawny	194	2,409	2,603	4,373.05	29.45	148.51	32.26
Westmoreland	216	3,370	3,586	2,283.04	18.23	125.26	22.06

The number of outages were allocated as shown in Table QF12 above and are illustrated geographically in Figure QF4 below.

Figure QF4: Number of Outages per Parish/Region for 2017

The computed values of SAIDI and SAIFI for the various areas of the country are as shown in Table QF12, above and are illustrated geographically in Figures QF5 and QF6 below.

Figure QF5: SAIDI per Parish/Region for 2017 (minutes/customer)

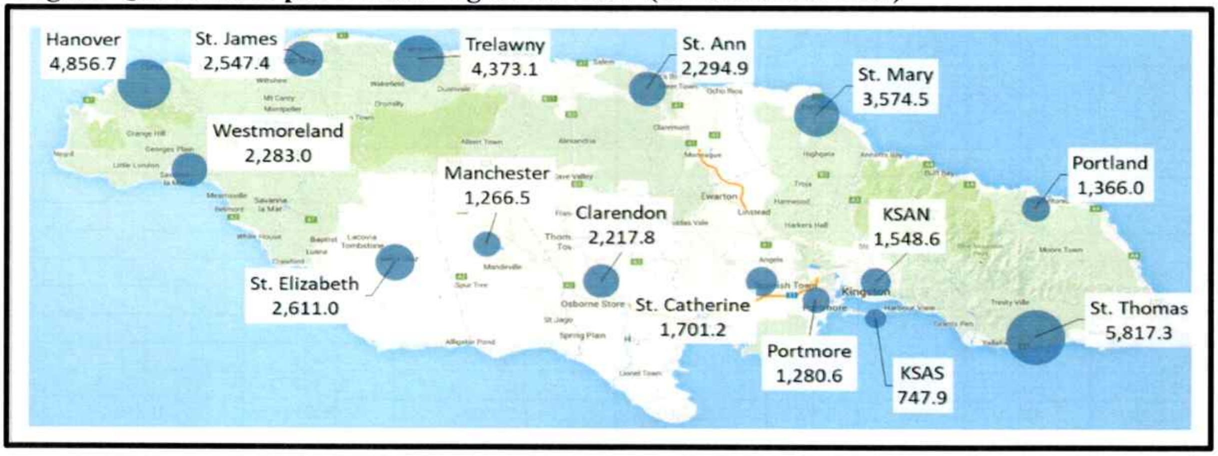
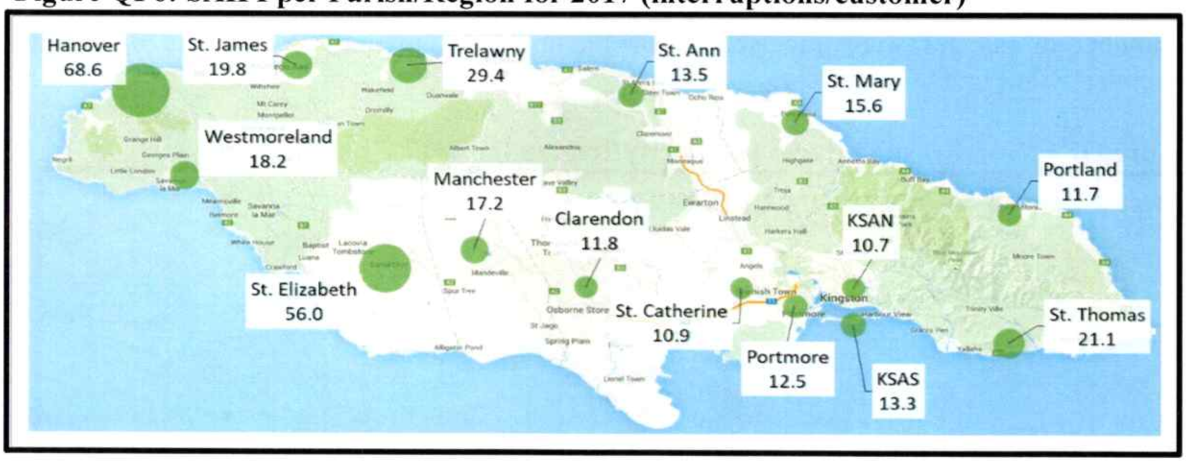


Figure QF6: SAIFI per Parish/Region for 2017 (interruptions/customer)



Figures QF5 and QF6 above provide a clear demonstration of the degree of variation in service reliability experienced by JPS's customers in 2017. For the parish of Hanover in particular, the average customer experienced well over six (6) times the number of outages, and more than three (3) times the outage duration compared to customers in the KSAN region. This example illuminates the embedded disparities in the quality of service provided to JPS customers dispersed across the service areas. Furthermore, this reinforces concerns regarding the shortcomings of the Q-Factor scheme in its current form, as customers in certain parts of the country frequently complain about poor quality of service, but are required to pay the same rates as those customers who consistently enjoy high quality service. This situation will therefore require greater effort on the part of JPS to ensure that electricity service is delivered to customers on a more equitable basis, in accordance with the requirements of the Licence and the EA.

Variations in Outage Information across JPS Datasets

During the Q-Factor review, inconsistencies were observed with the 2017 outage data reported in the MS Excel file "*Reliability 2018 dataset.xlsx*" and other regulatory reports, including JPS's 2017 monthly Technical Reports and "JPS's 2017 Final Dataset for OUR".

TREATMENT OF OTHER RELIABILITY INDICATORS

MAIFI-Related Issues

Based on the Licence 2016, MAIFI is not an index in the Q-Factor adjustment system. However, as dictated by the regulatory reporting requirements, JPS is required to record momentary interruptions experienced by customers and report them to the OUR on an on-going basis. Similar to sustained interruptions, outages caused by momentary disruptions are examined and analyzed as part of the regulatory assessment of JPS's reliability performance. The MAIFI index is also calculated for regulatory monitoring purposes.

Major Event Days

At the 2014-2019 Rate Review, JPS indicated that it has adopted the IEEE Standard 1366 – 2012 (the Guide for Electric Power Distribution Reliability Indices) as a guide for deriving the relevant quality indices, Major Event Days (MEDs), Major Event Day Threshold (T_{MED}), and other reliability indicators. This is acknowledged as good industry practice, as the standard supports uniformity in the computation of the relevant indices, and outlines a consistent approach for reporting service reliability. Notably, the OUR also recognizes the IEEE Standard 1366 – 2012 as a useful guide for distribution system reliability. However, in the regulatory treatment of the Q-Factor, the OUR has indicated that the use of this standard should not conflict with or deviate from the legal and regulatory requirements applicable to quality of service in the Jamaican electricity sector.

For the 2014-2017 annual system outage data, T_{MED} was derived and applied by JPS. In order to verify the accuracy of JPS's T_{MED} calculation, daily SAIDI figures were calculated using the 76,042 reportable forced outage events for 2017, as well as the 2014, 2015 and 2016 outage data previously submitted by JPS. The resulting T_{MED} calculated by the OUR varied from that calculated by JPS. JPS identified three MEDs in 2017 which OUR confirmed: January 9th, March 6th and May 16th. However, OUR also identified a fourth MED: September 27. A total of 2,897 reportable forced outage events were identified by the OUR that occurred on MEDs, as defined. It is not a surprise that 2017 January 9 is identified as a MED, because at the time there were numerous reports in the public domain of widespread outages on JPS's T&D system. On the request of the OUR, JPS submitted a technical report on the situation, which revealed that the supply interruptions did not involve the loss of generation capacity and shutdown of the transmission system, but instead were mainly attributed to maintenance-related issues, distribution equipment failure and impingement of uncontrolled vegetation on distribution circuits.

Based on the existing legal and regulatory framework, there is currently no provision or arrangement where system outages captured under MEDs are to be excluded from calculation of the quality indices. Further, in the 2014-2019 Determination Notice, the OUR made reference to the use of the IEEE Standard as a guide for application of the reliability indices. However, no explicit position was established regarding the exclusion of MEDs from the Q-Factor adjustment mechanism. Notwithstanding, the OUR made the following comments regarding major system shutdown incidents:

> *"With respect to major System shutdown incidents such as those which occurred since 2006, the OUR is of the view that these incidents in particular, should be treated within the framework of major events. That is, they should be separately reported and analyzed and addressed under a different penalty system. A penalty would apply if after investigation, it is confirmed that the occurrence of such incident was caused by negligence of JPS. For these outages, the measure of unreliability would be the dollar cost of the power outage to JPS' customers."*

Additionally, Recommendation #2 to the OUR in the 2016 August 27 total system shutdown investigation report, which was accepted, indicates the following:

> *"Consider an approach to incorporate a separate reliability performance measure to address the effects of major System outages determined to be within JPS' control, as a component of the QoS requirements. This may involve compensation to customers affected by a major System failure such as the 2016 August 27 incident, which would provide a further incentive to the System Operator to ensure that its actions or operations do not adversely impact System reliability."*

These positions suggest that major system failures/incidents that may constitute a MED in the annual system outage dataset should NOT be excluded from the computation of the quality indices unless a separate compensation/penalty system is in place to address the impact of these events.

For emphasis, since 2017 Annual Review, the OUR has been very explicit in its position regarding MEDs, indicating that the current legal and regulatory framework does not allow for the exclusion of MEDs from the outage data used for evaluation of the Q-Factor. As such, the OUR maintains its position that outage events related to MEDs, shall be included in the calculation of the relevant quality indices.

<u>Major System Failures</u>

Section 45 (16) (a) of the Electricity Act, 2015 defines a major system failure as follows:

> *a) "major system failure" means a system failure that –*
>
> *i. has not been planned by the System Operator;*
>
> *ii. affects at least one thousand customers; and*
>
> *iii. lasts at least two hours;"*

During the OUR's review, 478 outages were identified in the 2017 annual outage dataset that satisfied the above definition of a major system failure.

System Outages Related to Force Majeure Conditions

The OUR's review of JPS's 2017 system outage dataset also identified a number of outages that were reported to be caused by Force Majeure events. JPS did not include these events in their calculation of the primary quality indices, and instead, JPS separately presented their potential effect on the reliability indices together with the effect due to events related to MEDs.

OUR'S POSITION ON THE Q-FACTOR

Application of the Q-Factor in the annual PBRM as required by the Licence 2016, is dependent on the setting of a reliable baseline based on accurate and credible power outage information. This baseline is critical to implementation of the Q-Factor incentive scheme, as it represents the reference point for measurement of the annual actual quality of service performance versus the annual targets set by the OUR, in the applicable revenue cap period. Over the years, the OUR's review of JPS's annual outage datasets has identified varying issues impacting the quality of the data, some of which have remained outstanding, while others have recently surfaced. In recognition of these unfavourables, JPS has been proactive in eliminating the identified issues, which have progressively yielded notable improvements in the quality of the annual outage data in successive years, particularly since the commissioning of the OMS in 2013 December. Despite improvements, data quality implementation challenges still prevail, which will require continued consultations between the OUR and JPS on the Q-Factor. This collaborative approach is critical to achieving the objective of implementing the Q-Factor adjustment system at the 2019-2024 Rate Review.

Findings and Issues from Q-Factor Review

The findings and issues resulting from review of the 2017 annual outage dataset and JPS's Q-Factor proposals during this 2018 Annual Review, are discussed below.

Outage Data Related Issues

(1) Errors relating to duplication of records, incorrect classification of outage events, and negative duration events, which appeared in previous annual outage datasets, were not present in the 2017 outage dataset. However, the review found, a considerable number of outage event records denoted as "NULL". Additionally, an outage event was included in the raw outage dataset that did not appear in the calibrated dataset for no indicated reason. These errors were raised with JPS during the review process, but a response was not provided.

(2) Consistent with the 2016 annual outage dataset, daily customer count data was appropriately applied. However, while the degree of variability in daily customer counts has improved, there are observed inconsistencies with customer count data included in regulatory reports

and other data sources, submitted to the OUR during 2017. As was highlighted in the 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice, this situation needs to be urgently rectified by JPS, as customer count is an important variable that is integral to a wide range of utility metrics, including the prescribed quality indices, system losses, and other indicators. These disparities if not normalized, can introduce uncertainties in the collected outage data and distort the calculation of the quality indices.

(3) The number of outage events defined by JPS as "Non-Reportable Forced Outage Events" are still high relative to the total forced outages (approximately 7%). These outages were apparently screened out from the raw outage data in the calibration process. While JPS has implemented its "Rules Based Data Dictionary" to deal with abnormalities in the outage data, it is not clear as to the specific nature of some of non-reportable outages and the basis of the classification. This will require further discussion with JPS.

(4) A comparison of the "calibrated dataset" with the raw dataset, revealed a number of changes to outage event data elements. On closer examination, these changes all appear to be a result of the application of Rule 1 of JPS' "Rules Base Data Dictionary". However, there are three (3) other rules that form part of this "Rules Base Data Dictionary" that could change the designation of an outage event from "Reportable" to "Non-Reportable" if applied. Based on further investigation, it would appear that the rules were applied prior to JPS compiling the "raw" dataset, as almost 7% of the outage events in the "raw" dataset are classified as "Non-Reportable". This implies that there are still data classification and reconciliation issues connected to the application of "Rules Base Data Dictionary" that need to be addressed by JPS.

(5) As was detected in 2016 annual outage dataset and documented in the 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice, it was again observed that system outage data included in other regulatory reports to the OUR, was incongruent with the 2017 system outage data, in terms of the number of outage events and data categories. In the 2018 Annual Review submission, JPS sought to clarify this issue, claiming that they result from outage queries and subsequent resolution which are an ongoing part of its outage management process. However, JPS should recognize that these disparities can create uncertainties regarding the reliability of its reported outage data. In that regard, JPS should ensure that there is consistency in reported data through proper validation, and in cases where there are unavoidable deviations, appropriate reasons should be given. This matter may need further consultation with JPS.

(6) Currently, outage data submitted to the OUR as part of JPS' Monthly Technical Reports, does not include the full range of information for outage events occurring during the relevant month. While the OUR notes JPS' position that its outage management process may result in some outage information being amended after review, consistent with the

OUR's position on the Q-Factor in the 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice, JPS is required to submit the full outage data for the applicable month within fifteen (15) days after the end of that month. This is considered a necessary means to enable the early detection of potential errors or issues with the data on a progressive basis and at shorter intervals.

Reliability Measurement and Indicators

(7) In the 2017Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice, the OUR indicated that outage events occurring on days identified as Major Event Days (MEDs) must be included in the quality indices prescribed by the Licence, as there are no regulatory instruments which make provision for the use of a MED performance indicator in the Q-Factor. While JPS appears to be of the view that MEDs should be accounted for in the calculation of the quality indices, the OUR reiterates its position that outage events captured in MEDs, and outages caused by major system failures as defined in the Electricity Act, 2015, shall be included in the calculation of the quality indices prescribed by the Licence 2016.

(8) Similar to the 2016 outage situation, the 2017 annual outage dataset also contains a number outages JPS claimed resulted from Force Majeure events. Consistent with the 2017 Annual Review & Extraordinary Rate Review (CPLTD) Determination Notice, JPS in its 2018 Annual Review submission, indicated that the reported Force Majeure outage events are in accordance with Condition 11, paragraph 2 of the Licence 2016. JPS also indicated that details of the Force Majeure outage events with supporting documentation will be reported to the OUR on a monthly basis during the reporting year. However, to date, the OUR has not received such information from JPS. Based on the regulatory requirements, these will not be excluded from the calculation of the quality indices prescribed by the Licence unless there is clear evidence of the Force Majeure event and supporting documentation that the company was excused from complying with quality of service requirements in accordance provisions of the Licence 2016.

(9) Section 45 (16) of the Electricity Act, 2015 defines a "major system failure" as a system failure that (i) has not been planned by the System Operator; (ii) affects at least one thousand customers; and (iii) lasts at least two hours. Based on this threshold, the OUR's review identified 478 outages in the 2017 annual outage dataset that would qualify as a "major system failure". Under the said section 45 of the Electricity Act, 2015 there are stipulated obligations of the System Operator when a major system failure occurs. However, the OUR acknowledges that the identified effects that have precipitated in the 2017 outage data may have been unintended. In that regard, the OUR will collaborate with JPS on this issue, going forward, to facilitate normalization.

System Reliability Performance Improvement

(10) In the 2018 Annual Review submission, JPS reported that in 2017 the company invested US$49M in improving the system's reliability performance, with US$26M allocated to T&D initiatives and US$23M to Generation. On page 90 of JPS's submission, JPS also indicates that US$17.3M was invested in the rehabilitation and reinforcement of the T&D network during 2017. However, the connection between this expenditure and the $26M indicated above, is not clear. Additionally, the evidence to support the reported expenditures, capital investment schedule and the commensurate reliability impact was not provided.

(11) For system reliability improvements in 2018, JPS proposes to invest US$38.07M in areas, including grid management & modernization and integrated vegetation management. Despite these interim strategies for the Q-Factor assessment at the 2019-2024 Rate Review, JPS will be required to submit a detailed reliability improvement plan as part of its 5-year Business Plan, which should include a description of the proposed projects, costs, benefits, expected impact and project implementation timelines.

(12) According to the Licence 2016, the Q-Factor is based on the average reliability performance across the entire system. Furthermore, since there is no discrimination to customers on the electricity rate charged based on location, it would be logical for all customers served by the system to expect similar service levels regardless of location. However, the OUR's Q-Factor analysis based on the 2017 annual outage dataset, shows that there is a wide variation in service reliability across the country, as measured by the quality indices (SAIFI and SAIDI). This evidence suggests that reliability management in some service areas is inferior and exhibits disproportional characteristics. While it is recognized that service levels can be impacted by the technical and topographical features of the system, the System Operator should seek to ensure that an acceptable quality of service is provided to customers regardless of geographical location, to limit perceptions of discrimination.

OUR'S DETERMINATION ON JPS's Q-FACTOR

OUR's review of the 2017 system outage dataset revealed that the company continues to make progress towards ensuring that a reliable outage dataset is in place to set the Q-Factor baseline. However, as outlined above, there are still issues that need to be resolved before this objective can be achieved. As previously established, this will require continued consultation between the OUR and JPS on this issue, up to the 2019-2024 Rate Review.

Based on the Q-Factor evaluation, related issues and consideration, the Office determines that no Q-Factor adjustment will be allowed in the PBRM for the 2018-2019 rate adjustment period. Accordingly, the Q-Factor shall remain in the dead band range.

ANNEX 6: OUR'S 2018 SYSTEM LOSSES REPORT

Electricity loss is a key component in measuring the efficiency and financial sustainability of the power sector. It represents the difference between the amount of electricity that enters the System and the amount that is delivered to end-users, reflecting the degree of productivity of the transmission and distribution (T&D) systems. Losses also include the electricity delivered but not billed, directly translating into financial losses and, to a great extent, represent an indicator of the operational soundness of electric utilities. The total electricity loss for any given period is usually expressed as a percentage of total energy input to the System (net generation) and can be computed as follows:

System Losses (%) = [(Electricity to System (MWh) – Total Electricity Billed (MWh))/Electricity to System (MWh)] X 100%

There are two broad categories of losses encountered in power systems: Technical Losses (TL) and Non-technical Losses (NTL).

Overview

The 2016 Annual Review signaled a departure from the approach used to quantify system losses that was established in the 2014-2019 Determination Notice. In the 2014-2019 Determination Notice, the system losses target was broken down into a technical target and a non-technical target. In keeping with Schedule 3 of the Licence 2016, the system losses was disaggregated into three components:

a) Technical losses (Ya), designated TL;
b) Non-technical losses totally under JPS's control (Yb), designated JNTL; and
c) Non-technical losses not totally under JPS's control (Yc), designated GNTL.

For the component which is defined to be partially under JPS's control, a Responsibility Factor (RF) now applies. This is critical to the determination of the portion of NTL defined as Yc as shown in the equations below. The total system losses for which JPS is held accountable, is computed based on the formulae below:

Yy-1	**=**	**Yay-1 + Yby-1 + Ycy-1**	
	Yay-1	=	Target System Loss "a" Rate%y-1 – Actual System Loss "a" Rate%y-1
	Yby-1	=	Target System Loss "b" Rate%y-1 – Actual System Loss "b" Rate%y-1
	Ycy-1	=	(Target System Loss "c" Rate%y-1 – Actual System Loss "c" Rate%y-1)*RF

Where: Ya = TL; Yb = NTL totally within JPS's control; Yc = NTL not totally within JPS's control; and RF is a percentage from 0% to 100%, which is determined by the Office.

In translating system losses to a monetary value, the total system losses differential (Yy-1) must be multiplied by the Actual Revenue Target in the previous year (ARTy-1) which may be expressed as:

$$\text{TULos}_{y-1} = Y_{y-1} * ART_{y-1}$$

It is important to note that the system losses adjustment construct delineated above is a symmetrical incentive/penalty mechanism. If JPS underperforms it will be penalized since its revenues would be reduced. Alternatively, if the company out-performs the targets in aggregate terms, then it will receive additional compensation by way of higher revenues. Additionally, the application of the system losses mechanism has changed under the Licence 2016. Prior to 2016 July, the system losses mechanism was applied on a monthly basis to the total fuel cost. However, under the new arrangement the mechanism is applicable instead to the company's non-fuel revenue on an annual basis.

Summary of JPS's System Losses Proposals

In the 2018 Annual Review submission, JPS proposed:

- no TL target, stating that it is in the process of remodeling its network and no new information is available to inform a target for the 2019-2020 regulatory period;
- a total NTL target of 16.55% - 16.75%, stating that a short to medium term target setting process (2019-2020) that is aligned with the loss reduction strategy, resource alignment and expected results, was necessary; and
- Responsibility factor be reduced from 20% to 10%

The system losses target & actual level for the 2018-2019 adjustment and the proposed targets for 2019-2020, are shown in Table SLT1.

Table SLT1: System Losses Target & Actual for 2018-2019 and Proposed Target for 2019-2020

System Losses: Actual and Target				
Component	Symbol	2018-2019		2019-2020
		Target	Actual	Proposed Target
JPS TL	Ya	8.00%	8.60%	No Proposal
JPS NTL (Total) - JNTL	Yb	3.30%	6.63%	Proposal for total NTL of 16.55% - 16.75%
JPS NTL (Partial) - GNTL	Yc	9.70%	11.22%	
Responsibility Factor	RF	20%	20%	10%

Background on JPS's System Losses

System losses, calculated on a 12-month rolling average performance basis, was reported at 16.58% of net generation year-end 2001. However, over the years it has increased, peaking at 27% in 2015 and dipping slightly to 26.45 at the end of 2017.

In the 2009-2014 Determination Notice the OUR recognizing the challenges that JPS was facing in dealing with system losses:

- increased the target initially from 15.8% to 19.5% for 2009/2010 and set it at 17.5% for the rest of the Rate Review period; and
- established the EEIF, a US$13 million per annum Fund, financed by customers to combat system losses.

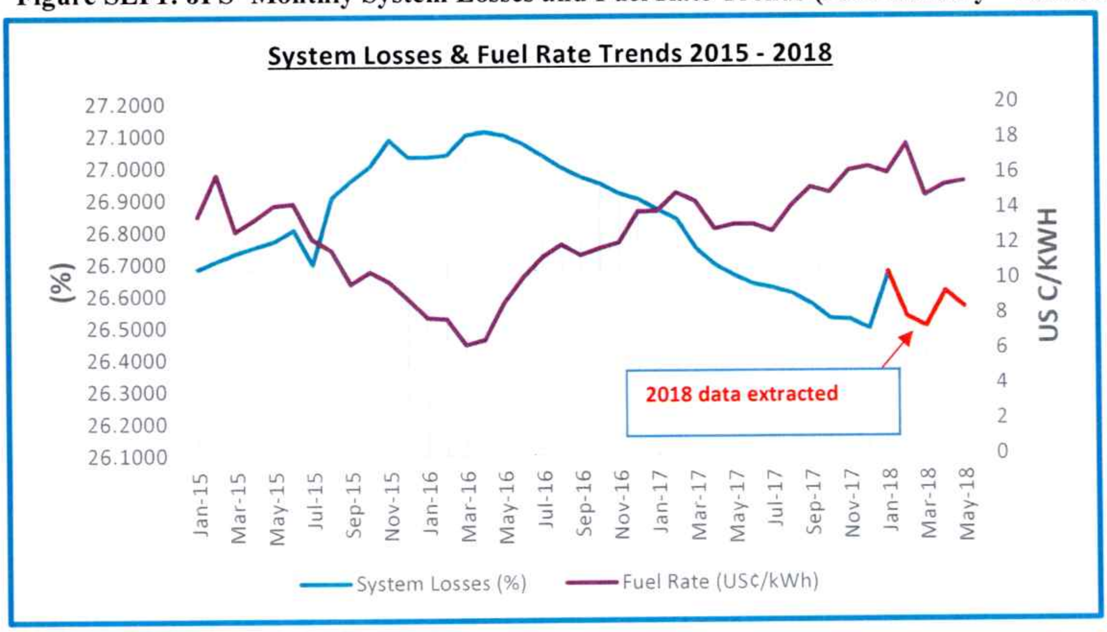
At the 2013 Annual Tariff Adjustment, the OUR in response to financial sustainability concerns from JPS, provided additional relief to the company by way of a Fuel Cost Recovery Adjustment (FCRA), which allowed JPS to recover approximately US$30.33 Million up to 2014 December, with conditions for a certain level of reduction in system losses. These strategies did not achieve the objectives as losses increased from 23.0% in 2009 to 26.6% at the end of 2014.

The determinations made in the 2014-2019 Determination Notice sought to keep the US$13 million per annum EEIF in place and the overall system losses target at 19.2%, with 8.4% and 10.8% assigned to technical and non-technical components respectively.

JPS's System Losses Performance

Figure SLF1 below shows the movement in the monthly system losses and Fuel Rate over the period 2015 January to 2018 May. It is evident that despite fluctuations in the Fuel Rate (declining at first and then climbing in the latter half of the period), system losses has remained more or less constant between 26.60-27.00% of net generation.

Figure SLF1: JPS' Monthly System Losses and Fuel Rate Trends (2015 January – 2018 May)



While the monthly Fuel Rates were linked to movements in fuel oil prices, there was no clear correlation between the reported system losses and Fuel Rates. This indication also provides a clear basis to negate the position that high fuel costs is one of the main drivers of System losses in the Jamaican electricity sector.

2017 Energy Balance

For 2017, the reported total net generation to the System was 4,363.1 GWh. As shown in Table SLT2, 73.55% (3,208.9 GWh) of this generation was used to supply billed energy, while the remainder (1,154.1 GWh) contributed to System losses, representing 26.45% of net generation. This breakdown constitutes the 2017 energy balance for the electricity system.

Table SLT2: Summary of JPS' 2017 Energy Breakdown

JPS's 2017 Energy Balance		
	Energy Distribution (MWh)	**% of Net Generation**
Technical Losses	375,225	8.60%
Non-Technical Losses	776,611	17.85%
TOTAL SYSTEM LOSSES	1,154,130	26.45%
BILLED ENERGY	3,208,949	73.55%
NET GENERATION	**4,363,079**	**100.00%**

Source: JPS 2018-2019 Annual Review Filing

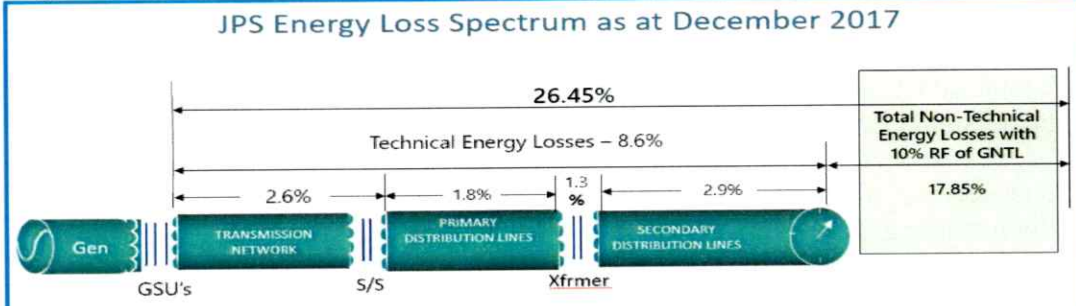
Categorization of JPS's System Losses

While system losses are often reported as a composite figure, they are comprised of various categories which stem from numerous sources.

A further breakdown of the total system losses as at 2017 December is captured in the 2017 December Energy Loss Spectrum (ELS) shown in Figure SLF2. At the 2014-2019 Rate Review, it was established that the ELS at the end of December of subsequent years will be the main basis for evaluation of the losses.

As shown in the 2017 ELS, the electricity losses (TL and NTL) are mainly concentrated in the distribution network and accounts for over 80% of the total losses. It also shows that NTL are driven by illegal practices and mismanagement.

Figure SLF2: JPS' 2017 December Energy Loss Spectrum



Description/Category		No. of Customers	Bill Sales (MWh)	Energy Loss (MWh)	% Loss	JNTL	GNTL
Billed Customers	Streetlight/Stoplight/Interchange (R60)	432	110,577	3,903	0.09%	0.09%	0.00%
	Large C&I (Rate 40, 50 & 70)	1,973	1,432,744	32,435	0.74%	0.74%	0.00%
	Medium C&I (rate 20)	5,738	257,825	11,890	0.27%	0.27%	0.00%
	Small C&I (rate 20)	59,670	338,459	14,622	0.34%	0.29%	0.05%
	Residential (rate 10)	569,488	1,069,344	261,224	5.99%	4.79%	1.20%
Sub-Total		**637,302**	**3,208,949**	**324,073**	**7.43%**	**6.18%**	**1.25%**
Unquantified				47,110	1.08%	1.08%	0.00%
Illegal users (non-customers)		180,000		407,722	9.34%	0.00%	9.34%
TOTAL		**817,302**	**3,208,949**	**776,611**	**17.85%**	**7.26%**	**10.59%**

Source: JPS System Performance Reports (2017)

Comparison of JPS's Energy Loss Spectrums

A comparison of the System losses components reported for 2014 to 2017 is provided in Table SLT3.

Table SLT3: Comparison of JPS's 2014 to 2017 Energy Loss Spectrums

2014 - 2017 System Losses Components						
Loss Category	**Components**	**2014 January**	**2014 December**	**2015 December**	**2016 December**	**2017 December**
TECHNICAL LOSSES (TL)	Transmission Network	2.60%	2.60%	2.60%	2.60%	2.60%
	Primary Distribution Lines	1.80%	1.80%	1.80%	1.80%	1.80%
	Distribution Transformers	1.30%	1.30%	1.30%	1.30%	1.30%
	Secondary Distribution Lines	2.90%	2.90%	2.90%	2.90%	2.90%
	Total Technical Losses	**8.60%**	**8.60%**	**8.60%**	**8.60%**	**8.60%**
NON-TECHNICAL LOSSES (NTL)	Streetlight/Stoplight (R 60)	0.20%	0.20%	0.09%	0.09%	0.09%
	Large C&I (Rate 40&50)	1.19%	0.75%	0.45%	0.45%	0.74%
	Medium C&I (rate 20)	0.45%	0.29%	0.31%	0.38%	0.27%
	Small C&I (rate 20)	0.31%	0.33%	0.32%	0.27%	0.34%
	Residential (rate 10)	4.36%	6.10%	7.08%	7.45%	5.99%
	Sub-Total	**6.51%**	**7.67%**	**8.25%**	**8.67%**	**7.43%**
	Internal Bleeds/Unquantified	1.56%	0.27%	0.53%	0.14%	1.08%
	Illegal Users (non-customers)	**9.85%**	**10.11%**	**9.60%**	**9.30%**	**9.34%**
	Total Non-Technical Losses	**17.92%**	**18.05%**	**18.38%**	**18.11%**	**17.85%**
TOTAL		**26.52%**	**26.65%**	**26.98%**	**26.71%**	**26.45%**
	NET GENERATION (MWh)	**4,141,643**	**4,112,698**	**4,209,322**	**4,343,812**	**4,363,079**

The data in Table SLT3 shows that:

- In 2017, total system losses decreased by 0.26% to 26.45% of net generation reflecting energy losses similar to those reported for 2014 January;
- In 2017, net generation increased by approximately 0.4% (19.3 MWh) over the 2016 level, marginally impacting the out-turn of the losses on a percentage basis;
- Total TL have remained at a constant level of 8.6% of net generation from 2014 January to 2017 December. This suggests that the reported TL reduction initiatives executed by JPS have not delivered the desired results or no tangible efforts have been employed to reduce these losses during the period under observation;
- Energy losses related to large C&I customers continue to be relatively high at level within 1.0% of net generation each year;
- Total NTL have increased from 17.92% of net generation in 2014 January to 18.38% in 2015 December but exhibited a slight reversal in 2016 and realized a modest reduction to 17.85% at the end of 2017 December;
- NTL attributable to residential customers (Rate 10) have increased steadily from 4.36% of net generation in 2014 January to 7.45% at the end of 2016 December but subsequently decreased to 5.99% as at 2017 December. However, there was no reported loss reduction activities to substantiate such impact
- NTL attributable to Illegal Users (non-customers) increased from 9.85% of net generation in 2014 January to 10.11% at the end of 2014 December. However, as reported by JPS, the estimated number of illegal users remained constant at 180,000 with the same annual energy loss of 403,920 MWh per year (33,660 MWh per month) over the period. This implies that the indicated movement in the losses percentage does not reflect any actual change in energy loss in terms of MWh for this losses category. Instead, these movements in percentage losses are essentially due to the effect of variations in annual net generation.

Analysis of JPS's 2017 Monthly System Loss Components

The breakdown for each category of the System losses for each month in 2017 is provided in Table SLT3.

Table SLT4: JPS's 2017 Monthly System Loss Breakdown

JPS' 2017 Energy Loss Spectrum: Monthly Breakdown														
Loss Category	**Components**	**2016 DEC**	**2017 JAN**	**2017 FEB**	**2017 MAR**	**2017 APR**	**2017 MAY**	**2017 JUN**	**2017 JUL**	**2017 AUG**	**2017 SEP**	**2017 OCT**	**2017 NOV**	**2017 DEC**
TECHNICAL LOSSES (TL)	Transmission Network	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%
	Primary Distribution Lines	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%
	Distribution Transformers	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%
	Secondary Distribution Lines	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
	Total TL	**8.60%**	**8.60%**	**8.60%**	**8.60%**	**8.60%**	**8.60%**	**8.60%**	**8.60%**	**8.60%**	**8.60%**	**8.60%**	**8.60%**	**8.60%**
NON-TECHNICAL LOSSES (NTL)	Streetlight/ Stoplight (RT 60)	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%
	Large C&I (Rate 40&50)	0.45%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.75%	0.74%	0.74%
	Medium C&I (Rate 20)	0.38%	0.37%	0.36%	0.35%	0.34%	0.33%	0.32%	0.31%	0.31%	0.30%	0.29%	0.28%	0.27%
	Small C&I (Rate 20)	0.27%	0.25%	0.25%	0.26%	0.27%	0.29%	0.29%	0.30%	0.30%	0.31%	0.32%	0.32%	0.34%
	Residential (Rate 10)	7.48%	5.90%	5.93%	5.95%	5.95%	5.97%	5.98%	5.97%	5.96%	5.96%	5.96%	5.97%	5.99%
	Sub-Total	**8.67%**	**7.35%**	**7.38%**	**7.39%**	**7.40%**	**7.41%**	**7.42%**	**7.42%**	**7.40%**	**7.40%**	**7.41%**	**7.41%**	**7.43%**
	Internal/ Unquantified	**0.14%**	**1.28%**	**1.24%**	**1.20%**	**1.07%**	**1.07%**	**1.03%**	**1.17%**	**1.18%**	**1.07%**	**0.90%**	**1.05%**	**1.08%**
	Illegal Users (non-customers)	**9.30%**	**9.38%**	**9.39%**	**9.40%**	**9.39%**	**9.40%**	**9.41%**	**9.39%**	**9.36%**	**9.35%**	**9.33%**	**9.34%**	**9.34%**
	Total NTL	**18.11%**	**18.01%**	**18.01%**	**17.99%**	**17.87%**	**17.88%**	**17.86%**	**17.97%**	**17.95%**	**17.82%**	**17.64%**	**17.80%**	**17.85%**
TOTAL		**26.71%**	**26.61%**	**26.61%**	**26.59%**	**26.47%**	**26.48%**	**26.46%**	**26.57%**	**26.55%**	**26.42%**	**26.24%**	**26.40%**	**26.45%**
2017 Final Dataset		**26.90%**	**26.87%**	**26.84%**	**26.75%**	**26.69%**	**26.66%**	**26.63%**	**26.62%**	**26.61%**	**26.57%**	**26.53%**	**26.52%**	**26.49%**

Source: JPS 2017 January-December ELS and "JPS 2017 Final Dataset"

The System losses data in Table SLT4 shows that:

- System losses reported in the 2017 monthly ELS are not consistent with those included in "JPS 2017 Final Data Set" and other reports, despite being calculated on the same basis, (12-month rolling average). These are perpetual discrepancies distorting the reported data and raise concerns on the credibility of the reported loss levels and JPS's approach for measurement, reconciliation and validation. There are also similar issues with customer count data, which is integral to the evaluation of NTL.

- All the components of TL have remained unchanged for each month in 2017, consistent with the situation in previous years. This clearly indicates that JPS's approach to reducing these losses have been ineffective and probably misdirected;

- NTL losses related to the Rate 60 class remained constant at 0.09% of net generation throughout the period, despite the replacement of approximately 35% of the existing street lighting with smart light emitting diode (LED) type from 2017 July – December under the smart streetlight programme (SSP);

- NTL due to Rate 10 customers accounted for 7.48% of net generation in 2016 December. However, in 2017 January, these losses sharply decreased to 5.99%, which remained in that range throughout the entire year. This shift equates to a change of 1.58% of net generation (similar to the magnitude of the shift recorded between 2016 June and July). Effectively, this change means that NTL caused by Rate 10 customers actually decreased by 5,718 MWh in 2017 January, with no significant increase in the number of residential customers recorded. Additionally, system performance reports submitted to the OUR do not identify any energy loss reduction achievement to substantiate such impact. Therefore, the basis for such a significant shift in 2017 January in such a short timeframe is questionable;

- NTL attributable to Illegal Users (non-customers) varied within the range 9.30% to 9.41% of net generation during the period. Nevertheless, the estimated number of "illegal users" remained constant at 180,000 with the same monthly average energy loss of 33,977 MWh (407.72 GWh per year) during the period. This indicates that the quantity of energy leakage in this category is fixed and the remaining segments of the ELS adjusted to reflect the total losses based on the estimated energy balance;

- In contrast to Rate 10 losses, NTL defined as "Unquantified" jumped from 0.14% of net generation in 2016 December to 1.28% in 2017 January but remained at over 1% for the entire 12-month period. This change means that NTL defined as "Unquantified" actually increased by 4,138 MWh in 2017 January. As exhibited in the data, NTL in both the Rate 10 and "Unquantified" categories, were altered in the opposing direction by a similar margin depicting a re-arrangement of the ELS. As it stands, there are no reported loss reduction intervention or additional loss enabling activity to justify such material re-allocations. As stated in previous Determination Notices, this situation therefore raises significant concerns as to whether there are deliberate attempts to manipulate the ELS, to target a certain predetermined performance outcome. According to JPS, "Unquantified" energy losses, usually stem from inefficiencies in its internal operations, such as: meter reading errors, estimation errors, metering inaccuracies (programming, installation, etc.), defective meters, human errors driven by business process weaknesses, etc. Based on the sources of these losses, it is not clear how they are being accounted for. Not properly accounting for these losses creates challenges for establishing a credible baseline for setting the relevant system losses targets;

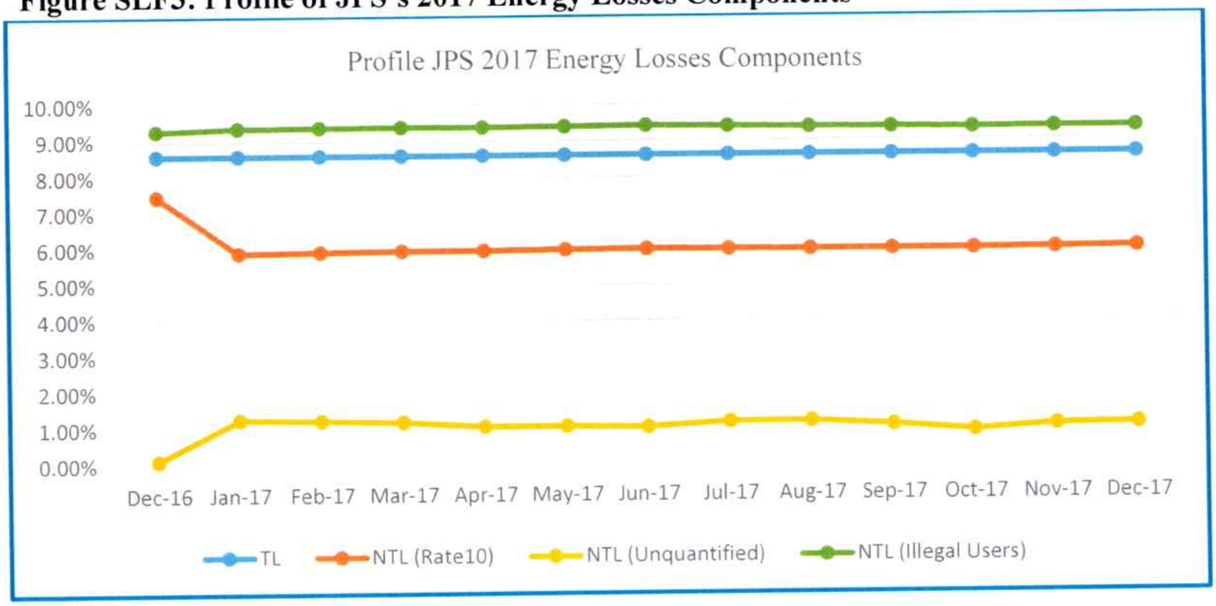
- NTL related to the large C&I (Rate 40, 50 &70) category (Rate 70 class added at the 2017-2018 Annual Review adjustment date) drastically increased from 0.45% of net generation in 2016 December to 0.74% in 2017 January and remained constant at that level to 2017 December. However, the specific factors that occasioned the sudden step change were not defined. Also, the constant loss level of 0.74% for the entire year suggests that the initiatives being implemented to address these losses are ineffective.

- All other categories of NTL remained fairly constant throughout the entire 12-month period, inferring that the strategy employed by JPS to reduce these losses is proving to be persistently unsuccessful or misguided.

Despite the burdensome economic consequences of electricity losses, it appears that there is no systematic approach to enable proper quantification of these losses, complemented by a robust monitoring strategy that enables clear identification of the sources and to accurately keep track of performance.

The movement in specific components of the System Losses in 2017 is illustrated in Figure SLF3.

Figure SLF3: Profile of JPS's 2017 Energy Losses Components



Licence Requirements Applicable to JPS's System Losses Targets

According to Schedule 3, paragraph 37 of Licence 2016, the Office shall have the power to set targets for JPS's System losses which should be reasonable and achievable, taking into consideration the Base Year, historical performance and agreed resources included in the five (5)-Year Business Plan, corrected for extraordinary events. The Office shall also take into consideration the role of the GOJ in addressing the non-technical aspect of the System losses that are not entirely within JPS's control.

Specifically, with respect to the setting of JPS's Systems losses targets, Schedule 3, paragraph 38 of the Licence 2016, provides as follows:

> *"The target set by the Office for System losses shall normally be done at the Rate Review and be for a "rolling"[1] ten (10)-year period broken out year by year over the following three (3) categories:*
>
> *a. Technical Losses*
> *b. The aspect of non-technical losses that are within the Licensee's control*
> *c. The aspect of the non-technical losses that are not totally within the Licensee's control."*

As delineated in the Licence 2016, the prescribed rolling 10-year approach is to assure a clear long term focus for loss mitigation, incentivizing JPS to go beyond what might have been agreed in the five (5)-year Business Plan, since the benefit will be accrued over a longer period. Schedule 3 of the Licence 2016 also states that the breakdown of the elements of the loss target will assure a linkage to the reductions targeted and the actions taken and/or funded in the five (5)-year Business Plan. It also supports a potential "Z-Factor" adjustment in case the non-technical losses that are not totally within JPS's control are strongly influenced by matters unforeseen during the rate review process.

REVIEW OF JPS's TECHNICAL LOSSES

Technical losses are associated with the configuration and characteristics of the transmission & distribution (T&D) infrastructure and inherent in the flow of current/power through the system.

Description of JPS's Technical Losses

Based on the ELS, JPS's TL is divided into four (4) categories. These are described in Table SLT5.

Table SLT5: Elements of JPS' TL

JPS's TL Components		
TL Components	**Current Level**	**Description**
(1) TL in the transmission system	2.6%	Measured losses - determined based on measurements from net generation meters, feeder meters, and metered energy delivered to customers supplied directly from the transmission system
(2) TL in distribution feeder lines	1.8%	Calculated losses - computed at peak load (kW) condition then converted to kWh energy losses by applying a system loss factor
(3) TL in distribution transformers	1.3%	Calculated losses - determined based on the manufacturer's power loss specification for each transformer size along with JPS' operating parameters.
(4) TL in secondary distribution networks	2.9%	Calculated losses - estimated in three portions: secondary line losses, service drop losses, and meter coil losses.

Based on regulatory reports submitted to the OUR, there is no clear indication that these components of TL are being measured, calculated and evaluated on a systematic basis and in accordance with prudent utility practice.

JPS's Technical Losses Proposals

In the 2018 Annual Review submission, JPS asserted that it recognizes the need to account for TL and the company has made investments towards improving its measurement and modelling ability in this regard. According to JPS, it acquired the DIGSILENT network modelling software in 2016, updated SCADA EMS and implemented the Automated Distribution Management System (ADMS) in 2017. JPS noted that the remodeling of its network in DIGSILENT commenced in 2017 and the process has continued in 2018. JPS also acknowledged that the TL measurement has not been updated in previous filings and it is preparing to address this situation in the upcoming Five-Year Rate Review. JPS indicated that such effort is pending the completion of the load flow simulations with DIGSILENT and more precise and frequent measurement of transmission losses. JPS posited that as a consequence of the remodeling efforts, there is no new information available to inform a target for TL and so the company elects not to propose one for the 2019-2020 regulatory period.

OUR's Comments:
While the OUR supports the idea of using modern engineering approaches to address the issue of TL, the focus should not only be centred on transmission losses, but also on the distribution components, which, as shown in the ELS, account for the bulk of these losses.

JPS's Technical Loss Reduction for the 2018-2019 Adjustment Period

JPS's TL is currently estimated at 8.6% of net generation, which was reviewed and benchmarked by KEMA DNV (international consultants), now DNV GL, back in 2013.

OUR's Comments:
This review of TL by KEMA DNV that JPS continues to reference was carried out back in 2013. Since that time there has been no improvement in JPS's TL as reflected in the 2014 to 2017 ELS and other regulatory reports, despite claims by the company that it has expended significant resources to address these losses over the years. Notably, JPS's 2014-2019 Rate Case Application in 2014, indicated that the estimated level of 8.6% in 2014 was actually due to an alteration to the measurement approach, which resulted in a downward adjustment in TL from 10.0% to 8.6% of net generation, as was represented in JPS's 2014 January ELS. For emphasis, this change in the level of JPS's technical losses in 2014 was not due to any loss reduction initiative implemented by JPS.

TL Reduction Initiatives

In the 2018-2019 Annual Review submission, JPS asserted that it continues to work diligently towards its optimal TL level through several economically feasible initiatives. These include: (1) primary distribution feeder power factor correction, (2) primary distribution feeder phase balancing and, (3) Voltage standardization program (VSP).

JPS indicated that these projects include, but are not limited to: (1) upgrading of over 75% of the primary distribution network voltages from 12kV and 13.8kV to 24kV; (2) re-conductoring of distribution lines; (3) reconfiguration of primary distribution feeders; (4) rehabilitation of the secondary distribution network; (5) installation of substation bulk capacitor banks; and (6) the replacement of distribution transformers (pole and pad mounted) with low loss transformers. The proposed TL reduction projects are described as follows:

Power Factor (PF) Correction

This is aimed at maintaining a minimum of 0.95 PF for each feeder during peak and off-peak load conditions. The PF of 0.95 is the optimal point at which the greatest return on investment is achieved. This can be realized by the use and application of both switched and fixed pole-mounted capacitor banks to address the peak and off-peak VAR demands, respectively.

Feeder Phase Balancing

Feeder phase balancing is essential in maintaining good voltage quality and reliability of supply by ensuring the neutral current for the 3-phase system is less than 10% of the feeder average current. Phase imbalance above 20% translates into energy loss due to increased line current and voltage drop, it also makes economic sense to prioritize and improve these to below 10%. According to JPS, in 2016 the focus was on identifying feeders with phase imbalances above 20% to economically improve and maintain them within acceptable phase-balanced levels. JPS indicated that for 2017-2021, efforts will be placed on the continuation of the activities in 2016 which will be incorporated as part of its routine operation of maintaining the phase imbalance of the corrected feeders within acceptable levels.

Voltage Standardization Program (VSP)

According to JPS, the VSP is aimed at standardizing the medium voltage network across the island at 24 kV, to improve the TL on these feeders. In 2016, the VSP was reportedly resumed and specific distribution feeders were targeted and upgraded to 24 kV. At the end of 2016, the Greenwood Substation 110 feeder was completed. In 2017, the feeders completed were Martha Brae Substation 110, Duncan's Substation 110, Roaring River 210, 310 & 410, and Hope 510.

JPS indicated that in 2018, the Ocho Rios 310, 410 and 510 feeders will be upgraded.

OUR's Comments:

It is important to note that JPS has repeatedly talked about implementing these activities for more than ten years. Moreover, these identical projects were presented in the 2017-2018 Annual Review Filing. Under the circumstances, it is rather unfortunate that at this 2018 Annual Review, the same strategy is again being replicated. Additionally, the efforts described by JPS to address these losses appear to be mediocre, on the basis that some of these proposed efforts can be classified as routine activities that are expected to be executed as part of the company's day-to-day operations in the process of meeting its obligations to operate the System in an efficient and reliable manner. It is imprudent to be doing the same thing repeatedly and expecting a different result.

In the 2016 Annual Review Filing, JPS also presented the same technical losses narrative as outlined above, as it consistently did in previous submissions. Despite JPS's persistence over the past 10 years in proposing these programmes and receiving funding to support such programmes, TL have remained static at 8.6% of net generation for almost five (5) years. This is a clear indication that no meaningful actions are being taken by the company to address these losses and to realize the optimal level for the Jamaican electricity System. It should be noted that no impact in terms of TL reduction was quantified by JPS for the proposed TL reduction initiatives to be deployed in 2017. Also, there was no budget presented by JPS for capital expenditure to fund the proposed TL reduction initiatives in 2017. This highlights some of the weaknesses in JPS's approach to combat these energy losses.

OUR's Evaluation of JPS's Technical Losses

At the 2014-2019 Rate Review, JPS presented its five (5)-Year Loss Reduction Plan for both TL and NTL for the period 2014 to 2018. The details of the referenced loss reduction plan is shown in Figure SLF4.

Figure SLF4: JPS's 2014-2019 Rate Review - Five (5)-Year Loss Reduction Program

Category	Initiatives	2014	2015	2016	2017	2018	Total
Illegal (Users) Non-customers	Strike Force, RAMI, CAAMI, Community Renewal Program	0.14%	0.25%	0.43%	0.43%	0.43%	**1.68%**
Residential	Field Audit	0.13%	0.15%	0.10%	0.10%	0.10%	**0.58%**
Small Commercial	Field Audit	0.07%	0.07%	0.10%	0.10%	0.10%	**0.44%**
Large Commercial & Industrial	Field Audit	0.24%	0.10%	0.10%	0.10%	0.10%	**0.64%**
Technical Energy Loss	Feeder PF & PB, S/s Capacitor Banks, Secondary Rehabilitation	0.18%	0.23%	0.24%	0.15%	0.10%	**0.90%**
Targeted Feeder Energy Balance Sol	RAMI, CAAMI, Field Audit & Aggregate meters	0.33%	0.50%	0.60%	0.70%	0.80%	**2.93%**
Impact on Losses		**1.09%**	**1.30%**	**1.57%**	**1.58%**	**1.63%**	7.17%

Source: JPS 2014-2019 Rate Case Application

The OUR's 2014-2019 Determination Notice, actually became effective in 2015 January. As such, the proposed 2014-2019 loss reduction plan was pushed forward to start in 2015 instead of 2014. Accordingly, it was expected that TL would be reduced by 0.18%, 0.23%, 0.24%, and 0.15%, at the end of 2015, 2016, 2017, and 2018 respectively. This would result in a cumulative reduction in TL of 0.80% of net generation by the end of 2018. Nevertheless, no reduction in TL was reported for 2015, 2016, 2017, and year-to-date 2018.

In the OUR's 2014-2019 Determination Notice, it was determined that the EEIF would be used to provide funding to support the implementation of the proposed loss reduction programmes.

EEIF-Supported Technical Losses Reduction Projects

Evidence of the inaction of JPS in addressing TL is also reflected in the EEIF reports submitted to the OUR by JPS on a quarterly basis up to the 1st quarter of 2017. The reports revealed that during the EEIF project schedule there was little or no loss reduction activity in relation to TL.

Optimal Level of Technical Losses

Technical losses depend on many interrelated factors within the system configuration (power line voltage, loads, etc.). However, an optimal level can be achieved with the implementation of a robust and feasible technical loss reduction programme encompassing a glide path to realize tangible reductions over a designated period. Adherence to good industry practices and reference to international benchmarks can also be used to gauge the degree of optimality.

Power Flow Simulations to Evaluate Transmission Losses

As part of a practicable approach to optimize transmission losses, the OUR has conducted a number of power flow analyses using power system simulation software models. The results indicate that under existing system configuration, JPS's transmission losses are in the range of **2.0% - 2.2%** of net generation, compared to the 2.6% being reported by JPS. These simulation results were factored into the setting of the TL target. Further, the OUR will continue to utilize these simulations and other scientific approaches to evaluate aspects of JPS's TL going forward.

OUR's Determination on JPS's Technical Losses Target

Following a comprehensive review and evaluation of JPS's TL losses, the OUR determined JPS's TL target as prescribed by the Licence 2016. In determining the target, the OUR took into consideration, among other things, the following factors:

- The level of TL reduction expected in 2017 based on previously approved loss reduction plans;
- JPS's TL reduction initiatives for 2018;
- The evaluation of transmission losses based on power flow simulations; and
- JPS's overall strategy to address TL since 2014.

As determined by the Office, the technical losses target to be applied in JPS's annual revenue adjustment mechanism for the 2019-2020 adjustment period shall be **8.0%** of net generation. This is set out in Table SLT6.

Table SLT6: JPS' TL Target Determined by OUR

OUR's Determination: JPS's Technical Losses Target for 2019-2020 Adjustment Period				
	[2018-2018] Adjustment	**[2018-2019] Adjustment**	**[2019-2020] Adjustment**	**[2018-2019] Adjustment**
ASPECT OF SYSTEM LOSSES [% of Net Generation]	JPS PROPOSED TARGET	OUR's APPROVED TARGET	NO TARGET PROPOSED	OUR DETERMINED TL TARGET
JPS TECHNICAL LOSSES (TL)	8.4%	8.0%	-	**8.0%**

REVIEW OF JPS's NON-TECHNICAL LOSSES

General

NTL as defined above, continues to be a problematic issue in the Jamaican electricity sector. However, these losses can be largely avoided by JPS if appropriate measures are implemented to eliminate or substantially reduce them. Based on the 2017 ELS, NTL account for approximately 70% of the total electricity losses. Given the severity of the problem, it demands urgent and robust action to ensure alleviation and to prevent further escalation. Notably, one of the unfavourable effects of NTL, is that customers who are being billed for accurately measured consumption and regularly paying their bills are required to subsidize users who illegally abstract electricity.

Reduction of NTL derives positive benefits to the electricity sector, such as decreasing retail electricity rates and releasing overburdened capacity to enable the utility to adequately, safely and efficiently meet legitimate electricity demands of the country and to contribute to economic development. Lower electricity losses also enhance financial sustainability of the utility, as additional revenues increase cost recovery and improves investment capacity.

Description of JPS's Non-Technical Losses

According to JPS's system losses data, total NTL are due to energy losses which occur in three main areas:

- NTL caused by Billed customers (RT10, RT20, RT40 & 50, and RT60)
- NTL defined as "Unquantified" that are internal to JPS's operations
- NTL due to Illegal Users (non-customers)

According to Schedule 3, paragraph 38 of Licence 2016, total NTL should be divided into two (2) categories:

- The aspect of NTL that are within JPS's control - designated by JPS as "JNTL"
- The aspect of NTL that are not totally within JPS's control – designated by JPS as "GNTL"

For 2017, JPS reported actual NTL of 17.85% of net generation, of which 9.34% was due to illegal users and 8.51% due to metered customers and "Unquantified" losses. Based on the 2017 ELS, the total NTL was disaggregated into JNTL and GNTL with 7.26% and 10.59% respectively. Refer to Figure SLF2.

JPS's Adjusted JNTL and GNTL

It was established from the 2014 Rate Review that the ELS at the December of subsequent years will be the foundational basis for assessment of the losses. This position was maintained even after the Licence 2016 became effective. It therefore holds that the evaluation of the losses at this 2018 Annual Review will be based on 2017 December ELS. However, after submitting the 2017 December ELS to the OUR, JPS subsequently altered the allocations to JNTL and GNTL shown in Table SLT7, without consultation with the OUR.

Table SLT7: JPS's Adjusted JNTL and GNTL

Description	Average Monthly Users	Billed Energy (MWh)	Energy Loss (MWh)	Energy Loss %	JNTL %	GNTL %
Billed Customers						
Streetlight, Stoplight, Interchange (RT60)	432	110,577	3,903	0.09%	0.09%	0.00%
Large Commercial (RT40&50)	1,973	1,432,744	32,435	0.74%	0.74%	0.00%
Medium Commercial (RT20)	5,738	257,825	11,890	0.27%	0.27%	0.00%
Small Commercial (RT20)	59,670	338,459	14,622	0.34%	0.13%	0.21%
Residential (RT10)	569,488	1,069,344	261,224	5.99%	1.53%	4.45%
Subtotal	637,302	3,208,949	324,073	7.43%	2.77%	4.66%
Internal Losses	N/A	N/A	47,110	1.08%	1.08%	0.00%
Illegal Consumers	180,000	N/A	407,722	9.34%	0.00%	9.34%
Grand Total	817,302	3,208,949	778,905	17.85%	3.85%	14.01%

Source: JPS 2018-2019 Annual Review Filing (Page 34)

This kind of interference with the reported System losses data is deemed imprudent and unacceptable. As such, the adjusted JNTL and GNTL will not be considered in the Annual Revenue Adjustment Mechanism at this 2018 Annual Review.

The information provided in Table SLT7 also suggests that JPS is accepting responsibility for only 15% of the total electricity losses.

JPS's NTL Proposals

JPS's NTL Target proposal is presented on page 46 of the 2018 Annual Review submission, as follows:

> ***"Based on the 5-year losses strategy and the progress in losses reduction to date, JPS expects to reduce losses by approximately 4 percentage points. At the end of the 2019/2020 tariff period, JPS expects to achieve a 1.1% - 1.4% reduction in the losses over the two year period. In light of this JPS is proposing a short to medium term target setting process (2019/2020) that is aligned with the loss reduction strategy, resource alignment and expected results. JPS believes that a reasonable and achievable non-technical loss target is 16.55% - 16.75%."***

As indicated, no specific target was proposed for JNTL and GNTL.

OUR's Evaluation of JPS's Non-Technical Losses Proposals

Energy Losses related to Streetlight/Stoplight/Interchange (Rate 60)

As reported in the 2017 December ELS, NTL related to Rate 60 accounts represented 0.09% of net generation (3.903 GWh). This percentage was the same for each month in 2017, indicating that no reduction in these losses was achieved, despite the replacement of approximately 35% of the existing street lighting with the smart LED type under the SSP.

In the 2018 Annual Review submission, JPS indicated that electricity losses assigned to this rate class have not changed since this is based on the same data as last year's submission. JPS also restated the streetlight situation with the Ministry of Local Government (MLG), which was previously articulated in previous Annual Review Filings. Notwithstanding, JPS, in recognition of the streetlights related losses, confirmed that the company takes full responsibility for **<u>100%</u>** of the electricity losses associated with the Rate 60 category.

<u>OUR's Position on JPS's Rate 60 Losses</u>

Despite JPS's concession on these losses, the nature of these energy leakages suggests that they are clearly within JPS's reach and should be eliminated. Therefore, consistent with the regulatory principles and determinations in previous Determination Notices, the OUR will continue to treat this category of NTL as being totally within JPS's control. Consequently, in concurrence with JPS's position, electricity losses related to Rate 60 accounts will NOT be factored into the relevant targets for NTL prescribed by the Licence 2016.

<u>Electricity Losses related to Large C&I (Rate 40, 50 & 70) Customers</u>

As reported in the 2017 December ELS, at the end of the year, a total of 1,973 large C&I customers were included in JPS's customer base, causing NTL equivalent to 0.74% of net generation (32.435 GWh). These NTL losses were reported at 0.45% in 2016 December but drastically increased to 0.74% in 2017 January, and remained constant up to 2017 December. However, the factors that contributed to the sudden step change in 2017 January were not identified.

In the 2018 Annual Review submission, JPS purported that electricity losses associated with Rate 40&50 customers were mainly caused by: Burnt Meter, Defective Metering, Defective Wiring, Bypass at/before Pothead, Bypass within the Meter, Idle Service, and Open Circuit. A distribution of these losses based on causation is provided Table SLT8 and illustrated in Figure SLF5.

<u>OUR's Comment</u>

For 2017, JPS claimed that 93.3% of Rate 40&50 losses were caused by "Open Circuit", translating to <u>30.3 GWh</u> of electricity losses. JPS defined this condition as a break in the conductor or conductors, supply to the meter, the customer or both, that results in the meter under-registering the energy consumed.

Whatever the mode, based on the level of visibility and monitoring capabilities available to JPS, it is inconceivable that losses due to open circuit conditions were allowed to reach such proportions. From a technical perspective, this is not a complex engineering problem, therefore, the solution should be quick and simple.

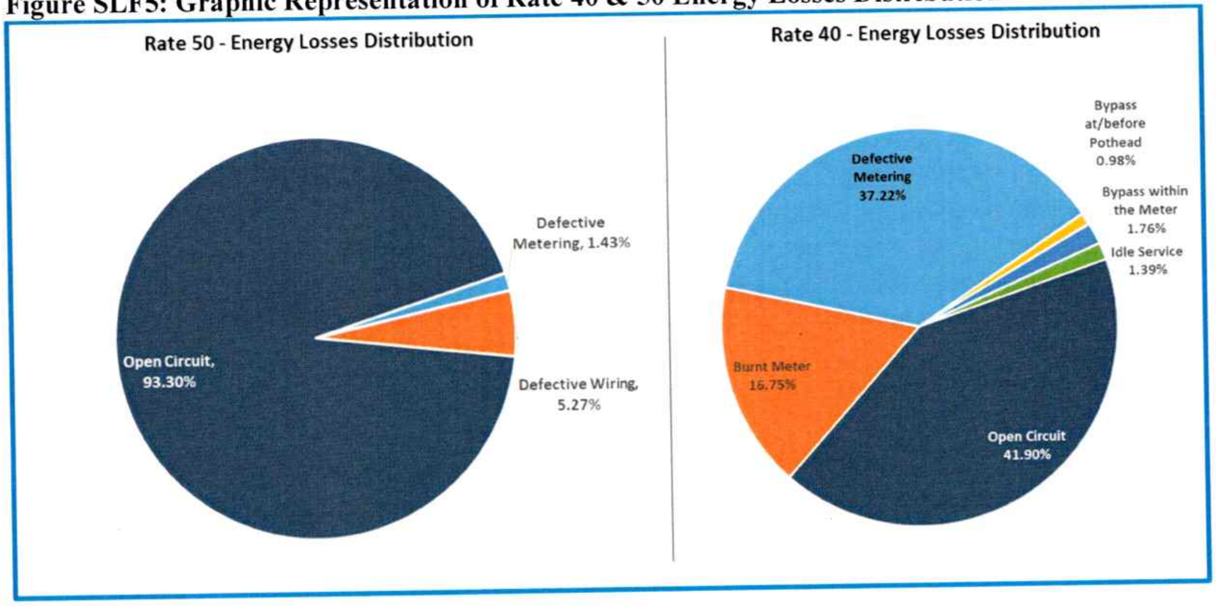
Table SLT8: Distribution of Electricity Losses attributed to Rate 40 & 50 Customers

Rate 40 & 50 - Energy Losses Distribution				
Mode of Losses	**RATE 40 Losses Distribution**		**RATE 50 Losses Distribution**	
	2016	**2017**	**2016**	**2017**
Burnt Meter	0.94%	16.75%	-	-
Defective Metering	23.32%	37.22%	49.00%	1.43%
Defective Wiring	49.15%	-	5.09%	5.27%
Bypass at/before Pothead	-	0.98%	-	-
Single Phasing	26.47%	-	45.91%	-
Bypass within the Meter	-	1.76%	-	-
Idle Service	0.12%	1.39%	-	-
Open Circuit	-	41.90%	-	93.3%
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Source data: JPS 2018-2019 Annual Review Filing

As shown in Table SLT8, there are significant variations in the reported sources and distribution of these losses from year to year. This raises concerns as to the consistency and appropriateness of the samples as well as the robustness and reliability of the methodology employed by JPS to evaluate these NTL. It is also not clear whether the losses reported from the previous years are being addressed.

Figure SLF5: Graphic Representation of Rate 40 & 50 Energy Losses Distribution



According to JPS, Rates 40 & 50 customers represent approximately 0.31% of its total customer base in 2017 but their contribution to billed energy was 44.65%. This means that a single incident of energy loss from any of these customers could diminish the company's revenues. Recognizing these detrimental effects, the company should be more strident in ensuring that electricity losses in these rate classes are restricted to zero on a sustained basis. Given the punishing financial consequences of these irregularities, JPS should rigorously seek to identify all possible sources of these losses, eliminate them and implement appropriate monitoring systems to prevent recurrence.

In the 2018 Annual Review submission, JPS indicated that customers have employed increasingly sophisticated methods to steal electricity that even with modern AMI infrastructure, these methods of theft are often very difficult to detect. It should be noted that this is characteristically a longstanding rhetoric being proffered by JPS, but this feeble excuse needs to be substituted with concrete action and staying ahead of the game.

With respect to the allocation of these NTL, JPS posited that there is little evidence that they are related to unauthorized customer intervention, and consequently 100% of electricity losses in the Rates 40 & 50 class should be assigned to JNTL. The OUR welcomes JPS's convergence on the treatment of this element of NTL, which is also consistent with the regulatory principles and determinations set out in previous Determination Notices. Notably, this approach was implemented by OUR since 2014, and will continue to be applied going forward.

<u>OUR's Position on JPS's Rates 40 & 50 Losses</u>

Despite JPS's position on these losses, the OUR maintains that their current level in terms of actual energy (32,435 GWh), is unacceptable and represents a departure from international best practice. The OUR therefore urges JPS to take the necessary actions to address these losses to the benefit of the utility and sector. The OUR is also of the view that these losses are not insurmountable and can be quickly reduced to zero based on the following factors:

- The main sources of Rates 40 & 50 losses have already been identified by JPS as shown in Table SLT8 and Figure SLF5. As such, there should be relative ease in formulating an effective strategy to eliminate them;
- All of the identified sources of the losses are related to metering or service connection defects which are directly within JPS' control.
- The number of customers/meters in these rate classes are relatively small compared to the total customer base, which should not impose any extraordinary challenges to the company in monitoring and auditing the accounts on an ongoing basis;
- According to JPS, all Rates 40 & 50 accounts have full AMI capability and coverage, including real-time monitoring and theft detection functionalities. These features can effectively increase JPS's capacity to monitor these accounts;
- The distribution of these Rates 40 & 50 losses indicates that JPS is fully aware of the loss drivers. Based on available System losses information, JPS possesses the capabilities to immediately detect service connection/metering irregularities as defined in the distributions. Given the nature of these irregularities, the recorded/estimated energy losses are recoverable, therefore JPS should seek to account for these leakages and recover the associated costs as applicable;
- The sources of some of these Rates 40 & 50 losses suggest that JPS can recover associated costs by means of adjustments in accordance with the relevant "Back Billing Policy" or other means available to JPS for redress.

JPS is required under the Licence 2016 to test 50% of its Rates 40 & 50 meters annually (Refer to Figure SLF6). However, JPS has indicated that it has exceeded this requirement by investigating 100% of its Rates 40 & 50 accounts annually. Compliance with this standard can also provide reasonable reinforcement to the company's efforts to reduce these losses.

Figure SLF6: Licence Requirement for JPS to Test Rates 40 & 50 Meters

SCHEDULE 2
OVERALL STANDARDS

CODE	STANDARD	UNITS	TARGETS JULY 2014 – MAY 2019
EOS7 (a)	Frequency of meter testing	Percentage of rates 40 and 50 meters tested for accuracy annually	50%
EOS7 (b)	Frequency of meter testing	Percentage of other rate categories of customer meters tested for accuracy annually	7.5%

Source: JPS Electricity Licence, 2016 (Schedule 2)

Based on the evaluation of the relevant system losses data, related issues and considerations, the OUR, consistent with its previous determinations, concurs with JPS that the company shall absorb **100%** of NTL associated with Large C&I (Rates 40 & 50) customers. As such, this component of NTL shall NOT be a part of the relevant NTL targets prescribed by Licence 2016.

Energy Losses related to Medium C&I (Rate 20) Customers

The Medium C&I (Rate 20) class captures customers that consume at least 3 MWh of electricity per month. As reported in the 2017 December ELS, at the end of the year a total of 5,738 medium C&I (Rate 20) customers were included in JPS's customer base, with contribution to NTL equivalent to 0.27% of net generation (11.89 GWh). At the start of 2017, these losses were reported at 0.37% but decreased steadily to 0.27% by the end of December.

Table SLT9: Distribution of Energy Losses due to Medium (C&I) Rate 20 Customers

Medium (C&I) Rate 20: Energy Losses Distribution			
Mode of Losses	**2015**	**2016**	**2017**
Burnt Meter	-	5.12%	8.60%
Defective Metering Infrastructure	25.00%	34.51%	58.24%
Defective Wiring/Incorrect Meter Configuration	3.00%	0.22%	-
Open Circuit/Single Phasing	-	18.25%	29.20%
Tampering	27.00%	-	-
Electronic Tampering	4.00%	-	-
Idle Service	-	0.15%	-
Bypass, Bypass at/before Pothead	4.00%	12.49%	3.49%
Bypass within Meter	-	29.26%	0.37%
Line Tap	37.00%	-	0.10%
TOTAL	**100.00%**	**100.00%**	**100.00%**

Source data: JPS 2016, 2017 & 2018 Annual Review Filing

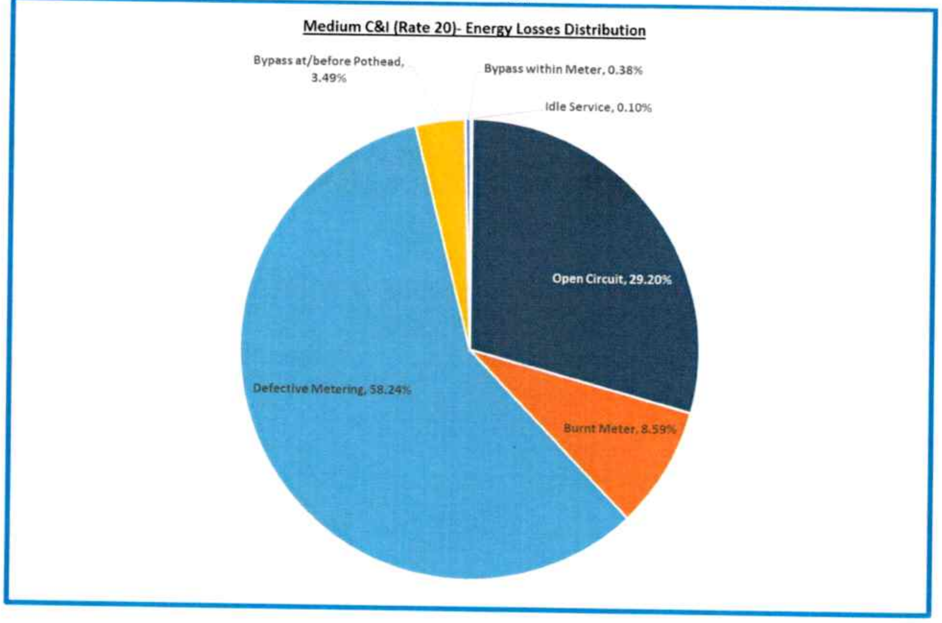
In the 2018 Annual Review submission, JPS claimed that electricity losses associated with Medium C&I (Rate 20) customers were mainly caused by: Burnt Meter, Defective Metering, Bypass at/before Pothead, Bypass within the Meter, Idle Service, and Open Circuit. A distribution of these losses based on causation is provided Table SLT9 and illustrated in Figure SLF7.

Similar to the Rates 40 & 50 analysis, this comparison for the Medium C&I category again reveals that there are significant variations in reported sources and distribution of these losses from year to year. This also raises concerns as to the consistency and appropriateness of samples as well as the robustness and reliability of the methodology employed by JPS to evaluate these NTL. It is also not clear whether the losses reported from the previous years are being addressed.

<u>*OUR Comments*</u>

Based on the losses data, approximately 58% of Medium C&I (Rate 20) losses was caused by "Defective Metering Infrastructure", translating to <u>9.6 GWh</u> of electricity losses. JPS describes this condition as a failure of the metering facilities to meet acceptable measurement tolerances arising from: manufacturing errors, environmental stress, fatigue, acts of nature and other circumstances affecting the meter, its socket and any other supporting accessories. However, it should be emphasized that these sources of losses are not directly related to illegal access but are rather associated with certain physical characteristics, which can be mitigated with strict conformance to relevant standards, regulations and protocols. Additionally, the existing regulatory framework makes reasonable allowance for redress to JPS, where it is impacted by losses due to some of these factors.

Figure SLF7: Medium C&I (Rate 20) - Energy Losses Distribution



JPS indicated that in 2017, approximately 60% of Medium C&I (Rate 20) customers' electricity supply was metered using AMI. These advanced meters have the capability to record customers' consumption profiles and, when interfaced with "analytics" resources, greatly enhance JPS's ability to monitor the Medium C&I (Rate 20) accounts. However, JPS cited that these meters have limited capability to detect bypass.

OUR's Comments:
The same argument was made in the 2017 Annual Review Filing, where JPS indicated that there were just over 3,000 AMI meters installed, giving an AMI penetration of over 60%. This indicates that no additional AMI meters were deployed during the 2018-2019 rate adjustment period.

JPS argued that installed AMI meters improved its ability to monitor Medium C&I (Rate 20) accounts but a significant portion of the losses are sustained from defective metering. Therefore, it is not clear why these conditions are contributing to the indicated level of losses.

JPS's Proposed Allocation of Medium C&I (Rate 20) NTL

JPS indicated that the majority of NTL associated with the Medium C&I (Rate 20) class are due to "Defective Metering" and "Open Circuit" conditions. Consequently, JPS proposes that **100%** of these losses should be assigned to JNTL.

OUR's Position on JPS's Medium C&I (Rate 20) NTL

Based on the evaluation of the relevant system losses data, related issues and considerations, the OUR, consistent with its previous determinations, concurs with JPS that the company shall absorb 100% of electricity losses related to Medium C&I (Rate 20) customers. As such, this component of NTL shall NOT be a part of the relevant NTL targets prescribed by the Licence 2016.

Energy Losses related to Small C&I (Rate 20) Customers

This rate class represents Rate 20 customers who consume less than 3 MWh monthly and are referred to as Small Rate 20 customers. As reported in the 2017 December ELS, at the end of the year a total of 59,670 small C&I (Rate 20) customers were included in JPS's customer base, causing NTL equivalent to 0.34% of net generation (11.62 GWh). JPS indicated that the company has expended significant resources in containing losses in this category and over 17,839 accounts were audited in 2017. However, these efforts appear to be unprofitable, because at the start of 2017, these losses were reported at 0.25% but steadily increased to 0.34% at the end of December.

In the 2018 Annual Review submission, JPS claimed that electricity losses associated with Small Rate 20 customers were mainly caused by: Burnt Meter, Defective Metering, Bypass at/before Pothead, Bypass within the Meter, Idle Service, Open Circuit, and Tampering. A distribution of these losses based on causation is provided in Table SLT10 and illustrated in Figure SLF8. JPS noted that the relative proportions were derived from weights, which are the product of the relative incident rate and the average recovery for each mode of the losses.

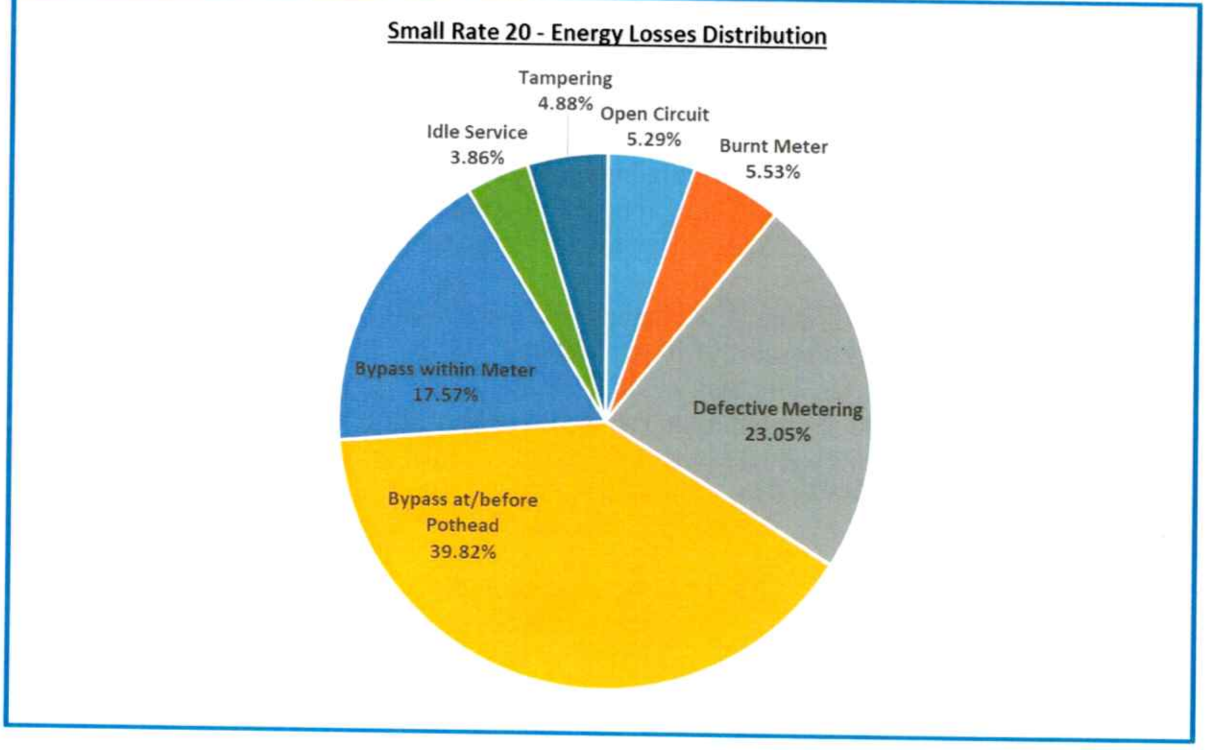
Table SLT10: Small Rate 20 - Energy Losses Distribution

Small (C&I) Rate 20: Energy Losses Distribution			
Mode of Losses	**2015**	**2016**	**2017**
Burnt Meter	14.00%	2.33%	5.53%
Defective Metering Infrastructure	-	13.22%	23.05%
Defective Wiring/Incorrect Meter Configuration	2.00%	0.48%	-
Single Phasing	9.00%	4.03%	-
Bypass/Direct connection within Meter	7.00%	70.52%	17.57%
Inverted Meter	2.00%	-	-
Idle Service	16.00%	0.25%	3.86%
Bypass at/before Pothead	9.00%	9.17%	39.82%
Line Tap	26.00%	-	-
Open Circuit	14.00%	-	5.29%
Tampering	-	-	4.88%
Other	1.00%	-	-
TOTAL	**100.00%**	**100.00%**	**100.00%**

Source data: JPS 2016, 2017 & 2018 Annual Review Filings

As with the previous cases, this comparison for the Small Rate 20 category again revealed that there are significant variations in the reported sources and distribution of these losses from year to year. This also raises concerns as to the consistency and appropriateness of samples as well as the robustness and reliability of the methodology employed by JPS to evaluate these NTL. It is also not clear whether the losses reported from the previous years are being addressed.

Figure SLF8: Small Rate 20 - Energy Losses Distribution



OUR's Comments:
Based on the distribution shown, irregularities denoted as "Bypass at/before Pothead" accounted for approximately 40% of the energy losses (5.85 GWh) in this category. JPS defines this condition as an unauthorized connection, or connections, that divert all or part of the energy being used around a JPS revenue meter, which results in under-registering of the energy consumed. This is a crucial observation in light of the large number of strike force operations reported by JPS. Nonetheless, this is a situation that potentially could be exacerbated, if appropriate measures are not implemented.

Additionally, some of the identified causes that contributed to NTL in the Small Rate 20 category are addressed in the relevant "JPS Back Billing Policy", which sets out the appropriate regulatory procedure for redress and recovery.

JPS should also recognize that electricity losses emanating from defects associated with a customer-owned electrical infrastructure, should be referred directly to that specific customer and not to the entire customer base, as implied in JPS's allocation of the losses between JNTL and GNTL.

JPS reported that in 2017, a significant number of field investigations were carried out on Small Rate 20 accounts, which resulted in the recovery of approximately 1.3 GWh of the energy. However, JPS argued that factors such as the size of the customer base, repeat offenders diverting resources, and lack of significant AMI penetration, are constraining its ability to effectively monitor this category.

In the 2018 Annual Review submission, JPS noted that only a limited number of Small Rate 20 customers (less than 2% as at December 2017) have revenue meters with remote monitoring capability. Consequently, intelligence for these accounts are obtained from analysis of monthly meter readings, historical trends, and other techniques. JPS argued that while there has been some success with these techniques, their shortcomings limit the efficacy of JPS's monitoring. To address this issue, JPS declared that the company is planning a complete roll-out of SMART AMI meters over the next five (5) years, to assist in the intelligence gathering process, augment its ability to monitor this rate class, and to detect and control the associated losses.

JPS also indicated that its ability to recover losses in this rate class is better than the residential rate class, but the company still faces significant challenges in understanding the nature and sources of losses in the rate class. According to JPS, because of the limited AMI penetration, field investigations remain the most effective tool in detecting electricity losses in the Small Rate 20 category.

JPS's Proposed Allocation of Small Rate 20 NTL

Based on the 2018 Annual Review submission, JPS proposed that NTL in the Small Rate 20 category should be allocated to JNTL and GNTL as 38% and 62% respectively.

OUR's Comments:
Consistent with the regulatory principles and related determinations in previous Determination Notices, the OUR disagrees with JPS's proposed allocation on the basis that most of the identified sources and causes of these losses involve issues related to JPS's metering facilities and electricity supply/connection irregularities, and are considered to be within the direct control of JPS, some of which tend to emerge over time as a consequence of continuous exposure to electrical conditions intrinsic to the delivery of electricity service to customers, while others have amplified because of the ineffectiveness of the ongoing System losses reduction strategy.

While the proposal for full deployment of AMI meters in this rate class is encouraging, it is important to note that JPS had previously committed to implementing these same initiatives as far back as 2009 with the support of the EEIF, but this was never executed. Given the magnitude of the losses problem, it is of necessity that JPS transition from the planning phase to full implementation of these projects.

OUR's Position on JPS's Small Rate 20 NTL

Based on the evaluation of the relevant system losses data, the OUR rejects JPS's proposed allocation of Small Rate 20 related NTL into JNTL and GNTL. The OUR is of the view that the total quantity of these NTL is within the control of JPS, and can be minimized with the implementation of the appropriate programmes and strategies. However, based on the constraints identified by JPS, the OUR has allocated NTL associated with Small Rate 20 customers, as follows:

- JNTL - 75%
- GNTL – 25%

These considerations were reflected in the relevant NTL targets prescribed by JPS's Licence.

Energy Losses related to Residential (Rate 10) Customers

Based on the 2017 December ELS, at the end the year a total of 569,488 Rate 10 customers (2.2% increase over 2016) were included in JPS's customer base causing NTL equivalent to 5.99% of net generation (261.22 GWh). These NTL losses were reported at 7.48% in 2016 December but sharply decreased to 5.90 % in 2017 January. This was followed by a slight increase to 5.99% by the end of 2017 December. However, the factors that influenced such a massive downward shift in 2017 January, were not identified.

In the 2018 Annual Review submission, JPS claimed that electricity losses associated with Rate 10 customers were mainly caused by: Burnt Meter, Defective Metering, Bypass at/before Pothead, Bypass within the Meter, Idle Service, Open Circuit, and Tampering. A distribution of these losses based on causation is provided in Table SLT11 and illustrated in Figure SLF9. JPS noted that the relative proportions were derived from weights, which are the product of the relative incident rate and the average recovery for each mode of the losses.

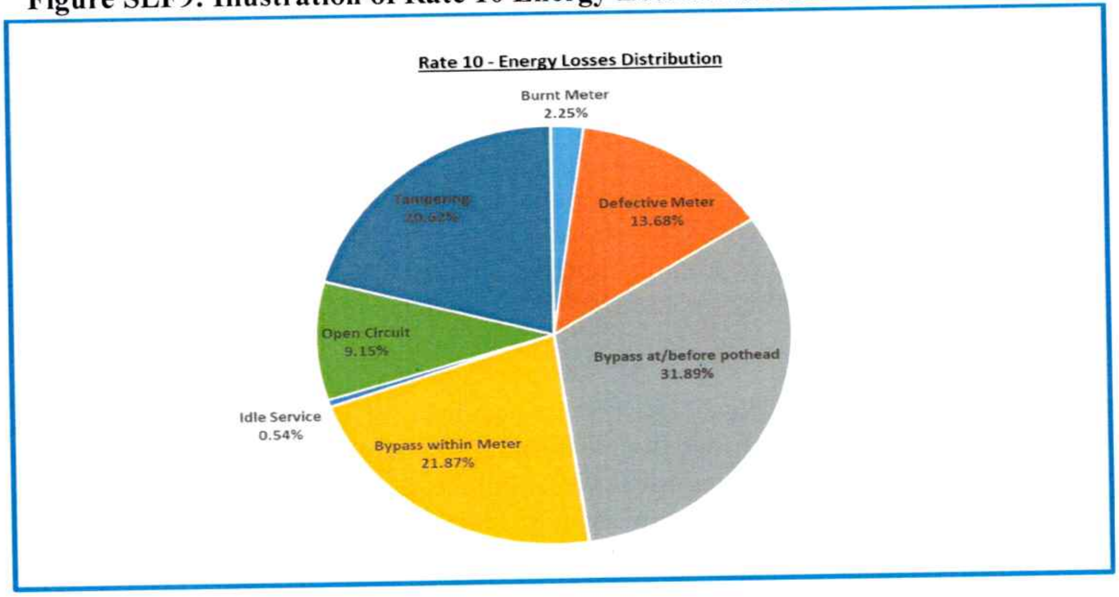
Table SLT11: Rate 10 - Energy Losses Distribution

Rate 10: Energy Losses Distribution			
Mode of Losses	**2015**	**2016**	**2017**
Burnt Meter	14.00%	7.43%	2.25%
Defective Metering Infrastructure	-	10.72%	13.68%
Defective Wiring/Incorrect Meter Configuration	-	0.29%	-
Single Phasing	21.00%	4.57%	-
Direct Connection within Meter	5.00%	-	-
Inverted Meter	-	-	-
Idle Service	2.00%	0.22%	0.54%
Bypass at/before Pothead	10.00%	8.97%	31.89%
Bypass within the Meter	-	61.28%	21.87%
Tampering	-	6.52%	20.62%
Line Tap	21.00%	-	-
Open Circuit	26.00%	-	9.15%
Other	1.00%	-	-
TOTAL	**100.0%**	**100.0%**	**100.00%**

Source data: JPS 2016, 2017 & 2018 Annual Review Filings

As with the previous cases, this comparison for the Rate 10 category again revealed that there are significant variations in reported sources and distribution of these losses from year to year. This also raises concerns as to the consistency and appropriateness of samples as well as the robustness and reliability of the methodology employed by JPS to evaluate these NTL.

Figure SLF9: Illustration of Rate 10 Energy Losses Distribution



OUR's Comments:

Based on the distribution shown, irregularities denoted as "Bypass at/before Pothead, Bypass within the Meter and Tampering" aggregately accounted for approximately 66% of the energy losses (172.4 GWh) in this category. As defined by JPS, these identified modes of losses directly or indirectly relates to JPS's revenue meters (internal or external), which form part of its electricity infrastructure and are critical to its commercial operations.

While the specific nature of the purported irregularities have not been identified and described by JPS, the OUR considers this reported level of interference with residential revenue meters, under JPS's watch to be unacceptable. Based on the stringent requirements for the security and protection of these revenue metering systems, this reported level of irregularities also implies, among other things, the following:

- *Inaccurate sampling and assessments;*
- *Mismanagement and poor monitoring of these accounts; and*
- *other forms irregularities*

Similar to the situation with Rate 20, most of the identified causes that contributed to NTL in the Rate 10 category are addressed in the relevant "JPS Back Billing Policy" which sets out the appropriate regulatory procedure for redress and recovery.

Based on JPS's arguments, with a relatively large residential customer base that is geographical dispersed, it is challenging to address the losses in this category. Similar to the Rate 20 situation, the company contends that it is constrained by limited resources to support intelligence-gathering, detection of irregularities and monitoring of accounts. According to JPS, the roll-out of the Smart Meter infrastructure project is still in its early stages and as at 2017 December, approximately 40,000 Rate 10 services have been equipped with Smart Metering.

JPS argued that the limited Smart Meter penetration limits the range of techniques used to detect losses to traditional methods, including monthly consumption profiling, exceptions analysis, payment history, and suspended account analysis, which have different business constraints that limit their effectiveness. JPS asserted that the traditional methods of detection have proven insufficient and somewhat ineffective in containing system losses. JPS expects the roll-out of its Smart Meter programme, aimed at installing 100,000 meters in 2018, will considerably improve its intelligence capability. Outcomes from this project include significantly reduced cycle times for detection, correction and recovery for instances of loss and the improved management of audit resources.

With respect to Rate 10 meter investigations, JPS reported that over 75,390 premises were audited in 2017 up from about 55,000 in 2016, and despite the large number of audits conducted each year, a large number of customers go unaudited due to the size of the customer base. Further, JPS posited that the company has demonstrated its commitment to addressing Rate 10 NTL through both the large number of audits, and investment in new technologies and strategies. JPS also argued that while the company is cognizant of the effectiveness of audits in detecting losses, these audits represent just a snapshot of a customer's premises at one point in time, that is, for the majority of time JPS has no visibility into the consumption patterns of customers with no AMI metering. JPS indicated that despite auditing about 13% of the customers in this category, only 2% of estimated losses were recovered in 2017.

OUR's Comments:
It is noted that in 2017 approximately 5.2 GWh of energy was recovered. However, information suggests that the rewards are not commensurate with extent of effort, which implies the initiatives are misdirected and/or ineffective. Based on the extent of these losses, the reported degree of impact will not be sufficient to inflict any serious dent to the current energy losses situation. Repeatedly citing convenient excuses will not deliver timely and positive results. JPS is designated the Single Buyer and System Operator of the Jamaica electricity System and in that regard, the company is expected under its Licence 2016 to operate the System in an efficient and reliable manner. This includes the appropriate identification and deployment of resources to address the issues and challenges impacting efficient operations.

JPS's proposal to deploy 100, 000 AMI meters in 2018 was previously presented in the 2017Annual Review Filing; again in 2018 the same strategy is proffered. The salient point in this case is that commitment and concrete action are required.

JPS's Proposed Allocation of Rate 10 NTL

Based on the 2018 Annual Review submission, JPS proposed that NTL in the Small Rate 20 category should be allocated to JNTL and GNTL as 26% and 74% respectively.

OUR's Position on JPS's Rate 10 Losses

Based on the evaluation of the relevant system losses data, the OUR rejects JPS's proposed allocation of Rate 10 related NTL into JNTL and GNTL. The OUR is of the view that the total quantity of these NTL is within the control of JPS, and can be minimized with the implementation of the appropriate programmes and strategies. However, based on some of the constraints identified by JPS, the OUR has allocated NTL associated with the Rate 10 class, as follows:

- JNTL - 70%
- GNTL – 30%

These considerations were reflected in the relevant NTL targets prescribed by JPS's Licence.

Unquantified/Internal Losses

Based on the 2017 December ELS, "Unquantified" losses accounted for 1.08% of net generation (47.1 GWh). These NTL losses were reported at 0.14% in 2016 December but drastically increased to 1.28% in 2017 January, then declined slightly to 1.08% at the end of 2017 December. However, the factors that contributed to the sudden step change in 2017 January, were not identified.

In the 2018 Annual Review submission, JPS defined "Unquantified"/internal losses as NTL sustained due to JPS's actions or inactions and accounts for the estimation error of the ELS model. In terms of solution, JPS indicated that it is undertaking an Internal Process Improvement project, an umbrella of initiatives aimed at reducing internal NTL and improving the commercial efficiency of the company. Based on the definition and nature of these NTL, JPS confirmed that it accepts full responsibility for their occurrence. Despite JPS's position to absorb 100% of these NTL, their continued presence creates undue financial burden to the company. In this regard, JPS should seek to urgently eliminate or minimize them.

OUR's Position on JPS's Unquantified/Internal Losses

Based on the evaluation of the relevant system losses data, related issues and considerations, the OUR, consistent with the regulatory principles and related determinations set out in previous Determination Notices, concurs with JPS that the company shall absorb **100%** of NTL designated as Unquantified/Internal losses. As such, this component of NTL shall NOT be factored in the relevant NTL targets prescribed by the Licence 2016.

Non-Technical Losses due to Illegal Users (Non-Customers)

Based on the 2017 December ELS, an estimated 180,000 "Illegal Users" illegitimately abstracted electricity from the System, resulting in NTL losses of 9.30% of net generation (407.72 GWh). These NTL varied within the range 9.30% to 9.41% of net generation throughout the year with the estimated number of "illegal users" remaining constant at 180,000.

In the 2018 Annual Review submission, JPS's arguments pertaining to "Illegal Users" remain largely the same as those presented in the 2016 and 2017 Annual Review Filings. That is, NTL related to "Illegal Users" are mainly due to socio-economic conditions, which are largely outside the company's purview.

The company purported that Data from the 2011 Census conducted by STATIN compared to the number of customers billed through JPS's Customer Information System (CIS) indicate that over 200,000 households may be connected illegally to JPS's grid. JPS also indicated that it recognized that a segment of the population resides in tenement housing facilities and therefore it cannot say definitively, without further information, that all 200,000 households are illegally connected. According to JPS, its conservative assessment indicates that there are approximately 180,000 illegal consumers. JPS is of the view that many of the "Illegal Users" are associated with inner city communities and squatter areas, and that 89.9% of the NTL are due to socio-economic conditions that are out of JPS's control.

OUR's Position on JPS's Losses caused by "Illegal Users"

With respect to NTL, the OUR maintains the view that all aspects of the System losses are largely within JPS's control, although some elements may be more difficult to control. Nonetheless, based on the provisions of the Licence, the OUR is required to give consideration to NTL that are within JPS's control and those deemed not to be totally within its control.

Based on a comprehensive evaluation of the available System performance data, it was found that approximately 80% to 90% of these NTL may be due to some of the conditions highlighted by JPS.

Based on the nature and orientation of the losses attributed to "Illegal Users", the OUR believes that the adoption of a comprehensive strategy, encompassing a systematic approach for proper quantification of the losses, infrastructure regularization and application of innovative technologies, complemented by a robust monitoring strategy, JPS can eliminate a significant portion of these losses, without insurmountable challenges.

Regarding the allocations of these NTL, in order to establish a representative distribution, the OUR has allotted the total amount to GNTL.

With reference to the System losses adjustment factor included in the annual revenue adjustment mechanism, it should be noted that aggregate NTL losses determined not to be totally within JPS's control will be subject to a responsibility factor (RF), which is addressed below.

Scope for Loss Reduction

It must be emphasized that electricity losses have an important impact on both the supply and demand side. On the supply side, a reduction in TL implies gains in the efficiency of the electricity system, reducing the amount of electricity production required to meet demand, with significant associated environmental benefits. On the demand side, NTL are synonymous with illegitimate consumption, encouraging over-consumption of electricity, thus imposing strains on electricity supply capacity. From an economic perspective, reduction of electricity losses would lead to increased financial sustainability of the utility, mainly resulting from increased billing and cost reductions associated with a better balance between capacity investment and demand.

JPS's Allocation of Total NTL

Based on System losses performance data, JPS's disaggregation of the total NTL into JNTL and GNTL is shown in Table SLT12.

Table SLT12: JPS's Allocation of NTL

JPS Allocation of NTL						
Loss Category	Components	2017 DECEMBER ELS			JPS 2018-2019 Annual Review Filing (Adjusted Values)	
		NTL	JNTL	GNTL	JNTL	GNTL
Non-Technical Losses (NTL)	Streetlight/Stoplight (R 60)	0.09%	0.09%	0.00%	0.09%	0.00%
	Large C&I (Rate 40&50)	0.74%	0.74%	0.00%	0.74%	0.00%
	Medium C&I (Rate 20)	0.27%	0.27%	0.00%	0.27%	0.00%
	Small C&I (Rate 20)	0.38%	0.29%	0.05%	0.13%	0.21%
	Residential (Rate 10)	5.99%	4.79%	1.20%	1.53%	4.45%
	Internal/Unquantified	1.08%	1.08%	0.00%	1.08%	0.00%
	Illegal Users	9.34%	0.00%	9.34%	0.00%	9.34%
	Total Non-Technical Losses	**18.11%**	**7.26%**	**10.59%**	**3.85%**	**14.01%**

For the reasons set out above, JPS's adjusted JNTL and GNTL of **3.85%** and **14.01%** respectively will not be considered in the annual revenue adjustment mechanism at this 2018-2019 Annual Review.

OUR's Determination on JPS's NTL Targets

OUR's Allocation of JPS's Total NTL

Based on the evaluation of the system losses data, related issues and considerations, the OUR has apportioned the total NTL into JNTL and GNTL as shown in Table SLT13. As shown, JNTL and GNTL were estimated at 6.63% and 11.22% of net generation respectively. These NTL components and the system losses target determined by the OUR for application at this 2018 Annual Review, were used in the revenue surcharge for adjustment to annual revenue. The actual NTL losses used in the revenue surcharge equations are normally extracted from the ELS without any adjustments, which would be JNTL – 7.26% and GNTL – 10.59%. However, based on the reported distribution and sources of the relevant NTL, these values were reasonably adjusted by the OUR in JPS's favour, to reflect the allocation of 6.63% and 11.22% for JNTL and GNTL respectively.

Table SLT13: OUR's Distribution of JPS's NTL

OUR's Distribution of JPS' NTL					
Loss Category	**Components**	**JPS NTL (2016 Dec ELS)**	**JPS NTL (2017 Dec ELS)**	**JNTL OUR Determined**	**GNTL OUR Determined**
Non-Technical Losses (NTL)	Streetlight/Stoplight (R 60)	0.09%	0.09%	0.09%	0.00%
	Large C&I (Rate 40&50)	0.45%	0.74%	0.74%	0.00%
	Medium C&I (Rate 20)	0.38%	0.27%	0.27%	0.00%
	Small C&I (Rate 20)	0.27%	0.38%	0.25%	0.09%
	Residential (Rate 10)	7.48%	5.99%	4.19%	1.80%
	Internal Bleeds/Unquantified	0.14%	1.08%	1.08%	0.00%
	Un-metered Households	9.30%	9.34%	0.00%	9.34%
	Total Non-Technical Losses	**18.11%**	**17.85%**	**6.63%**	**11.22%**

Non-Technical Losses Target

Since NTL designated as JNTL are defined to be totally within JPS's control, regulatory logic would suggest that the company should absorb the total share of JNTL (6.63%). As a result, the target for JNTL would be zero (0.0%). However, taking into consideration certain challenges faced by JPS in addressing these losses, the OUR, consistent with good regulatory practice, has included a portion in the target for JNTL. This set at 3.60% of net generation, for the 2019-2020 regulatory period.

For the GNTL, which was estimated to be 11.22% of net generation, the OUR, based on its evaluation and analysis, determines that the target for GNTL should remain at 9.7% of net generation, for the 2019-2020 regulatory period.

Table SLT14 shows the NTL targets to be applied in the 2018-2019 and 2019-2020 rate adjustment. Under the circumstances, the OUR considers these targets to be reasonable and provides an incentive to JPS to reduce its overall electricity losses.

Table SLT14: OUR's Determined NTL Targets for the 2019-2020 Rate Adjustment

OUR's Determination: JPS NTL Target for 2019-2020 Rate Adjustment				
	[2018-2019]	[2018-2019]	[2019-2020]	[2019-2020]
ASPECT OF SYSTEM LOSSES [% of Net Generation]	JPS PROPOSED TARGET	OUR's APPROVED TARGET	JPS PROPOSED TARGET	OUR APPROVED TARGET
NTL within JPS' Control	2.72%	**3.30%**	Proposal for total NTL of 16.55% - 16.75%	**3.60%**
NTL not totally within JPS' Control)	15.39%	**9.70%**		**9.70%**

Determination on the Responsibility Factor (RF)

According to Schedule 3, Exhibit 1 of the Licence 2016, one of the components of the System losses adjustment factor included in the annual revenue adjustment mechanism will be dependent on a responsibility factor, denoted as RF.

As defined in Schedule 3 of the Licence 2016, RF is the responsibility factor determined by the Office, which is a percentage from 0% to 100%. The RF shall be determined by the Office, in consultation with JPS, having regard to (i) nature and root cause of losses; (ii) roles of JPS and the Government to reduce losses; (iii) actions that were supposed to be undertaken and resources to be allocated in the Business Plan; (iv) actual actions undertaken by the resources spent by JPS; (v) actual cooperation by the Government; and (vi) change in external environment that affected losses.

In the 2018 Annual Review submission, JPS proposed that the responsibility factor should be set at 10%, relying on a report (dated 2013 October) of a study conducted by Quantum (Consultant), which concluded that about 90% of the variation in system losses is explained by the poverty level, murder rate and the relative cost of electricity. According to JPS, these are all factors that are largely outside its control.

In the determining the RF, the OUR considered, among other things, the following:

- The findings of the OUR's evaluation of JPS's NTL losses up to 2017 December, including their orientation, causes, distribution, and allocations;
- Actual loss reduction activities undertaken by JPS during the 2017-2018 rate adjustment period;
- Reports from JPS that provide information on the responsibility assigned to the relevant aspects of NTL;
- JPS's proposed loss reduction programmes and initiatives, including funding for the 2018-2019 adjustment period.

Accordingly, the OUR determined that the RF for NTL that are not totally within JPS's control, shall be **20%** for application at the 2019-2020 rate adjustment.

ANNEX 7: OUR'S 2018 FUEL COST ADJUSTMENT MECHANISM REPORT

Background

A significant portion of JPS's monthly operating expenses is related to the cost of fuel consumed by both JPS and IPPs thermal generating plants used to produce electrical energy required to supply aggregate System demand, subject to the requirements of the Licence 2016.

For a given billing period, the total fuel cost (US$) incurred is largely dependent on the following factors:

1) The price and quantity of fuel consumed by JPS and the IPPs generating plants;
2) The fuel conversion efficiencies (Heat Rates) of JPS's and IPPs' thermal generating plants;
3) The system total net generation (kWh) for the billing period;
4) The utilization level of each available generating unit in the despatch process; and
5) The fuel supply mix and the contribution of each generating unit to system total net generation.

It therefore follows that the total fuel cost in each billing period (monthly), will likely differ, given the propensity for changes to one or more of the above factors.

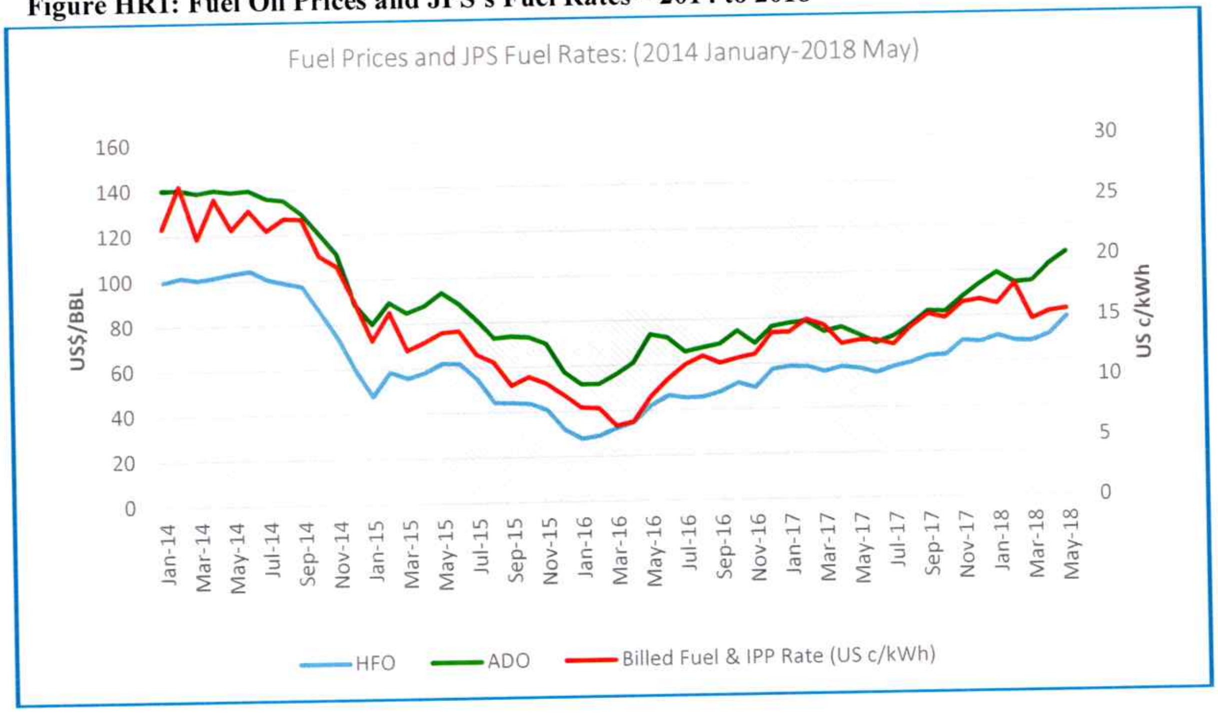
Based on the current price control regime, each month, the total fuel cost for the system is recovered through the monthly Fuel Rate (J$/kWh), calculated in accordance with the Fuel Cost Adjustment Mechanism (FCAM) defined under Schedule 3 of the Licence 2016. That is, for a given billing month, JPS is required to calculate the applicable Fuel Rate based on the system's total fuel cost, relevant energy quantities and efficiency adjustment parameters. Importantly, these Fuel Rate calculations are subject to the review and validation of the OUR, as part its regulatory monitoring framework. JPS then uses the applicable Fuel Rate to bill consumption (kWh) across its customer base, in order to recover the total fuel cost incurred.

Fuel Price Variation

The prices of the liquid-based fuels used for electricity generation are linked to international oil markets and as such, are subject to high volatility and unpredictability. Based on Petrojam's fuel oil billing invoices to JPS, since 2017 May, the average price of HFO delivered to JPS has increased from US$57 per barrel to approximately US$80 per barrel in 2018 May. For the said period, the average price of ADO has increased from approximately US$72 per barrel in 2017 May to a high of approximately US$108 per barrel in 2018 May.

The relative movements in HFO and ADO prices and the monthly Fuel Rate for the period 2014 January to 2018 May are shown in Figure HR1.

Figure HR1: Fuel Oil Prices and JPS's Fuel Rates – 2014 to 2018



As illustrated, the movement in the monthly Fuel Rate over the period exhibited a similar profile as those indicated for the respective fuel oils. This is reflective of the relationship between average fuel prices and the Fuel Rate. Based on the relatively low fuel environment since late 2014, the corresponding Fuel Rates on a US Cents per kWh basis have largely declined with the fuel charges currently representing approximately 50% of residential customers' electricity bill on average.

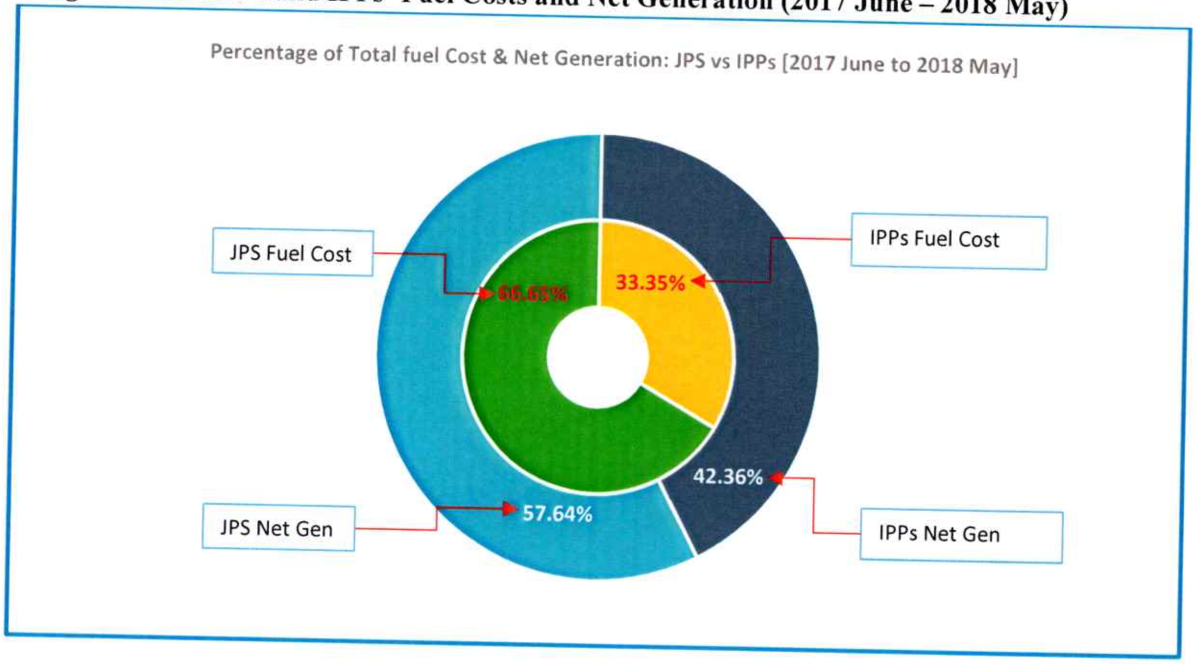
JPS and IPPs Plants' Contribution to Total Fuel Cost and System Generation

For the billing period 2017 June to 2018 May, a total fuel cost of approximately US$415.67 million was incurred to supply 4,365.97 GWh of net generation to the System.

Taking into consideration variations in fuel prices, the percentage of this cost in relation to JPS's and IPPs' plants, is approximately 67% and 33% respectively, as shown in Figure HR1. JPS's reported generation data also indicates that this cost distribution is consistent with the breakdown of monthly total fuel costs, observed since the implementation of the OUR's 2014-2019 Determination Notice in 2015 January.

In terms of net generation (MWh), the relative contributions from JPS and IPPs plants were approximately 58% and 42% respectively, for the same period. As illustrated in Figure HR1, IPPs' plants account for only approximately 33% of the total fuel cost, but their net energy output (NEO) represents over 42% of System total net generation. This fuel cost/output relationship is considered an indicative measure of the value of IPP generation to the Jamaican Electricity System.

Figure HR1: JPS's and IPPs' Fuel Costs and Net Generation (2017 June – 2018 May)



Fuel Supply Mix

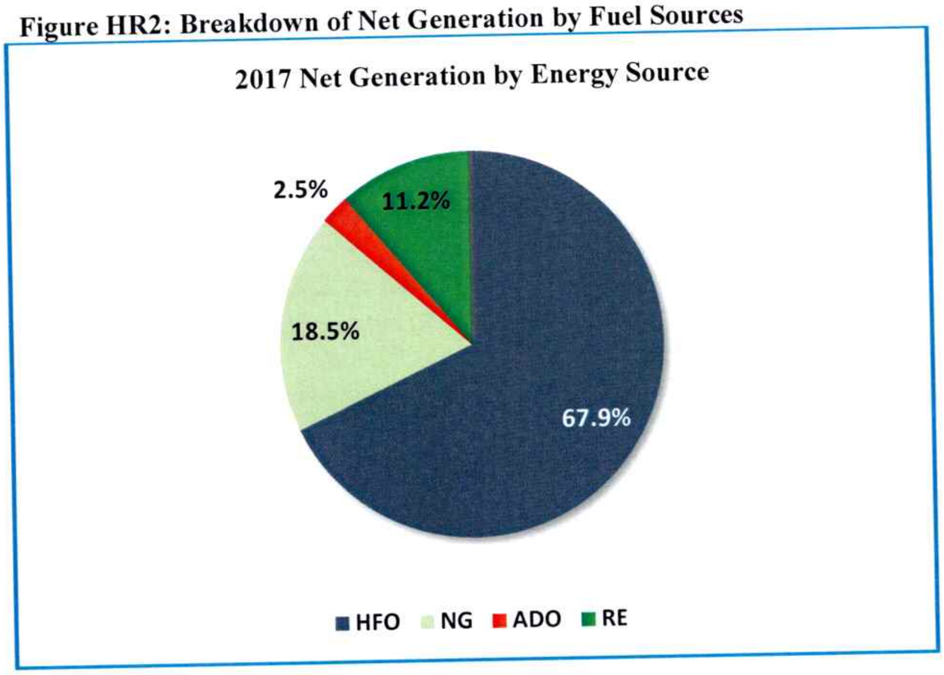
Despite the introduction of Natural Gas (NG) in the fuel supply mix in 2016, petroleum-based fuels in the form of heavy fuel oil (HFO) and automotive diesel oil (ADO) still represent a significant portion of the primary (input) energy used to generate electricity to supply System demand. Currently, these liquid-based fuels are mainly supplied to JPS and IPPs by Petrojam under long-term Fuel Supply Agreements (FSA).

HFO is predominantly used in JPS's oil-fired steam generating units and IPPs' Medium Speed-Diesel (MSD) and Slow Speed Diesel (SSD) generation facilities. ADO is mainly used in the operation of JPS's gas turbine (GT) units.

Net Generation by Fuel Sources

With the inclusion of NG in the present fuel supply mix, the reported net generation from the various primary energy sources between 2017 January to December, was allocated as represented in Figure HR2.

Figure HR2: Breakdown of Net Generation by Fuel Sources



LEGAL REQUIREMENTS FOR FUEL RATE ADJUSTMENT

Licence Requirements - Fuel Cost Adjustment Mechanism (FCAM)

As stipulated under Schedule 3 (paragraphs 57 and 58) of the Licence 2016, the monthly adjustments to the Fuel Rates shall be in accordance with Exhibit 2 of the said Schedule, which provides as follows:

> "A. ***Alternative** 1 Fuel Cost Adjustment Mechanism*
>
> *The cost of fuel per kilo-watt-hour (net of efficiencies) shall be calculated each month on the basis of the total fuel computed (inclusive of fuel additives) to have been consumed by the Licensee and Independent Power Producers (IPPs) in the production of electricity. Effective January 1, 2016, this will be calculated each month based on the Licensee's generating Heat Rate as determined by the Office at the adjustment date and the IPPs generating Heat Rate as per contract and system losses, as determined by the Office at the adjustment date, applied to the total net generation (the Licensee and IPPs). Effective July 1, 2016, this will be calculated each month based on the Licensee's generating Heat Rate as determined by the Office as at June 30, 2016 (at each succeeding rate review date) and the IPPs generating as per contract."*

As required by the Licence, the cost of fuel per kilo-watt-hour shall be computed on a monthly basis under the appropriate rate schedule in the following manner having regard to the applicable efficiency adjustments and effective dates as outlined in the paragraph:

"$F = F_m/S_m$

Where:

Billing Period	=	*The billing month during the effective period for which the adjusted fuel rates will be in effect as determined by the Office.*
F	=	*Monthly Fuel Rate in J$ per kWh rounded to the nearest one-hundredth of a cent applicable to bills rendered during the current Billing Period*
F_m	=	*Total applicable energy cost for period*

The total applicable energy cost for the Billing Period is:

(a) *the cost of fuel, adjusted for the determined heat rate and system losses up to June 30, 2016, and which fuel is consumed in the Licensee's generating units or burned in generating units on behalf of the Licensee or incurred in relation to the Licensee's contractual obligation, such as but not limited to the minimum take-or-pay obligation under a gas supply agreement, for the preceding calendar month plus;*

(b) *the fuel portion of the cost of purchased power (including IPPs), adjusted for the contract Heat Rate, for the said preceding calendar month; and*

(c) *an amount to correct for the over-recovery or under-recovery of total applicable energy cost for a billing period, such amount shall be determined as the difference between the actual total applicable energy cost for a given month adjusted for the determined Heat Rate the fuel costs billed for such month, using fuel cost and fuel weights.*

(d) *An amount to correct for the over-recovery or under-recovery of the non-fuel portion of the purchased power. This amount shall be determined as the difference between the actual IPP non-fuel cost for a given month and the estimated base non-fuel IPP charge billed to customers for such calendar month.*

S_m = *the kWh sales in the Billing Period.*

The Fuel Rate Adjustment including the Schedule for the application of the fuel charge to each rate class, shall be submitted by the Licensee to the Office ten (10) days prior to the end of the month just preceding the applicable billing month and shall become effective on the first billing cycle on the applicable billing month."

Licence Requirements - Heat Rate Target

According to Schedule 3 (paragraph 37) of the Licence 2016, the Office shall have the power to set targets for JPS's Heat Rate which should be reasonable and achievable.

Specifically, with respect to the setting of targets for JPS's Heat Rate by the Office, the legal requirements are set out under Schedule 3, paragraph 40 of the Licence 2016, which provides as follows:

"The Office shall determine the applicable Heat Rate (whether thermal, system, individual generating plants of the Licensee or such other methodology) and the target for the Heat Rate."

FCAM AND EFFICIENCY INCENTIVES

Recovery of Fuel Cost

As reflected in Exhibit 2 of Schedule 3 of the Licence 2016, JPS is allowed to recover its monthly fuel costs through the monthly Fuel Rate, derived in accordance with the defined FCAM, which has been in effect since 2016 July 1, and represented mathematically in the formula below.

$$\textit{Pass Through Cost} = \left[\textit{IPPs Fuel Cost (subject to PPAs)} + \left(\textit{JPS Fuel Cost} \times \left(\frac{\textit{JPS Heat Rate Target}}{\textit{JPS Heat Rate Actual}}\right)\right)\right]$$

According to the FCAM, the monthly Fuel Rates are derived from the monthly total fuel costs (IPPs and JPS), net of efficiency adjustment.

Efficiency Adjustment to IPPs Fuel Cost

For cost recovery, the IPPs component of the monthly total fuel costs reflects the cost adjusted by the IPPs' contracted Heat Rates as per their respective power purchase agreements (PPAs). As such, no Heat Rate targets are required to be determined for the IPPs.

Efficiency Adjustment to JPS's Fuel Cost

Based on the FCAM, the JPS portion of the monthly total fuel costs is subject to adjustment by a fuel conversion efficiency factor. That is the ratio of the OUR's determined Heat Rate target to the JPS generating Heat Rate. This efficiency adjustment approach is an implicit incentive scheme designed to encourage JPS to improve its operational efficiency as well as to optimize its generation dispatch operations. The embedded incentive mechanism innately delivers financial benefits or penalties to the extent that there is any over-achievement or under-achievement of the determined Heat Rate target. The rates are also adjusted to account for movements in the exchange rate between the United States dollar (US$) and the Jamaican dollar (J$).

Following the submission of the Fuel Rate Calculations to the OUR each month, the OUR, subject to its regulatory functions and monitoring framework, undertakes a comprehensive review of the elements of the submissions in order to validate the reasonableness and accuracy of the calculated Fuel Rates.

Heat Rate Definition

A generating plant Heat Rate is normally represented as its fuel conversion efficiency at rated capacity (full-load Heat Rate). However, a plant's average Heat Rate is based on its operation along its Input - Output Curve (fuel energy input – electrical energy output). The average Heat Rate at a level of generation is equal to the corresponding input energy in the fuel divided by the energy generated.

A lower Heat Rate means that less fuel is used per kWh of electricity and this corresponds to greater efficiency and to reduced fuel expenses. Heat Rates are not the same for all generating plants. Generating units used for peaking purposes, such as gas turbines, generally have higher Heat Rates than base-load units, which are more efficient. The existence of these differences in Heat Rates underscore the importance of the generation technology mix. Based on the variations in plant output during the System's load curve, the fuel conversion efficiency indicator of a generating plant is usually represented as the average Heat Rate over a given period.

Heat Rate Target

The Heat Rate target focuses on the System's generation operations and benchmarks how efficiently generating units owned and operated by JPS and IPPs convert input fuel (kJ or BTU) into electrical energy (kWh). Currently, the Heat Rate target is set at **11,450 kJ/kWh**. As previously indicated, to the extent that the monthly Heat Rate exceeds this ceiling, JPS is prevented from passing through costs related to fuel penalties as a consequence of its failure to meet the Heat Rate target, to customers. Conversely, to the extent that the monthly Heat Rate is better than the target, JPS is permitted to pass-through its fuel costs to customers on a dollar-for-dollar basis, plus the additional revenues applied as a reward for over-achievement of the target.

System Heat Rate

Despite the transition from a System approach to the use of a thermal plant methodology to set JPS's Heat Rate target, the OUR has maintained the position and has set out in its decisions that JPS should continue to calculate the System Heat Rate and include it in the monthly Fuel Rate Calculations, submitted to the OUR. Consistent with good industry practice, it will be recognized as a key performance indicator (KPI), to facilitate the regulatory monitoring and continual assessment of the overall efficiency of the System.

REGULATORY PRINCIPLES APPLIED TO HEAT RATE TARGET

As stated in previous OUR Determination Notices, the Heat Rate target for JPS's generation system is an essential efficiency measure to permit the efficient pass-through of fuel costs incurred by JPS to its customers. The target is set by the OUR on a periodic basis to ensure that electricity ratepayers are provided with fair and reasonable Fuel Rates. A key objective of the target is to provide JPS the incentive to improve the overall fuel conversion efficiency of its generation fleet.

Additionally, the target should encourage the minimization of electricity production cost through the employment of prudent merit order/generation dispatch practices by the System Operator, subject to the requirements of the Electricity Act, 2015, the Licence 2016 and the relevant Electricity Sector Codes.

The following regulatory principles have been considered by the OUR in setting the Heat Rate target:

1) The target should hold the System Operator accountable for the various factors related to generation operations and the FCAM, which are under its direct control;
2) The target should encourage optimal generation dispatch of available generating units to ensure the minimization of the total cost of electricity generation, which is mostly fuel cost.
3) The target should take into account legitimate System constraints (Generation and T&D), provided that JPS is taking reasonable action to mitigate these constraints;
4) The target shall be determined in accordance with the relevant provisions of the Licence and the relevant Electricity Sector Codes; and.
5) The target should be set on an annual basis and applied to the FCAM on a monthly basis.

ECONOMIC GENERATION DISPATCH

Central to the electricity production process is the generation despatch activity. As defined in the Electricity Act, 2015, "despatch activities" refer to the activities involved in the central management and direction of the generating plants and other sources of supply to the system in order to achieve the optimal safety, reliability and economical electricity supply. Under the existing legal and regulatory framework, despatch activities are guided by the Electricity Act, 2015, Generation & Despatch Codes, Licence 2016 and other relevant regulations. Section 45 of the Electricity Act, 2015 specifically sets out the responsibilities of the System Operator (JPS) and the Office in relation to despatch activities. Section 45 (7) of the Electricity Act, 2015 in particular, states that:

> *"The office shall cause the operations and despatch activities and related operations of the System Operator to be independently audited at least annually and the System Operator shall facilitate the audit and provide such access and information as the independent auditor may require to complete the audit within a reasonable timeframe determined by the Office."*

Since the introduction of private generation in the sector, concerns have been raised from time to time about the generation despatch process. With increased IPP participation, despatch-related issues have escalated, chief among them is the matter of merit order computation, dissemination of despatch information to owners/operators of generation facilities and sub-optimal despatch operations.

Consistent with that trend, in the first quarter of 2018, the major IPPs with conventional generation facilities raised a number of concerns to the OUR regarding the merit order and generation scheduling and despatch.

The specific issues raised include the following:

1) Transparency in the despatch process
   a. System Operator (SO) operating structure, separation of activities, reporting requirements, and information to be included in published merit order.

2) Despatch information supplied by SO and IPPs
   a. Provision of weekly merit order listing, including inputs to IPPs by SO (DSC 5.1)
   b. Submission of fuel price information by IPPs to SO (DSC 5.2.1)

3) Reporting requirements to the Office

4) Development of Merit Order System and Computation of Marginal Cost of Generating Units
   a. The methodology being used by JPS to develop the weekly merit order listing
   b. Timing of inputs to update the merit order system.

5) Treatment of specified costs in the despatch process
   a. Classification of JPS's fuel costs (NG fixed and variable costs) and "fuel additive" costs
   b. Treatment of JPS's VOM costs (OUR's 2014-2019 Determination Notice)

6) Implications of Government Policy on economic despatch

7) Sub-optimal despatch operations

8) SO's generation despatch strategy with the addition of the 24.5MW Energy Storage System (ESS) and the committed 37MW solar PV generation to the System.

9) Scope for grid flexibility to satisfy System security requirements and potential despatch challenges with the addition of SJPC (190MW) and Jamalco (94MW)

10) Scope for minimization of transmission losses in the generation despatch process

After reviewing the issues raised and evaluating the daily despatch information submitted by JPS, it was established that a deeper understanding of the situation was necessary to enable the OUR to structure a practical approach for regulatory oversight and monitoring going forward. In that regard, there will be a need for the Office to conduct an audit of the despatch activities as stipulated in the Electricity Act,2015 prior to the 2019-2024 Rate Review.

REVIEW OF JPS's HEAT RATE PERFORMANCE AND TARGETS

JPS's Heat Rate Performance

JPS's Heat Rate performance since the last Rate Review to 2018 June is summarized in Table HR1. The monthly Heat Rate trends and performance against targets are illustrated in Figure HR4.

Table HR1: JPS's Heat Rate Performance

JPS's Heat Rate Performance – [2014 July – 2018 June]												
Month	Heat Rate (kJ/kWh) [2014 July -2015 June]			Heat Rate (kJ/kWh) [2015 July -2016 June]			Heat Rate (kJ/kWh) [2016 Jul -2017 June]			Heat Rate (kJ/kWh) [2017 Jul -2018 June]		
	JPS Project-ion	Actual	OUR Target	JPS Project-ion	Actual	OUR Target	JPS Project-ion	Actual	OUR Target	JPS Project-ion	Actual	OUR Target
JUL	11,699	12,276	N/A	11,358	11,523	12,010	10,996	11,218	11,620	11,355	11,415	11,620
AUG	11,652	11,645	N/A	11,170	11,124	12,010	10,983	11,065	11,620	11,343	12,109	11,620
SEP	11,761	11,352	N/A	11,546	11,351	12,010	11,046	11,463	11,620	11,372	11,628	11,450
OCT	11,618	11,349	N/A	11,413	11,327	12,010	11,240	11,448	11,620	11,271	11,281	11,450
NOV	11,531	11,142	N/A	11,518	11,403	12,010	10,905	11,469	11,620	11,265	11,191	11,450
DEC	11,468	11,054	N/A	11,396	11,107	12,010	10,861	10,953	11,620	11,243	11,360	11,450
JAN	11,387	11,492	N/A	11,943	11,996	12,010	10,980	11,158	11,620	11,235	11,208	11,450
FEB	11,400	11,186	12,010	12,080	12,175	12,010	11,000	11,181	11,620	11,136	11,472	11,450
MAR	11,994	11,615	12,010	11,941	12,240	12,010	10,888	11,148	11,620	11,188	11,079	11,450
APR	11,183	11,190	12,010	11,903	12,044	12,010	10,868	11,081	11,620	11,132	11,425	11,450
MAY	11,148	11,343	12,010	10,902	11,436	12,010	10,907	11,134	11,620	11,257	11,261	11,450
JUN	11,332	11,335	12,010	11,002	11,352	11,620	11,209	11,227	11,620	11,247	-	11,450

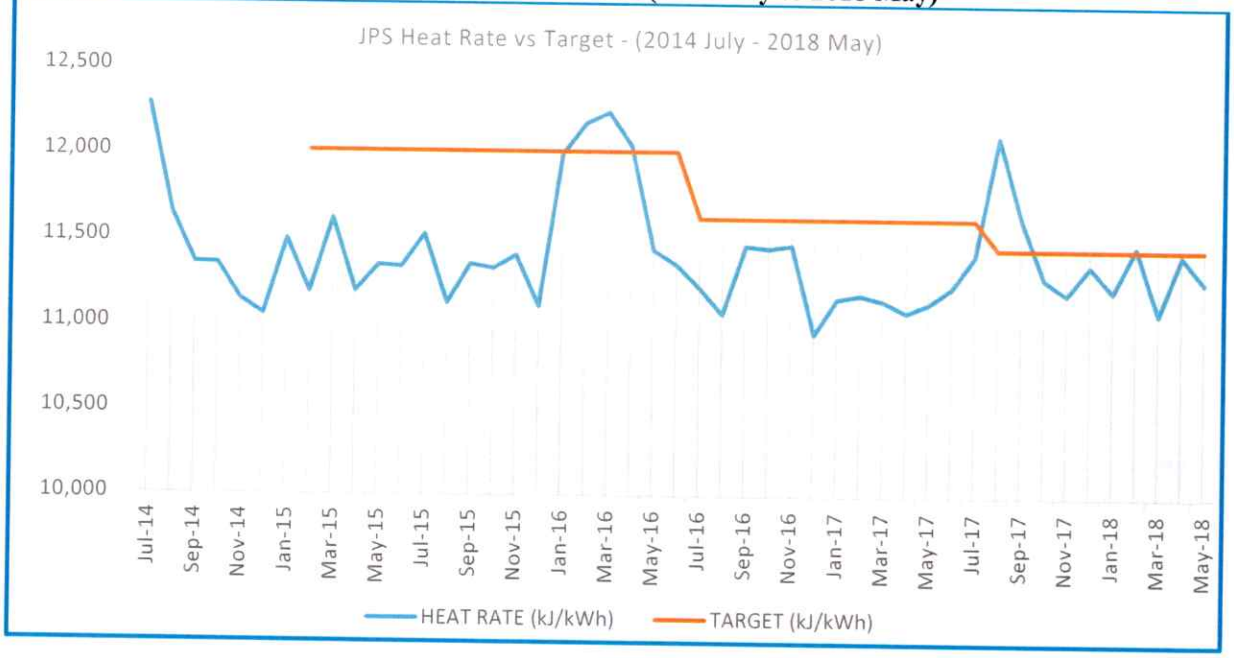
A statistical summary of the reported Heat Rates shown above is provided in Table HR2.

Table HR2: Statistical Analysis of JPS' Monthly Heat Rates

Statistical Summary: JPS's Monthly Heat Rates							
Period	NO. OF OBSV.	MIN	MEDIAN	MEAN	MAX	RANGE	STD DEV
2014 July-2018 June	47	10,953	11,349	11,405	12,276	1,323	328

For emphasis, the monthly Heat Rate trends and performance against targets over the 2014 July - 2018 May period are illustrated in Figure HR4.

Figure HR4: JPS's Heat Rate Performance Trend (2014 July to 2018 May)



Assessment of JPS's 2017-2018 Heat Rate Performance

<u>2017-2018 Heat Rate Target</u>

At the 2017 Annual Review, the OUR adjusted JPS's Heat Rate target downward from the existing 11,620 kJ/kWh to 11,450 kJ/kWh. This target was considered to be reasonable and achievable based on the technical configuration and operational capability of the generation system.

Given the reported Heat Rate outcomes, the OUR is of the view that the approach employed for setting the Heat Rate targets is prudent and reasonable and consistent with good regulatory practice. Additionally, the performance levels being achieved indicate that the Heat Rate targets have been effective in incentivizing JPS to improve the overall fuel conversion efficiency of its thermal generating plants.

Based on JPS' performance data, the monthly Heat Rate (thermal plants) recorded for the 2017-2018 adjustment period to date, is provided in Table HR3.

Table HR3: JPS's Thermal Generating Plants Heat Rate (2017 July - 2018 May)

JPS's Thermal Generating Plants Heat Rate Performance (2017-2018)													
(kJ/kWh)	2017 JUL	2017 AUG	2017 SEP	2017 OCT	2017 NOV	2017 DEC	2018 JAN	2018 FEB	2018 MAR	2018 APR	2018 MAY	2018 JUN	AVE
Heat Rate	11,415	12,109	11,628	11,281	11,191	11,360	11,208	11,472	11,079	11,425	11,261	-	11,401
Target	11,620	11,620	11,450	11,450	11,450	11,450	11,450	11,450	11,450	11,450	11,450	11,450	11,467
Variance	-205	489	178	-169	-259	-90	-242	22	-371	-25	-189	-	-66

As shown, the actual monthly Heat Rates ranged between 11,079 kJ/kWh to 12,109 kJ/kWh (a spread of 1,050 kJ/kWh), yielding an average monthly Heat Rate of 11,401 kJ/kWh. This is within 1% of the target and translates to an over-achievement of 66 kJ/kWh on average each month, in JPS's.

The Heat Rate data shows that during the adjustment period, there were three (3) occasions when JPS did not meet the target (2017 August, 2017 September and 2018 February). Based on JPS's generation performance reports, these results were largely due to the following events:

- 2017 August (12,109 kJ/kWh): Major forced outage of JPS Bogue combined cycle gas turbine (CCGT) unit in 2017 August, which extended to 2017 September. Based on regulatory reports from JPS, the forced outage was due to major damage to GT#12 generator (alternator). **A detailed report on the forced outage situation is required by the OUR.**

- 2017 September (11,628 kJ/kWh): Forced outage of major/critical equipment on a number of JPS's generating units.

- 2018 February (11,472 kJ/kWh): Planned outage to facilitate major overhaul of JPS Rockfort Unit2 (RF#2) and engine performance test.

During each of the billing months in question, these reported events apparently impacted normal operation of the generation system, resulting in the under-achievement of the target in each case. Despite the few instances of failure, for the overall rate adjustment period, the company was still able to better the target as indicated above.

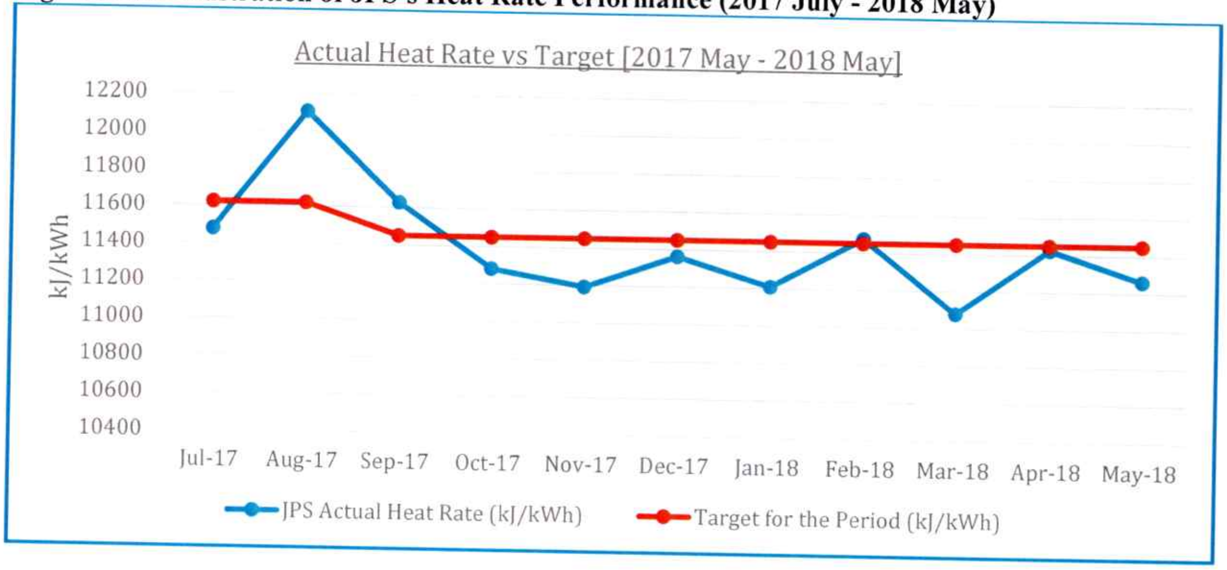
<u>Application of Heat Rate Target</u>

For the 2017 Annual Review, the OUR's Determination Notice (dated 2017 August 31) became effective, 2017 September 01.

Exhibit 2 under Schedule 3 of the Licence 2016 stipulates that the cost of fuel consumed in JPS's generating units for the preceding calendar month should be adjusted by the Heat Rate target determined by the OUR. However, the OUR's review of the monthly Fuel Rate Calculations revealed that in 2017 September, JPS did not apply the 2017-2018 Heat Rate target (11,450 kJ/kWh) to its 2017 August fuel cost, as required by the Licence 2016, but instead applied the previous target (11,620 kJ/kWh) during the adjustment period when all determinations became effective. Such application is deemed inappropriate, therefore JPS is required to make the necessary adjustment in the billing month when this Determination Notice becomes effective.

The profile of the monthly Heat Rate relative to the target for the adjustment period is illustrated in Figure HR5.

Figure HR5: Illustration of JPS's Heat Rate Performance (2017 July - 2018 May)



JPS's HEAT RATE PROPOSAL

JPS indicated that the generating Heat Rate of its thermal plants has improved by approximately 2.2% in the 2017 calendar year compared to 2016. The company asserted that this improvement was largely due to increased efficiency from generation plants returning from major overhauls (Rockfort Diesel Barge, Bogue CCGT), reduced operation of older facilities (Old Harbour Station), and increased electricity production from renewables such as wind and solar, as well as increased availability from new gas generation sources.

Proposed Heat Rate Target

For the 2018-2019 adjustment period, JPS proposed a Heat Rate target of **11,482 kJ/kWh**. To justify this proposal, JPS argued that although the overall heat rate performance has improved, the 2018-19 adjustment period will see JPS having to dispatch a thermal fleet which is a year older amongst aging IPPs units as well. According to JPS, the proposed Heat Rate is needed to assist JPS to at least partially mitigate negative impacts to JPS's thermal assets; to mitigate any hindrance to JPS's ability to fully recover on its fuel costs and ultimately its ability to serve its customers.

JPS's Heat Rate Forecast for 2018-2019 Adjustment Period

In the 2018 Annual Review submission, JPS indicated that its proposed Heat Rate target for the 2018-2019 adjustment period is based on two (2) Heat Rate forecast scenarios (best case and worst case). JPS asserted that in developing the scenarios, it took into consideration, among other things, the following assumptions, parameters and conditions:

- Projected Maximum Capacity Rating (MCR) of the existing generation system (conventional and RE generation facilities);
- Forecasted Capacity Factor of the available thermal and RE generating plants; and
- Forecasted Energy Production (net generation) for the System and individual generating plants.

The 2018-2019 Heat Rate forecasts scenarios are presented in Table HR4. According to JPS, these forecasted Heat Rates were generated by its Heat Rate model and were purportedly used to derive the proposed Heat Rate target of 11,482 kJ/kWh.

Table HR4: JPS 2018-2019 Heat Rate Forecast Scenarios

JPS Forecasted Heat Rates for 2018-2019 Adjustment Period													
HEAT RATE [kJ/kWh]	2018 JUL	2018 AUG	2018 SEP	2018 OCT	2018 NOV	2018 DEC	2019 JAN	2019 FEB	2019 MAR	2019 APR	2019 May	2019 JUN	AVE
JPS BEST CASE	11,156	11,067	11,179	11,292	11,057	10,998	11,561	12,176	12,037	11,228	11,080	10,843	11,306
JPS WORST CASE	12,675	11,488	11,015	11,382	11,578	11,423	11,555	12,176	12,037	11,228	11,080	10,843	11,540

As shown, the average Heat Rate for the best case and worst case forecast scenarios are 11,306 kJ/kWh and 11,540 kJ/kWh respectively. For the months 2018 September to 2019 June, the Heat Rates values appear to be quite similar in each forecast scenario. However, there is a significant variance with the 2018 July values, and no clear basis for deviation was established. Additionally, in the worst case forecast scenario there are Heat Rate projections for several months which appear to be superior to the best case.

JPS's Position

JPS posited that its thermal Heat Rate performance during the 2018-2019 adjustment period will depend on several factors affecting the economic dispatch, which include the following:

1) Growth in system demand;
2) The addition of more RE generation;
3) The addition of new generating units and the installed reserve margin (OUR);
4) Heat Rate improvements made to existing generating units (JPS);
5) Availability and reliability of JPS's generators (JPS);
6) Availability and reliability of IPP generators (IPPs);
7) Absolute and relative fuel prices for JPS and the IPPs and the impact on economic dispatch;
8) Spinning reserve policy (JPS & OUR); and
9) Network constraints and contingencies (JPS).

JPS contended that while all the above listed factors influence the resultant System Heat Rate, JPS has sole direct control over only a few. JPS also argued that the Heat Rate target must consider the effect of a major failure of one of the main steam units in the fleet that are almost at the end of their useful life.

JPS submitted that its Heat Rate target proposal was based on the planned mix of generating units, including IPPs, their projected availability and dispatch, and the foregoing discussion of Heat Rate affecting variables and the possible variation in Heat Rate performance for reasons beyond JPS's control, and that the target should take into account forced outage outliers. JPS is of the view that the Heat Rate target must significantly consider the effect of the major maintenance outage of JPS's most efficient generating unit, the Bogue CCGT Unit, given the fact that this unit was last overhauled in 2013. Specifically, the company noted that in 2017 August, Bogue CCGT experienced a forced outage on GT #12, causing the Heat Rate to spiral to 12,109 kJ/kWh in that month, and 11,628kJ/kWh in the following month, highlighting the importance of this unit to the system. JPS also believes that the OUR should also take into consideration a major failure of one of the key steam turbines lasting for a month. Additionally, JPS noted that there may be potential outages at the Old Harbour Power Station (OHPS) during 2019 to accommodate the commissioning of the South Jamaica Power Company (SJPC) 190MW CCGT. According to JPS, such outages are forecasted to negatively impact JPS's Heat Rate for 2019 by 17kJ/kWh.

<u>OUR's Comment</u>

The OUR notes JPS's concerns and perceived anxieties regarding considerations for setting the Heat Rate target and potential generation challenges that could be encountered during the adjustment period. However, it must be emphasized that consistent with the principles set out above, the target is determined based on the existing technical characteristics and operational capability of all available generating units in the system, credible system constraints and contingencies, effects of major maintenance activities, and scheduled commissioning of generation facilities under construction.

The Heat Rate target was never intended to provide coverage for any and all abnormal/extraordinary system conditions. Essentially, the main aim of the target as reflected in the FCAM, is to drive optimal generation dispatch and minimize fuel cost. Moreover, under the existing regulatory framework, JPS as the Single Buyer/System Operator, is required to operate the system in an efficient manner designed to afford its customers an economical and reliable service. This should be JPS's central focus supported by adequate reliability planning and outage management.

Regarding the impending effect of the commissioning of the SJPC 190MW generation facility, the indicated impact of 17 kJ/kWh for the year is considered very marginal. JPS should recognize that during the commissioning activities, the extent of the net energy output (NEO) from the facility to the system, could result in favourable Heat Rate outcomes for JPS during the commissioning period.

Lastly, it should be noted that while the Heat Rate target is applied monthly for Fuel Rate adjustment, it is effectively an annual target, which should have an aggregate effect over the applicable rate adjustment period.

OUR's REVIEW OF JPS's HEAT RATE PROPOSALS

General

As previously indicated, the Heat Rate parameter is a measure of the fuel conversion efficiency of an electricity generating plant or system. From a regulatory perspective, the consideration of a Heat Rate target or factor, for application in the FCAM to determine the monthly Fuel Rates (net of efficiencies) should be predicated on, among other things, the established regulatory principles outlined above

Heat Rate Evaluation

For the Heat Rate review, the OUR carried out a comprehensive evaluation of JPS's Heat Rate proposal in order to determine the Heat Rate target to be applied during the 2018-2019 tariff adjustment period, as required by the Licence 2016. The OUR's evaluation took into consideration, among other things, the following:

- Projected net generation and peak demand for the 2018-2019 adjustment period;
- JPS's and IPPs' existing thermal generating plants technical & operational capabilities:
  - Output capability - minimum and maximum operating levels (MW),
  - Plant Efficiency - Heat Rate curves, average Heat Rates, incremental Heat Rate,
  - Ramp rates within the specified operating range,
  - Utilization Levels - minimum sustained production level, capacity factor, etc.,
  - Operating reserves, spinning reserve requirements,
  - Equivalent availability, forced outage rates (FOR), scheduled maintenance days,
- JPS's and IPPs' existing RE generation facilities – installed and contracted capacity, projected monthly net generation, capacity factor, degradation factor, efficiency, etc.;
- RE generation facilities scheduled to be commissioned within the tariff period;
- JPS's historical Heat Rate performance;
- The Heat Rate assumptions provided by JPS in the 2018 Annual Review submission;
- Technical and operational constraints on generating units; and
- Network constraints.

The Heat Rate evaluation also encompassed statistical analyses in order to assess the effects of potential variations or uncertainties of the Heat Rate performance during the adjustment period.

OUR'S DETERMINATION ON JPS's HEAT RATE PROPOSAL

Based on the Licence 2016 requirements as referenced in the relevant sections above, and consistent with the 2016 and 2017 Determination Notices, the OUR has determined that:

- The Heat Rate (actual) to be used by JPS in the defined FCAM for efficiency adjustment each month shall be in relation to JPS's thermal generating Plants.
- The target for the Heat Rate target shall continue to be based on JPS's thermal generating plants.

Having reviewed JPS's Heat Rate proposal, the proposed Heat Rate target of 11,482 kJ/kWh is not approved on the basis that:

- It is not corroborated by a Heat Rate Model submitted by JPS
- Elements of the 2018-2019 Heat Rate projections appear to be unrealistic, unreliable and inconsistent with the technical configuration and operational capability of JPS's thermal generating system.
- Improvement in the generation dispatch operations could realize higher efficiencies.

OUR's Determined Heat Rate Target

Based on OUR's Heat Rate evaluation and giving due consideration to risks of breakdowns given the age of its base load plants and its maintenance plan for the Bogue Combined Cycle plant, the Office has determined that the Heat Rate target for JPS's thermal generating system for the 2018-2019 regulatory period should be kept at the existing level of **11,450 kJ/kWh.**