JPS

Jamaica Public Service Company Ltd.

2023-24

2022

2021

2020

2019

2019-2024 Tariff Application

DECEMBER 2019

JPS | Powering What Matters

Glossary

ABNF	-	Adjusted Base-rate Non-Fuel
ADO	-	Automotive Diesel Oil
CAIDI	-	Customer Average Interruption Duration Index
CIS	-	Customer Information System
CPLTD	-	Current Portion of Long Term Debt
CPI	-	Consumer Price Index
CT	-	Current Transformer
DPCI	-	Annual rate of change in non-fuel electricity revenues as defined in Exhibit 1 of the Licence
dI	-	The Annual Growth rate in an inflation and devaluation measure
EAM	-	Enterprise Asset Management
EEIF	-	Electricity Efficiency Improvement Fund
EGS	-	Electricity Guaranteed Standard
ELS	-	Energy Loss Spectrum
EOS	-	Electricity Overall Standard
FCAM	-	Fuel Cost Adjustment Mechanism
FCI	-	Fault Circuit Indicator
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
GWh	-	Gigawatt-hours
HFO	-	Heavy Fuel Oil
ICCP	-	Inter-Control Center Communications Protocol
ICDP	-	Integrated Community Development Programme
IPP	-	Independent Power Producer
JEP	-	Jamaica Energy Partners Limited
JMD	-	Jamaican Dollar

JNTL	-	Non-Technical Losses that are within JPS' control
JPS/Licensee	-	Jamaica Public Service Company Limited
KVA	-	Kilovolt-Ampere
KWh	-	Kilowatt-hours
Licence	-	The Electricity Licence, 2016
MAIFI	-	Momentary Average Interruption Frequency Index
MED	-	Major Event Day/s
MSET	-	Ministry of Science Energy and Technology
MVA	-	Mega Volt Amperes
MW	-	Megawatt
MWh	-	Megawatt-hours
NBV	-	Net Book Value
NPV	-	Net Present Value
NFE	-	New Fortress Enterprise
NTL	-	Non-technical losses
NWC	-	National Water Commission
O&M	-	Operating and Maintenance
OCC	-	Opportunity Cost of Capital
Office/OUR	-	Office of Utilities Regulation
Old Licence	-	The Amended and Restated All-Island Electric Licence, 2011
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
PIOJ	-	Planning Institute of Jamaica
PPA	-	Power Purchase Agreement
RAMI	-	Residential Advanced Metering Infrastructure
RE	-	Renewable Energy
Revenue Cap	-	The revenue requirement approved in the last Rate Review Process as adjusted for the rate of change in non-fuel electricity revenues

		(dPCI) at each Annual Adjustment date as set out in Exhibit 1 of Schedule 3 of the Licence.
REP	-	Rural Electrification Programme Limited
ROE	-	Return on Equity
ROI	-	Return on Investment
ROR	-	Return on Return
RPD	-	Revenue Protection Department
SAIDI	-	System Average Interruption Duration Index
SAIFI	-	System Average Interruption Frequency Index
SBF	-	System Benefit Fund
SJPC	-	South Jamaica Power Company
T&D	-	Transmission & Distribution
TFP	-	Total Factor Productivity
TL	-	Technical Losses
TOU	-	Time of Use
USD	-	United States Dollar
WACC	-	Weighted Average Cost of Capital
WKPP	-	West Kingston Power Plant
WT	-	Wholesale Tariff

Executive Summary

Introduction

As Jamaica's energy provider, we are deeply committed to modernizing Jamaica's energy infrastructure and support the national development plan to make Jamaica the place of choice to live, work, raise families and do business.

Jamaica Public Service Company Limited (JPS) is an integrated electric utility company and the sole entity licensed to transmit, distribute and supply electricity in Jamaica for public and private purposes. In addition to generating electricity, the Company also purchases power from a number of Independent Power Producers (IPPs). JPS has an important role in the development of a modern, efficient, diversified and environmentally sustainable Jamaican economy. JPS actively contributes to Jamaica's international competitiveness by helping to reduce the country's dependence on imported petroleum. The Company supports the growth of a thriving Jamaican society by providing accessible and affordable energy supplies with long-term energy security.

The JPS Rate Review Proposal Submission (2019-2023) to the Office of Utilities Regulation (OUR) is the presentation of our fourth five yearly filing for the continued transformation of Jamaica's electricity infrastructure. It is also the first under the Revenue Cap regulatory regime that allows the Company to support global trends towards energy efficiency and the integration of distributed energy resources.

The 2019 Rate Proposal is intended to:

- Recover the costs to operate the power system over the period 2016-2023
- Complete the implementation of the terms of the Electricity Licence, 2016
- Elevate the customer experience by transitioning from less efficient, end of life oil-fired generation fleets, to new Liquefied Natural Gas (LNG) and renewable generation.
- Improve operational efficiency while enabling customers to track, monitor and save on their electricity bills.
- Facilitate continued investments to modernize and transform the electricity system to a smart system.
- Review non-fuel rates to take account of past and future investments.
- Redesign tariff structures to offer more choices for our customers
- Drive commercial growth, customer retention and safeguard the affordability of the product.

The Rate Proposal includes an Annual Adjustment Filing to adjust rates to 2019 levels.

A Record of Proven Performance

JPS has been at the centre of the advancement of Jamaica's energy policy goals over the past five years. A major achievement was the creation of partnership to introduce LNG to the island and the conversion of the Bogue power plant to burn natural gas. The commissioning of 194 MW gas-fired replacement baseload capacity in 2019, along with investments in utility scale storage, will facilitate further diversification of fuel and enable integration of more renewable sources to meet the requirement of the national energy policy, thereby further diversify Jamaica's dependence on fuel by ~30% by the end of 2019.

The Company with strong support from our Regulators, has also accelerated its pace in adopting new technologies in supporting the goal of creating a modern and efficient grid. The installation of smart meters will not only improve JPS' ability to detect electricity theft and empower customers but will also enable higher levels of efficiency in grid management. With the support of the Government of Jamaica, the Company is replacing the installed inventory of streetlights, with high efficiency, brighter and smart LED luminaires.

Power stability, primarily impacted by existing non-firm renewable generating facilities, will improve with the investment and installation of the largest hybrid flywheel/battery back-up storage facility in the region. This was fully commissioned in November 2019.

The JPS generation fleet, despite ageing elements, continued the gains of previous regulatory periods and achieved the highest conversion rate of fuel to electricity, as measured by Heat Rate performance – 11,214 kJ/kWh and the best reliability as measured by plant availability was 89% equivalent and 5% equivalent force outage rate.

The Journey Since 2014 …

Since 2014, JPS has worked to modernize Jamaica's energy infrastructure and support the national development plan to make Jamaica the place of choice to live, work, raise families and do business.

1. **Transforming Jamaica's Energy Landscape**

Embracing new disruptive technologies to keep on a path of growth and prosperity.

- *Greater fuel diversification*
- *Smart technology creating a more robust grid and enabling the delivery of better service to customers*
- *Storage facility to ensure greater power stability.*

2. **Investments Are Delivering Real Results**

Investment of J$55 Billion in energy infrastructure has improved overall efficiency and reliability.

- *37% reduction in the frequency of outages*
- *30% reduction in average duration of outages*
- *Best fuel efficiency conversion in the Company's history*

3. **Customers Connecting much Easier**

Customers now access customer care with webchat, Twitter, Facebook and the JPS Mobile App at their convenience.

- *Choice of post-paid or pre-paid service*
- *30% more customers served via online platforms in 2018*
- *Introduction of E-bills*
- *Serving more than 660,000 customers*
- *Received several Customer service awards in 2017 from the Private Sector Organization of Jamaica/ Jamaica Customer Service Association*

4. **Creating Opportunities Where It Matters Most**

Help Jamaicans with safe access to electricity, opportunities for development, grants for high school students and a scholarship for an Electrical Engineering degree.

- *Over 3,000 illegal users converted to regularized customers*
- *Collaborated with agencies for more sustainable community development initiatives*
- *Grants to over 1,300 students sitting CSEC Electrical Exams*
- *University scholarships for an Electrical Engineering degree*

5. **Powering Jamaica's Economy**

- *Over 5,000 persons employed directly and indirectly by JPS*
- *Over J$87.1Billion paid into the economy for goods and services each year*
- *More than J$5.85 Billion paid in taxes each year*

Over the last five years, the average cost of electricity has reduced by 16% from US$0.33 to US$0.28 cents per kWh.

Other initiatives include enhancing the resiliency (in terms of risk management) of the grid system through sustained investment in the Electricity Disaster Fund (EDF). The replacement of aged, damaged and degraded structures such as poles as well as step changes in vegetation management have improved reliability resulting in an enhanced customer experience. Upgrades to the Supervisory Control and Data Acquisition (SCADA) system have allowed for greater coordination across the network and enabled faster restoration in the event of an outage.

2019-2023 Rate Review Challenges and Opportunities

The regulation of JPS is intended to reflect a balance between customers and national interests whilst ensuring a fair return on invested capital is achieved by the utility.

- Stable financial performance for the utility and its investors is required to underpin the Business Plan for the next regulatory period., JPS will work with our regulators and the GOJ to ensure that the intent of the Electricity Licence, 2016 (the Licence), to promote balanced sustainable performance is achieved through the setting of reasonable and achievable regulatory targets and a culture of operational excellence
- Over the course of the 2019-2023 period, JPS will continue to expand initiatives focussed on the customer, including improving customer services, energy security, and sustainability as well as constantly exploring ways to increase value and affordability.
- JPS as a prime enabler of the National Energy Policy will continue to advance policy objectives such as delivering maximum access to electricity through conventional or distributed systems

We see these interests as complementary with strong collaboration and partnership within the regulatory construct. This will be critical as JPS prepares to navigate the sector through an era of unparalleled change. It will require JPS to take bold steps such as making strategic investments in the infrastructure for the electrification of transport (electric vehicle) that will enable future cost benefits to customers through demand growth and asset utilisation. For JPS to grasp the opportunities of the unfolding future it will need strong and flexible financial capabilities and performance.

The global electric utility sector is facing dramatic changes, due to a combination of factors, including the introduction of new disruptive technologies; changing customer behaviour, and a rapidly evolving business model. JPS has been tracking these trends and adjusting to meet our customers changing needs and maintain the Company's market position. With a supportive regulatory and policy framework, JPS is confident that it will continue to deliver on customer's expectations over the next regulatory period and to thrive in the emerging environment.

In the development of our Business Plan, we have taken deliberate steps to maintain close alignment with the national development objectives of the Vision 2030 Jamaica – National Development Plan Jamaica's National Energy Policy and the UN Sustainable Development Goals which have been ratified by Jamaica, along with other national policy and regulatory considerations.

JPS will continue to drive the transformation of the energy sector in the medium term (2019-2023) through the strategic priorities:

- Partnering with key sector stakeholders to realize the National Energy Policy goal of secure, affordable and sustainable energy;
- Delivering customer value through customer service excellence with improved reliability and customer experience;
- Driving operational excellence through end-to end efficiency;
- Delivering greater value to customers and a reasonable return to shareholders.

To achieve JPS strategic objectives, ongoing and sustained investment in the electricity system is required. JPS has structured the Five Year Business Plan and Rate Case Submission to focus on these priorities and challenges to deliver a better quality of service/value to customers. These investments are needed to deliver better efficiency, service quality, and inform the rates JPS must charge to sustainably supply power.

JPS faces cost pressures that continue to require attention and diligent action. Many of these pressures are attributable to uncontrollable factors, or costs, such as fuel prices, foreign exchange movements, IPP fixed charges, depreciation, and high corporate tax rates attributed to its regulated business status.

Our Priorities Over The Next 5 Years Are Clear

1. Continue to drive improvements to address the cost of electricity to our customers

With the introduction of advanced power generation technology and multiple fuel sources, JPS will generate electricity more efficiently. The retirement of older, inefficient plants will contribute to the lowering of production costs. JPS will also take steps to improve end-to-end efficiency in order to reduce the costs that influence pricing to its customers.

- *Lower overall operating costs by 9%*
- *Reduce fuel cost by ~30% onboarding newer and more efficient generating plants*
- *Reduce electricity theft and other system losses by 2.25ppts*
- *Lobby for changes in how the sector is taxed (Lower Corporate Income Taxes)(Clearly Identify what is the problem with tax)*

2. Fully implement smart network technologies to provide Jamaica with a modern grid (this read like we have very old grid- can we consider- Fully Modernize the national grid with Smart Network Technology)

JPS will continue to invest in smart grid technologies to create a robust power delivery network that facilitates changes in how power is produced, delivered, and consumed by customers.

- *Achieve 100% smart meter penetration*
- *Fully implement an integrated Advanced Distribution Management System (ADMS) (state the benefit)*
- *Achieve 100% smart streetlight installation*

3. Deliver sustained reliable power supply, nationwide

Through continuing investments in: asset maintenance, upgrades and replacement.

- *Reduce average duration of unplanned power outages by 20%*
- *Expand automated outage detection and reporting capabilities*
- *Achieve self-healing on 15% of the distribution network*
- *Introduce innovative grid maintenance and improvement initiatives*

4. Elevate customer service, deliver more choices and service options

JPS will take steps to deliver even greater customer value.

- *Expand JPS use of digital platforms to be accessible when and how its customers want to connect.*
- *Provide more options and flexibility so customers can choose the type of services they want.*
- *Empower customers to track, monitor and save through the provision of energy usage data – right on their mobile devices.*
- *Provide solutions for the energy needs of every Jamaican, installation of charging infrastructure and offering energy management and data services and smart energy retail services.*

5. Build a culture of relentless high performance and accountability

JPS will focus on transformative performance management, engagement and training of its team members, so our customers can get even better service.

- *Implement a company-wide coaching and mentorship programme*
- *Implement a company wide leadership performance programme*
- *Drive greater levels of meritocracy through performance incentives*
- *Provide more job-specific training and development*
- *Create and maintain a safe and healthy work environment*

JPS has been taking ongoing action to reduce or control costs, with significant results in recent years observable in the areas of operating and maintenance costs, interest costs and commodity costs linked to new fuel types.

At the same time, cost pressures also drive rates that yield their own challenges for the electricity system:

The JPS Five Year Business Plan incorporates significant cost control efforts in response to cost pressures in its operations.

O&M Cost Control

In 2018, JPS spent US$130.4 million, which is US$12.88 million or 8.99% lower than the previous test year despite a number of changes within the operation of the business, which would have resulted in increased expenditure. The main drivers of the net reduction noted are:

- Ensuring costs drivers are within or below US inflation for the period of 7.7% cumulative
- Reducing headcount and operating footprint.
- Jamaican dollar devaluated by 20% from J$106.39:US$1 at the start of 2014 to J$127.72: US$1 at the end of 2018.

At the end of 2018, O&M expenditure was 12.5% (US$18.6 million) below that for 2017 driven primarily by:

- Payroll and related expenses decreased by US$8.1 million driven by reduced staff and overtime costs.
- Generation and T&D third party cost decreased by US$1.3 million driven by improved reliability.
- Insurance costs decreased by US$0.6 million from reduced premiums and adjusting the basis of coverage for older generating units.
- Transport costs decreased by US$0.8 million due to fleet optimization initiatives.
- Bad Debt decreased by US$3.4 million, the lowest in the five-year rate review period.

Interest Costs

In 2018, JPS identified and pursued a cost saving opportunity to refinance long-term high coupon debt of approximately US$180 million.

JPS successfully refinanced this long-term bond from a coupon rate of 11% to a blended coupon rate lower than 8%, despite increases in US Treasury rates in the last 18 months and a 200 basis points increase in LIBOR over the last two years.

The new bond structure included JMD equivalent of US$ 80 million strategically geared to address greater asset, liability matching which will serve reduce impact of changes in foreign exchange on interest costs as well as reduce demand for hard currency to service debt.

This initiative by JPS will result in approximately US$27.7 million savings over the 2019-2024 period based on the forecast rate base. JPS would have incurred early settlement penalties in 2018 of just over US$5 million in pursuit of this initiative.

Grid Churn

The development of a viable LNG supply source to Jamaica has been a significant benefit to JPS customers through more stable supply costs for generation. However, it has also opened options for large customers to develop their own on-site generation and reduce or terminate service from JPS. Customers who opt for this supply option may expose themselves to increased complexities.

A very real occurrence is that as these customers transition from having JPS as supplier, to the need to site, operate and maintain their own generation, there is the the potential for decreased reliability of sustained power to their businesses. The loss of JPS' integrated system and utility-grade reliability planning, creates a reliance gap which many of these customers are unprepared for.

Despite this, threat to continuity, Customers have indicated that the potential for savings may be large enough to justify grid defection. When this occurs, the remaining customers on JPS' system are at risk of cost shifting and upward pressures on rates. At the same time, independent cost studies have confirmed that these large customers by the nature and volume of their consumption have a different cost profile.

Our challenge here is straight forward, we must make it attractive for large scale customers to stay on the national grid.

Our response to this very real threat to business and network churn will be targeted, sustained and high value to customers. We will retain large customers by designing commercial offers that deliver significant value and cost savings, our level of customer service to these customers must be world leading, beyond the supply of power to our customers JPS will deliver innovative products that add value to the business operations of these companies.

JPS therefore requires the following:

1. A Rate structure for large customers that appropriately reflects the costs of serving these customers
2. Rate offerings that allow customers who have left the grid supply but continue to purchase backup services from JPS.

This will ensure the service to customers is accurately priced, and our rates cover fixed costs of system assets designated deliver a product that is affordable and high value.

Lifeline Rate

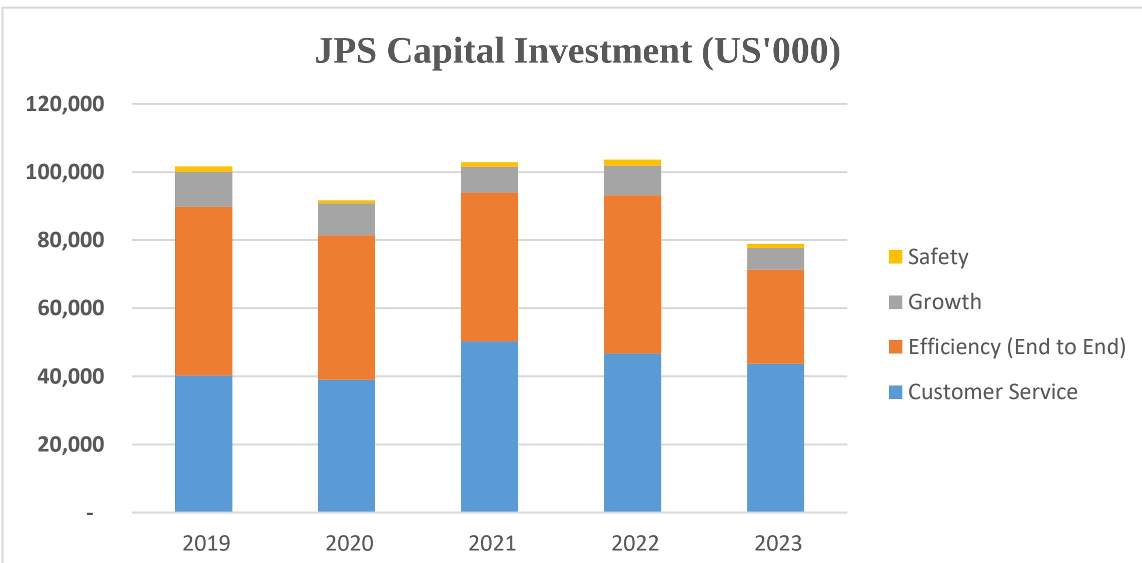
Current tariffs present a first block of 100 kWh that reflects a level of subsidized service associated with basic consumption. Consumption data shows that a large percentage of its rate 10 customers (approximately 44%) consuming at or below 100 kWh monthly. This offers an opportunity to reduce the lifeline consumption to 50 kWh, without doing injury to genuine lifeline consumers. While JPS recognizes the need to maintain a lifeline rate to protect vulnerable customers, reducing the first block to 50 kWh reduces the amount of revenue to be recovered from other customers within the class and therefore supports a reduction in the rate of customers consuming above lifeline while still maintaining the principle of equity.

JPS strongly recommend that the government extend the PATH programme to cover the economically vulnerable members of the society as discussed further in the Customer Rate Impact Support section.

Losses, Electricity Theft

JPS continues to face electricity theft, which undermines the ability of the utility to recover costs from some users. It remains a top priority of JPS to regularize, and eliminate as much illegal electricity use as possible, and to solicit stronger support from the Government of Jamaica (social funding intervention, policing and prosecution). The investment in loss reduction over the past years was very significant and necessary to bring losses down and to prevent the potential escalation of losses. Without such initiatives, the remaining customers who receive regular service would face upward rate pressures to ensure all system costs are covered, and to ensure that JPS can continue to operate a reliable, viable and safe system.

Capital Investment 2019-2023



JPS is undertaking an unprecedented level of capital investment. These capital investments will help improve services to customers, increase reliability, and support Jamaica's economic growth and expansion. JPS has sought to strike the right balance, sensitive to the need to keep rates as low as can reasonably be achieved, consistent with safe and reliable service. The investments cover the following main areas:

1) **Investments required to Modenize Infrastructure and to Improve Reliability:** Power reliability contributes to international competitiveness of all productive sectors of the Jamaican economy, and is a key concern for small customers. Over the past five years JPS has made significant improvements in its system reliability, achieving a 37% reduction in the frequency of outages. JPS Business Plan targets remain on this path as the Company continues to modernize the grid by investing in smart devices on the network, energy storage, and upgrades

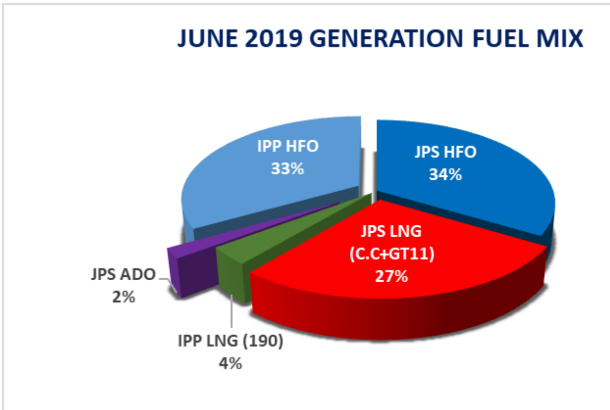
and expansion of the transmission and distribution network. The Cost of Unserved Energy Study was used to inform the reliability plan. This study provides insight to the Company in determining the optimal level of trade-off between reliability and costs for customers, helping to guide JPS' future investment decisions.

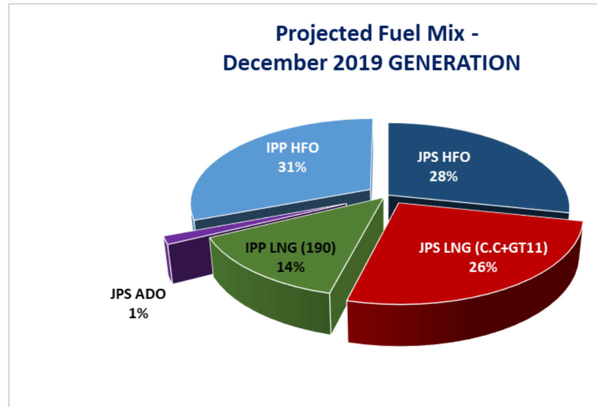
2) **Investments in End-to-End Efficiency:** We have targeted a system wide goal of 20% improvement in efficiency. We are focused on improvements from plant right through to customer delivery and usage. The planned operational efficiency initiatives will cover every stage in JPS' processes, seeking to eliminate as many steps as possible to optimize performance in every process. End-to-End Efficiency is intended to target overall delivery of key results across all business units and not just in one specific area, streamlining processes to eliminate inefficiency, cut waste and reduce operating costs. The main areas of focus for End-to-End Efficiency will be lowering costs, reducing system losses (theft) and improving Heat Rate performance and plant reliability. To reduce losses over the next five years JPS will focus on full data analysis across the grid of the energy delivered and consumed. This will include the smart customer metering, transformer metering, check metering, mapping and connectivity optimization to improve measurement, detection and the implementation of complementary systems to perform intensive data analysis.

3) **Investment in Fuel Diversification:** JPS supports the national goals of a modern, efficient, diversified and environmentally sustainable energy sector. Changes implemented by JPS in the last five years in the generation fuel supply (increasing use of LNG and renewables) have resulted in cleaner energy and reduced environmental impact of generation. This diversity in energy sources has also contributed to more stable energy pricing as Jamaica becomes less exposed to oil price volatility.

   JPS has commissioned a 194 MW LNG plant, which will replace 292 MW of steam units, which are over 40 years old. By 2023, JPS intends to retire a further 167.5 MW of generating capacity, subject to the requirements of the Third Schedule to the Electricity Act, 2015 and to commission a new 40 MW gas fired plant in Kingston.

   JPS is evaluating opportunities to undertake utility scale solar and wind energy projects, which will contribute significantly to achieving the GOJ's energy objectives of increasing the amount of renewable energy in the nation's energy mix to 30% by 2030. This will bring the percentage of renewables from 16% to 40% of total capacity. JPS is also investing in energy storage to support cleaner renewable energy on the grid without creating power quality issues for customers from the intermittent nature of some renewable energy.





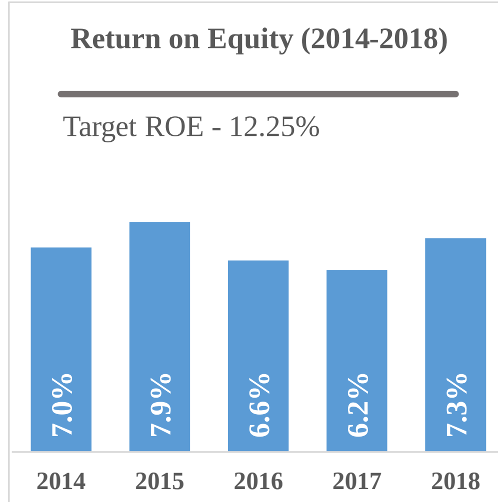
4) **Investment in Fuel Efficiency:** JPS aims to generate electricity in the most efficient and effective manner to meet its customers' demands and to improve Jamaica's competitiveness. The reliability of the generating units can significantly affect the dispatch and thus the fuel efficiency of the fleet. JPS operates a system that includes many components at or near end-of-life. These components require replacement or enhancement to continue to provide reliable and cost-effective power service. These investments are necessary and help control costs and improve quality. A good example is the investment made in JPS' generation fleet, which has increased uptime for JPS' most efficient plants. The more uptime for the plants, the more energy JPS can deliver from efficient units and keep less efficient units offline. Greater efficiency, and a lower average Heat Rate, translates into lower costs for customers via the fuel component of rates. JPS will continue its maintenance programme in OEM specifications, which includes conducting major overhauls throughout the period. For greater reliability and efficiency of all peaking units, major overhaul and transformer replacement will be completed (outlined in further detail in JPS Business Plan per the Asset Health Index). This will support the achievement of JPS' overall efficiency (thermal Heat Rate) and reliability (EAF%, EFOR %) targets.

5) **Investments in Growth, Safety and Customer Service:** Planned investment in Smart Meters will provide customers with more information on their consumption patterns with features such as remote meter control for faster service activation and future options such as time-based rates. JPS will continue to extend its service channels through online and mobile applications to provide more choice and convenience to customers in doing business with the Company. Over the next five years, JPS intends to make investment in poles and substations to increase the resilience of the grid and accommodate customer growth. The Company is implementing a streetlight replacement programme using smart light emitting diode (LED) technology to ensure quality service and improved safety to its customers.

   JPS intends as a key priority to transform its start, stop or moving to a new residence or commercial office electric service processes for all our customers. To simply making it far easier to do business with the Company, utilizing digital platforms.

Business Performance and Regulatory Matters

A separate challenge for the 2019-2023 regulatory period is rectifying the current state of JPS' financial position, as evidenced by JPS earnings and the historic Return on Equity (ROE). A sound financial position for JPS is critical to ensuring that the utility is able to generate sufficient returns and cash in the future to permit reinvestment in capital works, maintain a high level of productivity, target high priority initiatives (like loss reduction) and ensure a fair return to its shareholders. These outcomes are not only necessary to provide high quality service to customers, they are also necessary to ensure JPS can achieve the required standard prescribed by the OUR Act, that it be provided an "appropriate rate of return on investment required to satisfy the interests of persons investing in Jamaica"[1].



The Licence implemented significant changes designed to help ensure JPS would be able to recover the full Weighted Average Cost of Capital (WACC), including a return on the Shareholder's equity, as follows:

1) **ROE level:** The Licence provides that a Return on Equity (ROE) will be included in WACC "*…which allows the Licensee the opportunity to earn a return sufficient to provide for the requirements of consumers and acquire new investments at competitive costs based on relevant market benchmarks prevailing internationally for a similar business as the Licensee and adjusted for country risk..*"[2]. This provision emphasizes the interconnected nature of JPS' financial strength and the ability to acquire new investments and borrow at competitive rates to the overall benefit of customers.

2) **Reasonable and Achievable Targets:** JPS operates under a Performance Based Rate-making Mechanism (PBRM) regime, which means that the utility can secure bonuses and penalties in its financial returns tied to specified performance benchmarks as set out in the Licence. Paragraph 37 of Schedule 3 of the Licence stipulates that targets for losses, heat rate and quality of service should be "reasonable and achievable". This provision dictates that the targets must not only be capable of accomplishment by JPS, but must also be fair and appropriate based on all relevant circumstances. As mandated by the Licence, these circumstances are "*the Base Year, historical performance and the agreed resources included in the five (5) Year Business Plan, corrected for extraordinary events*"[3]. In determining the

[1] OUR (Amendment) Act, 2015 Subsection 4A(a)
[2] Electricity Licence, 2016, Schedule 3, Paragraph 30(c)
[3] Electricity Licence, 2016, Schedule 3, Paragraph 37

five year targets, the OUR is obligated to adopt an objective approach. Its decision must be grounded on an analysis of the actual performance of JPS in each of the three subject areas in light of the facts surrounding the performance in prior years and what JPS is capable of achieving given the proposed future initiatives of JPS as detailed in the Five Year Business Plan. The Electricity Licence, 2016 has established the criteria for target setting reducing much of the prior subjectivity around what is capable of being reasonably achievable by the Company.

3) **Z-factor risk/performance envelope:** Paragraph 46(d) (ii) of Schedule 3 of the Licence establishes a benchmark for the degree of risk that JPS should be exposed to as part of the PBRM regime, beyond which the degree of bonuses or penalties would be deemed a "special circumstance" and trigger a Z-factor adjustment. Such risk or performance envelope applies at the level of JPS' rate of return, and as such operates on all penalties and bonuses collectively, as well as productivity changes or changes in other financial variables. This envelope is *one (1) percentage point higher or three (3) percentage points lower than the approved regulatory target*. This means that fully implementing the Licence is intended to lead to no more than a specified quantifiable financial risk to JPS in each year from all factors. In setting targets and responding to proposals in this filing, the OUR therefore has a duty of care to ensure that it is not imposing or creating financial risk to JPS contrary to the reasonable limits contemplated by the provisions, spirit and intent of the Licence.

The Rate Review proposals by JPS are designed to achieve the objectives of the Licence in addressing these critical outcomes for JPS, Customers and the Jamaican economy. In particular, JPS' performance factor targets are proposed at levels, which JPS believes are both reasonable and achievable. This will ensure that the utility is able to generate sufficient revenue to permit future reinvestment necessary to provide high quality service to customers, and provide a fair return to the shareholder, while ensuring JPS bears a measure of financial responsibility if it fails to achieve the performance factors approved by the OUR.

A significant challenge for JPS now, is that the Licence provides for the Five Year Rate Review to be completed following the publication of the Government of Jamaica's Integrated Resource Plan (IRP). The JPS Revenue Requirement is based on its Five Year Business Plan, which should reflect, among other things, the approved system investments set out in the IRP. Given the IRP is not yet published, the Business Plan does not reflect investment decisions that have had the benefit of an updated supporting comprehensive system impact analysis. It will be critical to adapt the Five Year Business Plan where possible and is subjected to once the IRP is published. In the event, this review yields a different revenue requirement pool, an adjustment may be necessary via an appropriate licence mechanism such as an Extraordinary Rate Review.

Currency and Commodity risks

JPS has several payment obligation to suppliers, primarily independent Power Purchasers (IPPs) that are denominated in international currencies, primarily the US dollar. Jamaica's foreign exchange market is in transition with the focus of monetary policy directed to inflation targeting. This has resulted in significant volatility in the relative price of these trading currencies. Volatility in foreign exchange rate movement has clearly demonstrated the potential to erase the net profits of JPS. It therefore poses a material performance risk.

Simultaneously, the introduction of natural gas in Jamaica's fuel mix has increased the complexity of fuel price management that JPS must pursue to extract maximum value for customers. These developments require JPS to deploy more sophisticated strategies and tools to manage the risk exposure around currencies and commodities. As a result the Company has entered discussions with the Bank of Jamaica and the OUR on available hedge products that can offer customers better stability and predictability in electricity pricing. JPS anticipates that it will be granted approval for an appropriate mechanism to be included in the tariff to mitigate this material risk.

Summary of Rate Review Proposal Requested Approvals

The 2019-2023 Rate Review Proposal was guided by the OUR's Final Criteria (the Criteria) published on March 14, 2019, as amended April 24, 2019. The Final Criteria was prepared in advance of JPS' filing, and set out initial guidance on the principles and calculations that are to underlie the JPS Rate Review Proposal. JPS has found it possible to reflect most aspects of the Final Criteria in the Rate Review Proposal. Where exceptions arise, the attached materials describe and detail the impacts of required variations. In light of the divergent positions of JPS and the OUR in respect of certain decisions of the OUR captured in the Final Criteria, JPS exercised the right afforded to it under Condition 32 of the Licence. JPS has, however, in certain instances based its Rate Review Proposal on the disputed positions expressed in the Final Criteria. This submission in compliance with the Final Criteria is, however, being made without prejudice to JPS' right to pursue its appeal against the points of dispute, as permitted under the said Condition 32 and JPS hereby expressly reserves the right to so pursue its appeal.

Revenue Requirement

JPS seeks approval of a five year levelized revenue requirement as follows:

- 2019 –J$63,904 million (US$499.3 million)
- 2020 – J$62,350 million (US$487.1 million)
- 2021 – J$62,493 million (US$488.2 million)
- 2022 - J$60,842 million (US$475.3 million)
- 2023 – J$60,970 million (US$476.3 million)

The key drivers of the Revenue Requirement increase include:

- Increased 2018 rate base reflecting capital investment since 2014 (approximately US$22 million pre-tax ROI increase).

- Forecast Capital Investment of US$100.1 million for 2019 (net of IDC), impacting depreciation expense (US$4.9 million increase), and return on investment (US$2 million increase pre-tax based on rate base increase).
- Non-Fuel Purchase Power Costs is approximately US $59 million higher annually relative to the 2014 Rate Case filing. Non-fuel purchase costs is on average US$163M over the 2019-2023 period when compared with the 2014 filing of US$104 million.
- Decommissioning cost is J$4,428 million (US$34.6 million). Of this amount, J$3,121 million (US$24.4 million) is reflected in Revenue Requirement over the 2019-2023 rate review period.
- Stranded assets cost recovery is US$31.8 million for 2019-2023 rate review period
- Accelerated depreciation of Old Harbour and Hunts Bay plants (US$15.6 million).
- 2016-2018 investment depreciation (US$22.96 million)
- 2016-2018 ROI recovery (US$27.5 million).

These revenue requirement increases have been partly offset by reductions in the O&M forecast (by US$9 million), and discontinuation of previously approved adjustments (Z-factor, CPLTD, Billing Determinant Error Adjustment, and others) of approximately US$15 million.

The JPS Five Year Business Plan incorporates productivity in the preparation of all five-year forecasts for operating costs, as required by Paragraph 11 of Schedule 3 of the Licence. The Licence would have introduced an implicit productivity improvement factor (PI-Factor). Although the Licence provision did not state the methodology for calculating or application of the PI-Factor, JPS proposed a PI-Factor consistent with the Final Criteria. Furthermore, the Business Plan would have outlined the efficiency-based initiatives taken into consideration when determining the projected O&M and improvement for the Company. JPS proposes a PI-Factor of 1.9 % annually for the five-year, therefore yielding an O&M reduction from US$148.97M in 2017 to US$136.13M in 2023 (9% reduction).

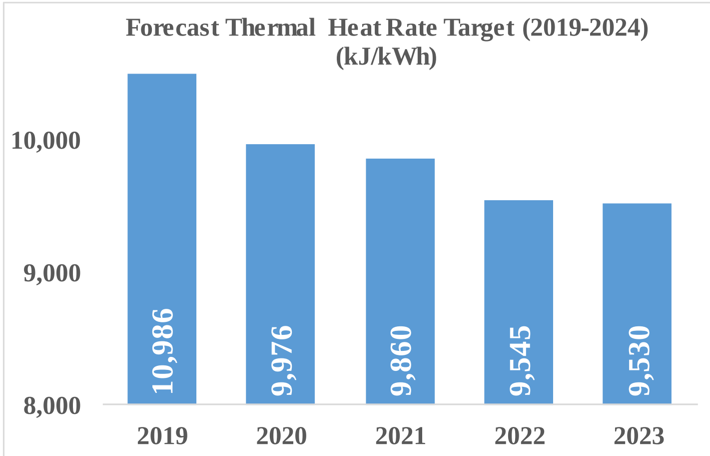
It is important to note that the Company continues to invest in technology to drive further efficiencies over the 2019-23 period. Such investments however would inevitably require some expansion in O&M to support the efficiency improvement objectives, which are reflected in the forecast operating expenditure.

Performance Factors

The JPS regulatory regime is characterized by performance targets for a number of key variables that affect the costs, quality and reliability of service received by customers. JPS has proposed adjusted targets for the performance factors as follows:

- **Heat Rate (H-factor):** The JPS Heat Rate performance factor sets the targeted efficiency for JPS' thermal generation plants. In the five-year rate review period, JPS expects a material reduction in its use of thermal plants as well as the retirement of some of its less efficient units. As a result, JPS' overall heat rate improves and benefit customers through reduced fuel charges. In total JPS expects the Heat Rate to improve from the current target of 11,450 kJ/kWh to less than 9,600 kJ/kWh.

JPS Forecasted Thermal Heat Rate Targets July 2019 to June 2024



The assumptions underlying the Heat Rate target, however, are highly dependent on the eventual IRP. A key challenge for JPS in the coming five years is that the JPS thermal fleet will transition from being the majority of generation on the system (approximately 62% in recent years) to a minority (approximately 33% or lower, depending on the IRP). As the JPS fleet decreases in relative size, the tendency for this component of the system generation to have less predictable dispatch increases, as well as the difficulties in predicting the Heat Rate (for factors that are outside of JPS' control). A further challenge is that the timing for major events, such as the in-service dates for new generation from IPPs, are not known with certainty, are not in JPS' control, and can have material impacts on the Heat Rate. JPS has provided H-factor targets in the Rate Review Proposal, but procedures will be required to adjust the targets, if necessary, for these unexpected and uncontrollable events.

In addition, to date, when IPPs underperform through unexpected outages or periods of lower output, the financial recoveries (liquidated damages) flow directly to customers. However, JPS can also effectively be charged with unintended penalties under the Electricity Licence, 2016 arising from IPP underperformance that is not within JPS' control. The proposals in the Rate Review submission seek to rectify this issue as JPS suffers from a lowered H-factor performance.

- **System Losses (Y-factor):** System Losses targets proposed by JPS for the 2019-2023 Rate Review period include targets for each of the three components – Technical Losses (TL), Non-Technical Losses that are within the control of JPS (JNTL), and Non-Technical Losses that are not totally within the control of JPS (GNTL). The proposal also includes the NTL allocation mechanism and the role of the Government.

  The proposed targets are based on and fundamentally tied to the ongoing and planned capital and operational system losses reduction initiatives, and rely on strong support from the Government, which is critical for the success of the planned initiatives. If either does not occur (capital and operational investment approval or Government cooperation), these targets will be neither reasonable nor achievable.

Proposed System Losses Targets (2019-2023)

Loss Component	2018	2019	2020	2021	2022	2023
TL	7.94%	7.94%	7.92%	7.89%	7.85%	7.74%
JNTL	4.22%	4.14%	4.93%	5.67%	6.36%	6.98%
GNTL	14.11%	13.85%	12.68%	11.52%	10.37%	9.25%
Total	**26.27%**	**25.93%**	**25.53%**	**25.08%**	**24.58%**	**23.97%**

JPS proposes 2.30% points overall reduction in system losses by 2023 over 2018 comprising 0.20% points reduction target in TL and 2.10% points reduction target in NTL.

In this regard, JPS notes that Exhibit 1 of Schedule 3 of the Licence requires the OUR to take into account (i) the role of the GOJ to reduce losses and (ii) actual cooperation by the GOJ in determining a Responsibility Factor (RF) (0-100%) to assign JPS for the GNTL portion of non-technical losses. JPS proposes that the RF is set at 10% initially, which is then adjusted annually based on the actual Government support in system losses reduction initiatives.

JPS also notes that currently there is no clear and consistent mechanism for determining NTL categorization between JNTL and GNTL either in the Electricity Licence, 2016 or the Final Criteria. The allocation between JNTL and GNTL and the resulting penalties has far-reaching implications on both the viability of the utility as well as the cost of electricity. Consequently, the utility is seeking transparency, equity and consistency in how it is treated, and has proposed a detailed framework for the NTL allocation.

JPS has developed an Energy Loss Spectrum (ELS) that generally describes and divides non-technical losses into different drivers. This ELS can be used to help understand and assess the evolution of losses. However, the ELS is not sufficiently quantifiable to be used as a basis for target setting due to the shortcoming acknowledged by the OUR. JPS recommends that the target setting be anchored to the provisions of the Licence. That is the base year, historical performance, agreed resources in the five-year business plan and GOJ involvement.

Under the premise of reasonable and achievable targets, JPS will not see any financial impact from losses outside of exceptional performance (leading to a positive impact on JPS' earnings) or a poor performance (leading to a negative impact on JPS' earnings). With targets set at a reasonable and achievable level, JPS understands that the likely outcome is achievement of the targets, with an incentivized structure to exceed the targets. The Final Criteria specifies that JPS is to propose a "methodology to manage the financial impact of Y-Factor"[4], however, there should be no presumed financial impact to manage. In the event of unexpectedly poor performance leading to a negative impact on JPS recoveries, JPS would be hard-pressed to secure offsetting savings from cutting operating costs or the capital programme in a manner that would not adversely affect safety or reliability or service to customers.

[4] Final Criteria, page 55.

- **Reliability (Q-factor):** In order to implement the performance criteria of the Licence related to reliability, JPS has proposed the first baseline targets that will initiate the performance-based regulatory mechanisms to operate. In recognition of the fact that there are no regulatory instruments that allow for the use of a Major Event Day(s) (MED) performance indicator in the Q-factor calculation, the submission of the annual reliability outage dataset, for the legal and Q-factor regulatory requirements, will not exclude MEDs.

  However, JPS adopts industry standards to allow for proper benchmarking. The IEEE 1366-2013 is the standard JPS adopts to define MEDs. In line with the aforementioned, JPS will have dialogue with the Ministry of Science, Energy and Technology to establish a framework to properly adopt industry practices for uniformity in the computation of the reliability indices.

Proposed Q-Factor Targets (2019-2023)

YEAR	SAIDI (minutes)	SAIFI (interruptions/ customer)	CAIDI (minutes)	% Improvement In SAIDI over previous year
Baseline (3-Year Average)	1,973.37	15.5	127.33	
2019	1,872.41	14.7	127.33	5%
2020	1,745.26	13.71	127.33	7%
2021	1,659.84	13.04	127.33	5%
2022	1,594.91	12.53	127.33	4%
2023	1,516.13	11.91	127.33	5%

- **Guaranteed Standards:** JPS is subject to performance standards compared to targets related to service to individual customers. These Guaranteed Standards lead to compensation to affected customers when the standards are not achieved. In general, JPS' achievements in comparison to the standards in recent years has been excellent. JPS proposes the modification of existing standards such as the conversion of EGS 3 – Response to Emergency to Overall Standards and revision of performance targets as well as put forward exceptions and exemptions to apply to some Guaranteed Standards.

2019 Annual Adjustment

As part its rate case submission, JPS has incorporated the annual adjustment for 2019 which will reflect the performance in the fifth year of the last rate review period. This annual review primarily focuses on the performance-related adjustments to the Annual Revenue Target (ART) – that is, determining revenue surcharge, foreign exchange loss/(gain) surcharge, and net interest expense/(income) surcharge for 2018. The revenue cap component of the 2019 tariff and the tariff related adjustment are covered in their respective chapters in this document.

The following outlines the results from the analysis:

- The 2018 revenue surcharge result in the ART increasing by J$636.1 million (US$5.0 million) for 2019.
- Volumetric performance adjustment of negative J$234.6 million (US$1.8 million).
- System losses performance adjustment of positive J$346.0 million (US$2.7 million).
- Foreign exchange surcharge of positive J$459.9 million (US$3.6 million).
- Net interest expense surcharge of negative J$9.5 million (US$0.074 million).

Cost of Service and Tariff Implications

Utilities use a cost of service (COS) study to measure the cost of providing service to different types of customers. The results of the COS study are considered when a utility develops rate proposals that are ultimately approved by the regulator. The results of the COS study and actual rate structures often differ. The regulator has to balance things such as:

1. The results of the COS study,
2. The need for basic rate increases to all customer groups resulting from inflation, capital additions and changes in operations; and
3. The desire for a graduated and predictable process of rate increases.

Criterion 7 in the Final Criteria established the general principles and guidelines for rate setting while Criterion 17 outlines the requirements for JPS to develop a Cost of Service and Load Research Studies. In accordance with the requirements of the Electricity Licence 2016, the OUR outlined the tariff requirements with respect to rate design in Section 3.10 of the Final Criteria. It emphasizes that rates ought to be cost reflective, economically efficient, non-discriminatory, transparent and compliant with applicable rules and regulations, as well as considerate of GOJ policy objectives with respect to the energy sector. The OUR suggested, that for prudency, the proposed rates should aim to achieve the often conflicting regulatory objectives of revenue adequacy, stability, predictability and simplicity.

JPS seeks approval of a five year levelized revenue requirement, which yields a 2019 Annual Revenue Target (ART) of J$636.1 million (US$5 million) following the Final Criteria guidelines in determining revenue caps for the 2019-2023 Rate Review period. The associated average rate increase resulting from the ART increase over the last approved rates, from the OUR determination dated October 1, 2018, is 10.6%, adjusted for non-fuel IPP surcharge in current bills.

JPS is proposing changes to current tariff structures and the corresponding price constituents to recover the 2019 ART. The design represents a more cost reflective tariff structure that considers customers consuming at the lowest levels in Rate 10 and Rate 20 classes. With these structures, JPS aims to keep electricity prices affordable to its vulnerable customers. The proposed changes are identified below:

JPS Tariff Design Objectives

1. Response to evolving markets
2. Enable increased customer options
3. Send appropriate price signals
4. Support grid retention and economic development
5. Cost reflective tariffs
6. Minimize rate impact
7. Increase fixed cost recovery

- **Rate 10:** The lifeline block is reduced from 100 kWh to 50 kWh with the class now having a three-tiered structure (0-50 kWh, 51-500 kWh and over 500 kWh). Current residential rates consist of two consumption blocks. JPS has suggested the revision to allow sufficient flexibility in terms of price signals. Fixed charges were increased in order to recover more revenues from fixed charges to improve the alignment of revenue recovery with the split between the Company's fixed and variable cost.
- **Rate 20:** Two tiered structure (0 -150 kWh and over 150 kWh), Current general services rates consist of a single consumption block. JPS believes this structure is not sufficiently adapted to the heterogeneous nature and consumption patterns of the rate class to send correct price signals. Fixed charges were increased in order to recover more revenues from fixed charges. Large RT 20 customers with demand of 25 KVA or greater for the 12 months in 2018 will be migrated to the RT 40 rate class.
- **MT 40X and MT50X:** Rate 40 and 50 customers with demand in excess of 1,000 kVA will be transferred to new rate classes MT40X and MT 50X, respectively. These new classes recognise the commercial and industrial customers with high demand that do not meet the eligibility criteria for the rate 70 tariff. The rates are designed to send appropriate price signals for efficient consumption of energy. The MT40X class has the average between the entire MT40 and MT70 tariff, times 1.2 while the MT50X has 70% of the average between the entire MT40 and MT70 tariff, times 1.2.

JPS is also proposing the following new tariffs:

- **DER (Distributed Energy Resource)** tariff for customers with self- generation but intends to continue to rely on the grid as a reliable source of supplemental or contingent supply. This new class will replace the existing stand-by rate. JPS's proposed structure will reflect a truer cost to serve and therefore more equitable than the existing tariff.
- **Electric Vehicle (EV) Tariffs:** JPS has proposed a methodology for deriving tariffs for the use of public charging infrastructure for electric vehicles. The rates are to support the acceleration of adoption of EVs by encouraging the development of publicly accessible charging points across the island.
- **Wheeling Tariff:** JPS has proposed cost reflective use of system charges, guided by the Cost of Service Study, for wheeling services as required by the 2016 Electricity Licence.
- **Streetlight Tariff Rate 60:** A redesigned tariff structure for Rate 60 is required to facilitate the transition to a new generation of public lighting underway through the Smart Streetlight Programme (SSP). Older generation High Pressure Sodium (HPS) lamps are being replaced with new efficient LED luminaires controlled by smart controllers that will enable future features of these streetlights such as to consumption control and illumination through dimming, failure detection and montoring as examples. Consequently, a more flexible tariff structure is required. The proposed structure will have a fixed charge per fixture designed to recover costs such as capital and operations and maintenance, imparirment plus an energy charge. In addition, the rate class will now have separate rates for streetlights R60S and traffic signals R60T.
- JPS is also looking to increase the participation of large customers under time of use (TOU) tariffs by proposing the removal of the current criteria, which states that in order to qualify

for TOU 50% of the load must be consumed in the off-peak period. JPS believes that the criteria has restricted the participation in this beneficial tariff.

Customer Rate Impact Support

JPS recognises the need to keep rates affordable and the Company continues to work hard to minimize the impact of higher costs that affect customers' rates. The following initiatives are being pursued to promote customer retention and safeguard the affordability for customers:

- **Electricity Affordability Assistance Programme:** Concurrent with the development of this Rate Proposal JPS has been in discussions with the GOJ and the OUR on the development of a programme for the GOJ to provide direct payment assistance to eligible vulnerable customers. The EAAP would be targeted to residential customers enrolled in the GOJ's social security programme, PATH an added benefit recognising the importance of electricity to social and economic welfare. This initiative will be complementary to the proposed changes to the Rate 10 lifeline that now reflect lower energy charges and will, taken together protect the legitimate access to the grid by vulnerable customers.

- **Prepaid tariff options:** JPS' customers also have considerably more options today to help manage usage and monthly power bills because of JPS' investment in the prepaid infrastructure. To facilitate far more customers joining the prepaid tariff options, JPS is working with the tax authorities to address how sales taxes (GCT) are levied on electricity service.

- **Time-of-use options for residential customers:** JPS is proposing real-time power consumption management opportunity for residential customers by offering TOU as an option applicable to energy charges. The customers who have flexibility in their consumption pattern during a day would be able to pay for a part of their consumption at lower rates reflecting their time of use. In order to incentivize uptake of this option, JPS is proposing simplification of the rules on TOU charge application.
- **Operating cost efficiencies:** The JPS Five Year Business Plan incorporates productivity gains on operational cost over the 5 year forecast. JPS remains justifiably proud of the achievements in cost control (9% reduction over the past five years, and 12.5% reduction over the 2017 audited actuals) and the efficient JPS operating cost structure in comparison to peer utilities on an O&M cost/kWh basis and an O&M cost/customer basis. JPS O&M expenses are expected to decrease by US$9.7 million over the five-year term to US$136.2 million in 2023.

Monthly Bill Impact

The overall net bill impact is expected to be 4.69% over the 5-year rate review period, subject to annual reviews. The primary drivers relate to changes in the non-fuel tariffs of approximately 17.54% linked to the introduction of more efficient generation, smart technology and other infrastructure investments as well as an expected reduction in fuel costs of approximately 6.10% linked to newer more efficient generating plants coming on line during the period.

The average impact will vary by customer class as well as within customer class depending on the customer's consumption and choice of tariff. The table below highlights the average monthly bill impact per category.

Bill Impact per rate category

Category	Non-Fuel Tariff			Fuel			Non-Fuel + Fuel		Bill Impact
	Current (2019)	Proposed	Variation	2019 Fuel Cost	2020 Fuel Cost	Variation	Current NF+F	Proposed NF+F	
MT 10- Metered Residential	20.59	29.11	41.37%	21.46	20.15	-6.10%	42.05	49.26	17.14%
MT 20- Metered Small Commercial	21.58	22.73	5.31%	21.46	20.15	-6.10%	43.04	42.88	-0.38%
MT 60 - Streetlighting	26.17	23.92	-8.63%	19.81	18.60	-6.10%	45.98	42.52	-7.54%
MT 40 - Metered Large Commercial (STD)	13.80	15.08	9.28%	19.81	18.60	-6.10%	33.61	33.68	0.21%
MT 40 - Metered Large Commercial (TOU)	11.87	14.56	22.69%	19.81	18.60	-6.10%	31.68	33.16	4.69%
MT40X_TOU	11.87	13.66	15.12%	19.81	18.60	-6.10%	31.68	32.26	1.85%
MT 50 - Meter Industrial (STD)	12.46	14.54	16.70%	19.81	18.60	-6.10%	32.27	33.14	2.70%
MT 50 - Meter Industrial (TOU)	12.38	13.43	8.46%	19.81	18.60	-6.10%	32.19	32.03	-0.50%
MT50X_TOU	12.38	9.06	-26.79%	19.81	18.60	-6.10%	32.19	27.66	-14.06%
MT 70 - MV Power Service (STD)	9.13	10.18	11.49%	19.81	18.60	-6.10%	28.94	28.78	-0.55%
MT 70 - MV Power Service (TOU)	9.88	9.91	0.34%	19.81	18.60	-6.10%	29.69	28.51	-3.96%
Total	**17.35**	**20.39**	**17.53%**	**20.64**	**19.38**	**-6.10%**	**37.99**	**39.77**	**4.69%**

Tariff Adjustment Impact Mitigation Alternatives

Schedule 3, paragraph 6 of the Licence stipulates as follows:

"The Licensee shall file with the Office proposed non-fuel rate schedules and shall demonstrate that the non-fuel rates proposed for the various rate categories will generate the non-fuel requirement on average over the five year rate review process."

In accordance with the Final Criteria paragraph 3.9.1, the referenced Licence condition is a basis that the OUR will establish the Revenue Requirement and an annual revenue cap for each of the five (5) years of the Rate Review period and the tariffs for 2019/2020. The Final Criteria paragraph 3.9.2 notes a key regulatory objective of maintaining price stability in establishing the revenue cap for each year designed to ensure that:

1) Non-fuel rates for the various rate categories will generate the non-fuel Revenue Requirement on average over the Rate Review period; and
2) The tariffs are relatively stable from year to year.

The Revenue Cap and resulting tariff proposal submitted in the current application by JPS have been prepared in compliance with the principle outlined in the Final Criteria and fully consistent with Criterion 6, which derives average tariffs by revenue component for the 5-year Rate Review period.

JPS notes however, a few points merit further consideration in the interest of price stability and rate adjustment impact mitigation for the benefit of customers:

1) While average tariff proposal based on one-time tariff adjustment in the beginning of the rate review period does offer price stability, it may be associated with significant adjustment in the initial year to account for the 5-year variations in the revenue requirement.
2) Average tariffs and resulting tariff proposal have been prepared on the basis of full 5-year (i.e. 60-month) revenue collection under the adjusted tariffs, consistent with Schedule 3, paragraph 6 the Licence. However, the first tariff adjustment year, 2019, has already passed. As such, the average one-time tariff adjustment would now be required to be higher given the fact that the 60-month revenue collection period would include a period with the existing tariffs in place (all of 2019, and part of 2020). This would further increase the tariff pressure faced by JPS' customers at the time of implementation.

While JPS prepared its tariff proposal following the exact mechanism prescribed by Criterion 6, due to delay in the tariffs implementation 5-year revenue requirement will be recovered over a shorter period. This shorter recover period has adversely impacted the level of Non-Fuel tariff increase. The tariff increase include a stranded asset cost recovery provision that contributes approximately 1.6 % to proposed non-fuel tariff rates.

In order to mitigate the required rate increase, JPS proposes an alternative mechanism to address the recovery of the stranded asset costs. This alternative would facilitate the inclusion in the Rate Base of assets previously excluded at an equivalent value to the stranded asset costs being recovered. For example, the smart meter assets, purchased under ALRIM 2, would under the proposal be included within the Rate Base up to the equivalent value of the cost of the stranded assets recovery being sought. The resulting impact would be a reduced annual revenue requirement provision due to removal of the stranded asset recovery and the longer amortization period for the newly included assets (i.e., instead of a 5-year recovery period, the cost of the assets would be recovered via depreciation charges over a 10-year period).

JPS will undertake preparation of a detailed asset swapping proposal for consideration if so requested by the OUR.

Conclusion

In summary, the Rate Case proposal reflects a balance between customer interests, and fair treatment for the utility allowing JPS to meet its mandate to provide affordable and reliable service, convenience, security, improve its overall efficiency and enhance customer service delivery. The current Rate Case proposal has been developed reflecting many challenges and opportunities, which put an upward pressure on tariff levels, including the following:

- Change in the regulatory regime and implementation of the terms of the 2016 Electricity Licence in response to the historical challenges under the Price Cap framework.

- Delay in the Rate Case filing driven by guidance constraints (absence of IRP) and first-time process under the new regulatory regime, which resulted in shorter revenue collection period under the adjusted rates.
- Accelerated depreciation for certain assets and decommissioning cost of the related plants, as well as stranded assets cost recovery. Retirement of older, inefficient plants will contribute to the lowering of production costs in the future but presents a tariff pressure in the current filing.
- Investment in the capital infrastructure has increased to help improve services to customers, increase reliability, and support Jamaica's economic growth and expansion. The Company continues to modernize the grid by investing in smart devices on the network, energy storage, and upgrades and expansion of the transmission and distribution network.
- JPS faces cost pressures many of which are attributable to uncontrollable factors, or costs, such as foreign exchange movements. JPS has been working with different financial institutions in finding a solution to this electricity price instability caused by foreign exchange market volatility.

In order to mitigate the impact of these drivers on the revenue requirement and to reduce the costs that influence pricing to its customers, JPS takes steps to improve end-to-end efficiency, which include lowering operating costs (by 9%), long-term debt refinancing initiative (approximately US$27.7 million savings to customers over the 2019-2023 period), and others.

With the Company's investment in newer and more efficient generating plants as well as the many initiatives discussed above the average bill impact for JPS customers is estimated to be an increase of 4.7% which reflects an increase in non-fuel rates of 17.5% offset by anticipated fuel savings of 6.1%.

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1 Introduction

1.1 Company Profile

Jamaica Public Service Company Limited (JPS) is a vertically integrated electric utility company and the sole entity licenced to transmit, distribute and supply electricity in Jamaica for public and private purposes. In addition to generating electricity, the Company also purchases power from seven Independent Power Producers. Marubeni Corporation and East-West Power (EWP), are joint indirect majority owners (80%) in JPS. The Government of Jamaica owns 19.99% and a small group of minority shareholders own the remaining shares.

Customer Base

With a staff complement of 1,536 employees, JPS currently serves approximately 658,052 customers of which approximately 89% or 587,606 are residential consumers, which accounts for approximately 33% of the billed energy sales. The General Services (R20) make up 10% of the Company's customer base and consume 19% of the billed energy. While large industrial and commercial consumers make up less than 1% of the customer base, but consume 46% of total billed energy.

The Network & Independent Power Producers

The Company's electricity system comprises of 25 generation plants, 52 substations, 112 distribution feeders and over 16,000 kilometers of transmission and distribution lines. The generating systems use a mix of technologies including steam, diesel, hydroelectric and gas turbines to produce electricity. The Company has an installed capacity of approximately 640.16MW complemented by 262.16MW of firm capacity purchased from Independent Power Producers (IPPs) under long-term Power Purchase Agreements (PPAs). The system also has over 121 MW of intermittent renewable energy of which JPS owns 3 MW. The Company also owns all 26 MW of hydro power capacity on the system.

South Jamaica Power Company Limited

JPS is leading the inclusion of Liquefied Natural Gas (LNG) in the fuel mix for power generation in support of the Government's fuel diversification strategy. In 2017, JPS incorporated a new subsidiary, South Jamaica Energy Holdings Limited (SJEH), through which it increased its investment in South Jamaica Power Company Limited (SJPC), which is also owned by MaruEnergy JPSCO 1 SRL, EWP (Barbados) 1 SRL and the Petrocaribe Development Fund. Through SJPC a 194 MW gas-fired power plant will be constructed and operated at Old Harbour Bay.

The 194 MW natural gas plant will replace retiring generating units that operate on heavy fuel oil. Leading the inclusion of natural gas in the fuel mix for power generation, JPS is supporting the Government's fuel diversification strategy, reducing the dependence on oil, and producing cleaner and more environmentally friendly energy.

Pending Power Purchase

JPS has signed two Power Purchase Agreements (PPAs) for plants that will be commissioned over the five-year regulatory period and which will result in even further diversification of the generation fuel mix. New Fortress South Power Holdings is to supply the grid with 94 MW from a new LNG-fired co-generation power plant to be built in central Jamaica and come online in 2020. Eight Rivers Energy Company will also supply energy from a new 37 MW solar power plant in Westmoreland, this plant was commissioned in June 2019.

National Role

Along with the provision of electricity, JPS is a key partner in national development. The Company has a strong corporate social responsibility portfolio and makes significant contributions in the areas of education and national development. The Company also has a strong environmental focus; participating in national and international environmental programmes and carrying out its operations in an environmentally friendly manner. Over the next five years, JPS will continue the transformation of the electricity grid into a modern, reliable network that supports Jamaica's economic and social development. This five-year focus will be on transitioning to a low carbon and diversified generation portfolio, the empowerment of customers and the pursuit of End-to-End Efficiency that delivers competitively priced electricity.

1.2 Background to the 2019-2024 Rate Case

The 2019-2024 Rate Review will mark the start of the third five-year regulatory period under the 2009 National Energy Policy and the wider Government of Jamaica Vision 2030 blueprint for attaining developed country status and making Jamaica the place of choice to live, work, raise families and do business. The national goals of Vision 2030 include the creation of a modern, efficient and secure energy sector.

As a key enabler of the National Energy Policy, over the last two five-year regulatory periods, JPS has implemented several initiatives to advance Jamaica's energy goals. A major achievement was the conversion of the Bogue Combined Cycle power plant to burn natural gas and the introduction of LNG to the island. This marked the achievement of a two-decade old national objective to diversify from fuel oil as the sole fuel source for thermal generation on the island. The SJPC 194 MW plant will further extend the benefits of diversification.

In the last regulatory period, the Company accelerated the pace of adoption of new technologies in support of the goal to create a modern and efficient grid. The installed number of smart meters jumped by 100,000 as JPS joined the global trend to utilize smart meters as portals to deliver greater value, choice and control to customers, improve network visibility and efficiency and better target losses through the acquisition of more and better data on customers' usage. These grid investments will enable faster identification and response to faults, and higher levels of efficiency in grid management, as well as shorter and less frequent outages.

Despite aging infrastructure, the JPS generation fleet continued the gains of previous regulatory periods and achieved the lowest conversion rate of fuel to electricity, as measured by heat rate performance and the best reliability as measured by plant availability. In managing replacement of generation on retirement, JPS has been strategically redeploying its generation assets not only to widen fuel diversification but in support of the emerging generation distribution trends working with large industrial and commercial customers to meet their grid needs.

With the support of the Government of Jamaica, the Company also embarked on its first ever initiative to replace the installed inventory of streetlights, with high efficiency, brighter luminosity LED luminaires. This project, which will be completed in the next regulatory period will be the largest energy efficiency project undertaken which will result in demand shaving and a smart, modern public lighting infrastructure.

These transformational programmes and outcomes were deliberately targeted under the largest capital expenditure programme in Jamaica's energy infrastructure in modern times. Over the last regulatory period, JPS' capital spend exceeded US$100 million annually and accumulatively and grid investments over the last five years totalled US$185.36 million. Collectively with the investment in the 194 MW plant through SJPC, JPS has enabled US$1 billion to modernize the electricity infrastructure and paving the way to a future of lower prices, greater reliability, resilience and value for customers.

Over the years, operating expenses have hit new lows, declining to $130.38M in 2018 as business process improved and technology have begun to impact operational and financial performance. Improved performance and a stabilizing Jamaican economy has allowed the Company to tap financial markets on improved terms that customers will benefit from in the upcoming regulatory period, as lower operating costs are passed through the tariff structure. The results of the investments are being experienced by customers via improve service and lower tariffs.

JPS has maintained customer service as one of its strategic priorities since 2014, and has been consistent in the implementation of its customer service improvement strategy during the review period. Apart from the performance framework provided by the Guaranteed and Overall Standards, JPS has implemented a number of initiatives to improve the way it serves its customers.

The Company implemented a rigorous monitoring and measurement framework, and introduced new customer solutions based on feedback from stakeholders, to include: prepaid electricity service, a JPS Mobile App, Online Customer Service, and the MyJPS Rewards programme. The sustained roll-out of initiatives to improve service delivery has resulted in a marked improvement in the customer experience, as evidenced by the positive feedback from customers reflected in the annual and quarterly customer surveys carried out by the Company. JPS' efforts to improve its services have also been recognized at the national level, with the Company winning several customer service awards from the Private Sector Organization of Jamaica / Jamaica Customer Service Association (PSOJ/JaCSA) in the following areas: Monitoring and Measurement, Leadership and Strategy, Service Excellence Charter and Standards. In addition to attaining the Overall Service Excellence Award for Large Businesses.

1.3 The 2019-2024 Rate Case: Building a grid-way for Jamaica's growth

The 2019-2024 Rate Review process represents the first application to the Office of Utilities Regulation (OUR) under the new regulatory regime. Since the National Energy Policy of 2009, several important changes to the legislative and policy landscape have contributed to the positive trend JPS has been driving in the sector. Leading up to the current Rate Review process, these include the introduction of the Electricity Act, 2015, the Office of Utilities Regulations (Amendment) Act, 2015 (OUR Act) and the Electricity Licence, 2016 (herein after referred to as the Licence). Combined, these regulatory changes have created a more flexible environment to address some of the emerging dynamics of the electricity landscape.

The 2019-2024 Rate Review will be the most important milestone event to determine the pace, depth and scope of the transformation and modernization programme. The Rate Review process presents JPS' Business Plan, which supports the continuation, acceleration and adoption of a programme of investments and initiatives to address Jamaica's electricity sector needs over the next five years. The Rate Review process and Business Plan provides an opportunity to create alignment between customers' evolving expectations, policy and regulatory objectives, and JPS' reasonable opportunity to earn commercial returns on its investments, on the way forward to a modern, efficient, reliable and secure electricity infrastructure.

JPS has operated under a Performance Based Rate Making (PBRM) tariff mechanism since its privatization in 2001. The Licence introduced a new forward-looking approach to rate setting based on a five-year Business Plan, which accompanies this Rate Review filing. The Business Plan will detail JPS' investment programme and performance targets for the 2019-2024 regulatory period therefore providing the basis for the revenue requirement needed to fund the approved investment programmes and operations. The Business Plan seeks to highlight three outcomes necessary for the commercial success and reinvestment priorities of JPS:

- Firstly, the setting of performance targets that are reasonable, achievable and affordable, and provide the Company with appropriate incentives to improve service quality. The

Business Plan incorporates the investments and operating costs needed to achieve the Company's proposed targets.

- Secondly, the Business Plan underpins the financial performance that allows for continuing investment in the modernization, efficiency and sustainability of the electricity sector. Without sufficient financial provisioning, JPS will not have the financial capacity to undertake the needed investments.
- Thirdly, the Business Plan targets the opportunity to achieve a reasonable return on investment, which lays the foundation for future investment in the electricity sector.

A challenge for the current Rate Review process is the absence of the GOJ' Integrated Resource Plan (IRP). The Licence contemplates that the Ministry of Science, Energy & Technology (MSET) will make the IRP available and will be one of the key inputs in the JPS Business Plan. In the absence of the IRP, JPS has made reasonable efforts to reflect prudent planning assumptions for the system.

Over the upcoming regulatory period, JPS will focus on:

- Enabling the realization of the National Energy Policy goals with sector stakeholders.
- Delivering customer value through service and product excellence.
- Improving reliability and customer experience.
- Driving operational excellence through End-to End Efficiency.
- Achieving competitive rates for customers and a reasonable return to shareholders.
- Maintaining a high level of regulatory compliance.

It is against this background that JPS is making its fourth five-yearly Rate Review filing. JPS has been working at achieving alignment with customers, policymakers and the regulator to realize mutually beneficial outcomes. This filing, and the accompanying Business Plan, provide the opportunity for a high degree of success in realizing that alignment.

1.4 JPS Tariffs

The JPS electricity tariff consists of two components, the fuel rate and the non-fuel rate.

<u>Fuel Rate</u>

The fuel rate represents the pass-through of fuel cost incurred by JPS and IPPs to generate electricity. It is recovered directly each month from customers subject to an efficiency adjustment for the Heat Rate Factor and movement in the rate of exchange of the domestic currency.

The cost of purchasing electricity under PPAs is also recovered directly from customers. An estimate of these costs is embedded in the base non-fuel rate at five-year rate reviews, with variations in actual cost from the estimates recovered monthly through a surcharge that is combined with the fuel rate and shown on bills as a line item – Fuel and IPP Charge.

Non-Fuel Rate

The five-year rate review is primarily to reset the non-fuel rates based on a full economic review of the Company's operations that is used to recover all costs. The non-fuel rates are subject to specific revision intervals as follows:

a. At Five-year Rate Reviews.
b. Extra-ordinary Rate Review
c. Annually under the Annual Adjustment filing of the PBRM.
d. Monthly adjustment for foreign exchange movements.

1.4.1 Summary of Requested Approvals

In accordance with the Licence provisions (Schedule 3), the Office shall determine all rates that shall be charged to customers in accordance with rate classes approved by the Office.

Paragraphs 37-40 of Schedule 3 of the Licence also stipulate that the Office shall have the power to set targets for losses, heat rate and quality of service. All targets set should be reasonable and achievable taking into consideration the base year, historical performance and the agreed resources included in the Five Year Business Plan, corrected for extraordinary events.

Pursuant to the provisions of the Licence, JPS hereby seeks Determinations of the OUR:

1. **Approving the Base Non-Fuel Revenue Requirements** of:
    - 2019: J$63,904 million (US$499.3 million)
    - 2020: J$62,350 million (US$487.1 million)
    - 2021: J$62,493 million (US$488.2 million)
    - 2022: J$60,842 million (US$475.3 million)
    - 2023: J$60,970 million (US$476.3 million)

    Including:

    a) **Decommissioning total costs** is J$4,428 million (US$34.6 million). Of this amount, J$3,121 million (US$24.4 million) is reflected in Revenue Requirement over the 2019-2023 rate review period.

    b) **Stranded assets cost recovery** of J$4,064 million (US$31.8 million) over the five-year period. JPS is requesting recovery of the stranded costs related to the implementation of the 2018 Depreciation Study results, meter replacements, and streetlight replacements initiatives as part of the depreciation expense. These initiatives result in related assets becoming obsolete or nonperforming well ahead of the expiration of their useful lives.

c) **Recovery of depreciation expense** of J$2,939 million (US$23.0 million) on capital investments made in 2016-2018 period. JPS proposes that, consistent with paragraph 27(b) of Schedule 3 of the Licence, a provision be included in the 2019-2023 revenue requirement for the depreciation charges related to regulatory assets incurred during the fiscal years 2016 to 2018 over and above the approved depreciation charge determined in the January 7, 2015 rate review determination and modified by the August 2017 Annual Determination Notice.

d) **Recovery of return on investment** of J$3,522 million (US$27.5 million) on capital investments made in 2016-2018 period. JPS proposes that, consistent with paragraph 27(b) of Schedule 3 of the Licence, a provision be included in the 2019-2023 revenue requirement for the return on incremental investment related to regulatory assets incurred during the fiscal years 2016 to 2018 over and above the approved rate base determined in the January 7, 2015 rate review determination and modified by the August 2017 Annual Determination Notice.

e) **Electricity Disaster Fund** (EDF) contribution of J$256 million (US$2.0 million) per year (net of taxes). JPS' transmission and distribution assets are not protected by conventional insurance and receives disaster coverage under EDF self-insurance fund, which was established in 2004 to address damages caused to the electricity grid by natural disasters. In the 2014-2019 Rate Review filing, JPS proposed and the OUR approved the annual payment into the EDF of US$2.0 million net of taxes.[5] For the current submission, JPS proposes to continue with the EDF annual payment amount as approved in the 2014-2019 Rate Review filing.

2. **Approving the proposed Revenue Caps** for the 2019-2023 rate review period of:
    - 2019: J$60,922 million (US$476.0 million)
    - 2020: J$61,443 million (US$480.0 million)
    - 2021: J$62,249 million (US$486.3 million)
    - 2022: J$63,012 million (US$492.3 million)
    - 2023: J$63,784 million (US$498.3 million)

    JPS has followed the Final Criteria guidelines in determining revenue caps for the 2019-2023 rate review period. The revenue caps calculated on the revenue requirements, which have been adjusted to reflect revenue from special contracts and unregulated expenses as an offset.

3. **Approving the Forecast Rate Base** reflecting net book value of fixed assets in-service, five-year capital plan forecast, allowance for working capital, customer funded assets offset:

[5] 2014-2019 JPS Tariff Review Determination Notice, Determination #17.

- 2019: J$90,428 million (US$ 706.5 million)
- 2020: J$91,826 million (US$717.4 million)
- 2021: J$94,119 million (US$735.3 million)
- 2022: J$96,847 million (US$756.6 million)
- 2023: J$96,081 million (US$750.6 million)

The forecast Rate Base represents relevant costs associated with JPS' property, plant and equipment/intangible assets employed by JPS to carry out the activities of the Generation, Transmission, Distribution, Supply and Dispatch of electricity to its customers.

The forecast Rate Base computed is in accordance with Licence provisions and the formula provided in Criterion 3 of the Final Criteria. Customer contributed assets have been excluded from the proposed Rate Base.

4. **Approving proposed Weighted Average Cost of Capital** of 12.12% (post-tax), comprising:
   - Cost of Debt of 7.45%
   - Return on Equity (ROE) rate of 11.20%
   - Gearing ratio of 50%

   Cost of debt is based on JPS' audited financial position as at 2018 December 31. Further, the computation of weighted average interest on long-term debt takes into account JPS successful refinance of its US$180M bond and the attendant interest rate savings, in keeping with Determination #6, or the Refinancing Incentive Mechanism from the 2018 Annual Adjustment Filing Determination Notice.

   The ROE rate computed is consistent with Criterion 2, with the exception of the Country Risk Premium (CRP) component. JPS' recommended ROE was derived using a three-year average of the Jamaican USD denominated sovereign bond and the US 20-year Treasury bond.

5. **Approving JPS' Five Year Business Plan** for the 2019-2023 Rate Review period provided as an Annex of this Rate Case filing. The five-year Business Plan supports the revenue requirement projections and provides detailed information in accordance with the requirement of Criterion 6 of the Final Criteria.

6. **Approving JPS' Forecast Five Year Capital Plan** of $US508,727 million gross ($US468,390 million excluding IDC cost) for the 2019-2023 Rate Review period provided as an Annex of this Rate Case filing. The forecast 5-year Capital Plan has been developed aligning proposed investment activities with JPS strategic priorities identified as Customer Service, Efficiency, Growth and Safety, to ensure these priorities are achieved.

7. **Approving 2019 Revenue Target upward adjustment for 2018 performance true-up** of J$636.1 million (US$5.0 million) comprising:
   - Volumetric performance adjustment of negative J$234.6 million (US$1.8 million).
   - System losses performance adjustment of positive J$346.0 million (US$2.7 million).
   - Foreign exchange surcharge of positive J$459.9 million (US$3.6 million).
   - Net interest expense surcharge of negative J$9.5 million (US$0.074 million).

8. **Approving the revised customer class categories** comprising:
   a. **Lifeline Residential RT10.** JPS is proposing a reduction in the current lifeline block from 100 kWh to 50 kWh.
   b. **Residential RT10 blocks**. A three tiered structure is proposed which comprises:
      i. Tier one - customers with consumption less than 50 kWh/month
      ii. Tier two - customers with consumption between 51 and 500 kWh/month
      iii. Tier three - customers with consumption over 500 kWh/month
   c. **Small Commercial RT20.** Based on the heterogeneity of this class, JPS is proposing the breakout of the current rate 20 class to a two-tiered structure. The two block structure has:
      i. First block which applies to customers with consumption up to 150 kWh/month
      ii. Second block for customers with consumption over 150 kWh/month.
   d. **Large Commercial RT40**. JPS is proposing two changes to this existing category:
      i. Differentiated energy charge per time period for customers on Time of Use
      ii. The creation of a MT40X tariff for current rate 40 customers with a demand between 1 and 2 MVA.
   e. **Industrial RT50**. JPS is proposing two changes to this existing category:
      i. Differentiated energy charge per time period for customers on Time of Use
      ii. The creation of a MT50X tariff for current rate 50 customers with a demand between 1 and 2 MVA.
   f. **Large Industrial RT70.** Customers on Time of Use will now benefit from a differentiated energy charge.
   g. **Streetlight RT60**. The new structure is based on a per fixture fixed charge, arising from the replacement of the old High Pressure Sodium fixtures to the new SMART LED lighting infrastructure with added system functionality. A variable energy charge will continue as customary for this rate class.
   h. **Distributed Generation Tariff.** JPS proposes a DER rate for all customers with on-site generation capacity across all classes of customers. Fixed cost allocated to these customers will be recovered fully through a TOU demand charge based on actual registered kVA, and a system reliability component billed on the customer's 12-month ratchetted kVA demand.

9. **Approving the proposed demand forecast for 2019-2024 regulatory period.** Sales are forecasted to grow from 3,215 GWh in 2019 to 3,361 GWh in 2023, at an annual growth rate of approximately 1%. Customer numbers are forecast to grow at an average annual rate of 1.4% between 2019 and 2023, and estimated to increase from approximately 668,404 in 2019 to 717,322 by the end of 2023. Peak Demand (MW) is projected to increase from the recorded 654.5 MW in 2018 to 660 MW in 2019 and 661 MW in 2023.

10. **Approving proposed tariffs** to be charged to customers covering the 2019-2023 rate review period.

Proposed Tariff by Rate Class (2019-2023)

Tariff Category	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)			Demand Charge (JMD/ kVA)			
		On	Partial	Off	STD	On	Partial	Off
MT10 (0-50 kWh)	853.74	8.95	8.95	8.95				
MT10 (51-500 kWh)	853.74	29.33	29.33	29.33				
MT10 (500+ kWh)	853.74	27.78	27.78	27.78				
Residential TOU	380.75	9.86	9.15	3.29	2,091.23			
MT20 (0-150 kWh)	1,488.71	17.50	17.50	17.50				
MT20 (150+ kWh)	1,488.71	20.61	20.61	20.61				
MT60 Streetlights	374.88	12.01	12.01	12.01				
MT60 Traffic Signals	749.76	12.01	12.01	12.01				
MT40 STD	12,000.00	6.85	6.85	6.85	2,437.85			
MT40 TOU	12,000.00	9.31	8.65	3.11		1,077.34	1,001.00	359.52
MT40X	12,000.00	7.70	7.16	2.57		891.50	828.33	297.50
MT50 STD	12,000.00	6.50	6.50	6.50	2,315.96			
MT50 TOU	12,000.00	8.84	8.22	2.95		1,023.47	950.95	341.54
MT50X	12,000.00	7.20	6.69	2.40		701.31	651.61	234.03
MT70 STD	12,000.00	4.95	4.95	4.95	2,141.35			
MT70 TOU	12,000.00	6.24	5.80	2.08		946.31	879.25	315.79
Electric Vehicles		26.17	26.17	26.17				

11. **Approving an interim Electric Vehicle Tariff** revenue cap mechanism that will allow JPS to fulfil its obligation as one of the key stakeholders in launching a national charging infrastructure that will enable the development of the EV market, in line with the policy objectives of the Jamaican Government. This will also mitigate any potential risk to the reliability and security of the electricity grid. JPS in consultation with the OUR, proposes to revise these rates as the appropriate time as the EV market develops.

12. **Approving the contractual mechanism** outlined by JPS for effecting a Power Wheeling Service at the request of a customer, having met all the preconditioning criteria. JPS strongly urges the finalization of the Power Wheeling regulatory and legal framework, prior to the approval of stated contract and associated power wheeling fees and or rates.

13. **Approving proposed performance targets,** including:
    a) Utilizing the most recent three-year average (2016-2018) of the actual reliability dataset, adjusted to exclude non-reportable and approved Force Majeure (FM) events, as the baseline for **quality of service (Q-factor) targets for 2019-2023**. The forecasted targets will result in an overall 23% improvement in the system reliability.

Proposed Q-factor Targets

YEAR	SAIDI (minutes)	SAIFI (interruptions/customer)	CAIDI (minutes)
2019	1,872.41	14.70	127.33
2020	1,745.26	13.71	127.33
2021	1,659.84	13.04	127.33
2022	1,594.91	12.53	127.33
2023	1,516.13	11.91	127.33

    b) **JPS Thermal Heat Rate target** for the 2019-2024 Rate Review period.

Year	Thermal Heat Rate (kJ/kWh)
July 2019 - June 2020	10,986
July 2020 - June 2021	9,976
July 2021 – June 2022	9,860
July 2022 – June 2023	9,545
July 2023 – June 2024	9,530

    c) **System losses reduction target** of cumulative 0.20% points for Technical Losses (TL) and cumulative 2.10% points for Non-Technical Losses (NTL) over the 2019-2023 rate review period.

    d) **System losses Responsibility Factor (RF) adjustment mechanism** for Government of Jamaica (GOJ) cooperation. JPS proposed that the RF would be established subject to an agreed upon programme of actions by the GOJ for the five-year period (with actions organized by year), and GOJ meeting this programme of actions. If the GOJ fails to meet any of the actions, which in turn impact JPS' planned actions, then the RF factor would be adjusted downwards. If the GOJ fully meets its committed actions (both in term of scope and schedule), then the RF score stays as established.

e) **NTL Allocation Mechanism** proposal. The allocation between JNTL and GNTL and the resulting penalties have far-reaching implications on both the viability of the utility as well as the cost of electricity. Consequently, JPS is seeking transparency, equity and consistency in how this important topic is treated, and has proposed in this submission a detailed framework for the NTL allocation.

14. **Approving Purchased Power Decoupling from Non-Fuel Costs mechanism.** Final Criteria Section 3.7.8 requires that non-fuel power purchase cost should be decoupled from other non-fuel costs and treated as a direct pass through on customers' monthly bill. However, Final Criteria does not outline a mechanism for decoupling power purchase cost from other non-fuel costs. In this regard, JPS has developed and proposes a decoupling mechanism for power purchase cost and its treatment as a direct pass through on customers' monthly bill.

2 JPS Tariff Performance over the Previous Regulatory Period

2.1 Review of Tariff Performance

In the 2014 Rate Review application, JPS made a number of proposals aimed at ensuring fair and cost-reflective tariffs with the objective of balancing affordability with sending appropriate price signals to customers. JPS was unable to achieve acceptable tariff performance from 2014 to 2017, as noted in Table 2-1[6] below:

Table 2-1: Non-Fuel Revenue Performance

US$'000	**2014**	**2014/2015**	**2015/2016**	**2016/2017**
OUR's Determination	370,654	373,934	367,576	368,420
Actual Non-Fuel Revenue		365, 521	346,662	357,624
Non-fuel Revenue Under-recovery		**(8,413)**	**(20,914)**	**(10,796)**
Base Exchange Rate	112.00	115.50	122.50	131.00
Billed Sales (MWh)		2,979,803	2,972,549	3,083,667
Demand (kVA)		5,848,092	5,194,994	5,233,851

One major contributor to the performance was load risk. This contributed to the decision to revise JPS' Licence (as further discussed in Chapter 3) to adopt a revenue cap model. With the introduction of the revenue cap on August 1, 2016 as part of the Licence, major exposure to revenue variations arising from deviation of actual sales from billing determinants was largely mitigated, but not entirely eliminated[7]. Since 2016, the actual average tariffs have been materially on target with the target tariffs resulting in no material difference in recoveries.

One other factor that caused JPS to underperform in the recovery of the determined Revenue Requirement is the establishment of performance targets for system losses that were not possible to achieve. Over the course of the rate review period, system losses penalties have totalled over

[6] The revenue from Carib Cement is not included. The revenues in US dollar were converted from the Jamaican equivalent using the Base Exchange rate established by the OUR.

[7] The new regime requires a reconciliation of revenues recovered each year based on quantity reconciliations in the categories of customer charge, kWh sales and kVA demand during each year. By performing the reconciliation based on sales quantities in these sales categories the company remains exposed to variations in revenue recovery caused by price mix differences. This is caused by the fact that there are a number of tariffs points (for each rate class) in each revenue category. Negative price mix variances are generated when the actual average tariff falls below the average target tariff and this result in the under-recovery of the revenue requirement while positive price mix variances are generated when actual average tariff is higher than the average target tariff and this result in an over-recovery of the revenue requirement.

US$20M. Therefore, impacting the Company to operate efficiently and allocating investments rigorously to efficiency driven initiatives.

2.2 Business Performance

Over the last five years, JPS has consistently improved its performance and its service to customers in an effort to provide safe, reliable and cost-effective electricity supply across the island. Significant improvements have been achieved in three areas:

- Customer Service Excellence
- Operational Performance
- Financial Performance

2.2.1 Customer Service Excellence

JPS trains and empowers its staff to engage customers, understand their concerns or complaints and follow through with resolution while keeping the customers informed along the way. The following are some of the achievements over the past five years:

Customer Satisfaction: JPS is committed to improving its service delivery and creating positive customer experiences. To this end, there has been steady improvement in JPS' customer satisfaction rating each year. This has moved from a low of 40% in 2013 to 60% in 2018. The findings of the 2018 CSAT survey was supported by JPS Cost of Unserved Energy Study (2018), in which most customers expressed satisfaction with the quality of service provided by JPS. Furthermore, the trend was also confirmed by the surveys done by the OUR. The OUR's National Consumer Satisfaction Survey (2016) showed a significant movement in the level of satisfaction moving from 4.4 in 2014, to 6.3 (out of 10) in 2016.

JPS' efforts to improve service were recognized nationally, with the Company winning several customer service awards from the Private Sector Organization of Jamaica / Jamaica Customer Service Association in the following areas in 2017 as mentioned above.

Service Standards: JPS has consistently maintained a greater than 90% compliance rate with respect to the Guaranteed Service Standards, with the overall average Guaranteed Service Standards compliance rate at 91.1% as of the end of 2018.

Reliability Improvement: The number and duration of outages customers' experience have improved over the past 5 years. The Company has upgraded its Grid Control Systems to improve reliability and to accommodate the integration of more variable sources of energy, such as solar and wind. The system upgrades include the installation of smart devices that will facilitate quicker response from the utility. These include; distribution automation switches, reclosers, automatic trip savers, fault circuit indicators and power quality monitors. These includes JPS' intense vegetation management and structural integrity programmes to improve power reliability.

Customer Options: JPS continues to provide its customers with a variety of options for managing their energy consumption and overall costs. The Company has introduced a number of options such as:

- The Pay-As-You-Go (PAYG) prepaid meter solution, which allows access to electricity for persons, while giving greater control over actual consumption.
- Expanded channels for customers to access information. This included the introduction of a digital solution in the form of a Mobile App, and greater focus on customer service delivery via online platforms – including webchat, Facebook and Twitter. In 2018, more than 29,400 customer engagements were via webchat, while 24,035 customer cases were handled via Facebook and Twitter.
- Self-help options to include an online outage reporting and service via an in-office kiosk that provides bill balances.
- The launch of the JPS eStore which provides an even more tangible way of helping customers in managing their energy costs and usage. The eStore provides customers with a range of energy saving devices, energy audits, and energy management training, as well as renewable energy solutions to help customers – especially businesses, with a view to helping them reduce their operating costs.

Customer Service: JPS has implemented a number of initiatives to improve the way it serves its customers. The Company has made deliberate and sustained efforts to increase customer gains and address customer pain points. The initiatives implemented over the past five years include:

- Upgrade of the Customer Information System (CIS) which has contributed to improved operational efficiency and customer satisfaction
- The introduction of Customer Advisory Councils, which has improved stakeholder engagement and provided an effective feedback loop for the Company
- The introduction of a Top 50 Programme, to ensure structured engagement of key business customers
- More channels for communicating with customers – including dedicated segments in the traditional media, social media, text messages and emails
- The introduction of E-bills, with 38% of customers (250,934) receiving their bills electronically as at the end of 2018
- The outsourcing of the Call Centre to improve service quality: the average service levels for calls in 2018 was 89% (versus the industry target of 82%), compared to 62% prior to outsourcing

JPS has placed great emphasis on customer engagement and has expanded the platforms available for information sharing and dialogue with customers. To this end, the Company has implemented a sustained customer education programme, expanded the channels for customers to contact the organization, as well as created opportunities for more targeted stakeholder messaging. JPS has maintained a consistent presence in the traditional media, enabling customers to interact with its representatives on popular radio discussion programmes. Through an innovative PowerSmart Energy Challenge reality TV show (2016 and 2017), the Company engaged Jamaicans in the sharing of practical conservation and energy efficiency information.

2.2.2 Operational Performance

Fuel Diversification: Fuel diversification is an integral part of Jamaica's National Energy Policy, as the country seeks to reduce its heavy dependence on oil. After more than a decade of seeking to bring natural gas to Jamaica, in 2014, the Government gave JPS the mandate to lead the effort as part of the national push for fuel diversity. In accordance with this mandate, the Company has successfully commissioned and advanced the following facilities in the 2014-2019 period:

- Bogue Plant Reconfiguration: JPS completed the Bogue 120 MW combined cycle project in 2016 and introduced natural gas to Jamaica at a cost of US$23.2M. The plant presently accounts for approximately 10 percent of JPS' electricity production.
- New 194 MW Gas-Fired Plant: As the Jamaican Government continued its aggressive push for fuel diversification, in 2015 the Government appointed Energy Sector Enterprise Team (ESET), the Ministry of Energy and the Office of Utilities Regulation to proceed with the construction of a new power plant to replace JPS' oldest power station in Old Harbour in Central Jamaica. The Company entered into a new Gas Supply Agreement with New Fortress Energy, and through a subsidiary company, in 2017 broke ground for a new 194 MW power plant, which will operate on natural gas. On completion in 2019, the 194 MW plant, combined with the Bogue plant, will bring JPS' production from natural gas to approximately 55%.
- Bogue GT11 Rehabilitation and Conversion: In 2018, JPS invested US$15.1M to rehabilitate and convert a 20 MW plant at the Bogue Power station (GT11), which was out of use for a number of years, to generate electricity utilizing natural gas.
- Eight Rivers Energy Company: In 2017, the JPS signed an agreement with an Independent Power Producer (IPP) for the purchase of power from a new 37 MW solar power plant, being built in Western Jamaica. The plant will be the largest solar facility on the island, and will contribute to substantial reductions in carbon emissions from power generation. This was commissioning in June 2019.

This means that customers would be experiencing lower fuel bills as the more efficient plants are used in the generation of electricity, resulting in lower quantities of fuel being consumed, and lowering the overall fuel costs to generate electricity. Table 2-2 below provides summary of key operational performance indicators for the 2013-2018 period.

Table 2-2: Operational Performance 2013-2018

	2013	2014	2015	2016	2017	2018
JPS Net Generation (GWh)	2,342.2	2,450.7	2,529.9	2,557.2	2,535.8	2,560.4
JPS Share of System Net Gen. (%)	56.6%	59.7%	60.1%	58.8%	58.1%	58.8%
JPS Thermal Heat Rate (kJ/kWh)	12,034	11,457	11,332	11,570	11,330	11,214
SAIDI (Hours) - Total System	32.9	41.0	33.1	33.2	34.3	28.7
SAIFI (Occurrence) - Total System	19.3	22.4	18.9	17.5	17.5	14.1
System Losses %	26.64%	26.73%	27.00%	26.80%	26.45%	26.27%

Heat Rate

JPS has made significant strides in improving the efficiency with which fuel is converted to electricity as measured by Heat Rate. JPS' thermal Heat Rate has improved from 12,034 kJ/kWh in 2013 to 11,214 kJ/kWh in 2018. The performance in 2018 was the best Heat Rate performance by the JPS thermal fleet. In 2018, the Bogue GT11 unit was rehabilitated and converted to use natural gas, this unit contributed an average of 11,600 kJ/KWh to the system between August and December, contributing to the overall record performance.

While Heat Rate overall continues to improve, the particular mix of plants used in a given year can affect the average Heat Rate. The performance deteriorated from 11,332 kJ/kWh to 11,570 kJ/kWh in 2016, due mainly to the Bogue plant gas conversion project which resulted in the combined cycle unit being offline for approximately three months during the planned major maintenance and conversion (from using automotive diesel oil to natural gas). The performance was also impacted by higher than normal forced outages on other key base-load steam units during the year. Since then, performance has improved from 11,570 kJ/kWh to 11,214 kJ/kWh, an improvement of 356 kJ/kWh over the three-year period. This resulted in a reduction in the quantity and cost of fuel used to generate electricity therefore lowering cost to the customers.

SAIDI and SAIFI

Customers have experienced fewer and shorter outages over the five-year period as demonstrated by the SAIDI and SAIFI performance over the period. Total SAIDI hours (duration of total outages) has shown consistent improvement over the five-year period from 41 hours in 2014 to 28.7 hours in 2018 that is, a reduction of 12.3 hours or 30%. Total SAIFI (frequency of outages) has also showed improvement over the five-year period reducing from 22.4 times in 2014 to 14.1 times in 2018, a reduction of 8.25 times or 36.8%.

JPS continues to focus its attention on improving the reliability and stability of the transmission and distribution grid. To this end, JPS has invested approximately US$185.4M over the five-year period. This included the routine replacement of defective structures and equipment, voltage standardization and upgrade of the network including the leveraging of various grid technologies. This has resulted in an improved and more resilient grid and reduction in the frequencies and duration of outages as outlined in the SAIDI and SAIFI performance.

Systems Losses

Systems losses continues to be an area of significant concern for the Company. System losses performance has shown reductions over the five-year period due to significant efforts and investment made by the Company. System losses at the end of 2013 was 26.64% which was deteriorated by 0.36 percentage point to 27.00% in 2015, however, it has been improving each year since and ended 2018 at 26.27% representing a 0.73 percentage point movement. At the end of 2018, technical losses represented 8.24% of total losses and non-technical losses of 18.33%. The performance was impacted largely, by socio-economic conditions existing in the environment over which the Company has little to no control.

The degree of effort expended by the Company has been high, both in capital investment and in operating initiatives. Improvements are measurable, but are achieved slowly, only with diligent effort and major investments of time and capital.

The Company has invested over US$51.2M in capital expenditure, in addition to operating expenses over the five-year period in the fight against systems losses. Some of the key initiatives include:

- The installation over 144,000 Smart Meters at a direct cost of US$28.3 M, which is helping to address and improve JPS' ability to identify system energy loss at a circuit, level by providing measurement visibility at the customer level. It also provides greater efficiency and flexibility to the billing operations and improvement in the frequency of resorting to meter reading estimates.
- Installation of 685 Check Meters in 2018, specifically designed for industrial and commercial customers with the implementation of secondary meters for each of the large customers to continuously measure and verify energy delivered.
- Installation of RAMI and Total Meters (US$13.1M)
- Community Renewal Initiative
- Quadlogic and YPP/ENT upgrades
- Voltage Standardization Programme (VSP), between 2016 and 2018 at a cost of US$7.8M

Sales

Billed sales have grown by 173.1 GWh or 5.7% between 2013 and 2018. In 2014, sales declined by 1%. However, since then, sales have grown each year, ranging from a growth rate of 3.6% to growth of 0.1%. In 2015, JPS achieved sales growth of 2.1% (63.3 GWh), recovering from four previous years of declining sales. In 2016, the Company achieved growth of 3.6% (110.9 GWh), however, it has since been experiencing lower rates of growth, attaining only a 2.5 GWh (0.1%) growth in 2018.

The main contributor to the diminished growth was the decline in the rate of consumption growth in the Residential (RT10) and Small Commercial (RT20) customer categories. Increasingly, the Company is facing the effect of customer conservation via the use of more energy efficient tools and equipment and the proliferation of renewable energy solutions such as rooftop solar panels, as well as complete grid defection. This, along with lower temperatures, a number of large customers being off the grid at various times during the year for maintenance activities, and the impact of changing HPS streetlights to utilizing LED technology, has resulted in reduced consumption (approx. 30-40%). The aforementioned were identified as key drivers to the 2018 results.

Grid Modernization and Technological Advancement

The Company has been integrating the latest technological advancements in its operations in order to improve system efficiency and accountability. Examples of these initiatives include:

- **Smart Meter Technology:** In 2016, the country took the first steps toward the introduction of smart city technology in Jamaica's capital, with the rollout of AMI smart meters in the New Kingston commercial district, along with smart street lighting, and the implementation of a web portal energy management solution. The Company also unveiled the country's first smart home in Western Jamaica in 2016. JPS invested US$28.4M in installing and commissioning approximately 144,700 smart meters (22% of total customer base by the end of 2018).
- **Smart Street Lighting:** JPS launched a Smart Streetlight project in 2017, and has replaced approximately 42,000 Smart LED (Light Emitting Diode) streetlights at the end of 2018. The plan is to change out the country's approximately 105,000 traditional High Pressure Sodium (HPS) streetlights. In addition to improved public safety, Smart Streetlights are delivering tangible benefits to the country, in the form of lowered energy costs, improved efficiency, and a reduction in the carbon emissions from power consumption. JPS has invested US$13.3M since the start of the project in 2017.
- **Smart Devices:** JPS has been leveraging various grid technologies to improve system reliability and efficiency, this includes:
    - Installation of 220 Distribution Automated (DA) switches
    - Smart Fault Circuit Indicators (FCI) totaling 385
    - Dropout Reclosers (Tripsaver II) at sub feeder levels totaling 542
    - Calibration of Feeder Reclosers with Single Pole Tripping (SPT) features -64 feeders

These devices provide the benefit of identifying and isolating faults on the transmission and distribution system, thereby reducing the duration and the number of customers impacted by faults on the system.

- Introduction of Hybrid Storage Facility: As JPS continues to embrace the introduction of more renewables to the grid, in 2017 the Company sought and received approval from the regulators for a grid scale energy storage project. Ground was broken in early 2018 for the 24.5 MW hybrid energy storage solution, which is reportedly the largest hybrid facility being built in the world at this time. When completed in 2019, the energy storage unit will help to secure grid stability and reliability, in the face of the increasing impact of intermittency from the renewable energy on the grid.

2.2.3 Financial Performance

JPS prepares its financial statements in accordance with International Financial Reporting Standards ("IFRS") and has a financial year that ends on December 31 in keeping with Condition 5 (1) of the Licence. A selection of key financial information from JPS' audited financial statements for the 2014–18 tariff review period is highlighted in Table 2-3 below.

Income Statement

In terms of net income, JPS performance over the past five years has been significantly hampered by its inability to recover all costs involved in operating the regulated business (including Return on Equity), and significant penalties tied to unachievable targets, primarily associated with losses. JPS has achieved an average return on investment of 6.9% relative to the 12.25% allowed.

Table 2-3: JPS Historical Income Statement 2014-2018

{US$ Thousand}	2013	2014	2015	2016	2017	2018	Total 2014-2018
Operating revenues:							
Fuel revenues	683,010	633,472	345,209	299,048	395,812	483,714	2,157,254
Non-fuel revenues	416,373	389,768	414,610	413,486	441,057	424,540	2,083,461
Total operating revenues	**1,099,383**	**1,023,240**	**759,819**	**712,534**	**836,869**	**908,254**	**4,240,716**
Cost of sales:							
Fuel	(728,745)	(651,880)	(367,291)	(306,389)	(390,892)	(477,553)	-2,194,005
Purchased Power (excluding fuel)	(104,270)	(97,318)	(105,771)	(121,064)	(157,270)	(141,480)	-622,904
eStore	-	(968)	(569)	(339)	(805)	(560)	-3240
Total cost of sales	**-833,015**	**-750,166**	**-473,631**	**-427,792**	**-548,967**	**-619,593**	**-2,820,148**
Gross profit	**266,368**	**273,074**	**286,188**	**284,742**	**287,902**	**288,661**	**1,420,567**
Operating expenses	(143,265)	(137,063)	(142,093)	(142,729)	(148,969)	(130,384)	-701,238
EBITDA	**123,103**	**136,012**	**144,095**	**142,013**	**138,933**	**158,277**	**719,330**
Depreciation	(49,168)	(54,077)	(57,949)	(77,607)	(76,589)	(80,666)	-346,888
Net finance costs	(61,775)	(55,198)	(42,478)	(39,814)	(34,932)	(35,843)	-208,265
Other income/(expenses) net	83	(4,578)	(12,840)	8,400	2,619	(1,882)	-8281
Taxation	(3,054)	847	(4,323)	(8,941)	(5,444)	(8,848)	-26,709
Other Comprehensive Income Net of Taxes	-2,211	0	0	4,469	3,534	1,490	9,493
Net profit/(loss) after taxation	**6,978**	**23,006**	**26,505**	**28,520**	**28,121**	**32,528**	**138,680**

The Company made total comprehensive income of US$138.7M during the five-year period from cumulative revenue of sales of US$4.2B (which includes fuel and purchased power pass-through revenues). Non-fuel revenues accounted for US$2.08B, which was driven primarily by movement in sales quantity over the period. The 2014-2019 Determination made provision for JPS to earn net profit of approximately US$30M ceteris paribus. However, the Company’s net profits remained relatively flat over the period averaging US$26.8M annually over the five years, with the lowest level of US$23M in 2014 and the highest at US$32.5M in 2018. Of note, is the fact that this net income includes income from IPPs and unregulated business as well as one-off extraordinary items in some years.

The main drivers are:

Total cost of sales of US$2.8B, driven primarily by the fluctuation in fuel prices over the period. Fuel costs decreased significantly between 2014 and 2015 due to the drastic reduction in fuel prices from an average West Texas Intermediary (WTI) of US$93.26 to US$48.69 per barrel but has since started to increase, ending 2018 at US$64.9 per barrel. The IPP costs rose as a result of new IPPs being added to the grid during the period.

JPS has spent over US$700M in operating expense over the five-year period. This cost was trended up during the first two years of the review period, increasing in year 4 by US$6M then reducing significantly in the last few years, resulting in the 2018 O&M being 11% (US$18.6M) below that for 2017. This is testament to the Company’s commitment to operate the business efficiently and to deliver electricity to the consumer at the lowest possible price.

Net finance costs have declined over the five-year period, after being significantly increased during the first two years as a result of the high level of foreign exchange losses in the first year.

<u>Balance Sheet</u>

A review of the balance sheet presented in Table 2-4, demonstrates the significant capital investment that the Company has made in property, plant, and equipment, as well as the significant amount of capital required to fund the business. As at December 31, 2018, the Company had fixed assets of more than US$776 million and total debt of more than US$400 million, making it one of the largest private sector companies in Jamaica, in terms of asset base. At the end of 2018, JPS also had equity investment of $38M in South Jamaica Power Company (SJPC). During 2018, the Company was able to collect on long outstanding receivables from the Government relating to streetlight bills.

The Company has continued to increase shareholder investments in support of important utility initiatives, on the premise of fair and achievable returns on the equity invested. Given the scale of investment required to advance the business, this objective is critical to continued success.

Table 2-4: JPS Historical Balance Sheet 2014-2018

US$'000	2013	2014	2015	2016	2017	2018
Current Assets						
Cash & cash equivalents	25,496	7,736	5,558	8,650	12,203	27,267
Accounts receivable	186,878	172,516	124,968	156,089	217,218	182,384
Inventories	40,870	33,652	30,710	32,143	41,405	40,072
Other	1,568	27,542	31,347	45,074	40,968	41,913
	254,811	**241,446**	**192,583**	**241,956**	**311,794**	**291,636**
Current Liabilities						
Short-term loans	1,938	-	-	-	25,924	20,000
Accounts payable & provisions	190,083	162,842	113,733	138,942	191,237	193,026
Current maturity on long-term debt	37,492	54,917	47,935	59,622	36,341	35,537
Other	-	1,702	1,924	660	-	943
	229,513	**219,461**	**163,592**	**199,224**	**253,502**	**249,506**
Working capital	**25,299**	**21,985**	**28,991**	**42,732**	**58,292**	**42,130**
Non-current Assets						
Property, plant and equipment	708,448	704,037	712,946	699,544	735,484	776,513
Employee Benefit Asset	20,389	21,290	27,652	32,167	41,730	46,454
Other	4,606	3,998	616	89	16,000	36,825
	733,443	**729,325**	**741,214**	**731,800**	**793,214**	**859,792**
Financed by:						
Shareholders' equity						
Share capital & reserves	281,687	265,931	265,931	265,931	266,546	266,546
Preference Share	27,688	27,688	27,688	24,688	24,688	24,688
Retained earnings	47,066	70,289	100,958	129,479	157,601	174,538
	356,441	**363,908**	**394,577**	**420,098**	**448,835**	**465,772**
Non-current liabilities						
Long-term loans	326,442	316,160	306,282	284,582	317,704	346,068
Customer deposits	26,827	25,732	25,054	24,294	27,150	29,989
Other long-term liabilities	49,032	45,510	44,292	45,557	57,817	60,094
	402,301	**387,402**	**375,628**	**354,433**	**402,671**	**436,151**

Capital Investment

JPS has continued to make significant investments in maintaining and improving its assets over the past five years. The Company has invested approximately US$416.3M. This investment has resulted in a more diversified generation mix, greater efficiency in the production of electricity and lower fuel bills; enabling a more resilient T&D network that is smarter, as well as the strengthening the Company's position in the fight against electricity loss through improved measurement and detection of illegal abstraction of electricity.

Generation: US$143M was invested in the maintenance of the Company's generation fleet. This included the conversion of the Bogue 120 MW Combined Cycle Plant to natural gas in 2016, and the restoration and conversion of GT11 to natural gas in 2018. Other investments included, major overhauls, annual maintenance, statutory testing, and inspections on all steam units as well as the overhaul of Rockfort Units 1 & 2 twice during the period 2014 to 2018. Hot gas path inspections on GT12, GT3, GT5 and major inspections on GT13, GT7, and GT10 were also completed. The overall efficiency of the generating fleet improved with the addition of the Maggoty hydroelectric plant at the start of 2014. This investment has resulted in JPS' Thermal Heat Rate improvement from 11,433 kJ/kWh in 2013 to 11,214 kJ/kWh in 2018, while plant availability improved from 75% in 2013 to 89% in 2018 and the company had the lowest forced outage rate of 5.4% in 2018.

Transmission and Distribution: US$185M was invested in the network, resulting in a 31% reduction in outage duration, a 41% reduction in frequency of outages, which resulted in a reduction in customer complaints. This investment included the routine replacement of defective equipment and infrastructure, the installation of covered conductors in high vegetation areas, the expansion of the transmission and distribution infrastructure, as well as the introduction of LED streetlights and smart sensors. This also included investment of US$6.5M for the New Spur Tree Substation 69kV expansion and modification, which facilitated the secure interconnection of some 94 MW of wind energy from Wigton and BMR to the national grid.

The Company is in the process of completing a new distribution substation at Michelton Halt, as well as Jamaica's first grid-scale energy storage facility at a cost of US$18.1M. This is a significant step for Jamaica, as when it is commissioned in 2019, it will enable the mitigation of outages caused by the intermittent nature of solar and wind energy, ultimately facilitating the incorporation of more of these renewable energy sources on the national grid. JPS has also invested US$8.0M to date to facilitate the interconnection of the new 194 MW natural gas powered power plant built at Old Harbour, to the transmission grid.

Loss Reduction: JPS invested US$51.2M, which was used to focus on the metering infrastructure to improve measurement and detection of losses and reduce the occurrence of tampering.

Support Services: JPS has invested in assets geared at enabling the core business to deliver on its goals. This includes investment in technology, upgrading of its SCADA system, and the implementation of Enterprise Asset Management (InFor EAM) across all generating plants and the transmission network.

2.3 Performance Based Rate Making Outcomes

JPS has operated under a PBRM regime throughout the previous five-year tariff period. A key factor of the PBRM is the use of performance targets and "factors" that lead to tariff adjustments to customers, which can serve to either penalize or incentivize JPS for performance outcomes in relation to targets.

With respect to the reliability (Q-factor) target, the OUR has withheld the establishment of a baseline while JPS implements necessary system capability to reliably collect and report outage information. Q-factor targets are expected to be established for the first time as a part of the 2019 rate review exercise.

With respect to heat rate performance (H-factor), the targets set in the past have been closely aligned with the operating capability of the company. This positive alignment has resulted in continued improvements in fuel efficiency, while setting targets at a level that allowed the utility a fair opportunity to achieve them. The heat rate incentive mechanism is the symmetrical type that operates by permitting the utility to benefit or suffer a financial penalty depending on its performance relative to the fuel conversion efficiency target. The resultant impact on the company's financial performance has been small in the current rate review period despite the efficiency gains achieved, as the H-factor has been set closely aligned to performance that JPS could reasonably achieve.

JPS' experience in relation to system losses (Y-factor) has unfortunately not been the same. The revised system loss incentive mechanism outlined in the Licence has a penalty/reward system that is linked to the pool of non-fuel revenues in the company's revenue cap. Due to unreasonably low and unachievable targets (notwithstanding significant commitment of capital, staff time and resources), JPS' recent experience is that the penalty has fluctuated from US$9M to $16M annually. This level of penalty is experienced in the context of a total permitted profit of US$31M. The unachievable system loss targets have hampered JPS' financial capabilities far beyond the new benchmark of +1%/-3% of ROE, and created an inability to finance future investment in the utility. In short, the penalties have been both punitive, and detrimental to financing future performance improvements, which would be in the interest of customers.

3 Overview of the 2019-2024 Rate Case

The JPS 2019-2024 Rate Case has been prepared to meet the following tariff objectives:

- Establish fair and cost-reflective tariffs that send appropriate price signals.
- A tariff structure that encourages affordable grid access, affordable consumption and customer retention;
- Continuation of the grid modernization and digitization of the electricity infrastructure;
- Competitive tariffs that support economic growth and job creation;
- Improvement in service quality, options and control for customers;
- Strengthen JPS' financial and operational performance to protect sustainability
- Support national energy policy goals

According to the Licence, the justification for the 2019-2024 rate proposal should be provided through the JPS Business Plan, the most recent Integrated Resource Plan (IRP) from the Ministry of Science, Energy & Technology, the published final criteria from the OUR, and the declared Base Year and the Cost of Service Study done by JPS. Each of these are addressed as part of the Rate Case, with the exception of the IRP. At the time of filing, the most recent IRP was not available from the Ministry. This plan, which is to inform the expansion of the generation and transmission systems, is not likely to be available in its final form before the conclusion of the rate review process. As a result, the JPS Rate Case submission has limitations with regard to estimating the range of actions and costs that may be necessary to support the eventual IRP. The Licence, at Schedule 3 paragraph 59 makes provisions for the Licensee (JPS), or the Minister to request of the OUR to conduct an Extra-Ordinary Rate Review to take account of events that were not considered or known at the five yearly Rate Review. Depending on the outcome of the IRP, JPS or the Minister, following consultations with the OUR may find it necessary to make such a filing during the 2019-2024 period.

Outside of this constraint, in accordance with the Licence, JPS therefore submits this filing of its application for new non-fuel tariff rates and for revisions to the PBRM for the 2019-2024 regulatory period.

3.1 Objectives of Tariff Submission

<u>Modernizing plants and the network</u>

Jamaica has placed the country's energy security, sustainability and affordability as a major priority on the Vision 2030 agenda. This means that Jamaica requires an efficient and reliable electricity supply to sustain the Vision as the basis for the country's long-term development. Due to the capital-intensive nature of the electricity sector and the long planning-to-commissioning cycle for projects, JPS has to continue to invest in upgrading its T&D network and replacement of power plants approaching end-of-life. The company will also have to continue to play the leading role in diversifying the energy mix, increasing the use of renewable energy while simultaneously promoting efficient consumption. The company will continue to develop its capacity to take advantage of emerging technologies that will reduce the country's dependence on fossil fuels and contribute to the development of a green economy. Major focus will therefore be placed on the integration of electric transportation systems.

Beyond the planned and proceeding IPP developments, further uncommitted generation expansion, and any associated T&D upgrades, are not considered directly as a part of this tariff submission. This is because at the time of submission, the Ministry's IRP was not available. Nevertheless, JPS believes timely retirement and replacement of its existing fleet is key to its long term objective of reducing the real cost of electricity and improved financial performance. It will also be central to the Company's future capability to effect its obligation to serve.

Promoting legitimate access and affordability

The proposed new tariff structure is reflective of the cost to serve the various rate classes. Nevertheless, in an effort to support continued access to electricity service for the most vulnerable social groups, JPS has proposed a tariff design that considers affordability and the consumption level of these customers. The distribution of the proposed rate increase is done through a tariff design sensitive to low consumption residential customers and small businesses. The design also offers large and commercial customers competitive pricing solutions taking into account their best alternative option for electricity service.

Rebalancing energy and demand-type charges

JPS proposes the continued rebalancing of the proportion of revenue that the Company earns from fixed charges and variable energy charges to increase fixed cost recovery through more cost reflective tariff. Currently, approximately 77% of JPS' non-fuel costs are fixed while only 23.4% of revenues are recovered through a fixed charge. This has continued to manifest itself in revenue leakage and volatility for JPS. The situation continues to be exacerbated with the moderation in energy sales growth due to changing consumption patterns driven by efficiency gains or load displacement. If the link between cost drivers and cost recovery is not maintained, JPS will continue to under-perform on revenues with the attendant adverse effect on financial performance.

Addressing electricity theft

As one primary outcome of the 2019-2024 Rate Review, JPS seeks to achieve an effective system losses framework that improves the fair distribution of the burden of this crime on customers and JPS. The success of the System Losses Reduction Plan in targeting lower losses over the next five years will rely heavily on the active involvement of the government in fighting electricity theft.

The Rate Case includes a holistic proposal and includes system losses targets and penalties that, in keeping with the Licence, are both reasonable and achievable. JPS also proposes that targets be reviewed annually, linked to previous year's actual performance and based on defined efforts undertaken rather than exclusively on the outcome. The Company has also explicitly defined and identified roles and responsibilities for the Government of Jamaica. This will enable the setting of the responsibility factor for Non-Technical Losses not totally within JPS' control (GNTL) to be informed by the GOJ's performance on its role and responsibilities.

Investing in the future grid

The five-year Capital Investment Plan is the resource blueprint for JPS to align policy goals, customers' expectations, network transformation and JPS' sustainable performance over the next regulatory period. The plan identifies the portfolio of projects and programmes with supporting business cases and a robust prioritization framework for regulatory approval. Over the upcoming regulatory period, JPS intends to make prudent investments in the amount of US$243.5M to further improve the robustness, security and reliability of the T&D network and deliver customer value. These investments will expand the network to accommodate demand growth while maintaining a high quality of service reliably to all customers.

3.1.1 Amended Legislative and Regulatory Framework

Since the last five-year Rate Review in 2014, there has been a comprehensive overhaul of the legislative framework for the electricity sector. The 2019-24 filing is therefore being done against the backdrop of sweeping changes to the root legislation, the Electricity Act, 2015, which replaced the 1890 Electric Lighting Act and major amendments made to the OUR Act, 1995 (amended 2000) the principal law governing the Office of Utilities Regulation.

In 2016, the Government of Jamaica and JPS renegotiated several elements of the existing Licence and replaced it with the Electricity Licence 2016.

The 2019-24 Rate Review is filed in keeping with these statutes and Licence provisions. The result is an application, which encompasses significant departures from previous reviews. This section summarizes some of the relevant provisions of the statutes to the filing.

3.1.2 OUR Act 2015

The Office of Utilities Regulation (Amendment) Act, 2015 was amended and gazette on November 17, 2015, which replaced the Office of Utilities Regulation (Amendment of First Schedule to the Act) Order, 2014. The purpose of the amendment was to enhance the transparency of the tariff setting mechanism in the electricity sector. The following are highlights of amendments:

1. Section 4 amended to require the OUR to set the rates in relation to electricity in accordance with the OUR Act and any regulations made thereunder, and the Electricity Act. Also amended to require the OUR, when setting rates to take into account the following:
    a. The interest of consumers in respect of matters, including the cost, safety and quality of the services
    b. Jamaica's economic development
    c. The best use of indigenous resources
    d. Possibility of including specific tariffs to encourage the regularization of, and payment for electricity usage by, consumers who are unable to pay for the full cost of the services provided
2. Section 16 has been amended to allow the OUR to make regulations prescribing the procedure for analytical tools to be used in determining the tariffs applicable to prescribe utility services for the generation, transmission, distribution, supply and use of electricity.

The result of the above changes is an increased focus on customer interests, the importance of JPS to the Jamaican economy, and a shared responsibility to help regularize consumption and address affordability.

3.1.3 Electricity Act 2015

The Electricity Act 2015 repealed the 125-year old Electric Lighting Act, the Electricity (Frequency Conversion) Act and Electricity Development Act to consolidate and modernize the laws relating to the generation, transmission, distribution, supply and dispatch of electricity in the island. The objectives of the Act are as follows:

1. Provide for a modern system of regulation of the generation, transmission, distribution, supply, dispatch and use of electricity
2. Promote transparency in the identification and allocation of costs and revenues within and between participants in the electricity sector
3. Promote clarity in relation to the respective roles and responsibilities of the stakeholders in the electricity sector
4. Facilitate the achievement of the efficient, effective, sustainable and orderly development and operation of electricity supply infrastructure, supported by adequate levels of investment
5. Promote energy efficiency and the use of renewable and other energy sources
6. Prescribe the required standards in the electricity sector
7. Ensure the protection and safety of consumers of electricity and the public
8. Ensure that the regulation of the electricity sector is transparent and predictable

The Act also establishes the roles and responsibilities of the persons charged with the regulation of the sector. They are outlined as follows:

1. The Minister have the responsibility for system planning and the issuance licenses for the various activities,
2. The Generation Procurement Entity will procure new generating capacity,
3. The Government Electrical Regulator shall regulate electricians and electrical inspectors, and
4. The Office is responsible for the general regulation of the electricity sector.

3.1.4 Amended Operating Licence 2016

The most significant development affecting the 2019-2024 Rate Case is the issuance of a new Electricity Licence to JPS. The Electricity Licence is a foundational codification of JPS' rights and obligations in respect of regulated energy supply. The Licence replaced the Amended and Restated All-island Electric Licence 2011, and brought a fundamental shift in JPS' regulatory framework.

In JPS' view, there were four critical changes incorporated into the JPS Electricity Licence 2016 as compared to the previous regulatory framework:

1. A change from a price cap to a revenue cap regime.
2. Incorporation of the principle that performance targets for JPS should be "reasonable and achievable" in light of past performance, and in light of the resources devoted to meeting the targets in the Business Plan. Targets should not be aspirational or "stretch" goals, they should be routinely attainable or exceeded where JPS has expended the resources and efforts agreed to as part of non-fuel tariffs.
3. Incorporation of the principle that JPS should see performance-based variations in its earnings but that the band for such variation should not be more than +1% to -3% on in relation to the target Return on Equity.
4. Adoption of the principle that JPS performance-based financial results should be driven by factors under JPS' control, with clear and explicit mechanisms to address matters primarily or entirely outside of JPS' control, notably such aspects as (a) Z-factors for such issues as Government Imposed Actions, or unexpected but prudent new capital expenditures, (b) components of system losses (theft) that are primarily under the control of others such as Government, and (c) other extra-ordinary or exceptional circumstances that have a significant impact on the electricity sector.

In combination, the above provisions codify a performance-based regime that is not intended to be punitive in nature to JPS, or to substitute the regulator for management of JPS. The continuation of Overall and Guaranteed Standards, Q-factor adjustments for service quality, H-factor adjustments to ensure efficient generation operation, and Y-factor adjustments for system losses leaves JPS with a significant incentive to ensure high quality service to customers, and permits JPS to manage its operational and capital activities to ensure costs are minimized while still meeting the service standards over the five-year rate review period.

More specifically, it provided for the following:

1. Under the price cap regime, prices were capped for five-year rate review period with annual adjustments to prices allowed for inflation, productivity (X), quality improvements (Q) and special circumstances beyond the control of the utility (Z). It meant that revenues varied in direct relationship with the level of kWh sales. While, the revenue cap provides for the decoupling of revenues from sales quantities. Under this regime, revenues are capped for each of the five years of the rate review period with the allowance of annual adjustments.
2. A new System Losses efficiency target mechanism. The system losses incentive mechanism was removed from the fuel rate derivation mechanism, which required monthly adjustments to reflect fuel penalty adjustments. Instead this provision was included instead in the non-fuel rate calculation, the incentive adjustment for which is reflected annually. The Licence also allowed for the disaggregation of system losses to account for losses that are outside of the control of JPS. The three factors are outlined below:
    a. TL = Technical losses
    b. JNTL = Aspects of non-technical losses within the control of JPS
    c. GNTL = Aspects of non-technical losses not totally within the control of JPS
    d. For GNTL, JPS is to propose and the OUR is to determine a responsibility factor (RF), which is a percentage from 0% to 100% for losses not totally within JPS' control. The responsibility factor shall be determined by the Office, in consultation with the Licensee, having regard to the following:
    e. Nature and root cause of losses;
    f. Roles of the Licensee and Government to reduce losses;
    g. Actions that were supposed to be taken and resources that were allocated in the Business Plan;
    h. Actual actions undertaken and resources spent by the Licensee;
    i. Actual cooperation by the Government; and
    j. Change in external environment that affected losses.
3. Revision of fuel rate adjustment mechanism. With the removal of the system losses efficiency target from the FCAM, only the heat rate factor is included in the monthly fuel rate adjustment formula as of July 1, 2016. Additionally, the cost of fuel additives that was previously excluded from the computation in the 2014-2019 Determination Notice has been included in the fuel costing.
4. Inclusion of costs previously excluded from Revenue Requirement such as:
    a. FX Losses - The Licence allows for inclusion of FX losses as a prudently incurred business cost. In the annual adjustments, a FX surcharge will be included to account for deviations from the FX losses target included in the revenue requirement. The FX surcharge is offset by interest charges collected from commercial customers.
    b. Current portion of long-term debt (CPLTD). The Licence makes provision for the exclusion of the CPLTD offset from the Rate Base used to derive the investor return component of the Revenue Requirement. In the previous Rate filings and

determinations, both the OUR and JPS included this offset in the Revenue Requirement derivation, thus incorrectly reducing the return due to the Company, however, the Licence stipulated that the CPLTD should not be an off-set since it is a part of the company's long-term funding. The company has been recovering the CPLTD through the Z-factor since 2017.

5. Provision for Interest and Late-Payment Fees (LPF) to be charged on accounts on which arrears have been generated. The Licence allows JPS to charge late payment interest to GOJ and commercial customers whose accounts are in arrears, and LPF on residential accounts not settled in full by the due date. These include:
    a. Interest on Commercial customers at commercial bank overdraft rates.
    b. Interest on GOJ accounts at three (3) year USD bond rate or the nearest equivalent instrument issued by BOJ.
    c. Late payment fee and early payment incentive for residential customers.
6. Changes to Rate Case Filing Process including procedural criteria, documentary support, content and scheduling requirements, a detailed description of the derivation of the Rate Base and the establishment of performance targets:
    a. It enunciated that the Revenue Requirement should be based on a 5 Year Business Plan, predicated on among other things:
        i. An IRP completed by MSTEM
        ii. OUR led Stakeholder Engagement to establish the Final Criteria.
7. Expansion of the Z-factor recovery mechanism to include:
    a. Adjustment to the annual revenue cap to reflect deviation of the target ROE beyond the range of 1% above to 3% below the target in the preceding period; and
    b. The adjustment of the annual revenue target to account for cumulative underutilization of capital or special project expenditure to the tune of 5% or more of the forecasted annual expenditure.
8. The establishment of the Extraordinary Rate Review Mechanism. This mechanism provides for the inclusion of costs not previously contemplated by the rate review mechanism, owing to exceptional circumstances might have significant effect on the electricity sector in the revenue target, upon approval by the OUR. Such reviews may be requested by the Licensee or the Ministry and their occurrence does not reschedule the five-year rate review.

The Licence requires annual rate adjustments in between rate review filings to adjust for changes in the revenue target to reflect general movements in inflation, changes in service quality, true-ups for system loss, volume sales, interest and foreign exchange losses relative to preset targets, and where applicable, the Z-Factor adjustment for unforeseen occurrences beyond management control not captured in the other elements of the PBRM. Tariff rates are set annually and adjusted monthly based on indices of foreign exchange rate movements. The PBRM operates by adjusting the revenue cap for inflation, performance against quality of service targets set by the regulator and special circumstances outside of the control of JPS as indicated in the revenue adjustment framework determined through the following formula:

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

where:

> *dI = the growth rate in the inflation and JMD to USD exchange rate measures*
>
> *Q = 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 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.*

3.2 Regulatory Risks and Uncertainties under PBRM

PBRM is a particular technique through which utility regulators set the rates that utilities may charge to their customers. PBRM involves two basic steps: first, regulator sets an initial revenue requirement based on the utility's observed and projected costs. Next, the regulator provides the utility with incentives to reduce these costs and pass some of the resulting savings on to the consumer. JPS recognizes the importance of the PRBM in generating efficiencies for the electricity sector. The Company also recognizes the improvement in the stability of the regulatory improvement given the amendments made to the Legislative framework and the Licence. While these changes have brought a greater level of stability to the market, the Company is mindful that since privatization, it has failed to achieve the regulatory determined profit target primarily arising from the operation of certain aspects of the PBRM.

The risk factors driving the underachievement of returns to shareholders, while significantly mitigated by the Licence, still exist and can again cause significant harmful impact on the business. In the past, these deleterious effects were generated by penalties tied to aggressive system losses targets which, in the context of operational trends, past history and committed resources, were impossible to achieve. These penalties are in effect leakages on the utility's business model, which makes it impossible to achieve the level of profitability determined by the regulator as reasonable given the operational and environmental risks associated with the business.

The PBRM operates by setting a revenue target that almost exclusively drives the utility toward increased economic efficiency while using targeted incentive mechanisms to achieve regulatory goals around desired quality and performance outcomes considered important to the sector. In the Jamaican scenario, the revenue target has a productivity factor built into the mechanism to keep the utility focused on improving cost efficiency. Incentives are set to motivate the utility to operate more efficiently by allowing them to keep a proportion of the costs saved, rewarding them with higher returns, or symmetrically rewarding or penalizing the utility for achieving or failing to achieve target outcomes. In any of these circumstances, targets are to be set given a certain level of baseline performance that allows the utility a fair opportunity to achieve the target. The structure of the mechanism is critical to ensuring that the utility operates efficiently and that consumers are charged a fair price for electricity even though the market is monopolistic.

In JPS' experience, it is critical that the regulator recognizes a credible baseline for the purpose of establishing all performance targets. The current application sets out JPS' proposals with respect to reasonable and achievable targets. Schedule 3, paragraph 27 of the Licence requires that targets established for performance factors should be reasonable and achievable. In order to achieve this objective, the establishment of targets requires the establishment of a normative operating baseline, usually linked to historical performance, on top of which the regulator overlays a performance increment to establish the target, to incentivize the utility to reduce costs. The utility is permitted to include in the Business Plan the investments and operating costs necessary to give effect (on a forecast basis) to the targeted improvements. This link cannot be understated – performance targets and committed Business Plan resources (both capital and operating) must be aligned, and one cannot be adjusted without the other. This is similar to the approach being taken with respect to the establishment of the Q-factor target and is a principle that must be found in the establishment of all targets.

JPS believes that the need for procedural fairness and the application of natural justice will be critical over the course of the upcoming rate review period, especially given the unavailability of the IRP, a listed critical requirement under the Licence for the completion the filing. JPS cannot afford to delay its filing on the basis of the absence of one piece of input, critical though it may be, given that the company continues to incur depreciation charges well above the level approved in the 2015 rate review determination for which applications for recovery have been rejected by the OUR in its annual review Determination Notices of 2017 and 2018. As JPS and the OUR embark on this initial rate review period where all the provisions of the amended Licence can be applied, there will be a need for great understanding and fairness to be displayed in order to ensure the successful operation of the sector.

3.2.1 Practical Operation of Five-year Business Plan

In accordance with paragraphs 10 to 13 of Schedule 3 in the Licence contents of the non-fuel rate proposal are as follows:

1. The Business Plan, the most recent Integrated Resource Plan ("IRP"), the published final criteria, the Base Year and the cost of service study shall comprise the justification for the rate proposal of the Licensee.
2. The criteria published by the Office shall include but not be limited to the following:
    a. Anticipated change to the demand for electricity;
    b. The productivity improvement;
    c. Allowed return on equity ("ROE"); and

    d. All annual targets.

3. The published final criteria, the most recent IRP and the Base Year shall form the basis of the Business Plan.
4. The Business Plan shall include but not be limited to the following:
    a. The matters listed in the published criteria;
    b. The most recent IRP;
    c. Investment activities;
    d. System loss mitigation activities and related funding requirements;
    e. Grid Security;
    f. Annual targets for losses (Y-factor), heat rate (H-factor) and quality of service (Qfactor);
    g. Operating and maintenance expenses;
    h. Smart technologies, energy efficiency and other policy initiatives; and
    i. Balance sheet, profit and loss statement and cash flow statement.

The Business Plan is the principal document for determining the revenue cap for each year of the rate review period and was developed using the information supplied by the other major documents described in paragraphs 10 to 13 of Schedule 3 in the Licence (with the exception of the IRP). Once the Business Plan was developed, it was converted into the revenue requirement. It is important to note that the Business Plan is just a document setting out the business' future objectives and the strategies for achieving them. The plan is completed by the development of a forecast to capture the financial implications of the business plan. It is the financial distillation of the business plan that is used to develop the projected revenue cap.

The mechanism for operating the Business Plan need to recognize that actual implementation will deviate from plan and these eventualities require a fair, efficient and objective process for accommodating necessary changes without unduly hampering the operation of the business. The need to minimize roadblocks, promote transparency, enable efficiency in the approval process and accommodate flexibility in the use of budget funds is crucial to the success of JPS in this new dispensation. This does not mean that JPS should be permitted to modify the projected O&M at will. The process should, however, permit the orderly submission of changes to the Business Plan for significant items. One possible example could be the replacement of the Rockfort diesel plants with new combined cycle generation technology operated on natural gas. Should a change like that be considered more cost efficient to customers (and consistent with the IRP), it would have far reaching implications for both the capital and O&M components of the revenue requirement for multiple years.

There may be instances where certain projects may become irrelevant owing to changes in the operating cycle driving changes in the business model. Where the strategic objective does not require the implementation of a replacement project, the capital investment becomes available for reprioritization. Given the need for investment in other strategic priorities, in such circumstances, the capital expenditure must be managed as part of the overall capital portfolio, channeled to fund projects that have arisen as important but for which there was no funding identified in the planning stage due to the natural changing of circumstances. For this reason, JPS will follow good utility practice or maintaining a slate of critical projects, fully planned and scoped and only awaiting funding or prioritization for implementation.

The adjustment mechanisms presented by the Licence are the Extraordinary Rate Review and the Z-Factor under the Annual Adjustment mechanism. While these will most likely capture the major amendments including required changes to targets, there still remains a need for a practical approval process to accommodate changes in project schedules within the course of each regulatory year.

3.2.2 Agreement on process for adjusting tariff for deviations from plan

The occurrence of deviations from plan signals the need for reconciliation to ensure that ratepayers pay only for value received. The Z-factor adjustment makes provisions to account for delays in project implementation resulting in variations of 5% or more of the annual expenditure. JPS' expectation is that while the reconciliation to the Revenue Requirement will be done annually for which the Z-factor provision is sufficient, a degree of involvement of the OUR will be required to maintain efficiency in the process of prioritizing projects. JPS recognizes that under the PBRM model, it has responsibility for generating the computation of necessary adjustments for each year with the summary of changes in capital investments and necessary adjustments to the Revenue Requirement presented as a component of the annual filing.

4 JPS Strategic Priorities

This chapter highlights JPS' Strategic priorities and its position in a rapidly changing energy landscape. It also outlines the sector wide considerations of the Vision 2030: Jamaica - National Development Plan, the National Energy Plan and United Nations Sustainable Development Goals among other things. All of which help to shape the Company's strategic position and alignment.

4.1 Jamaica's Energy Landscape

The global electric utility sector is facing dramatic changes, as a result of a combination of factors, including: changes in regulatory and policy frameworks; new disruptive technologies; changing customer behavior; and competition where none previously existed.

The changes in stakeholder expectations and behaviour are directly impacting utilities across the globe. Electricity sales have generally stagnated or declined as a result of the push for greater energy efficiency, and the emergence of new technology that has enabled customers to take more control of their energy usage[8].

The Energy Sector is in transition, change is all around and so too are possible opportunities.

The dramatic changes in the global energy sector are being felt locally, influencing both the business environment and customer behaviour. Technology is transforming the existing power systems and creating a new power reality for individuals, businesses and the nation. The 'green revolution' has gained momentum, with the Government and customers alike prioritizing the environment and placing greater emphasis on alternative energy sources.

Renewables have become mainstream. With falling prices for solar solutions in particular, more customers are pursuing renewables as an option to reduce their energy costs. The continuing expansion in rooftop photovoltaic systems and the spreading doctrine of energy efficiency are keeping downward pressure on kilowatt hour sales, despite signs of an uptick in economic activity. The improved economics of fuel prices is creating a tempting attraction to self-generation for large industrial and commercial customers lured by the prospect of avoiding grid costs. As a result, there has been an increase in the number of suppliers of rooftop photovoltaic systems to both residential and commercial customers. In recent years, JPS continues to face potential loss of demand from self-generation options facilitated by the availability of liquefied natural gas (LNG) on the island from New Fortress Energy (NFE). The presence of NFE – supplier of LNG to JPS' power plants – in the fuel market, has created the potential for grid defection by large commercial and industrial customers.

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[8] Tom Flaherty, Norbert Schwieters, Steve Jennings. 2017 Power and Utilities Trends. Retrieved from https://www.strategyand.pwc.com/trend/2017-power-and-utilities-industry-trends

The operating environment has become quite challenging for customer service delivery. Global and national trends, including the volatility of fuel prices and foreign exchange rates, continues to negatively impact the Company's operations. Coupled with Jamaica's unemployment rate of approximately 8%[9], the unemployment rate for youth is considerably higher at 21.8%[10], the lowest rate since 2007. The country continues to be confronted by serious social issues that negatively affect employment rate. Some of these social issues have resulted in high levels of corruption, crime and violence and high incidences of electricity theft.

JPS is severely impacted by the pervasive problem of electricity theft, with the utility being penalized each year, which attracts a penalty if not controlled within the approved target level. Electricity theft is one of the most prevalent crimes in Jamaica, and directly impacts the country's economy. More than 18% of the electricity produced is stolen. Numerous studies have concluded that, electricity theft is largely a socio-economic problem, which can only be successfully addressed through a holistic approach, involving public and private sector partnerships.

The difficult economic environment has also resulted in challenges in revenue collection and growing bad debt, as customers place a low priority on bill payment. Only about 50% of customers pay bills in full and on-time, and this severely impacts the Company's cash flow.

At the same time, customers have become more demanding of the utility, expecting improved service and immediate responses to their queries. Changing customer behaviour has already prompted JPS to make changes to its service offerings, in order to provide more convenience to customers. Today's customers are "fully connected", and want to be engaged on their own terms using a wide variety of channels, to include: voice, webchat, email, video and social media. They expect the utility to be "always on", ready to respond to them via whatever channel they choose to contact the Company. JPS has also responded with improvements in its system reliability and will, over the next regulatory period, modernize the grid by installing trip savers and fault circuit indicators; energy storage to minimize the impact of intermittency on the grid, install transmission lines to reduce wide spread outages, among other things. JPS will continue to refine its product and service offering to meet the demands of its customers.

Government policies and regulations continue to gently but firmly guide the energy sector towards a more competitive future, even as policy makers and the regulator proceed to operate within the boundaries of the current legal framework in which JPS holds a market dominant position.

Customers are perceiving options never before imagined in controlling their energy future. With a new power wheeling framework inching its way into implementation, a Net Billing Programme controlled by the GOJ coupled with LNG in Jamaica, it has also opened up the possibility for

[9] Statistical Institute of Jamaica (May 29, 2019). Labour Force Statistics. Retrieved from http://statinja.gov.jm/LabourForce/NewLFS.aspx

[10] Statistical Institute of Jamaica (May 29, 2019). Labour Force Statistics. Retrieved from http://statinja.gov.jm/LabourForce/NewLFS.aspx

containerized distributed fuels that can support distributed economical self-generation. At the central station power generation level, investors, industries and the Government are awaking to the big potential for combined heat and power (CHP) projects to deliver mutual benefits to steam reliant industry and electricity customers, when done right. Tumbling technology prices and the government's commitment to an energy mix of 30% by 2030 are propelling the relentless march of renewable energy forward. Emboldened by recent success in integrating 87 MWs in a year, the industry can expect larger procurements of utility-scale RE projects - including energy from waste - over the next five years.

To further bolster the march of renewable energy, the Prime Minister has recently revealed his ambitions for the country to reach 50% renewable energy by 2030, up from the commitment of 30%. This however, will have implications for the grid's ability to handle additional intermittency as a result of increased penetration from variable renewable energy sources. Jamaica is also a signatory to an Energy Cooperation Framework with the United States Department of the Treasury to foster collaboration on energy and infrastructure investment. This cooperation is intended to further energy diversification, integrate cleaner energy sources including natural gas and renewable energy and accelerate the use and adoption of innovative power technology such as micro-, mini-grid and battery storage systems[11].

The development of an Electric Vehicle Policy is also on the horizon showing the Government's commitment to creating a diversified, environmentally sustainable and efficient energy sector that provides affordable and accessible energy supplies to Jamaicans[12].

There are also new pieces of legislation that impact JPS' operation and strategic positioning, namely the Electricity Act, 2015, the Electricity Licence, 2016 (the Licence) and Electricity Grid Code. Perhaps the biggest change in the Licence is the switch from a Price Cap to a Revenue Cap regulatory regime. The Licence has also introduced changes to the five-year Rate Review process, which will be done in accordance with the revenue cap principle. The Revenue cap will be arrived at based on the (1) most recent IRP; (2) Business Plan; (3) Final criteria; and (4) Base year. In addition, the Business Plan should incorporate the Final Criteria, the IRP, and form the basis for the rate review process to establish the non-fuel rates. The IRP, however, has not yet been finalized to inform the Business Plan for the 2019-2024 Rate Review filing.

In addition, there is a new regulation governing the guiding principles, operational standards and established procedures for handling the generation, transmission, distribution, supply and dispatch of electricity across the nation – the Electricity Grid Code.

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[11] U.S. Department of the Treasury (October 28, 2018). U.S. and Jamaica Sign Energy Cooperation Framework. Retrieved from: https://home.treasury.gov/news/press-releases/sm557

[12] Jamaica Information Service (February 27, 2019). Government to Craft Energy Policy Retreived from: https://jis.gov.jm/govt-to-craft-electric-vehicle-policy/

While many of these trends may slow JPS initially, our market position, recent changes in the legislative and regulatory framework and potential for first mover advantage, places our Company in good stead to not just survive but also thrive in the emerging environment. The first right of replacement of generation guarantees a pool of generation assets that can be smartly deployed to support grid loads and stabilization. Smart Grid technologies provide more reliable and cost efficient/effective services to our customers. At the same time, the green world emerging is offering unprecedented opportunities for an organized JPS to take advantage of a new world of energy services.

By continuing to position itself as a company nimbly finding solutions for the energy needs of all Jamaicans, JPS can remain relevant, grow and satisfy the expectations of stakeholders, including shareholders.

4.2 Outlook for the Future

4.2.1 Sector Goals

JPS, in the development of its Business Plan, factored the applicable goals and outcomes of the Vision 2030 Jamaica –National Development Plan (Vision 2030), Jamaica's National Energy Policy and the Sustainable Development Goals among other things, to ensure inclusiveness and alignment with national development.

Jamaica's Vision 2030 – National Development Plan outlines four (4) goals and fifteen (15) outcomes for which JPS supports **Goal 3** (Jamaica's Economy is Prosperous) and **Outcome 10** (Energy Security and Efficiency). Energy Security is broadly defined as ensuring adequate and affordable energy supplies in order to sustain economic performance and national development. The long-term plan for the energy sector focuses on electricity generation and emphasizes (1) the development and use of new sources of energy; (2) promotion and improvement of energy conservation and efficiency; (3) modernization of the energy infrastructure with efficient electricity generating plants and distribution system; (4) reduction in the amount of oil we need to import; and (5) decrease in the cost of energy to businesses and consumers.

Jamaica is also a signatory to the United Nations Sustainable Development Goals (SDGs) agenda, which is consistent with Jamaica's Vision 2030. **SDG Goal 7** - Ensure access to affordable, reliable, sustainable and modern energy for all – is in direct alignment with Jamaica's Vision 2030, which identifies energy security and efficiency as a fundamental policy position. To realize this goal, Jamaica's National Energy Policy (NEP) 2009 -2030 was created, with the primary objectives being: to increase energy efficiencies, reduce energy costs, support diversification, and develop renewable energy and other indigenous energy sources. It is also intended to reduce Jamaica's energy intensity while seeking to protect the environment.

Government policy, as well as changes in the regulatory framework, clearly outlines the energy future envisioned for the country:

- For Jamaicans to use energy wisely and aggressively pursue opportunities for conservation and efficiency.
- For Jamaica to have a modernized and expanded energy infrastructure that enhances energy generation capacity and ensures that energy supplies are safely, reliably, and affordably transported to homes, communities and the productive sectors on a sustainable basis.
- For Jamaica to realize its energy resource potential through the development of renewable energy sources and the enhancement of its international competitiveness and energy security whilst reducing its carbon footprint.
- For Jamaica's energy supply to be secure and sufficient to support long-term economic and social development and environmental sustainability.
- For Government Ministries and agencies to model/lead in energy conservation and environmental stewardship.
- For Jamaica's industry structures to embrace eco-efficiency for advancing international competitiveness and move towards building a green economy.

Jamaica's move towards the establishment of a green economy, the introduction of more renewables, and the promulgation of energy efficiency has clear implications for the future of the energy sector, and for JPS in particular, as the primary operator in this sector. The National Energy Policy (NEP) sets out targets for the percentage of renewable energy in the nation's energy mix of 12.5% by 2015 and 20% by 2030 with a further commitment of 30%. The aim is to reduce greenhouse gas (GHG) emissions from the energy sector to 3.5 MtCO2/year by 2030, down from an estimated 5 MtCO2/year in 2008.

The of Government of Jamaica's ten (10) point Energy Priorities are also in alignment with the UN Sustainable Developments Goals, Vision 2030 Jamaica – National Development Plan and the Jamaica's National Energy Policy (NEP) 2009 -2030. Table 4-1 outlines the Energy Priorities.

Table 4-1: Government of Jamaica: Energy Priorities

GOJ 10-point Energy Priorities	
Competition	• Create a Competitive Energy Environment.
Modernization	• Modernize the nation's power generation.
Diversification	• Continued diversification of energy sources with a strong emphasis on renewables.
Regulation	• Overhaul all regulations to create a true 21st century framework combined with newer and relevant institutions, which together provide the state infrastructure capable of delivering sustainability and innovation.
Energy Efficiency	• Transform the energy efficiency of the Jamaican economy to include amongst other things, world class conservation techniques
Inclusiveness	• Ensure that the National Energy Policy as part of the economic growth model addresses socio-economic issues to create inclusiveness in development.
Carbon footprint	• Manage our carbon footprint to preserve Jamaica's natural environment and fulfill our international agreements and obligations.
Demand Reduction	• Set targets for the reduction of national demand for energy over a five year period.
Green Economy	• Market & BSJ standards for an adequate supply of energy efficient appliances. • Enforce energy efficiency standards and codes with aim of (I) reducing energy consumption in new buildings by 50% in 2020 (ii) Ensuring that all new buildings use zero net energy – net zero by 2025
Fuel Pricing	• Revise the Refinery Reference Pricing system and JPS fuel pass through to ensure that Jamaican consumers enjoy the best prices for energy products – petroleum or electricity.

In essence, the Government's primary objective is to diversify the national energy supply to a mix of energy sources for energy security. The policy of the GOJ is that there is no restriction on the sources of electricity generation, which may include solar photovoltaic, wind, hydro, biofuels/biomass and waste to energy solutions, petroleum coke, coal and natural gas.

4.2.2 JPS' Role

JPS has been proactive in its efforts to support national development by aligning with the Vision 2030 Jamaica – National Development Plan, Jamaica: National Energy Policy 2009-2030 and the

United Nations Sustainable Development Goals. Table 4-2 outlines the alignment of JPS' Strategic Priorities and Initiatives with the development goals.

Table 4-2: JPS' Strategic alignment with National Development

National Goals/National Outcome	National Energy Policy Goals	UN SDGs	JPS Strategic Priorities 2019-2024	JPS Priority Area/Strategy 2019-2024	JPS Strategic Initiatives 2019-2024
Goal 3: Jamaica's Economy is Prosperous **Outcome 10:** Energy Security and Efficiency - **New sources of energy;** - **Energy conservation** - **Modernized energy infrastructure;** - **Decrease the cost of energy**	**Goal 1:** Energy Conservation and Efficiency **Goal 2:** Modernized and expanded energy Infrastructure **Goal 3:** Development of renewable sources **Goal 4:** Energy supply is secure and sufficient	**Goal 7:** Ensure access to affordable, reliable, sustainable and modern energy	**End-to-End Efficiency** **NG3,G1, G3, G4, G7**	▪ Diversify the energy supply - Generation Replacements ▪ Reduce System Losses ▪ Efficiency Improvements	▪ Commission a 194 MW LNG plant units ▪ Enterprise Asset Management ▪ Business Process Optimization ▪ Organization Transformation ▪ Smart Meter Programme ▪ Check Meter Programme ▪ RAMI
			Customer Service **NG3, G2, G3, G4, G7**	▪ Grid Modernization; ▪ Asset Rehabilitation ▪ Renewable Energy Integration	▪ Smart LED Street Lights ▪ Energy Storage ▪ Distribution Automation ▪ Fault Circuit Indicators ▪ Trip Savers
			Growth **NG3, G1, G3, G7**	▪ Increase use of renewable energy ▪ Energy efficiency and conservation	▪ Renewable Developments (wind, solar, hydro, biomass, waste to energy) ▪ Electric Vehicles and charging stations ▪ Distributed Generation ▪ eStore
			Safety **NG3, G2, G4, G7**	▪ Employee and Public Safety ▪ Compliance with laws, regulations and standards relating to Health, Safety Environment & Climate Change	▪ Safety and Health Management System Implementation ▪ Public Education Campaign

4.3 JPS Strategic Priorities

In arriving at a strategic direction for the Company, many of the current and future changes in the Energy Landscape were considered. As such, the strategic direction for JPS' Business Plan is centered around five strategic priorities, namely - delivering exceptional **customer service**, ensuring the **safety** of our employees and the public, achieving **end-to-end efficiency**, **growing the business** and **strengthening relationships** with our key stakeholders; all of which are underpinned by key enablers – our people, processes and technology.

It is therefore intended that at the end of this regulatory cycle, JPS will be (1) a more efficient company; (2) delivering more reliable and improved products and services to its customers; (3)

perceived as the energy provider of choice -caring for our customers, employees and the environment; and (4) continuing to support national development and deliver shareholder value. The five Strategic Priorities[13] are expounded below:

1. Safety

Safety is a core value of the Company and continues to be our number one priority. The safety of employees and the public is a critical factor in ensuring JPS' long-term viability. JPS will continue to create and maintain a safe and healthy work environment, complying with all applicable laws and regulations, and sustainable business practices. In order to meet these objectives, the Company has taken steps to ensure that its current operations as well as all expansion plans are in keeping with applicable policies, regulations, standards and guidelines. In addition to government regulations, our credit agreements contain covenants that require that our facilities and activities operate in compliance with governmental regulations.

The vision for safety is best described in two components- safety system and safety culture.

Major initiatives being rolled out over the period include:

- The implementation of a Safety and Health Management System to minimize and prevent any work related ill health, injury or death by managing safety elements in the workplace. Utilizing a systems-based approach to safety and occupational health that will allow the organization to continually improve its safety performance and compliance with health and safety legislations, programmes and standards;
- Strengthening our employee safety culture and embed a zero harm philosophy and
- Public education.

2. Customer Service

Delivering exceptional customer service is a key component of JPS' business strategy. The Company aims over the next five years, to continue to improve its service delivery by being more targeted and deliberate in identifying and addressing the needs of its customers. The primary objective is to deliver a superior experience with every touch point. The focus is on making it a pleasure for customers to do business with the Company, by anticipating customers' needs, eliminating pain points and maximizing customer value. JPS aims to move beyond mere transactional interactions with our customers, to the creation of mutually beneficial relationships that result in long-term brand loyalty and customer retention.

[13] Further information is provided in the JPS Business Plan 2019-2024

The main objectives over the next five years are to: **improve quality of service performance** by providing a more reliable system; **improve the ease of doing business** with the Company – seamless transaction, quicker resolutions and real time information; **customer empowerment** - expansion of self-service options and customer education which will drive **customer retention** and improve the **brand perception** - reposition the JPS brand as a valuable partner**.** JPS aims to use the opportunities provided by the changing marketplace to move the Customer Satisfaction Index from its current 60% (2018) to 70% by 2023 and Quality of Service – Q- Factor targets by 20% over the next five years.

The major initiatives aligned with each objective are outlined below:

2.1 Improve Quality of Service Performance

Power quality and reliability are among the greatest pain points of our customers. Over the past five years, JPS has responded through improvements in its system reliability achieving a 26% reduction in outages and will over the next regulatory period remain on this path. As we continue to **modernize the grid** by installing among other things, trip savers and fault circuit indicators, standardizing voltage distribution and optimizing power flow, installing energy storage systems to minimize the impact of intermittency on the grid related to renewable power generation. This also includes **routine replacement, upgrade and expansion of the transmission and distribution network** including substations to ensure **grid security and stability and compliance with T&D Grid Codes and Design Criteria**. The reliability plan is informed by the **Cost of Unserved Energy Study,** undertaken to provide keen insight for the Company to determine the optimal level of reliability for the utility and its customers thereby guiding our reliability investment decisions going forward.

2.2 Improve Ease of Doing Business

The Company will continue its focus on the implementation of initiatives to ensure compliance of 97% for Guaranteed Standards, and 95% compliance for Overall Standards by 2023. One initiative is the **automation of the Outage Notification** via SMS and emails for all outages. **Maximizing the benefits of smart meter technology** is also another way in which service delivery will see notable improvements, as customers will benefit from fewer estimations, quicker reconnections, faster and better analysis and diagnosis of issues, and real-time information on their energy consumption. JPS will also focus on **bill production and delivery automation**, the integration of meter data and billing systems, and the implementation of a debt management solution.

2.3 Customer Empowerment – Putting the Power in the Customers' Hands

JPS has an opportunity to improve the customer experience, while reducing the cost of serving customers, by providing more self-service options for customers. Self-service options will be provided primarily through online and digital platforms. Over the upcoming five years, the

Company will utilize Artificial intelligence (AI) in the form of Chatbots to address basic customer queries online and deploy an updated version of the MyJPS Mobile App and fully operationalize the Pay-As-You-Go (PAYG) service.

The availability of information when customers need it, where they want it, is a critical part of customer empowerment. Therefore, expanding its customer education programme to ensure that information is available on all platforms, in a format that is accessible and useable by customers.

2.4 Customer Retention

JPS is faced with the increasing reality of load defection, as customers seek more affordable options and more choices to suit their lifestyles. It is no longer a case of 'one size fits all', whether in terms of products and services, or communication methods. It is therefore imperative, that JPS gets to know its customers and develops partnerships with key customer groups. With more intimate knowledge of customers, the Company can better tailor its products and services to meet customers' needs, and increase its chances of keeping these customers. The expansion of the customer loyalty programme- MyJPS Rewards and partnerships with customer interest groups will also help the company to better plan for the needs of its customers.

2.5 Brand Perception

JPS will continue its strategy to reposition itself as a valuable partner for residential customers, businesses, communities, and at the national level. While highlighting operational initiatives to improve service delivery. JPS will be more deliberate in aligning itself with issues and causes that matter to our stakeholders, and which make a difference in the lives of individuals.

The Company will ensure the fulsome dissemination of information on its projects and initiatives that contribute to national growth. JPS will develop and implement a 360-degree Marketing Communications programme that provides information on all areas of the business, while showcasing the people behind the operations. This programme includes: continuing the regularly scheduled interview programme, "JPS Cares" on radio stations and the introduction of a YouTube weekly series among other things.

2.6 Customer Value

To create customer value, JPS must first address the customer pain points, and then demonstrate the value that the products and services bring to our customers. The implementation of the strategies outlined in the Business Plan, are expected to result, first and foremost, in improved customer satisfaction, which the company will then work to convert to customer loyalty.

Customer value will be created by making it easier for customers to do business with the Company, and providing the services required by each customer segment.

3. End-to-End Efficiency

Efficiency is defined as the ability to avoid wasting materials, energy, efforts, money, and time in doing something or in producing a desired result. 'End-to-End' Efficiency would therefore cover every stage in a particular process and seeks to eliminate as many steps as possible to optimize performance in every process. End-to-End efficiency is intended to target an overall delivery of key results across the business and not just in one specific area.

Therefore, JPS in its pursuit of end to-end efficiency, will be streamlining its processes to eliminate inefficiency and reduce operating costs, which will help to lower electricity costs for our customers. This improvement will be defined in the context of an efficiency target or a Productivity Improvement Factor to be achieved by JPS.

The main areas of focus for End-to-End Efficiency will be lowering costs, reducing system losses and improving heat rate performance and plant reliability:

3.1 Lowering Cost

JPS has been actively working on minimizing its operating costs. Over the past five years the Company's average operating costs has reduced, with a significant decrease of 11% (US$18M)[14] noted in 2018 when compared to 2017. This was all in an effort to improve operational efficiency and to deliver electricity to the consumer at the lowest possible cost.

Lowering costs includes the identification of process improvements to achieve cost savings, efficiency gains and enhanced customer satisfaction. This will be done through a number of key initiatives- Business Process Optimization (e.g. Meter to Cash and Purchase to Pay), organization transformation, the management of controllable OPEX (e.g. bad debt, maintenance), reducing the costs associated with breaches of Guaranteed Standards and fuel diversification – lower fuel cost. A depreciation study was undertaken in 2018 to determine the annual depreciation rates for the Company's assets. This is done to match the recovery of cost over the period in which the asset will be serviced thereby developing a reasonable depreciation rate that will properly balance the interests of both JPS and its customers in the rate design process.

JPS continues to lead the transition to Smart LED (Light Emitting Diode) street lighting as part of a plan to change out the country's traditional High Pressure Sodium (HPS) streetlights. Since 2017, when the programme was launched, approximately 42,000 smart LED streetlights have been replaced. In addition to improved public safety, smart streetlights are expected to deliver tangible benefits to the country, in the form of lowered energy costs, improved efficiency, and a reduction in the carbon emissions from power consumption.

[14] For additional information see Chapter 6: Operational and Financial Performance

3.2 Minimize System Losses

In addition to reducing our operating costs, minimizing losses is the single biggest area of opportunity for JPS to realize customer and shareholder value. JPS recognizes the importance of reducing both technical and non-technical losses, and has embarked on a number of initiatives and process improvement strategies to address this issue. Some of these initiatives were started in 2018 and will continue as programmes. The ultimate objective of these loss reduction initiatives, is to reduce system losses by 2.3% point over the next five years and define a ten year long-term losses strategy.

The system losses reduction efforts are focussed on three (3) key strategies: measurement, analytics and process control. Losses from illegal abstraction is seen as socio-economic issue and therefore the fight against losses must also incorporate the Government, including a strengthened legislative framework in order to achieve marked improvement in this area.

The major losses initiatives for the upcoming five years will be: smart customer metering; check metering; mapping and connectivity optimization to improve measurement; the implementation of an analytic platform; the use of the Advanced Automated Theft Detection Analytical Tool (AATDAT) and design surveys to improve analytics. This will drive targeted audits and investigations and identify areas of losses and reduce leakages by improving loss impacting processes- the details of which are in Chapter 9.

3.3 Improved Heat Rate and the Efficiency of Generation Assets

JPS aims to generate electricity in the most efficient and effective manner to meet its customers' demands. The reliability of the generating units can significantly impact the dispatch and thus the plant Heat Rate performance.

JPS will continue its maintenance programme in OEM specifications, which includes conducting major overhauls, which will also be executed over the period. For greater reliability and efficiency of all peaking units, major overhaul and transformer replacement will be completed (as outlined in further detail in JPS Business Plan as per the Asset Health Index). This will support the achievement of JPS' overall efficiency (thermal heat rate) and reliability (EAF%, EFOR%) targets.

Generation replacement: The first phase includes the retirement of the 292 MW steam generating plants at Old Harbour (OH1, OH2, OH3 and OH4) totalling 223.5 MW and 68.5 MW at Hunts Bay (HB6). A ROFR was granted for 194 MW of the 292 MW in 2016, via South Jamaica Power Company (SJPC). JPS will pursue the remaining 98 MW under the ROFR clause using technology to be determined by the IRP.

As per the he planned schedule maintained by the Minister, the second phase of 171.5 MW will be ready for retirement by 2023 in keeping with the planned schedule that was approved by the Minister of Energy on September 6, 2019.

To ensure that best practices are utilized, the systematic expansion of the Enterprise Asset Management (EAM) module will continue to be implemented on a phased basis over the period.

4. Growth: Defining a New Path for JPS- 360 Provider

JPS aims to maximise value to customers and other stakeholders by successfully pursuing sustainable business growth in the evolving energy market which includes:

4.1 Utility Scale Renewables

JPS is in support of the national goals of a modern, efficient, diversified and environmentally sustainable energy sector. To this end, the Company is seeking to take advantage of the opportunity to grow its generation capacity using renewable sources of energy. The total capacity of utility scaled renewables at the end of 2018 was 151 MW. JPS is evaluating opportunities to undertake utility scale renewable projects in solar and wind energy, which will contribute significantly to achieving the GOJ's energy objectives of increasing the amount of renewable energy in the nation's energy mix to 30% by 2030.

4.2 Behind the Meter Energy Services and Solutions

Rapidly declining costs of Distributed Energy Resources (DERs) has presented consumers with more options for them to take greater charge and control of their "power" needs. As a result, today's energy customers are "plugging" into the energy business in a new way. Customers are moving towards a reduction (load defection) or elimination (grid defection) of their regular power from the centralized grid by installing rooftop solar panels, building self-generation plants or purchasing storage units.

JPS is seeking to respond to the changing needs of its customers by providing customized energy solutions. JPS intends to explore the incorporation of unique, customizable services and solutions into the regulated business e.g. roof-top solar PV lease, smart home services, individual and bundled services.

4.3 Electrification- Electric Vehicle Penetration (EVs)

Globally, the energy sector is experiencing a significant increase in electrification in the transportation industry. Electric vehicles are a more efficient, cleaner form of transportation, and have a lower life cycle cost than internal combustion engine (ICE) vehicles. Global trends, such as the need to protect the environment, have led to a number of countries implementing policies to proliferate the use of electric vehicles.

JPS currently owns an electric vehicle and charging facility and has undertaken several feasibility studies to position itself to take advantage of the emerging EV market. JPS will support the creation of an enabling environment to facilitate the deployment of EV through active stakeholder engagement, lobbying of the Government and strategic public and private partnerships. Some of the key initiatives to be undertaken over the period include, supporting the development of a national roadmap for electric vehicle deployment, supporting the development of the EV infrastructure; deploying in 2019 an EV pilot programme which includes the installation of eleven (11) charging stations as an initial step towards the build out of a public electric vehicle charging network and supporting the creation of partnerships for EV financing for fleets and large transportation vehicles.

4.4 Smart Energy Retail Services: Delivering value to our Customers

Energy efficiency among JPS's residential customer base has primarily been supported by its eStore. Over the last six years, the JPS E-Store has focused on empowering residential customers to manage their energy usage more actively and efficiently through the provision of low-cost energy efficient equipment and devices. Likewise, the eStore offers bulk sale of energy retrofitting supplies for businesses.

Over the five years, JPS will reposition the eStore to increase the value delivered to both residential and commercial customers in keeping with shifting preferences and needs. Through a suite of products that marry energy and technology, the eStore will smarten homes and businesses; empowering and enhancing the quality of life for our customers and supporting the achievement of business objectives.

4.5 Energy Management and Data Service

There is an increasing participation of Governments in energy efficiency programmes where energy use has an obvious impact on the cost of operations. Energy efficiency is one of the GOJ's Top 10 priorities with a goal to reduce the public sector's energy use through the implementation of an Energy Management & Efficiency Programme (EMEP).

Corporate energy strategies are also becoming a main feature of corporate business plans as customers are actively seeking to optimize their energy use due to rising energy costs reported to consume profit margins at 20% or more.

Energy efficiency presents other opportunities in the energy market to create non-traditional revenue streams. To support efficiency goals, JPS is seeking to establish an energy management and data services hub to grow its presence and participate in this component of the energy space.

4.6 New Business Growth

To avoid revenue erosion and to grow business, global utilities have begun to diversify revenue streams in a creative way. Many have begun to leverage physical assets and infrastructure, and existing customer databases and relationships for new business opportunities. These include telecommunications/wireless connections, landscaping and tree-trimming, pay-to-use mobile apps, energy efficient technologies developed in partnership with third party vendors; and acquisitions and joint ventures to add additional capabilities and expand geographical footprint.

JPS intends to explore the likelihood for new business lines by leveraging existing assets within its core regulated operations

4.7 Energy Sales Growth

Energy sales is projected to grow by an average of 1% per annum over the rate review period while customer numbers are projected to grow by an average 1.7% per annum over the five-year period, driven primarily by growth in industry, household and reductions in illegal connections. The consumption per customer is expected to fall as more customers employ energy efficiency measures or install energy production systems.

Over the five-year period, JPS will invest in projects to deliver on its growth priority. Some of the key initiatives include: completing the Distributive Generation projects at Hill Run and Lyssons. (started in 2018); implementation of customer growth projects - these are primary and secondary line extensions and transformer upgrades, which will meet the residential and business customers' need for power, implement the Distribution Transformer Programme to expand capacity to serve new customers and building charging stations for electric vehicle roll out.

5. Stakeholder Relationship

JPS strives to maintain a positive relationship with its key stakeholders and will continue to engage the various groups in an effort to better understand how it can improve and serve them, while building stronger partnerships now and for the future.

JPS will continue to build and strengthen strategic partnerships to deliver benefit to its customers – by partnering to reduce losses (with JSIF and GOJ), implementing an electric vehicle penetration strategy and maintaining our corporate social responsibility.

JPS will seek to actively participate in various organization meetings and forums to ensure that its positions are appropriately and adequately represented.

6. Key Enablers

The strategic alignment of our people, processes and technology with the Company's overall business strategy, is a key component for achieving our targets/results over the next five years. As JPS' business model changes from a traditional utility to meet the changes in market trends, so too will changes in employee skill sets, supported by efficient systems and processes be equally important. How the enablers will support the strategy over the upcoming five years is outlined below:

6.1 People

Employees play a critical role in the success of the Company, therefore, we will focus on building a culture of high-performance and accountability, as part of our overall employee engagement strategy. Employee engagement is a critical driver of business success in today's competitive marketplace in recognition of this, JPS over the upcoming five years will have high levels of engagements to promote the retention of talent, foster customer loyalty and improve organizational performance and stakeholder value. Another area of focus, is the establishment and implementation of the supporting infrastructure to enable efficiency and effectiveness across the organization. This will be done through utilizing strategic manpower planning, improved cost control and strategic employee development. JPS will continue its commitment in ensuring that employees have the appropriate training, tools, technology and resources to execute their jobs in a safe and effective way.

6.2 Process

JPS aims to optimize its business processes in order to maximize the value being delivered to its customers through cost effective means. JPS's approach to optimization will be: (1) identifying all the enterprise business processes and (2) measuring and optimizing the processes. During the period 2019 to 2024, several processes will be identified, measured and optimized for maximum throughput. Some of these processes are, Procure to Pay (P2P) and Meter to Cash (M2C). These process improvement initiatives will support reducing internal inefficiencies, maximizing cash flow potential and delivering maximum value to customers.

6.3 Technology

For the upcoming five years, JPS will continue to provide a modern IT Infrastructure, establish a robust and effective data recovery platform and drive operational efficiency through automation. This will be done through the (1) development of a **resilient technology infrastructure** framework geared towards simplifying the environment for efficiency and productivity improvements, data loss prevention and process automation; (2) implementation of **system upgrades and infrastructure optimization** of enterprise applications such as EAM, CIS and Oracle Financial Reporting; (3) continuous **improvement** of the AMI and **core**

telecommunication networks to ensure that the requirements for smart grid operation are met and thereby supporting the strategies for improving service delivery, reliability, asset management and reducing losses; and (4) improvement of the controls and management of technology and cyber security across our networks.

5 Guaranteed and Overall Standards

5.1 Overview of Standards

Licence Provisions

Pursuant to Condition 17.1 of the Licence, JPS shall use "all reasonable endeavours" to achieve the Guaranteed Standards and the Overall Standards. The Guaranteed Standards and the Overall Standards are a set of standards more particularly detailed as follows:

1. Guaranteed Standards are set service levels that must be met for each individual customer. If the Company fails to meet a Guaranteed Standard, then the Company must make the applicable compensatory payment set out in Schedule 1 of the Licence to the affected customer(s).
2. Overall Standards are set service levels for more general areas of performance that affect most or a large number of customers, such as how much prior notice is given to customers ahead of a planned outage. These standards cover areas of service where individual guarantees are not feasible but JPS is still required to deliver a set minimum standard of service to all customers. As a result, these standards do not carry specific financial penalties or compensation for individual customers.

The Office of Utility Regulations (OUR) has various functions in respect of the Guaranteed and Overall Standards. First, the OUR establishes the quantitative service standard levels applicable to each standard. Second, the OUR monitors JPS performance[15]. Third, the OUR periodically reviews the Guaranteed Standards and the Overall Standards as well as the level of compensation payments, and can introduce new standards[16].

This approach to setting service standards, initially introduced in 2000, was implemented to ensure that the Company provides an adequate level of electricity service to its customers. Under this mechanism, the OUR sets minimum performance standards customers can expect in respect of their electricity supply, when requesting services or doing business with JPS with several service quality indicators.

Final Criteria

The OUR's Final Criteria addresses the Quality of Service Standards in Criterion 9. The OUR specifically notes in paragraph 3.12.5 of the Final Criteria that "The Rate Review Process provides an opportunity for the evaluation and improvement of the existing Quality of Service Standard Schemes."

[15] The Electricity Licence 2016, Condition 17, paragraph 3
[16] The Electricity Licence 2016, Condition 17, paragraph 5 and 7

JPS is required to review its performance on all the EGS over the 2014 – 2018 Rate Review period and this review should "include any challenges that were or are being faced in meeting the EGS performance criteria, as well as the proposed measures to mitigate those challenges".

As part of the Rate Review filing, JPS is also required to: "Indicate any proposed changes, it deems appropriate, to the EGS Scheme and provide the rationale for its proposal. This should include the proposal for the development of a list of exemptions to the Guaranteed Standard."

The Final Criteria further provides that JPS in outlining its proposed performance targets on the Overall Standards over the Five Year Rate Period, should include "any challenges that were or are being faced in meeting the performance criteria for existing standards as well as the proposed measures to mitigate those challenges."

Principles for Implementation

In preparing the attached proposals, JPS was guided by the principles set out below:

1) The OUR is enabled to periodically review the Guaranteed Standards and Overall Standards and where appropriate and in consultation with JPS can introduce new standards.
2) The set of standards that are in force from time to time form part of the Licence and are subject to publication in the Jamaica Gazette under the authority of the OUR.
3) Condition 17(1) of the Licence which obligates JPS is to use all "reasonable endeavours" to achieve the Guaranteed Standards and Overall Standards.
4) For Guaranteed Standards, the level of compensation can also be reviewed and adjusted by the OUR where it is appropriate to do so and in consultation with JPS. JPS submits that this includes assessing whether the reconnection fee is the appropriate benchmark for compensation.
5) In areas where JPS has exhibited exceptional performance or has demonstrated that a punitive recourse-based incentive is not required, the continued application of Guaranteed Standards is of little benefit.

5.2 Guaranteed Standards

Guaranteed Standards cover areas such as connections, customer complaints, and estimation of billing charges. JPS has fifteen Guaranteed Standards, however, the Company has eighteen Guaranteed Standards in effect, as several standards are multi-part with distinct service requirements and associated penalties, and are tracked separately. The Guaranteed Standards currently in effect are listed in Schedule 1 of the Licence and reproduced in Table 5-1 below.

Table 5-1: Guaranteed Standards

Code	Focus	Description	Performance Measure
EGS 1(a)	Access	Connection to Supply - New & Simple Installations	New service Installations within five (5) working days after establishment of contract, includes connection to RAMI system. Automatic compensation as of June 1, 2015.
EGS 2(a)	Access	Complex Connection to Supply	From 30m and 100m of existing distribution line i) estimate within ten (10) working days ii) connection within thirty (30) working days after payment Automatic compensation as of January 1, 2016
EGS 2(b)	Access	Complex Connection to Supply	From 101m and 250m of existing distribution line i) estimate within fifteen (15) working days ii) connection within forty (40) working days after payment Automatic compensation as of January 1, 2016.
EGS 3	Response to Emergency	Response to Emergency	Response to Emergency calls within five (5) hours - emergencies defined as broken wires, broken poles, fires. Automatic compensation as of June 1, 2016.
EGS 4	First Bill	Issue of First Bill	Produce and dispatch first bill within forty (40) working days after service connection. Automatic compensation as of January 1, 2016.
EGS 5(a)	Complaints/Queries	Acknowledgements	Acknowledge written queries within five (5) working days Automatic compensation as of June 1, 2016.
EGS 5(b)	Complaints/Queries	Investigations	Complete investigations within thirty (30) working days. Complete investigations and respond to customer within thirty (30) working days. Where investigations involve a 3rd party, same is to be completed within sixty (60) working days. Automatic compensation as of June 1, 2016.
EGS 6	Reconnection	Reconnection after Payments of Overdue amounts	Reconnection within twenty-four (24) hours of payment of overdue amount and reconnection fee. Automatic compensation.
EGS 7	Estimated Bills	Frequency of Meter reading	Should NOT be more than two (2) consecutive estimated bills (where Licensee has access to meter). Automatic compensation as of June 1, 2016.
EGS 8	Estimation of Consumption	Method of estimating	An estimated bill should be based on the average of the last three (3) actual readings.

		consumption	Automatic compensation as of June 1, 2015.
EGS 9	Meter Replacement	Timeliness of Meter Replacement	Maximum of twenty (20) working days to replace meter after detection of fault which is not due to tampering by the customer. Automatic compensation.
EGS 10	Billing Adjustments	Timeliness of adjustment to customer's account	Where it becomes necessary, customer must be billed for adjustment within three (3) months of identification of error, or subsequent to replacement of faulty meter. Automatic compensation as of June 1, 2015.
EGS 11	Disconnection	Wrongful Disconnection	Where the Licensee disconnects a supply that has no overdue amount or is currently under investigation by the Office or the Licensee and only the disputed amount is in arrears. Automatic & special compensation.
EGS 12	Reconnection	Reconnection after Wrongful Disconnection	The Licensee must restore a supply it wrongfully disconnects within five (5) hours. Automatic & special compensation
EGS 13	Meter	Meter change	The Licensee must notify customers of a meter change within one (1) billing period of the change. The notification must include: the date of the change, the meter readings at the time of change, reason for change and serial number of new meter. Automatic compensation as of January 1, 2016.
EGS 14	Compensation	Making compensatory payments	Accounts should be credited within one (1) billing period of verification of breach. Automatic compensation as of June 1, 2015.
EGS 15	Service Disruption	Transitioning existing customers to RAMI System	Where all requirements have been satisfied on the part of the Licensee and the customer, service to existing JPS customers must not be disrupted for more than three (3) hours to facilitate transition to the RAMI system. Automatic compensation as of January 1, 2016.
Pre-paid Metering Guaranteed Standards			
EPMS 1	Service Connection	Transitioning existing customers to pre-paid metering system	Transition to the pre-paid metering service must be completed within fifteen (15) days of establishment of contract.

EPMS 2	Service Disruption	Transitioning existing customers to pre-paid metering system	Except where there is the need for the premises to be re-certified by a licensed electrical inspector, there should be no disruption in customer's service.

Pursuant to Condition 17(4) of the Licence JPS monitors and reports to the OUR data on performance of Guaranteed Standard and Overall Standards and the associated compensation on a quarterly basis. Compensation payments are automatically credited to the customers' accounts when a breach is detected or brought to the Company's attention.

5.2.1 Performance Review

JPS has maintained "Customer Service" as one of its strategic priorities since 2014, and has been very deliberate in the implementation of a customer service improvement strategy during the previous rate review period.

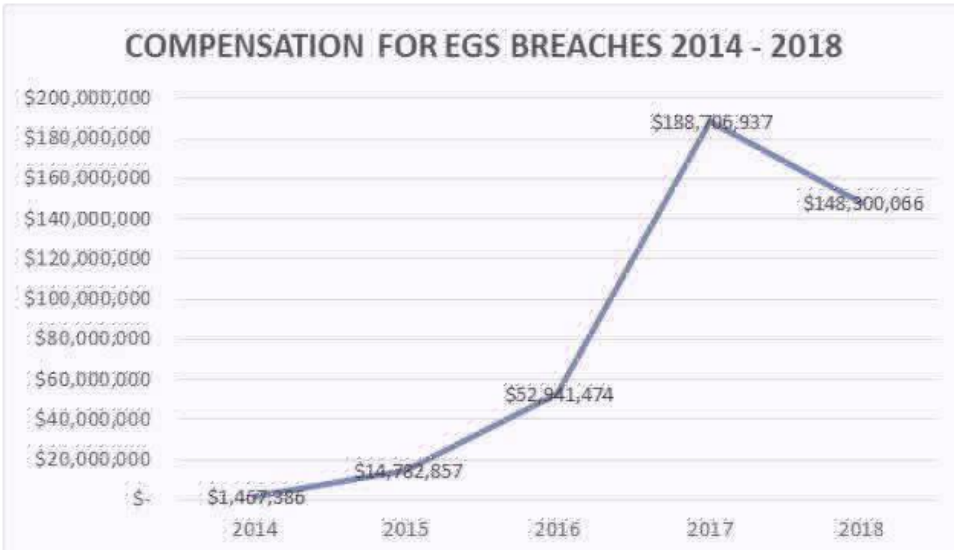
The Company has maintained a compliance rate of over 90% for the Guaranteed Standards. Table 5-2 shows the compliance levels for the years 2016 to 2018:

Table 5-2: Guaranteed Standards Performance 2016-2018

Guaranteed Standards	2016	2017	2018
EGS1 - Connection to Supply - New & Simple Installations	98%	99%	97.50%
EGS2 - Complex Connection to Supply	90%	98.20%	79.30%
EGS3 - Response to Emergency Calls	not tracked	not tracked	not tracked
EGS4 - Issue of First Bill	99.90%	100%	100%
EGS5 - Investigations	99.40%	100%	92%
EGS6 - Reconnection after Payments of Overdue Amounts	98.20%	98.80%	97.90%
EGS7 - Frequency of Meter Reading (Number of Estimated Bills)		79.90%	72.90%
EGS8 - Method of Estimating Consumption	98.90%	97.60%	99.40%
EGS9 - Timeliness of Meter Replacement	99.90%	99.90%	99.90%
EGS10 - Timeliness of Adjustment to Customer's Account	85.90%	90.90%	96.20%
EGS11 - Wrongful Disconnection	89.90%	100%	99.90%
EGS12 - Reconnection after Wrongful Disconnection	78.80%	96.50%	88.90%
EGS13 - Notification of Meter Change		99.90%	100%
EGS14 - Making Compensatory Payments	99.90%	99.90%	100%
EGS15 - Transitioning Existing Customers to RAMI System	not tracked	not tracked	51.85%
Compliance (%)	**95%**	**97%**	**91%**

JPS paid out approximately J$406M in compensation for breaches of the Guaranteed Standards during the last rate review (2014-2018). Of note, is the fact that there was a dramatic increase in compensation payments in 2016 and 2017, as a direct result of automatic compensation being applied to most of the standards, starting in the latter half of 2016. The Company has since introduced a number of measures to address the breaches, with the corresponding improvement in compliance, and a downward trend in compensation in 2018, as illustrated in Figure 5-1 below.

Figure 5-1: Trend in Compensation Payment (J$)



Just over 90% (approximately J$369M) of the compensation paid over the review period was for breaches of the standards that apply to estimated bills and estimation of consumption:

- EGS 7: Estimated Bills (Frequency of Meter Reading) - A customer should not be presented with more than two (2) consecutive estimated bills (where company has access to meter).
- EGS 8: Estimation of Consumption - An estimated bill should be based on the average of the last three (3) actual readings.

JPS has assessed the causes of the breaches of these standards, and has implemented a number of initiatives to address the main contributors. These include the increased roll-out of technology through the Smart Meter project, the upgrading of the communication system, meter upgrades, and increased internal controls.

The Company has begun to see the results of these initiatives. In 2018, the breach compensation payments for EGS8 saw a reduction of over 80%, compared to 2017.

The Company's high level of compliance with the Guaranteed Standards is reflected in the number of standards for which less than One Million Dollars has been paid out for the entire review period, 2014-2018. Table 5-3 presents the Guaranteed Standards with High Compliance/Low Compensation (amounts in table quoted in Jamaican dollars).

Table 5-3: Guaranteed Standards with High Compliance/Low Compensation

Guaranteed Standards With Low Compensation & High Compliance Levels			
CODE	**Area of Service**	**Amount Paid (2014-2018)**	**Compliance (2018)**
EGS 4	First Bill	$ 43,468	100%
EGS 5	Complaints / Queries (acknowledgement & investigation)	$ 88,119	92%
EGS 9	Timeliness of Meter Replacement	$ 1,227,276	99%
EGS 11	Wrongful Disconnection	$ 1,337,220	96%
EGS 12	Reconnection after wrongful disconnection (5hours)	$ 488,596	89%
EGS 13	Notification of Meter change	$ 50,405	100%
EGS 14	Making Compensatory Payment	$ 751,932	100%
TOTAL		**$ 3,987,016**	

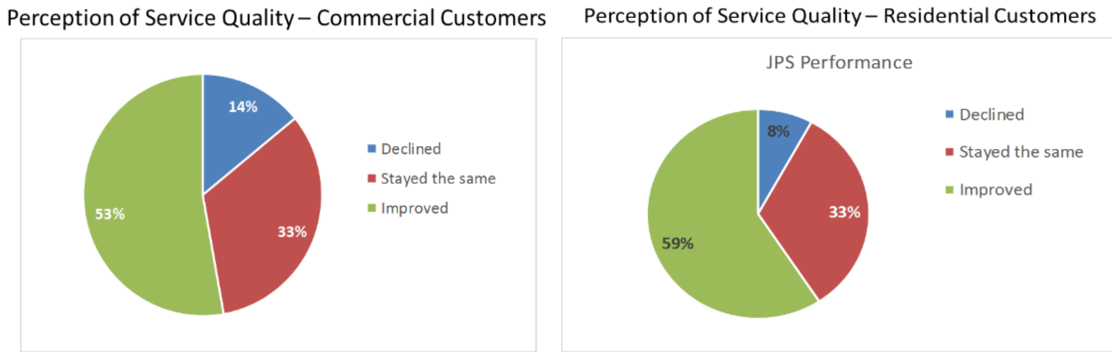
5.2.2 Customer Service Improvements

Even outside of the performance framework provided by the Guaranteed and Overall Standards established by the OUR, JPS has implemented a number of initiatives to improve the way it serves its customers. A culture of continuous improvement and service excellence has been established, accompanied by organizational changes, to make service delivery more efficient and services more accessible to customers. Deliberate and sustained efforts have been made over the past five years to increase customer gains and address the challenges to the delivery of outstanding service. The Company implemented a rigorous internal monitoring and measurement framework, and introduced new customer solutions, based on feedback from stakeholders, to include: prepaid electricity service (Pay-As-You-Go), a JPS Mobile App, Online Customer Service, and the MyJPS Rewards programme to reward customers who pay their bills in full and on time.

The sustained roll-out of initiatives to improve service delivery has resulted in a marked improvement in the customer experience, as evidenced by the positive feedback from customers reflected in the annual and quarterly customer surveys carried out by JPS as well as research firms contracted by the Company. In the recent survey conducted for the Cost of Unserved Energy Study, most customers expressed a relatively high level of satisfaction with the quality of service provided by JPS. The results indicate that 58% of commercial customers and 62% of residential customers were satisfied or very satisfied with the service, while only 11% of commercial customers and 13% of residential customers were dissatisfied or very dissatisfied with the service provided by JPS.

As shown in Figure 5-2, 59% of residential customers and 53% of commercial customers indicated that the service provided by JPS has improved, while only 8% of residential customers and 14% of commercial customers surveyed said the service has declined.

Figure 5-2: Perception of Service Quality by JPS' Customers



JPS received a Customer Satisfaction Index (CSI) of 60% from the 2018 Customer Satisfaction Survey. This represents a significant improvement over the 40% score received in 2014. The 2018 Customer Satisfaction Survey covered strategic areas, including those pertinent to the Guaranteed Standards. In particular, the following survey outcomes illustrate customers' experience in the areas which can be related to Guaranteed Standards:

- **General Customer Service:** Satisfaction with JPS as it relates to general customer service areas was fairly high, with over 7 in 10 (71%) customers expressing that they were 'very satisfied or satisfied'. Customers were most satisfied with 'The appeal of JPS field staff branding' (73%). A fair level of satisfaction was expressed regarding 'the professionalism of field staff' (66%), 'the ease of doing business overall' (64%), 'the courteousness of JPS staff in office' (63%), and the 'professionalism' of JPS staff in office (62%).
- **Customer Care Centre:** 71% of customers indicated that they were either very satisfied or "satisfied" with the service received from the JPS Customer Care Centre. The areas of greatest satisfaction were: the clarity of communication by the staff, the staff's willingness to assist, friendliness, and professionalism.
- **Billing & Bill Payment:** Customers expressed high satisfaction with timeliness of receiving bills, with 79% of respondents indicating that they were either satisfied or very satisfied with this aspect of the Company's service. In addition, 90% indicated satisfaction with the variety of payment options, and 88% said they were satisfied with the ease of paying their electricity bills.
- **Bill Queries:** Overall JPS customers who made a bill queries in 2018 expressed a fair level of satisfaction with the length of time it took to achieve a resolution; with 6 out of 10 (60%), reporting that they were 'very satisfied or satisfied'.
- **Connections:** Just over half of customers surveyed (56%) indicated a high level of satisfaction with the ease of applying for electricity supply, while 45% said they were 'very satisfied or satisfied' with the 'ease of requesting re-connection' and the 'speed of reconnections'.

In response to the customers' feedback on the service provided by JPS, and as part of the Company's ongoing customer service improvement strategy, JPS has continued the expansion of its Customer Education Programme, the aim of which is to empower and educate customers about the Company and the services offered, while making them aware of their responsibilities. The following are among the topics included in JPS' Customer Education Programme:

1. Understanding the bill;
2. Meter reading;
3. Getting electricity service;
4. Reconnection process;
5. Certification requirements and processes; and
6. Other services offered by JPS (including: Prepaid Service, Mobile App; eStore, etc).

JPS uses the following communication channels to educate customers: Electronic Media, Text Messages, Emailers, Digital Media, Print, Website, Community Meetings, and Events.

The Company's efforts to improve service has been recognized at the national level, with JPS winning several customer service awards from the Private Sector Organization of Jamaica/ Jamaica Customer Service Association in 2017 for its outstanding performance in the following areas: Monitoring and Measurement; Leadership and Strategy; Service Excellence Charter & Standards; Recognition and Reward; International Benchmarking; and the Overall Service Excellence Award for Large Businesses.

5.3 Proposed Modifications to the Standards

Compensation values and modes, whilst being a sufficient incentive for JPS to comply with all standards, should not represent an onerous burden for the Company, but should be fair and consistent with the level of inconvenience suffered by affected customers in the event of a breach.

In compliance with Condition 17 paragraph 1 of the Licence, and as evidenced by the Company's performance in relation to the Service Standards, JPS uses all reasonable endeavors to achieve the established targets for the Guaranteed and Overall Standards.

The Company's past performance in relation to the Service Standards and ongoing efforts to improve customer service should, therefore, be given due consideration in determining the necessity of maintaining the existing standards.

In this regard, the Company proposes certain modifications and exemptions to the Guaranteed Standards as discussed in the following sections.

5.3.1 Modification of Existing Standards

The eighteen Guaranteed Standards that JPS is required to meet, monitor and report on, is a large number for a utility of the size of JPS. The United Kingdom, the originator of the concept of performance standards, has ten primary standards with the complexity of standards governing customer connections handled in a separate code. Among the Caribbean countries, Trinidad has eight standards and Barbados has nine Guaranteed Standards.

A. Conversion to Overall Standards

The Company is proposing that at least one of the existing Guaranteed Standards be converted to Overall Standard. As a start, JPS recommends that EGS3 be monitored as an Overall Standards for the reasons outlined below:

EGS3 – Response to Emergency: It is difficult to capture the 'JPS response', in order to accurately measure the response time. Factors such as safety considerations already ensure that utility companies react in a timely manner to emergency situations, thus tracking emergency response for individual customer compensation is unnecessary and inappropriate. A review of service quality standards in Trinidad and Barbados as well as research on service quality regulation in other jurisdictions conducted by the Ontario Energy Board revealed that the use of an emergency response guaranteed standard is not widespread[17] .

Furthermore, Guaranteed Standards are meant to compensate a customer for the Company's failure to provide a service to an individual customer or respond to an individual or well defined set of customers based on the Company's actions or inaction that caused an inconvenience. Emergencies, by nature, are usually unplanned and random events that can be triggered by third parties. While it is reasonable for JPS to have a standard to respond to these emergencies, individual customer compensation under these circumstances is inappropriate. The tracking of the Company's response to emergencies is foremost and most importantly a matter of public safety and should be tracked as an Overall Standard. The Company would also continue to report on this standard quarterly to the OUR.

B. Revision of Performance Target

JPS is proposing that the performance target for Guaranteed Standard EGS15 be modified. While it continues to ensure improved efficiency in its operations, based on the experience gained from the implementation of several RAMI projects, the Company has concluded that the requirement that "existing JPS customers must not be disrupted for more than three (3) hours to facilitate transition to the RAMI system" is impractical and, therefore, not achievable.

[17] https://www.oeb.ca/documents/cases/RP-2003-0190/sqr_discussionpaper_150903.pdf

The time required will vary depending on the scope of the project and the number of customers involved. JPS is therefore proposing that the process to facilitate the transition to RAMI be treated as one requiring a planned outage, for which adequate advance notice must be provided to customers. Where the Company fails to complete the transition to RAMI within the time communicated, then compensation must be paid to the affected customers.

JPS does not propose any new standards for the 2019-2024 Rate Review period.

5.3.2 Exceptions and Exemptions

The Guaranteed Standards have been applied since inception on the basis that, except in force majeure conditions, payments are validly to be made in every instance of claim or breach. This is true in the vast majority of instances. But, most jurisdictions have considered it important to establish guidelines on exemptions to inform customers and the utility of those circumstances under which Guaranteed Standard payments are not obligatory.

In the 2014-2019 Tariff Review Determination Notice, the OUR expressed its view that circumstances that warrant suspension of the Guaranteed Standards should be restricted to those that are outside of JPS' control and must be specific to individual standards. The Company notes that certain circumstances may become applicable to a number of standards. For this reason, the Company submits the proposed list of exemptions with respect to the circumstances with indication of standards that these circumstances could reasonably be applicable to.

Having carefully considered the factors for developing in relation to certain Guaranteed Standards, JPS proposes that it should not be obliged to make Guaranteed Standard payments in the following circumstances, which are outside of JPS' control:

i. The customer informs JPS before the standards contravention period that they do not want JPS to take any action or further action in regard to the matter. For example, customer requests connection on a date outside of the established period within which action should be completed. The standards where such situation would be applicable are EGS 1, 2, and 6.
ii. Where information is required from the customer and (a) it is not given the appropriate telephone number, address or email account as indicated and published by JPS; or (b) it is not provided within a timeframe that would allow the Company to take action before a breach occurs. The standards where such situation would be applicable are EGS 1, 2, and 5.
iii. Where the information provided is erroneous or requires verification. This situation would be applicable to all Guaranteed Standards.

JPS understands that customer education is an important factor in preventing most of the circumstances proposed for the exemption. In this regard, JPS' Customer Education Programme, discussed in Section 5.2.2, is aimed at educating customers about JPS' services, as well as customer responsibilities. JPS will continue its efforts to educate customers with respect to the processes related to the Guaranteed Standards and compensatory payments to minimize the exemption cases in its operations.

Further, it is important to note that in compiling its quarterly report on performance, JPS will be required to report on any exemption invoked in relation to any breach/claim, and the reasons. As such, the implementation of these exemptions will be fully monitored by the OUR. Any dispute by a customer will be treated with by the OUR in its established customer dispute resolution process.

5.4 Overall Standards

The Overall Standards continue to provide a strong framework for the provision of a high quality of service for JPS customers. JPS has twelve Overall Standards and are listed in Schedule 2 of the Licence and reproduced in Table 5-4 below.

Table 5-4: Overall Standards

Code	Standard	Units	Targets July 2014 - May 2019
EOS1	No less than 48 hours prior notice of planned outages.	Percentage of planned outages for which at least forty-eight (48) hours advance notice is provided.	100%
EOS2	Percentage of line faults repaired within a specified period of that fault being reported	Urban: 48 hours Rural: 96 hours	100% 100%
EOS3	System Average Interruption Frequency Index (SAIFI)	Frequency of interruptions in service	To be set annually
EOS4	System Average Interruption Duration Index (SAIDI)	Duration of interruptions in service	To be set annually
EOS5	Customer Average Interruption Duration Index (CAIDI)	Average time to restore service to average customers per sustained interruption.	To be set annually
EOS6	Frequency of meter reading	Percentage of meters read within time specified in the Licensee's billing cycle.	99%
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%

EOS8	Billing punctuality	98% of all bills to be mailed within a specified time after meter is read.	5 Working Days
EOS9	Restoration of service after unplanned (forced) outages on the distribution system	Percentage of customer's supplies to be restored within 24 hours of forced outages in both Rural and Urban areas.	98%
EOS10	Responsiveness of call centre representatives	Percentage of calls answered within 20 seconds	90%
EOS11	Effectiveness of call centre representatives	Percentage of complaints resolved at first point of contact	To be set
EOS12	Effectiveness of street lighting repairs	Percentage of all street lighting complaints resolved within 14 days	99%

5.4.1 Performance Review

For the 2014-2019 regulatory period, some Overall Standards were not reported on, primarily because of the absence of monitoring and reporting mechanisms. However, in 2018 the Company started submitting monthly reports on two Overall Standards to the OUR: EOS 1 – Notice of planned outages, and EOS 10 – Responsiveness of the Call Centre.

EOS1 - No less than 48 hours prior notice of planned outages

This is the percentage of Planned Outages for which at least forty-eight (48) hours advance notice is required. The Company's performance on EOS1 for 2018 is shown in Table 5-5:

Table 5-5: Planned Outages Advance Notice Performance

PERFORMANCE ON EOS1 - ADVANCE NOTICES FOR PLANNED OUTAGES January 2018 - December 2018					
Standards	Performance Indicators	Achievement Level			
		1st Quarter	2nd Quarter	3rd Quarter	4rd Quarter
EOS01 - Planned Outages: Advanced Notice	**Compliance (%)**	**60.4%**	**53.7%**	**47.7%**	**53.7%**
Percentage (%) of planned outages for which at least forty-eight (48) hours advance notice is provided. ***Note: this data does not capture all notification given by the hand- delivered outage cards, a notification method used frequently for sub-feeder level outages***	Target (%)	100.0%	100.0%	100.0%	100.0%
	Variation from target (%)	-39.6%	-46.3%	-52.3%	-46.3%
	Number of Outages	449	620	384	287
	Compliant Notices	271	333	183	154

JPS uses direct mail, email and text messages, radio, outage cards, and social media to communicate advance notices to its customers. The Company introduced emails and text message notification in 2018, as part of efforts to improve the effectiveness of its outage communication.

However, the overall compliance rate for 2018 was approximately 54%, which fell below the 100% target. The challenge is that the quarterly reports in 2018 did not capture all notifications given by the hand- delivered outage cards, a practical notification method used frequently for sub-feeder level outages.

Unlike the primary channels, the actual time of notification to individual customers via outage cards and the reachacross affected customers are not readily auditable for verification. Though an effective and time-honoured means of providing outage notification, card outages pose a verification challenge, which the Company is presently addressing.

EOS10 – Effectiveness of Call Centre Representatives

This is the percentage of call answered within 20 seconds. The Company's performance on EOS10 for 2018 is shown in Table 5-6.

Table 5-6: Percentage of Calls Answered

PERFORMANCE ON EOS10 - RESPONSIVENESS OF CALL CENTRE REPRESENTATIVES					
January 2018 - December 2018					
Standard	Performance Indicators	Achievement Level			
		1st Quarter	2nd Quarter	3rd Quarter	4rd Quarter
EOS10 - Responsiveness of Call Center Representatives	Compliance (%)	98.0%	93.6%	92.4%	91.2%
(% Calls Answered within 20 seconds)	Target (%)	90.0%	90.0%	90.0%	90.0%
	Variation from target (%)	8.0%	3.6%	2.4%	1.2%
Percentage of calls answered within 20 seconds	Calls Offered	393,206	486,503	538,451	491,703
	Calls Answered Within Standard	385,455	455,317	497,502	448,212

The target set for this standard is 90%, which the Company notes is markedly higher than the industry standard target of 80% as surveyed by JPS. However, JPS has still been able to consistently meet this compliance target with an average compliance rate of approximately 94% for 2018. This achievement was in part due to the implementation of the workforce management software by JPS (Avaya Quality Monitoring Tool), and the outsourcing of the in-bound call management functions of the Call Centre.

5.4.2 Proposed Modifications

The Company is proposing the following modifications:

i. **EOS 1 – No less than 48 hours prior notice of planned outages:** The Company is proposing that the target be revised to a more reasonable and achievable 95%, instead of the existing 100%.

ii. **EOS 10 – Responsiveness of Call Centre Representatives:** JPS is proposing the following:

    i. The standard be reworded to include the Interactive Voice Response system. This technological advancement used by general utilities provides the customer with self-help options to effectively address some of the issues that drive customer contacts. Therefore, instead of "Responsiveness of Call

Centre Representatives", this standard would be "Call Centre Responsiveness".

iii. **EOS 12 – Effectiveness of street lighting repairs:** JPS is proposing the following:
   i. That the time given be changed to 20 working days – the same time given for meter replacement after a defect is found.
   ii. The Company is proposing that the target be revised to a more realistic 95%, instead of the existing 99%.

JPS remains committed to improving the experience of its customers at every point of contact, and will continue to implement measures to address the areas of weakness in its service delivery.

6 Productivity Improvement Factor

6.1 Introduction

This chapter presents an historical performance of the JPS' productivity for the regulatory period 2019-2024, a synopsis of the productivity improvement study, sensitivity analysis as well as the JPS proposal for productivity improvement factor.

Licence Provisions

Paragraph 11 of Schedule 3, of the Licence, states that the criteria published by the Office shall include the productivity improvement. In March 2019, the OUR published the Final Criteria stipulating the basis for computing the productivity improvement factor. In addition, paragraph 10 of Schedule 3 of the Licence states that the Business Plan should provide the justification for the rate proposal. Therefore, JPS forecasted operating and maintenance expenses (O&M) should be based on the initiatives outlined in the Business Plan.

The OUR had engaged DNV-GL to commission a productivity study which formed the basis for criterion 8 in the Final Criteria. Criteria 8 states the following:

a) *The Productivity Improvement Factor (PI-Factor) to be used in the annual adjustment of JPS' Revenue Cap shall be based on a DEA analysis, the results of which may be supported by other productivity improvement study approaches.*

b) *In the DEA analysis, CAPEX shall not be included as an input factor unless JPS provides a sound justification for doing so. Output factors may include kWh sales, customer count, network length and size of service area or any other justifiable variables.*

c) *JPS shall include an updated productivity study based on its latest audited financial statement in the 2019 – 2024 Rate Review application or the prior year's audited financial data if benchmarking data is not readily available from other jurisdictions. The updated productivity study shall be based on the DEA method using the approach proposed by OUR or an approach which is very similar and can be justified by JPS.*

d) *The OUR will utilize the results of the updated productivity study to determine the PI-Factor for the Rate Review period.*

e) *JPS' controllable OPEX for 2020 – 2023 shall be adjusted by the PI-Factor and a factor, which is the weighted average of the projected sales, demand and customer number growth rates.*

Additionally, the Final Criteria states at paragraph 3.11.4 that the re-computation of the productivity factor should use an appropriate set of utilities including those proposed in Annex 1 of the Productivity Report (DNV-GL Report). As such, MacroConsulting S.A. was engaged by JPS to review the DNV-GL report and assist in the computation of JPS' PI-Factor defined by the Final Criteria.

Principles for Implementation

The Licence does not prescribe the application of the productivity factor nor the methodology, however, the Final Criteria stated that the factor would be applied to controllable O&M and JPS' level of efficiency would be determined based on the data envelopment analysis (DEA) methodology. In addition, the controllable O&M would be adjusted on the weighted average of the growth rate of JPS' revenue shares taking into account the growth rates of sales, demand and number of customers. In determining the PI-Factor to forecast O&M, JPS would consider the DEA results supported by the total factor productivity (TFP) methodology and most importantly, the initiatives outlined in its Business Plan.

6.2 Historical Performance

One of the aims of regulatory reform is to provide utilities with incentives to improve their investment and operating efficiency and to ensure that consumers benefit from the efficiency gains[18].

JPS operates under a performance based rate-making (PBRM) mechanism that encapsulates an efficiency factor to incentivize the Company and allow efficiency gains to be transferred to customers. Since privatization, JPS views the productivity improvement factor as a continuous driver of operational efficiencies to reduce cost by raising efficiency. However, there needs to be a balance between the utility managing its cost and the growing demand of customers for greater reliability, service convenience and low tariffs. As such, there is a need to balance this trade-off between reducing costs and the desire to maintain and improve service quality when determining the trajectory for productivity gains.

Prior to the Electricity Licence, 2016, the productivity factor was calculated based on the expected productivity gains of the Licensed Business. The factor was set equal to the difference in the expected TFP growth of the Licensed Business and the general total factor productivity growth of firms whose price index of outputs reflect the price escalation measure.

Table 6-1: Regulated Productivity Improvement Factor (2004-2019)

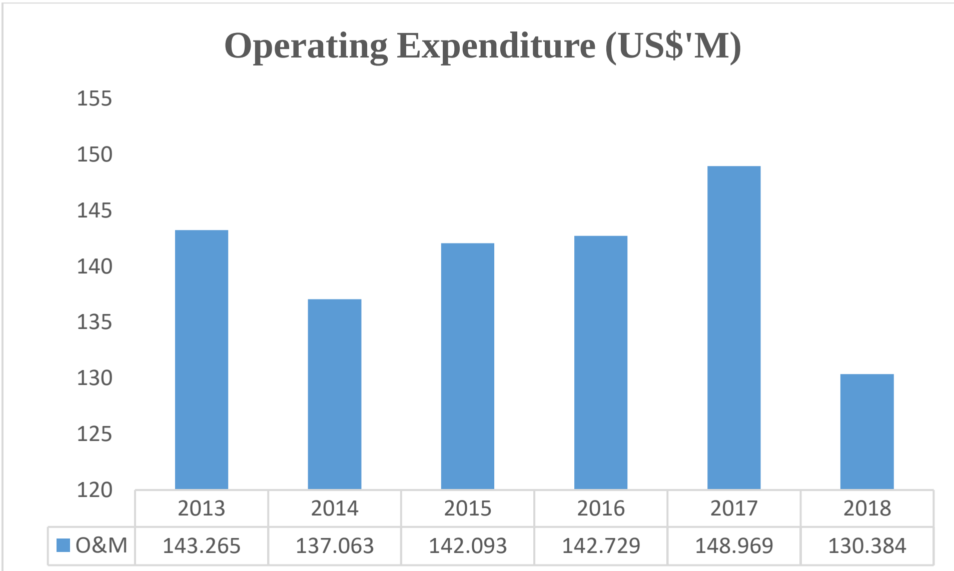
Regulatory Period	Regulated Improvement Factor
2004-2009	2.72%
2009-2014	2.72%
2014-2019	1.10%

Table 6-1 shows the regulated productivity factors using the TFP methodology. During the referenced regulatory periods, the regulated improvement factors were applied to JPS' revenue requirement thereby lowering tariffs. However, besides from the regulated improvement factors,

[18] Jamasb, T., & Pollitt, M. (2000) - Benchmarking and Regulation: International Electricity Experience. Utilities policy, 9(3), 107-130.

the Company would have taken additional measures to reduce its costs and increase internal efficiencies by outsourcing its fleet management, call centers, meter reading and network maintenance operations. Furthermore, JPS would have automated some of its major processes through grid modernization and the implementation of smart meters.

Figure 6-1: JPS' Operating Expenditure (2014-2018)



In 2013, O&M expenses totaled US$143.3M and declined by 9% to US$130.4M by the end of 2018 as illustrated in Figure 6-1. Within the past regulatory period, O&M expenses fluctuated – declining to US$137M in 2014, then increasing between 2015 and 2017 with an 8.7% increase to US$148.9M. The movement of O&M expenses corroborates that O&M expenses are impacted by many factors which include (further discussed in Section 13.3):

- Foreign Exchange movement
- Local and US inflation
- Business strategic priorities such as improving customer services, loss reduction and reliability improvements

Transmission and Distribution utilities generally have high level of fixed costs and drastic methods to reduce costs are not fully sustainable because as JPS increases its customer service, system reliability and heat rate performance and reduce system losses which increase costs.

In 2014, O&M expenses were reduced by US$6.2M (4.3%). One area of significant reduction was bad debt expenses driven primarily by changes in back-billing policy relating to irregularity. Additionally, there was an involuntary curtailment of O&M expense imposed by loan covenant breaches.

By 2015, O&M expansion became necessary due to:

a) Business imperatives to improve operating performance including:

   i. Reliability improvements by 19% resulting in the duration of system average interruption reducing by 7.9 hours, that is 41.0 hours to 33.1 hours

   ii. Heat Rate improved by 125 kJ/kWh as plant availability increased from 78.6% to 80.7%.

   iii. Customer satisfaction improved from 52.8% to 68.4%

b) Payroll increases from contractual obligations

The improved business performance drove increase expenditure in third party services, telecom and technology expenses. There were also cost efficiency improvement initiatives, which led to reduction in areas such as insurance and utility expenses (further discussed in Section 13.3). Thus, the increases in costs do not result in inefficiencies within the Company.

Customers benefitted from the increase in fuel efficiency through lower fuel cost and improved reliability reflected in fewer and shorter outages. System loss containment slowed revenue leakage and the investment in the improvement in customer service showed returns in significantly higher satisfaction with the service by customers. This demonstrates the emphasis JPS places on improving its operation.

6.3 JPS' Productivity Improvement Study

6.3.1 Data Envelopment Analysis (DEA)

The OUR has prescribed the DEA methodology to compute JPS' efficiency level. DEA is a non-parametric benchmarking tool used to determine the relative efficiency of firms based on a sample of firms, their input use, and their outputs. DEA identifies the most efficient firms and creates an efficiency frontier based on these firms' input usage per unit of output. The efficiency score is the distance between the assessed firm and firms on the efficiency frontier, which serve can be seen as the target to reach.

The criticisms of the DEA are that the results depend on the selection of the input and output factors, and most importantly, it provides no information about statistical significance of the results. The results can be influenced by random errors, measurement errors or extreme events. Additionally, companies exhibiting extreme parameters will be classified as efficient by default. Although the DEA has some flexibility, its weaknesses reduce its validity. As such, JPS recommends that more than one benchmarking methodologies are employed to determine a reasonable productivity improvement factor as discussed in Phase 1 Draft Report – Annex to the Rate Case Filing.

Jamasb and Pollitt (2000) indicated that regulators have full discretion with regards to the choice of benchmarking method, model and inputs but there is no consensus amongst regulators as to a preferred methodology as benchmarking is an indication and not a confirmation of efficiency position. Furthermore, other jurisdictions incorporate different methodologies to support the efficiency target. As such, JPS posits that the integration of the benchmarking results should take into account its imperfections.

Benchmarking Sample and Data

The productivity improvement factor was re-computed as prescribed by the Final Criteria. The benchmarking exercise used variable returns to scale the DEA model. The input variable is operating expenses (USD) while the output factors are sales (GWh), the number of customers (#), network length (km), and supply size area (km^2).

1. **Sample**

The availability and quality of data are important factors to consider when performing the benchmarking analysis. Likewise, having a homogenous sample increases the quality of the data as well as the robustness of the results (Nepal & Jamasb, 2015). Using an incomparable dataset may result in misleading or unreliable results.

The DNV-GL Report stated that when selecting utilities "a key factor is to try to ensure that the operating environment of the companies is as similar as possible to be able to compare 'like-with-like'"[19]. It further states that "for any efficiency analysis, a data sample consisting of as many utilities as possible that are similar to JPS is required"[20]. This similarity is stated in terms of being an island utility, with comparable size (as measured by the number of customers), supply areas, and sales.

The utility that meets the two (2) criteria stated in the DNV-GL report simultaneously, that is, "similar in terms of being an island utility and with comparable size as measured in the number of customers, supply areas, and sales" is the Electric Authority of Cyprus. All other islands included in the prescribed sample are much smaller than Jamaica and those utilities with similar size (in terms of customers, sales, area) are non-island mostly developed economies.

The defined sample was expanded to include Trinidad & Tobago Electricity Commission and Grenada Electricity Services Limited. Trinidad & Tobago Electricity Commission is the Caribbean utility that comes closest to JPS in respect of the two criteria established above. Efforts to include additional island utilities similar to JPS in the DEA study were not successful due to data unavailability.

[19] DVN-GL Report, page 4.
[20] DVN-GL Report, page 17.

Table 6-2: Final Benchmarking Sample

Country/Region	Number of utilities		
	Final Sample	DNV-Report	DNV-Report – Corrected
United States of America	**11**	12	8
Caribbean	**9**	13	12
Jamaica	**1**	1	1
Germany	**11**	11	11
Cyprus	**1**	1	1
Austria	**-**	1	1
Norway	**1**	1	1
Great Britain	**1**	1	1
Australia	**1**	1	1
Total	**36**	42	37

Table 6-2 illustrates the final sample used in JPS' productivity study compared to the DNV-GL report. The final sample comprised eleven (11) utilities from the USA, ten (10) utilities from the Caribbean and fifteen (15) utilities from Europe including eleven (11) German utilities from the DNV-GL report. The complete dataset is highlighted in the Productivity Report – Annex I to the Rate Case Filing.

It should be noted that the inclusion of the European and German utilities reflected only a strict compliance with the directive of the Final Criteria to include all companies in the DNV report, with allowance for addition to the sample. JPS proposed, in responding to the Draft Criteria published by the OUR, that an appropriate pool of utilities should be included in a revised sample. This recommendation was not accepted therefore, the inclusion of the European comparators and in particular the German utilities have limited the effectiveness of the report.

JPS' concerns with the inclusion of these companies include:

a) The European utilities did not satisfy the criteria of an island utility

b) The utilities are primarily city or provisional utilities that have significant difference in level of energy sales and customer-density compared to JPS.

    i. Five of the 11 German utilities have customer-density between 1.5- 5 times that of JPS

    ii. The other six utilities have customer-density more than 10 times that of JPS with two being as high as 70 times

iii. All German utilities have energy sales that were more than twice that of JPS and three of them had in excess of five times that of JPS

c) The energy sales and customer–density disparity are significantly apparent when applying partial benchmarking[21].

In addition to heterogeneous sample, the input-output variables used must also be taken into account when interpreting the results from the benchmarking exercises. The two most relevant issues are (a) OPEX as an Input Factor and (b) Sales as an Output Factor.

a. <u>OPEX as an Input Factor</u>

The mandated database is skewed towards developed countries, which face different input prices such as labour and the cost of capital. This differential in price between these key inputs lead to different decisions with utilities from developed countries displaying a preference for investment in capital rather than labour. Additionally, due to a certain degree of substitution between productive factors, the consideration of only OPEX inputs may create perverse incentives in terms of input choice by the utility, favoring capital-intensive solutions, which may not be the most cost efficient[22]. For example, JPS currently leases its transport fleet, which is strictly an O&M expense that contributes approximately US$6M to JPS' T&D costs while Belize owns its fleet which is capitalize cost[23].

Since the model uses a single input, the problem is further exacerbated as it neglects the input options available to utilities in developed countries. It should be noted that the OUR in response to the concerns expressed by JPS, indicated the Final Criteria that CAPEX could be included as an input factor but its inclusion would have to be justified by JPS. JPS however, was unable to include CAPEX due to the lack of available data for most comparator utilities in the mandated sample.

The fact that many of the utilities in the sample, including JPS, are vertically integrated also presents some problems, since costs must be allocated to the different activities of the companies. In general, OPEX are much more difficult to allocate to particular activities (generation, transmission, distribution) than assets.

b. <u>Sales as an Output Factor</u>

The DNV-GL report stated that "sales in kWh is a primary output factor for any electricity company as at the end of the day, this is the product that is supplied to customers"[24]. From an

[21] The DNV-GL study conceded that "as may be expected, cost levels in the US and German companies are more favourable" and "differences in uni-dimensional performance can be attributed to different factor". Interestingly, companies that first show lower per-unit costs than JPS under the sales analysis, turn out to have higher cost when customer numbers are chosen which suggest that the structural factor in the performance is not driven by cost alone (DVN-GL Report, page 22).

[22] An example of this may be buying own servers instead of contracting in the "cloud" or acquiring transport fleet instead of leasing them.

[23] Belize Electric Limited 2018 Annual Report Page 9

[24] DNV-GL Report, page 29.

economic perspective distribution is generally understood as the pure "wires" business. The supply business (that is, buying bulk power for resale to final users) is a separate activity with very different economic characteristics; and the kWh are the product of the supply activity, rather than the distribution one.

Also, the use of sales as a cost driver is questionable as stated in the DNV-GL Report "generally, the higher the supply, the higher will be the costs…. more sales imply more assets to be installed and therefore more staff and cost, hence more OPEX." There is indeed a relationship between sales and costs, but not for a pure distribution business.

JPS has recently moved from a price cap to a revenue cap regulatory regime. The rationale was there was international trends to decoupling sales in the modern electricity landscape with its emphasis on policy enabling energy efficiency and distributed energy resource which do not have a direct correlation with O&M cost and sales volumes are out of JPS' control.

The use of sales as an output is therefore questionable given the activity for which the benchmarking is performed (distribution), and the regulatory framework within which JPS is operating.

6.3.1.1 DEA Results

The variable returns to scale DEA model yielded the efficiency score shown in Table 6-4. The estimation shows that JPS is 67% efficient relative to the sample. The average sample efficiency is 46%. Thus, JPS is above the average efficiency of the group of comparable peer utilities included in the sample defined by the OUR.

Figure 6-2: Utilities' Efficiency Scores

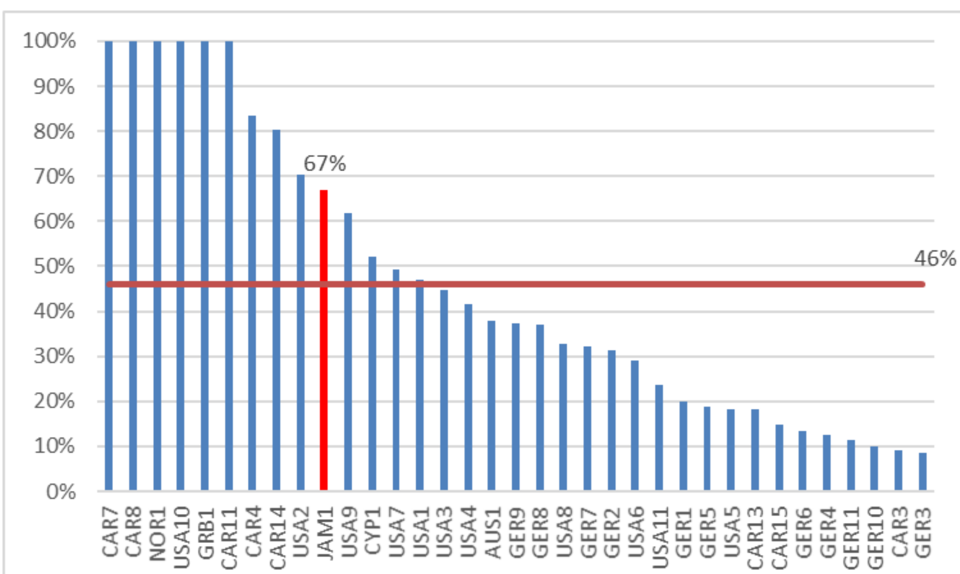


Table 6-3: Utilities Efficiency Scores

JAM1 Efficiency			67%
Sample Average Efficiency			46%
Utility	**Efficiency**	**Utility**	**Efficiency**
USA1	47%	CAR14	80%
USA2	70%	CAR15	15%
USA3	45%	GER1	20%
USA4	41%	GER2	31%
USA5	18%	GER3	9%
USA6	29%	GER4	12%
USA7	49%	GER5	19%
USA8	33%	GER6	13%
USA9	62%	GER7	32%
USA10	100%	GER8	37%
USA11	24%	GER9	37%
CAR3	9%	GER10	10%
CAR4	83%	GER11	12%
CAR7	100%	CYP1	52%
CAR8	100%	GRB1	100%
CAR11	100%	NOR1	100%
CAR13	18%	AUS1	38%

Overall, JPS is ranked the 10th most efficient utility and nine utilities that are more efficient than JPS:

- Six utilities on the frontier with efficiency score of 100%
- CAR4 (Belize Electricity Limited) with efficiency score of 83%
- CAR14 (Grenada Electricity Service) with efficiency score of 80%
- USA2 (Empire) with efficiency score of 70%

1. Frontier Utilities

Out of the 35 utilities, there are six utilities that are on the frontier. The utilities on the frontier are deemed fully efficient, that is they are 100% efficient. The frontier comprises of Caribbean Utility Co. (Cayman), Dominica Electricity Service Limited (Dominica), Hafslund (Norway) UNS Electric (USA), Scottish & Southern Electric (Great Britain), St. Lucia Electricity Limited (St. Lucia). The model identified Dominica Electricity Service Limited (CAR8) and Scottish & Southern Electric (GRB1) as JPS' comparators[25].

Table 6-4 shows that four utilities on the frontier have a customer base below 100,000 while Great Britain has an excess of 1 million customers which is approximately six times JPS' customer base.

[25] The DNV-GL also had Great Britain, Norway and St. Lucia on the frontier from their DEA results.

Table 6-4: Country and Customer Size of Utilities on the Efficient Frontier

Country	<100K	100K-500K	500K-1M	>1M
Cayman	1			
Dominica	1			
Norway			1	
USA	1			
Great Britain				1
St. Lucia	1			
Total	4	-	1	1

a. Comparative Analysis – JPS and DOMLEC

The DEA model identified Dominica Electricity Service Limited (DOMLEC) as one of JPS' comparators. Since, DOMLEC is located in the Caribbean, an in-depth analysis was done to support a reasonable productivity factor for JPS. Table 6-6 shows the different characteristics of both utilities.

Dominica and Jamaica have different landscape and topologies, even though located in the Caribbean. Importantly, Dominica was severely affected by Hurricane Maria (Category 5) in 2017 and had only 74% of their T&D system restored by the end of 2017. The impairment significantly affected their operation, thus very low operating costs which would deemed very efficient based on the limitations of the DEA model[26].

Table 6-5: JPS and DOMLEC Characteristics

Characteristics	JPS	DOMLEC	DOM/JPS
Sales (GWh)	3,207	78	0.024
Customers	642,944	36,499	0.057
Network Length (km)	12,538	1,325	0.106
Supply Size (km^2)	10,991	754	0.069
Losses (%)	26.50%	9%	0.340
Avg consumption (kWh/cust)	4,988	2137	0.428

Dominica Electricity Services is a vertically integrated utility company which employs 254 employees and their distribution and transmission networks carry electricity to 73,925 citizens.

[26] Dominica would deemed efficient by default as the DEA model views its parameters as extreme (very low) thus, the model wouldn't have a suitable comparator to estimate its parameters.

The DEA benchmarking exercise identified DOMLEC, one of the utilities comprising the efficiency frontier, as a comparator to JPS. However, Table 6-5 illustrates significant differences in size and operating characteristics between both companies. Sales and losses are deemed outside the control of most utilities and are more influenced by socio-economic conditions. In 2017, Jamaica had a debt to GDP ratio of 103.3% while Dominica had 75.51%, this vast differential is supported by its GDP per capita which are US$5,109.55 and US$7,609.61 for Jamaica and Dominica respectively. Therefore DOMLEC has significantly lower system losses than JPS.

Even though, DOMLEC is recognized as 100% efficient, based on the partial benchmarking analyses JPS outperforms DOMLEC and is more efficient. This reiterates the importance of not determining the productivity factor based on the results of one benchmarking analysis.

b. Comparative Analysis – JPS and SSE

Scottish and South Eastern (SSE) is a vertically integrated utility company with operations in Great Britain and Ireland. Its subsidiary Southern Scottish Electricity Networks employs 4,000 employees and their distribution and transmission networks carry electricity to over 3.7 million homes and businesses across the north of the Central Belt of Scotland and also Central Southern England.

The DEA results identified SSE as the second comparator to JPS. As highlighted in Table 6-6, there are significant size and operating characteristic differences that have to be taken into account when determining relative efficiencies between the two companies.

Table 6-6: Comparison between SSE (Great Britain) and JPS

Characteristics	SSE	JPS	SSE/JPS
Sales [GWh]	37,100	3,207	11.6
Customers	3,799,848	642,944	5.9
Network Length [km]	126,457	12,538	10.1
Supply Size Area [km²]	94,204	10,991	8.6
Losses [%]	5.7%	26.8%	0.2
Avg. consumption [kWh/cust]	9,764	4,988	2.0

As indicated above, size provides economies of scale and SSE is 10.1 times and 5.9 times larger than JPS based on the network length and number of customers respectively. In the case of operating characteristics, SSE has significant advantages in respect of sales (11.6 times) and network losses (5.7%). These variables are significantly outside the control of the utilities and are more influenced by socio-economic conditions. It should be noted that SSE size disparity extended to the entire group within the sample as SSE had 2.3 million or 2.7 times the number of customers as the next largest utility within sample. This disparity no doubt has influenced its ranking as 100% efficiency as measured by DEA, number 1 for OPEX per kWh and number 2 for OPEX per customer.

Therefore emphasizing the limitations of the DEA methodology in classifying comparators displaying extreme parameters as efficient by default. The results demonstrated that the smallest and the largest utilities in the sample have formed the frontier with Cayman, St. Lucia, Dominica, Great Britain and Norway are deemed as 100% efficient.

c. Comparative Analysis – JPS and Hafslund

Hafslund is one utility on the frontier that can be considered a comparator to JPS based on customer size. Hafslund, a Norwegian utility has 710,000 customers. There are a number of factors that should be taken into account when assessing relative productivity benchmarks for JPS including:

- Sales per Customer
- Operating area
- Network Losses

Hafslund (NOR1) achieved annual sales per customers of 27,465 kWh in 2017 which is 5.5 times higher than JPS[27]. As noted by the OUR consultant (DNV-GL), "when customers have relatively high consumption, this creates a scale advantage and as a consequence lower per-unit operational costs. For example, the additional costs of maintaining a distribution line will not increase significantly if the line has a higher capacity so as to accommodate more throughout. Rather, the maintenance cost will tend to be constant per km for lines of similar type."

Hafslund distributes electricity to customers in Oslo, Akershus and Østfold counties which essentially is an urban utility. These areas do not have significant terrain issues that impact their ability to serve and maintain. Additionally, while Hafslund has a smaller service area of 9,554 km^2 (13%) compared to JPS' (10,991 km^2), Hafslund has approximately 60,000 (10%) more customers. Therefore, Hafslund's customer density is 74 (Table 6-8) compared to 59 for JPS. This combination of smaller service area and higher customer density provides another scale-advantage and opportunity to lower their costs to serve.

Another key consideration is the relative difference in the level of system losses. In 2016, Hafslund recorded system losses of 6.2% compared to 26.8% for JPS, therefore their total losses is lower than JPS' technical losses. Managing system losses is a significant issue for JPS and one of the major cost drivers. Given the level of theft experience, JPS incurs significant costs to contain/reduce system losses with activities such as auditing and investigations of 100,000 accounts annually as well as the removal of 250,000 throw-ups. JPS spends approximately US$7M

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[27] The annual sales per customers data was calculated based on Table 6 in the Productivity Study by MacroConsulting (page 13).

per annual in O&M expenses in the direct fight against system losses. Without the need to incur this level of expenditure, JPS productivity would increase to 76%.

Even though, DEA results determined Hafslund as 100% efficient, the partial benchmarking analyses produce contradicting results. The cost per kWh sold metric shows that Hafslund has the lowest cost at US$0.01 per kWh (Figure 6-3). This compares to US$0.03 per kWh for JPS. However, this comparison is significantly influenced by the socio-economic conditions of the countries in which both utilities operate. While, the OPEX per customers shows JPS ranking 3rd at US$169 compared to Hafslund whose ranked 7th at US$257.

2. **Comparable Utilities**

Having established that the majority of the utilities that are not reasonable comparators to JPS due to size and operating characteristics, it is important to assess JPS efficiency against appropriate comparators. Benchmarking comparison (such as DEA) seek to adjust for size disparity by using unit averages which ignores economies of scale consideration (as in the case of the SSE comparison) or introduces modelling bias as previously discussed. A key measure of the size of a utility is the number of customers it serves. The more customers connected to the system, the more costs utilities incurred by serving these customers.

Table 6-7 categorizes the 35 utilities in the sample into five groups based on size using the number of customers served. Approximately 26% of the utilities have a customer base of between 500,000 and 1M and could be considered peer utilities for JPS in this respect. This category includes five German companies and no US companies fall within that range. Also, there are no other Caribbean companies within this range as most of those companies are in the smallest category (less than 100,000).

Table 6-7: Electric Utilities Categorized by Number of Customers served

Countries	<100K	100-250k	250-500k	500k-1M	>1M	Total
Caribbean	**6**	**1**	**1**	**1**	**-**	9
USA	**4**	**4**	**3**	**-**	**-**	11
German	**-**	**-**	**4**	**5**	**2**	11
British	**-**	**-**	**-**	**-**	**1**	1
Norway	**-**	**-**	**-**	**1**	-	1
Australian	**-**	**-**	**-**	**1**	**-**	1
Cyprus	**-**	**-**	**-**	**1**	-	1
Total	**10**	**5**	**8**	**9**	**3**	**35**

As such, based on the range, the utilities that are similar to JPS are shown in Table 6-8. The utilities in the category has an average efficiency score of 36% (half of JPS). Among this group of nine (9) utilities, JPS ranks 2nd to Hafslund. As noted above, while Hafslund is comparable to JPS in respect to customer-size, other factors as explained previously do impact the extent to which efficiency comparison can be applied to JPS.

Table 6-8: Utilities with Customer Numbers of 500k - 1M

Code	Sales GWh	Customers #	Network Km	Area Km2	OPEX 2017 USD	Sales/ Customer	Customer Density	Efficiency score
JAM1	3,207	642,944	12,538	10,991	108.5	4,988	58.5	67%
GER1	19,945	737,097	44,346	948	948.5	27,059	777.5	20%
GER3	23,281	799,982	51,540	1,185	2,716.10	29,102	675.1	9%
GER4	8,960	994,993	31,258	938	893	9,005	1060.8	12%
GER6	18,467	726,219	27,549	818	1,315.30	25,429	887.8	13%
GER11	6,700	683,000	30,165	6,433	874.8	9,810	106.2	12%
CYP1	4,496	568,500	27,289	6,027	174.8	7,909	94.3	52%
NOR1	19,500	710,000	43,624	9,554	182.7	27,465	74.3	100%
AUS1	7,604	667,118	13,243	1,472	227.7	11,398	453.2	38%

The cost to serve customers in a city are lower due to shorter distances to be bridged and better opportunities to operate the network more efficiently. Also, the majority of the German companies (mainly big cities) has much higher density than Jamaica as well as the other islands in the Caribbean.

Another indicator of size is network length, and Table 6-9 outlines the size distribution of companies using network length as the primary metric. Network length acts as an indication of the size of the system and hence the costs involved. The more network there is to maintain, the higher the costs. 10 companies including JPS or approximately 28% of the sample have network length within the band of 10,000-30,000 km. The companies within this band could also be considered peer companies of JPS. Included in this band are two Caribbean companies (T&Tec and JPS), three US companies (Dayton, Empire and Green Mountain) and three German companies (e-netzi Sudhessen GmbH & Co. KG, Stromnetz Hamburg GmbH and MDN Main-Donau Netzgesellschaft). This band also include the Australian firm, United Energy as well as EAC of Cyprus. The average efficiency of this band is 40.6% compared to JPS 71%. Within this band only one utility, the American company, Empire, with efficiency score of 79% ranked higher than JPS.

Table 6-9: Utilities categorized by Network Length (km)

Countries	<1,000 KM	1,000-5,000 km	5,000-10,000 km	10,000-30,000 km	>30,000 km	Total
Caribbean	**3**	**4**	**0**	**2**	**-**	**9**
USA	**1**	**4**	**3**	**3**	**-**	**11**
German	**-**	**1**	**2**	**3**	**5**	**11**
British	**-**	**-**	**-**	**-**	**1**	**1**
Norwegian	**-**	**-**	**-**	**-**	**1**	**1**
Australian	**-**	**-**	**-**	**1**	**-**	**1**
Cyprus	**-**	**-**	**-**	**1**	**-**	**1**
Total	**4**	**9**	**5**	**10**	**7**	**35**

The Empire District Electric Company (USA2) is an investor owned utility with a workforce of 750 serving around 170,000 customers in 119 communities in Missouri[28]. The Empire District Electric Company is a part of a larger group that provides utility services such as electric, natural gas, and water service. While Empire was determined to be more efficient than JPS by 3% using DEA, the following is worth noting:

a. Empire sales to customer ratio is 5.6 times that of JPS

b. In respect to the partial benchmarking measures (Section 6.3.4), Empire ranks fourth in respect of OPEX per kWh (compared to JPS' 15th) but ranks 13th (compared to JPS being 3rd) for OPEX per customers.

3. Summary of DEA Results

Overall, the analysis of the DEA methodology provided the following insights:

1. The inherent weakness of the DEA methodology (skewed by outliers) was evident with the frontier companies predominantly represented by size extremes
2. Heterogenous sample
3. Despite the sample, JPS efficiency score has demonstrated a high level of productivity as evidenced by:
   a) JPS ranked 10th overall and therefore recorded efficiency score better than 25 utilities of the 35;
   b) Compared to utilities of similar size: JPS ranked 2nd whether using the number of customers or network length

[28] DNV GL – Energy – Tariff Productivity Improvement Advice for the Electricity Sector – Jamaica (Page 49)

c) JPS efficiency score of 67% is significantly higher than the Caribbean average of 64%

d) Four of the five Caribbean utilities that ranked higher than JPS had customer density that is more than twice that of JPS.

e) JPS is significantly more efficient than the two (2) utilities that best fits the criteria of appropriate peer for JPS. These are EAC of Cyprus (52%) and T&Tec of Trinidad (15%).

6.3.2 Partial Benchmarking Measures

The Final Criteria requires JPS to submit the following partial benchmarking analysis:

- OPEX per kWh sold
- OPEX per kWh generated
- OPEX per customer

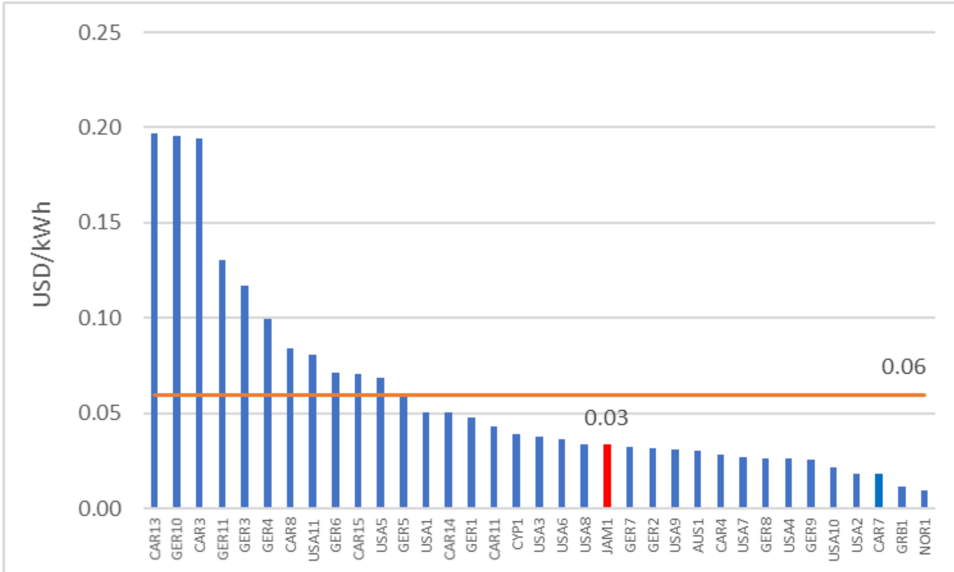
Partial productivity measures account for the ratio of a single output to a single input across firms and over time. Partial productivity methods produce simple, easy to calculate straightforward indicators of performance but it does not recognize the trade-offs between different improvement possibilities or areas. As such, it should only be viewed as a rough indicator as it can potentially mislead and misrepresent the performance of a firm.

The third measure, OPEX per kWh generated was not computed. This was due to the sample comprising mainly T&D utilities and therefore the generated data would not be comparable across the sample. Unlike JPS, most of the utilities do not own their own generating assets. Hence, computing this benchmark measure would be restricted to a very few number of the utilities and results that are inconclusive at best and misleading at worse.

1. OPEX per kWh sold

Figure 6-3 shows the results of OPEX per kWh sold. The result indicates that JPS spends US$0.03 per kWh sold. JPS is ranked the 15th most efficient utility and is performing above the average efficiency score. Of the fourteen companies, that ranks higher than JPS, six are European, five are American, two Caribbean and one Australian. These utilities have significantly higher average consumption per customer (3.25 times) than JPS.

Figure 6-3: OPEX per kWh sold



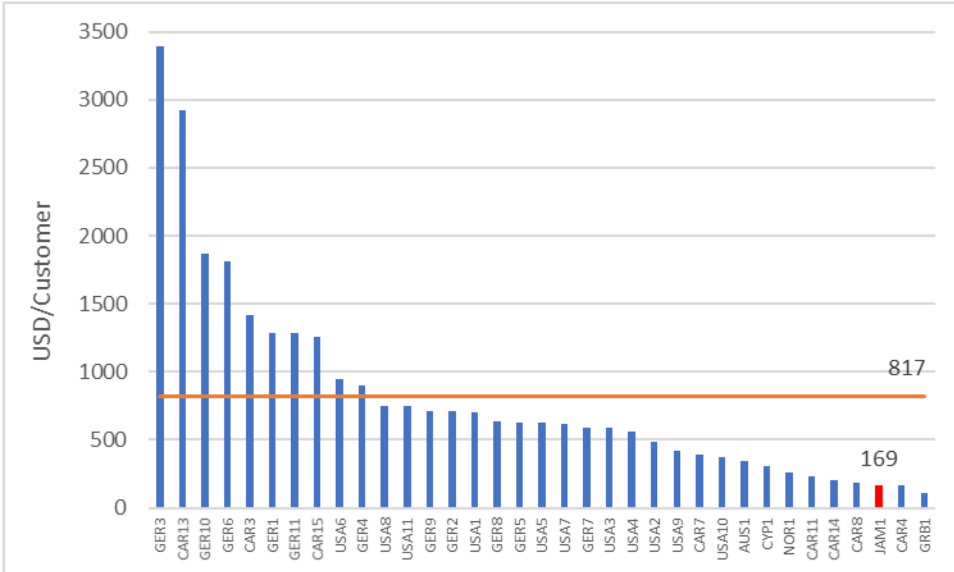
As noted by DNV, *"it is important to note that both sales and customer numbers are variables over which the company in principle has no control."*[29] Energy sales is primarily determined by socio-economic factor such as GDP and climatic conditions. JPS' operating environment is significantly different compared to the European, American and Australian utilities that ranks above JPS in respect to this measure. Two Caribbean country utilities that rank higher than JPS are Belize and Cayman. While these utilities have similar climatic condition compared to JPS, the Cayman utility would benefit from the higher per-capita GDP and income economic environment of that island as evidenced by a sales-to-customer ratio of 4.3 times relative to JPS.

2. OPEX per Customer

Figure 6-4 shows the results of OPEX per customer. The result indicates that JPS spends US$169 in O&M per customer. It depicts that JPS performs extremely efficient ranking the 3rd most efficient utility. In regards to operating expenses per customer, the results demonstrate that JPS has significantly lower cost relative to utilities in developed countries such as Germany and USA.

[29] DNV GL – Energy – Tariff Productivity Improvement Advice for the Electricity Sector – Jamaica (Page 22)

Figure 6-4: OPEX per customer



In conclusion, the results from the DEA model and the partial benchmarking measures show that JPS is performing efficient relative to the sample of comparable utilities determined from the methodology prescribed by the Final Criteria. The Company operates in the top quintile of the comparator group, which is representative of utilities operating in developed countries and those within the Caribbean that share some of the region's unique island challenges.

While the Company is not yet at the frontier, the performance is evidence that the application of aggressive growth productivity improvement (PI-Factor) targets in the preceding regulatory periods has been successful in inducing a strong focus and culture of improving operational efficiency at JPS. Many of the known areas for efficiency gains have already been exploited in attaining third quartile performance. Therefore, to get to the frontier it will require larger investments and a longer horizon to achieve given that the frontier is dynamic.

6.3.3 Sensitivity Analysis[30]

Studies have shown that other jurisdictions perform more than one benchmarking results in determining a reasonable productivity factor. On that basis, the following productivity methodologies were computed.

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[30] In addition to TFP, the Ordinary Least Square (OLS) regression was performed using the predefined sample. The OLS is a regression analysis and is used to determine the values of parameters by calculating the line of best fit and the line cuts across the observation by minimizing the distance between the variable and the other observation. OPEX was used as the dependent variable and supply size area, network length, sales and the number of customers were used as the independent variables. The model did not yield statistical or economically significant results. The estimated co-efficient related to area was negative which meant that the larger the supply size area, the lower the operating cost. Therefore, those results will not be included in the analysis

1. **Total Factor Productivity (TFP)**

As indicated, prior to the Licence (2016), the productivity improvement factor, previously known as the X-factor, was calculated based on the expected productivity gains of the Licensed Business. Since the TFP was a suitable model used by both JPS and the OUR in the past, the model was updated as a gauge to determine JPS' potential efficiency gains in the next regulatory period. Total Factor Productivity (TFP) index measures the change in total output relative to the change in the usage of all inputs. The TFP accounts for the use of a number of factor inputs in production and can be used to analyze a company's performance over time.

In the previous tariff determinations, the X-factor was set equal to the difference in the expected total factor productivity (TFP) growth of the Licensed Business and the general total factor productivity growth of firms whose price index of outputs reflect the price escalation measure, shown below:

$$X = \Delta TFP_{JPS}^{Expected} - \Delta TFP_{General}$$

The TFP model used in the 2014-2019 Tariff Review Application was updated to include audited information up to 2017. The expected TFP for JPS used the input variables O&M and capital expenditure while the output variables are the number of customers, energy and demand. While, the TFP for the general economy is calculated as the weighted average of the TFP growth rates of the United States and Jamaican economies and is derived as:

$$\Delta TFP_{general} = (0.76 * \Delta TFP_{US}) + (0.24 * \Delta TFP_{Jamaica})$$

Table 6-10 shows the results of the TFP model for the period 2012-2017. The result shows JPS TFP growing at 0.363% for the period. The low TFP values were mainly driven by slow output growth, as both the peak demand and total energy recorded growth rates of less than 1% while the number of customers grew at a rate of 1.5% per year. Over the period, JPS has been able to reduce its O&M input variable but its capital expenditure has increased significantly albeit not totally within JPS' control as the Company had to be investing heavily to improve reliability, grid stability and reducing system losses.

Table 6-10: JPS TFP Results

TFP Calculation	Results
PI-Factor	**-0.13%**
General TFP	**0.492%**
JPS TFP	**0.363%**
Total Inputs	0.91%
O&M	-2.65%
CAPEX	3.52%
Total Output	1.28%
Customers	1.53%
Energy	0.43%
Demand	0.96%

Conversely, the general economy grew at 0.49% over the time horizon. This result in a PI-Factor of -0.13%, which suggests that the expected productivity growth of JPS was slower than the general economy. This suggests that there is a lag in the translation of the investments in efficiency and productivity gains in energy and demand growth even though the economy itself is growing at a faster rate. This should not be entirely surprising given the global and domestic gains in energy efficiency and the trend in DER-driven load defection. This reiterates the need for caution in too aggressive a push for greater investment in efficiency that may not necessarily translate into the benefit expected over a defined time horizon.

Another important point indicated by the TFP result in relation to the presented DEA outcome is the duration of the trend. Contrary to the TFP, DEA outcome is reflective of a single year performance. However, in a competitive market, which PBRM mechanism tries to incorporate via incentives and penalties, equilibrium prices are affected only by changes in long-run average costs. In the short run however, the productivity may fluctuate across industry or peer utilities due to myriad of reasons. An illustrative example could be that in the 2017 sample of utilities, some of the difference in the O&M expenses may be due to the fact that certain utilities have accelerated maintenance expenses of T&D structures, while others are doing it in the regular scope, and some others have already completed it. This difference however would be smoothed out over a longer term.

2. Customer Relevance

A sensitivity analysis was carried out to demonstrate the impact of customers on JPS' operating costs. Given that the average consumption per customer is extremely low in Jamaica, a sample was developed with US utilities that are similar in size respective to number of customers. The sample and data for the list of utilities are shown in Table 6-11. The sensitivity analysis is to illustrate Fares' theory that the single major determinant of utilities' costs is the number of customers[31]. Uni-dimensional benchmarking measures were carried out and the results are depicted in Figure 6-5.

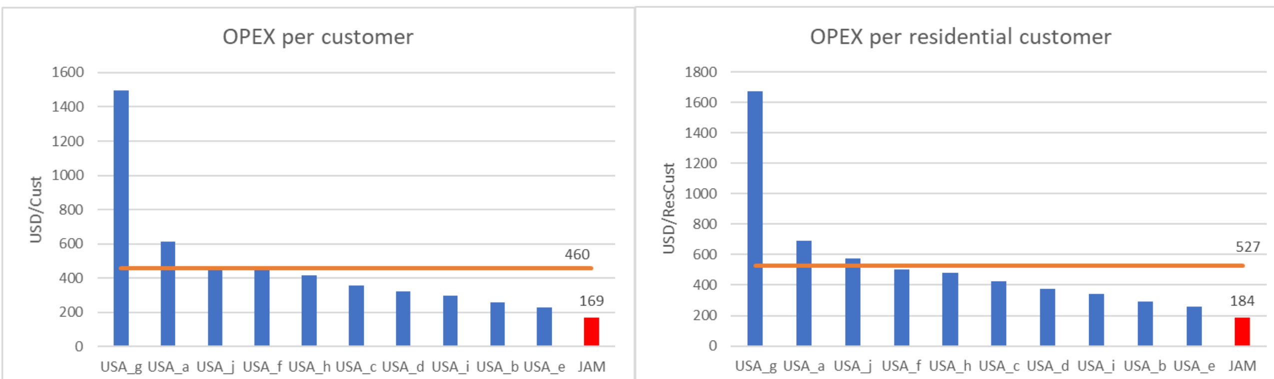
Table 6-11: US Utilities similar to JPS

Utility Name	Total Customers	Residential Customers	OPEX 2017 USD
Central Maine Power Co	624,511	557,647	384,387,649
Duke Energy Ohio, Inc.	712,328	634,069	183,502,152
Entergy Arkansas, Inc.	708,728	591,113	251,336,661
West Penn Power Co	724,589	624,915	234,334,555
Tampa Electric Company	744,690	659,362	170,233,040

[31] Fares, The U.S. Electric Grid's Cost in 2 Charts - Scientific American Blog Network. See further details in the Productivity Study by MacroConsulting – Annex to the Rate Case Filing.

Utility Name	Total Customers	Residential Customers	OPEX 2017 USD
Cleveland Elec. Illum. Co, The	750,660	666,598	333,669,066
Massachusetts Electric Co	755,116	675,962	1,130,667,152
MidAmerican Energy Co	770,330	661,776	318,708,337
Duke Energy Indiana, LLC	819,569	714,024	245,397,645
Oklahoma Gas and Electric Co	838,252	660,803	380,515,586

Figure 6-5: OPEX per customer – US sample and JPS



The results show JPS as the most efficient utility in the sample. This corroborates the results presented in the Partial Benchmarking Measures (Section 6.3.2) which shows JPS ranking 3rd most efficient utility in the sample.

6.4 Business Plan Initatives

Condition 10 of Schedule 3 of the Licence requires the Rate Application be supported by a Business Plan. As such, JPS has developed a comprehensive Five-Year Business Plan which clearly outlines the strategic objectives, measures and targeted outcome to be achieved. It also states the strategies, initiatives and activities to be undertaken within the rate review period.

Table 6-12: Highlights of JPS Scorecard for 2019-2023

PERFORMANCE MEASURES	2017	2018	2019	2020	2021	2022	2023
Customer Satisfaction Index	60%	60%	60%	64%	66%	68%	70%
Guaranteed Standard Compliance	97%	91%	93%	94%	95%	96%	97%
Overall Standards Compliance		75%	85%	90%	93%	95%	95%
SAIDI (Hours)	28.70	32.51	31.07	29.40	28.29	27.29	26.16
SAIFI (Occurrence)	16.33	15.82	15.12	14.31	13.77	13.28	12.73
JPS Heat Rate (kJ/kWh)	11,330	11,214	11,350	10,246	9,327	9,613	9,337
System Losses (% reduction)	0.35%	0.19%	0.35%	0.40%	0.45%	0.50%	0.55%

JPS' strategic direction is centered on five strategic priorities - delivering exceptional customer service, ensuring the safety of its employees and the public, achieving end-to-end efficiency, growing the Company and strengthening relationships with our key stakeholders, all of which are underpinned by key enablers – our people, process and technology.

PRIORITY 1: SAFETY

Section 4.3 of the Business Plan outlines Safety as JPS first Strategic Priorities. The vision for safety is best described in two components- safety system and safety culture with the strategic direction to **"attain, sustain a culture of safety leaders".** Therefore, the goal is to ensure compliance with applicable policies, regulations, standards and guidelines and covenants of credit agreements. The strategic objectives to be achieved are:

a) Improve and Maintain a Safe & Healthy Work Environment (Section 8.1 of the Business Plan)
b) Embed Zero Harm Philosophy (Section 8.2 of the Business Plan)
c) Improve and Manage Regulatory Compliance (Section 8.3 of the Business Plan)
d) Promote and Lead Environmental Stewardship (Section 8.4 of the Business Plan)
e) Improve Security of Our People (Section 8.5. of the Business Plan)
f) Improve Security of Our Equipment and Infrastructure (Section 8.6 of the Business Plan)

As a part of the Improve and Maintain a Safe & Healthy Work Environment initiative, in 2019, all linemen were equipped with Pole Chokers to prevent falling on the job. This resulted in an increase of US$200k for 2019. Additionally, implementing various initiatives in support of the strategic objectives will result in an annual increase of US$50k.

PRIORITY 2: CUSTOMER SERVICE

JPS aims to use the opportunities provided by the changing marketplace to move the Customer Satisfaction Index (CSI) from its current 60% (2018) to 70% by 2023, which is in line with the average CSI rating of US utilities[32]. JPS' customers have identified power quality and reliability, pricing, and proactive communication on power outages among the areas of the Company's service delivery that matter most to them. In addition, JPS' customers have indicated some dissatisfaction with its responsiveness specificallyt to resolve queries. An important characteristic of the dynamic and evolving energy landscape is the increasing choice and needs of the customer. JPS recognizes the importance of delivering excellent customer service quality and during 2019 to 2023, the Company will invest in improving both customer service experience and power supply quality.

As outlined in Section 2.2.1 – Customer Service Excellence, the Company has won several customer service awards in 2017 and JPS' efforts to improve service were recognized by the PSOJ/JCSA. The Company has developed a comprehensive Customer Service Excellence Plan for 2019-2023 to build on these achievements. Therefore, to improve customer service experience, the Company has targeted the following four objectives as outlined in the Business Plan:

a) Improve the Ease of Doing Business (Section 9.1.of the Business Plan)
b) Customer Empowerment 'Putting the Power in our Customers' Hands (Section 9.2. of the Business Plan)
c) Customer Retention (Section 9.3. of the Business Plan)
d) Positive Perception of the JPS Brand (Section 9.4. of the Business Plan)

The outcomes targeted are to improve the compliance with Guaranteed Standards from 91.1% (2018) to 97.1% (2023) and Overall Standard from 74.5% (2018) to 97.1% (2023). To deliver on the four objectives and to achieve the outcomes identified, JPS will execute on the initiatives outlined in the Business Plan including:

a) Deploy Technology to eliminate customer pain points & enhance customer value (Section 9.1.1. of the Business Plan)
b) Provide Multi-channel service and more self-service options (Section 9.2.1. of the Business Plan)
c) Customer segmentation and partnerships (Section 9.3.1. of the Business Plan)
d) Position the JPS Brand as a valuable partner (Section 9.4.1. of the Business Plan)

The implementation of these initiatives requires investment albeit some CAPEX involved, primarily with technology implementation including provide multi-channel service and more self-service options, a significant amount of recurring (O&M) expense is required. For the period 2019-2023, JPS will spend on average of US$0.7M to realize its strategic objective and targeted outcomes.

The second major focus of Customer Service delivery is the improvement in power supply quality. Section 4.2.1- Sector Goals outlines the importance of energy in general and electricity as a

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[32] Electric Utility Customer Benchmark Study by J.D. Power & Associates, a global leader in customer satisfaction scoring and benchmarks

national imperative as articulated by Jamaica's Vision 2030 and the National Energy Policy. While, the primary focus is on the generation infrastructure, the importance of operating and maintaining the T&D system for the delivery of energy must be underscored. JPS conducted a Cost of Unserved Energy Study which is used to provide an economic value to the cost of electricity interruptions to electricity customers and the economy as a whole. This was used to inform investment and maintenance decisions on the electrical power system for the Business Plan to optimize the reliability of the network. The Business Plan speaks to the following initiatives:

a) Improve Transmission and Distribution Reliability (Section 9.6.)
b) Strengthen Grid Security and Stability (Section 9.7.)
c) Improve Grid Management (Section 9.8.)
d) To Modernize the National Grid (Section 9.9.)
e) Compliance with Transmission & Distribution Design Criteria (Section 9.10.)

Therefore, the next five years will see the implementation of initiatives that address these areas and ensure that JPS delivers on its commitment including significant improvement in system reliability. The following initiatives will impact the O&M for 2019-2023:

a) Address Known Grid Deficiencies (Section 9.6.1. of the Business Plan):
b) Target SAIDI Drivers (Section 9.6.3. of the Business Plan)
c) Improve operation of the power system in a safe, reliable & economical manner (Section 9.1.1. of the Business Plan)
d) Improve Stakeholder Situational Awareness (Section 9.1.1. of the Business Plan)
e) Improve The Management of Variable Renewable Energy (VRE) (Section 9.1.1. of the Business Plan)
f) Development of A Smarter Grid

Therefore, O&M will increase by US$1.1M per annum due to technology and transportation. Investing in modern technologies to improve asset management practices and enable workforce mobility will reduce the expected increase in asset maintenance and replacement costs due to an ageing infrastructure and increased severe weather events over the next 10 years. These technologies will optimize the planning, scheduling and execution of work to improve overall system reliability and prioritize asset investment decisions based on empirical data. As the Company modernizes its core technology platforms and ramps up its Smart Grid strategy, it will incur increases in software and telecommunications cost relative to base year.

PRIORITY 3: END-TO-END EFFICIENCY

JPS is committed to efficiency improvements, thus, End-to-End Efficiency is the third strategic priority. End-to-End efficiency examines the Company from Generation to Customer Service delivery and for 2019-2023, the Business Plan targets improvement through:

a) Reducing the cost of generation by improving Heat Rate performance and plant reliability,
b) Reducing system losses; and

c) Lowering operating costs through business process improvement and the optimization of technology.

JPS' Thermal Heat Rate performance has improved over the five-year period (2014 – 2018) from 11,457 kJ/kWh to 11,214 kJ/kWh, the best performance by the JPS thermal fleet in the Company's history. The improved performances are primarily attributed to deliberate actions taken by the Company to ensure that the reliability and efficiency of its generating fleet were optimized by effecting major maintenance activities on key base load assets over the period. For 2019-2023, JPS fleet will experience significant changes with two phases of retirement planned. The commissioning of the 194MW LNG plant, and the retirement of Old Harbour and Hunts Bay generating plants between 2020 and 2021 followed by the Rockfort Barge and the remainder of the Hunts Bay station scheduled to retire in 2023. This has implication for increased O&M expenses as previously capitalized expenditure will be expensed.

The reduction of system losses remains a key priority of JPS, however, it impacts JPS productivity that is by accounting for the energy losses and the number of illegal customers of 180,000, JPS' efficiency rises considerably (85%)[33]. JPS has developed a 10 year system losses reduction plan which is intended to outline a sustainable path towards system losses reduction over time. The emphasis of the strategy will be centred on measurements, process evaluation and improvements, analytics driven actions, technical and non-technical initiatives, continued research and development and engagement of key stakeholders.

Over the five-year period, system losses will be reduced by 8.9% (2.30% basis point) due to a combination of capital investment initiatives and operating activities. In managing TL on the distribution system, the Company will commit O&M resources to carry out power factor correction and phased balancing activities. With respect to NTL, the Company will deploy resources to aggressively remove throw-ups as well as conduct significant amount of audits and investigation of accounts. In 2019 and 2020, approximately 96,000 accounts will be audited each year and this will increase by approximately 15% to over US$109K in 2023. While the proportion of audits driven be smart meter analytics will increase, these activities required increases in O&M resources including:

- Increasing the number of field teams from 30 to 40;
- Increasing the number of Customer Relations Representatives (CRRs) providing back office support from 6 to 10

Therefore, JPS will increase its annual O&M on average of US$330K to tackle loss reduction.

Lower Operating Expenses

[33] Further details in JPS' Productivity Report in Annex I.

JPS is committed to productivity improvement and in 2018 aggressively sought to reduce it operating expenses but recognizes the need to balance expenditure reduction and the achievement of other dimension of business performance. As a part of JPS operating plan, a comprehensive approach to lower operating expenses was developed and is outlined in Section 10.3 of the Business Plan. In the pursuit of End-to-End efficiency, JPS will lower operating costs through the execution of the following strategies:

a) Execute capital investment that are primarily technology initiatives;
b) Implement business process initiatives;
c) Pursue cost reduction initiatives

CAPEX programme to be undertaken by JPS during the period will garner net savings in O&M totaling US$9.6M over 2019 to 2023. The major programmes that will positively impact O&M include Smart Meter Deployment, Smart Street Lighting, Grid Modernization and Business Intelligence. In addition to enhancing the Company's Loss detection capabilities, the implementation of the Smart Meter Deployment Project will yield significant cost reduction benefits including savings in the O&M category of Bill Delivery and Meter Reading, reduction in penalties from breach of Guaranteed Standards and decreasing Disconnection and Reconnection contractor costs.

JPS will optimize its business processes to maximize the value being delivered to its customers through cost effective approaches. Through this effort, JPS intends to improve operational efficiencies across the business by re-examining work-flows, eliminating ineffective or redundant steps in processes, and improving synergies in operations. In addition to productivity gains in Procure to Pay and Meter to Cash (M2C) processes, this will result in reduced T&D maintenance costs from efficiency gains of automation, an integrated approach to Vegetation Management programme and overtime reduction.

In conjunction with executing, capital investment efficiency initiatives and business process optimization, JPS will pursue the following cost reduction initiatives across the business for 2019-2023:

- Optimize fleet operating and maintenance costs;
- Negotiate and access lower prices through effective supplier chain management
- Expand digitization of business transactions including electronic bill delivery;
- Continued gains from outsourcing and technology implementation

These cost reduction initiatives will result in approximately US$2M of saving per annum illustrated in Table 6-13.

Table 6-13: Productivity Improvement Initiatives

	2019	2020	2021	2022	2023
a) Capital Investment Initiatives	0.59	1.60	2.15	2.47	2.84
b) Business Process improvement Initiatives		0.57	2.1	2.67	3.07
c) Other Cost Reduction Initiatives	1.26	2.00	1.98	2.02	2.04
	1.85	**4.17**	**6.27**	**7.16**	**7.96**

Details of these productivity improvements initiatives are outlined in Section 10.3 of the Business Plan.

PRIORITY 4: GROWTH

JPS aims to maximize value to customers and other stakeholders by successfully pursuing sustainable business growth in the evolving energy market. Given the increase in options for energy supply, JPS has to remain vigilant and will seek to innovate, create and capture significant value from new and existing customers. Growth is anticipated to be impacted by planned defection by large customers, loss of new load primarily in the hotel sector where DGs are a feature of construction design, increase in ownership of energy efficient appliances and energy saving equipment as well as customer renewable energy solutions and the LED smart streetlights project. The consumption per customer is expected to fall as more customers employ energy efficiency measures or install energy production systems. Energy sales is projected to grow by an average of 1% per annum over the rate review period while customer numbers are projected to grow by an average of 1.4% per annum driven primarily by growth in industry, household and reductions in illegal connections.

JPS will support the creation of an enabling environment to facilitate the deployment of EV through active stakeholder engagement, lobbying of the Government, and strategic public and private partnerships. In addition, JPS will be pursuing the following initiatives to grow its energy sales:

- **Customer Engagement**: Engaging large at-risk customers to better understand their needs and develop best fit solutions
- **Product Value**: Demonstration of product value and the value proposition for remaining on the grid
- **Strengthen Relationships**: JPS will also strengthen relationships with major developers and Parish Councils, and continue to position itself as the preferred provider of power and energy services.

PRIORITY 5: STAKEHOLDER RELATIONSHIPS

Stakeholder engagement goes beyond transactional relations with customers, business partners, policy makers and other influencers. It is signifies connecting with persons in a way that facilitates the winning of hearts and minds, and the creation of a collaborative environment that fosters mutually beneficial partnerships. The Company's stakeholders are many and varied, therefore, the Stakeholder Engagement strategy must necessarily address the unique nature and needs of each segment.

JPS primary goal is the creation and maintenance of an enabling environment for the utility, through transparency, information-sharing, and overt facilitation of varying perspectives in decision-making. The engagement of key groups such as businesses, communities and government, is expected to result in greater trust of the organization and mutually beneficial strategic partnerships. The primary objectives of Stakeholder Engagement are therefore to:

- Educate, build awareness and understanding
- Generate more objective conversations around JPS and the energy sector
- Influence the policy making process
- Facilitate partnerships that advance JPS' commercial agenda
- Create Allies and Advocates
- Build brand affinity

KEY ENABLERS

The realization of the objectives and targeted outcomes from JPS strategic priorities is in part dependent on three key Enables:

a) Human Resources;
b) Technology;
c) Business Process Optimization

Human Resources

Employees are key enablers of the organization as they help to shape, develop and contribute to the effectiveness of the organization. Organizational effectiveness is achieved through the identification of actions and plans that positions JPS in the best possible place to be able to address the multiple and complex challenges the organization faces and deliver on the goals and commitments of the Company. This includes managing risk and competition, taking advantage of opportunities, supporting JPS' commitment to national development, meeting service standards and continuously providing value for key stakeholders, while operating in an effective and efficient manner.

JPS recognizes the need to deliver increased value to customers and shareholders while enabling its employees to achieve their goals. For 2019-2023, JPS will build a culture of high performance and accountability by engaging and equipping its employees with the right skills, tools and conditions to succeed.

The following are the key objectives of the people strategy:

- Improve Employee Engagement
- Increase People and Organizational Effectiveness and Efficiency
- Training and Development

Critical to the realization of its strategic objectives for the 5year period, is the continued recruitment, development and retention of the requisite skills. Faced with the needs for increased skills especially with the rapid expansion in the use of technology, along with the challenges of retaining such skills, JPS must invest more in building human capacity. JPS will therefore be spending an additional US$960K for 2021-2023.

Technology

Technology is a driving force for innovation, optimization and process improvement. This has become more important in enabling and supporting the Company to deliver value to its customers. There are four key areas of technology; namely:

a) IT Applications and Technology Optimization
b) Technology Infrastru-cture
c) Smart Grid Operations - Telecommunications
d) Technology and Cyber Security

A key strategy aimed at realizing these objectives is to develop a resilient technology infrastructure framework. Major programmes which seek to improve the technology infrastructure and resilience over the course of the next five years are (a) Data Loss Prevention Programme, (b) Hardware Modernization Programme, (c) Customer and User Experience Transformation Programme, (d) Utilize Behaviour Analytics to inform solutions creation to improve staff productivity, and (e) Data Centre Facilities Improvement Programme.

As JPS continues to advance technologies for improvement in service delivery, reliability, losses, asset management and growth, telecommunication will be at the centre and become increasingly important. JPS will focus on continuously improving the core networks that support SCADA, Tele-protection, Corporate Services, smart metering and intelligent grid operations. A primary objective is to improve core network availability and telecommunication network by improving both equipment and implementation. Additionally, JPS is seeking to improve organization cyber security culture, processes and controls which include implementing and supporting robust processes, technological controls and creating a security-minded culture for all employees. Initiatives and programmes will be executed to improve the cybersecurity posture of JPS' infrastructure, which is designed to mitigate the risk associated with cyber incidents and breaches that may adversely affect the reputation and JPS' finances and customers.

This relates to the current global trend of software as cloud-based service, and with accounting treatment as an O&M expense rather than a capital cost, increasing migration to software service by utilities is inevitably accompanied by higher O&M expenses. For 2019-2023, JPS will incur additional software expenses including:

1. UIQ and Operations Optimizer SaaS Fees US$2.5M,
2. AP Maintenance Cost and Communication Cost of US$1M, as well as MDMS Fees US$600K.

Table 6-14- Summary of Incremental O&M Expense for Business Plan Initiatives

	2019	2020	2021	2022	2023
Safety	250	50	50	50	50
Customer Services	639	1,277	1,818	1,881	1,885
End-End- Efficiency	(357)	410	238	367	315
Training	(328)	(343)	231	317	411
Technology Support	1,660	2,145	1,970	1,681	1,488
	1,864	**3,539**	**4,306**	**4,297**	**4,149**

6.5 Proposed Productivity Improvement Factor

The results of the DEA analysis provide a measure of JPS' level of efficiency, which along with other considerations, will be used by the Office to determine an efficiency target (ET). The Office will determine the number of years over which this target should be achieved (YET). The Office will utilize these two factors (ET and YET) and any considered cap on productivity improvement in determining the final PI-Factor. The Office reserves the right to consider other benchmarking tools such as partial benchmarking in determining the annual PI-Factor adjustment[34].

In determining the efficiency target (ET) and number of years over which the target should be achieved (YET), the following factors should be considered from a financial and regulatory perspective.

[34] Final Criteria - Jamaica Public Service Company Limited 2019 – 2024 Rate Review Process Page 45 of 137 Document No. 2019/ELE/003/RUL.001 2019 March 14

1. The imperfections of the DEA model should be considered and therefore a realization that the results are an indication and not a confirmation of efficiency position. It should be noted that the following weaknesses reduce its validity:

    - It provides no information about statistical significance of the results.
    - The results can be influenced by random errors, measurement errors or extreme events.
    - The largest and smallest companies were classified as efficient by default.

2. The sample used in the DEA analysis is skewed towards developed countries. Against that background the following are important to consider:

    - One of the principles of benchmarking is the comparability of the sample. The prescribed sample consists of European utilities (mostly from Germany), US utilities and smaller Caribbean utilities, which have different customer density and geographic terrain.
    - JPS's DEA efficiency score of 67% is significantly higher than the two (2) utilities that best fit the criteria of appropriate peers for JPS - Cyprus (52%) and Trinidad (15%).

3. The results depend on the selection of the input and output factors and the input-output variables used in the DEA model raises some concerns as previously discussed and summarized as follows:

    - Using one input variable (OPEX), the model ignores alternative to input available such as capital, this favors developed countries;
    - The use of sales as an output is questionable, given the activity for which the benchmarking is performed (distribution). Sales is not a major direct cost driver for a pure distribution business.

4. JPS encourages the appropriate consideration of the Partial Benchmarking results and the following insights should inform the determination of a reasonable and achievable productivity improvement factor

- JPS ranked third using OPEX per customer and is surpassed by the largest utility in the sample (SEE) that has 3.7 million customers (5 times that of JPS) and Belize that has approximately 94,500 customers which is 7 times less that of JPS
- JPS ranked 15th in relation to OPEX per sales however the limitation of using sales as an output factor should be noted. Additionally, the following impacted the results
    - Of the fourteen companies, that ranks higher than JPS, twelve are from developed countries and these utilities have significantly higher average consumption per customer (3.25 times) than JPS

- Energy sale is primarily determined by socio-economic factor such as GDP and climatic conditions.

In consideration of the above, JPS is proposing that the OUR take into account the following when determining the PI-Factor:

1. Observed Frontier
2. Reasonable and Achievable targets
3. Business Plan Initiatives

Frontier

DEA methodology defines the efficiency frontier and calculates companies' efficiency relative to the frontier then implies that the gap between that point and the frontier is the level of efficiency improvement that the utility should achieve.

In Section 6.3.1, a detail analysis of the companies deemed to be on the frontier was done and the following were observed:

a) None of the utilities on the frontier satisfied the two key criteria established for appropriate peer. Of the six utilities on the frontier
   i. Three are island utilities: St. Lucia, Dominica and Cayman have significantly different operating conditions in respect of terrain of the service area, the level of system losses, customer-density
b) Only one utility has a comparable size to JPS (Hafslund of Norway). Section 6.3.1 outlines its comparability with JPS.
c) Four of the six utilities on the frontier have customer base of less than 100,000

d) Removing SSE from the sample, JPS would move to the frontier

e) There are other factors that impact the validity of these utilities are 33% more efficient than JPS including a certain degree of substitution between productive factors and accounting/financing approaches that result in differences in input choice by the utility that influences, favoring capital intensive solutions.

In addition to those factors, another major hurdle JPS has to clear to get to the frontier is non-technical system loss which is an issue that neither of the firms on the frontier has encounter on the same severity as JPS.

Reasonable and Achievable

A fundamental principle of the Licence is the concept of reasonable and achievable targets. While the Licence explicitly identified target setting within the context of Reliability, Systems Losses and Heat Rate, it is clear that the principle and spirit outlined under the target setting section is universally applicable to all regulatory targets. It should therefore apply to the productivity improvement targets as well. It is important that the OUR does not impose rigid targets that would significantly erode JPS' ability to achieve these targets. The definition of the productivity improvement factor should therefore make appropriate allowance for JPS' capability of attaining the target performance levels within the timeframe.

Business Plan Initiatives

JPS is committed to productivity improvement and in 2018 aggressively sought to reduce it Operating expenses but recognizes that:

a) The Company has a high level of fixed costs;
b) Aggressive reduction can impact service quality and other strategic objectives.

JPS has taken proactive steps to continue to reduce operating costs and project $27.4M of savings between 2019-2023 from efficiency initiatives through CAPEX, process improvement and other cost reduction strategies. These strategies will collectively contribute to 20% catch-up in JPS productivity.

The Business Plan is an important factor in determining JPS O&M targets for 2019-2023. In developing the Business Plan, JPS has established five strategic priorities and three enablers for those strategic priorities. These strategic priorities are intended to deliver a number of improved outcomes for the organization including areas of regulated performance.

Table 6-15: Analysis of O&M Expense movement 2019-2023 (Relative to 2017)

	2017	2019	2020	2021	2022	2023
JPS Productivity 2017	108.54	108.54	108.54	108.54	108.54	108.54
Productivity improvement		(1.85)	(4.17)	(6.27)	(7.16)	(7.96)
Business Plan Initiatives		1.86	3.54	4.31	4.30	4.15
	108.54	108.56	107.91	106.58	105.68	104.73
Generation & Other Shared Services	39.73	38.85	34.73	30.22	30.18	30.14
Off-Set (excluded Non-Regulated)	(2.39)	(2.11)	(2.03)	(2.19)	(2.27)	(2.29)
Total	145.88	145.30	140.62	134.62	133.58	132.58

JPS regulated O&M (excluding offsets) was $145.8M in 2017 and included Transmission & Distribution (including Retail) of $108.5M. JPS Business Plan targets productivity improvement annually and projects that O&M cost savings will by $7.96M in 2023. However to achieved planned business performance outcomes, JPS will also have to resource a number of initiatives and anticipates that the incremental costs for these initiatives will be approximately $4.1M by 2023.

JPS is therefore, recommending a PI-Factor that reflects reasonable target which global experiences have shown are necessary to achieve these improvements. In this way, while the Company continues to hone improvements across the operational spectrum, the PI-Factor will be aligned to and factor in the major objective of JPS' Business Plan and a high-priority regulatory and policy objective.

Based on the aforementioned, JPS therefore proposes that the target be achieved over the next regulatory period, that is YET is 5 years spanning from 2019 to 2023 as well as it proposes to reduce its "inefficiencies" by 20% which implies an efficiency target (ET) of 1.9% annually applied to controllable OPEX. The ET would result in JPS' efficiency target moving from 67% to 74% by the end of 2023.

Applying the PI-Factor of 1.9%, starting with 2017 controllable operating expenses (US$M) yields the following projected operating expenditure (2019-2023):

Table 6-16: JPS OPEX Projections with productivity factor (US$'M)[35]

Operating Expenditure (US$M)	2017	2018	2019	2020	2021	2022	2023
T&D Direct Cost	*108.54*	*95.04*	*108.36*	*107.55*	*106.63*	*105.72*	*104.81*
Generation	28.13	23.96	24.85	19.74	16.77	16.84	16.92
Other Shared Costs	11.60	10.31	14.01	14.99	13.46	13.33	13.22
Non-Regulated O&M	0.70	1.08	1.38	1.07	1.25	1.25	1.25
Total	148.97	130.38	148.59	143.35	138.10	137.14	136.19
Offset	3.09	3.22	3.49	3.10	3.43	3.52	3.53
Total O&M with Efficiency Improvements	145.88	127.16	145.10	140.25	134.67	133.63	132.66

JPS believes that the projected O&M is reasonable and is consistent with achieving the initiatives outlined in the Business Plan which support furthering efficiency across its operations. This will ensure that JPS is not deprived of resources for this effort through an inappropriate PI-Factor that defeats the very purpose it is intended to incentivize.

[35] The projected operating expenditure excludes the projected Generation O&M costs for 2019-2023.

7 Quality of Service – Q-Factor

7.1 Introduction

Licence Provisions

As part of the performance-based ratemaking regime established for JPS, the quality of service regarding reliability, or Q-Factor, defines one measure of performance, leading to potential benefits or penalties to JPS.

As defined in paragraph 46(a) of Schedule 3 of the Licence, the Q-Factor is the annual allowed price adjustment to reflect changes in the quality of service provided by the Company to its customers relative to the annual target set in the five-year Rate Review determination. In essence, the Q-Factor measures the level of reliability of electricity supply to customers through three quality indices, viz, SAIFI, SAIDI and CAIDI. In realizing its effect on tariffs, the Q-Factor operates as a part of the Performance Based Rate-making Mechanism (PBRM) described in Exhibit 1 of the Licence 2016, where the rate of change in the Revenue Cap for each year will be determined through the following formula:

$$dPCI = dI \pm Q \pm Z, \text{ where}$$

$dPCI$ = *Annual rate of change in non-fuel electricity revenues; and*

Q = *the allowed price adjustment to reflect changes in the quality of service provided to the customers versus the target for the prior year.*

Exhibit 1 of the Licence further provides for the application of the mechanism as follows:

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.

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

(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

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

(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 of dividing the duration of the average customer's sustained outages (SAIDI) by the frequency of outages for that average customer (SAIFI).

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

(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 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 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%*

As outlined in Exhibit 1, the Licence provides for the modification of these three (3) indices but only after agreement between the Office and JPS.

Final Criteria

The published Final Criteria (the Criteria) from the OUR reflects the same quality indices, performance thresholds and adjustment factors as set out in the Licence.

Criterion 11 of the Final Criteria requires JPS to provide in the 2019-2024 rate review application proposed Q-factor Baseline, projected annual quality of service performance, and proposed annual Q-factor targets for each of the 12-month adjustment period, during the Rate Review period.

The Criteria also provides for one additional quality index for reporting purposes, but not as part of the adjustment factors. The Licence does not make provision for the tracking or application of Momentary Average Interruption Frequency Index (MAIFI), however, as recommended by a KEMA study in 2012, the Regulator has required that JPS record momentary interruptions and report them to the OUR as part of the regulatory reporting framework, for review and analysis. MAIFI provides information about the average frequency of momentary interruptions, 5 minutes or less, per customer, caused by the operation of an interrupting device.

JPS has certain limitations in its ability to collect MAIFI data, in that currently, the system is only capable of capturing the data at the circuit breaker and Pole Mounted Re-closer (PMR) level. This excludes interruptions at the fuse and transformer level. With the exception of these limitations, the Company will continue to provide the information as stipulated by the OUR. The collection of MAIFI data at a more granular level would require further investment in the data collection system.

The Criteria also provides for the following computations:

1) The average monthly value of SAIFI, SAIDI, CAIDI and MAIFI, based on the annual outage data sets specified above;
2) Stage restoration;
3) Daily Total Customer Count;
4) Customer Minutes Loss (CML); and
5) Other relevant information.
6) Major Event Days (MED) for reference but not will not be applied to the Q-Factor.

Annex 2 of the Criteria lists information requirements pertaining to JPS OMS data and improvements, including certain reports on outages, which have been provided within this chapter.

Regulatory Principles for Implementation

Based on paragraphs 1-4 of page 126 of the 2018 Determination Notice, for proper implementation, the Q-Factor should, in principle, be based on the following criteria:

1. It should provide proper financial incentive to deliver a level of service quality based on the customers' view of the quality of service. In this regard, it is important that random variations should not be the source of reward or penalty;
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 in accordance with the Licence;
4. It should be symmetrical in application, as stipulated in the Licence with appropriate caps or limits of effects on rates.

Consistent with the foregoing principles and paragraph 37 of Schedule 3 of Licence, the targets for the three quality indices relevant to the Q-Factor adjustment mechanism, SAIDI, SAIFI, and CAIDI, should be reasonable and achievable, taking into consideration the baseline as captured in recent historical performance, the Base Year outcomes and the agreed resources included in the Five-Year Business Plan, corrected for extraordinary events. JPS proposes to utilize the most recent three-year average of the actual reliability dataset adjusted to exclude non-reportable and IPP outages for setting the Q-Factor targets for 2019-2024. Additionally, in furtherance of transparency, JPS proposes the establishment of a clear mechanism with the Minister for the approval of Force Majeure as per Licence requirements.

Based on the 2018 Determination Notice, the OUR expressed that there is no provision for the treatment of MEDs under the Q-Factor mechanism, hence it cannot be excluded from the calculation of the reliability indices. JPS will observe the OUR's position by including MEDs in the baseline calculation and for regulatory reports henceforth.

The setting of five year targets for the three quality indices is a tedious task, especially, for CAIDI. If the rate at which SAIFI improves is greater than that of SAIDI then the CAIDI performance actually increases or appears to worsen. Hence, to overcome this, JPS has set CAIDI targets by keeping the CAIDI baseline fixed over the next five years and then deriving the SAIFI targets from the SAIDI projections predicated on the business plan. This methodology allows for the development of targets for the three indices that are fair and reasonable in keeping with the provisions of the Licence.

7.2 Overview of Reliability Programme 2014 to 2018

JPS has made significant strides in its quest to deliver high-quality, consistently-reliable electricity service to its customer base of over 640,000 customers. Since 2014, the Company has invested more than US$175 million in pursuit of this goal. The essence of JPS' reliability strategy and philosophy is summarized below:

- Employment of automated technological approaches on the T&D network;
- Enhancing the security and resiliency of the T&D network;
- Reinforcement and rehabilitation of the T&D network;
- Improvement in Outage Management and Outage Management System (OMS) data quality and accuracy;
- Optimization of asset performance through Enterprise Asset Management (EAM) thereby maximizing output over their lifecycle.

The following highlights some of JPS' major undertakings in line with the reliability philosophy:

Employment of Automated Technological approaches on the T&D network

JPS has embarked on a programme to modernize the distribution grid through the installation of Tripsaver II single-phase reclosers, communication-enabled fault circuit indicators, distribution automation (DA) switches, smart meters and single pole tripping (SPT) reclosers. JPS has installed 542 Tripsaver II devices, 385 communication-enabled fault circuit indicators, 220 DA switches, 144,721 Smart Meters, and outfitted 64 feeders with SPT reclosers, over the past five years. These devices help to avoid or eliminate sustained outages that are the result of transient faults, improve outage response by reducing patrol time, minimize the number of customers affected for main-line faults and allow for remote transferability of power supply so as to restore supply to customers promptly. The Company is also implementing an Enterprise Asset Management (EAM) system to optimize the output of major T&D facilities and equipment. Brief descriptions of the operation of these pieces of equipment and systems are provided below.

Distribution Automated Switches

These devices reduce the number of customers affected by faults on the main line and allow for faster response and restoration of affected circuits at the primary distribution level. They are pivotal to the Company's self-healing grid strategy and will further optimize the functionality of the recently acquired advanced distribution management system (ADMS). Since 2014, 220 devices have been installed on the network as follows:

- 2014 – 41 devices
- 2015 – 35 devices
- 2016 - 62 devices
- 2017 – 60 devices
- 2018 – 22 devices

Smart Fault Circuit Indicators

With the introduction of the smart fault circuit indicators (FCIs), field personnel no longer need to patrol line sections from the substation to locate faults as they can now be guided by the system controller/dispatcher on duty to the specific faulted area with this technology. Additionally, the FCIs will give a visual identification (flashing lights) to direct the crews. These devices will further optimize the functionality of the ADMS. The continued leveraging of these technologies on the network will continue to improve overall response time.

Single Pole Tripping (SPT) Reclosers

A total of 64 feeders have been implemented with SPT reclosers on the distribution network. Distribution line faults are predominately single-line-to-ground in nature and as such the faulted phase can then be isolated and the remaining phases remain in service. This functionality will allow the affected feeder to maintain supply to the customers being supplied by the unaffected phase(s). This initiative has and will continue to improve system reliability as only the affected phase(s) will experience outages.

Smart Meters

Consistent with its objective to develop a smart grid, as of February 2019, JPS has installed 144,721 Smart Meters and will continue this project more aggressively over the 2019-2024 Rate Review period. These meters will ultimately be integrated into existing OMS and ADMS, thereby providing real time outage and electrical data.

Advanced Distribution Management System (ADMS)

JPS has installed an Advanced Distribution Management System (ADMS) that has a suite of applications including Volt/Var Control, Fault location, Isolation and Service restoration (FLISR), Demand-side Management etc. With the implementation of the FLISR application across all feeders, System Controllers are now advised on optimal switching sequences to restore customers safely and in the most time efficient manner.

Enhancing the security and resiliency of the T&D network

1. The installation and upgrading of substation transformers to allow for improved transferability.
2. Voltage Standardization Programme (VSP) to standardize feeders at 24 kV voltage level. JPS completed the upgrading of the Ocho Rios, Roaring River, Duncans, Martha Brae feeders and a section of Hope 510.
3. Upgrading of the protection system for increased grid security. This is supported by improved engineering intervention on selected worst performing transmission lines.

4. With the growing penetration of renewables on the system, JPS has seen a significant increase in intermittencies affecting both the quality and reliability of supply. This has manifested itself in an increase in the number of under frequency points operating as part of the system protection, giving rise to a heightened level of customer dissatisfaction. To resolve this issue, JPS has invested in a 24.5 MW Hybrid Energy Storage Project, which is expected to rapidly deploy power to the grid where supply intermittencies create a shortfall in generation.

Reinforcement and rehabilitation of the T&D network

1. The installation of contamination sensors in targeted areas supported by the procurement of additional Washer Units to perform live line washing to address the issue of contamination.
2. Routine maintenance activities such as detailed and hazard patrols using drones, ultra-sound and infrared technology to identify and correct defects on transmission and distribution circuits.
3. Lightning mitigation activities to reduce the impact of severe lightning strikes.
4. Structural integrity improvements including pole replacement and rehabilitation.
5. Vegetation management including intensified vegetation control on the worst performing feeders. Over 300 km of #2/0 Medium Voltage Covered Conductors were installed to reduce the impact of vegetation. The Company has developed a fairly robust maintenance routine for addressing the problem of vegetation however, its effectiveness is affected by weather conditions, particularly the incidence of rainfall. Scientific approaches to controlling vegetation growth deliver more effective results over the long term. In this regard, JPS engaged the services of a Utility Arborist starting 2018, to establish an Integrated Vegetation Management Framework (IVM) to minimize vegetation related outages.
6. Distribution fuse coordination to reduce the extent of outages on line sections.

Improvement in Outage Management and Outage Management System (OMS) data quality and accuracy

1. The procurement of Arc Facilities Manager (ArcFM) to improve GIS data quality through the use of an electrical connectivity model.
2. Maximize use of OMS to facilitate quicker response to outages;
3. Implementing automatic call-out of crews/trouble-shooters for faster outage restoration;
4. Increasing crew availability and hours of coverage;
5. Institutionalizing a culture of “restore before repair” where customers are restored before repairs are conducted

Optimization of asset performance through Enterprise Asset Management (EAM)

In 2017, JPS embarked on an asset management approach to its maintenance practices in the Generation and Transmission business areas. This approach is expected to optimize resources to ensure the efficient maintenance of our assets, thereby improving system reliability in furtherance of its reliability centered philosophy. JPS will continue expanding EAM across the business to facilitate full coverage of Generation, Transmission and Distribution assets in an integrated manner to improve the lifecycle management of these assets.

With these investments, JPS has realized improvements to the tune of 30% and 37% in SAIDI and SAIFI respectively since 2014 which shown in Table 7-1. While these achievements are fairly remarkable, the programme is ongoing and the Company intends to pursue further improvements in the 2019 to 2024 Rate Review period based on the Business Plan developed to support reliability operations. Table 7-1 shows the reliability performance under the last rate review regime. The figures represent forced and sustained outages across Generation, Transmission and Distribution with the inclusion of Major Event days and the exclusion of Non-Reportables.

Table 7-1: Reliability Improvement 2014-2018

Year	SAIDI (minutes)	SAIFI (interruptions/customer)	CAIDI (minutes)
2014	2,459.55	22.388	109.86
2015	1,983.72	18.851	105.23
2016	1,993.19	17.548	113.59
2017	2,059.55	17.471	117.88
2018	1,719.65	14.141	121.61

Table 7-1 shows that there was a gradual improvement in reliability with the exception of 2016 and 2017 when JPS experienced three and four major events respectively.

In addition, in the first quarter of 2017, JPS conducted an island-wide Customer Satisfaction Survey on a random basis to solicit feedback on overall customer satisfaction with JPS' service, and specifically the reliability of electricity supply experienced over the preceding three months. The results revealed that 79% of customers believed JPS power supply is very reliable or reliable, 14% of respondents were neutral, while 5% indicated that the service was unreliable and 2% of the population did not provide a response. JPS will use this information along with technical information available and experiential knowledge about various areas, to develop its reliability improvement plan for the subject Rate Review period.

7.3 Status of Q-Factor initiatives

Since 2016, JPS has maintained a status grid on the quality of OMS data produced. This grid was presented to the OUR in the JPS Annual Adjustment 2016 filing. It addressed two important components of reliability data; namely, its accuracy and completeness. Accuracy refers to the ability of the data to represent the "real world" values that they are expected to model, while completeness measures the availability of all the relevant information required to create the model.

In the context of GIS, accuracy refers to the extent to which the GIS model represents the actual system in the field, inclusive of circuit and customer to transformer connectivity by phase. The completeness on the other hand, indicates the extent to which all the network assets inclusive of switching devices are included in the GIS model. Electric Power Research Institute (EPRI) carried out a Smart Grid Assessment study in 2012 in which the completeness and accuracy of GIS data for US utilities was assessed. The majority of utilities fell in the very functional and acceptable range of 75% - 90% data quality. Only a few utilities indicated a higher level of accuracy. Table 7-2 shows the current status of JPS' data quality as measured by its completeness and accuracy using the guidance of the EPRI study.

Table 7-2: Status of OMS data based on Accuracy and Completeness

Item	Accuracy	Completeness	Ranking WRT to Utility Best Practice
Customer –to-Feeder Mapping	99%	99%	Better than 90%
Transformer Mapping	98%	99%	Better than 90%
Transformer to Feeder Mapping	98%	99%	Better than 90%
Customer to Transformer Mapping	84%	91%	75-90%
Reporting Practice			Best/Good

The following summarizes solutions that were implemented to resolve the issues encountered:

- The procurement of ArcFM to improve GIS data quality.
- Using a daily customer count as opposed to a fixed customer count to calculate reliability indices.
- OMS Integration Modifications such as the automatic freezing of outages to prevent roll up, integration of SCADA enabled devices and routine system updates.
- Ongoing/additional training for JPS teams (controllers, dispatchers, field crews etc.)

Evidence indicating resolution of OMS/GIS Interface Issues

JPS has resolved all issues with regards to the GIS/OMS interface. The following were initiatives implemented:

- The GIS/OMS extractor was re-developed to account for ArcFM updates on the GIS database.
- All feeders were updated in the OMS as of 2018.
- JPS takes a lifecycle approach by continually updating the OMS on a fortnightly basis.

7.4 Establishing a Q-Factor Baseline

The implementation of the Q-Factor PBRM adjustment mechanism has long been delayed on account of the requirement to establish a reliable baseline based on accurate and credible outage information from which changes in the quality of service can be measured. This is a crucial step in the process of implementing the mechanism as it has implications for the determination of JPS' Annual Revenue Target (ART) as at the completion of the first year of its operation. An overly favourable target could result in unjustified incentives for the utility, while an unfavourable one will result in unwarranted penalties. It is therefore crucial that the baseline is founded on accurate supporting data, reliably reported by a systematic process that can faithfully deliver reliable and credible information consistently. In recognition of this requirement, JPS has spared no effort in implementing the recommended system, an OMS, and has taken steps to improve the quality of data that is generated by the system over the past five years. Alongside the OMS, the Company implemented a GIS system and most recently ArcFm, to improve the quality of information generated by the system. The Company also developed a business process around reliability management to ensure that the process was given the requisite level of focus in order to generate the desired results. This process has been one of the strategic imperatives of JPS over the past five years and the amount of resources dedicated to the effort is testimony to its importance.

JPS believes the quality of information being generated by the OMS is of a sufficiently high standard to support the establishment of a credible and reliable baseline for the Q-Factor targets. This assertion is made against the background that there have been progressive improvements in the quality of data generated by the system since the implementation of the OMS in December 2013. These improvements were secured by a process of diligently identifying errors and correcting them through system-based applications both within and outside of OMS, procedural modifications and the implementation of best practice methodologies. Today there remains a need to calibrate raw system data to improve its credibility. However, the Company continues the process of resolving the issues with the aim of removing human intervention from the data generation process, in the medium to long-run. Table 7-3 indicates the extent of improvements achieved over the period. As depicted, there are no duplicate outage events, incorrect classification of outages and no discrepancies related to outages with negative durations except for one instance in 2016, which was corrected in 2017. The 824 events with "NULL" for 2017 represented approximately 1% of the total events. The error was introduced when the data was pulled from the OMS for selected single restoration stage events. This problem has since been resolved.

Table 7-3: Evidence showing correction of all OMS Issues from 2016-2018

Discrepancy	2016	2017	2018
Outage Events With Negative Duration	1	0	0
Duplicate Outage Events	0	0	0
Incorrect Classification of Outages as Momentary or Sustained	0	0	0
Events with "NULL" data points.	0	824	0

In its 2017 and 2018 Annual Review Determination Notices, the OUR recognized JPS' proactive approach to eliminating data issues identified and noted that such approaches "have progressively yielded notable improvements in the quality of the annual outage data in successive years." The regulator went on to note that there were issues, both lingering and new, that are still having an effect on outage data and listed 12 issues spanning three categories, viz, Outage Data Related Issues, Reliability Measurement and Indicators, and System Reliability Performance Improvement. The latter category consists of three items that are suggestions focused primarily on the clarity of JPS' reliability planning and the effects of project deployment. The reliability measurement indicators category had three items also which reinforce the requirements of legislative and regulatory documents in relation to the classification of reliability data. JPS accepts these positions and has made amendments to the calculation of the reliability indices to incorporate the OUR's suggestions. The data related issues are therefore five items and these are addressed in Table 7-4.

Table 7-4: JPS response to OUR concerns regarding data quality

Item Number	OUR Concern	JPS' Response:
1a.	*824 events with "NULL" in the "Restoration Stages" category;*	These 824 events represent approximately 1% of the total events. The error was introduced when the data was pulled from the OMS for selected single restoration stage events. However, this problem has been resolved.
1b.	*One outage record reflected in raw dataset (Annex A of the Annual Filing) did not appear in the calibrated dataset (Annex B of the Annual filing)*	This item, identified as Record ID #472270001 or outage event # 472270, is a momentary outage. This outage came directly from SCADA in the raw dataset with a start time that is fourteen (14) seconds later than the actual restoration time. This would have been automatically determined as being an invalid SCADA outage, hence not represented in the calibrated data set.
2a.	*The customer count for the Q factor outage data not in alignment with customer counts reported by other business units.*	Customer count values submitted for the Q-factor dataset are daily real time values extracted from banner CIS. However, for other reports, customer count values are pulled from CIS at varying intervals and would vary depending on the period (daily average, weekly average, monthly average or annual average) for which these reports were run in Banner. JPS will standardize the customer count reporting process across all business units.
2b.	*Variation of daily System Customer count (Up to 4.4% of the average count).*	Further analysis of the data shows six (6) days where customer count varies by more than one thousand (1000) & nineteen (19) days where customer count varies by more than five-hundred (500). Customer count data is pulled real time from Banner CIS daily which includes suspended accounts. Due to the high level of daily disconnection/reconnection we experience an average of 2,000 accounts in suspended state. At times, the normal daily "move in/move out" process associated with disconnection/reconnection is delayed or not effected in banner CIS due to system challenges. The spike seems to occur when two or more delayed daily move in/move out are run at once. This issue has been resolved.

3.	*No rationale given for outages made Non-reportable.*	Going forward JPS will provide the reason in the outage dataset for which outages were made non-reportable in accordance with the "Non-reportable data dictionary" approved by the OUR.
4.	*Outage data included in other Regulatory reports incongruent with Outage data reported by the Reliability Team.*	In order to prevent uncertainty regarding the outage dataset, JPS will ensure consistency in outage data submitted to the OUR across all business units.
5.	*JPS does not include the full range of outage information for each month to the OUR by the stipulated reporting deadline.*	Monthly outage data required by the OUR will be sent within the fifteen (15) days stipulation.

JPS recommends that the baseline for the three reliability indices, SAIDI SAIFI and CAIDI, be established based on the most recent three years (2016-2018) of outage data submitted to the OUR. JPS recognizes the OUR's assertion that the Licence does not provide for the exclusion of MEDs and Force Majeure events that do not strictly accord with Condition 11, paragraph 2 of the Licence. Additionally, work is ongoing to resolve data issues which will result in the further improvement in the accuracy of the data. With these acknowledgements, JPS recommends that the Q-Factor baseline be established using the data submitted for 2016 to 2018, including the outages attributed to MEDs. Use of this dataset as the baseline for setting the Q-Factor targets provides a basis for the establishment of reasonable and achievable indices against which JPS' performance can be measured.

7.4.1 Exclusion of IPP Forced outages & approved Force Majeure Events

Based on JPS's calculations in relation to forced outage data over a three-year period (2016-2018), IPPs accounted for approximately 25% and 28% of Generation SAIDI and SAIFI respectively. It is clear that system reliability is impacted negatively by IPP inefficiencies and so special care must be taken to exclude their impact from the calculation of the quality indices required by the Licence going forward. As enunciated by JPS in several regulatory filings and affirmed by the OUR in the Annual Review 2018 and Extraordinary Rate Review Determination Notice, both JPS and the OUR agreed on four principles which the Q-Factor should satisfy, one of which states as follows:

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

This criterion specifically requires the exclusion of outages caused by IPPs from the derivation of the Q-Factor.

Also according to section 4.3.4 of the Final Criteria "*JPS shall not be penalized under the Q-Factor mechanism for IPP generation outages, unless the cause of the IPP generation outage/s is/are due to fault/s on the part of JPS*." Hence, JPS will exclude IPP generation outages in line with the conditions stated in this criterion.

In like manner, JPS anticipates that the OUR will have no objection to the exclusion of sustained forced outages caused by approved Force Majeure events from the derivation of the Q-Factor indices. Based on the commentary provided in the Annual Review Determinations issued by the OUR over the past four years, no explicit concerns have been raised by the OUR in relation to Force Majeure impacting outages except that JPS has not presented relevant approvals to support outage data presented in its filings. JPS therefore concludes, that the agreed principle will be observed in practice.

7.4.2 Exclusion of Non Reportable Outages

It is industry best practice to utilize data calibration as a means of ensuring that outage data is an accurate representation of the outage event. In line with industry best practices a "Rules Based Non Reportable Data Dictionary" was developed by JPS and presented, discussed and accepted by the OUR.

While the OUR offered no-objection to JPS' rules based calibration, on page 143, paragraph 2 of the 2018 Annual Review Determination Notice the OUR states that, they are not clear on the basis on which some outages were made non-reportable. JPS has put a justification for all Non-Reportable outages in the 2018 dataset submitted in 2019.

Data Calibration Practices: "Rules Based" Calibration (Data Dictionary) Update

Most utilities have some process for verifying outage events prior to it being used for the calculation of reliability indices (i.e. data is calibrated). Event verification and calibration are generally considered important processes for reliability reporting. Outage validation and adjustment is a routine process in utilities and for JPS it is no different. Calibration is done when outage characteristics are abnormal. Reported outages that have major discrepancies when compared with the actual outage event are either adjusted, corrected or made non-reportable.

In line with aforementioned, JPS developed a "Rules Based Data Dictionary" which outlines the criteria that must be met for an outage to be excluded from the dataset. This document was shared with the OUR in 2017, and subsequently approved for the operation of the exclusion mechanism. Non-Reportable outages are classified under the following categories:

- Excessive Customer Count/ (OMS/GIS Glitches)
- Customer related/Non-Utility Related Outage
- Incorrect Customer to device mapping
- Operator Error

The following provides an overview of the Rules Based Criteria:

Rule 1 - Excessive Customer Count/OMS/GIS Glitches

Conditions:

1) Fuses where the customer count is greater than or equal to 120% of the device capability. The Outage is excluded.
2) Assignment of loads to a transformer in excess of 120% of its capacity. Corrective action is the automatic limiting of loads based on the transformer capacity. The outage(s) is/are adjusted and remains as reportable.
3) Opening of a SCADA device, trigger OMS to infer that the start time is equal to the earlier start time of that of a previously unverified or unfrozen downstream outage. For all instances of outage on a SCADA device, automatically, start time and end time is taken from the actual time of operation reported by ICCP and initial staged time maintained for downstream outage. The outage(s) is/are adjusted and remains as reportable.
4) Difference of 10 minutes between OMS outage completion time and field crew mobile tablet completion time. The outage completion/restoration time is automatically adjusted to crew completion time as recorded by mobile tablet. The outage(s) is/are adjusted and remains as reportable.

Rule 2- Customer related/Non-Utility Related Outage

Outages where the Secondary causes are: premises found locked and the customer outage cannot be verified, premises not found, defective customer equipment and disconnection are made non-reportable.

Rule 3- Incorrect Customer to device mapping

When a customer is incorrectly represented in GIS on the wrong transformer, feeder or parish, the customer is transferred to the correct device and the original outage is made Non Reportable. OMS generates a new outage.

Rule 4-Operator Error

If outage mismanagement results in an outage greater than 50% of actual SAIDI, the outage is made non-reportable. Such events include Load Transfers, the use of Mobile Transformers and Protection & SCADA functional checks. Ongoing refresher training and operator performance appraisal is carried out to minimize these occurrences.

Report on Non-Reportable Outages

In 2019, JPS performed an internal audit of all Non-Reportable for the 2016-2018 baseline dataset to ensure that there is proper justification in accordance with the OUR approved “Rules based Data Dictionary”. Table 7-5 shows a summary of the audit:

Table 7-5: Summary of Non-Reportable Outages

	# Of Outages Made Non-Reportable based on:				**# Of Outages that did not meet criteria.**		
Year	**Rule 1**	**Rule 2**	**Rule 3**	**Rule 4**	**Planned outages reported as Non-reportable**	**Reportable**	**Total # of Non-Reportable Outages reported to the OUR**
2016	698	548	1219	300	-	2,116	4,881
2017	1117	818	338	170	5	2,416	4,864
2018	869	1505	107	182	-	-	2,663

Table 7-5 shows a progressive decline in the number of non-reportable outages from 2016 to 2018. For 2016, there were 2,116 outages with an associated SAIDI and SAIFI of 62.944 minutes and 0.211 times that did not meet the criteria. For 2017, there were 2,416 outages with an associated SAIDI and SAIFI of 146.189 minutes and 0.672 times that did not meet the criteria as approved by the OUR and hence is re-classified as reportable. This high number of misclassification took place during a period where the “Rules based” data dictionary was being developed and finalized with the OUR.

For 2018, there are 2663 outages made non-reportable with no misclassification. Ongoing GIS/OMS feeder updates such as the correction of phasing data, customer-to-transformer and transformer-to-feeders mapping and refresher training of system operators will ensure that the number of Non-Reportables continue to decrease progressively.

7.4.3 Treatment of Major Event Days (MEDs)

In recognition of the fact that there are no regulatory instruments that allow for the use of a MED performance indicator in the Q-Factor calculation, the submission of the annual reliability outage dataset, for the legal and Q-Factor regulatory requirements, will not exclude MEDs.

However, JPS adopts industry standards to allow for proper benchmarking. The Institute of Electrical and Electronics Engineers (IEEE) 1366-2013 is the standard JPS adopts to define MEDs.

The standard defines a major event as follows: "An event that exceeds reasonable design and or operational limits of the electric power system." Moreover, a Major Event Day (MED) as "a day in which the daily SAIDI exceeds a MED threshold value." (IEEE Power & Energy Society 2012). The standard states that activities that occur on MED should be separately analyzed and reported.

In line with the aforementioned, JPS will have dialogue with the Ministry to establish a framework to properly adopt industry practices for uniformity in the computation of the reliability indices.

7.5 Q-Factor Reliability Benchmark

7.5.1 Benchmarking SAIDI, SAIFI and CAIDI

The IEEE 1366 is the standard for Electric Distribution Reliability Indices. This standard recommends the use of the SAIDI, SAIFI and CAIDI indices to track reliability. These indices are calculated using only unplanned, sustained outages, where a sustained outage is defined as an interruption that lasts for more than five minutes (IEEE Power & Energy Society 2012). According to Siemens Power Academy TD, the tracking of reliability metrics allows utilities to:

- Identify positive or negative trends in reliability.
- Report performance to regulatory bodies.
- Benchmark against other utilities.
- Identify worst performing circuits to better make reliability investments.

The IEEE standard acknowledges that there are factors that cause variation in the reported indices among utilities, some of which are:

- Level of automated data collection.
- Geography.
- System Design.
- Data Classification (Use of Major events, planned interruptions etc.).

The IEEE standard therefore recommends the exclusion of Major Events for uniformity in the computation of the reliability indices. It defines a Major Event as *"An event that exceeds reasonable design and/operational limits of the electric power system. A Major Event includes at least one Major Event Day."* (IEEE Power & Energy Society 2012) Examples of a Major Event are widespread outages caused by hurricanes, flood, earthquakes, windstorm.

Based on industry practice, a major event typically includes the following:

- Extensive damage to the electric power system.
- More than a specified percentage of customers simultaneously out of service.
- Service restoration several times longer than the average.

Also according to Siemens Power Academy TD, some utilities have a 'storm' definition. This definition typically includes characteristics such as:

- At least 10% of the customer base being interrupted.
- All customers being out of supply for at least 24 hours.
- Damage exceeds design limits.
- Weather classification.
- State of emergency declared.

JPS has adopted the practice of Force Majeure and Major System Failures in line with industry standards and as mandated by the Electricity Act, 2015 (the Act). These practices may be analogous to IEEE's definition of a 'Major Event' and other utility-based definition of a storm event, however, the current definition for major system failure, as captured in the Act is far more restrictive than the IEEE standard. Section 45(16) (a) of the Act defines a major system failure as a system failure that has not been planned by the System Operator, affects at least one thousand customers and has a duration of at least two hours. JPS believes the appropriate standard should be that proposed by the IEEE and currently in use in major utility operations in North America.

It is also noteworthy that the Licence does not recognize the exclusion of MEDs from the computation of the Q-Factor indices. It is important to benchmark the Company's performance against other utilities operating under similar conditions. Furthermore, the operation of the Q-Factor mechanism should recognize international best practice to help to develop a gauge of the kinds of improvements that may be possible given similar circumstances. While the Company will adhere to the OUR's mandate, it will continue to seek to have the relevant amendments in the regulatory framework in line with IEEE methodology.

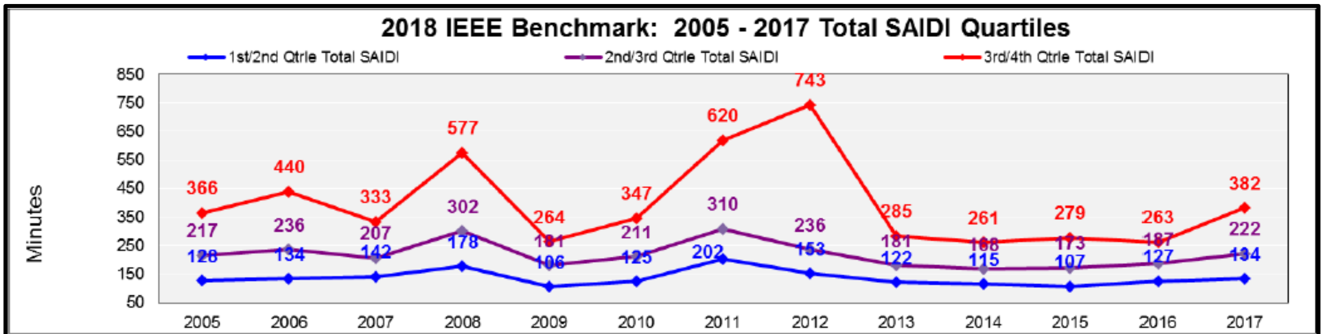
JPS proposes that in line with international utility best practices, the definition of "Major System Failure" should also be consistent including the requirement that "*At least 10% of the customer base is affected"*. This will allow for fair treatment for factors affecting performance that are outside of JPS' control. JPS, however recognizes the challenge faced by the OUR in that it is constrained by the Legislative and Regulatory Framework currently in place. The objective of amending the definition of Major System Failure, therefore becomes one which JPS will pursue with the Ministry.

As stated previously, the tracking of reliability indices allows for the benchmarking of performance against other utilities. In 2018, the IEEE Distribution Reliability Working group conducted a study which benchmarked reliability indices across ninety-three (93) utilities across North America. The analysis is based on thirteen (13) years of data from 2005 – 2017. Two sets of indices are shown:

- Total – Includes Major Events
- IEEE – Excludes Major Events

Figure 7-1 shows SAIDI performance among utilities in North America:

Figure 7-1: 2005 – 2017 Benchmark for SAIDI (Without IEEE Adoption)



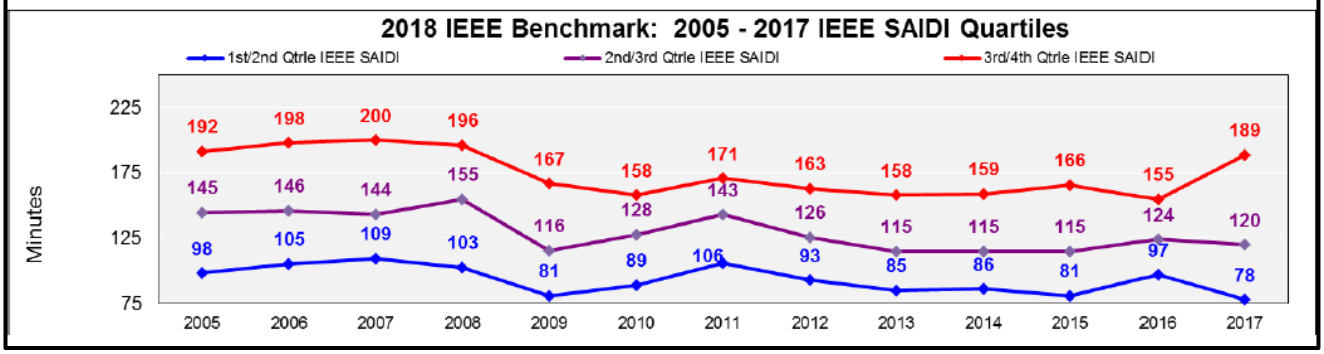
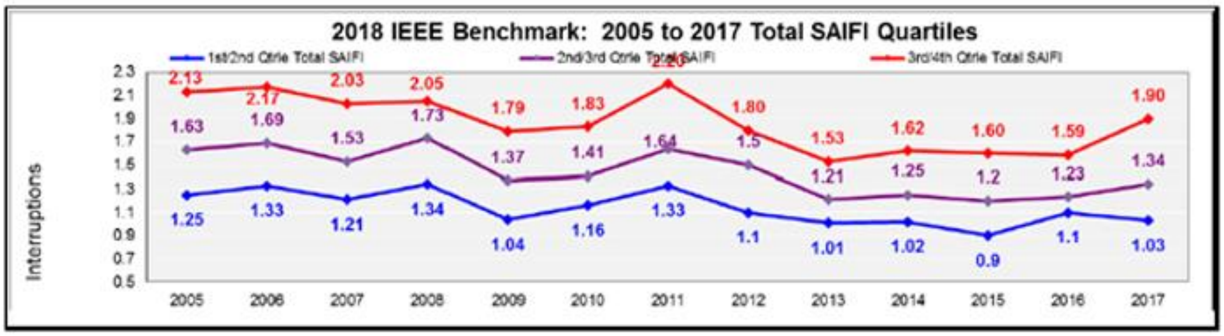


Figure 7-2: 2005-2017 IEEE Benchmark for SAIDI (With IEEE Adoption)

Figure 7-1 and 7-2 shows that as of 2017 all of the 93 North American Utilities that participated are operating under 400 minutes with and without IEEE standard adoption. While comparatively JPS is performing significantly less efficiently than these utilities in respect of SAIDI, it is instructive to note the difference between the IEEE and total results for each Q-Factor index.

Figures 7-3 and 7-4 shows a comparison of SAIFI performance:

Figure 7-3: 2005-2017 IEEE Benchmark for SAIFI (Without IEEE Adoption)



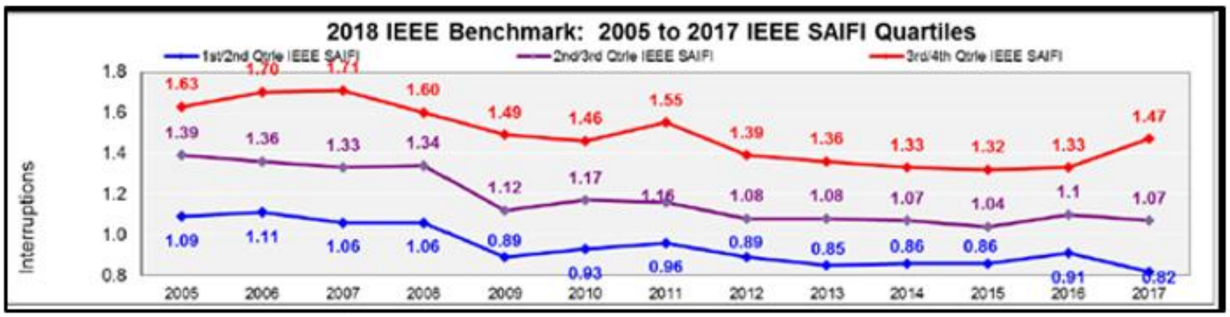
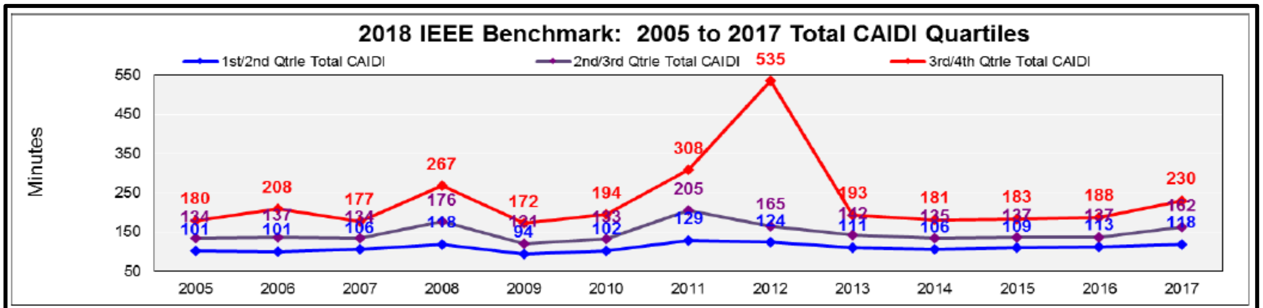


Figure 7-4: 2005-2017 Benchmark for SAIFI (With IEEE Adoption)

Figures 7-3 and 7-4 shows that as of 2017 all of the 93 North American Utilities that participated are operating under 2 sustained interruptions/customer with and without IEEE standard adoption.

Figures 7-5 and 7-6 shows a comparison of CAIDI performance:

Figure 7-5: 2005-2017 Benchmark for CAIDI (Without IEEE Adoption)



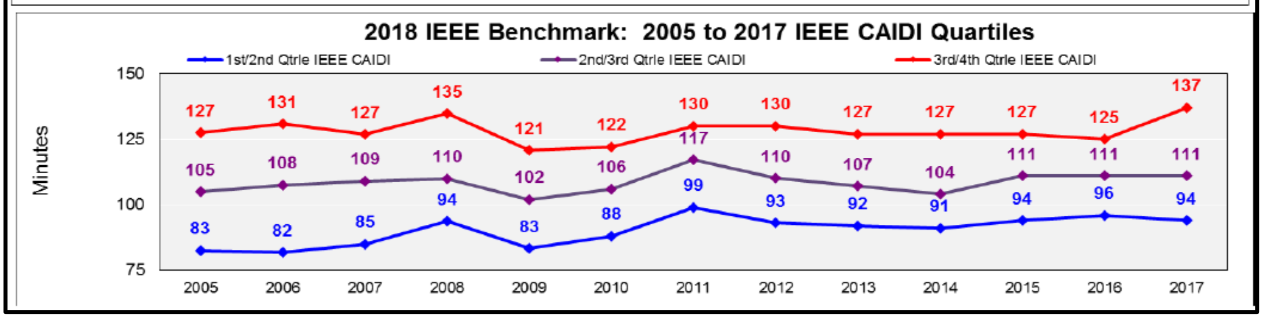


Figure 7-6: 2005-2017 IEEE Benchmark for CAIDI (With IEEE Adoption)

Figures 7-5 and 7-6 shows that all utilities are operating under 250 minutes with and without IEEE standard adoption. Based on the comparison JPS is operating within the second quartile for CAIDI performance.

7.6 The Cost of Unserved Energy

JPS commissioned a cost of unserved energy report on the Jamaican electricity sector through the MRC Group in 2017. The report was completed in December 2018 and updated in September 2019. The report presents some informative findings.

The COUE is an indicator of the economic value of the cost of electricity interruptions to customers and the Jamaican economy. The consultants used a range of methodologies to develop a perspective on the value Jamaicans placed on electric service interruptions in order to generate a reliable estimate. This is particularly important, as a similar study had not been commissioned by the sector for the 15 years preceding the December 2018 report. Also, with the introduction of the Q-Factor mechanism and a more sensitive customer base, given improvements in living standards and the increasing dependence on electronic equipment and gadgets to sustain and support those standard, plans for reliability improvement must take into account the value the society places on the consistency of electricity supply. Thus, these values were used to inform the investment decisions to improve reliability which ultimately seek to optimize the reliability of the network. The value will justify the urgency of improving certain parts of the grid due to the relatively high level of outages experienced.

The COUE report recommended a system average of 4.77 US$ per kWh. JPS does not interpret this number as a recommendation for increases in electricity rates but sees it as a metric to improve the quality of service provided to customers in the short to medium term. Table 7-6 shows the capital that will be invested to improve the quality of service to our customers.

Table 7-6: Annual capital investments required for reliability improvement

		2019	2020	2021	2022	2023	Total
#	**Reliability Impacting Projects**	**CAPEX (US$' 000)**	**CAPEX (US$' 000)**	**CAPEX (US$' 000)**	**CAPEX (US$' 000)**	**CAPEX (US$' 000)**	**CAPEX (US$' 000)**
1	**Voltage Standardization Programme**	**$ 1,975.00**	**$ 3,496.00**	**$ 3,254.00**	**$ 4,239.00**	**$ 4,628.00**	**$ 17,592.00**
2	**Grid Modernization Programme**	**$ 1,784.00**	**$ 2,092.00**	**$ 2,827.00**	**$ 2,968.00**	**$ 2,864.00**	**$ 12,535.00**
3	**Distribution Structural Integrity**	**$ 3,771.00**	**$ 4,489.00**	**$ 4,564.00**	**$ 4,763.00**	**$ 4,822.00**	**$ 22,409.00**
4	**Distribution Line Reconductoring and Rehabilitation**	**$ 2,000.00**	**$ 1,345.00**	**$ 2,173.00**	**$ 2,084.00**	**$ 2,405.00**	**$ 10,007.00**
6	**Transmission Structural Integrity**	**$ 1,800.00**	**$ 1,770.00**	**$ 1,870.00**	**$ 1,858.00**	**$ 1,839.00**	**$ 9,137.00**
7	**Substation Structural Integrity**	**$ 1,553.00**	**$ 1,700.00**	**$ 1,753.00**	**$ 1,830.00**	**$ 1,870.00**	**$ 8,706.00**
8	**Energy Storage**	**$ 9,110.00**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9,110.00**
9	**Michelton Halt (LILO)**	**$ 1,817.00**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,817.00**
11	**Distribution Transformer Replacement/Upgrade Programme**	**$ 3,008.00**	**$ 2,848.00**	**$ 2,243.00**	**$ 1,635.00**	**$ 361.00**	**$ 10,095.00**
12	**Bellevue/Roaring River 69 kV**	**$ -**	**$ 500.00**	**$ 3,170.00**	**$ 3,089.00**	**$ -**	**$ 6.759.00**
	Grand Total	**$ 26,818.00**	**$ 18,240.00**	**$ 21,854.00**	**$ 22,466.00**	**$ 18,789.00**	**$ 108.167.00**

Based on the capital projects stated in Table 7-6, the expected SAIDI improvements to be gained based on the reliability drivers are shown in Table 7-7

Table 7-7: SAIDI Improvements – CAPEX projects (subset)

		2019	2020	2021	2022	2023	Total
#	**Reliability Impacting Projects**	**SAIDI (mins)**	**SAIDI (mins)**	**SAIDI (mins)**	**SAIDI (mins)**	**SAIDI (mins)**	**SAIDI (mins)**
1	**Voltage Standardization Programme**	0.379	4.661	6.051	8.449	13.208	**32.748**
2	**Grid Modernization Programme**	18.267	17.280	23.783	13.096	16.397	**88.823**
3	**Distribution Structural Integrity**	32.030	11.284	8.753	7.490	4.772	**64.329**

The complete list of all reliability impacting projects and their benefits are provided in Appendix B to the Rate Case Filing (Annex II). The benefits were derived based on the mathematical analysis explained in Section 7.9.

Table 7-8 shows the annual expected SAIDI and SAIFI over the five-year period based on JPS' capital expenditure and O&M activities. As stated earlier, the SAIFI improvement is found by keeping the CAIDI fixed and deriving the SAIFI from the SAIDI calculated and the fixed CAIDI.

Table 7-8: Expected Quality of Service Performance

Year	Expected Annual SAIDI improvement (mins)	Expected Annual SAIFI improvement (interruptions/customer)
2019	100.961	0.793
2020	127.147	0.999
2021	85.423	0.671
2022	64.927	0.510
2023	78.778	0.619

7.7 Computation of Q-Factor

The establishment of a credible and reliable baseline is the most important step in the implementation of the Q-Factor adjustment mechanism. This is because the baseline becomes the benchmark against which targets will be established. As outlined in Section 7.4, JPS recommends that the Q-Factor baseline be established using the Outage dataset submitted for 2016 to 2018, modified to include outages attributed to MEDs, exclude IPP outages and justified non-reportable outages. This recommendation is made consistent with pronouncements made by the OUR in the Annual Review Determinations regarding the exclusion of MEDs (falling outside the definition of Major System failure), force majeure events not approved by the MSET and JPS Generation outages, its acceptance of data calibration in principle and the exclusion of IPP forced outage events. JPS further stated that the use of this dataset as the baseline for setting the Q-Factor targets provides a basis for the establishment of reasonable and achievable indices against which JPS' performance can be measured. Table 7-9 provides a clear representation of the computed baseline.

Section 7.8 and Section 7.9 outline the forecast reliability indicators and proposed targets JPS considers to be fair and reasonable over the 2019 to 2024 Rate Review period.

7.8 Forecasting Reliability Indices for 2019-2024

The forecasting process originates with the establishment of the baseline, the principles underlying which both JPS and the OUR have developed agreement. However, estimating the most likely impact that a project will have on the baseline and accumulating the individual effects to derive a combined impact on the baseline can impose a technical challenge to the process while maintaining the objective of proposing reasonable and achievable targets, as per the Licence.

Cost estimation is an important part of the business planning process and given that business planning is a routine part of the commercial activity of a business, experience shows that there is a high propensity for estimates to vary from actual expenditure. In the context of setting the targets for the Q-Factor, the process was constrained by having an estimated improvement for each project then translating those improvements into reliability indices. Taking into consideration that each project is being implemented in a dynamic environment that may have inherent limitations embedded therein, the implementation of multiple projects may not realize results that are discreetly incremental but instead generate sub-optimal outcomes owing to the physical configuration of the power delivery system and also environmental factors. Since JPS is developing this process for the first time, the projected impact per projects for the five years, might be different once materialized.

One of the underlying principles of the establishment of the Q-factor adjustment mechanism is that it *"...should provide the proper financial incentive to encourage JPS to continually improve service quality. It is important that random variations should not be the source of reward or punishment."* This principle underscores the need for the target to be set at a level where it remains within the reach of the utility but provides a stretch factor that requires improvement on current performance. The eventual outcome is one determined by prudent judgement which balances the need for improved service to customers, particularly in relation to incremental investments on their behalf with the Licence requirements for reasonable and achievable targets.

The absence of the IRP results to support the planning process has negatively impacted the process. In fact, it is a major deficiency in the Rate Case Filing development processes. It is JPS' submission that based on paragraphs 12, 13 and 17 of Schedule 3 of the Licence, it permits JPS to update its filing to accommodate the results once a sufficiently robust IRP is completed. The failure to deliver the IRP as required resulted in the Company choosing projects for implementation which might irrelevant when the IRP becomes available. The planning model requires the insight of the prescribed IRP for ensuring credibility, fairness, objectivity and a shared platform for good decision making in the rate review process to benefit both the customers and JPS.

JPS' Investment Plan outlines a comprehensive level of detail for the projects, budget and an estimated improvement identified in Table 7-6 which will have an impact on the reliability indices. The expected impacts on the reliability would have examined the historical performance as well as international experience. The projects are primarily owned by the Generation, Transmission and Distribution functional areas of the Company.

As a general rule, maintenance projects are not assumed to have a permanent impact on the reliability indices and would not generate step reductions in the reliability target. Typically, Maintenance Projects are intended to maintain the status quo. There are, however, instances in which a maintenance activity (for example Vegetation Management) will produce step changes in the reliability output and in such instances the Investment Plan recognizes reductions in the SAIDI and SAIFI over the rate review period. The benefits to be derived from the retirement of aged Generation units are also factored in the derivation of the reliability benefits to be experienced over the rate review period. Table 7-10 summarizes the impact of projects on the baseline and sets the basis for proposing targets for the rate review period.

It should also be noted that some projects in the Investment Plan are justified, not necessarily, based on reliability impact but rather based on condition and the level of risk to grid security. For example, the replacement and upgrading of substation transformers may not necessarily result in a direct improvement in reliability however if the asset is past its useful life and in poor condition, then the probability of failure is high and the risk to the grid may be severe hence the asset must be replaced. Some projects also enable JPS to be in conformance with the requirements of the T&D Grid Codes.

7.9 Proposed Q-Factor Targets for 2019-2024

JPS imposed the anticipated outcomes from the implementation of the projects captured in the Investment Plan to develop an adjusted view of the potential for improvement in service reliability.

A two-pronged engineering analysis approach was used to develop the targets suggested in this section. The DigSilent engineering modelling tool was used to assess the impact of projects that resulted in improvement to network infrastructure, for example transformer upgrades, new transmission lines and a mathematical calculation developed to estimate the level of improvement all other projects would provide based on expenditure.

The reliability targets were developed utilizing the methodology outlined below:

1) Generate Reliability baseline using an average of three sequential years' data (2016-2018). The following exclusions were made:
    - 2016-2018 Forced Outages due to Independent Power Producers (IPPs);
    - Non-reportables as defined by the "Rules based" data dictionary.

    The following were included:
    - Major Event Days (MEDs) were included since there is no allowance for excluding MEDs under the Q-Factor mechanism;

The treatment of Force Majeure is under discussion with the Ministry of Science Energy and Technology (MSET) to establish a mechanism for the approval as per Licence requirements.

A tabulated form of the baseline calculation is shown in Table 7-9:

Table 7-9: Calculation of Baseline

	Reportable SAIDI (mins) (MED included)	Reportable SAIFI (times) (MED included)	IPP SAIDI (mins) (Excluded)	IPP SAIFI (times) (Excluded)	SAIDI (Did not meet data dictionary criteria - included)	SAIFI (Did not meet data dictionary criteria - included)	SAIDI (mins)	SAIFI (times)
2018	1,719.654	14.141	27.716	1.127	-	-	1,691.938	13.014
2017	2,059.545	17.471	19.719	1.609	146.189	0.672	2,186.015	16.534
2016	1,993.191	17.548	13.979	0.813	62.944	0.211	2,042.156	16.946
Average							**1,973.370**	**15.498**

Table 7-9 shows the SAIDI and SAIFI for 2016-2018, which was used to calculate the baseline. The average for all three years is 1,973.370 minutes, 15.498 times and 127.334 minutes for SAIDI, SAIFI and CAIDI respectively.

1) Derive the expected percentage improvements to be achieved by the various capital and maintenance strategies over the next five years utilizing the DigSilent software and mathematical modelling. The expected improvement is 457.236 minutes (See Appendix B – Annex II for analysis)
2) Keep the CAIDI baseline fixed at 127.334 minutes or 2.12 hours as the annual target over the rate review period.
3) Derive the SAIFI target by transposing for SAIFI utilizing the equation for CAIDI as described in Exhibit 1 of the Licence.

It is important that there is transparency in JPS' reliability improvement projections in the Investment Plan so that, not only the OUR, but all stakeholders understand and are confident in the fairness of the Q-Factor targets projected. Hence, JPS has appended the analysis and assumptions for the benefits to be gained from the reliability-impacting projects.

DigSilent Modelling:

DigSilent Powerfactory is a load flow software that has a number of tools including a tool for Reliability Analysis. The reliability analysis tool was used to determine the expected improvement for some projects. Historical data such as the failure frequency, outage duration and customer count per feeder are inputs for the model.

Projects and associated electrical data is modelled, the calculation run and the resulting reliability indices observed. It is assumed that newly commissioned assets will have zero (0) failures for the year subsequent to installation. In addition, these calculations are run under normal network conditions.

Some projects yielded no improvement in reliability for example some transformer upgrades, however these projects are justified based on their risk to grid security, the condition of the asset, improvement in flexibility for load transfers etc.

Table 7-10 illustrates the proposed Q-Factor targets for the next five years based on JPS' Investment Plan.

Table 7-10: Proposed Q-Factor Targets for 2019-2023

YEAR	SAIDI (minutes)	SAIFI (interruptions/customer)	CAIDI (minutes)	% Improvement In SAIDI over previous year
Baseline (3-Year Average)	1,973.37	15.50	127.33	
2019	1,872.41	14.70	127.33	5%
2020	1,745.26	13.71	127.33	7%
2021	1,659.84	13.04	127.33	5%
2022	1,594.91	12.53	127.33	4%
2023	1,516.13	11.91	127.33	5%

8 System Losses – Initiatives and Targets

8.1 Introduction

This chapter presents overview of the system performance for the last rate review period, ongoing activities with respect to the system losses reduction objectives by the Company and other stakeholders, and presents JPS' proposals with respect to the system losses reduction initiatives and performance targets for the 2019-2023 rate review period.

Licence Provisions

The Licence (2016), at paragraph 37 of Schedule 3, provides for the setting of targets to measure JPS' performance tied to the level of system losses.

System losses are the difference between the energy generated by the system and the energy sold to customers. System losses can be split into two components: technical losses and non-technical losses. Technical losses refer to system losses related to physical properties of the power system and may occur due to energy dissipation in transmission and distribution lines, and equipment used for transmission, transformation, and distribution of energy. Non-technical losses on the other hand are caused by factors that are external to the power system's physical properties. These primarily consist of power theft, with a less substantial amount attributed to metering inaccuracies, unmetered energy, errors in billing and recordkeeping.

Furthermore, paragraph 38, Schedule 3 in the Licence states that targets for losses are to be set based on rolling 10-year periods, broken out year-by-year. The concept of the rolling target is intended to provide JPS with a benefit when targets are exceeded, which JPS can accrue over a period longer than one (1) year. It also stipulates that the targets are to be "reasonable and achievable, taking into consideration the Base Year, historical performance and the agreed resources included in the Five Year Business Plan, corrected for extraordinary events".

The calculations to implement the Licence provisions result in JPS receiving a benefit or penalty for each of three components:

- Technical Losses as compared to target
- Non-Technical Losses that are within the control of JPS, compared to target
- Non-Technical Losses that are not totally within the control of JPS, compared to target, as adjusted for a "Responsibility Factor".

The percentage by which JPS exceeds or fails to meet the targets is multiplied by the Annual Revenue Target (ART) from the previous year. As a result, variances in losses compared to targets lead to penalties or benefits to JPS on the order of $4.5 million USD[36] for each 1% variance, for losses categories within the control of JPS, or $4.5M times the Responsibility Factor for categories not totally within the control of JPS.

[36] Based on an Annual Revenue Target on the order of $450 million USD

When losses are avoided, the financial impact depends on whether the avoided losses lead to reduced load (for example, reduced technical losses, or reduced non-technical losses through theft elimination) or increased revenue (through reduced non-technical losses that convert to regularized sales). In the former case, the cost savings is largely avoided fuel or IPP purchases, and in the latter it is increased revenue for both non-fuel rates, and the fuel component of rates. Either case benefits the overall system cost profile, and the rates for other customers.

Principles for Implementation

The reduction of system losses is a significant opportunity to improve efficiency, quality of service and lower the cost of electricity in Jamaica. This has many benefits for the utility, its customers and the competitiveness of the country. Comprehensive reviews of international experience have shown that achieving sustainable loss reduction is challenging and requires significant investment and collaboration between the Government, utility and other stakeholders including customers.

The Amended Electricity Licence 2016 (the Licence) embraces the shared approach between the utility and the Government in regards to addressing system losses. System losses are split into technical loss (TL) and non-technical losses (NTL). NTL is further broken up into aspects that the utility has full control over (JNTL) and aspects that is not fully within the control of the utility (GNTL). The Licence further assigns a responsibility factor to the utility for GNTL that must consider the GOJ's plans and actual performance.

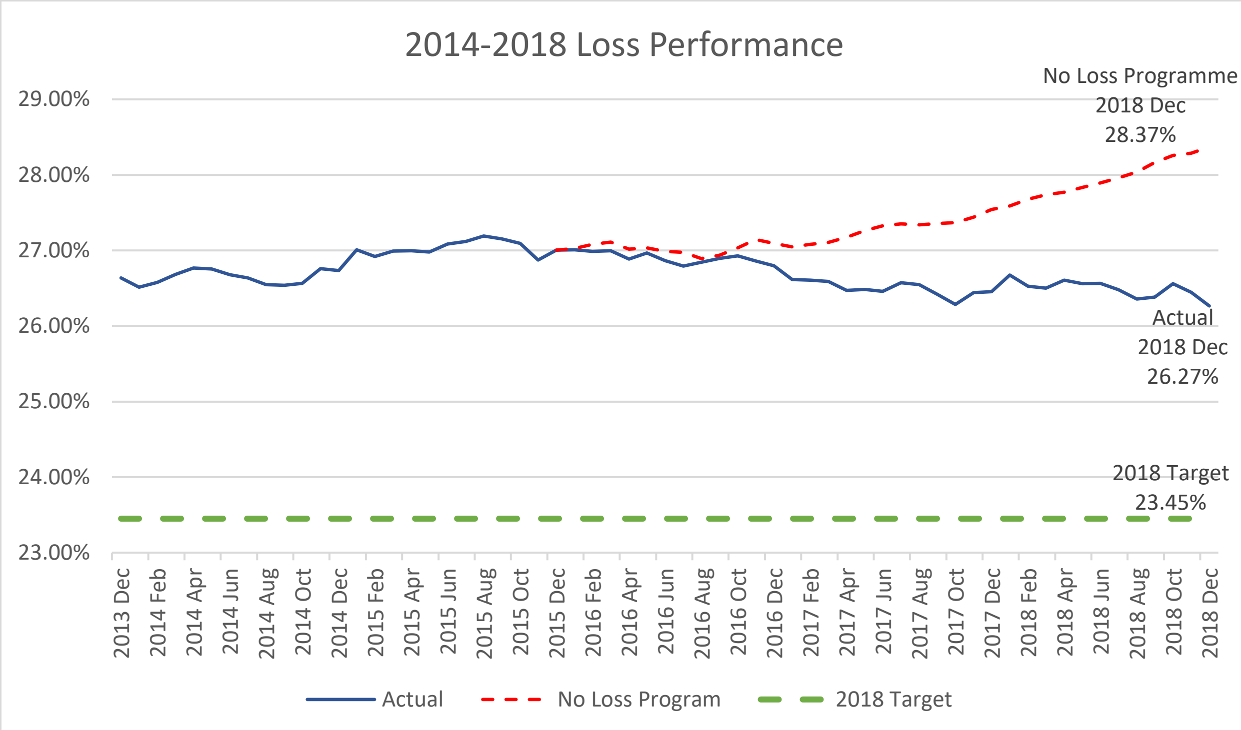
In the following sections, JPS will propose targets in keeping with the provisions of the Licence. The key elements of which are reasonable and achievable targets, with consideration for the base year, the historical performance of the utility, planned resources and the role of the Government.

8.2 Historical Performance

JPS's system energy loss at the end of December 2018 was 26.27%. Technical losses were estimated as 7.94% and non-technical losses at 18.33% or 68% of total system losses.

The maximum annual reduction in system losses over the period was 0.26 percentage points experienced in the 2017 calendar year. This improvement was made in an environment where there is a natural upward pressure on system losses caused by various external factors such as the socioeconomic environment. An ARIMA model was created to simulate how losses would have progressed from 2016 to 2018 without the intervention of JPS' loss reduction programme. The model shows that system losses would be at 28.37% at the end of 2018 compared to the 26.27%, an estimated impact of 2.10%.

Figure 8-1: 12 Month rolling system losses for December 2013 - December 2018



While system losses have shown a slight downward trend and are at their lowest in recent history, they are still significantly higher than the targets approved by the OUR in every year. In fact, the Jamaica Public Service Company Limited's Annual Review 2018 & Extraordinary Review Determination Notice imposed on JPS a target which equated to an over 1400% improvement in performance when compared to the utility's most successful year (from 0.21% to 3.0% reduction)

8.2.1 Technical Losses

Technical losses are natural losses occurring mainly due to the power dissipation in the electrical system such as transformers, transmission and distribution lines, and other equipment. These losses can be computed and maintained with the optimal level of control dependent on the topography, network configuration; T&D standardized voltage levels, electrical materials specification, and customer distribution across the network.

JPS' technical losses are broken out into the following components:

- Transmission losses: measured as the difference between net generation energy output and that of the distribution substation feeders' revenue class meters energy output over the same period;
- Primary distribution losses: estimated using method of computerized power flow simulation;

- Distribution transformer losses: calculated manually based on manufacturers' specification on no-load loss (core loss) and load loss (copper loss) data coupled with the quantity of each size transformer; and
- Secondary distribution losses: estimated based on rule of thumb and/or its standards governing conductor type, length per circuit, average loading per circuit and the number of secondary distribution circuits.

For measurement of technical losses, in the 1990's to early 2000's JPS began the implementation of metering on its substation transformers and feeders, and on the Net Generation side at its generating stations. At the end of 2018, JPS has 27 net generation meters covering 5 power stations, 111 feeder meters emanating from 42 substations and 11 frontier meters measuring energy transmitted/received across parish boundaries. JPS also has 79 sub-feeder meters installed which measure the energy delivered for sub sections of feeders.

In the Jamaica Public Service Company Limited's Annual Tariff Adjustment 2016 - Determination Notice the OUR stated as follows:[37]

> *"For technical losses on JPS' transmission network, the OUR is of the view that based on the configuration of the network, the estimated losses of 2.6% may not be representative. JPS is encouraged to employ feasible approaches to investigate the optimality of the power flows in the transmission network to ascertain the true level of technical losses resulting from this segment of the System."*

In 2016, JPS shifted from the traditional Synergee Electric load flow tool and invested in the state of the art DIgSILENT Power Factory load flow simulation tool. The two main advantages with this change are the modelling and analysis of all networks under one system and standardization with the Regulator.

JPS is in the process of modelling its T&D network inclusive of not only power lines but also the transformers from high voltage (138kV) to the low voltage (110/220V) network. To date the transmission network is completed while the primary distribution network is approximately 75% complete.

In short, measurement of technical losses continues to be a mixture of direct measurement, plus modelling. In the Jamaica Public Service Company Limited's Annual Review 2018 & Extraordinary Rate Review - Determination Notice, the OUR commented that based on regulatory reports submitted, there was no clear indication that these components of technical losses are being measured, calculated and evaluated on a systematic basis and in accordance with prudent utility practice. JPS notes that its technical energy loss estimation methodology is consistent with typical loss estimation methods utilized by other international electric utilities.

[37] 2016 Annual Review Determination, p. 77

With respect to the losses performance for the 2014-2017 period, the computed technical losses on JPS network were at 8.6% of generation in each year. The applicable technical losses targets over this period were 8.4% in 2014 and 2015, 8.2% in 2016, and 8.0% in 2017.

For 2018, the approved target for technical losses was set at 8.0%. As at December 2018 the technical losses computed on JPS network is 7.94%, with transmission losses measured at 2.24%, as detailed in Section 10 of JPS' 2019-2023 Business Plan.

8.2.2 Non-Technical Losses

Non-technical system losses are caused by actions external to the power system and consist primarily of electricity theft. Other factors affecting non-technical system losses include metering inaccuracies, unmetered energy, and billing errors/records. A variety of factors lead to NTL, however the most pronounced factors are related to socio-economic conditions such as affordability, culture, accessibility and crime.

In the early 2000s, customers were mapped to feeders and an energy balance was developed to determine the level of losses on each feeder. In 2011, the measurement programme started metering on distribution transformers to identify smaller pockets of losses more granularly and to develop strategies to address these smaller pockets at the local level.

For non-technical losses, the energy balance model utilizes this data for the calculation of the losses in different network components. There are 15 parishes, 42 substations and 111 feeders that emanate from these substations. At the parish level, the focus will be transformer meters that facilitates the comparison of the energy delivered from transformers onto a low voltage circuit and serving one or more customers. As at the end of 2018, JPS is able to determine losses by feeders, parishes and at various transformer locations.

Similar to countries with similar socio-economic backgrounds, NTL is a significant feature of the energy sector in Jamaica at 18.33% of net generation in 2018. It is estimated that 90% of NTL is due to theft or fraud which often times involves bypassing or tampering with the meter, or operating illegal connections. This infers that an estimated 23% of the households in Jamaica enjoy a supply of electricity but have no contract with the utility.

Non-technical loss levels over the last rate review period reduced year over year as seen in Table 8-1 below taking into consideration of the new methodology.

Table 8-1: Showing retroactive System Energy Loss given revised new methodology

Year	TL	NTL	Total
2016	8.05	18.75	26.81
2017	8.13	18.32	26.45
2018	7.94	18.33	26.27

Table 8-1 highlights the updated TL reflects that there were improvements in measurement. It should be noted that NTL have in fact been declining over the last three (3) years, however, it is still significantly above the approved targets in each year despite the Company's efforts. The Company's performance is evidenced that the approved targets were not reasonable and achievable. The NTL experienced in 2014-2018 is further elaborated in the Section 10 of JPS' Business Plan.

Notwithstanding the harsh economic and operating environment, the utility has managed to reduce NTL for the last 3 years, which has led to an overall reduction in system energy losses. Over those three (3) years, system losses have declined by 0.73 percentage points. This is a fundamental shift from the upward trend of system losses experienced in prior years. Additionally, it marks the first time in JPS' history where system losses reduced consistently for three consecutive years.

As previously stated, the most significant factors that influence users to commit electricity theft or fraud are socio-economic conditions. This is supported by several studies performed locally and internationally amongst industry peers[38]. These factors include the rising cost of energy, the accessibility of devices and information that enable abstraction, the social acceptance and encouragement of abstraction, the low probability of being caught and the low cost of punishment. For many users, the deterioration in these factors has made abstraction of electricity a more attractive option compared with legitimate supply. Therefore, leading to a significant increase system losses from factors over which the utility has very limited control.

8.2.3 Loss Reduction Activities 2014-2018

JPS has been implementing a significant range of strategies targeting loss reduction, including non-technical losses, for over ten (10) years. Some of the examples of activities developed and implemented prior to the 2014-2018 rate review period include:

- Energy Balance Project aimed at improving the measurement accuracy of generation and losses at various points in the system;
- Central Intelligence Unit project targeting identification of internal and external factors negatively affecting billed sales, and investigation of irregularities;
- Residential Anti-Theft Advanced Metering Infrastructure (RAMI) installation
- Meter Replacement project which replaced approximately 30,000 outdated electro-mechanical meters in 2011-2012 to improve metering/billing accuracy.
- Commercial Automated Metering Infrastructure (CAMI) meter replacement/installation
- Meter Center projects, where the meters in the areas where JPS traditionally faced operational challenges were removed from residences and installed in tamper-proof cabinets mounted on light poles.

[38] World Bank Group Energy Sector Strategy – "Reducing Technical and Non-Technical Losses in the Power Sector", July 2009, KEMA Study on Technical and Non-Technical Losses in The JPS Power System and on Regulatory Treatment of System Losses, 2013, USAID Workshop on best practices for loss reduction, July 2015, to name a few.

- Strike Force operations to target illegal “throw-up” connections and encourage the users to regularize their supply.

It is noted that the JPS loss reduction team experienced hostility from the affected people in the execution of many of these activities. In addition, JPS has also faced stoppages in project execution due to political interference. A contributor to the targeted meter changes not being met in 2011 was because of the public outcry between August and September 2011 regarding high bills and adjustments. The OUR and JPS initiated an audit of the project as well as the suspension of the meter change project during that period. While this work stoppage lasted for a period of approximately two months, upon resumption, JPS observed many customers resisting to have their meters changed, which greatly hindered the programme’s effectiveness. It was also observed that the irregularities immediately subsided for these accounts, as it gave customers the opportunity to remove illegal abstractions before allowing JPS access.

Other initiatives, for example RAMI, were very time-consuming and capital intensive, because of the high level of planning, community intervention, house rewiring and certification, and network construction required but appeared to offer the best return over the long-term.

Despite the challenges in undertaking these initiatives, JPS continued with implementation of many of these activities in the last rate review period. New activities were also undertaken by JPS, which was presented and discussed with the OUR prior to the implementation, as well as at each Annual Review filing in 2014-2018. Major activities over this period included the following:

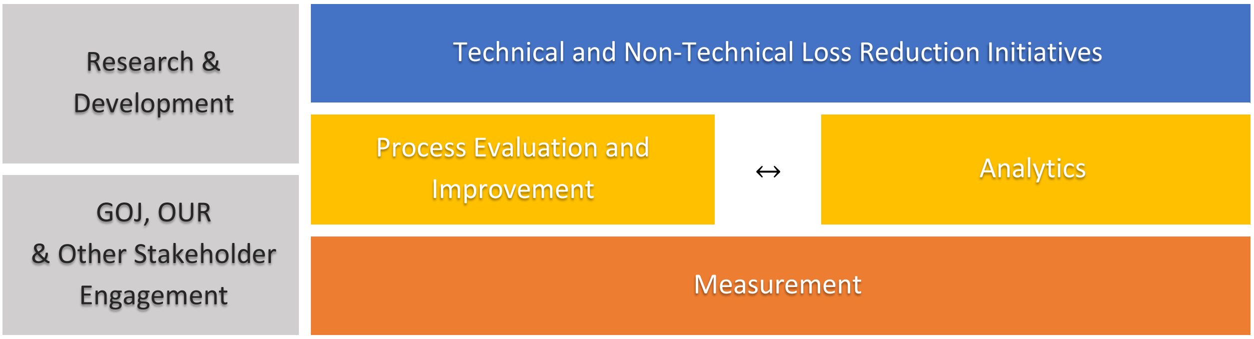
1. **Community Renewal Programme:** this programme is spear-headed by JPS and started in 2015, the Company collaborated with JSIF and other government agencies in improving services to low-income communities, island-wide.
2. **Project Step-Up Pilot Programme:** This project was implemented in selected communities with an objective to educate customers in the targeted communities on energy and bill management, and to introduce more flexible payment options. The core objectives of the programme included, inter alia, facilitation of conversion of 2,000 illegal users of electricity to regular customers; establishment of satellite offices in these selected communities, electrical skill training and employment opportunities for residents of McGregor Gardens and Majesty Gardens; public education in energy conservation, meter reading and electricity bill literacy.
3. **Smart Grid AMI ANSI Smart Meters:** The implementation of the Smart Grid AMI ANSI meter project included the replacement of the customer meters, the installation of transformer meters (Total Meter) and the building out of a smart grid communication network that will support the remote and automated connectivity to these meters.
4. **RAMI and CAAMI Rehabilitation and Reliability Improvement:** This was a continuation of the programme, which started in 2009. The RAMI/CAMI system was designed to move the metering point from easy access by installing the meters in an enclosure situated on the utility’s pole. The system design allowed for the meters in the

enclosure to be read and controlled remotely. Over time, the failure of the communication system affected the efficacy of the metering platform and the Company embarked on a programme to rehabilitate the communications systems in 2015. In assessing the root cause of communication problems, it was determined that there was a high level of interference from unauthorized personnel accessing the enclosures to illegally abstract electricity. The interference and the persistence of these persons affected the communication in such a way that it was nearly impossible to overcome this problem. A decision was taken to explore other solutions to this problem, which included rehabilitating where feasible or replacing Quadlogic system with an alternative that has a more robust communication platform, and resolving the communication issues for the ENT and YPP systems.

5. **Continuation of Strike Force Operations:** The Strike Force teams comprising of linesmen, technicians and the police have been engaged in the removal of illegal connections from the electricity network, arresting guilty parties and providing information to residents on the available options for accessing electricity service legally. These efforts are targeted at communities in which highest losses are experienced across the island. In 2017, the strike force operations within the parishes helped to deter energy theft and reinforced the physical presence of JPS teams. There were in excess of 273,322 throw-ups removed, 4,273 idle services removed, 396 arrests, 82 court summons along with 282 customers regularized in the period.
6. **Transformer Total Meter Installation:** Transformer Total Meters are energy meters installed on the low voltage side of distribution transformer locations, to which the customer connections are made. The Transformer Total Meters are used to measure the energy delivered to services via the secondary distribution network. The information from the Transformer Total Meters is compared against the sum of the energy registered on customers' meters and is used to compute the energy loss on each transformer circuit. Recovery and forward billing[39] rates are expected to improve with the implementation of these two systems. Just over 6,000 transformer total meters were installed from 2014 to 2018. The total meters would be associated with over 140,000 Revenue Meters to create an energy balance for the transformer circuits.

[39] Forward Billing is the estimation of the energy that the utility would continue to "lose" if an irregularity were not corrected. Recoveries are an estimation of the energy that has been lost prior to an irregularity being corrected.

8.3 Five Year Strategy and Resource Plan



In developing the proposed loss reduction strategy for the 2019-2024 period JPS, in addition to its own experience, also thoroughly reviewed international practices, studies and recommendations by international practitioners, global, as well as those that are specifically developed for Jamaica. The initiatives proposed for this rate review period are based off measures which have been very successful in many other developing countries with socio-economic conditions similar to those of Jamaica. It is noted however, that while the utility can champion implementation of these initiatives, strong support by the Regulator and the Government is critical for their level of success. This is especially true given that socio-economic factors are underlying problems of the present situation in Jamaica that directly impacts the scale of non-technical losses in the electricity sector. Some of these underlying factors were highlighted in the recent discussion between JPS and Professor Anthony Clayton, a renowned expert in the areas of national and citizen security, energy security, urban development, environmental management and development planning with over 30 years of international experience in policy development. The underlying factors share a high degree of coincidence with Professor Clayton's studied observations on the prevalence of crime and its manifestation in communities across Jamaica, which include:

- Entrenched poverty, high inequality, poor education, few job opportunities
- Gang-dominated informal settlements, bad housing
- One-third of population steals electricity, and two-thirds of the water supplied by NWC is lost or stolen
- High levels of violence which are effective deterrent to investment, perpetuating economic under-development and poverty
- Dysfunctional justice system

It is obvious, that JPS on its own, will never be able to tackle or resolve these problems to any level, but yet they are a significant part of system losses issue. As such, in order for the proposed strategy to have any sustainable impact on system losses reduction, JPS requires engagement of the stakeholders, which include but not limited to the following:

Office of Utility Regulation

The OUR is a critical stakeholder as they determine the losses target while ensuring the rates are fair to our customers. JPS requests the OUR to play a key role in reviewing and shaping JPS' loss reduction plans, approving its loss-reduction activities and providing positive incentives for loss-reduction. The OUR engagement is needed regularly to ensure we are on the same page in meeting the targets and this should be maintained through the Losses Interface Committee (LIC).

Community Leadership

A part of reducing losses in a sustainable way, culture change has to take place. This is accomplished through the elected community and constituency leaders. Losses projects will be done in phases. At each phase community leaders and MPs will be engaged before to ensure buy-in on the project. Community Leaders and MPs have already been engaged in the Community Renewal Projects and the losses special projects. This level of engagement will continue throughout the proposed plan.

Government of Jamaica Support

The GOJ role will be discussed in the sections to follow. However, the importance of this support needs to be reiterated for the success of the plan, especially from the Ministries, law enforcement authorities and Court system to enforce policies and laws.

8.3.1 Technical Losses Initiatives

The Company will be implementing the following Technical Loss reduction initiatives in the 2019-2024 period, detailed overview of which is provided in Section 10 of the 2019-2024 Business Plan:

- **Voltage Standardization Programme (VSP):** VSP is geared towards normalising all distribution feeders to 24 kV. Therefore, feeders which were previously powered at 12 kV and 13.8 kV are now being upgraded to 24 kV. This provides tremendous flexibility for loads transfer to neighbouring feeders. But most importantly, the added benefit is in the area of technical loss reduction. Increasing the voltage to 24 kV results in a considerable reduction in current relative to supplying the same load at 12 and 13.8 kV. The reduction in current in the primary distribution network means a decrease in I^2 losses, which is the technical power losses. JPS plans to upgrade twelve (12) of the existing 12 and 13.8 kV substations to 24 kV, in the next five (5) years. This initiative is expected to reduce system losses by approximately 5.09 GWh (0.14 percentage point reduction in technical losses).
- **Distributed Generation**
  Distributed generation refers to the concept of generating electricity in a decentralized manner. Electricity is generated closer to where it will be used. A benefit of this is that electrical energy has to travel over shorter distances to reach loads and incurs less technical losses as a result. As a part of JPS strategic objective to provide more reliable and efficient generating facilities on the distribution grid, JPS plans to install a 5 x 2 MVA natural gas fired plant in Hill Run, St. Catherine with co-generation facilities to supply a neighbouring

customer. This plant is part of a 14MW Right of First Refusal Initiative of JPS to replace a portion of the existing generation fleet with distributed generation. The distributed generation plant will be primarily interconnected to the New Twickenham 410 feeder which operates at 24 kV.

- **Transmission Line Upgrade**
  There is a chronic low voltage condition below the nominal operating range from Cardiff Hall, Roaring River through Ocho Rios to the Hydro Units generally affecting all the substations in the Parish of St. Ann, whenever the Bellevue - Lower White River 69 kV transmission line trips offline or is experiencing a maintenance outage. Similar conditions occur each time a 69 kV transmission line connecting Bellevue or Duncans Substations trips offline or is experiencing a maintenance outage. This situation affects over fifty thousand (50,000) customers, including large hotels and hospitals, costing JPS millions of dollars in both loss of revenue and damage claims. The System Controller will have to manually shed customer loads at Cardiff Hall, Roaring River, Upper White River and Ocho Rios S/S to alleviate the problem and requires the generators to provide additional voltage support. This is due to the very long radial 69kV line created from the N-1 condition. The construction of the new 69kV Transmission Line between the Bellevue and Roaring River substations will lead to significant improvements in Bus Voltages when either the Bellevue - Lower White River or the Duncan's Rio Bueno 69 kV transmission line trips offline. Besides the improvements to grid reliability and safety, this initiative improves the operating voltage of sections of the grid during adverse conditions. The increased voltage has a technical loss benefit.

Further details with respect to the planned technical losses reduction initiatives are provided in Section 10 of the 2019-2024 Business Plan. Technical Loss Breakdown Transmission Line provides breakdown of technical losses and the power flow simulation is provided as in Annex III.

Altogether, the TL initiatives above are targeted to result in total system losses reduction of approximately 0.20% points over the five-year period.

8.3.2 Non-Technical Losses Initiatives

While technical losses reduction initiatives can be implemented by JPS independently and as such are not contingent on collaboration with other stakeholders, many initiatives with respect to non-technical losses do require closely working with all the stakeholders outlined in Section 10 of the 2019-2024 Business Plan.

The proposed initiatives for the 2019-2024 period are summarized below. Detailed discussion of these initiatives, including roll-out schedules and cost projections, is provided in Section 10 of the 2019-2024 Business Plan.

- **Smart Meter Programme:** The smart meter programme forms part of a greater JPS business strategy that is critical to deliver value to customers across numerous areas of the business. The installation of SMART Meters will address and improve JPS' ability to effectively identify system energy loss at a circuit level by providing measurement visibility down to the transformer level. It will also provide greater efficiency and flexibility to the billing operations and improve on the frequency of resort to meter reading estimates. The Company therefore views system loss reduction as a significant but not the sole benefit of a smart meter deployment as the multi-dimensional operational capabilities it brings can create value for customers across a range of application. The intention is to roll out the smart meter programme feeder by feeder, parish by parish, prioritizing C& I customers and feeder losses (yellow zone) until the entire network is covered.

  - Smart Check Meter Programme**:** This programme is specifically designed for large commercial customers. This programme will see the implementation of secondary meters for each of the large customers (where technically and economically feasible) to continuously measure and verify energy delivered as this will bolster the existing audit and investigation strategy by providing real time alerts whenever the energy being delivered to these large customers deviate from the energy being recorded on the customers' meters.
  - Smart Meter Residential Anti-theft (RAMI): These meters form part of the overall smart meter rollout and will be installed in areas where electricity theft is higher and the propensity to steal is much greater. These areas will use prepaid metering solution with anti-theft enclosures to serve customers.

- **Audits and Investigation:** As part of JPS' routine operation, 100% of Rate 40 and 50 customers' metering facilities are audited annually. In addition, a further 4,000 Rate 20 customers utilizing greater than 3MWh per month are now equipped with AMI smart meters. This represents approximately 6,000 customers or 1% of JPS' customer base. This category of customers is referred to as our Priority Industrial and Commercial (PIC) customers and accounts for approximately 45% of sales. JPS continues to perform 100% audit of all 1,922 (as at December 2016) Rate 40 and 50 accounts and plans to audit an additional 4,000 Rate 20 accounts. With the addition of analytics through the smart meter programme it is anticipated that the audit and investigations will become progressively more effective over the next five years.
- **Community Renewal Programme:** The Community Renewal Programme has embarked on a different approach for the delivery of sustainable energy services to volatile and vulnerable communities. Increased presence, coordination and harmonisation is important in creating the required mind-set needed to boost cultural change towards accepting the need to become regularized, responsible citizens of Jamaica. In keeping with the Vision 2030 Jamaica goals 1 & 2; the CRP team seeks to empower citizens in the areas JPS serves, to achieve fullest potential and contribute to safety and the security of their communities and by large the Jamaican society. The approach for the 2019-2024 period will employ new strategies and initiatives conducted in coordination with various Government agencies and community groups as detailed in Section 10 of the 2019-2024 Business Plan.
- **Strike Force Operations:** This initiative is planned to continue in the communities in which highest losses are experienced across the island. The initiative will heavily utilize

the service of the police force in order to increase conversion of electricity consumers to JPS' customers.

Altogether, the NTL initiatives above are targeted to result in total system losses reduction of approximately 2.10% points over the five-year period.

8.3.3 Funding and Budgetary Requirements

Loss reduction initiatives are generally capital-intensive and the effect from these initiatives are usually materialized over several years. As such, pure cost-benefit approach for estimating the efficiency of loss reduction initiatives at times may not indicate significant returns. Table 8-2 provides projected cost and losses reduction estimates for each initiative proposed for the 2019-2023 period.

Table 8-2: Losses Reduction Initiatives Cost and Impact Projections

<table>
<tr><th>Initiative</th><th>Period of Implementation</th><th>Total CAPEX/ OPEX Cost over Period (US$000)</th><th>Expected System Losses Reduction Over Period (% Points)</th></tr>
<tr><td>Technical Losses</td><td></td><td></td><td></td></tr>
<tr><td>Voltage Standardization Programme</td><td>2019-2023</td><td>$17,593</td><td>0.14%</td></tr>
<tr><td>Transmission Line Upgrade</td><td>2019-2023</td><td>$6,759</td><td>0.02%</td></tr>
<tr><td>DG</td><td>2019-2023</td><td>$9,000</td><td>0.04%</td></tr>
<tr><td></td><td>TOTAL TL</td><td>$33,352</td><td>0.20%</td></tr>
<tr><td>Non-Technical Losses</td><td></td><td></td><td></td></tr>
<tr><td>Smart ANSI Meter Programme</td><td>2019-2023</td><td>$82,777</td><td rowspan="5">1.7%</td></tr>
<tr><td>Audits and Investigation</td><td>2019-2023</td><td>$26,160</td></tr>
<tr><td>Analytical Software Procurement and Development</td><td>2019-2023</td><td>$307</td></tr>
<tr><td>Metering Infrastructure Replacements</td><td>2019-2023</td><td>$815</td></tr>
<tr><td>Smart Check Meter Programme</td><td>2019</td><td>$1,200</td></tr>
<tr><td>Smart Meter Anti-theft (RAMI)</td><td>2019-2023</td><td rowspan="2">$17,259</td><td rowspan="4">0.40%</td></tr>
<tr><td>Community Renewal Programme</td><td>2019-2023</td></tr>
<tr><td>Strike Force Operations</td><td>2019-2023</td><td>$5,000</td></tr>
<tr><td>RAMI Rehabilitation</td><td>2019-2023</td><td>$2,500</td></tr>
<tr><td></td><td>TOTAL NTL</td><td>$136,018</td><td>2.10%</td></tr>
</table>

8.4 The Role of the Government

In 2015, the GOJ and JPS entered into negotiations for amendments to JPS' operating Licence. A major concern behind the re-negotiations was the effect of the ongoing high penalties from system losses on JPS and the singular responsibility placed on JPS to address this primarily socio-economic problem. The breakout of non-technical losses into JNTL and GNTL acknowledged for the first time within the legal and regulatory framework a shared responsibility for addressing NTL between JPS and the GOJ. In particular, the Licence takes a shared responsibility approach that recognizes the roles that the GOJ plays in addressing NTL. Specifically, the Licence states at paragraph 37 of Schedule 3 that:

> *"The Office shall take into consideration the role of the GOJ in addressing the non-technical aspect of the system losses that are not entirely within the control of the Licensee."*

It is important to note however that GOJ's assistance is also required in addressing non-technical losses which had been considered to be within JPS' control by the OUR in the previous filings. As has been discussed in the above sections, the initiatives pursued by JPS could only have a sustainable impact on system loss reduction if complemented by strong engagement of all the stakeholders, the biggest one of this being the GOJ.

8.4.1 The Role of the Government in GNTL Reductions

Exhibit 1 of the Licence requires the OUR to take into account (i) the role of the GOJ to reduce losses and (ii) actual cooperation by the GOJ in determining a RF (0-100%) to assign JPS for the GNTL portion of non-technical losses. These criteria are clearly subjective and the Licence does not prescribe a methodology as to how they are to be factored in determining a RF.

To quantify and increase the objectivity of this input to the target setting process, JPS has developed a range of initiatives that are within the implementation and enforcement jurisdiction of the GOJ to improve the effectiveness of the NTL reduction effort. A weighting will be assigned to each of the criterion outlined in Exhibit 1 to be considered in determining the RF.

The listed criteria are:

- (i) nature and root cause of losses;
- (ii) roles of the Licensee and Government to reduce losses;
- (iii) actions that were supposed to be taken and resources that were allocated in the Business Plan;
- (iv) actual actions undertaken and resources spent by the Licensee;
- (v) actual cooperation by the Government; and
- (vi) change in external environment that affected losses.

Given that by definition GNTL reflects losses not totally within JPS' control and the Company is directly bearing the full burden of JNTL, the highest weighting of the GNTL criteria should be assigned to those not related to JPS.

Furthermore, JPS currently absorbs the financial penalty for all loss above the target level and this is calculated partly by applying the RF (currently set at 20%) to the GNTL. In assessing performance on GNTL therefore for setting a RF for JPS, a negative score should result in a reduced RF for JPS while a positive score keeps the RF constant. In other words, the RF would be established subject to an agreed upon programme of actions by the GOJ for the five-year period (with actions organized by year), and GOJ meeting this programme of actions. If the GOJ fails to meet any of the actions which in turn impact JPS' planned actions, then the RF factor would be adjusted downwards. If the GOJ fully meets its committed actions (both in term of scope and schedule), then the RF score stays as established.

This is a reasonable and rational approach as a positive score, meaning the GOJ is playing its role and cooperating specifically on losses, should translate into an overall positive trajectory for the reduction in actual losses that will be beneficial to all. A negative score implies that JPS is bearing a disproportionate burden in fighting losses and a reduction in RF signals this to policymakers and transmits the urgency for effort. This would be fair and reasonable as it mirrors the outcome on JNTL where JPS bears the full consequences for positive or negative trends in JNTL.

The proposed scoring and RF adjustment mechanism is illustrated in Table 8-3 below -

Table 8-3: Proposed RF Adjustment Mechanism for GOJ Cooperation

Approved Action Plan for GOJ for 2019	Illustrative Approved Weighting of Actions	Completed by GOJ in full?	Score
A	B	C	D
Item 1	20%	Yes	0.2
Item 2	10%	No	0
Item 3	25%	No	0
Item 4	25%	Yes	0.25
Item 5	20%	Yes	0.2
	100%		0.65
Approved RF			20%
RF Adjusted for GOJ Actual Cooperation [D x Approved RF]			**13%**

8.4.2 The Role of the Government in JNTL Reductions

With respect to the JNTL, the Company identifies the following factors that must be achieved to ensure success in the reduction of system losses:

Prevention	The ability of the utility to prevent a loss from occurring
Detection	The ability of the utility to detect when and how a loss occurs
Recovery	The ability of the utility to "back-bill" or otherwise fully recover from the affected accounts
Sustainability	The ability of the utility to prevent further loss from occurring

While some modes of non-technical system losses, like defective infrastructure, can be argued within control of the Company (subject to resource constraints) to prevent, detect and sustain the proper quality of infrastructure, many other modes can only be under utility's total control if social conditions of the neighbourhoods are at adequate level across the country. For example, the modes of losses such as meter defects/tampering, line taps, and bypasses are very common in many poor regions of the country. Firstly, the utility cannot have resources to control all 600,000 plus customers on a continuous basis, while being responsible for reliable and safe electricity supply, and secondly does not have legal authorities to take proper actions against such cases.[40] While JPS can be successful in detection of many of the modes currently considered as JNTL, on its own the Company has no capacity to prevent non-technical losses from occurring, fully recover lost sales when detected, and more importantly to sustain any achieved level of success in fighting system losses across the country. This reality has been confirmed by international practitioners both in literature and in locally hosted events.

In this regard, JPS emphasizes that Government support should not be limited only to non-technical losses identified as GNTL, but to overall system losses reduction, and this support has to be continuous. Further, JNTL targets as well as actual performance results must be tied to the GOJ legal and financial long-term support to the Company's loss reduction initiative.

8.4.3 Proposed Government Action Programme in Supporting NTL Reduction

In order to enable effective and sustainable non-technical losses reduction, clear roles must be identified for the GOJ and initiatives with targets established to which the GOJ commits. This is not a fast or easy process that must take account of the complexities and speed of decision-making by the state. It is especially difficult to achieve commitment when it requires new allocation of resources.

Nevertheless, some progress has been made over the last five years as JPS has intensified its consultations with the GOJ. The new Electricity Act introduced in 2015 (the Electricity Act, 2015)

[40] The implied proper actions are in reference to legal responsibility measures, as well as government social programmes aimed at improving overall conditions in these regions.

significantly increased the criminal fines for electricity theft. As previously mentioned, the Licence explicitly acknowledged a role for the GOJ with an impact on performance assessment.

In 2018, a Terms of Reference (TOR) was developed for the GOJ's role in loss reduction plan which included the following:

1. Define a role for the GOJ in reducing losses that will:
    a. help achieve actual lower losses
    b. identify and fulfil GOJ's responsibility under Licence
2. Identify potential initiatives for GOJ's ownership
3. Map and engage relevant stakeholders to secure GOJ's commitment

The support roles identified for the GOJ are:

- Policy & legislative deterrence
- State enforcement of the law
- Enable legitimate grid access
- Affordability support for the vulnerable

Discussion around each support role is provided below.

Policy & Legislative Deterrence

International experience has shown that jurisdictions that exhibit an entrenched culture of electricity theft most often begin the slow process of change with strong policies and laws to curb the practice. Radical legislation with exemplary sanctions signals a government's break with tolerance of a practice that is often viewed as a cultural norm. The Electricity Act, 2015 increased maximum fines to $5M for illegal abstraction and amended the language of related legislation.

JPS has had consultations with the National Council on Justice (NCJ), a cross-functional body chaired by the Minister of Justice that spans the state's judicial and enforcement arms. Representations include the ministries of Justice, national security, the offices of the Chief Justice, Court of Appeal parish courts, commissioner of police, Director of Public Prosecution, among other agencies. Those consultations identified other possible areas of strengthening of legislation that JPS can pursue.

Change of legislation can be a long and difficult process. However, the Electricity Act, 2015 has a review cycle of five years and will therefore become due for review by the Parliament in the summer of 2020. JPS will take this opportunity to seek a complete schedule of strong sanctions, language amendment and supporting regulations to further strengthen the deterrence effect of the legislative framework against power theft. In the period 2019-2020, the Company will pre-align and consult with the portfolio ministry, the NCJ and other stakeholders including the OUR to build consensus and increase the probability of success.

State Enforcement of the Law

JPS is entirely dependent on ongoing state intervention to enforce the law. The lack of consistent enforcement of sanctions renders the legislation ineffective, therefore the losses fight that requires strong political will if it is to act as an effective deterrent. Global experience has shown that consistent enforcement of the law is the most effective deterrent against an ingrained culture of crime. Fighting power theft competes with other crimes for allocation of resources and is not assigned a high priority despite being the most commonly occurring crime. This has not been an area that JPS can claim major success in fighting losses. JPS has very limited ability to influence heightened performance of this state function.

The Company has nevertheless identified some areas to target. One is the lack of technical knowledge of methods of stealing electricity as an obstacle preventing the police from independently identifying and prosecuting offenders of the law without reference to JPS. The Company is therefore in consultation with the police leadership on developing a syllabus of training for selected teams of officers across the island.

JPS will also be pursuing recommendations at the NCJ for the Company to train a large pool of investigators that can be assigned the powers of district constables (DCs) to work alongside a smaller team of police officers trained as electricity theft specialists. These teams will form regional squads to prosecute electricity theft without overly stretching the resources of the police to address other crimes.

Over 2019-2020 period, the Company will also sensitize the police to the higher penalties available for prosecution under the Electricity Act.

Enable Legitimate Grid Access

The third role identified for the GOJ is a programme to encourage and accommodate legitimate access to the grid. Jamaica has a high level of informal settlements and housing. Safety regulations require that, as a pre-requisite for electricity service a premise must receive a government certificate of inspection for conformity of the electrical installation with prescribed standards. JPS is legally obligated to supply electricity to premises only in instances where the premises have been certified, which poses a barrier to entry for legitimate electricity services.

In the modern world, access to electricity is viewed increasingly as a basic human right symbolized in the United Nations Sustainable Development Goal (SDG) #7 calling for universal access to affordable electricity. Jamaica has endorsed the UN’s SDGs.

Repeated survey findings have shown that the inability to fund safe electrical installations is a leading contributor to electricity theft with the highest incidence in informal settlements. The near full coverage of the island by the electricity distribution grid means that it is within reach and accessible to most communities, island-wide. Government data suggests that close to 200,000 households[41] could have illegitimate electricity supplies based on JPS' customer base. The relatively high cost of house wiring would be the inhibiting factor for many of these potential JPS customers.

Only the Government can sustainably fund the improvement in the housing stock, including the internal electrical installation, of low-income families through social intervention. JPS along with the Jamaica Social Investment Fund (JSIF) have attempted modest programmes in the past that wired a few thousand homes over the past five years. To have any meaningful impact on losses however, the scale of any house-wiring programme must be amplified dramatically.

JPS is proposing that the GOJ targets the wiring of 5,000-10,000 homes per year for the coming regulatory period.

This programme is best implemented as an element of a wider social intervention programme that addresses other issues in marginal communities, such as access to other utilities like water, security, and social and infrastructural improvement. The GOJ's Zones of Special Operations (ZOSO) programme of social intervention provides a platform for a structured and targeted expansion of customer premise wiring for low income and vulnerable households.

Affordability support for the vulnerable

JPS is proposing to redefine and reshape the Lifeline tariff into a more targeted rate for those customers with consumption patterns within the lifeline range. Analysis of consumption within the Rate 10 residential class show that 41% of this customer class consumes at or below 100 kWh per month with an average consumption of just under 45 kWh. Of those consuming below 100 kWh, 74% consume below 75 kWh. This means that the observed average consumption of the bulk of lifeline customers falls well below the ceiling of the Lifeline tariff.

The Lifeline tariff is applied to the first 100 kWh of consumption for all residential customers. The average consumption within the lifeline range infers that the lifeline tariff rate is set at a higher consumption limit than is necessary to protect affordability to the most vulnerable. Commensurately, other residential customers are benefiting from more of their regular consumption being billed at the lifeline rate than is necessary.

As part of a new tariff design and structure to be proposed at the 2019-2024 five-year Rate Review, JPS will need to rebalance its tariffs in keeping with the results of a cost of service study. This will include a recommended reduction in the ceiling of the lifeline rate to 50 kWh and an increase in the rate for that first block of energy.

[41] The National Census (2011) recorded over 800,000 households with access to electricity, which far exceeds the number of active accounts on the company's customer database.

In order to address tax distortion in the residential group between the post-paid (tax above 150 kWh) and prepaid service, a linear tax structure will be required that will negatively affect lifeline consumption.

To protect affordability to the most vulnerable, tailor assistance to the deserving customers and combat losses, JPS is proposing that the GOJ simultaneously introduce a direct electricity service subsidy through the PATH programme. The proposal is that the GOJ directly funds the gap between what is considered an acceptable level of expenditure (income) vulnerable households should spend on electricity, how much electricity that purchases and the cost of the lifeline basket of service. The subsidy would be paid to eligible PATH beneficiaries in the form of vouchers to apply to electricity bills. A match of PATH beneficiaries registered as JPS customers suggest there may be scope for significant regularization among beneficiaries of social welfare.

The social tariff is intended to be complementary to the comprehensive programme of house wiring, ban on incandescent bulbs, bulb replacement and tightening of the legislative and enforcement mechanisms.

8.4.4 Determining the Responsibility Factor

Quantum America (2013) looked at the socio-economic situation of Jamaica and its effects on system losses. The study considered electric utilities in countries with similar socio-economic conditions in order to benchmark non-technical energy loss. The study established the strong relationship between non-technical losses (NTL) and the social conditions of the population living in the areas supplied by JPS. To confirm the hypothesis that NTL are higher in those utilities operating in regions that have living conditions that are less favourable, data about utilities in Argentina, Bolivia, Brazil, Guatemala, El Salvador and the Dominican Republic corresponding to the years 2004 –2011 were used. These socio-economic conditions can be broken down by:

- Demographic characteristics, violence, schooling, income, inequality, infrastructure, labour informality, temperature, market characteristics of the electric utility and electricity price.

In looking at fifty-three (53) distribution companies, the model considered the NTL to low voltage index, poverty index, the average residential rate based on GDP per capita index and the violence index (murder rate per 100,000). The study has clearly demonstrated a very strong correlation between electricity theft, and the socio-economic and political conditions within which the utility operates. Hence, the following were concluded:

- About 90% of the variability in the NTL is explained by socio-economic variables.
- NTL depend positively on the poverty level, on the payment capabilities of the population and the degree of violence present in the environment.
- For each 1% increase in the proportion of the population that lives in conditions of poverty, the NTL level increases by 0.63%.

- The result confirms the importance of the social dimension on the performance of the electric utilities.
- This task cannot be performed solely by JPS, but requires the joint efforts of the Regulator, GOJ, customers and other stakeholders."

The key conclusion from the utility's perspective is that only 10% of the losses seen in the 53 jurisdictions studied, including Jamaica, could not be explained by socio-economic variables over which the utility has no control. The utility has used the findings of the Quantum study as a basis to support its assertion of the responsibility factor.

8.5 Proposed System Losses Targets 2019 – 2023

A collaborative framework addressing target setting, and the roles of the utility and the Government ensures that the interests of each stakeholder is represented. It creates a verifiable process for holding each party accountable in a way that is consistent and transparent.

Targets

37. **The Office shall have the power to set targets for losses, heat rate and quality of service. All targets set should be reasonable and achievable taking into consideration the Base Year, historical performance and the agreed resources included in the five (5) Year Business Plan, corrected for extraordinary events. The Office shall take into consideration the role of the GOJ in addressing the non-technical aspect of the system losses that are not entirely within the control of the Licensee.**

1. *Reasonable and Achievable*
    a. The Licence requires that the targets must not only be capable of accomplishment by the Company, but must also be fair and appropriate based on all relevant circumstances.
    b. JPS proposes that the success or failure of initiatives should not be determined on a period of less than three years.
    c. No component of system losses should have a target of absolute zero. There are no examples of perfectly efficient systems in the real world and this is not achievable.
    d. Target setting for system losses must allow for the proper functioning of the performance based ratemaking mechanism (PBRM). This again requires that targets are set which leaves room for JPS to be financially rewarded for good performance, versus the target setting where the only theoretically achievable outcome would be avoiding financial penalties.
2. *Historical Performance*
    a. There is a significant natural upward pressure on system losses due to factors like the socioeconomic conditions. The utility believes that the impact of this should be considered and offset against the final targets when making a determination. The utility estimated that system losses would have been higher by approximately two percent if these factors where not being countered.

b. The maximum reduction in system losses over the past 5 years was 0.21 percentage points. The most recent target set by the OUR (23.45%) requires the utility to reduce system losses by 3.0 percentage points. This is a required improvement of over 1400% compared with its best performance. With investments in technology and efficiency gains, the utility expects that it can gradually improve on its best performance to 0.55 percentage points by 2023.

3. *Five (5) Year Planned Resources*
   a. Based on the strategy and five-year plan for losses, the targeted reduction is 2.30% over the five-year period

	CAPEX	Expected Reduction
TL	33,352	0.20%
NTL	104,858	2.10%
Total	**138,210**	**2.30%**

Note: Approximately 80% of the NTL CAPEX is for the implementation of Smart meters. The benefits from Smart meters are not limited to losses but will accrue from other areas of the business.

4. *The Responsibility Factor*
   a. The RF should be established subject to an agreed upon programme of actions by the GOJ for the five-year period (with actions organized by year). If the GOJ fails to meet any of the actions, which in turn affect JPS' planned actions, then the RF factor would be adjusted downwards. If the GOJ fully meets its committed actions (both in term of scope and schedule), then the RF score stays as established

8.5.1 Final Criteria

The published Final Criteria (the Criteria) from the OUR requires JPS to provide system loss proposals for each 12-month adjustment interval.

The Criteria also specifies that JPS is to provide an Energy Loss Spectrum (ELS) which is the "methodology used for the categorization and quantification of electricity losses over a designated time period"[42]. The ELS breakdown is required by the Criteria, "despite the losses being segregated into three (3) distinct components"[43] namely Technical Losses and the two groupings of Non-Technical Losses.

The Criteria required the submission of the ELS prior to the current rate review application.

With respect to Non-Technical Losses, the Criteria cites that Non-Technical Losses "can be largely avoided by JPS if appropriate measures are implemented to eliminate or substantially reduce

[42] Final Criteria, page 81.
[43] Final Criteria, page 82.

them"[44]. In making this determination, the Criteria does not yet specifically address the determination of an appropriate target consistent with the Licence, taking into account:

- **Responsibility:** Responsibility Factors, or which parties' "appropriate measures" could in fact lead to largely avoiding Non-Technical Losses
- **Trends:** The implications that the Base Year, 10 year rolling average trends, and historical performance do not indicate a basis for achieving the large scale avoidance of Non-Technical Losses in the 5 Year Rate Review Period.
- **Resources:** The 5 Year Business Plan does not provide resources required to achieve the large-scale avoidance of Non-Technical Losses in the 5 Year Rate Review Period, nor does the Business Plan conclude that the necessary resources (if it were possible) would be cost effective given the scale that would be required far beyond the spending already proposed.

In short, while the Criteria cites the theoretical concept that Non-Technical Losses can be largely avoided, this filing addresses the practical implementation of a process of incremental improvement that meets the tests of "reasonable and achievable".

The Criteria also specifies that JPS proposes a "methodology to manage the financial impact of Y-Factor"[45]. The premise of the Licence is that there would be no financial impact outside of exceptional performance (leading to a positive impact on JPS earnings) or a poor performance (leading to a negative impact on JPS earnings). With targets set at a reasonable and achievable level, JPS understands that the likely outcome is achievement of the targets, with an incentivized structure to exceed the targets. In short, there should be no presumed financial impact to manage. In the event of unexpectedly poor performance leading to a negative impact on JPS recoveries, JPS would be hard-pressed to secure offsetting savings from Operating Costs or the Capital Programme in a manner that would not adversely affect safety or reliability or service to customers. As a result, JPS is unable to propose a "methodology" for this hypothetical outcome.

The Criteria does not address the implementation of a mechanism for JPS to benefit from ten-year rolling averages, as provided for in the Licence.

8.5.2 Consumer Efficiency Factor

System losses by way of its calculation is impacted adversely as customers improve efficiency and pursue energy conservation efforts. As signaled by the Government of Jamaica, there is a national push towards energy efficiency and conservation. As the average consumer improves efficiency, the net effect is lower energy sales per customer. This will have an inverse impact on system losses, even without electricity theft increasing, simply by way of mathematical computation i.e.

$$system\ losses\ (\%) = \left(1 - \frac{billed\ sales}{net\ generation}\right) x\ 100$$

[44] Final Criteria, page 84.
[45] Final Criteria, page 55.

There has been a significant increase in customers and load defection over the last five years especially on our large customers. There has also been a marked increase on roof top solar on our residential customers in the same period. Over 300 customers have been converted to net metering in the last five years

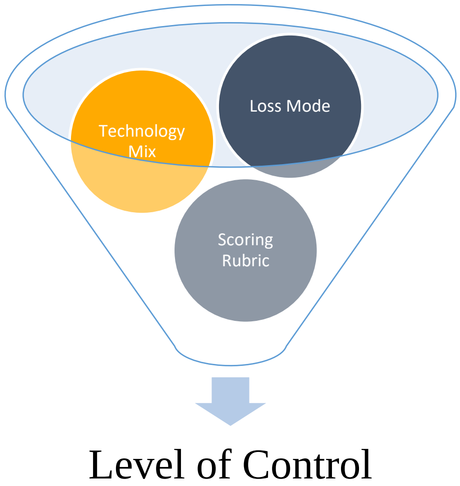
Year	2014	2015	2016	2017	2018
Total Annual Sales for net billing customers (GWh)	0.5	1	1.2	1.9	2.6
Total # Net Metering Customers	49	122	181	295	369
Average Annual Sales Per Customer (MWh)	10.2	8.2	6.6	6.4	7.0

As demonstrated in table above, there has been an approximate 30% fall off in billed sales per customer for this group. Using the present system losses calculation and target setting, JPS proposes that a CEF factor of 30% be considered when determining the targets.

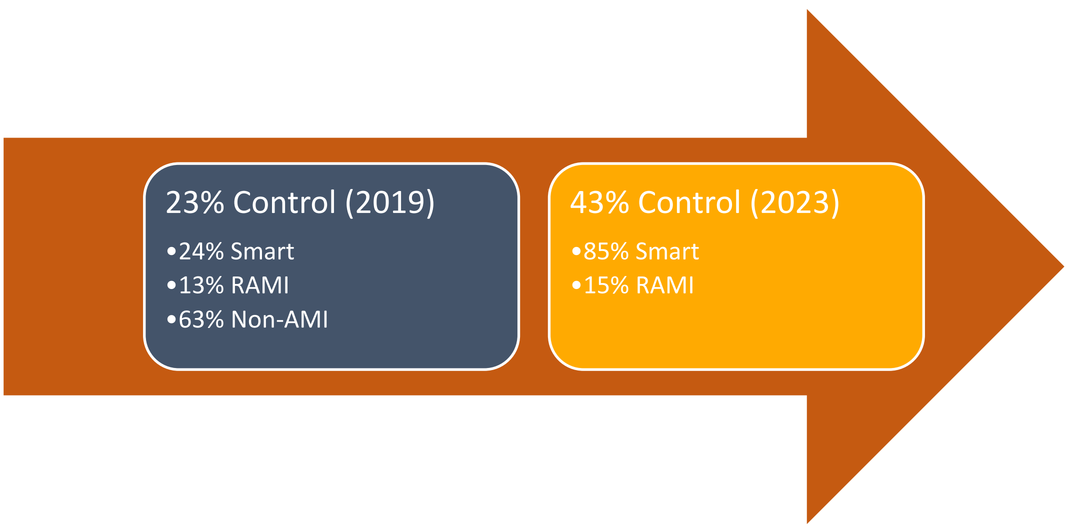
Alternately, JPS is open to exploring the revision of the metric used to monitor system losses performance to take into consideration kWh recovery/loss reduction as oppose to percentage loss reduction. This will address the issue of grid defection, energy efficiency programmes and conservation that impacts the current losses computation.

8.5.3 NTL Allocation Mechanism Proposal

JPS notes that currently there is no clear and consistent mechanism for determining NTL categorization between JNTL and GNTL. While the Licence introduced the concept of control over NTL by establishing two categories of NTL (JNTL and GNTL), it however, does not explicitly outline a method to determine which aspects of NTL are within the control of the Licensee and there has been a difference in position between the OUR and JPS on this matter. The allocation between JNTL and GNTL and the resulting penalties has far-reaching implications on both the viability of the utility as well as the cost of electricity. The utility cannot quantify progress and adjust strategies to reduce JNTL effectively because it does not know how expectations and its level of control over NTL are determined. The level of control determined by the regulator can and has changed dramatically between rate reviews, with no evidence that the parameters of system have materially changed. Stakeholders, which include the Government and the utility, require a consistent and objective way to determine who is responsible for what in order to design and fund the multi-year loss-reduction strategies. Consequently, the utility has developed a framework as a basis for the determination of JNTL and GNTL in a manner that is transparent, equitable and consistent with the intent and language of the Licence.



The framework considered the different modes of losses, the utility's ability to detect, correct and prevent these modes of losses and the mix of technology deployed. A detailed framework for determining the level of control and responsibility that the utility possesses is presented in NTL Control and Responsibility – Annex III to the Rate Case Filing.



- The level of control possessed by the utility (JNTL) would gradually increase from 23% – 43% over the five-year period with the rollout and upgrading of the metering system presented as Annex III to the Rate Case Filing – "NTL Control and Responsibility".

8.5.4 Projected System Performance and Proposed Targets

Based on the considerations above and proposed mechanism for the system losses categorization, the Company proposes system losses targets covering each of the 12-month adjustment intervals of five-year review period as presented in Table 8-4.

Table 8-4:2019-2023 Proposed System Losses Targets

	2018	2019	2020	2021	2022	2023
Total Reduction %		**0.34%**	**0.40%**	**0.45%**	**0.50%**	**0.61%**
12 Month Rolling System Losses - %	26.27%	25.93%	25.53%	25.08%	24.58%	23.97%
TL - Technical Losses %	7.94%	7.94%	7.92%	7.89%	7.85%	7.74%
Total Non-Technical Losses %	18.33%	17.99%	17.61%	17.19%	16.73%	16.23%
JNTL - Non Technical Losses within JPS' Control	4.22%	4.14%	4.93%	5.67%	6.36%	6.98%
GNTL - Non Technical Losses not totally within JPS' Control	14.11%	13.85%	12.68%	11.52%	10.37%	9.25%

RF should be set at 10% initially an adjusted annually as outlined in Sections 8.4.2 and 8.4.3 based on actual GOJ involvement

JPS proposes a combined 2.30% reduction over the 5-year period. JPS believes that these proposed targets are fair and achievable for the short and long-term periods, subject to all stakeholders and in particular GOJ fully meeting its commitments with respect to the system losses reduction initiatives agreed upon for the upcoming Rate Review period.

Details supporting the proposed targets are provided in Loss Reduction Plan with Targets, Justification and analysis for NTL reduction 2.10%, and Justification and analysis for TL reduction 0.20%.

The Licence asks for a 10 year target for system losses. It was discussed and agreed in the Loss Interface Committee meeting (LIC) that JPS will propose a 5 year target consistent with the 5 year plan and do a trajectory for the latter 5 years. In this regard, the latter five (5) year target projections are as follows:

Table 8-5: Proposed System Losses (2024-2029)

Year	2024	2025	2026	2027	2028
Total System Losses	**23.17%**	**22.41%**	**21.69%**	**21.00%**	**20.33%**
TL	7.73%	7.73%	7.72%	7.71%	7.71%
NTL	15.20%	14.49%	13.83%	13.19%	12.58%

8.6 Losses Spectrum

The System Energy Loss Spectrum ("ELS" or "the Spectrum") report seeks to disaggregate system losses using both measurement and modelling. The technical losses and non-technical losses among customer classes, illegal users and issues internal to the utility are estimated.

The ELS is published monthly on a rolling 12-month basis. The December 2018 ELS report is shown in Figure 8-2.

Additional information and details with respect to the ELS derivation are provided in Energy Loss Spectrum – Details, and Loss Spectrum Methodology.

Figure 8-2: ELS Sample

JPS ENERGY LOSS SPECTRUM

December 2018
(All figures in MWh unless otherwise stated)

Transmission Network	2.24%
Primary Distribution Network	2.80%
Secondary Distribution Network	2.90%
Technical Losses	7.94%
Billed Customers & Internal Losses	8.01%
Illegal Users	10.32%
Non-Technical Losses	18.33%
Technical Losses	7.94%
Non-Technical Losses	18.33%
System Losses	26.27%

Category		Average Monthly Cust./Cons.	Net Generation	Billed Sales	Energy Loss	
					Loss	Total %
Billed Customers	Streetlight/Stoplight (R60)	476	-	96,925	325	0.01%
	Wholesale Tariff (R70)	23	-	272,117	-	-
	Large C&I (R50)	133	-	414,411	3,178	0.07%
	Large C&I (R40)	1,839	-	763,723	15,812	0.36%
	Medium C&I (rate 20)	6,536	-	371,023	17,110	0.39%
	Small C&I (rate 20)	60,497	-	227,115	9,812	0.23%
	Residential (rate 10)	581,524	-	1,066,228	266,745	6.12%
SUBTOTAL BILLED CUSTOMERS		651,028	-	3,211,542	312,983	7.19%
Other Non-Technical	Illegal Users (Non-Customers)	180,000	-	-	449,400	10.32%
	Internal Losses	-	-	-	35,913	0.82%
SUBTOTAL NON-TECHNICAL		831,028	-	3,211,542	785,229	18.33%
Technical Losses		-	-	-	354,698	7.94%
GRAND TOTALS		831,028	4,355,535	3,211,542	1,143,993	26.27%

8.6.1 Limitations of the Energy Loss Spectrum

This level of system loss disaggregation is uncommon for a utility and there is very little literature addressing the challenges to this approach. Limitations in telemetry have made the direct measurement of losses amongst customers particularly difficult. The utility has had to rely on indicative metrics and rules-of-thumb that are non-ideal but were viewed as the best option available. These proxy metrics were repurposed for the estimation of losses but still suffer from the business constraints of their original purpose. The strike rate is featured heavily in the existing spectrum design but it was originally meant as a measure of the efficiency of the audit process. It is used to indicate the likelihood of there being a loss at a particular account with a lower likelihood being a desirable outcome. Due to these challenges, there have been concerns raised by the Regulator about the accuracy, consistency and reliability of the spectrum.

Now an opportunity exists to combine the metering information provided by the aggressive rollout of AMI metering with statistical techniques to design a more accurate and robust spectrum. The proliferation of smart transformer and customer metering has improved the utility's ability to measure the losses for small groups of customers directly. The energy balance is an account of the energy delivered by the transformer compared with the energy registered by the customer metering downstream of the transformer. By measuring losses directly, there is no need to rely on the strike rate and recovery metrics. The plan to improve the spectrum relies heavily on sampling circuits and applying statistical principles to estimate the loss in the wider population. Over time as the smart metering coverage increases, the estimates will become more and more accurate and will converge on the true loss. For some categories like the Rate 70 and 50 customers, this process has started in Q4, 2018. In this regard, the Company has developed a spectrum report improvement plan summarized in Table 8-6:

Table 8-6: Spectrum Reporting Improvement Plan by Category

Category	Plan
Streetlights and Interchanges	This loss has been eliminated
Residential	Sampling of circuits in the short term. As the number of circuits in the energy balance increases this will converge to the true loss.
Commercial	
Large Commercial and Industrial	Check metering will cover the entire customer base. This will allow the measurement of losses for this entire category
Internal Inefficiencies	Updating of policies and procedures. Stringent monitoring and adherence to policies.
Illegal Users	Segmenting specific communities will enable community level energy balances. This coupled with studies about the number of users will improve the accuracy of the estimated loss.

While the utility is confident that the breakdown of system losses into technical and non-technical is reasonably accurate, the same view is not shared about the disaggregation of non-technical losses into the different rate classes. The utility has acknowledged the shortcomings of this area of the ELS to the Regulator. Consequently, the Company asserts that the disaggregation of non-technical loss in the ELS should **NOT** be used as a basis for target setting. Instead, the target setting should be anchored to the provisions of the Licence. This is the base year, historical performance, and agreed resources in five-year plan and GOJ involvement.

9 Fuel Recovery – Heat Rate Target

9.1 Introduction

Licence Provisions

The Licence provides that JPS' costs will be recovered through two (2) components of rates – the non-fuel rates which are adjusted annually, and the fuel tariffs which are adjusted monthly.

One (1) factor in the adjustment of the fuel tariff is the Heat Rate Incentive, or "H-factor". The Heat Rate Incentive is designed to incentivize efficient operation of the JPS generation fleet. The effect of the H-factor is to implement financial penalties if JPS fails to achieve the regulatory determined efficiency targets, or financial rewards to the extent that JPS generation efficiency is better than the targets. The fuel tariff is computed each month based on the cost of fuel in the previous month. The Licence provides, in paragraph 40 of Schedule 3 that the OUR "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". However, the normal approach is for the Heat Rate Target to be set annually.

In the 2014 – 2019 Rate Case Determination Notice, the OUR determined that the Heat Rate Factor that shall be used in the Fuel Cost Adjustment Mechanism (FCAM) should be the ratio of JPS Heat Rate target (thermal) to JPS heat rate actual (thermal) which is used in the fuel pass through formula as follows:

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

The Heat Rate target is to be established having regard to the requirement on JPS to operate on the basis of a Merit Order dispatch, per Condition 23 of the Licence.

More than any other performance criteria, the Heat Rate is a function of the generation facilities, and to a lesser degree the transmission facilities, installed on the system. The Licence is designed to help take this into account by sequencing the Five Year Rate Review to follow the publication of the Government of Jamaica's (GOJ's) Integrated Resource Plan (IRP) and by considering the IRP a foundational document for the preparation of JPS' Five Year Business Plan.

Final Criteria

The Final Criteria addresses the determination of the Heat Rate Target at Criterion 14. Criterion 14 specifies that JPS is to provide a substantial set of data and information, and that the OUR will review "the reasonableness of the projected annual Heat Rate performance and proposed targets for each twelve (12) month period of the Rate Review period, as well as the degree to which they are consistent and achievable with the System configuration at the respective times".

The OUR indicated the need for engagement with JPS prior to the Five Year Rate Review submission.

Criterion 14 provides that JPS shall submit "the projected Heat Rate performance and proposed targets for each 12 month period (June – May) of the Rate Review period"[46]. Consistent with normal practice, JPS has provided monthly calculations of the Heat Rate projections, along with annual values based on July-June of each year – these are readily revised to June-May in such revision as is required to address the Criteria.

Principles for Implementation

The principles underlying the Licence are that JPS is incentivized to maintain a high heat rate through such actions as merit order dispatch, maintaining JPS plants in good efficient working order, and through the pursuit of fuel efficiency initiatives.

A significant limitation on JPS in preparing this forecast of Heat Rates is the failure to deliver an IRP in accordance with the Licence. While there is no option but to proceed with the Rate Review Process in advance of the IRP, it is a fundamental challenge that the eventual IRP may not accord with JPS' assumptions in this analysis. This must be viewed as an exceptional circumstance meriting a potential change to the previously established heat rate targets at some interim point during the Five Year Rate Review period.

The implementation of the Licence provisions reflects an intention to hold JPS responsible for Heat Rate effects that are within JPS' control, but requires that "items outside of the Licensee's control" are excluded, which the Licence specifically links this to "higher than anticipated forced outages at the IPP's or 3rd party generators"[47]. Some of the effects caused by IPP issues are beyond JPS' control is presently reflected in the fuel tariff; however, the H-Factor is not presently adjusted for these IPP effects – this is proposed to be adjusted in the current Rate Review.

Additionally, there are a number of other IPP-related factors beyond JPS' control that can materially affect the H-factor calculation, such as changes to the assumed IPP in-service date for new generation. Such changes would necessitate the adjustment to the proposed targets in keeping with the principles of the Licence. This proposal therefore, contains remedial measures for the subject five-year Rate Review period.

Heat Rate Targets

Currently, the heat rate target is set at 11,450 kJ/kWh. This reflects the capabilities of the generating units in service at the time the target was set, and the associated merit order dispatch.

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[46] Final Criteria, page 61. Criterion 14 a)

[47] Licence, Schedule 3, Exhibit 2.

This chapter reviews JPS' system thermal heat rate performance during the current regulatory period (2014 -2018). This chapter also presents the results of the heat rate forecast model for each of the five years of the next rate review period and outlines JPS' proposals for the heat rate target for the five years based on the known operational thermal generation plants of JPS. In the 2019-2024 rate review period, both of these factors will change materially a number of times, in some cases with more than one major change within the same year. For this reason, the annualization of targets is a coarse summation of 12 months, each of which is independently modelled for the relevant fleet and configuration projected to be in service.

Consistent with Paragraph 37 of Schedule 3 of the Licence, JPS proposes that the targets established for heat rate efficiency "should be reasonable and achievable". The development of reasonable and achievable targets should therefore take cognizance of current state of assets, performance levels, investments planned for the sector during the rate review period including planned changes in the generation fleet, the level of investments required to improve fuel conversion efficiency, and projects currently in train and the likely impact they will have on heat rate efficiency. The electricity sector will experience significant changes with respect to the fleet of generating units that will be used to supply power to the grid during the rate review period. The need for appropriate modelling and flexibility in setting heat rate targets will therefore be paramount if JPS is to be held accountable to targets established in accordance with the principles of the Licence. JPS believes this is such a critical and pervasive factor that, notwithstanding the need to set annual targets over the five-year rate review period, the Company recommends periodic reviews of the system heat rate target, no less than annually, over the rate review period to appropriately account for the impact of deviations as they become known. This would include deviations such as changes in planned commissioning dates or adverse performance of IPP assets outside of JPS' control on the heat rate target. These impacts would result in the continued operation of less efficient generating units beyond planned retirement dates.

Of particular note is the pending commissioning of the South Jamaica Power Company Limited (SJPC) Old Harbour 194 MW power plant in 2019, which will result in more than 70% of the net generation of the system being provided by IPPs. Once commissioned, JPS' regulated generation capacity will increasingly operate not like baseload operation, but like peaking supplemental generation operation. This change in the character of the operation of JPS' generation fleet, will unavoidably result in the H-factor becoming increasingly difficult to project and to achieve. JPS and the OUR may find it increasingly necessary during this five-year period to consider alternatives to the methodology used (as provided for in Schedule 3, Paragraph 40 of the Licence 2016) as more experience is gained in this new mode of operation.

Additionally, where there is a delay in the commercial operation date (COD) of the new generation capacity to the grid, along with any other condition/s that may require the delayed retirement of any of JPS units, it is only reasonable that a review of the JPS thermal heat rate target should be considered in order to preserve the principle of the Licence that the targets set must be "reasonable and achievable".

9.2 Heat Rate Target Objectives

The system heat rate is expected to progressively improve in the 2019-2024 rate review period with the retirement of 262 MW of aged less efficient steam generating units currently in operation. The overall heat rate outcomes will improve significantly with the addition of the new generation facilities from SJPC and the NFE South Power Holdings Limited, 94 MW Combined Heat and Power (CHP) Plant. The targets for JPS, however, must remain grounded in the quality and type of units that will remain in the Company's fleet the performance for which remains in the control of JPS, subject to the change in the character of operation from base load to akin to peaking units.

The OUR stated in the "Jamaica Public Service Company Limited Annual Review 2017 and Extraordinary Rate Review Determination Notice, (August 31, 2017)" that the heat rate target in the Fuel Cost Adjustment Mechanism is to ensure that customers benefit from fair and reasonable rates by permitting the efficient pass-through of fuel expenses incurred by JPS. The target provides JPS with the incentive to minimize overall electricity production costs by improving the overall fuel conversion efficiency of its generation fleet and employing prudent merit order/generation dispatch practices operating in its capacity as the System Operator subject to the requirements of the Electricity Act, 2015, the JPS Electricity Licence, 2016 and the relevant Electricity Sector Codes. The OUR in the Jamaica Public Service Company Limited Annual Review 2017 and Extraordinary Rate Review Determination Notice also, outlines that in setting the heat rate target the following regulatory principles are observed:

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 the 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 transmission and distribution), 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.

The establishment of reasonable and achievable targets require that certain factors are weighed heavily in the target setting process. These factors include the current state of the assets, operating performance levels, the impact of investments planned on the generation fleet operated by the

Company, investments required to improve fuel conversion efficiency, and projects currently in train and the likely impact they will have on the overall efficiency of JPS's fleet.

JPS proposes that the existing JPS thermal heat rate model be continued in the 2019-2024 rate review period in light of the demonstrated use of the methodology to successfully establish targets that were reasonable and achievable, and benefitted customers in the overall improvement in efficiency achieved. The familiarity of the sector by JPS and the OUR with this methodology provides a basis of stability on which to set new targets given the fleet changes anticipated. For JPS, at least in the earlier years of the rate review period, there is a planned fleet reduction (retirement of the Old Harbour Units 2, 3, 4 & Hunts Bay B6). This will result in a change in the heat rate given these are lower efficiency plants.

At the same time, the decisions of sector participants can adversely impact the fuel efficiency of JPS. This may include the new renewable resources due to customers' choices or Government of Jamaica objectives that could drive the use of increased spinning reserve by thermal plants to manage variations in power supply or IPP forced outages over which JPS has no control but which have a negative consequential effect on JPS's heat rate.

The introduction and retirement of several generating plants during the rate review period brings a new dynamic to the target setting process. The SJPC Old Harbour 194 MW Plant, The NFE South Power Holdings Limited, Clarendon 94 MW Combined Heat and Power Facility, Eight Rivers 37 MW Solar Plant, as well as possible replacement of more than 170 MW that may be dictated by the planned schedule maintained by the Minister in accordance with the Electricity Act, 2015 could present scheduling challenges for the rate review, specifically the establishment of annual heat rate targets for the 2019-2024 rate review period. The commercial operations date of these plants cannot be predicted with absolute certainty.

JPS also proposes that where there is a delay in the retirement of any of the plants scheduled to be retired by 2020 or thereafter due to the delays in the commissioning of new generation or transmission, the heat rate target for the intervening period should be adjusted to address any negative implications to the heat rate experiences by JPS' fleet, so as to be reasonable and achievable.

In addition, when IPPs experience higher than anticipated forced outages, JPS is compelled to use less efficient generators to fill the deficit left by the more efficient IPP generators. When targets are established, the targets contemplate a planned level of outage hours on the part of IPPs. The targets therefore do not account for outages beyond the planned levels. However, the use of less efficient units by JPS results in a heat rate performance that is worse than planned, or would have occurred had the IPP generator not exceeded its forced outage rate. This is where JPS suffers a reduced H-factor performance which is a consequence of the IPP failure. Even though the IPP may be penalized through the imposition of liquidated damages required by their power purchase agreement, this is paid to the customer and does not offset the impact of the worsened heat rate to the Company. Such an outcome is not consistent with the principles that JPS would be held harmless against actions it cannot control, and is not consistent with the principles set out in Schedule 3, Exhibit 2, footnote 3 of the Licence 2016, whereby JPS would be held harmless against IPP outage impacts on the Heat Rate when customers receive the credit for Liquidated Damages.

Another key consideration for the OUR in its determination of a target that is reasonable and achievable is the mix of JPS generating plants after the retirement of the Old Harbour units and B6. With Bogue Combined Cycle Plant and Rockfort averaging 40% efficiency and the remainder of the fleet averaging 23% efficiency, there are some inherent risks to consider:

- Forced outages on IPPs will have greater impacts to JPS' Heat Rate performance due to the composition of the JPS fleet after the retirement of the steam units.
- An extended forced outage on Bogue CC plant and Rockfort will result in a deleterious impact on the JPS heat rate performance due to the mix of less efficient units performing peaking duties.
- In light of the further planned retirement of the existing fleet, JPS will adopt a prudent and conservative maintenance strategy (deferral of maintenance Capex) for the units to be retired. In this regard, there is the likelihood of potential higher than normal forced outages that will manifest in negative heat rate impacts.

JPS also highlights the potential for issues to arise from the use of alternate fuels in dual fuel power plants where the primary fuel becomes unavailable. This can be significant where there is extended operation on the alternate fuel as this drives a more frequent maintenance routine that will impact operating cost and the availability of such units on the system. In the JPS fleet both the Bogue CCGT and GT11 are likely to be impacted by this scenario. In the case of the Bogue CCGT, the impact can be significant given its expected higher capacity factor. This factor can be incorporated in the periodic review of heat rate targets between JPS and the OUR as proposed in this submission.

9.3 JPS Thermal Heat Rate Performance – 2014 – 2019

JPS has made significant strides over the last five years in improving its thermal heat rate performance. This is evidenced by the fact that the average heat rate for the 2012-2013 regulatory year was 11,586kJ/kWh as compared to the 2017- 2018 regulatory year Heat rate of 11,403 kJ/kWh as illustrated in Table 9-1.

Table 9-1: JPS Thermal Heat Rate (kJ/kWh) Performance 2013 vs 2018

Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Avg
12,196	11,888	11,624	11,657	11,397	11,107	11,317	11,339	11,390	11,398	11,529	12,196	11,586
Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Avg
11,474	12,109	11,628	11,281	11,191	11,360	11,208	11,472	11,079	11,425	11,262	11,349	11,403
Improvement 183 kJ/kWh or 1.58%												

Figure 9-1: JPS Thermal Heat Rate Performance 2012 - 2013

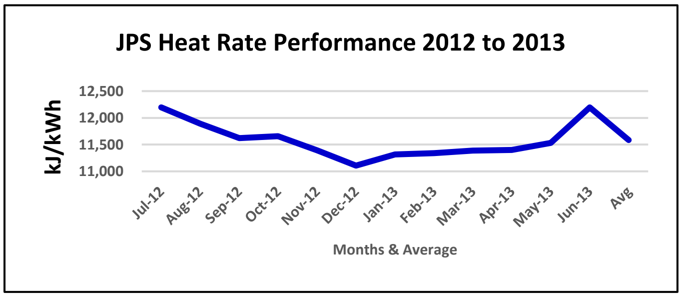
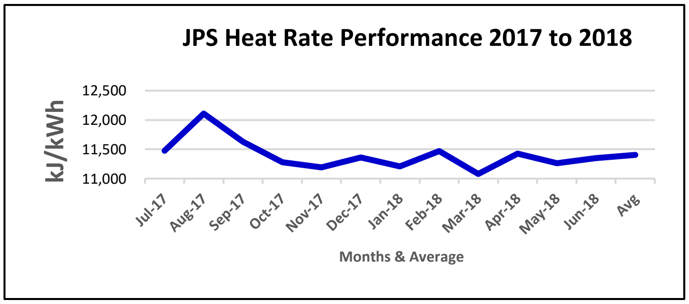


Figure 9-2: JPS Thermal Heat Rate Performance 2017 - 2018



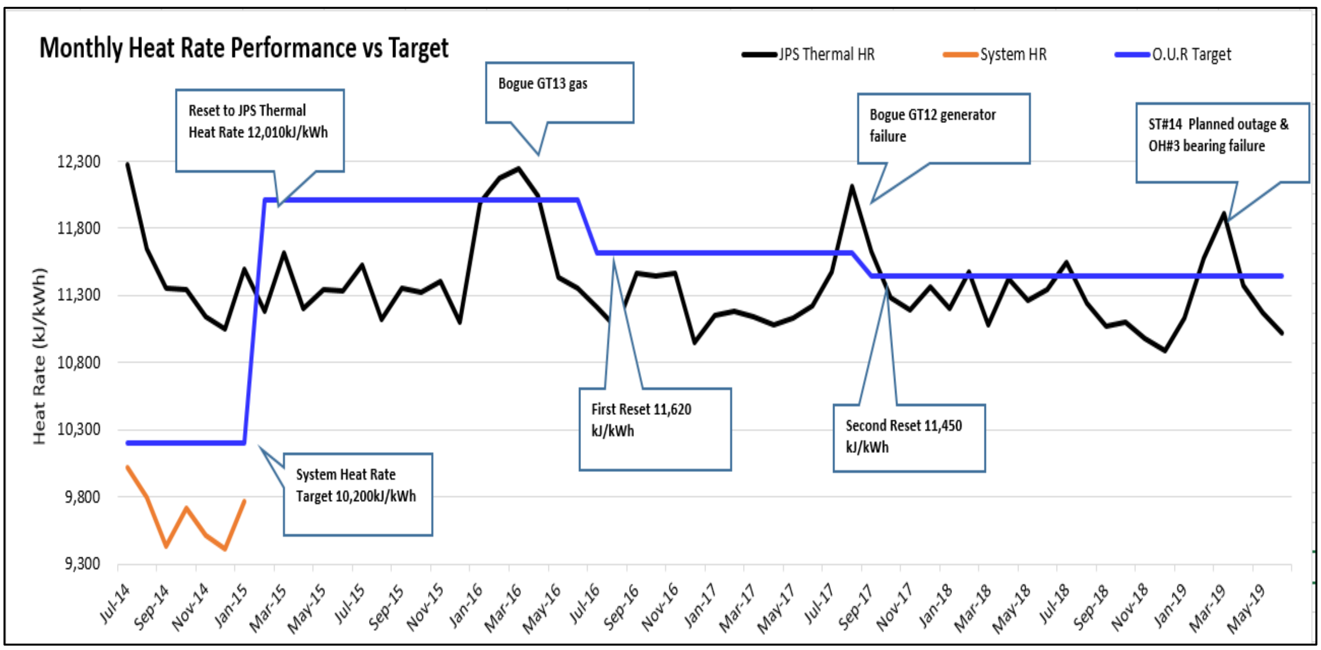
The 2018 Heat Rate performance represents 169 kJ/kWh (1.5%) efficiency improvement over the period 2014 – 2018 and 127 kJ/kWh (1%) improvement over 2017. This has been achieved by prudent operations and maintenance management and fleet utilization and optimization to promote asset reliability.

The improved reliability performance is the catalyst to the improved heat rate performance. The improved reliability that has been achieved is notable and not guaranteed to continue, in that approximately 45% of JPS' thermal assets are over 40 years old. Amongst the initiatives that spurred this performance were prudent asset management, capital investment to enhance asset lifecycle extension and optimization that are geared towards maintaining reliability of key base load assets in the JPS fleet. The rollout of Enterprise Asset Management (EAM) across JPS' Generation Division in 2016 has begun to bear fruit; in that all generating facilities maintenance programmes are now guided by a computerized maintenance management system. The resultant outcomes from this system has led to improvements in key operational areas of generation division, thus improving and optimizing the operation of the generation fleet.

The addition of 6.3 MW of Hydro to the system in 2014, 60.3 MW of wind from Wigton Wind Farm Limited & BMR Jamaica Wind Limited in 2016, the conversion of the Bogue Combined Cycle Plant from single fuel Automotive Diesel Oil to dual fuel with Natural Gas in 2016, 20 MW of solar from Content Solar also in 2016, as well as the successful repowering of Bogue GT#11(20 MW) on natural gas in 2018, are some of the major drivers that contributed towards the improvement in the thermal Heat Rate over the last five year period. This is because addition of the newer generation allows reduced dispatch of less efficient units of the JPS's fleet.

The OUR made four adjustments to the heat rate target over the last five years. The "System" heat rate model was utilized over the period 2013 – 2015, with the target being 10,200 kJ/kWh. The OUR adopted the "JPS Thermal" heat rate model in February 2015 and made three (3) adjustments to the heat rate target since then (this model is still used today). The JPS Thermal heat rate target was set at 12,010 kJ/kWh, (February 2015) then later reduced to 11,620 kJ/kWh in July 2016, and to 11,450 kJ/kWh from July 2017 to present. This represents an average 243 kJ/kWh reduction over the last four years. Figure 3 below shows a graphical summary of the System, JPS' thermal heat rate performance and the OUR's targets for the period July 2014 – June 2019.

Figure 9-3: Monthly Heat Rate Performance July 2014 – June 2019



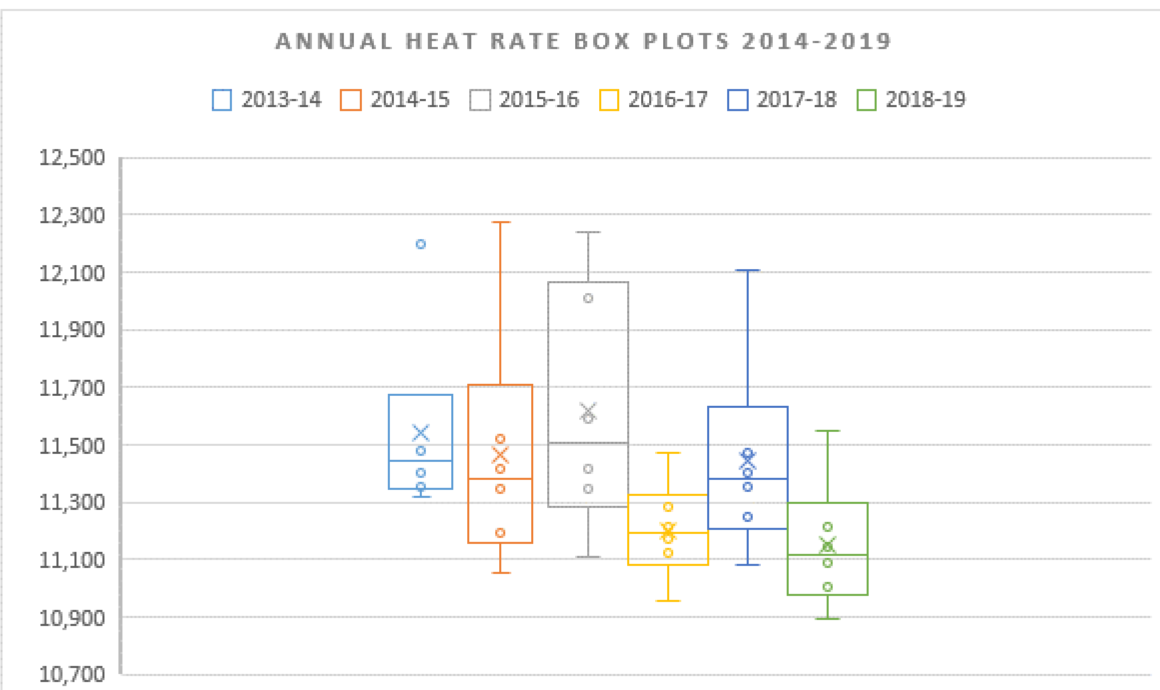
Statistical illustration of JPS thermal annual heat rate performance shown in Table 9-2 below to further illustrate the general trend of heat rate improvement over the tariff review period 2014 – 2019.

Table 9-2: Descriptive Statistics - Heat Rate Performance (Regulatory period 2013 – 2019)

Year	N	Mean	ST Deviation	Min	Q1	Median	Q3	Max	Range
2013-14	60	11,480	326	11,317	11,357	11,404	11,504	12,196	879
2014-15	12	11,416	325	11,052	11,197	11,346	11,523	12,276	1,224
2015-16	12	11,590	408	11,107	11,345	11,419	12,008	12,240	1,132
2016-17	12	11,212	167	10,953	11,120	11,170	11,282	11,469	516
2017-18	12	11,403	268	11,079	11,248	11,355	11,473	12,109	1,030
2018-19	12	11,143	233	10,895	11,004	11,091	11,213	11,551	656
2014-19	**60**	**11,373**	**94**	**10,953**	**11,120**	**11,346**	**11,523**	**12,276**	**1,323**

The statistical performances above are illustrated by the following box plots**.**

Table 9-3: Heat Rate Box Plot for 2014 – 2019



From a comparison of JPS' performance over the period 2013-2014 as against 2018-2019, it is evident that there has been an overall improvement in respect of both the average heat rate and the range (max – min) of heat rate variation. The major drivers of this improved efficiency was the continuous efforts of JPS to improve and maintain its generation fleet through the employment of a more efficient electronic asset management approach to the implementation of maintenance practices during the period shown in Table 9-4.

Table 9-4: Major Maintenance and Efficiency Improvement Projects 2014 - 2018

Years	Major Maintenance & Efficiency Projects	US$(000)
2014	Bogue GT12 Hot Gas Path Insp.	1,038
2014	Bogue GT6 Restoration of Generator	947
2014	Bogue GT5 Transformer Replace	636
2014	Hunts Bay B6 Main Condenser Tubing	1,159
2014	Hunts Bay GT10 Hot Gas Path Insp.	1,983
2015	Bogue GT3 Hot Gas Path Inspection	2,889
2015	Bogue GT#12 & GT#13 Dual Fuel Conversion	23,231
2015	Old Harbour Unit #3 Major Overhaul	9,322
2015	Rockfort Unit #1 Main Engine Overhaul	3,068
2015	Bogue GT#13 Major Overhaul	1,448
2016	Rockfort Unit #2, Main Engine Overhaul	3,488
2016	Bogue GT7 Gas Generator Major Overhaul	1,325
2016	Old Harbour Unit #2 Major Overhaul-Boiler / turbine works	4,169
2016	Hunts Bay GT10 Major Overhaul	2,162
2017	Hunts Bay Gt5 Hot Gas Path Inspection	2,124
2017	Rockfort Unit #1 Main Engine Overhaul	2,843
2017	Maggoty A Hydro Plant Restoration & Substation Improvement	1,685
2017	Bogue Repairs To Spare Aero Gas Generator & Free Turbine	1,502
2017	Bogue GT#11 Re-Powering.	14,987
2017	Old Harbour Power Station Unit 4, Mini Overhaul.	3,152
2017	Old Harbour Unit #3 Transformer Replacement;	2,930
2018	Rockfort 2 Major Overhaul Maintenance	3,520
2018	Lower White River Hydro Replacement Pipeline	334
2018	Roaring River Hydro Steel Penstock replacement	441
2018	Bogue CC Plant Chiller Unit Overhaul	510
		90,893

With the investments made over the regulatory period 2014 to 2019, JPS continues to improve in its efficiency & reliability indices. Equivalent Availability Factor (EAF) and Equivalent Forced

Outage Rate (EFOR) performance has shown consistent improvement post investment into the maintenance and efficiency programmes on the Generating fleet shown in Table 9-5.

Table 9-5: JPS Key Performance Indicator (KPIs) 2013 – 2018 (Calendar year)

OPERATING METRICS	2013	2014	2015	2016	2017	2018
JPS EAF	75%	78%	78%	81%	87%	89%
JPS EFOR	17%	13%	15%	12%	8%	5%
JPS Thermal Units (kJ/kWh)	**12,034**	**11,457**	**11,332**	**11,570**	**11,341**	**11,214**

The EAF achieved over the period 2016 to 2018 showed marked improvements from the lows of 2013 (75%) to the highs of 87% & 89% achieved in 2017 & 2018, representing the best reliability performance for the JPS fleet in more than a decade.

The 5% EFOR achieved in 2018 represents an improvement of 71% over the period 2013, and the 8% of 2017, a 53% improvement over 2013.

The effect of improvements to EFOR and EAF gave rise to improved efficiency in Heat Rate performance. The 11,214kJ/kWh for the JPS Thermal Fleet achieved in 2018 represents an improvement of 7% over the period 2013, and the 11,341kJ/kWh of 2017, a 6% improvement over 2013.

Investments in the conversion of the Bogue Combined Cycle Gas Turbine (CCGT) plant to dual fuel natural gas (NG) and automotive diesel oil (ADO) in 2016 has led to improved reliability on this asset. Major overhauls that were effected on other key base load assets for the following units are Rockfort Engine #1 & Engine #2, Old Harbour Units #3 & Unit #4 and Hunts Bay Unit #B6. These assets also generated reliability results not seen in decades. These investments have reaped benefits for both JPS and its customers.

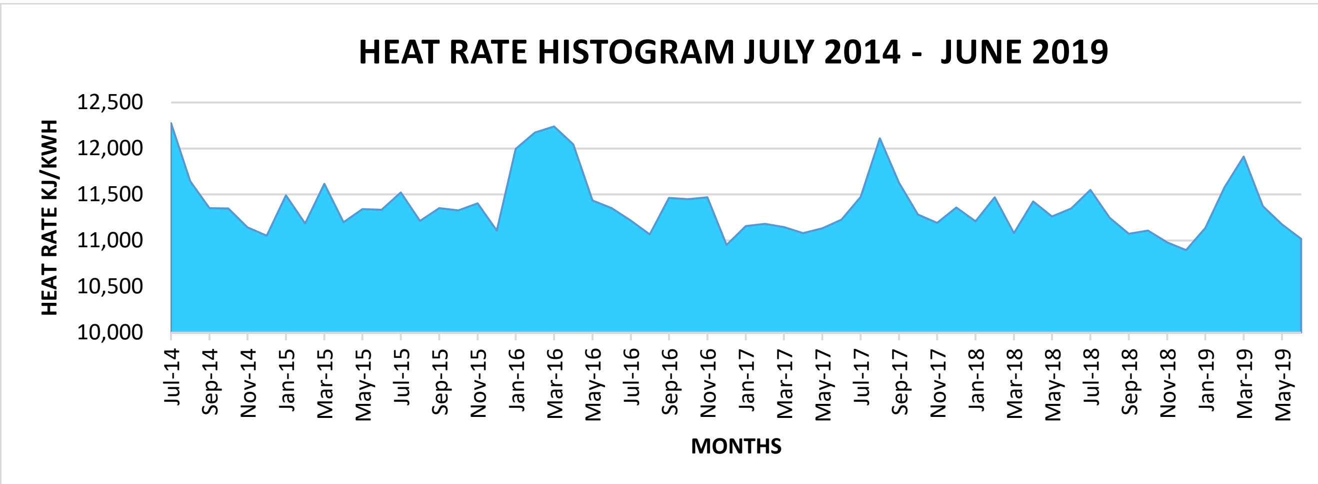
A key investment in the operational process was the rollout of an Enterprise Asset Management (EAM) tool across JPS' Generating fleet in 2016 - 2018. Enterprise Asset Management is the management of the assets of an enterprise across departments, facilities, business units and geographical locations. This has led to significant improvements in JPS asset management capabilities and has positively impacted all generating facilities maintenance programs. These improvements are evidenced by the following benefits derived:

- Improved maintenance planning process.
- Provide opportunity to develop and track maintenance KPIs
- Better maintenance management decision making.

- Increase staff interaction and development and technological exposure.
- Improved data availability, accuracy, accessibility and data management.
- Ease in conducting performance analysis due availability of data.
- Improved Reliability of key generating plants.
- Reduction in EFOR of key generating plants.

Figure 1- shows the distribution of the monthly performances.

Figure 9-4: Heat Rate Performance for range 2014 – 2019



While the mean heat rate over the five-year period was 11,373 kJ/kWh, the standard deviation of 94 statistically indicates that 82% of the monthly average heat rate values ranged between 10,953 and 11,553 kJ/kWh. This statistic indicates that the JPS thermal fleet was able to operate at a very high level of efficiency for the majority of the period. The 600 kJ spread is influenced by the varying technology mix of the JPS Generating fleet. The range between 12,153 kJ/kWh and 12,453 kJ/kWh was experienced during the period JPS implemented the dual fuel conversion project at the Bogue Combined Cycle Plant.

9.4 Factors Impacting JPS Heat Rate Forecast

9.4.1 Improvements to Existing Units

JPS has invested significantly in the existing generating units over the past five years to effect operational improvements. Generally, positive heat rate is the result of availability, reliability and efficiency improvement based investments. The performance of the existing JPS fleet of units represents the best levels that will be achievable over the next five years without significant capital injection. Greater levels of efficiency may be achieved with some design improvements and certainly with the replacement of some generating assets, but such aspirations would require significant capital investment. The current heat rate forecast model assumptions for 2019-2024 includes the retirement of Old Harbour Units #2, #3 & #4, the Hunts Bay Unit #B6 facility and the commissioning of SJPC 194 MW plant in Old Harbour, the NFE South Power Holdings Limited, Clarendon Combined Heat and Power Facility 94 MW plant and Eight Rivers 37 MW Solar Facility in Westmoreland.

This mix of retirement and replacement will result in a reduced JPS thermal generating fleet consisting of Bogue Power Station with 114 MW of combined cycle and 97.5 MW of simple cycle peaking gas turbines. Rockfort Power Station with 40 MW of HFO fired slow speed diesel engines, and Hunts Bay Power Station with two simple cycle gas turbines totaling 54 MW of capacity.

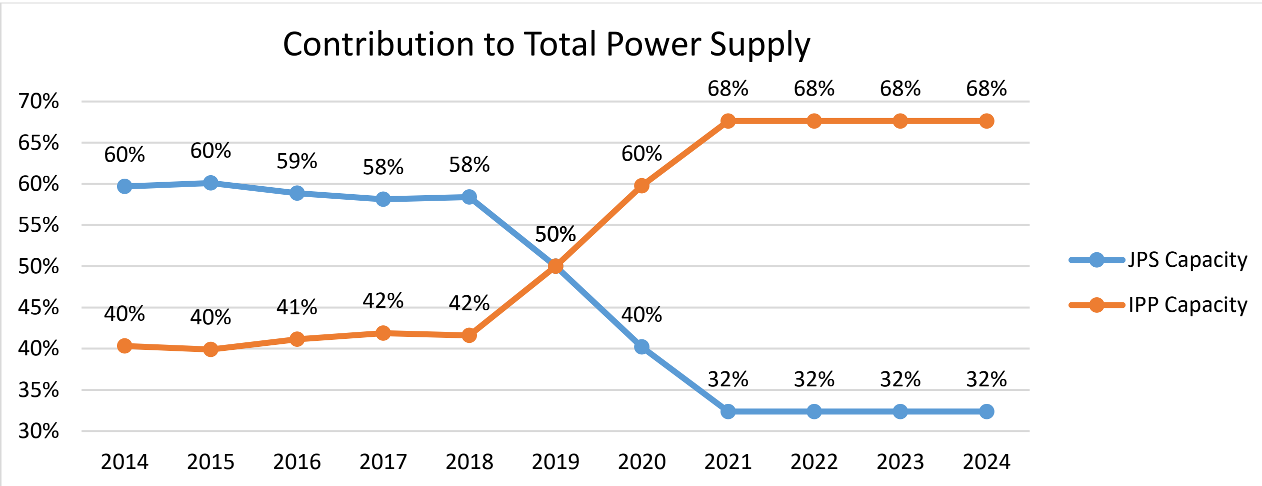
9.4.2 Impact of New Generation on Economic Dispatch and Heat Rate

Since July 9, 2007, with the reassignment of the authority to prepare and determine the Generation Expansion Plan to the OUR, JPS' role in generation expansion planning diminished. To date, the responsibility for the procurement of new generation rests with the Generation Procurement Entity (GPE) and that for integrated resource planning, with the Ministry of Energy.

The introduction of new generation units to the system during the 2019 –2024 revenue cap period is expected to positively affect the thermal efficiency of the system and fuel cost pass-through to customers. The impact of any new unit on the system heat rate can be determined by modelling the new unit in the system's economic dispatch model reconciled with the expected growth in sales and demand during the period. With the retirement of 262 MW of technologically inefficient steam generation capacity, JPS will be left with a fleet of generating units having the potential to achieve 39% efficiency relative to the current fleet which operates at 32% efficiency. With a reduced share of the generating capacity comprising mainly generation peaking units, JPS' thermal heat rate target will require adjustment to account for the new asset mix in the generation fleet.

It should be noted that since the last rate review the proportion of electricity demand supplied by IPPs has increased from 40% in 2014 to 42% in 2018 with a projection for a 50:50 share by the end of 2019. IPPs will provide the majority of the generation capacity for the upcoming rate review period. JPS' economic dispatch model based on known approved projects assumes that only renewables and baseload capacity in the form of combined cycle gas turbines (LNG) and solar will be added during the next five years. This is projected to result in IPPs providing 68% of total generating capacity. Figure 6 shows the changes throughout the period.

Figure 9-5: JPS and IPP Capacity 2014 -2024



9.4.3 Impact of Fuel Price on Economic Dispatch, Merit Order and Heat Rate

The variable cost of each generator comprises fuel cost and variable operating and maintenance (O&M) costs, of which fuel cost represent 95%. The cost of fuel includes all charges associated with making fuel available for usage in a power generating unit. The main fuels used in JPS generating units are HFO, LNG and ADO. The prices of these fuels change constantly on the world market based on economic conditions.

In either high or low fuel price scenarios, the cost differential between JPS units and IPPs will influence the system heat rate and in the same token JPS thermal heat rate performance. It should be noted that renewables have must run conditions under the Generation Codes and this have these conditions have the effect of causing very efficient JPS thermal units to run at suboptimal levels due to the requirement to accommodate renewable generation. It is projected that the SJPC 194 MW Natural Gas (NG) Combined Cycle Gas turbine (CCGT) plant will have a positive impact on the fuel component of the dispatch decision.

9.4.4 Impact of IPP Performance on Economic Dispatch and Heat Rate

The availability and reliability of IPPs has a direct effect on JPS' thermal & the overall system heat rate. Under the existing Power Purchase Agreements (PPAs), the large IPPs provide either a guaranteed heat rate point or a curve. A similar PPA is in place for the incoming SJPC 192.6 MW NG CCGT plant. This new IPP is projected to provide an average of over 35% of the required energy demand. Accordingly, its performance will directly influence the resultant JPS thermal & system heat rate.

The expected performance of IPPs is defined in their PPAs. Each IPP is allowed planned and forced outage hours and by extension is required to perform with a forecast level of availability and reliability. To the extent that the required IPP performance is not realized, more expensive and less fuel-efficient (peaking units with worse heat rate) units have to be dispatched to provide for this energy shortfall. This negatively impacts the expected JPS Thermal & System heat rate, for which there is no direct compensation for the sole benefit of JPS.

9.5 Heat Rate Forecast for Tariff Period

9.5.1 Model Assumptions

For the purposes of forecasting heat rates, JPS has adopted the use of PLEXOS as our simulation tool since 2017 to run its model assumptions. PLEXOS is a proven simulation tool that uses cutting-edge data handling, mathematical programming, and stochastic optimization techniques to provide a robust analytical framework for power market analysis. Since its release in 2000, PLEXOS has emerged as the worldwide simulation tool of choice. This technology is in use in most regions of the world by many of the world's largest utilities and system operators. Since the adoption of this performance simulation tool, JPS' performance forecasting and assumptions has improved significantly and is now better able to do more flexible performance simulations. A key output from the modelling process is the heat rate performance over the next five years. In support of this output, the modelling process takes into account the following elements: projected maximum capacity rating of each generating unit, forecasted capacity factor and forecasted energy production by each generating unit over the five-year period.

Projected Maximum Capacity Rating (MCR)

Table 9-6: System Projected Maximum Capacity Rating (MCR)

Plant	Unit	2019	2020	2021	2022	2023	2024
		MCR (MW)	MCR (MW)	MCR (MW)	MCR (MW)	MCR (MW)	MCR (MW)
Rockfort	1	20.00	20.00	20.00	20.00	20.00	20.00
	2	20.00	20.00	20.00	20.00	20.00	20.00
	Subtotal	**40.00**	**40.00**	**40.00**	**40.00**	**40.00**	**40.00**
Hunt's Bay	B6	68.50	68.50				
	GT #5	21.50	21.50	21.50	21.50	21.50	21.50
	GT #10	32.50	32.50	32.50	32.50	32.50	32.50
	Subtotal	**122.50**	**122.50**	**54.00**	**54.00**	**54.00**	**54.00**
Old Harbour							
	OH #2	60.00					
	OH #3	65.00					
	OH #4	68.50	0.00				
	Subtotal	**193.50**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Bogue	GT #3	21.50	21.50	21.50	21.50	21.50	21.50
	GT #6	14.00	14.00	14.00	14.00	14.00	14.00
	GT #7	14.00	14.00	14.00	14.00	14.00	14.00
	GT #9	20.00	20.00	20.00	20.00	20.00	20.00
	GT #11	20.00	20.00	20.00	20.00	20.00	20.00
	GT #12	40.00	40.00	40.00	40.00	40.00	40.00
	GT #13	40.00	40.00	40.00	40.00	40.00	40.00
	CCGT ST #14	40.00	40.00	40.00	40.00	40.00	40.00
	Subtotal	**209.50**	**209.50**	**209.50**	**209.50**	**209.50**	**209.50**
JPS Hydro	**Subtotal**	**22.39**	**22.39**	**22.39**	**22.39**	**22.39**	**22.39**
JPSCo's Total		**587.89**	**394.39**	**325.89**	**325.89**	**325.89**	**325.89**
JEP		74.16	74.16	74.16	74.16	74.16	74.16
JEP-50		50.20	50.20	50.20	50.20	50.20	50.20
JPPC		60.00	60.00	60.00	60.00	60.00	60.00
WKPP		65.00	65.00	65.00	65.00	65.00	65.00
SJPC 194		194.00	194.00	194.00	194.00	194.00	194.00
Jamalco 94MW		0.00	94.00	94.00	94.00	94.00	94.00
Jamalco		2.00	2.00	2.00	2.00	2.00	2.00
Jamaica Broilers		0.00	0.00	0.00	0.00	0.00	0.00
Wigton I		20.00	20.00	20.00	20.00	20.00	20.00
Wigton II		18.00	18.00	18.00	18.00	18.00	18.00
Wigton III		24.00	24.00	24.00	24.00	24.00	24.00
Blue Mountain Wind		36.30	36.30	36.30	36.30	36.30	36.30
WRG Solar		20.00	20.00	20.00	20.00	20.00	20.00
Eight Rivers Solar		37.00	37.00	37.00	37.00	37.00	37.00
JPS Munro		3.00	3.00	3.00	3.00	3.00	3.00
Maggotty B		7.20	7.20	7.20	7.20	7.20	7.20
	Import Sub Total	**610.86**	**704.86**	**704.86**	**704.86**	**704.86**	**704.86**
Total		**1198.75**	**1099.25**	**1030.75**	**1030.75**	**1030.75**	**1030.75**

Rockfort's maximum capacity rating is forecasted to remain at 20 MW x 2 for the period 2019 to 2024.

Hunts Bay's maximum capacity rating will remain at 122.5 MW up to end-2020 when the HB #B6 is scheduled to retire. The stations maximum capacity rating will be reduced by 68.5 MW in 2020 to reflect a balance of 54 MW. HB GT#5 (21.5 MW), HB GT#10 (32.5 MW)

Old Harbour's maximum capacity rating will remain at 193.5 MW up to mid-2019 when the retirement of OH#2, OH#3 is scheduled to take place. OH#4 is scheduled to retire at the end of 2019.

Bogue's maximum capacity rating is forecasted to remain at 209.5 MW over the period 2019 to 2024.

JPS' Renewables MCR is forecasted at 32.59 MW over the period 2014 to 2019. This includes

3 MW Munro wind farm and 7.2 MW Maggoty "B" plant.

IPP's MCR is forecasted to grow by 325 MW in aggregate, comprising 194 MW of Combined Cycle Gas Turbine NG fired generation and 37 MW Solar in 2019 and 94MW from a Combined Heat and Power plant in 2020. This will take the aggregate IPP power supply from 379.86 MW currently to 610.86 MW in 2019.Then from 610.86 MW in 2019 to 704.86 MW in 2020. It must be noted that no existing IPP unit was forecasted to be retired during the 2019 to 2024 rate review period. The JPPC 61.2 MW plant was recently granted an extension on their License, which is slated to expire on December 31, 2024.

Approximate Merit Order

The Licence is designed on the principle of a fixed merit order. While this concept is appealing, in practice the dispatch of units varies with changes in relative fuel price, the specific load and generating unit characteristics, and maintenance schedules. The dispatch of units also must be done on a moment-to-moment basis to meet overall power and reliability needs. For a basic overview of the system, however, it can be helpful to understand a basic merit order to be approximately as follows:

Table 9-7: September 2019 Merit Order

GENERATION ORDER OF MERIT

Sep-19

MERIT ORDER	UNIT NAME	CAPACITY (MW)	MERIT ORDER COST (US$/MWH)
1	JAMALCO	11	82.47
2	BOGUEGEN CC	114	84.28
3	ROCKFORT 1	20	88.26
4	ROCKFORT 2	20	88.70
5	WKPP	65.5	106.72
6	JPPC	60	106.93
7	BOGUEGEN GT11	20	108.71
8	HUNTSBAY B6	68.5	110.63
9	OHARBOUR OH4	68.5	111.97
10	OHARBOUR OH3	65	115.34
11	JEP	124.36	117.65
12	BOGUEGEN GT13	38	122.52
13	BOGUEGEN GT12	38	123.63
14	OHARBOUR OH2	60	127.78
15	HUNTBAYB GT10	32.5	203.37
16	HUNTBAYB GT5	21.5	218.35
17	BOGUEGEN GT9	20	229.57
18	BOGUEGEN GT7	18	248.82
19	BOGUEGEN GT3	21.5	255.28
20	BOGUEGEN GT6	14	257.98

Forecasted Capacity Factor

Rockfort's capacity factor is forecasted to average 78% throughout the period from 2019 to 2024, upon the addition of the SJPC 194 MW in 2019. This is inclusive of major maintenance outages each year. Should the system demand grow at a rate >1% post SJPC 194 MW installation the capacity factor for this plant would increase as it remains consistently high on the merit order. It has the capacity to run at 80% as its potential is not de-rated.

Hunts Bay's #B6 capacity factor is forecasted to average 53% during the period from 2019 to 2020. After the commissioning of the SJPC 194 MW in 2019, this unit is scheduled to be retired by December 2020. The capacity factor of Hunts Bay's gas turbines is projected to average 8% throughout the rate review period. Should the system demand grow at a rate >1% post SJPC 194 MW installation the capacity factor for these peaking units would increase based on their location in the corporate area load center.

Old Harbour's capacity factor is forecasted to average 37% during 2019 until its' retirement in December 2019.

Bogue's capacity factor is forecasted to average 48% during the period 2019 to 2024. Should the system demand grow at a rate >1% post SJPC 194 MW installation the capacity factor for Bogue's peaking units would increase marginally.

JPS Hydro Renewables capacity factor forecasted to average 62% for the 2019 to 2024 rate review period.

The capacity factor for the wind farms in the system are as follows: Wigton I: 31%; Wigton II: 35%; Wigton III: 26%; JPS Munro: 13% and Blue Mountain Renewables: 38%. With respect to the two solar farms currently licensed by the Ministry, the capacity factors are as follows: Eight Rivers: 20% and WRG Solar 24%.

With the installation of SJPC 194 MW in 2019 & the NFE South Power Holdings Limited, Clarendon Combined Heat and Power Facility 94 MW in 2020. The total IPP's capacity factor forecasted for the rate review period will average 49%.

The overall system capacity factor is forecasted to average 57% for the period 2019 to 2024. This is predicated on a flat demand and improved reliability from new generation plants to be commissioned in 2019 and 2020.

Forecasted Energy Production

The energy productions forecast was developed using the past five years' demand trend as per data taken from System Control, corrected for future residential and commercial growth of 0.1 – 0.2%. The energy production was estimated from the forecasting tool Plexos.

Rockfort's energy production is forecasted to average 273.7GWh annually for the period 2019 to 2024. Should the system demand grow at a rate greater than 1% after the commission of the SJPC 194 MW plant the energy production from this plant would increase, based on its standing in the merit order. Hunts Bay B6 energy production is forecasted to average 308 GWh annually for the period 2019 to 2020, after which it is slated to go offline. The gas turbines at Hunts Bay are forecasted to average annual production of 35.8 GWH for the period 2019 to 2024. Should the system demand grow at a rate greater than 1% post SJPC 194 MW installation the energy production from these peaking units would increase in small amounts.

Old Harbour's energy production is forecasted to be 590.7GWh in 2019, upon commissioning of the SJPC 194 MW combined cycle plant in 2019. Energy production from the Old Harbour plant is projected to cease by the end of the year 2020. Bogue's CCGT forecasted to average 868GWh annually in energy production for the rate review period. In regard to the other GTs at Bogue, GT #3 to GT#11 are projected to average 111.9 GWh annually 2019 to 2024, largely due to GT#11 being fired on LNG. Should the system demand grow at a rate greater than 1% after the SJPC 194 MW commissioning the energy from Bogue's peaking units would increase by a small amount.

JPS Hydro Renewables energy projection is expected to average 144.6 GWh annually during the period 2019 to 2024. The other renewable Plants are forecasted to have the following average energy production for the 2019 to 2014 period: Wigton wind: 164 GWh; BMR Wind: 113.6 GWh; JPS Munro Wind: 3.24 GWh; Eight Rivers Solar: 59.7 GWh; and WRB Solar: 42.6 GWh. Thermal energy production at IPP locations (SJPC 194 MW, JAMALCO 94, JEP 124 MW, JPPC 60 MW and WKPP 65 MW) is expected to average 2,310.6GWh per year for the period 2019 to 2024.

The overall system demand is forecasted to remain flat annually over the period 2019 to 2024, largely in part due to anticipated demand projected to come from small commercial and residential customers. Should demand grow by greater than 1% post SJPC 194 MW Plant commissioning, the system production numbers will have the potential to increase. The forecasted energy production of each plant for the five-year period are attached as in Annex III to the Rate Filing.

9.6 System Heat Rate Model Results

9.6.1 Fuel Price Forecast 2019-2024

Table 9-8: Average Forecasted Fuel Price (US$/Barrel)

UNITS	Fuel Type	2019	2020	2021	2022	2023	2024	Average
		US$/Barrel	US$/Barrel	US$/Barrel	US$/Barrel	US$/Barrel	US$/Barrel	US$/Barrel
Old Harbour	HFO	71.670	64.890	59.460	62.935	60.160	60.760	63.313
Hunts Bay	HFO	72.000	65.520	60.080	63.560	60.790	61.380	63.888
Rockfort	HFO	72.390	66.230	60.790	64.270	61.500	62.090	64.545
Hunts Bay	ADO	95.150	87.240	80.120	85.204	81.090	81.920	85.121
Bogue	ADO	101.520	93.350	86.230	91.312	87.200	88.030	91.274
Bogue	NG	84.020	57.910	57.910	57.910	57.910	57.910	62.262
IPP	HFO	78.820	65.590	59.810	60.250	60.780	61.230	64.413
IPP	NG	95.590	48.830	48.830	48.830	48.830	48.830	56.623

Table 9-9: Average Forecasted Fuel Price for JPS Plants (US$/MMBTU)

UNITS	Fuel Type	2019	2020	2021	2022	2023	2024	Average
		US$/MMBTU	US$/MMBTU	US$/MMBTU	US$/MMBTU	US$/MMBTU	US$/MMBTU	US$/MMBTU
Old Harbour	HFO	11.560	9.498	9.876	9.590	9.703	9.800	10.004
Hunts Bay	HFO	11.610	9.598	9.971	9.690	9.805	9.900	10.096
Rockfort	HFO	11.680	9.713	10.080	9.805	9.919	10.015	10.202
Hunts Bay	ADO	16.380	13.652	14.252	13.790	13.957	14.100	14.355
Bogue	ADO	17.470	14.704	15.249	14.842	15.009	15.151	15.404
Bogue	NG	14.470	9.967	9.967	9.967	9.967	9.967	10.718
IPP	HFO	13.360	11.115	10.087	9.959	10.305	10.125	10.825
IPP	NG	16.470	7.967	7.967	7.967	7.967	7.967	9.384

Fuel forecast data was obtained from Henry Hub Natural Gas Futures forecast, Gulf Coats HSFO (Platts) futures settlement for HFO and ADO. It is managed by The CME Group. They allow market participants significant hedging activity to manage risk in the highly volatile fuel price market: This is the price reference tool for JPS fuel supply agreement with NFE and Petrojam.

- The third-largest physical commodity futures contract in the world by volume
- Widely used as a national benchmark price for natural gas, which continues to grow as a global and U.S. energy source
- An independent, stand-alone commodity

HFO prices are forecasted for the five-year rate review period at different prices based on transportation cost variations and in the case of the IPPs gradation of fuel. The forecast for the average price per barrel and the average for each plant is presented in Table 9-8 & 9-9.

The variable O&M for all the plants in the system were computed as per their PPA for IPPs and actual spend for JPS assets. The main outputs of the projection process are as follows: VOM for the IPPs JPPC US$12.92 / MWh, JEP US$23.058 / MWh & WKPP US$15.006 / MW.

NB: The fuel price for IPP Natural Gas in 2019 is based on the test fuel price due to the fact that SJPC did not achieve commercial operation date (COD) at the time of this submission.

9.6.2 Individual Plant Heat Rate Forecast

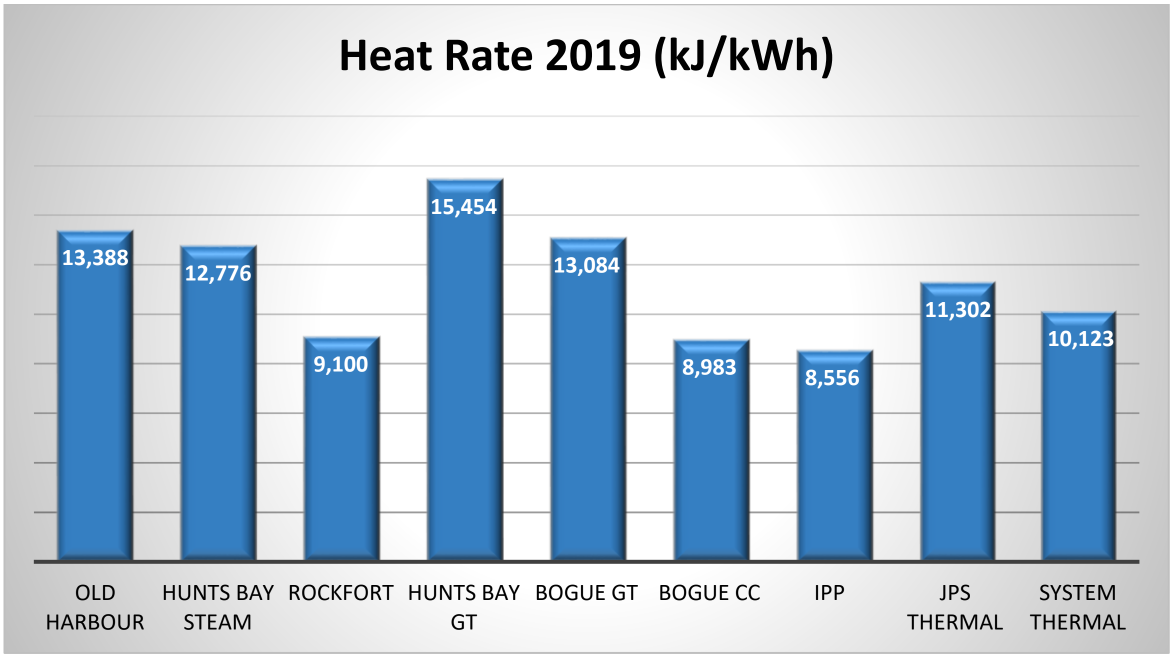
The forecasted heat rate by plant for 2019 is based on actual (July – November) and projected performances and is as follows:

1. Rockfort is forecasted at 9,100 kJ/kWh with planned major outage (February 2019) intervention on RF#1.
2. Old Harbour plant heat rate is forecasted at 13,388 kJ/kWh, largely due to a forecasted lower capacity factor after the commissioning of SJPC 194 MW end of November 2019. This will result in deteriorated performance of OH#4 as this unit will be performing mainly cycling duties during the commissioning phase.
3. Hunts Bay HB#B6 forecasted at 12,776 kJ/kWh with planned maintenance intervention.
4. Hunts Bay gas turbines forecasted at 15,454 kJ/kWh which is reflective of their peaking duties.
5. Bogue gas turbine GT#3-GT#11 are forecasted at 13,084 kJ/kWh and will only be used for peaking duties. Bogue CCGT is forecasted at 8,983 kJ/kWh with major outage intervention on CC GT#12 (Aug – Sept 2019) and minor works on Steam Turbine #14.
6. IPPs are forecasted at 8,556 kJ/kWh with major outage intervention forecasted for JEP Barge #2, major overhaul on JPPC Engine#1, Major overhaul on JPPC engine #2 and major maintenance some WKPP engines. SJPC 194 MW commissioning and testing activities in progress at the time of submission.

The 2019 JPS Thermal heat rate is forecasted at 11,302 kJ/kWh in accordance to the above assumptions. If there are any delays, such as the SJPC194MW plant commissioning, JPS heat rate performance will be adversely impacted in light of the need to operate less efficient units.

The 2019 System Thermal Heat Rate is forecasted at 10,123 kJ/kWh

Figure 9-6: Heat Rate Forecast 2019



9.6.3 Heat Rate Forecast 2020

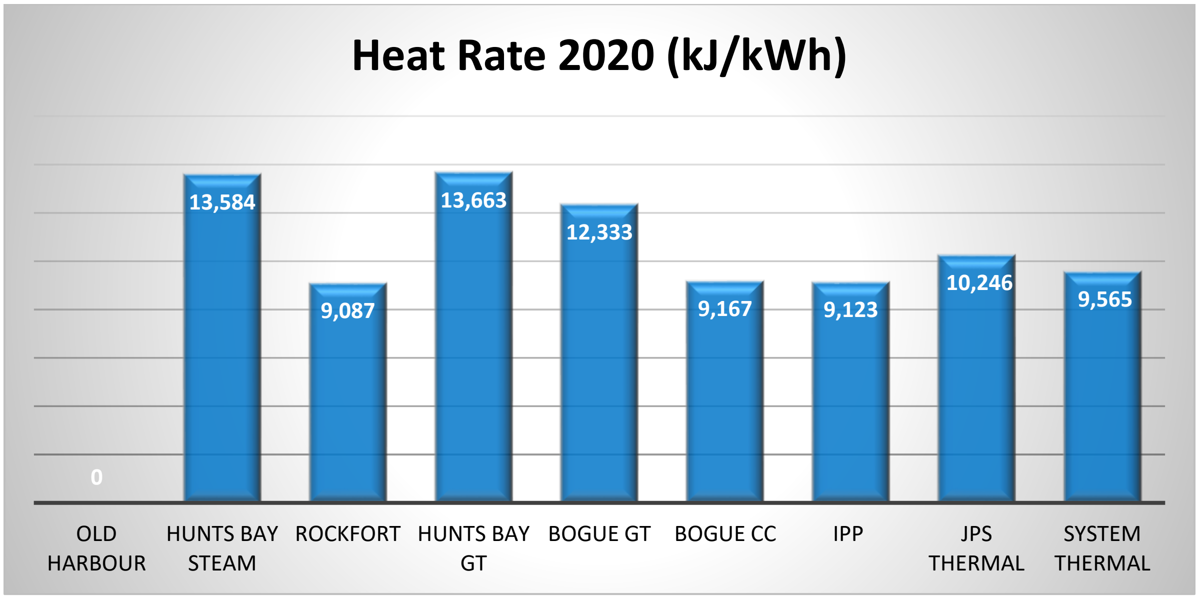
The forecasted heat rate by plant for 2020 is as follows.

1. Rockfort is forecasted at 9,087 kJ/kWh with planned major outage intervention on RF#2.
2. Old Harbour steam generation plants will be fully retired at the end of 2019.
3. Hunts Bay HB#B6 forecasted at 13,584 kJ/kWh with planned maintenance intervention.
4. Hunts Bay gas turbines forecasted at 13,663 kJ/kWh, which is reflective of their peaking duties.
5. Bogue gas turbine GT#3-GT#11 are forecasted at 12,333 kJ/kWh as and will only be used for peaking duties. The poor heat rate is made worse by the frequent starts and stops required for satisfying peaking requirements. Bogue CCGT is forecasted at 9,167 kJ/kWh with major outage intervention on CC GT#13.
6. IPPs are forecasted at 9,123 kJ/kWh with major outage intervention forecasted for some JEP Engines, Maintenance outages at the JPPC Complex and Major maintenance on some WKPP engines. SJPC 194 MW will have routine inspections on its gas and steam turbines.

The 2020 JPS Thermal heat rate is forecasted at 10,246 kJ/kWh

The 2020 System Thermal Heat Rate is forecasted at 9,565 kJ/kWh

Figure 9-7: Heat Rate Forecast 2020



9.6.4 Heat Rate Forecast 2021

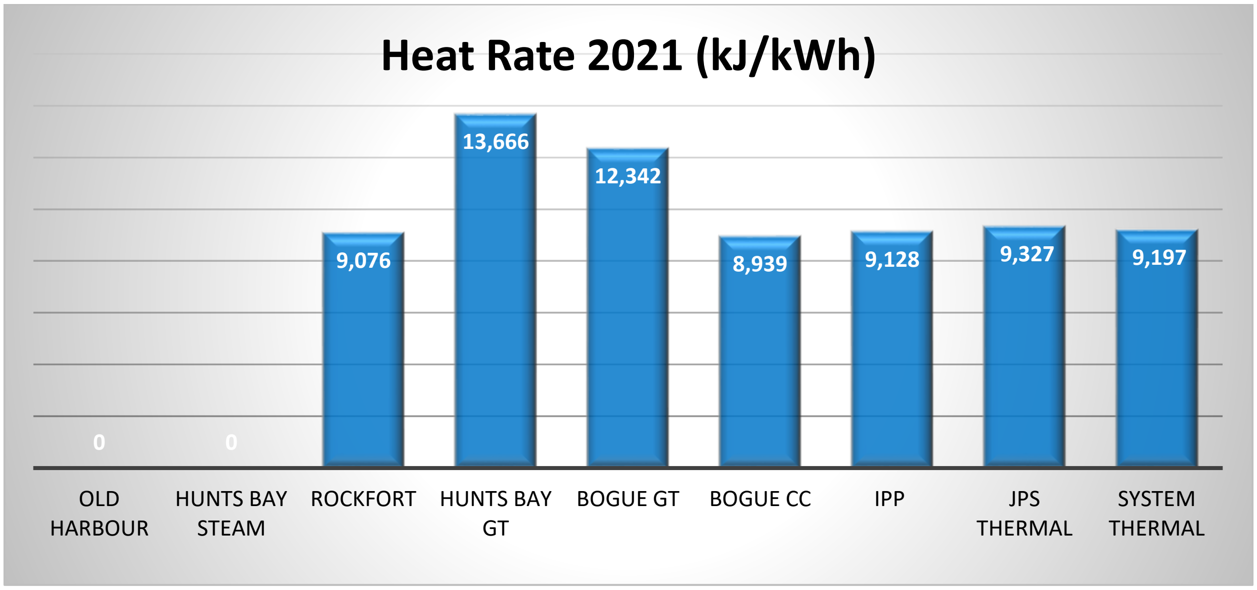
The forecasted heat rate by plant for 2021 is as follows.

1. Rockfort is forecasted at 9,076 kJ/kWh with planned major outage intervention on RF#1.
2. Old Harbour plant fully retired at the end of 2019.
3. Hunts Bay HB#B6 fully retired at the end of 2020.
4. Hunts Bay gas turbines forecasted at 13,666 kJ/kWh which is reflective of their peaking duty requirements.
5. Bogue gas turbine GT#3 to GT#11 are forecasted at 12,342 kJ/kWh which is reflective of their peaking duty requirements. Bogue GT#11 will have a major inspection and the Bogue CCGT is forecasted at 8,939 kJ/kWh.
6. IPPs are forecasted at 9,128 kJ/kWh with major outage intervention forecasted for some JEP Engines, Maintenance outages at the JPPC Complex, and major maintenance on some WKPP engines. SJPC 194 MW routine inspections on its gas and steam turbines.

The 2021 JPS Thermal heat rate is forecasted at 9,327 kJ/kWh

The 2021 System Thermal Heat Rate is forecasted at 9,197 kJ/kWh

Figure 9-8: Heat Rate Forecast 2021



9.6.5 Heat Rate Forecast 2022

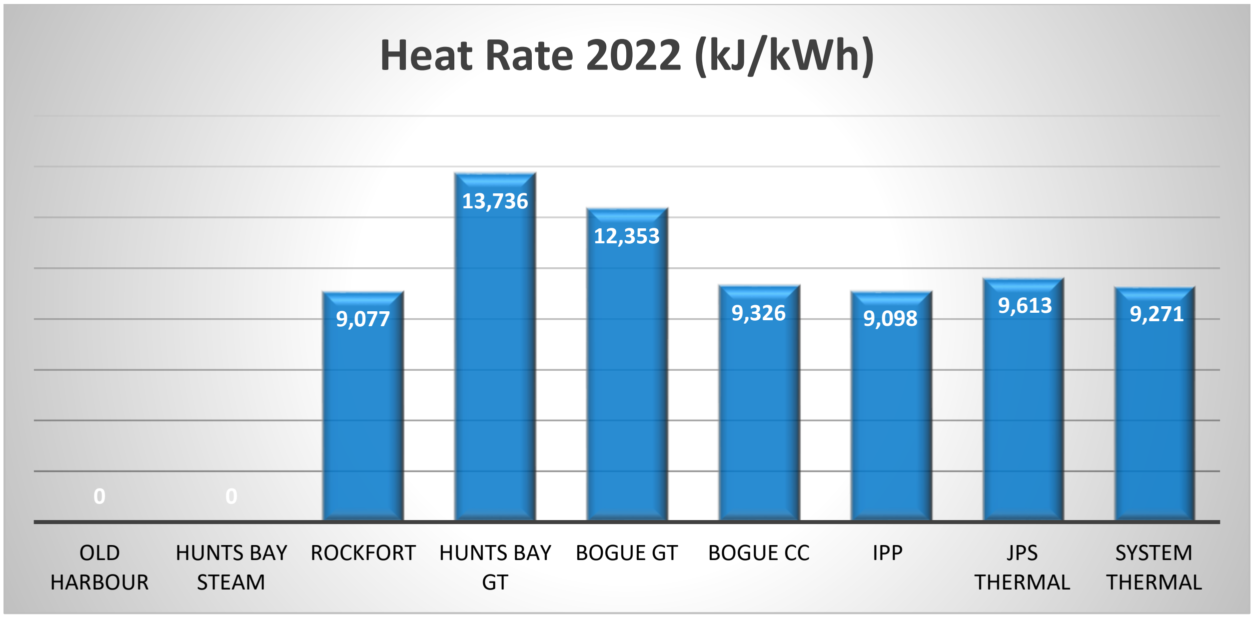
The forecasted heat rate by plant is as follows for 2022.

1. Rockfort is forecasted at 9,077 kJ/kWh with planned major outage intervention on RF#2.
2. Old Harbour plant fully retired at the end of 2019.
3. Hunts Bay HB#B6 fully retired at the end of 2020.
4. Hunts Bay gas turbines forecasted at 13,736 kJ/kWh which is reflective of their peaking duty requirements.
5. Bogue gas turbine GT#3-GT#11 are forecasted at 12,353 kJ/kWh which is reflective of their peaking duty requirements. Bogue CCGT is forecasted at 9,326 kJ/kWh, with major overhaul of steam turbine #14.
6. IPPs are forecasted at 9,098 kJ/kWh with major outage intervention forecasted for some JEP Engines, maintenance outages at the JPPC Complex, and major maintenance on some WKPP engines. SJPC 194 MW will have major inspections on some gas turbines and routine steam turbine inspection.

The 2022 JPS Thermal heat rate is forecasted at 9,613 kJ/kWh

The 2022 System Thermal Heat Rate is forecasted at 9,271 kJ/kWh

Figure 9-9: Heat Rate Forecast 2022



9.6.6 Heat Rate Forecast 2023

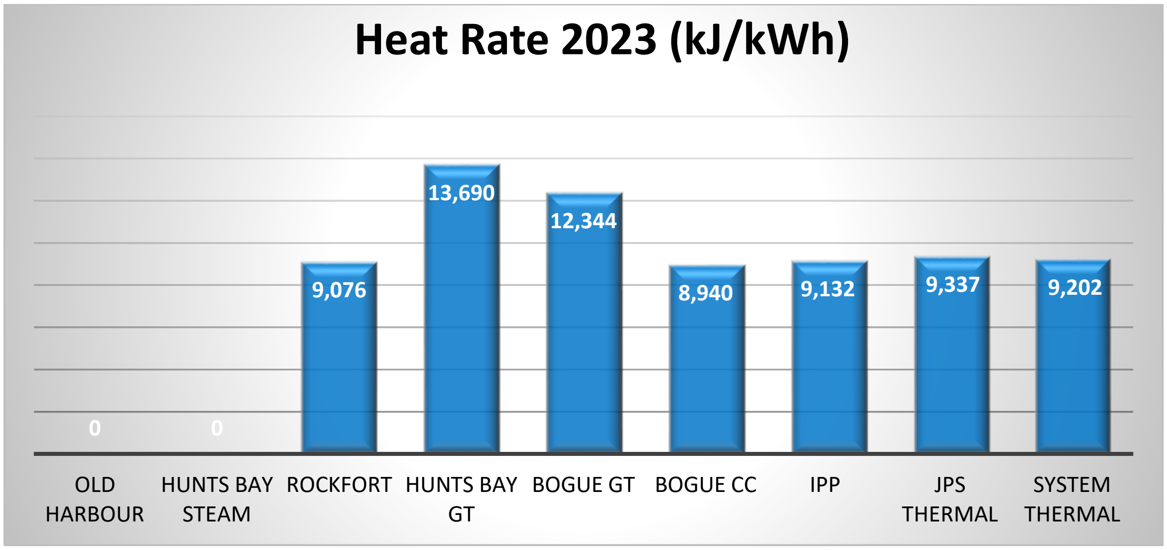
The forecasted heat rate by plant is as follows for 2023.

1. Rockfort is forecasted at 9,076 kJ/kWh with planned major outage intervention on RF#1.
2. Old Harbour plant fully retired at the end of 2019.
3. Hunts Bay HB#B6 fully retired at the end of 2020.
4. Hunts Bay gas turbines forecasted at 13,690 kJ/kWh which is reflective of their peaking duty requirements, with major inspection on GT#5 and major inspection on GT#10.
5. Bogue gas turbine GT#3-GT#11 are forecasted at 12,344 kJ/kWh which is reflective of their peaking duty requirements, with major inspection on GT#3. Bogue CCGT is forecasted at 8,940 kJ/kWh, with major inspection GT#13.
6. IPPs are forecasted at 9,132 kJ/kWh with major outage intervention forecasted for JEP Engines, maintenance outages at the JPPC Complex, and major maintenance on some WKPP engines. SJPC 194 MW will have routine inspections on its gas and steam turbines.

The 2023 JPS Thermal heat rate is forecasted at 9,337 kJ/kWh

The 2023 System Thermal Heat Rate is forecasted at 9,202 kJ/kWh

Figure 9-10: Heat Rate Forecast 2023



9.6.7 Heat Rate Forecast 2024

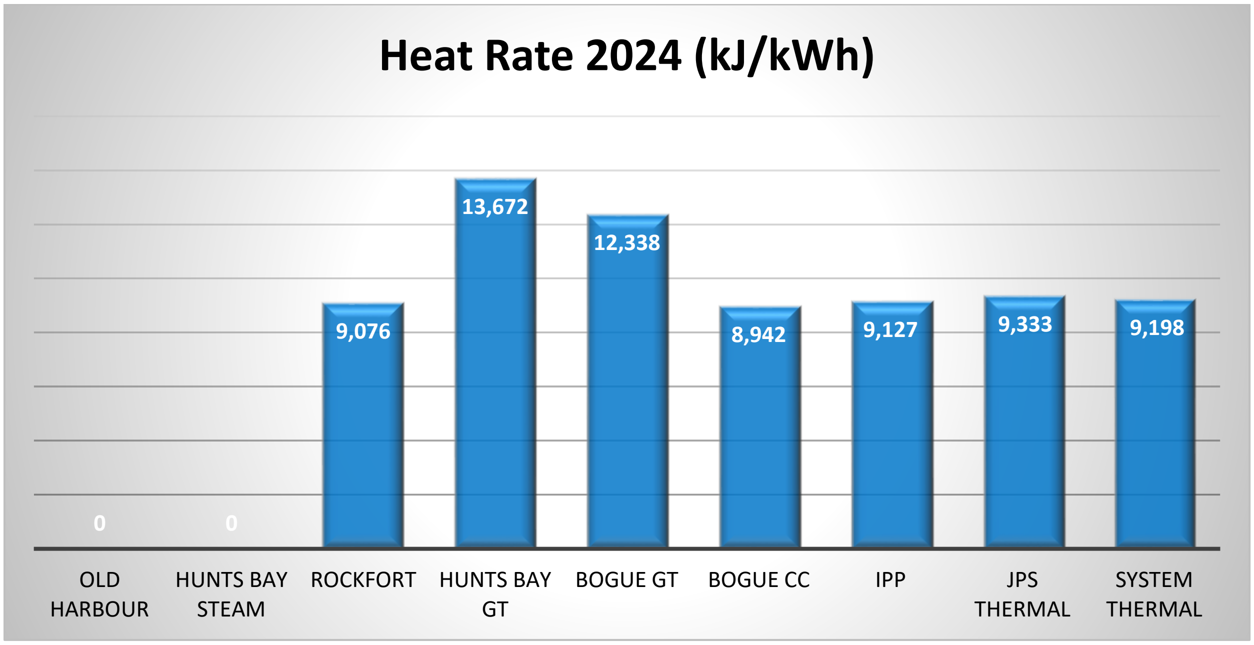
The forecasted heat rate by plant is as follows for 2024.

1. Rockfort is forecasted at 9,076 kJ/kWh with planned major outage intervention on RF#2.
2. Old Harbour plant fully retired at the end of 2019.
3. Hunts Bay HB#B6 fully retired at the end of 2020.
4. Hunts Bay gas turbines forecasted at 13,672 kJ/kWh which is reflective of their peaking duty requirements.
5. Bogue gas turbine GT#3-GT#11 are forecasted at 12,338 kJ/kWh, which is reflective of their peaking duty requirements. Bogue CCGT is forecasted at 8,942 kJ/kWh.
6. IPPs are forecasted at 9,127 kJ/kWh with major outage intervention forecasted for some JEP engines, maintenance outages at the JPPC Complex, and major maintenance some WKPP engines. SJPC 194 MW will have routine inspections on gas and steam turbines.

The 2024 JPS Thermal heat rate is forecasted at 9,333 kJ/kWh

The 2024 System Thermal Heat Rate is forecasted at 9,198 kJ/kWh

Figure 9-11: Heat Rate Forecast 2024



9.7 Proposal for Heat Rate Target

The JPS thermal heat rate performance over the five-year rate review period will depend on several factors affecting the economic dispatch, which include the following:

1. Growth in system demand;
2. The addition of new generating units and the installed reserve margin, matters controlled by the MSET/GPE and OUR respectively;
3. Heat rate improvements made to existing generating units;
4. Availability and reliability of JPS generators;
5. Availability and reliability of IPP generators;
6. Absolute and relative fuel prices for JPS and the IPPs and the impact on economic dispatch;
7. Spinning reserve policy; and
8. Network constraints and contingencies.

While all the above factors influence the resultant thermal heat rate from JPS operated units, JPS has direct control over only a few.

In this regard, JPS recommends that the basis for establishing the heat rate target should continue to be the generating units in the JPS Thermal Fleet. This approach lends itself most appropriately to the objective of optimizing overall system production cost through economic dispatch. The high level of flux anticipated in the generation fleet brings with it uncertainty relating to the timing of commissioning, and the extent to which retired units will be required to provide backup services during the transitional phase. Changes in market conditions could also render the variable cost of plants used to model merit order and availability completely unrepresentative in a short period. The variation in oil prices between US$80 and US$50 per barrel over the past three months is testimony to that possibility.

Historically, the heat rate target for each year is set based on the average performance having regard to historical achievement and the projection for the next 12 months. Average heat rate performance for a year does not fully capture the effect that a wide range of monthly heat rate values would have on a monthly penalty/reward calculation, especially given the monthly variation in fuel prices and foreign exchange rates throughout a given year. In effect, the numbers on average could suggest that JPS is performing more efficiently than the target requires but the Company finds itself either a net penalty if the cost of fuel in months where JPS performs less efficiently than the target is higher than the months when the company outperforms the target. In this regard, it is JPS' view that the heat rate target must consider the effect that such influencing factors, which are outside JPS' control, would have on the JPS Thermal Heat Rate actual monthly value.

JPS faces increased performance risk to the IPPs as they generate a larger share of the electricity supply while their plants continue to age over time. A failure to achieve the target level of availability and reliability by the IPPs has the potential largest negative effect on JPS Thermal heat rate, all other factors remaining constant. Since the performance guarantees (e.g. liquidated damages) that the IPPs provide for under performance is effectively refunded to the customer through the IPP fuel surcharge/adjustment, it is JPS that suffers the penalty when the system heat rate worsens due to the poor performance of IPPs.

The targets must therefore be established with provision to adjust to IPP forced outages. The mechanism could readily operate as a part of the monthly adjustment process, with JPS submitting details of timing and quantum of output driven by IPP forced outages. This is easily verifiable given the reporting system already in place to capture liquidated damage payments due from IPPs. Such effects would be best neutralized from the calculation of JPS' actual heat rate performance.

Forced outages are a reality in the operation of the generation function. Reasonable and achievable targets must take this into account. JPS has implemented an enterprise asset management system to improve the management of generating units with the aim of optimizing output. Even with this system forced outages are unavoidable. A reasonable level of forced outages has been provided for in the target, and must be maintained.

Although Paragraph 39 of Schedule 3 of the Licence provides that the heat rate target is "normally" set by the OUR at the Rate Review for each of the five years within a Rate Review period, broken out year by year, this is merely suggestive and does not preclude the OUR from setting the heat rate target annually. This latitude in the provisions of the Licence allows the OUR to establish targets in accordance with the Licence, namely reasonable and achievable heat rate targets. 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' control, JPS proposes the following heat rate targets for the regulatory period 2019 –2024 beset for subsequent years according to the output of the Plexos modelling, as shown below and are subjected to periodic review and adjustment of the heat rate target with OUR to reflect the known impact of new generation added to the grid. These targets should reflect updated conditions and operating parameters.

Table 9-10: JPS Forecasted Thermal Heat Rate Targets July 2019 to June 2024

DATE	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	AVG
2019-2020	11,088	11,897	11,519	11,028	11,184	10,597	10,040	10,438	10,429	10,511	10,213	10,182	10,761
2020-2021	10,157	10,241	10,152	10,184	10,222	10,272	9,334	9,329	9,317	9,411	9,322	9,306	9,771
2021-2022	9,304	9,309	9,287	9,346	9,327	9,343	9,357	10,516	12,056	9,411	9,322	9,306	9,657
2022-2023	9,304	9,332	9,351	9,344	9,326	9,343	9,332	9,496	9,324	9,412	9,319	9,305	9,349
2023-2024	9,302	9,308	9,286	9,345	9,325	9,333	9,398	9,356	9,319	9,410	9,318	9,305	9,334

9.7.1 Proposed Regulatory Targets

Based on the heat rate targets obtained from JPS forecasted model for the period: July 2019 to June 2024 as indicated above, JPS propose that the OUR consider the following targets below for the regulatory period July 2019 –June 2024. These target are predicated on JPS experiencing a forced outage incident on its most efficient unit (Bogue CC Plant) lasting approximately one month:

- **July 2019 -June 2020:** JPS proposes a Thermal Heat rate target of **10,986 kJ/kWh**
- **July 2020 – June 2021:** JPS propose a Thermal Heat rate target of **9,976 kJ/kWh**
- **July 2021– June 2022:** JPS propose a Thermal Heat rate target of **9,860 kJ/kWh**
- **July 2022 – June 2023**: JPS propose a Thermal Heat rate target of **9,545 kJ/kWh**
- **July 2023 – June 2024:** JPS propose a Thermal Heat rate target of **9,530 kJ/kWh**

10 Demand Forecast

10.1 Introduction

The Ministry of Science, Energy and Technology (MSET) retained a consultancy firm, Manitoba Hydro International (MHI), in August 2017 to provide support to the Office of the Utilities Regulation (OUR) in the development of a long-term demand forecast model (the model) for the Jamaican electricity sector for the 2017-2040 period.

The methodology employed by MHI was subsequently proposed by the OUR to be used for the projection of JPS' billing parameters for the 2019 to 2024 regulatory period. The proposed model in its current state did not account for the changes in the billing parameters structure necessary for the revenue requirement recovery calculations. The model was accepted by JPS on the premise that it may be amended through a consultative process with JPS, the OUR and MSET to account for anomalies and/or omissions subsequently identified. MacroConsulting, a consultancy firm, was hired by JPS to review and update the model's assumptions and incorporate the additional billing parameters listed below:

- KVA Demand,
- kWh sales for the new rate 70 category,
- Time of Use (TOU) kWh energy and KVA demand for the large commercial and industrial customer groups (Rate 40, Rate 50 and Rate 70),
- Customer count for the Rate 70 category, and
- System Peak Demand.

These elements were deemed necessary to improve the reliability of the model and for it to better map the existing electricity demand landscape. This chapter also presents the methodology, the updates, as well as the associated justifications that were incorporated by JPS/MacroConsulting to improve the forecasting capability of the model.

The format of this chapter is organized as follows:

- **Economic Outlook**

This section presents the outlook for the Jamaica economy for the regulatory period, 2019-2024. The indicators referenced in this section impact the domestic economic climate and by extension JPS' customers purchasing power and demand. The amended version of MHI's model does not model these indicators as endogenous variables. Techniques used to estimate growth rates however accounts for customers' historical reactions to variations in these indicators.

- **Demand Forecast**

This section is primarily organized by Rate Class Grouping and outlines the Modelling Approach, the assumptions and the forecasted results for each Rate Class Grouping.

  - **Modelling Approach and Assumptions**

The proposed MHI methodology for forecasting total electricity sales and all adjustments intended to improve the model is outlined. The proposed model was adjusted/extended to account for missing billing parameters necessary for the revenue requirement calculations (demand projections). Minor adjustments were also made to the model to improve its forecasting capabilities.

In addition to total sales (kWh) forecasting, the approach taken to project system losses, net-generation and peak demand are also presented. Total sales and demand are estimated by rate class and the assumptions for each rate class are outlined.

- **Results**

Forecasted results are presented for the number of customers and projected energy sales for each Rate Class Grouping.

Licence Provisions

Schedule 3, paragraph 11 of the Licence notes that the criteria published by the Office should include "anticipated change to the demand for electricity."

Final Criteria

The Final Criteria outlines the proposed model to be employed by JPS to estimate the billing parameters required for the Revenue Requirement process. In this regard, Criterion 5 of the Final Criteria states:

In presenting its billing data projections for the 2019 – 2024 Rate Review period, JPS shall:

a) Employ the model to develop its projections and support any adjustments made to the proposed model with clear and logical explanations;
b) Disaggregate gross losses projection before allocation to each rate class into:
    i. Station Use
    ii. Technical Low Voltage Losses
    iii. Technical Medium Voltage Losses
    iv. Unbilled (Non-technical) Losses
c) Provide annual projections for sales-kWh, demand-KVA and number of customers by rate categories; and
d) Clearly indicate all assumptions made along with rationale for their use in its billing data projections.

Principles for Implementation

As outlined in section 3.8.5 of the Final Criteria, the methodology adopted by the OUR in developing the proposed model incorporates the following three (3) steps:

1. The employment of a model that uses a combination of extrapolation, statistical and econometric approaches in forecasting the model variables for each rate class.
    a. Rates 10, 20, 40 and 60 customer categories are based on projections of number of customers multiplied by projected unit consumption (average consumption) for the rate class.
    b. Rate 50 sales forecast is derived from a regression analysis of total sales. Table 04 below provides a summary of the final factors used to develop the base forecast of the number of customers and unit consumption for each rate class or, in the case of Rate 50, total consumption.
2. The computation of gross system losses by adding net system losses to station use. The model projected net system losses and station use from extrapolated trends, but also considered JPS' system loss reduction plans and JPS' stated objective of reducing station use over time. Each component of gross system losses is allocated to the rate classes to derive gross electricity kWh consumption.
3. The derivation of projected system peak demand, using the following methodology:
    a. The estimation of the system load factor from recent historical trends, which is held constant across the forecast horizon.
    b. The computation of the peak demand for each year, by dividing the projected gross generation by the number of hours in the year multiplied by the system load factor.
    c. The estimation of the contribution of each rate class to the system peak, using JPS' 2009 load research information (coincident and non-coincident peak data).
    d. Adjustments to the system peak contributions through a reconciliation process which adjusts the non-coincident and coincident factors."

As required in the Final Criteria, the MHI model was adopted, however, the model was amended to include the missing billing parameters and refinements were made to certain assumptions and parameters in order to improve the statistical robustness of the estimates and to reflect the short-term nature of the projections. These adjustments to the MHI model are explained in detail in the Modelling Approach and Assumptions section. The output of the adjusted model represents JPS' view on the future evolution of the demand for electricity. Without these adjustments the forecasted demand, based on MHI's model, would not accurately reflect JPS' business model going forward.

Demand Forecast Summary

The final output of the model projects a total system demand of 4,425 GWh by 2024, an increase of 69 GWh (1.6%) from the recorded 4,356 in 2018. The projected growth in demand is primarily driven by the forecasted annual growth[48] of approximately 1% in total energy sales and the anticipated decline of 2.3% in system losses by 2023. Customer numbers are forecasted to grow at an average annual rate of 1.5% between 2019 and 2024. It is estimated to increase from

[48] compound annual growth rate (CAGR)

approximately 658,052 billed customers recorded in 2018 to 729,233 customers by the end of 2024. Table 10-1 shows total sales by rate class. Table 10-2 provides breakout of the customer number projections by rate class.

Table 10-1: JPS Total Demand 2019-2024

Billed Sales	Units	2018	2019	2020	2021	2022	2023	2024
Rate 10	GWh	1,066	1,073	1,096	1,116	1,133	1,150	1,168
Rate 20	GWh	598	604	444	448	451	455	459
Rate 40	GWh	801	809	978	988	998	1,008	1,018
Rate 50	GWh	356	364	373	378	382	385	387
Rate 60	GWh	62	58	48	40	40	40	41
Rate 70	GWh	294	272	274	279	284	289	294
Other	GWh	35	34	34	34	33	33	32
EV	GWh		0.07	0.08	0.08	0.10	0.12	0.19
Total Sales	GWh	**3,212**	**3,215**	**3,246**	**3,284**	**3,322**	**3,361**	**3,399**
System Losses	GWh	1,144	**1,126**	**1,113**	**1,099**	**1,082**	**1,059**	**1,025**
Net-Generation	GWh	4,356	**4,341**	**4,359**	**4,384**	**4,404**	**4,420**	**4,425**

Table 10-2: JPS Total number of Customers: 2019-2024

Rate class	2018	2019	2020	2021	2022	2023	2024
Rate 10	587,606	597,467	610,270	623,172	633,918	644,644	655,847
Rate 20	67,944	68,392	68,031	68,690	69,357	70,029	70,708
Rate 40	1,847	1,882	1,888	1,897	1,906	1,915	1,924
Rate 50	144	144	146	148	152	155	159
Rate 60	486	494	509	524	538	553	568
Rate 70	23	23	23	23	24	24	25
Other	2	2	2	2	2	2	2
Total Customers	**658,052**	**668,404**	**680,868**	**694,457**	**705,897**	**717,322**	**729,233**

10.2 Domestic Economic Environment: 2019-2024

The prospect for growth in the Jamaica economy is expected to continue and will strengthen over the medium-term. Projections regarding key economic indicators are improving in tandem with debt reduction and increasing stability owing to the structural and macroeconomic reforms being undertaken by the Government of Jamaica (GOJ). The recently completed three (3) year precautionary Stand-By Arrangement with the IMF has also served to further strengthen the credibility of Jamaica's economic reform agenda.

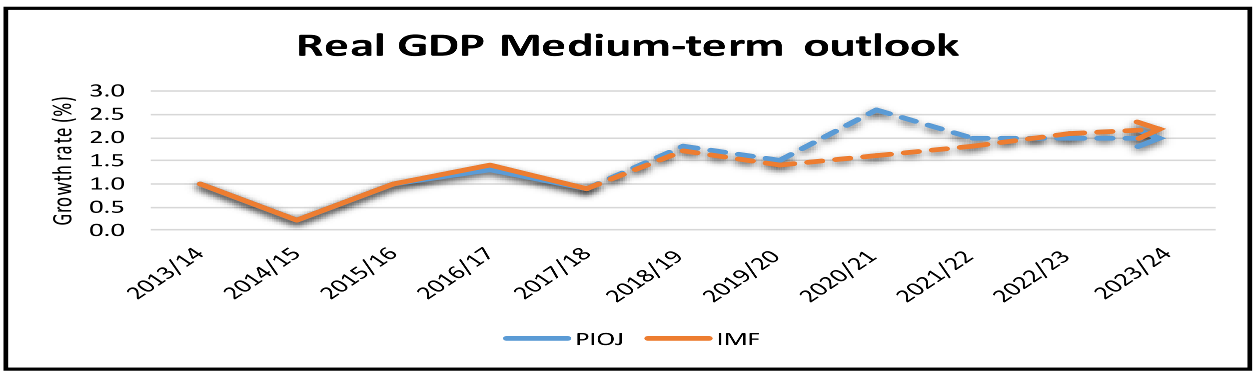
Inflation is expected to stabilize at around 5% between 2019 and 2024. This expectation is made against the country's inflation targeting regime. The current account deficit as a percentage of Gross Domestic Product GDP is projected to remain relatively low, averaging 1.7% over the medium term. This is predicated on the expectation of improvements in Jamaica's external competitiveness. Furthermore, the loosening of the monetary policy stance of the Bank of Jamaica (BOJ), through the reduction of the policy rate[49], is expected to foster greater credit expansion, stronger growth in economic output and further improvements in the labour market, and by extension, support the inflation targeting regime.

10.2.1 Gross Domestic Product (GDP)

GDP is expected to perform positively over the medium-term, predicated on improvements in most industries, macroeconomic stability and fiscal consolidation. Stabilization efforts are therefore expected to take root and lead to improved output performance.

The IMF projected an increase in real growth over the medium term, from about 1.7% in 2019 to approximately 2.2% by 2023[50], whereas the Planning Institute of Jamaica (PIOJ), driven by the 'The GOJ's *5 in 4* growth agenda', expects growth to average 2.0%. The projected improvements in the economic climate anticipates improvements in selected industry output, enhanced private sector confidence, investment, and strong external demand, supported by increased consumption, and growth in the travel and tourism sectors.

The graph below illustrates Real GDP growth forecasts by the IMF and PIOJ for the Jamaican economy.



[49] The local benchmark interest rate, the policy rate, was lowered in March 2019 from 1.5% to 1.25%.
[50] International Monetary Fund World Economic Outlook Database, October 2018
https://www.imf.org/external/pubs/ft/weo/2018/02/weodata/weorept.aspx?sy=2016&ey=2023&scsm=1&ssd=1&sort=country&ds=.&br=1&pr1.x=49&pr1.y=11&c=343&s=NGDP_RPCH&grp=0&a=

10.2.2 Assumptions driving outlook

The growth in economic output over the medium term is expected to be sustained through:

- **Greater utilization of expanded capacity in some industries as a result of higher demand.**[51]
- The mining sector is expected to expand by more than 36% in FY2020/21 and 6% thereafter.

- Relatively stable growth between 5% to 8% is expected for the Agriculture, Forestry & Fishing over the medium term.

- The Hotels and Restaurant industry is projected to grow between 4% to 5% over the medium-term. The projected growth is expected to be sustained primarily by increased visitor arrivals, associated with continued growth for Jamaica's main trading partners.

- The Manufacturing sector is expected to grow by 2.2% in FY2010/21.

- **Improved performance of the external accounts.**
  The current account deficit is expected to converge to around 3.5 % of GDP over the medium-term. This is expected to reflect higher imports to support the increases in public-sector private sector investment.

- **Improvements in the labour market.**
  According to the BOJ, the average unemployment rate is expected to decline to approximately 8.0% between March 2019 and December 2020. The total labour force and the employed labour force are also estimated to increase year over year, at an average rate of 0.5 % and 1.5% respectively, per quarter. The expected improvement in the labour market conditions supports employment growth in the Mining & Quarrying, Manufacturing, Finance & Insurance sector and Business Process outsourcing.

10.2.3 Potential Risks to Forecast

- Potential impact of adverse weather conditions on domestic production
- Slower than anticipated growth in the global economy.
- Lower than anticipated international commodity prices, particularly crude oil.

[51] Government of Jamaica, Fiscal Policy Paper FY 2019/20: http://www.mof.gov.jm/documents/documents-publications/document-centre/file/1970.html.

10.3 Modelling Approach and Assumptions

The model developed by MHI was proposed by the OUR to forecast JPS' billing parameters for the 2019 to 2024 regulatory period. The proposed model in its current state represented a base case[52] which, if needed, could be adjusted with clear and logical support.

Criterion 5 of the Final Criteria requires JPS to project billing parameters that are missing from the MHI model. These parameters include:

- KVA Demand,
- kWh sales for the new rate 70 category, and
- Time of Use (TOU) kWh energy and KVA demand for the large commercial and industrial customer groups (Rate 40, Rate 50 and Rate 70).

The MHI methodology was therefore adjusted\extended to account for these missing billing parameters which are necessary for the revenue requirement calculations. In addition, minor adjustments were made to some of the model's existing parameters in order to account for changes in JPS' tariff structure and to improve the statistical robustness of the model.

The adjusted model that was employed for the 2019-2024 projections replicates the unmodified version of MHI's methodology outlined in section 3.8.5 of the Final Criteria in that:

1. It uses a combination of extrapolation, statistical and econometric approaches in forecasting the model variables for each rate class;
2. It computes net system losses and station use based on JPS' system loss reduction plans and JPS' stated objective of reducing station use over time, and each component of gross system losses is allocated to the rate classes to derive gross electricity kWh consumption;
3. It projects system peak demand using the latest Load Characterization parameters for each class (load factor, external coincident factor, and non-coincident factor)

Adjustments were only introduced to MHI's methodology at points 1a and 1b of section 3.8.5 of the final criteria, the sales projection models by rate class *(See the Principles for Implementation in the Introduction above).* In particular, an Autoregressive Integrated Moving Average (ARIMA) estimation technique was employed to derive growth rates for specific rate categories and to derive total consumption for new consumption blocks. In modelling the various patterns in the dataset, the ARIMA model captures and accounts for measures taken by customers to influence their consumption patterns in the past. Any activities that are not recent phenomena are embedded in the output from the ARIMA models. Use of the ARIMA model in the proposed demand projection is explained in detail in the Demand Forecast Report provided in Annex I.

[52] See section 3.8.6 of the Final criteria

The main rationale behind the adjustments relates to the short-term nature of the required projections in the context of the Rate Case Filing as compared to the long run nature of the MHI model. The historical data used in the MHI model was also updated and the model was extended to incorporate the missing billing parameters.

The existing differences in the projections for each rate class are summarized in the tables below. The first column of each table identifies the variables that are being compared, the second column (MHI) contains the description of the MHI model as presented in *Table 04 in the Final Criteria*, the third column describes any adjustments to the MHI approach, if any, while the fourth column summarizes the reasons supporting the chosen alternative.

Residential (Rate 10)

Variable	MHI	Macro	Differences
No. of customers	Number of households	Number of households	No Differences
Unit (Average) consumption	Average consumption extrapolated from average growth between 2005 and 2016	Average consumption projected with an ARIMA model using monthly data for the period 2005-2018	Using monthly data and an ARIMA model allows more statistically robust short term estimates
Total Consumption	Number of customers × Average consumption	Number of customers × Average consumption	No Differences
Comments	Rate Class is divided into: • Block 1 – Cons ≤ 100kWh/month • Block 2 Cons > 100kWh/month Analysis completed for each block and then aggregated. MHI conducted a demographic analysis to forecast growth in the number of households.	Rate Class is divided into: • Block 1 – Cons ≤ 100kWh/month • Block 2 Cons > 100kWh/month According to JPS billing database information	No Differences, Except that Wiring is treated as a policy variable and not as an ad hoc value

Small commercial (Rate 20)

Variable	MHI	Macro	Differences
No. of customers	Population growth over age 15	Average growth rate over the last 10 years - OLS function of population over age 15	Using a regression instead of the same growth rate improves statistical robustness
Unit (Average) consumption	▪ Wholesale and retail trade per capita ▪ Government services per capita	Average consumption projected with an ARIMA model using monthly data for the period 2005-2018 separated in 3 consumption blocks (see comments)	Using monthly data and an ARIMA model provides statistically robust short term estimates. Avoids the problem of forecasting exogenous variables
Total Consumption	Number of customers x Average consumption	Number of customers x Average consumption	No Differences
Comments	The forecasts of consumption for two (2) large interchange customers were done separately and then aggregated with the total consumption for the other Rate 20 customers	3 blocks: ▪ Block 1 customers with annual consumption < 1,200 kWh (but greater than 60 kWh/year). ▪ Block 3, annual consumption over 20,170 kWh. (20% of customers whose consumption is the higher within the class, from the rest of the customers Not classified as Block 1) ▪ Block 2, composed by the remaining 80% of customers Not classified as Block 3.	To reflect the high heterogeneity of this class users were segmented by consumption levels (as MHI did for Rate 10). This allows for better projections of consumption by different user types.

Large Commercial and Industrial: Rate 40

Variable	MHI	Macro	Differences
No. of customers	Customer growth rate estimated from historical trend	MHI growth rate applied to 2018 figures	Difference is only on initial number of customers.
Unit (Average) consumption	▪ Mining and Quarrying component of GDP growth rate ▪ Hotel and restaurants component of GDP growth rate ▪ Electricity and Water Supply component of GDP growth rate	▪Cluster analysis according to 2-digit industrial code, ▪ 4 clusters (C1; C2; C3; Hotels) ▪ Within cluster *total* consumption projected with ARIMA models using monthly data for the period 2008-2018	Cluster analysis allows to objectively group users with similar behavior in terms of growth rates. ARIMA model provides statistically robust short term estimates Avoids problems of forecasting exogenous variables
Total Consumption	Number of customers Average consumption	Total consumption was estimated as the sum of each clusters' projected demand	Total consumption was the forecasted variable

Large Commercial and Industrial: Rate 50 and Rate 70

Variable	MHI	Macro	Comments
No. of customers	Customer growth rate estimated from historical trend (Rate 50)	MHI growth rate applied to 2018 figures (and split between Rate 50 and Rate 70)	Difference is only on initial number of customers.
Unit (Average) consumption	Producers of Government Service as a component of GDP (Rate 50)	▪Cluster analysis according to 2-digit industrial code, ▪ 4 clusters (C1; C2&C3; Caribbean Cement Co.; Hotels) ▪ Within cluster *total* consumption projected with ARIMA models using monthly data for the period 2008-2018	Cluster analysis allows to objectively group users with similar behavior in terms of growth rates. ARIMA model provides statistically robust short term estimates Avoids problems of forecasting exogenous variables

Variable	MHI	Macro	Comments
Total Consumption	Total consumption was adjusted for expected changes in load due to analysis of expansion and demand reduction plans supplied by JPS' key account customers (Rate 50)	Total consumption was estimated as the sum of each clusters' projected demand This was also done for Rate 70, were 2 clusters arose from the clustering analysis: C1 and hotels	Total consumption was estimated under borh approcahs, but Macro split analysis into clusters

Streetlight and Traffic Signals (Rate 60)

Variable	**MHI**	**Macro**	**Differences**
No. of customers	Customer growth rate extrapolated from trend from 1997 - 2016	+ Lighting policy (2019 - 2023) + Urban population growth (2024-2040) Bulbs stock composition arising from replacement plan (number of LED and HPS bulbs)	No customers were estimated instead bulbs were
Unit (Average) consumption	Urban population growth rate	Average consumption per bulb, LED and HPS (LEDs twice as efficient)	Average bulb consumption was used
Total Consumption	Number of customers Average Consumption	▪Number of each type of bulb ▪Consumption of each type of bulb	A bottom-up or engineering approach was used
Comments	Forecast of total sales was adjusted for expected reduction in sales due to the street light replacement programme which is expected to be completed by 2021	Total consumption was estimated as product of number of bulbs and average consumption, accounting for bulbs in each year and lighting policy	A bottom-up or engineering approach was used

The different customer categories short term forecasts, along with their methodological aspects, are detailed in what follows.

10.3.1 Residential (Rate 10)

Customer number

Following the MHI model, the projected growth in customer numbers (number of households) for the residential category was determined by the change in population, the number of persons per household and the number of illegal connections. The growth of customers due to the reduction of illegal connections implying a trend towards a single meter per household was not estimated but assumed to be a policy parameter. This parameter allows for the projection of customer regularization in line with JPS Business Plan.

The total number of residential customers was split into two (2) subclasses and the share of each class in the annual growth of new customers was estimated. The two (2) subclasses were defined by those consuming less than 1200 kWh/year (Block1) and those consuming strictly more than the threshold (Block2). The total number of new customers and its composition was extrapolated from the historical billing dataset for the period 2008 - 2018.

Average consumption

In estimating the evolution of average consumption, only those customers that were present in all billing periods between 2008 and 2018 were considered. The average consumption behaviour, for each subclass of residential customers was estimated using an ARIMA model. The yielding average consumption series were not used to project total residential consumption for each subclass. Instead, yearly growth rates were computed from the series and then applied to actual 2018 average consumption for both subclasses (including *all* customers present in 2018). Using an ARIMA model instead of a simple annual extrapolation to derive the growth rates increases the statistical robustness of the projections. Energy efficiency and the adoption of new appliances are implicitly accounted for in the past consumption behavior and by extension the structure of the ARIMA model. The precise specification of each model for each subclass behaviour is listed in section four (4) of the Demand Forecast Report

Prepaid [53]

This is a relatively new tariff category which was not captured in MHI's model and there is little information to project rate 10 prepaid customers' consumption. For this reason, to project the rate category, the following assumptions were made:

- 2018: Proportion of rate 10 prepaid overall rate 10 consumption equal to past proportion (0.5%), based on billing data.
- 2019-2024: Same historical proportion and all customers from wiring policy initiative are pre-paid (when assuming a wiring policy).

[53] Pre-paid meters were first deployed in Jamaica in 2015, when around 2,000 pieces of equipment were offered to MT10 and MT20 customers, connected to 220v in Kingston, St Andrew and St Catherine. A year later, JPS started expanding PAYG to these customers in all parishes.

Assumptions – Residential customers

Table 10-3: Assumptions - Residential consumption

Parameters	Assumptions
Household growth	The number of households is a function of the population and the number of persons per household. The population is expected to increase by approximately 0.2% between 2019 and 2024. The growth in the number of customers per household is assumed to decline from 1.7% to 1.2% between 2019 and 2024
Illegal connections	Illegal connections are assumed to reduce by 3,000 each year until 2023 after which this figure increases by 500 annually until reaching maximum of 7,000. This reduction will be the result of a collaborative House Wiring initiative between JPS and the GOJ
	All new customers resulting from this initiative are assumed to belong to Block1
Customer's composition	Approximately 40% of total number of customers over the forecast period belong to Block 1 while 60% belong to Block 2
	All new customers are assumed to constitute 53% Block1 and 47% Block2.
Average consumption	Output of ARIMA model accounts for patterns and trends already impacting residential customer's average consumption such as Energy Efficiency and conservation measures.

Model output: Rate 10

The compound annual growth rate for the rate 10 category between 2013 and 2018 was 1.9%. This is forecasted to decline to approximately 1% by the end of 2019 followed by an increase of 1.8% in 2021. It is thereafter expected to remain at approximately 1.4% until 2024 where total Rate 10 sales are projected to be approximately 1,165 GWh. The total number of customers for Rate 10 are expected to increase to 655,847 by 2024 from the recorded 587,760 in 2018.

Table 10-4: Rate 10 Total Energy Sales

Rate 10	2008	2013	2018	2019	2020	2021	2022	2023	2024
Average Consumption (kwh)									
Block 1	573	570	596	608	618	627	636	644	652
Block 2	2,670	2,478	2,579	2,558	2,561	2,561	2,561	2,561	2,561
Number of Customers									
Block 1	192,971	213,964	226,507	231,615	239,774	247,986	255,063	262,129	269,683
Block 2	344,602	348,704	361,254	365,852	370,495	375,186	378,856	382,515	386,164
Total	537,573	562,668	587,760	597,467	610,270	623,172	633,918	644,644	655,847
Total energy (GWh)									
Block 1	***111***	***122***	***135***	***140***	***149***	***157***	***164***	***172***	***180***
Block 2	***920***	***864***	***932***	***933***	***947***	***960***	***969***	***979***	***989***
Total	**1,031**	**986**	**1,067**	***1,073***	***1,096***	***1,116***	***1,133***	***1,150***	***1,168***
CAGR		**-0.9%**	**1.6%**	***0.6%***	***2.1%***	***1.9%***	***1.5%***	***1.5%***	***1.6%***

10.3.2 Small commercial (Rate 20)

Customer number:

An analysis of several parameters revealed statistical and logical links between the population aged fifteen (15) and over and the number of small commercial customers. To estimate the total number of customers, a linear regression[54] was estimated and the "population over fifteen (15) years old" was used as an explanatory variable, which is consistent with the MHI model.

To further improve the out of sample forecasting ability of this rate category, it was divided into three (3) subclasses to account for the high heterogeneity in terms of consumption found in this rate class[55]:

- **Block1** - composed of those customers consuming strictly less than 1,200 kWh but above 60 kWh annually;
- **Block 3** - composed of the 20% of customers whose consumption is the highest within the class. That is, those customers having an annual average consumption of 20,170 kWh/year; and
- **Block 2** – composed of the remaining 80% of customers not classified as Block1.

[54] See estimated equation in section 4.1.2.1.1 of the Demand Forecast report prepared by Macro Consulting

[55] For a detailed discussion on the heterogeneity of this rate class see Tariff Structure Report section 3.4.

As with the case of residential customers, to identify these subclasses in the billing database, a per customer analysis was undertaken to classify each customer according to their 2008 consumption, considering the abovementioned thresholds. The resulting proportions of the various blocks were extrapolated to the entire population of small commercial customers. Once a given customer was classified as belonging to a particular block according to this procedure, it was assumed that the customer remained within that subclass over the forecast period. These figures were afterwards corrected to account for customers that will be migrated to Rate 40 starting in 2020.

Average consumption

To project average consumption for the small commercial rate category, an ARIMA[56] model was specified for each subclass and the yearly growth rates computed and applied to 2018 average consumption data for the specific subclass. The justification to use a time series approach rather than the econometric function adopted in the MHI model is twofold. Firstly, the time series approach allows the use of monthly data which improves the statistical robustness of the model[57]. Secondly, it avoids the need to project the explanatory variables (for which there is no official projections covering the required period).

Furthermore, energy efficiency and the adoption of new appliances were accounted for in the structure of the ARIMA model.

Others

Two (2) large customers that are charged Rate 20 tariff are grouped in the small commercial category and classified as "others." These were modelled separately due to their distinct consumption behaviour. Their historical average growth rate between 2008 and 2015 was used to project total sales. It is expected that the number of customers in this group will remain fixed at two (2) over the forecasted period.

Prepaid

This rate category was not included in MHI's model. For projecting Rate 20 pre-paid consumption, the following assumptions were made:

- 2018: Proportion of Rate 20 prepaid overall Rate 20 consumption (without considering "Others") equal to past proportion (0.07%), based on billing data.
- 2019 – 2023: Increasing pre-paid proportion until reaching 2% of total Rate 20 consumption by 2023 (without considering "Others")

[56] The precise specification of each model is identified in section 4.1.2 of the Demand Forecast Report prepared by Macroconsulting

[57] A lack of monthly data for MHI explanatory variables prevents the use of their model with this level of granularity.

- 2024: Increasing pre-paid proportion until reaching 5% of total Rate 20 consumption by 2040 (without considering "Others")

Assumptions –Small commercial customers

Table 10-5: Assumptions - Small Commercial consumption

Parameters	Assumptions
Population over 15 yrs.	Significant statistical relationship between population over 15 years and number of small commercial customers. R square = 0.9
Customer's composition	Approximately 29.2% of total customers belong to Block 1, 59.1% belong to Block 2 and 11.7% belong to Block 3
	Between 2019-2024: 46% of all **new customers** belong to Block 1, 49% to Rate Block 2 and 5% to Block 3. Migration of 1,015 customers (164 GWh) in 2020 to rate 40
Average consumption	Output of ARIMA model accounts for patterns and trends already impacting residential customer's average consumption such as Energy Efficiency and conservation measures. Migration of customers results in a decline of 7.38% in Block 3's average consumption.

Model output: Rate 20

Total energy sales for rate 20, excluding the other category is forecasted to decrease from the recorded 601 GWh in 2018 to 459 GWh in 2024. This is due primarily to the migration of customer from Rate 20 to Rate 40. Customer numbers is projected to increase from 67,745 recorded in 2018 to 70,708 by 2024.

Table 10-6: Rate 20 Total Energy Sales and Customer numbers

Rate 20	2008	2013	2018	2019	2020	2021	2022	2023	2024
Average Consumption									
Block 1	453	460	455	469	479	488	496	503	510
Block 2	5,038	5,084	5,093	5,164	5,181	5,197	5,211	5,224	5,236
Block 3	64,787	62,637	58,869	58,648	40,236	40,142	40,071	40,015	39,972
Number of Customers									
Block 1	17,659	20,572	22,662	22,958	23,257	23,559	23,863	24,171	24,481

Rate 20	2008	2013	2018	2019	2020	2021	2022	2023	2024
Block 2	35,801	35,145	38,372	38,692	39,015	39,341	39,670	40,002	40,337
Block 3	7,070	6,297	6,710	6,742	5,759	5,791	5,823	5,856	5,889
Total	**60,530**	**62,014**	**67,745**	**68,392**	**68,031**	**68,690**	**69,357**	**70,029**	**70,708**
Total energy (GWh)									
Block 1	***8***	***9***	***10***	***11***	***11***	***11***	***12***	***12***	***12***
Block 2	*180*	*179*	*195*	***199***	***202***	***204***	***206***	***209***	***211***
Block 3	***458***	***394***	***395***	***394***	***231***	***232***	***233***	***234***	***235***
Total	**646**	**583**	**601**	***604***	***444***	***448***	***451***	***455***	***459***
CAGR		**-2.1%**	**0.6%**	**0.9%**	**-26.6%**	**0.8%**	**0.8%**	**0.8%**	**0.8%**

The number of customers in the "other' category is projected to remain at two (2) over the regulatory period. Total sales for the category is projected to steadily decline by approximately 1% following the projected 34GWh expected for 2019.

Table 10-7: Other Total Energy Sales and Customer numbers

Other	2008	2013	2018	2019	2020	2021	2022	2023	2024
Total customer number	2	2	2	2	2	2	2	2	2
Total energy (GWh)	28	30	34	34	34	34	33	33	32
CAGR		1.40%	3.38%	-1.6%	-1.1%	-1.2%	-1.2%	-1.2%	-1.2%

10.3.3 Large Commercial and Industrial customers (Rate 40, Rate 50 and Rate 70)

Energy sales

The approach used by MHI to forecast Rate 40 and Rate 50 customers assumes that companies in the same economic activity (GDP component) have similar behavior[58]. This assumption has been refined and customers have been grouped using cluster analysis. This estimation technique improves the projections by facilitating the identification of differences in growth patterns across different economic activities. Cluster analysis was also used to estimate the Rate 70 category. Since the Rate 70 is relatively new (established in October 2017), the historical series was constructed by identifying and tracking these customer's behaviour from Rate 50 and Rate 40 customer data.

[58] Even if this assumption is a priori acceptable, MHI does not test it nor does it provide a clear justification of the chosen groups.

For the three rate classes mentioned above, total consumption was estimated and forecasted as the dependent variable and not as the product of average consumption and number of customers. To forecast total consumption for these rate categories, the customers were separated into different customer subclasses within each rate according to their two (2) digit industrial code[59]. Within each rate class, and according to the identified industrial codes, a cluster analysis using the K-means[60] method was conducted to identify which group of sectors presented similar consumption growth patterns. They were projected in this manner because these categories are composed of relatively more heterogeneous customers, which are easier to identify and characterize, and the notion that expected electricity consumption depends on the specific sector to which customers belong.

Four (4) clusters were identified for Rate 40, three clusters were identified for Rate 50, and two (2) clusters were identified for Rate 70. In addition to the three clusters identified for Rate 50, Carib Cement, a Rate 50 customer charged at a special tariff, was modelled as a distinct group. For each of these clusters or groups identified, a Seasonal Autoregressive Integrated Moving Average (SARIMA) model was estimated to derive total consumption. Adopting a SARIMA technique does not diminish a priori the accuracy of the forecast, it however, avoid problems associated to the forecasting of independent variables. The model specifications and cluster details are summarized in Section 4.1.3 of the Demand Forecast Report.

The forecasted total energy sales for Rate 40 as well as Rate 50 was further split into three subcategories to facilitate proposed changes in the tariff structure.

- Rate 40 (Rate 50) STD: customers subject to a standard rate
- Rate 40 (Rate 50) TOU: Rate 40 customers subject to a Time of Use rate
- Rate 40X (Rate 50): New proposed category, time of use rate applicable to those rate 40 customers with demands over 1000 kVA.

All users in Rate 40 (Rate 50) with demand over 1MVA in 2018 are migrated to the newly created Rate 40X (50X). The split between the remaining customers between STD and TOU was made assuming that, by 2028 (two regulatory periods), all users would be TOU. Rate 70 customers were only split into standard time of use.[61]

Number of customers:

The number of customers under these categories were estimated based on the projected growth rates from MHI models, applied to 2018 values.

[59] Section 4.1.3 of the Demand Forecast Study – Annex to the Rate Case Filing

[60] K-means clustering is a data mining and machine learning tool used to cluster observations into groups of related observations without any prior knowledge of those relationships.

[61] See JPS' Tariff Structure Analysis report.

Model output: Rate 40

Rate 40's total energy sales is projected to grow at an average annual rate of 5% over the regulatory period. This increased growth rate relative to other periods is attributed to the migration of customer from Rate 20. Rate 40 is projected to increase from 809 GWh in 2019 to 1,018 GWh in 2024, an increase of 217 GWh. The total number of customers are expected to increase from the recorded 1,863 customers in 2018 to 1,924 customers by the end of 2024.

Table 10-8: Rate 40 Total Energy Sales and Customer numbers

Rate 40	2008	2013	2018	2019	2020	2021	2022	2023	2024
Cluster C1	390	443	502	511	515	523	531	538	545
Cluster C2	108	122	134	133	132	132	132	131	131
Cluster C3	169	94	43	40	39	38	38	38	38
Hotels	108	111	122	125	127	129	131	133	135
Migrated Rate 20 customers					164	165	166	168	169
Total energy sales (GWh)	**775**	**770**	**801**	**809**	**978**	**988**	**998**	**1,008**	**1,018**
CAGR		**-0.1%**	**0.8%**	**0.95%**	**20.8%**	**1.1%**	**1.0%**	**1.0%**	**1.0%**
Total customer number			**1,863**	**1,882**	**1,888**	**1,897**	**1,906**	**1,915**	**1,924**

Model output: Rate 50

Total energy sales for Rate 50 is projected to grow at an annual rate of approximately 1% between 2019 and 2024. It is projected to increase from 364 GWh in 2019 to 387 GWh in 2024, an increase of 23 GWh. The total number of customers are forecasted to increase from the recorded 141 customers in 2018 to 159 customers by 2024.

Table 10-9: Rate 50 Total Energy Sales and Customer numbers

Rate 50	2008	2013	2018	2019	2020	2021	2022	2023	2024
Cluster C1	202	126	24	22	21	21	21	21	21
Cluster C2&3	76	94	115	112	113	114	115	116	117
Hotels	60	77	128	141	148	152	154	155	156
Carib Cement	95	90	88	90	91	91	92	93	94
Total energy sales (GWh)	**433**	**387**	**356**	**364**	**373**	**378**	**382**	**385**	**387**
CAGR		**-2.2%**	**-1.7%**	**2.5%**	**2.3%**	**1.5%**	**1.0%**	**0.7%**	**0.6%**
Total customer number			**141**	**144**	**146**	**148**	**152**	**155**	**159**

Model output: Rate 70

The total number of customers in the Rate 70 category is forecasted to increase from the recorded 23 customers in 2018 to 25 customers by 2024, while total energy sales is expected to increase by annual average of 1.5% between 2019 and 2024

Table 10-10: Rate 70 Total Energy Sales and Customer numbers

Rate 70	**2008**	**2013**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Cluster C1	115	126	169	146	146	150	154	157	161
Hotels	46	91	125	126	128	129	131	132	133
Total energy sales (GWh)	**161**	**217**	**294**	**272**	**274**	**279**	**284**	**289**	**294**
Total customer number			**23**	**23**	**23**	**23**	**24**	**24**	**25**
CAGR		**6.2%**	**6.3%**	**-7.4%**	**0.6%**	**1.9%**	**1.8%**	**1.7%**	**1.6%**

10.3.4 Streetlight and Traffic Signals (Rate 60)

The technique employed in the MHI model to project total sales for the streetlight category involved estimating the average consumption and the number of customers using historical and projected (efficiency) data. Customer numbers were forecasted using historical growth rates while average consumption was estimated using an econometric model with urban population as the independent variable. This approach was adjusted to account for the impact of the replacement of the conventional HPS bulbs with more energy efficient LED bulbs during the regulatory period. This impact was calculated using information from JPS' HPS light bulbs replacement plan for 2019 to 2020 and historical consumption data. This bottom-up or engineering approach avoids any problems associated with a "customer" concept of forecasting which is not significant for this rate category.

Energy Sales for this rate category is projected to vary yearly according to two opposing forces:

- Introduction of more efficient lamps (technical aspect)
- Lighting of previously unserved areas (policy aspect)

Total consumption is therefore computed by multiplying the number of bulbs by its average consumption, taking into account the yearly mix of bulbs (HPS vs LED). Over time, both the bulbs stock and its composition changes. The number of bulbs changes due to an expansion plan for 2019-2024 and afterwards, following urban population growth. The mix in the bulbs stock changes due to JPS replacement plan, reaching a 100% LED lamps stock by end 2021.

Assumptions –Streetlight customer

Table 10-11: Assumptions - Streelight Consumption

Parameters	**Assumptions**
Bulb replacement	Installation of 68,000 LED bulbs to replace HPS counterparts between 2019 and 2021.
Energy efficiency	LED bulbs are assumed to be, on average, twice as efficient as their HPS counterparts. All new bulbs from the lighting policy are assumed to be LED
Urban population	Significant statistical relationship between urban population and streetlight

Model output: Rate 60

Approximately 64% of the total number of HPS streetlights will be replaced by LED counterparts between 2019 and 2021. Following the implementation, total energy sales is projected to decline by 7.1% in 2019 ending the year at 58 GWh. It is estimated to decline by another 16.4% in 2020 and 16.5% in 2021. Energy sales is expected to remain relatively flat at approximately 40 GWh from 2022 to 2023 before reaching 41 GWh in 2024.

Table 10-12: Rate 60 Total Energy Sales and Customer numbers

Rate 60	2008	2013	2018	2019	2020	2021	2022	2023	2024
Total energy sales (GWh)	69	70	62	58	48	40	40	40	41
CAGR		**03%**	**-2.3%**	**-7.1%**	**-16.4%**	**-16.5%**	**-1.2%**	**1.1%**	**0.9%**
Total number of acounts			480	494	509	524	538	553	568

10.3.5 Electric Vehicles

The model was extended to include electricity sales projections for Electric vehicles (EV). The forecast was conducted using a bottom up approach. This approach was chosen because the deployment of EV is a relatively new in Jamaica and there is no historical data to rely on.

Specifically, for estimating the electricity demand of EV owners, assumptions were made on:

- The expected number of EV over the period 2019-2040[62]
- Average EV efficiency (consumption kWh/km) [63]
- Average annual km travelled

[62] JPS Co. Electric Vehicle Charging Network (EVCN) Business Development Case - EV Market Share Sensitivity Analysis Low Growth Scenario
[63] https://ev-database.org/cheatsheet/energy-consumption-electric-car

- Percentage of charges in EV stations

Assumptions - Electric vehicles

Parameter	Value
Average efficiency	0.178
Annual km	10,000
% station charge	25.0%
EV stock yearly growth rate	
2019-2030	55%
2031-2040	27.6%

10.4 System losses

The forecast for JPS' system losses and its disaggregation into technical and non-technical losses reflects the outlook for system losses as presented in JPS' Business Plan for the regulatory period 2019-2023. Estimates for the losses trajectory beyond 2023 are based on JPS' expectations over the long-term. All assumptions and planned initiatives to achieve the projected system losses are outlined in JPS' Business plan for the period 2019-2023. Losses associated with station use was also estimated. It was estimated as the difference between gross generation and net-generation. Using JPS' 2018 gross generation and net-generation data, station use was estimated to remain relatively flat at approximately 0.4% over the review period illustrated in Table 38 in the Demand Forecast Report.

10.4.1 Model output: System Losses

The totalsystem losses is estimated to be 1,126 GWh at the end of 2019 and 1,025 at the end of 2024, a reduction of approximately 2.3%. The primary components of system losses, non-technical and technical losses, are expected to decrease from the recorded 18.03% and 8.24% in 2018 to 15.93 % and 8.03% respectively by 2024.

Table 10-13: Distribution of System Losses

	2019	2020	2021	2022	2023	2024
Technical Losses (GWh)	**358**	**358**	**359**	**358**	**355**	**353**
Secondary Distribution Network	126	126	127	128	128	126
Primary Distribution Network	135	134	134	132	129	129
Transmission	97	98	98	99	98	98
Non-Technical Losses (GWh)	**768**	**755**	**740**	**724**	**704**	**672**
Low Voltage	765	752	738	722	702	670 .6
Medium Voltage	3	3	3	2	2	1.8
Total System Losses (GWh)	**1,126**	**1,113**	**1,099**	**1,082**	**1,059**	**1,025**

10.5 Total system demand (GWh)

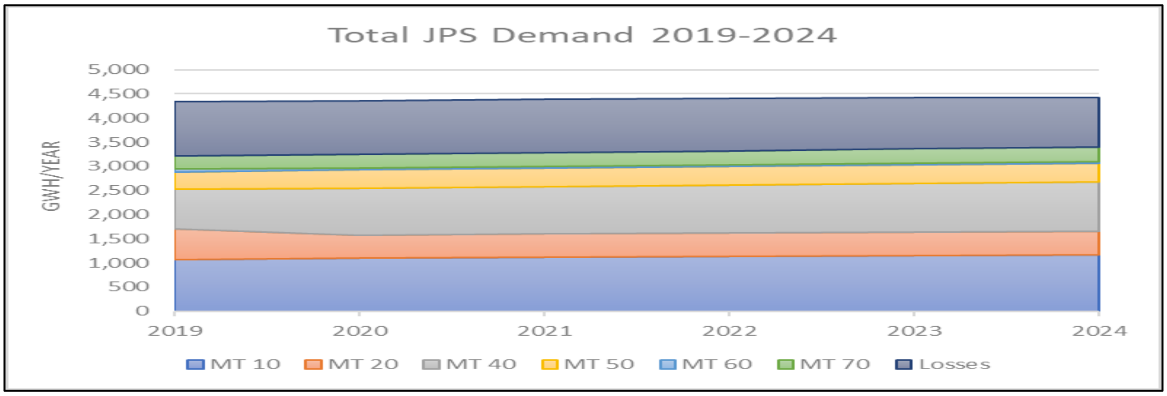
	Units	2018	2019	2020	2021	2022	2023	2024
Total Sales	GWh	3,212	3,215	3,246	3,284	3,322	3,361	3,399
System Losses	GWh	1,144	1,126	1,113	1,099	1,082	1,059	1,025
Net-Generation	GWh	4,356	4,341	4,359	4,384	4,404	4,420	4,425

The projected net-generation represents JPS' expected growth trajectory over the medium-term. It reflects the system losses profile that is expected to be achieved from planned technical losses initiatives and the demand profile that JPS expects, given trends in its customers' present and historical consumption patterns.

Total system demand is estimated to increase at an annual growth rate[64] of 0.3% from the 4,356 GWh recorded in 2018 to 4,425 GWh in 2024, an increase of 69 GWh. The increase is primarily driven by the projected annual growth of 1% in total sales and the anticipated decline in system losses of 2.3% between 2019 and 2024. Total sales is projected to reach 3,399 GWh in 2024 from the recorded 3,212 GWh in 2018.

[64] compound annual growth rate

Figure 10-1: JPS Total Demand 2019-2024



10.6 Capacity Forecast

Capacity demand projections were derived from the energy projections and assumptions regarding the behaviour of the class and systems load factors. Projecting demand (MW or MVA) from the energy forecasts involved two steps:

- Estimating the impact of an increase in energy demand in a given tariff category on the peak of that category; and
- Deriving the system wide impact.

The load factors and the coincidental factors used for estimating capacity demand were taken from JPS' 2019 load characterization study[65] shown in Section 4.3 of the Demand Forecast Report.

The resulting load factors were adjusted, based on JPS 2019 actual data and considering the fact that RE, primarily solar, penetration worsens (decrease) large customers (Rate 40, Rate 50 and Rate 70) load factor. Solar energy deployment lowers average customers' demand, while not affecting their peak demand.[66] To capture this phenomenon, it was assumed that Rate 40, Rate 50 and Rate 70 load factors decreased at a constant 0.8% yearly rate until 2024.[67] The resulting capacity demand is shown in **Error! Reference source not found.**2. For computing capacity in M VA, the capacity expressed in MW was adjusted by a power factor of 0.85.

10.6.1 Model output: Demand

Demand MW

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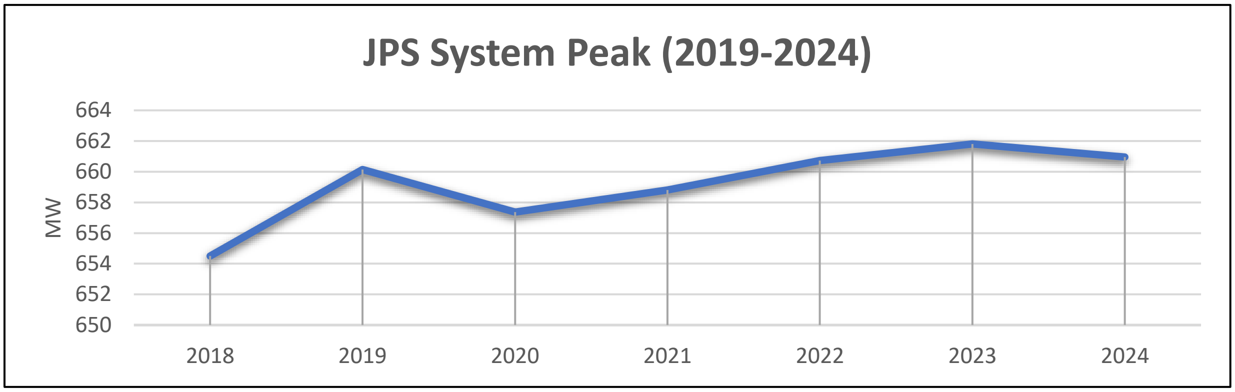
[65] Please see the load characterization study for all assumptions relating to the load factors and coincidental factors.

[66] According to internatinal experience this has occured, for example, in California, where the LF worsened by 6.7% (see https://www.ucalgary.ca/hzareipo/files/hzareipo/2016-h.-shaker-impacts-of-large-scale-wind-and-solar-power-integration-on-californias-net-electrical-load.pdf).

[67] As will be seen in what follows, this assumption generalizes to all rate classes in the medium term, accounting for the deployment and adoption of RE by small customers as well.

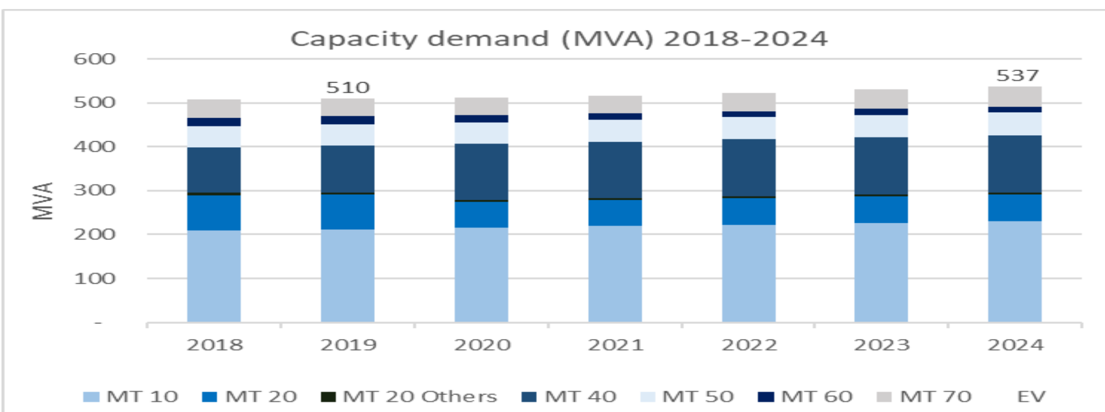
The system peak demand (MW) is estimated to fluctuate slightly between 2019 and 2024. It is expected to increase from the recorded 654.5 MW in 2018 to 661 in 2024, an increase of 6.5 MW.



Demand MVA

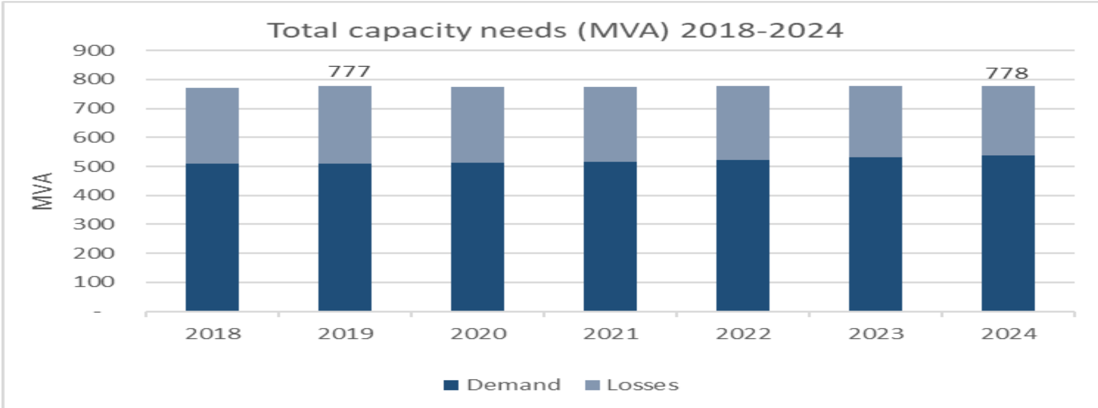
Demand was computed for losses and sales at the rate category level and then aggregated to determine JPS total capacity needs. Total maximum demand is projected to be approximately 778 MVA by 2024.

Figure 10-2: JPS Capacity demand by Rate class (MVA) 2018-2024



Adding the demand estimation for losses, yields the following capacity needs over the forecasting period:

Figure 10-3: JPS total Capacity (MVA) 2018-2024



10.7 Summary

Table 10-14: JPS Total Demand (2019-2024)

Billed Sales	Units	2019	2020	2021	2022	2023	2024
Rate 10	MWh	1,076,917	1,096,879	1,116,352	1,132,434	1,148,520	1,164,613
Rate 20	MWh	605,942	609,326	612,948	616,751	620,690	624,735
Rate 40	MWh	806,508	814,958	823,951	832,714	841,098	849,067
Rate 50	MWh	364,911	373,459	378,981	382,696	385,385	387,490
Rate 60	MWh	58,068	43,232	38,022	38,022	38,022	38,022
Rate 70	MWh	268,813	274,308	279,486	284,396	289,067	293,521
Other	MWh	34,518	34,087	33,662	33,243	32,828	32,419
Total Sales	**MWh**	**3,215,675**	**3,246,250**	**3,283,401**	**3,320,255**	**3,355,610**	**3,389,866**
System Losses	**MWh**	**1,125,139**	**1,112,303**	**1,098,557**	**1,081,515**	**1,060,828**	**1,025,113**
Net-Generation	**MW**	**4,340,814**	**4,358,553**	**4,381,958**	**4,401,770**	**4,416,438**	**4,414,979**

Table 10-15: Total number of Customers by Rate Category

Rate class	2018	2019	2020	2021	2022	2023	2024
Rate 10	587,606	597,467	610,270	623,172	633,918	644,644	655,847
Rate 20	67,944	68,392	68,031	68,690	69,357	70,029	70,708
Rate 40	1,847	1,882	1,888	1,897	1,906	1,915	1,924
Rate 50	144	144	146	148	152	155	159
Rate 60	486	494	509	524	538	553	568
Rate 70	23	23	23	23	24	24	25
Other	2	2	2	2	2	2	2
Total Customers	**658,052**	**668,404**	**680,868**	**694,457**	**705,897**	**717,322**	**729,233**

11 Capital Plan

11.1 Introduction

Licence Provisions

In accordance with Schedule 3, paragraph 29 of the Licence, the Rate Base includes construction in progress. Schedule 3, paragraph 10 of the Licence notes Business Plan, which includes JPS' investment activities, as part of the justification for the rate proposal of JPS.

Schedule 3, paragraph 46(d) and 48 of the Licence defines adjustment provisions, including Z-Factor, also addressing annual capital expenditure variation from the Business Plan.

Final Criteria

Criterion 15(a) of the Final Criteria requires JPS to submit a Business Plan predicated on a five-year time horizon, which shall include, inter alia, JPS' investment activities.

Criterion 13 outlines the process for Z-Factor adjustment for JPS' capital investment, which may be triggered by:

- Project delays
- Unimplemented projects
- Unplanned projects; and
- Change in project scope

Criterion 19 requires JPS to submit a Construction Work in Progress as part of the Business Plan.

JPS' five-year capital plan with detailed information on the Company's planned investment activities is provided in the 2019-2023 Medium Term Investment plan document which is an Annex to the Rate Case Filing.

Capital expenditure supporting JPS' investment activities is proposed as follows for each tariff year:

- 2019 forecast: US$100.1 million (US$101.7 million, inclusive of IDC)
- 2020 forecast: US$90.1 million (US$91.7 million, inclusive of IDC)
- 2021 forecast: US$100.9 million (US$102.9 million, inclusive of IDC)
- 2022 forecast: US$101.1 million (US$103.6 million, inclusive of IDC)
- 2023 forecast: US$76.3 million (US$78.9 million, inclusive of IDC)

The capital expenditure included in the rate base is net of IDC amounts.

11.2 Review of Past Investments - A look back 2014-2018

JPS is Jamaica's largest electricity generation company and the only entity licensed to transmit. distribute and supply electricity in Jamaica. The Company has delivered value to its customers through the capital investments it made over the 2014-2018 rate review period. The investments made led to a more diversified generation mix, facilitated greater efficiency in the production of electricity and lower fuel bill. The investment delivered a more resilient T&D network that is smarter and on its way to becoming self-healing. The fight against electricity loss received record levels of investment; improving measurement and detection of illegal abstraction of electricity while hardening the network against theft. This segment will focus on some of the key investments JPS has made to maintain its place as Jamaica's energy company of choice while positively impacting the energy experience of its customers.

In the past five years JPS made record levels of capital investments cumulating to US$416.4M by the end of 2018. In 2017, the Company set a new record for single year investments at US$102M, and US$117.6M in 2018.

Table 11-1 : Capital Expenditure Summary 2014-2018

	US$ 000						
JPS	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Total	Average
Generation Expansion	1,991	1,725	0	0	0	3,716	743
Generation Conversion	0	12,577	10,654	2,309	6,183	31,723	6,345
Generation Routine	22,557	17,867	15,735	32,148	19,286	107,593	21,519
Generation Sub-Total	**24,548**	**32,169**	**26,389**	**34,457**	**25,469**	**143,032**	**28,606**
Transmission							
Transmission Expansion	247	6,277	9	0	27	6,560	1,312
Routine Asset Replacement	1,738	1,344	1,170	1,535	1,575	7,362	1,472
System Upgrade	1,848	2,463	2,377	7,488	23,053	37,229	7,446
Transmission Sub-Total	**3,833**	**10,084**	**3,556**	**9,023**	**24,655**	**51,151**	**10,230**
Distribution							
Distribution Expansion	5,463	4,444	5,097	4,634	5,980	25,618	5,124
System Upgrade	3,787	3,563	2,726	21,103	17,774	48,953	9,791
Routine Asset Replacement	13,027	9,853	9,014	12,395	15,351	59,640	11,928
Distribution Sub-Total	**22,277**	**17,860**	**16,837**	**38,132**	**39,105**	**134,211**	**26,842**
Losses	**3,662**	**6,482**	**6,145**	**11,174**	**23,782**	**51,245**	**10,249**
Information Technology	**9336**	**2,510**	**5,785**	**4,566**	**3,305**	**25,502**	**5,100**
Facilities and Other	**939**	**686**	**1,346**	**2,779**	**1255**	**7,005**	**1,401**
Marketing and Sales	**1,508**	**0**	**0**	**-**	**0**	**1508**	**302**
System Control	**0**	**0**	**866**	**1,850**	**0**	**2,716**	**543.118**
Total	**66,103**	**69,791**	**60,924**	**101,980**	**117,571**	**416,370**	**83,274**
YoY-Growth Rate	0.30%	5.58%	-12.70%	67.39%	15.29%		

Investing in the Generation Business

JPS invested US$143M or 34% of the investment outlay over the five-year period into the generation business. This includes the overhauling of baseload units at Rockfort, Hunts Bay and Old Harbour as well as peaking units at Hunts Bay and Bogue to ensure JPS could remain responsive to the energy demands of its customers. This routine reinvestment amounted to US$107.6M and were triggered by original equipment manufacturer (OEM) recommended running hours before overhaul and in limited cases by unplanned asset failure.

Coming out of its Environmental assessment JPS made the strategic decision to diversify its fuel mix, this was done to mitigate against the growth trends in the cost of oil and its subsequent impact on the cost of electricity. In 2014, JPS spent US$1.99M to complete and commission the new 6.3 MW Hydro Plant at Maggoty, thereby enhancing the overall efficiency of the generating fleet and adding renewables capacity to the fleet.

Between 2015 and 2016, JPS executed its flagship generation project; the Bogue GT12 and GT13 Power plants were converted from using ADO to Natural Gas at a cost of US$23.2M. This saw the introduction of gas to Jamaica's fuel mix, over the long term this will lower Jamaica's fuel bill, reduce emissions and extend the time between major maintenance activities. JPS retooled the GT11 power plant at Bogue at a cost of US$15.1M and this has increased the usage of gas and increased the efficiency of the generating fleet by being in the top tier of the generation dispatch since its reintroduction. The Company is in the process of building its first two Distributed Generation plants in 2019 having spent US$8.5M in the construction phase between 2017 and 2018. This will provide feeder level generation support using gas generators to improve reliability and reduce dispatch costs.

Overall, the investments made in Generation have yielded great benefits to customers, the Equivalent Availability Factor (EAF) has moved from 78.2% in 2014 to 88.9% in 2018 and Equivalent Forced Outage Rate (EFOR) moving from 13.1% to 5.4%. This tremendous achievement has seen customers benefit from reduced outages due to generation shortfall. The investments resulted in maintaining the Heat Rate below the regulated target during the period. JPS' Thermal Heat Rate moved from 12,034 kJ/kWh at the end of 2013 to 11,214 kJ/kWh at the end of 2018.

Investing in the T&D Business

JPS' T&D network has suffered from underinvestment over several years. The grid suffers from some design deficiencies as well as exposure to tropical weather conditions that impacted its reliability performance over time. In 2014, JPS' customers experienced average system outage of 41 hours. This reality drove JPS to increase its investments over the 2017-2018 period to meet the needs of customers as well as position Jamaica to achieve a more reliable energy future. JPS invested US$185.4M in the T&D grid, this represents 45% of total investment. Of this total, US$111M or 60% took place over the past two years 2017 and 2018, as the drive to modernize the network takes shape. These investments enabled the Company to achieve a 31% reduction in outages over the period with annual system outage at the end of 2018 of 28.2 hours.

JPS invested US$67M in the **routine replacement of defective structures and equipment** on the Transmission and Distribution network including substations over the five-year period. The recapitalization of aged, damaged and degraded structures such as poles, cross arms, insulators, steel structures, transformer, streetlights and meters has been a driver in improving reliability, reduction in customer complaints and facilitated quick recovery after adverse weather conditions that plagued the network as the realities of climate change impacts the Company.

During the five-year period, the Company completed one major transmission expansion project, this was the **New Spur Tree Substation 69 kV Expansion and Modification.** The investment of US$6.5M facilitated the secure interconnection of approximately 94 MW of wind energy from Wigton and BMR to the national grid. This investment took on added significance as it further enabled the national energy strategy of moving towards 30% renewable energy in the energy mix. The Company invested in activities to expand the distribution network through its complex connection efforts. The total expenditure of US$25.6M enabled customers and streetlights to be added to the grid. This is a critical investment for our customers as it provides access to the power they need. With the new revenue-cap tariff structure, the more customers added to the grid, the lower the cost of electricity to all customers, therefore, this reality means that the investments to expand distribution take on even greater significance for our customers.

Between 2014 -2016 JPS invested a total of US$16.7M to upgrade its T&D network while during 2017-2018 a total of US$69.4M was invested. This represent a 400% increase in upgrade investments as JPS moves to roll out a smarter more efficient grid that facilitates renewable integration, responds to increased demand, and is hardened against the drivers of outages.

Several major projects were complete to upgrade the distribution system. The Company has invested US$13.3M in the replacement of HPS streetlights with **Smart LED Streetlights** between 2017 and 2018, with approximately 42,000 replaced at the end of 2018. This investment has resulted in a 50% reduction in energy consumption from the lights replaced, leading to lower bills for the Government and lower maintenance costs for streetlights.

The **voltage standardization programme** introduced 2016 to 2018 facilitated the upgrade of distribution feeders from 12 kV to 24 kV at a cost of US$7.9M. The focus area has been the north coast where critical tourism interests are located; to date 10 feeders have been upgraded, resulting in transferability of load between six substations that previously could not transfer; resulting in reduced duration of outages up to 70%, as well as reduction in technical losses on the upgraded feeders and significant improvement in the quality of power experience on these feeders.

The **roll out of smart devices** such as DA switches, Fault Circuit Indicators and Trip Savers at a cost of US$5.2M over the period made a significant impact on the duration and frequency of outages as these smart devices facilitated fault isolation and improved response times for crews. The New Kingston area has been transformed into a self-healing grid through the installation of these devices resulting in shorter and less frequent outages. To address the impact of vegetation on reliability the Company has rolled out the **Covered Conductor** programme at a cost of US$3M over the period to reduce outages in high vegetation areas where contact with conductors is made. These areas have shown 20% reduction in outages and a 50% reduction in the number of bushing cycles required in the areas where these conductors are installed. This also reduced the public hazard that arises from trees encroaching on exposed lines. JPS invested US$3M on the replacement of **Distribution transformers** at Hunts Bay, Cardiff Hall and Bogue to respond to increased demand that caused overloading of the transformers. At the end of 2018, the Company has invested US$1.8M on a **new distribution substation at Michelton Halt** to be completed in 2019, to meet the increased demand in the area.

Transmission network upgrade also had important investments over the period. At the end of 2018, the Company had invested US$18.1M in Jamaica's first grid-scale **energy storage facility**. This is a significant step for Jamaica as it will enable the mitigation of outages caused by the intermittent nature of solar and wind energy ultimately facilitating the incorporation of more of these renewable energy sources on the national grid when commissioned in 2019. JPS invested US$8.0M to date to facilitate the **interconnection of the new 194 MW Natural Gas powered power plant** built at Old Harbour to the transmission grid. This investment will allow the energy generated at the new plant to reach the grid in a safe and reliable manner, helping to deliver the benefits of fuel diversification. JPS added a new **Interbus transformer** at Duncan's Substation at a cost of US$2.2M driven by increased load demand on the north coast due to major hotel and housing developments.

Investing in Loss Reduction

One inefficiency that JPS made progress in addressing in its investment programme between 2014 and 2018 is system losses, particularly non-technical losses. The loss reduction effort has seen investment of US$51.2M over the five-year period, these investments have focused on installation on meters' infrastructure to improve measurement and the detection of losses as well as moving meters off customer's properties to reduce the likelihood of meter tampering. From 2015 to2018, there was a gradual reduction in the percentage of energy lost, moving from 27.04% in 2015 to 26.27% at the end 2018. Since 2016, JPS has invested US$28.4M to install 144,000 Smart Aclara AMI meters to enable the detection of losses. These meters communicate using a newly built mesh network and provide instant feedback if tampered with, in combination with transformer meters installed in the programme, enabling energy balancing and improved measurement. These meters can be read remotely and provide additional efficiency by reducing meter reading and billing costs for customers.

Significant investment was made in the RAMI metering infrastructure totaling US$13.2M. Transformer meters were installed to detect losses at different points along feeders and customer meters moved from their properties to locked cabinets on poles to harden the grid against tampering. The Company also rolled out a community renewal programme in 14 communities in six parishes across the island during the rate review period. This approach was taken in areas identified as red zones where energy theft is high and where the socio-economic condition is depressed. In these areas, the distribution network was modified to be more resistant to *'throw-up'* illegal connections and led to the onboarding of new customers.

Support Services

JPS invested in assets geared towards enabling the core business to achieve its strategy, reduce overhead costs and improve efficiency. Several key **information technology** investments were made during the period to achieve this; the SCADA system was upgraded between 2016 and 2017 at a cost of US$2.7M, this was necessary as the previous version was at end of life. The upgrade enabled the system controllers to safely operate the system with full view of the generation and transmission systems as well as improved view of the distribution network.

JPS began the roll out of Enterprise Asset Management (EAM) with a US$2.4M implementation of InFor EAM across all generating plants as well as the transmission network. This investment brings structure and accountability to the maintenance programme for assets, allowing the Company to extract maximum value from its assets and better manage maintenance costs. During the period 2017 and 2018, JPS rolled out Business Intelligence and Corporate Performance Management platforms at a cost of US$1.1M. This facilitated more efficient planning, monitoring and reporting while allowing for speedier decision-making and course-correction. These investments are critical to facilitate the overall strategic management of the Utility.

The investments JPS has made over the past five years have not only laid the foundation for Jamaica's energy future, but have already delivered value for customers.

11.3 Eyes on the Future

The Medium Term Investment Plan developed by JPS is a demonstration of the Company's values and demonstrates its commitment to securing the energy grid of the future. JPS intends to make prudent investments over the next five years to deliver greater value to customers by improving service experience, increasing efficiency and enabling economic growth and development.

JPS will make investments that are aligned to its strategic plan and are prioritized to deliver optimum value for its customers. The investment activities have been aligned to enable the Company's strategic priorities of Exceptional Customer Service, End to End Efficiency, Growth and Safety. The table below outlines JPS' annual investment by strategic priorities. JPS will invest

46% of its five-year capital budget to improve Customer Service and 44% to improve efficiency across the business, the remaining 10% will deliver improved safety as well as growth objectives.

Table 11-2: Capital Expenditure - Strategic Drivers

Strategic Priorities	2019	2020	2021	2022	2023	Total	Percentage %
Customer Service	40,169	38,988	50,227	46,728	43,711	219,822	46%
Efficiency (End to End)	49,602	42,451	43,717	46,513	27,618	209,901	44%
Growth	10,308	9,440	7,643	8,635	6,361	42,386	9%
Safety	1,605	773	1,273	1,768	1,259	6,679	1%
Grand Total	101,683	91,652	102,859	103,644	78,949	478,788	100%

JPS construction work-in-progress (CWIP) continuity schedule is provided in Annex V.

JPS 2019-2023 Medium Term Investment Plan provides additional information with respect to the forecast capital projects, including business cases for all projects organized by project category (Major, Extra-ordinary, and Minor).

Deficiencies previously identified by the regulator have been addressed in the JPS 2019-2023 Medium Term Investment Plan. These include alternative analysis for major projects, analysis to support the benefits outlines for losses and reliability projects and bid information to support the costing of 2019 projects.

The Investment Plan provides analysis of project alternatives for Grid Modernization, Smart Meter, Voltage Standardization, RAMI, MV Conductor Line, 138 kV Transmission Line, and Roaring River 69 kV Transmission Line projects.

Major Projects Overview

One of the major customer service projects JPS will embark on, is the construction of a new Single Circuit Transmission line from Old Harbour to Hunts Bay and Upgrade the Duhaney to Hunts Bay lines in Kingston at a cost of US$37M. This investment in transmission expansion will support the provision of power in the load centre of Kingston as Thermal generation in the area is retired. This will also allow customers to benefit from a stable, secure power grid that reduces technical losses.

JPS will also execute the change-out of streetlights across the island by the end of 2021. The programme will facilitate a further 68,000 high pressure sodium (HPS) lamps being replaced with Smart light-emitting diode (LED) lamps bringing the total to 110,000. This will result in the reduction of the street lighting bill and energy consumption by 50%, improve visibility, support the smart grid and allow for remote monitoring and control of all streetlights in Jamaica.

JPS will enable the delivery of End to End Efficiency through the following projects:

- Complete the roll out of Smart meters throughout the network; this will enable the detection of losses while significantly reducing the operations and maintenance costs related to meters reading and billing.
- The Company will also execute the overhaul of critical generating units such as the Bogue combined cycle plant and the Rockfort Units to ensure they deliver power more efficiently. This will keep maintenance costs from growing while ensuring units convert fuel to electricity at the most efficient rates.
- Complete the development of Enterprise Asset Management to facilitate greater efficiency and accountability as the proper management of assets becomes more structured, scientific and achievable.

The agenda for growth will see JPS commission two distributed generation projects during the period. The initiative comprises 14 MW of generation placed directly on feeders where large customers reside, boosting reliability and reduce the incentive for grid defection. This is a key prong of the growth strategy as it encourages commercial and industrial customers to remain on the grid while boosting their production.

JPS will invest in the roll out of electric charging stations as the base requirement for the development of the Jamaican electric vehicle industry. This investment will provide the means through which EV owners will have the ability to charge their vehicles throughout the island if needed. The potential for growth from electrification of transportation can be exponential for JPS and therefore have a price benefit for customers.

To boost safety JPS will complete the roll out of digital mobile radios to operations staff, upgrade its emissions monitoring infrastructure at power plants and continue the installation of security cameras at critical locations. Information Technology security is critical for JPS especially as data storage needs grow. To this end cloud security, firewall infrastructure and BOYD security will be improved throughout the period to ensure greater security of data of staff, customers and business partners. Over the next five years, JPS will achieve compliance with the Regulated Thermal Heat Rate Target, Improve Reliability by 20%, reduce System Losses by 2.30% and improve productivity by an annual rate of 1.9% on controllable operating expenses.

To achieve these outcomes, the Company will make the necessary investments in its Generation, Transmission and Distribution and General Plant. Some of these investments will be transformative to how the utility operates.

Table 11-3: Forecasted Capital Expenditure

JPS	US$'000						
	Forecast					Total	Average
	2019	2020	2021	2022	2023		
Generation							
Generation Routine	18,563	16,511	13,643	22,208	13,277	84,203	16,841
Generation Sub-Total	**18,563**	**16,511**	**13,643**	**22,208**	**13,277**	**84,203**	**16,841**
Transmission							
Transmission Expansion	154	2,170	9,900	16,789	14,862	43,875	8,775
Routine Asset Replacement	3,511	3,747	3,908	3,983	4,012	19,162	3,832
System Upgrade	12,972	4,315	6,279	1,667	2,667	27,900	5,580
Transmission Sub-Total	**16,637**	**10,233**	**20,087**	**22,439**	**21,541**	**90,937**	**18,187**
Distribution							
Distribution Expansion	6,800	6,000	5,000	7,000	6,000	30,800	6,160
Routine Asset Replacement	8,863	8,425	8,983	9,351	9,547	45,168	9,034
System Upgrade	17,526	19,151	17,876	11,341	10,692	76,587	15,317
Distribution Sub-Total	**33,189**	**33,576**	**31,859**	**27,692**	**26,239**	**152,555**	**30,511**
Losses	**27,099**	**21,554**	**25,219**	**20,533**	**10,452**	**104,857**	**20,971**
IT	**3,045**	**5,514**	**6,878**	**4,975**	**3,825**	**24,237**	**4,847**
Facilities and Other	**2,650**	**2,497**	**3,773**	**2,768**	**2,596**	**14,284**	**2,857**
Business Development	**500**	**592**	**400**	**-**	**-**	**1,492**	**298**
System Control	**-**	**1,176**	**1,000**	**3,029**	**1,018**	**6,223**	**1,245**
Rate Base Total	**101,683**	**91,652**	**102,859**	**103,644**	**78,949**	**478,788**	**95,758**
Business Development (Non-Rate Base)	**2,500**	**6,800**	**5,700**	**5,000**	**5,000**	**25,000**	**5,000**
Grand Total	**104,183**	**98,452**	**108,559**	**108,644**	**83,949**	**503,788**	**100,758**

Generation

JPS' generating fleet has the capacity to deliver 640 MW of power on a daily basis. JPS will invest US$84.2M over the five-year period to overhaul the units that have reached their OEM recommended running hours before overhaul. This investment will enable improved customer service and greater efficiency as they enable the Company to deliver more efficient fuel conversion and improved unit availability. Some key interventions include the investments of US$32M on the Combined Cycle Plant at Bogue with overhauls to GT12 and GT13 in 2019 and 2020 as well as in 2023. A full Overhaul of the highly efficient ST14 will take place in 2022. This investment will keep the gas powered plant delivering 120 MW of power at a heat rate below 9000kJ/kWh.

The WoodStave pipeline network along with turbine and generator units at five Hydro Plants will also be upgraded at a combined cost of US$8.5M, these systems are degraded and outdated, with their productive capacity reduced, resulting in forced outages. The upgrades will result in improved efficiency of the hydro generation fleet.

T&D

JPS is the sole entity licensed to Transmit and Distribute electricity in Jamaica, as such the Company must ensure the T&D grid is capable of reliably moving power from power plants to customer's premises; while ensuring safety and stability of power supply. To ensure customers are served with improved reliability, JPS will invest US$243M over the next five years to address some known deficiencies while enhancing the resilience of the grid. The plan will require the Company to expand, upgrade and replace defective assets to become more compliant with grid codes while staying true to the service area concept. These investments will enable JPS to achieve its strategic objectives of exceptional customer service and growth thus improving the customer experience while lowering energy bills.

One major T&D project to be executed over the period is the construction of a new 69kV Transmission line from Bellevue to Roaring River in the northern side of the island. The line will be built at a cost of US$6.8M and solve the chronic low voltage condition in and around the Ocho Rios area. With the expansion in tourism expected in the area, this line will provide the stability required to the existing 50,000 customers while allowing for seamless new additions. This new line has been outstanding for several years as the system design requires a new access point to eliminate the radial design in the service area. This new transmission line will also put the grid closer to N-1 contingency compliance as required by the Grid codes.

A refresh of the transformer network is another significant feature of the Investment Plan. By investing US$16.5M over five years JPS will replace or add 8 Distribution Transformers and 4 Interbus transformers to the grid. The transformers chosen for replacement are the most overloaded or most at risk of failure given ongoing operations tests conducted. Transformers to be added will facilitate the connection of new load across growing population centers. The programme will also aid the transferability of power within service areas enabling greater grid code compliance and reducing the effect of maintenance outages on customers.

JPS will also make a significant US$17.6M investment to continue its Voltage Standardization Programme; moving 12 feeders across north central Jamaica from 12 kV to 24 kV. This will reduce technical losses thus improving efficiency while facilitating transferability of load to neighboring substations. With the ability to transfer load the customer service experience on these feeders will significantly improve in the event of an outage. Feeders upgraded in the past shows significant improvement in the duration of outages of up to 70%. This will be a major contributor to customer service improvement over the medium term.

The Company will invest US$13.1M to continue the Grid Modernization Programme. This will see close to 1,500 smart devices rolled out across the distribution network including 1,250 trip savers and 110 DA switches, 23 Pole Mounted Reclosers and 180 fault circuit indicators. These devices will address transient faults, which account for 90% of all faults at the distribution level. These smart devices will play a major role in enabling JPS to achieve its objective of 20% reduction in the duration of outages hence enhancing the customer service experience.

The routine replacement of defective poles and related equipment on the T&D Distribution network will benefit from increased investment over the medium term. Data from the outage management system has shown that one of the leading causes of outages is defective equipment such as poles, cross arms and insulators. JPS' patrol and asset management data revealed that close to 10% of the 280,000 poles on the network are currently defective at an 80% defect level. This level of defect increases each year as equipment ages. The Company will invest US$40M over the next five years to replace or rehabilitate defective poles and equipment to improve customer service helping to achieve the targeted 20% SAIDI and SAIFI reduction. Through the investment activities, JPS will replace or rehabilitate close to 37,000 aged distribution poles and 59,000 pieces of equipment over the five-year period. Over 2,700 Transmission poles will be impacted along with 1,600 insulators and 166 steel towers. These investments will result in a 15% improvement to the T&D asset health index, reduce risk and improve customer service.

Loss Reduction

System losses is one of the greatest inefficiencies that currently exists within the company with 26.27% of energy produced being lost at the end of 2018. This inefficiency presents a cost that impacts the Company's profitability as well as electricity prices. To tackle the problem of system losses and deliver a 2.30% improvement JPS will take on two major investment programmes.

JPS will complete the roll-out of smart meters and supporting field area network within the five-year period at a cost of US$85.2M. Smart meters will optimize the remote detection and measurement of losses, enabling response teams to carry out spot audits. These meters also allow for end to end efficiency as they eliminate the need for meter reading, reduce the cost of billing as well as enable remote disconnections and reconnections. Smart meters will also impact losses derived from internal process inefficiencies. This will improve the company's productivity and help to lower the cost of energy for each customer while delivering the communication network required for JPS' Smart Grid.

The continued roll-out of RAMI infrastructure will continue throughout the period with US$17.3M earmarked for this investment. The RAMI programme is an anti-theft solution to be rolled out in 80 communities where the level of theft is so high that the success of smart meters may be compromised. The solution involves moving the customer meter to an enclosure on a pole and makes tampering extremely difficult. It also discourages throw-ups, as energy usage would still be recorded on the meters. This programme will enable the conversion of 14,500 customers across 70 communities to this technology.

IT Business

As JPS modernizes its operations, information and operational technology investments will play an increasingly significant role in future success. JPS must therefore calibrate its IT investments to take advantage of new technologies that can improve its operational performance and productivity. IT systems can become outdated in a three to five-year window as technological advancement takes place. Within the medium term, JPS will invest US$25M in its IT infrastructure to keep key platforms capable of delivering value and to unleased new functionalities for the benefit of our customers.

The Company will replace the Customer Suite platform for US$3.5M with an upgraded and more interconnected customer service platform to enable shorter processing times and improved internal controls. As technologies such as smart meters and smart streetlights are rolled out, the functionalities needed in a customer service platform change to become more automated. The upgraded customer suite platform will enable the business to take advantage of the benefits of these technologies.

JPS will expand its Business Intelligence and analytical capabilities with a US$3.6M investment. This will enable the Company to put in place the necessary systems to deliver actionable business insights on a timely basis to give decision makers the needed tools to drive improvements. As JPS' data volume grows the Company must put itself in a position to take advantage of big data. The Business Intelligence Programme will facilitate the rollout of a data lake, data warehouses and data virtualization platforms to enable JPS to become a truly digital business utilizing analytics and business intelligence. This programme will enable the reduction of O&M costs and lead to productivity improvements.

The company will complete the rollout of the EAM platform throughout the Generation and Distribution operation units with a US$2.6M investment. This investment will allow the Company to complete the programme and provide a structured way of planning and monitoring asset management efforts. The project will support the JPS asset management philosophy for each asset class and will give all stakeholders a scientific way of tracking the way the utility manages its assets.

With its critical telecommunication systems, JPS must also invest in communication network infrastructure. The communication network allows for safe and seamless interaction between field teams and system control teams and is critical to the safe and efficient operation of the electric grid. The Electric Grid Communication Network Rehabilitation and Upgrade Programme will be executed over the five-year period at a cost of US$4.8M to modernize the Core Telecoms Network, carry out Radio Tower rehabilitation and to update SCADA and Teleprotection Fiber devices to IP based devices. This asset replacement project will improve service delivery through a more robust network supporting centralized and decentralized operating systems, increased productivity and business effectiveness through reliable communications and facilitate a Smart Grid to support loss reduction activities.

11.4 Conclusion

As JPS seeks to transform the Jamaican electricity landscape to meet the ever more sophisticated needs of customers while providing a return to shareholders it must ensure its investments are sound and that proposed benefits are achieved. The investment plan that will accompany the Rate

Case filing will outline the details for the development of the investment portfolio as well as more exhaustive detail on individual projects and how they will deliver value to customers. In the absence of the IRP, this investment programme reflects the best electricity investments for Jamaica at this time. It highlights the right investments in the right assets at the right time. The investment will deliver a reduction in the duration and frequency of outages across the island by 25%, facilitate a 2.30% reduction in system losses, help to improve productivity by 1.9% and ensure JPS meets its generation efficiency targets.

12 Cost of Capital

12.1 Introduction

Utilities, including JPS, finance their investment needs and asset base, which are required to provide utility services to their customers, via long-term capital. This long-term capital employed by utilities to finance their physical plants and assets generally include long-term debt (bonds, debentures) and investors' equity.

The Cost of Equity is the return that investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return that they expect is equal to, or greater than, the return that they require to accept the risk of providing funds to the firm. From JPS' perspective, that required return, whether it is provided by debt or equity investors, has a cost. Individually, the "Cost of Debt" and the "Cost of Equity" are measures of those costs; together, they are referred to as the "Cost of Capital."

The Cost of Capital (including the costs of both debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset, whether debt or equity, implies a foregone opportunity to invest in alternative assets. For any investment to be utilitarian, its expected return must be at least equal to the return expected on alternative. Although both debt and equity have required costs, they differ in certain fundamental ways. Most noticeably, the Cost of Debt is contractually defined and can be directly observed as the interest rate, or yield, on debt securities. The Cost of Equity, on the other hand, is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity. Because equity investors bear the "residual risk," they take greater risks and require higher returns than debt holders. In that basic sense, equity and debt investors differ: they invest in different securities, face different risks, and require different returns. Whereas the Cost of Debt can be directly observed, the Cost of Equity must be estimated or inferred based on market data and various financial models, in this case, the Capital Assets Pricing Model (CAPM).

Licence Provisions

Condition 13(7) of the Licence 2016 permits JPS to include in its rates a reasonable rate of return on its capital. This approved rate of return on capital (investment) will be set by the OUR.

As per the Paragraph 27 (a) of Schedule 3 of the 2016 Licence the Revenue Requirement under the revenue cap principle includes Rate Base multiplied by the weighted average cost of capital (WACC) to calculate the capital recovery element.

With respect to the cost of debt, in accordance with the Paragraph 30 30(b) of Schedule 3 of the 2016 Licence the interest rate will reflect the weighted average interest rate in place for the latest audited financial statements. The 2016 Licence however, continues that the interest rate should be ‘corrected for known material changes in the funding structure related to refinancing or new PPE capital outlays’. The interest rate should be ‘corrected for known material changes in the funding structure related to refinancing or new PPE capital outlays’ has captured and is reflecting a forward-looking approach to the interest rate component of the weighted average cost of capital.

With respect to the Return on Equity (ROE), Paragraph 30(c) of Schedule 3 the 2016 Licence stipulates that the Bank of Jamaica will provide guidance on the ROE, which allows JPS the opportunity to earn a return sufficient to provide for the requirements of consumers and acquire new investments at competitive costs based on relevant market benchmarks prevailing internationally for a similar business as JPS and adjusted for country risk, which will be used by the OUR and JPS to calculate the WACC.

The approved rate of return on capital is merely a target estimate and it does not guarantee that JPS will earn that rate of return. So long as performance targets are reasonable and achievable, the OUR sets tariffs sufficient to provide a reasonable opportunity for JPS to achieve its overall revenue requirement, including rate of return, however whether JPS achieves this target rate of return or not depends on actual operations.

Further, Paragraph 46(d)(ii) of Schedule 3 of the 2016 Licence entitles JPS to request a Z-Factor adjustment to the non-fuel rates where JPS’ rate of return is one percentage (1%) point higher or three percentage (3%) point lower than the approved regulatory target (after taking into consideration the allowed true-up annual adjustments, special purpose funds included in the Revenue Requirement, awards of the Tribunal and determinations of the OUR and adjustments related to prior accounting periods).

Final Criteria

The Final Criteria outlines that the cost of debt should be based on the weighted average borrowing cost for JPS’ long-term debt.

Criterion 1 requires JPS to provide a schedule showing the weighted average interest rate of its long-term debt, and that the schedule shall be based on the Company’s audited financial position as at 2018 December 31 and shall include:

a) A list of all its long-term debt and their corresponding amounts.
b) The associated interest rate for each loan.
c) The computation of the weighted average interest rate.
d) Prudently incurred costs associated with the issuance of debt such as commitment fees, arrangement fees, due diligence fees, breakage costs and refinancing fees should be included in the non-fuel operating expenses.

With respect to the computation of the return on equity (ROE) rate, Criterion 2 of the Final Criteria states that in computing the ROE, JPS shall use the CAPM methodology based on the formula below:

$$r_s = r_f + \beta * \left[(TMR - r_f)\right] + [CRP]$$

where

	Component
r_f	Risk Free Rate
β	Levered Beta
TMR	Total Market Return (or Equity) Risk Premium
CRP	Country Risk Premium
r_s	**Rate of Return on Equity**

Criterion 2 also states that the following shall be observed with regards to the data set used in the ROE calculation:

i. R_f shall be the U.S. long-run historical average return on bonds (1998-2018);

ii. β shall be based on the latest information on the five-year beta for all U.S. electric utilities from Bloomberg database;

iii. The Mature Market Equity Risk Premium shall be computed indirectly by subtracting the risk free rate (Rf) from the Total Market Return (TMR);

iv. The TMR is the arithmetic average of long-run historical data of U.S. Market (1900-2018);

v. The CRP shall be derived from the 2018, one (1) year average of the bond yield spread of the ten (10) year Jamaican USD denominated sovereign bond and the US 10-year Treasury bond.

Principles for Implementation

JPS is in agreement with the OUR that the weighted average interest rate of JPS' long-term debt should include JPS' audited financial position as at 2018 December 31, which is consistent with the Licence. This interest should be 'corrected for known material changes in the funding structure related to refinancing or new PPE capital outlays', in accordance with the Licence; hence reflecting the forward-looking approach to the interest rate component of the weighted average cost of capital for which the Final Criteria ought to have expressly provided in calculating the cost of debt. As such, JPS' recommended computation of the weighted average interest on long-term debt deviates from the Final Criteria.

With respect to the Equity Risk Premium (ERP) component of the ROE computation, JPS believes that it should be computed directly on a forward-looking basis as compared to the indirect computation as proposed by the NERA using a historical analysis to capture the average realized returns for the Total Market Return (TMR). In light of this, JPS is willing to recognize the calculation of ERP by NERA, as the result of the historical analysis converges with the results of JPS forward-looking analysis.

JPS also objects to the Country Risk Premium (CRP) component derivation from one (1) year average of the bond yield spread of the ten (10) year Jamaican USD denominated sovereign bond and the US ten (10) year Treasury bond as outlined in Criterion 2. JPS proposes that the CRP be calculated based on a three (3) year average of the bond yield spread on the twenty (20) year Jamaican sovereign bond and the U.S. Treasury twenty (20) year bond.

The filed cost of debt, ROE rate and WACC for the 2019-2023 test years have been calculated to be as follows:

- Cost of Debt: 7.45%
- ROE rate: 11.20%
- WACC: 8.08% (post-tax)

The cost of debt is based on JPS' audited financial position as at 2018 December 31. Furthermore, the computation of weighted average interest on long-term debt takes into account JPS successful refinance of its US$180M bond and the attendant interest rate savings, in keeping with Determination #6, or the Refinancing Incentive Mechanism from the 2018 Annual Adjustment Filing which states, "The OUR shall use JPS' weighted average cost of debt that results from the debt refinancing under this mechanism to compute the Company's weighted average cost of capital (WACC) in the 2019-2024 Rate Review exercise."

The filed ROE rate in this case is consistent with Criterion 2, except for the CRP component, which was derived using a three (3) year average of the Jamaican USD denominated sovereign bond and the US Twenty (20) year Treasury bond, which computes JPS' preferred ROE.

The WACC has been computed from the proposed cost of debt and ROE rate, based on a 50% gearing ratio.

12.2 Cost of Debt

The cost of debt represents the costs (interest) that a company must pay to borrow from commercial lenders to fund its operations. Paragraph 30(b) of Schedule 3 of the Licence stipulates that the interest rate will reflect the weighted average interest rate in place for the latest audited financial statements, corrected for known material changes in the funding structure related to refinancing or new PPE capital outlays.

JPS is in agreement with the OUR that the weighted average interest rate of JPS' long-term debt should include JPS' audited financial position as at 2018 December 31, which is consistent with the Licence 2016. The Licence 2016 however also provides that the interest rate should be 'corrected for known material changes in the funding structure related to refinancing or new PPE capital outlays'.

In general terms, the cost of debt depends on the default risk that lenders perceive on the firm. JPS is mandated to and is making significant strides towards the modernization of Jamaica's electricity grid, improvement of its overall efficiency and enhancing service delivery. This requires JPS to make significant capital investments in its asset base; hence the Company has to continually source new funding as repayments of existing loan.

Further, as at end of December 2018, approximately 37% of JPS's long-term debts have variable interest rate linked with then-effective LIBOR. JPS considers it reasonable and strategic to retain long-term debts with variable interest rates, which results in benefits to customers derived from a lower WACC due to historic lower LIBOR over a decade. It is however, important to clarify that future variability in the LIBOR will have a financial impact on JPS.

Pursuant to the Licence 2016 the fact that the interest rate should be 'corrected for known material changes in the funding structure related to refinancing or new PPE capital outlays' has captured and is reflecting a forward-looking approach to the interest rate component of the weighted average cost of capital. The Final Criteria for the cost of debt calculation should have accommodated a similar forward-looking approach; the concept which is embedded in the revenue cap principle.

Despite the recommended deviation from the Licence 2016, as the Licence 2016 requires that the filing be based on the Final Criteria, the calculation for the 2019-2024 rate review period is based on the guidance provided in Criterion 1 of the Final Criteria document and is shown in Schedule 12-1 below. This submission in compliance with the Final Criteria is, however, being made without prejudice to JPS' right to pursue its appeal against this point of dispute, as permitted under the said Condition 32 of the Licence 2016 and JPS hereby expressly reserves the right to so pursue its appeal.

Table 12-1: JPS' Average Cost of Long-term Debt

LT Debt Facility	Maturity Date	Dec. 31, 2018 Closing Bal. (USD '000)	Interest Rate	Weighted Avg. Interest Rate
NEXI/Citibank Japan Ltd.	27-Dec-20	$ 16,250	4.35%	0.18%
Export Development Canada	15-Sep-20	$ 1,529	2.01%	0.01%
PROPARCO	30-Nov-20	$ 13,441	8.37%	0.29%
Peninsula Corporation	30-Jan-19	$ 9,000	9.05%	0.21%
IFC US$30M Loan Facility	15-Sep-20	$ 6,667	7.84%	0.13%
FCIB US$60.625M Loan (JMD Portion)	11-Oct-28	$ 10,727	7.50%	0.21%
FCIB US$60.625M Loan (USD Portion)	11-Oct-28	$ 25,000	6.00%	0.38%
Caribbean Development Bank	1-Jan-29	$ 15,000	4.50%	0.17%
NCB Syndicated J$2.45B Loan	31-Jan-23	$ 16,924	9.95%	0.43%
OPEC Fund for Int'l Development	30-Nov-20	$ 5,554	7.72%	0.11%
Citibank/OPIC US$120M (2016)	15-Dec-26	$ 65,000	7.63%	1.27%
Citibank/OPIC US$120M (2016)	15-Dec-21	$ 20,000	6.73%	0.34%
KFW Loan - DM 7M	30-Dec-30	$ 4,271	7.00%	0.08%
Sagicor 180M Refinance (JMD Portion)	22-Feb-34	$ 82,154	8.40%	1.76%
Sagicor 180M Refinance (USD Portion)	22-Feb-29	$ 34,000	7.35%	0.64%
Sagicor 180M Refinance (USD Portion)	22-Feb-29	$ 66,000	7.35%	1.24%
		$ 391,516		**7.45%**

12.3 Return on Equity

In light of the inherent risks investors face, it is important that the utility be allowed the opportunity to earn a return that is adequate to attract capital at reasonable terms. This enables JPS to provide service while maintaining its financial integrity. The ability to attract capital is particularly important for JPS in this Rate Review, as the Company will be engaged in an extensive capital expenditure programme over the next five years. As such the allowed return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. Based on these standards, JPS anticipates that the OUR's determination in this Rate Review provides the Company with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments among utilities that face corresponding risks.

The ROE determination from the OUR should enable the Company to finance its capital expenditures and maintain its financial flexibility over the five-year period during which the allowed ROE is expected to remain in effect. To the extent JPS is provided a reasonable opportunity to earn its market-based Cost of Equity in accordance with the Licence 2016, neither customers nor shareholders should be disadvantaged, as a return that is adequate to attract capital at reasonable terms will only further enable JPS to provide safe, reliable service while maintaining its financial integrity.

12.4 CAPM Methodology

In the Final Criteria for the 2019-2024 Rate Review Process, the OUR notes that it carried out an exercise with regards to the use of different models for the ROE rate determination.[68] On the basis of the results from this exercise, the OUR concluded that the Capital Assets Pricing Model (CAPM) remains the most appropriate model for estimating JPS' ROE for the following reasons:

- CAPM has very strong theoretical underpinnings that are supported by empirical evidence for explaining stock returns, including those in emerging markets.
- The practicality of its use in the Jamaican context particularly, as it relates to access to relevant data.
- It affords balanced regulatory discretion regarding the estimation of the parameters in the CAPM formulation.

JPS supports the use of the CAPM methodology, given that it is based on the theory that equity investors are compensated for their exposure to undiversifiable market risk and represents mutually agreeable methodology in calculating the ROE. JPS is, however, proposing certain adjustments to the data set used as input into the formula which is discussed in latter sections of this document.

<u>JPS' Position on Final Criterion No. 2</u>

For the avoidance of doubt, Criterion No. 2 also states that the following shall be observed with regards to the data set used in the ROE calculation:

i. R_f shall be the U.S. long-run historical average return on bonds (1998-2018);

ii. β shall be based on the latest information on the five-year beta for all U.S. electric utilities from Bloomberg database;

iii. The Mature Market Equity Risk Premium shall be computed indirectly by subtracting the risk free rate (Rf) from the Total Market Return (TMR);

iv. The TMR is the arithmetic average of long-run historical data of U.S. Market (1900-2018); and

[68] OUR, Consultation Document, Final Criteria for 2019-2024 Rate Review Process, p. 25.

v. The CRP shall be derived from the 2018, one (1) year average of the bond yield spread of the 10 year Jamaican USD denominated sovereign bond and the US 10-year Treasury bond.

Overall, JPS is in agreement with the OUR with respect to the methodology for a certain parameter of the CAPM formula. However, JPS proposes that further clarification and changes to inputs are required to the OUR's CAPM methodology in the computation of the Risk Free Rate (Rf), Equity Risk Premium (ERP) or Mature Market Equity Risk Premium (MMRP) and Country Risk Premium (CRP). As it relates the derivation of the Levered Beta, JPS utilized a four-step approach in estimating Beta, which involves:

- Five year betas for all regulated U.S. electric utilities from Bloomberg.
- The un-levered beta for each company based on its capital structure.
- The computation of a simple average of the unlevered betas.
- Re-levered of the betas based on JPS's model (50:50) capital structure.

JPS focused on U.S. electric utilities versus Professor Damodaran's Global Power Sector dataset as initially recommended by the OUR. JPS' use of the U.S. electric utilities ensured that all of the covariances were computed with reference to the same capital market. This results in a beta of 0.75. On the basis of the results from this exercise, the OUR concluded that JPS' estimation is reasonable and the approach reflects greater consistency than the use of a global beta, since the mature market under consideration is the US electricity market and not the global electricity market.[69]

JPS' proposes the following adjustments to the data set used as input for other variables of the formula:

Risk Free Rate

The OUR's Final Criteria, specifically Criterion #2 (b) (i), recommends the Risk Free Rate is computed using the 20 year (1998-2018) historical average return on the US Treasury Bonds. While the Final Criteria is not explicit in a preference of the class of US Treasury Bonds to be used in the computation of the Risk Free Rate, JPS can appreciate the simplicity of using an historical average of the bond rates. However, the class and tenure of the bond being assessed is an important consideration that must be taken into account. JPS notes the OUR's comments in the Final Criteria of international investors preference to use the US Ten (10) Year Treasury Bond for capital asset valuation because of the high levels of liquidity that exist among that specific type of bond. However, given the nature of the business in which JPS is involved and the illiquid class of assets being invested, it therefore stands to reason that the length of the bond used in the valuation of the Company's return should match the investment life of the assets (notably, the average life of JPS

[69] OUR, Consultation Document, Final Criteria for 2019-2024 Rate Review Process, Annex 5 p. 101.

assets as at December 31, 2018 was 22 years). Therefore, it is JPS' recommendation that any analysis of the appropriate risk free rate be done using the historical average on the US 20 Year Treasury Bond. There are many factors that affect the price of US Treasury bonds including interest rate, movements in the stock market, the prices of the US dollar, the maturity tenure and arguably the US political climate. The US 20 Year Treasury Bond by nature of its tenure allows for a more balanced evaluation of the risk free rate for JPS' rate of return valuation, as the investor yield to maturity on the 20Year bond represents a more comprehensive spread of the risks associated with the US market returns, interest rates, foreign exchange movement and political atmosphere.

Attendant to the position outlined above, JPS' analysis of the US 20 Year Treasury Bond over the period 1998 to 2018 yielded a result of 4.24% on a nominal basis. It is JPS belief that the aforementioned analysis and results is an appropriate estimate of the Risk Free Rate to be used in the computation of the regulated return of equity over the five-year Rate Review period. JPS' position is further bolstered in the OUR's comments to Stakeholders Response in the Addendum Final Criteria, section Annex 5, page 102, which states, "the OUR is of the view that the 20 Year bond provides a suitable proxy, all things considered."

Market/Equity Risk Premium

The OUR by way of their consultant NERA computed the Total Market Return (TMR) as the sum of the risk-free rate and the Equity Risk Premium (ERP). Specifically, NERA's estimation of the TMR and risk-free rate relied on the US long-run historical data for the period 1900 to 2016, which they argued was the most appropriate and the longest time series available for estimating the TMR. NERA further stated that the results were more reflective of a stable TMR estimate across regulatory periods, that is, when compared to their analysis of the TMR estimates for the forward-looking DGM for market valuation. Consequently, the OUR adopted this methodology and endorsed in the Final Criteria, specifically under Criterion #2b, point iii, that: "The Mature Market Equity Risk Premium shall be computed indirectly by subtracting the risk free rate (R_f) from the Total Market Return (TMR)." The Criterion further opined in point iv, that: "The Real TMR is the arithmetic average of long-run historical data of U.S. Market (1900-2018)."

The position outlined in Final Criterion #2 was further maintained in the OUR's comments to Stakeholder Response Annex 5 of the Final Criteria document, where it states, that: "The OUR maintains that the use of historic rates as a forecast for the Equity Risk Premium is reasonable. In fact, this is the dominant approach to forecasting in general and forms the backbone of multivariate analysis."

While JPS appreciates the use of historical market data for the estimation of equity risk premium in capital asset valuations, the results of the OUR's recommended methodology fails to take into consideration the relationship between investor expectation of equity risk premium and the level of interest rates. There have been numerous studies that have validated the conclusion that the relationship between the equity risk premium and interest rates is inverse, that is, the equity risk premium increases when interest rates decline, and the equity risk premium decreases when interest rates increase. The OUR's simple arithmetic average of US long-run total market return and US risk free rate for the period 1900-2016 ignores the strong inverse relationship between forward looking market returns and interest rates.

JPS believes that the ERP should be computed directly on a forward-looking basis as compared to the indirect computation as proposed by the NERA using a historical analysis to capture the average realized returns for the Total Market Return (TMR). Notably, this forward-looking view is not unique to JPS as it is supported by NYU Stern Prof. Damodaran, "what investors ultimately care about is the equity risk premium for the future. Consequently, the approach that has the best predictive power should be given more weight."[70] It is also consistent with the OUR's 2014-2019 Rate Review rationale outlined in the Final Criteria for the 2019-2024 Rate Review Process (see 3.5.5, Table 3-2 ("ROE should be forward looking").

For the reasons stated above, JPS initially proposed the discounted cash flow (DCF) forward-looking two stage methodology for calculating ERP, which has been adopted in other regulatory jurisdictions. Specifically, in the Federal Energy Regulatory Commission (FERC) Docket No. EL11-66-001 Opinion No. 531 Order on Initial Decision, the Commission ordered the adoption of the two stage DCF methodology in all ROE proceedings for public utilities henceforth. The Commission states on page 8, lines 24-25 of Docket No. EL11-66-001

"For the reasons discussed, we find that the ROE in this proceeding, as well as in future public utility cases, should be based on the same DCF methodology the Commission has used in natural gas pipeline and oil pipeline cases for many years—the two-step, constant growth DCF methodology, or two-step DCF methodology."

JPS' proposed DCF Two stage methodology is also consistent with the ruling of the Illinois Commerce Commission (ICC), a utility regulator in the US State of Illinois, which ordered the adoption of the two stage DCF in the Nicor Gas 2008 Order Docket No. 08-0363.

The ERP calculated by JPS's consultant (Concentric Energy Advisors) under this forward-looking approach is approximately 6.6%, which is slightly higher by 70 basis points compared to the OUR's ERP of 5.9% using a historical arithmetic average. In light of this, JPS is willing recognize the calculation of ERP by the NERA, as the result of the historical analysis converges with the results of JPS forward-looking analysis.

JPS reaffirms its position that the forward-looking approach of estimating ERP is the more appropriate methodology for the estimation of ERP and the regulated ROE for JPS. Nevertheless, JPS will use the OUR's estimation of the ERP. This submission in compliance with the Final

[70] Damodaran- Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2015 Edition

Criteria is, however, being made without prejudice to JPS' right to pursue its appeal against this point of dispute, as permitted under the said Condition 32 of the Licence, 2016 and JPS hereby expressly reserves the right to so pursue its appeal.

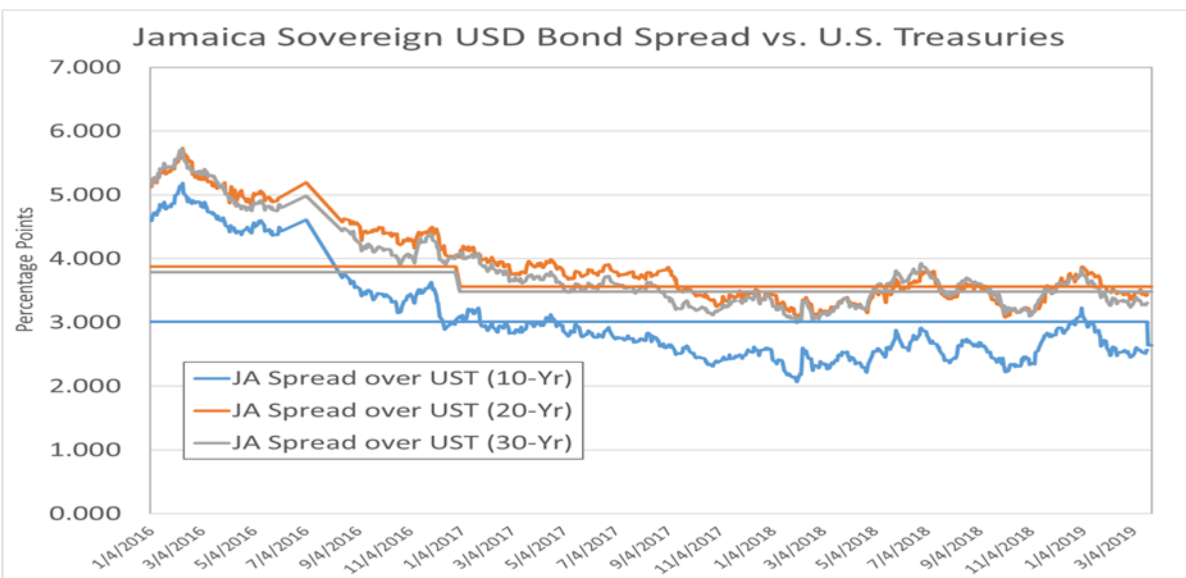
Country Risk Premium

The OUR Final Criterion No. 2 (b) (v) states: "The CRP shall be derived from the 2018, one (1) year average of the bond yield spread of the 10 year Jamaican USD denominated sovereign bond and the US 10-year Treasury bond."

JPS objects to this proposal in the Final Criteria and proposes that the CRP be calculated based on a three-year average of the bond yield spread on the 20 year Jamaican sovereign bond and the U.S. Treasury 20 -year bond.

As is consistent with the Final Criteria for the 2019-2024 Rate Review Process, JPS relied on the sovereign spread approach as being most reasonable. Figure 14-1 below, shows the results of the computations for different maturity bonds. The Jamaica 20-year bond has the longest history, and the average yield difference is approximately 3.90% since 2016. The yield differential on the 10-year bond is the lowest, with an average of 3.04% since 2016. The OUR' proposed CRP is a low 12-month average of 2.53% on the 10-year bond which was recorded in 2018.

Figure 12-1: Jamaica Sovereign Spreads



JPS finds that the OUR's one (1) year average of the sovereign spread is inconsistent with the rate review period and favorably selects the "best year" of Jamaica's recently improved macroeconomic environment without regard to future instability in the Jamaican economy. JPS finds this one (1) year average inconsistent and inadequate as it does not capture Jamaica's susceptibility to exogenous shocks from a hurricane event. Jamaica suffered its last major hurricane event in 2005, and while JPS is not advocating a fifteen (15) year average, the Company believes a three-year average is a more appropriate estimation of the extant **Country Risk**. Of particular importance, in the aftermath of a hurricane JPS does not have Federal funds or large capital markets to help rebuild the utility, furthermore JPS has significant fixed costs with no revenues in the short-term nor the opportunity to recover such costs beyond the limits of EDF over a long period after rebuilding the system. The OUR's proposed one (1) year is unacceptable for a business which recoups its capital on average over 20 years.

Furthermore, JPS believes the OUR's spread of CRP using the Jamaica and US 10-year bond does not match the life of JPS investments, which invariably fails to capture the risk factors that affect the price of US Treasury bonds, these include: interest rate, movements in the stock market, the price of the US dollar, and the US political climate.

Whereas, the US 20-year bond by nature of its tenure allows for a more comprehensive assessment of CRP, as the investor yield to maturity on the 20 Year bond represents a more inclusive spread of the risks associated with the US market returns, interest rates, foreign exchange movement and political atmosphere across the tenure. This tenure matches the average life of JPS' investments and is comparable to the period in which our shareholders will recoup their investment.

Beyond CRP, the OUR's inconsistent application of the ROE parameters sends the wrong message to investors. It is important to note that JPS' ROE at the time of privatisation was 14.85%, this was later upgraded to 16% and then unpredictably reduced to 12.25% in 2014. This kind of volatility sends a wrong message to investors who have already sunk their investment for the next 20 plus years.

Based on the results of our analysis and the above-mentioned arguments, JPS proposes the CRP be set at 3.90% using a three-year average of the Jamaican and US 20-year bond, which is a better representative compared to the one (1) year average of 2.53% on the Jamaican and US 10-year bond.

12.5 Proposed ROE Rate

The ROE rate calculation parameters as proposed by JPS based on the considerations above are provided in Table 12-2.

Table 12-2 – JPS ROE Proposal Rationale

	Component	**JPS Proposal**	**Rationale**
r_f	Risk Free Rate	4.24%	1998-2018 Avg. US 20-year bond
β	Levered Beta	0.75	US utility dataset

MRP	Market (or Equity) Risk Premium	5.9%	NERA/OUR 1900-2016 Avg. TMR
CRP	**Country Risk Premium**	**3.90%**	**2016-2018 Avg. spread of JA & US 20-year bond**

JPS requests approval of the ROE rate of 12.57% calculated under these parameters. Calculation of the proposed ROE rate by parameters is provided in Table 12-3.

Table 12-3– JPS Proposed ROE Computation

JPS 2019-2023 Return on Equity		
Line		
[1]	Gearing	50%
[2]	Tax Rate	33%
[3]	Real Risk-Free Rate (1900-2016)	**2.50%**
[4]	Nominal Risk-Free Rate (1998-2018)	4.24%
[5]	Equity Risk Premium	5.90%
[6]	Required Market Return	8.40%
[7]	Country Risk Premium	3.90%
[8]	Unlevered Beta	0.45
[9]	Levered Beta	0.75
[10]	**Nominal Required Return on Equity**	**12.57%**

While the JPS proposed ROE computation is actively being contested before the All Island Electricity Appeal Tribunal in the matter of an appeal against the Final Criteria, pending the outcome of a ruling; JPS in its 2019-2023 Rate Review submitted a revenue requirement as per the instructions promulgated by the OUR in its Final Criteria Document for the computation of the Cost of Capital. Calculation of the filed ROE rate by parameters is provided in Table 12-4. This submission in compliance with the Final Criteria is, however, being made without prejudice to JPS' right to pursue its appeal against this point of dispute, as permitted under the said Condition 32 and JPS hereby expressly reserves the right to so pursue its appeal.

Table 12-4: Filed ROE Computation.

2019-2023 Return on Equity		
Line		
[1]	Gearing	50%
[2]	Tax Rate	33%
[3]	Real Risk-Free Rate (1900-2016)	**2.50%**
[4]	Nominal Risk-Free Rate (1998-2018)	4.24%
[5]	Equity Risk Premium	5.90%
[6]	Required Market Return	8.40%
[7]	Country Risk Premium	2.53%
[8]	Unlevered Beta	0.45
[9]	Levered Beta	0.75
[10]	**Nominal Required Return on Equity**	**11.1990%**

12.6 Weighted Average Cost of Capital

12.6.1 Capital Structure

Determining the Company's capital structure is required in order to calculate a WACC, which becomes overall rate of return on JPS' regulatory investment. This WACC is then applied to the Company's rate base to determine return on rate base portion of the revenue requirement.

JPS' capital structure for ratemaking purposes comprises a combination of equity and long-term debt. Short-term debt is not included in the capital structure for regulatory purposes, as short-term debt cost of capital is separately treated, and as such is not included in setting the rate of return.

In accordance with Paragraph 30(a) of Schedule 3 of the Licence 2016, "the WACC will be based on the actual capital structure of the Licensee corrected for planned and approved major changes in the gearing of the Licensee."

Table 12-5 shows JPS' actual capital structure (gearing ratio) for the period of 2014-2018 using the company's audited financials.

Table 12-5: JPS' Actual Capital Structure and Gearing Ratio

	JPS Audited Financials				
	2014	**2015**	**2016**	**2017**	**2018**
Shareholder's Equity (US$'000)	336,220	366,891	395,411	424,147	441,084
Long-term Debt (US$'000) + CPLTD	371,077	354,217	344,204	354,045	381,605
Gearing Ratio	**52%**	**49%**	**47%**	**45%**	**46%**

As per Condition 2 Paragraph 10 of the Licence 2016 (General Conditions) any proposed reorganization of the capital structure of JPS shall be on such basis where it:

a. Meets the ruling conditions in major international markets; and
b. Establishes an overall equity/debt ratio which conforms to the customary practices of electric utility operation recognizing the specific peculiarities of operating exclusively in Jamaica (i.e. sovereign rating).

For the 2019-2024 Rate Review period, JPS has planned attracting long-term financing in the amount of US$100 – US$500 million to support its capital program, in addition to recently completed refinancing of a portion of the current long-term debt as discussed during the 2018 Annual Adjustment Filing process. The capital programme will also continue to be financed by the Company's equity in order to meet project commitments. As such, JPS does not expect major changes in the gearing for the 2019-2024 Rate Review period. Accordingly, JPS' proposes that the gearing ratio for the rate review period be established at 50%, which is the approved ratio for the last rate review period and consistent with the Licence 2016 requirements.

12.6.2 Derivation of JPS WACC

WACC is calculated as the weighted average of equity and long-term debt components of a company's capital structure. The Licence sets out the WACC calculation formula as follows:

The WACC or "K" = ROE/ (l-tax rate) * (1 - gearing ratio) + Interest rate* gearing ratio

Table 12-6 provides calculation of WACC rates for the current application based on the proposed parameters.

Table 12-6: Derivation of WACC

Filed 2019-2023 WACC	
Firm Tax Rate	33.33%
Cost of Equity	11.20%
Cost of Debt	7.45%
Debt Gearing	50.0%
Equity Gearing	50.0%
Nominal Pre-Tax WACC	**12.12%**
Nominal Post-Tax WACC	**8.08%**

13 2019 Revenue Target Adjustment for Annual Review

13.1 PBRM Annual Adjustment Overview

Paragraphs 42 to 56 of Schedule 3 of the Electricity Licence, 2016 (Licence 2016) sets out the methodology to be used in making an annual Performance-Based Rate-making Mechanism (PBRM) filing to determine rates.

The PBRM methodology is outlined in Exhibit 1 to Schedule 3 of the Licence 2016 and states as follows:

> *"The Annual Revenue Target shall be adjusted on an annual basis, commencing July 1, 2016, (Adjustment Date), pursuant to the following formulae:*

$$\mathrm{ART_y = RCy(1 + dPCI) + \left(RS_{y-1} + SFX_{y-1} - SIC_{y-1}\right) \times (1 + WACC)}$$

where:

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

$$\mathrm{SFX_{y-1} = AFX_{y-1} - TFX}$$

$$\mathrm{SIC_{y-1} = AIC_{y-1} - TIC}$$

and

$\mathrm{ART_y}$ = Annual Revenue Target for Year "y"

RCy = Revenue Cap for the current tariff adjustment year "y" as established in the last Rate Review Process

$\mathrm{RS_{y-1}}$ = Revenue surcharge for Year "y-1"

$$\mathrm{TUVol_{y-1}} = \left\{\frac{\mathrm{kWh\ Target_{y-1} - kWh\ Sold_{y-1}}}{\mathrm{kWh\ Target_{y-1}}}\right\} \times \text{Non Fuel Rev Target for Energy}$$

$$+ \left\{\frac{\mathrm{kVA\ Target_{y-1} - kVA\ Sold_{y-1}}}{\mathrm{kVA\ Target_{y-1}}}\right\} \times \text{Non Fuel Rev Target for Demand}$$

$$+ \left\{\frac{\mathrm{\#Customer\ Charges\ Billed\ Target_{y-1} - \#Customer\ Charges\ Billed_{y-1}}}{\mathrm{\#\ Customer\ Charges\ Billed\ Target_{y-1}}}\right\} \times$$

$$\text{Non Fuel Rev Target for Customer Charges}$$

Given that all tariffs charged to customers can be broadly allocated to three (3) primary revenue buckets, namely, Energy, Demand and Customer Charge, the true-up mechanism will be operated on that basis. The revenue target for each year will be allocated to each bucket with the target quantities estimated to achieve each revenue bucket forming the basis for the true-up adjustment for each revenue bucket as outlined in the formulae above.

For the purpose of administering the system losses component of the Annual Revenue Target Paragraph 38 of Schedule 3 of the Licence 2016 describes the losses targets as follows:

> "*The target set by the Office for losses shall normally be done at the Rate Review and be for a "rolling" ten (10) year period and 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 control of the Licensee; and*
> *c. The aspect of the non-technical losses that are not totally within the control of the Licensee.*

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

$$Y_{y-1} = Ya_{y-1} + Yb_{y-1} + Yc_{y-1}$$

$$Ya_{y-1} = \text{Target System Loss "a" Rate\%}_{y-1} - \text{Actual System Loss "a" Rate\%}_{y-1}$$

$$Yb_{y-1} = \text{Target System Loss "b" Rate\%}_{y-1} - \text{Actual System Loss "b" Rate\%}_{y-1}$$

$$Yc_{y-1} = (\text{Target System Loss "c" Rate\%}_{y-1} - \text{Actual System Loss "c" Rate\%}_{y-1}) * RF$$

where:

Ya = System losses that fall under subsection "a" of paragraph 38.

Yb = System losses that fall under subsection "b" of paragraph 38.

Yc = System Losses that fall under subsection "c" of paragraph 38.

RF = *The responsibility factor determined by the Office, which is a percentage from 0% to 100%. This responsibility factor shall be determined by the Office, in consultation with the Licensee, having regard to the (i) nature and root cause of losses; (ii) roles of the Licensee and Government to reduce losses; (iii) actions that were supposed to be taken and resources that were allocated in the Business Plan; (iv) actual actions undertaken and resources spent by the Licensee; (v) actual cooperation by the Government; and (vi) change in external environment that affected losses.*

SFX_{y-1} = *Annual foreign exchange result loss/(gain) surcharge for year "y-1".*

This represents the annual true-up adjustment for variations between the foreign exchange result loss/(gain) included in the Base Year revenue requirement and the foreign exchange result loss/(gain) incurred in a subsequent year during the rate review period.

AFX_{y-1} = *Foreign exchange result loss/(gain) incurred in year "y-1".*

TFX	=	*The amount of foreign exchange result loss/(gain) included in the revenue requirement of the Base Year*
SIC_{y-1}	=	*Annual net interest expense/(income) surcharge for year "y-1".* *This represents the annual true-up adjustment for variations between the net interest expense/(income) included in the Base Year revenue requirement and the net interest expense/(income) incurred in a subsequent year during the rate review period. The net interest income shall be deducted from the revenue requirement while net interest expense shall be added to the revenue requirement.*
AIC_{y-1}	=	*Actual net interest expense/(income) in relation to interest charged to customers and late payments per paragraph 49 to 52 of Schedule 3 in year "y-1".*
TIC	=	*The amount of net interest expense/(income) in relation to interest charged to customers and late payments included in the revenue requirement of the Base Year.*
$dPCI$	=	*Annual rate of change in non-fuel electricity revenues as defined below*
$WACC$	=	*The Weighted Average Cost of Capital determined in the Rate Review process.*

The annual PBRM filing will 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:

dI	=	*the growth rate in the inflation and JMD to USD exchange rate measures;*
Q	=	*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 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."*

13.2 Annual Adjustment Approach for 2019 Tariff Year

With respect to the annual review, the Licence 2016 does not explicitly state if there shall be annual revenue target adjustments for performance indicators in the fifth year of the last rate review period which coincides with the first test year of the new rate review period. However, in the Jamaica Public Service Company Limited Annual Review 2018 & Extraordinary Rate Review - Determination Notice (OUR 2018 Determination Notice), the OUR stated targets for 2018/2019 which suggests an annual adjustment in 2019 reflecting JPS' performance in the fifth year of the last rate review period. As such, JPS will incorporate the annual adjustment as part of the 2019 Rate Review application in the interest of regulatory efficiency.

JPS notes that the revenue cap component for the 2019 tariff year will be established based on the information presented in other chapters of the Rate Review proposal. As such, for the 2019 annual adjustment, JPS considers to focus on the performance-related adjustments to the Annual Revenue Target (ART) – that is, determining revenue surcharge, foreign exchange loss/(gain) surcharge, and net interest expense/(income) surcharge for 2018.

Further, in contrast to the annual adjustment filing practice in the interim years, the 2019 annual adjustment will not address related tariff adjustments, which is presented in the Tariff Design chapter of the Rate Review proposal.

13.3 2018 Revenue True-Up

13.3.1 2018 Revenue Surcharge

The revenue surcharge is comprised of: the true-up for volume adjustments and the true-up for system losses. These true-ups reconcile with JPS' actual performance during 2018 against the targets set for that year, and result in the ART increasing by J$111.4 million for 2019. The increase is primarily driven by JPS achieving its system losses targets but was reduced by JPS outperforming its sales targets in 2018.

13.3.2 True-Up Volumetric Adjustment

In accordance with the methodology outlined in Paragraphs 42 to 56 of Schedule 3 of the Licence 2016, the volumetric adjustment for any year is dependent on the variance between the target billing determinants and those that were actually achieved during that year.

Consistent with the OUR's approach in the (OUR 2018 Determination Notice), the billing determinant targets for 2018 are as follows:

$$\text{kWh}_{\text{Target}_{2018}} = \text{kWh}_{\text{Sold}_{2017}}$$

$$\text{kVA}_{\text{Target}_{2018}} = \text{kVA}_{\text{Sold}_{2017}}$$

$$\text{\# Customers Charges Billed}_{\text{Target2018}} = \text{\# Customers Charges Billed}_{2017}$$

where:

$$\text{kWh}_{\text{Sold}_{2017}} = \text{kWh billed in 2017}$$

$$\text{kVA}_{\text{Sold}_{2017}} = \text{kVA billed in 2017}$$

$$\text{\# Customers Charges Billed}_{2017} = \text{\# Customers Charges Billed in 2017}$$

The non-fuel revenue targets for energy, demand and customer charge should be matched to the respective components of the target billing determinants. Since the billing determinant targets for 2018 are the actual billing determinants for 2017, the non-fuel revenue targets for energy, demand and customer charge should be the product of the 2018 approved prices and the 2017 quantities for each revenue category. Table 8.12 of the OUR 2018 Determination Notice captures the 2018 non-fuel revenue targets for energy, demand and customer charge as computed by the OUR using the annual escalation factor computed in 2018. A copy of Table 8.12 is shown below.

Table 8.12: Approved Annual Revenue Target: 2018

Class		Block/Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA				Total Revenue
					Std.	Off-Peak	Part Peak	On-Peak	
									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**

The tariffs approved by the OUR in 2018 multiplied by the billing determinants do not exactly equal to the Revenue Target depicted in Table 8.12 of the OUR 2018 Determination Notice due to rounding errors.

As revenue targets are set using the tariffs determined by the OUR the corrected and approved revenue target is J$48,866,805,215 as illustrated in 13-1 below.

Table 13-1: Corrected Approved Annual Revenue Target: 2019 – 2020

	Block/ Rate Option			12 Months 2018 Customer Revenue	Energy Revenue	Demand (KVA) revenue				Total Demand Revenue	Total Revenue
						Std.	Off-Peak	Part Peak	On-Peak		
Rate 10	LV	<100	-	1,238,500,872	5,109,997,479					-	6,348,498,351
Rate 10	LV	>100	-	1,816,201,543	12,148,127,638					-	13,964,329,181
Rate 20	LV		-	781,921,833	11,830,066,759					-	12,611,988,592
Rate 40	LV - Std		-	142,458,726	3,864,042,347	4,018,065,107				4,018,065,107	8,024,566,181
Rate 40	LV - TOU		-	9,556,437	654,773,925		23,037,606	234,908,285	237,142,539	495,088,430	1,159,418,792
Rate 50	MV - Std		-	9,745,189	1,128,068,741	1,124,438,378				1,124,438,378	2,262,252,309
Rate 50	MV - TOU		-	1,964,418	290,806,668		14,223,870	129,183,311	122,628,587	266,035,769	558,806,855
Rate 70	MV -STD		-	1,593,905	952,073,941	976,590,768				976,590,768	1,930,258,614
Rate 70	MV -TOU		-	314,586	162,475,250		8,312,263	80,534,995	87,995,709	176,842,966	339,632,803
Rate 60	LV		-	14,553,877	1,652,499,659					-	1,667,053,537
TOTAL				4,016,811,387	37,792,932,408	6,119,094,254	45,573,739	444,626,591	447,766,835	7,057,061,420	48,866,805,215

Using 13-2 as the basis, the Non-Fuel Energy, Customer Charge and Demand revenues are calculated as follows:

Table 13-2: Customer Charge and Demand Revenues

Component of Revenue	Target Value
Non Fuel Rev Target for Energy	$37,792,932,408
Non Fuel Rev Target for Customer Charges	$4,016,811,387
Non Fuel Rev Target for Demand	$7,057,061,420

As illustrated in Table 13-3, $TUVol_{2018}$ is determined by substituting the values computed in Table 13-2 above. 2018 volumetric adjustment is J$234.6 million (US$1.8M) reduction to the 2019 ART before the opportunity cost adjustment.

Table 13-3: Computation of Volumetric Adjustment

Volumetric Adjustment $TUVol_{2018}$			
Line	**Description**	**Formula**	**Value**
	Energy Surcharge		
L1	kWh $Target_{2018}$		3,113,504,786
L2	kWh $Sold_{2018}$		3,122,336,893
L3	Revenue Target for Energy		37,792,932,408
L4	kWh Surcharge	(L1-L2)/L1*L3	(107,207,547)
	Demand Surcharge		
L5	kVA $Target_{2018}$		5,288,413
L6	kVA $Sold_{2018}$		5,328,991
L7	Revenue Target for Demand		7,057,061,420
L8	kVA Surcharge	(L5-L6)/L5*L7	(54,148,691)
	Customer Count Surcharge		
L9	#Customer Charges Billed $Target_{2018}$		639,615
L10	#Customer Charges $Billed_{2018}$		651,280
L11	Revenue Target for Customer Charges		4,016,811,387
L12	Customer Charges Surcharge	(L9-L10)/L9*L11	(73,254,620)
L13	**$TUVol_{2018}$**	**L4+L8+L12**	**(234,610,858)**

13.3.3 System Losses Adjustment

As stated in the Licence 2016, the annual non-fuel adjustment clause includes the system losses incentive mechanism. The system losses true-up, represented in the formulaic representations as TULos is computed by first disaggregating system losses into three (3) components: TL, JNTL and GNTL where:

TL = Technical Losses

JNTL = Portion of Non-technical losses which is completely within JPS' control

GNTL = Portion of Non-technical losses which is not completely within JPS' control

Each component of system loss is then measured against a target that would be set by the OUR as shown in the following equations.

Ya_{y-1} = Target System Loss "a" Rate$\%_{y-1}$ – Actual System Loss "a" Rate$\%_{y-1}$

Yb_{y-1} = Target System Loss "b" Rate$\%_{y-1}$ – Actual System Loss "b" Rate$\%_{y-1}$

Yc_{y-1} = (Target System Loss "c" Rate$\%_{y-1}$ – Actual System Loss "c" Rate$\%_{y-1}$) * RF

where RF = The responsibility factor determined by the Office, is a percentage from 0% to 100%.

The Licence 2016 stipulates that the responsibility factor is to be "determined by the Office, in consultation with the Licensee, having regard to the (i) nature and root cause of losses; (ii) roles of the Licensee and Government to reduce losses; (iii) actions that were supposed to be taken and resources that were allocated in the Business Plan; (iv) actual actions undertaken and resources spent by the Licensee; (v) actual cooperation by the Government; and (vi) change in the external environment that affected losses".

The variance of the three losses components from target is used to compute a total variance Y_{y-1} in year "y-1" as shown below:

$$Y_{y-1} = Ya_{y-1} + Yb_{y-1} + Yc_{y-1}$$

Finally, $TULos_{y-1}$ for year "y-1" (the year preceding the adjustment year) is computed as:

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

In order to complete the calculations for the losses true-up, $TULos_{2018}$, the actual system losses for the year must be disaggregated into the respective three (3) components stipulated in the Licence 2016 to enable the comparison against the targets set by the OUR in the Jamaica Public Service Company Limited Annual Review 2018 & Extraordinary Rate Review -Determination Notice. Once disaggregated, the three (3) components will be computed separately and re-aggregated to derive the losses penalty. This disaggregation of the 2018 system losses is shown in System Losses (Chapter 9).

In the OUR's assessment, the regulator considered the advantages of smart meters to fight losses and as such, devised a special losses initiative designated as the "Accelerated Loss Reduction Mechanism" (ALRIM) which will allow the capital investment needed for the smart meters. ALRIM provided JPS with two options: ALRIM-1 and ALRIM-2 and JPS selected ALRIM-2.

Under ALRIM-2, the targets applicable for the 2018-2019 Annual Review period are:

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

Using the Losses Spectrum shown in Chapter 8 of the Rate Case Filing, the computation of $TULos_{2018}$ is shown in Table 13-4 below:

Table 13-4: Computation of TULos2018

System Losses Adjustment $TULos_{2018}$			
Line	**Description**	**Formula**	**Value**
	Losses Surcharge		
L14	Actual TL_{2018}		7.94%
L15	Target TL_{2018}		8.00%
L16	Ya_{2018}	(L15-L14)	0.06%
L17	Actual $JNTL_{2018}$		4.22%
L18	Target $JNTL_{2018}$		5.75%
L19	Yb_{2018}	(L18-L17)	1.53%
L20	Actual $GNTL_{2018}$		14.11%
L21	Target $GNTL_{2018}$		9.70%
L22	RF		20.00%
L23	Yc_{2018}	(L21-L20)*L22	-0.8820%
L24	Y_{2018}	L16+L19+L23	0.71%
L25	ART_{2018}		48,866,805,215
L25	**$TULos_{2018}$**	**L24*L25**	**345,976,981**

The 2018 system losses adjustment results in J$345.98 million (US$2.7M) increase to the 2019 ART before the opportunity cost adjustment.

13.4 Foreign Exchange and Interest Surcharges

Foreign exchange losses and interest charges were not included in the revenue requirement that was set by the OUR in the Jamaica Public Service Company Limited Tariff Review for the Period

2014 – 2019 - Determination Notice (2014 – 2019 Tariff Review Determination Notice). However, Paragraph 31 of Schedule 3 of the Licence 2016 makes provision for the inclusion of FX losses in the revenue requirement to be set at the time of a Rate Review. The Annual Adjustment mechanism described in Exhibit 1, includes a true-up for FX losses (FX surcharge) which is offset by interest surcharge on customer arrears. At the time of an Annual Adjustment, the FX surcharge is computed as the actual FX loss incurred during the previous year less the target for FX loss set at the last rate review. Similarly, the interest surcharge is calculated as the actual net interest expense/ (income) (including net late payment fee) less the provisions made for the net interest expense in the revenue requirement. Since no provisions were made in the previous rate review for FX losses in the revenue requirement, the true-up will be computed as though the target was set at zero (0).

The actual net interest expense in relation to interest charged to customers in 2018 reflects the realized interest income. The realized income is based on the distribution of the payments made and credit balances applied to the interest charge for commercial and government accounts created in Customer Suite. Based on this assumption the true-ups for 2018 are computed as illustrated in Table 13-5.

Table 13-5: Computation of FX and Interest Surcharges

FX and Interest Surcharge for 2018 (SFX_{2018} - SIC_{2018})			
Line	**Description**	**Formula**	**Value**
	FX Surcharge		
L1	TFX_{2018}		-
L2	AFX_{2018}		459,901,824
L3	**SFX_{2018}**	**L2-L1**	**459,901,824**
	Interest Surcharge		
L4	Actual net interest expense/(income) in relation to interest charged to customers for 2018		(123,326,720)
L5	Actual Net Late Payment fees for 2018		132,803,712
L6	AIC_{2018}	L4+L5	9,476,992
L7	TIC_{2018}		-
L8	**SIC_{2018}**	**L6-L7**	**9,476,992**
L9	**SFX_{2018} - SIC_{2018}**	**L3-L8**	**450,424,832**

Foreign exchange and interest surcharges result in J$450.4 million (US$3.5M) increase in the 2019 ART.

13.5 Opportunity Cost Adjustment

JPS is not proposing an adjustment to the WACC that will be applied to the 2018 true-ups. As such, the WACC that will be used for the 2018 true-ups is the pre-tax WACC of 13.22% that was set in the 2014 – 2019 Tariff Review Determination Notice. Table 13-6 presents calculation of the total revenue true-up amount for 2018 adjusted for the opportunity cost, for net decrease of J$636.06 million (US$4.97M) to the 2019 ART.

Table 13-6: 2018 Revenue True-up

2018 Revenue True-Up			
Line	**Description**	**Formula**	**Value**
L1	Revenue Surcharge 2018 (RS_{2018})		111,366,123
L2	SFX_{2018}-SIC_{2018}		450,424,832
L3	WACC		13.22%
L4	**2019 Revenue True-Up**	**(L1+L2)x(1+L3)**	**636,059,720**

14 Cost of Service and Load Research

14.1 Introduction and Background

Significant shifts in the electricity sector have disrupted the operations of utilities both locally and overseas. Customers have become increasingly sophisticated and are demanding greater value and choice from their service providers, at a lower cost. Their sensitivity to price signals has heightened, given the increasing number of options available, with many customers investing in renewable or alternative energy sources to fully supplant or complement their energy requirements from the grid. Utilities worldwide are now grappling with increasing demand for higher reliability of power supply, greener energy to protect the environment, new supply modes to satisfy consumer preferences and new business models to improve the delivery of electricity at a reduced cost.

In response to these challenges, one of the actions JPS has taken is the commissioning of a Load Characterisation Study and two Cost of Service Studies (COSS) namely an Embedded Cost of Service Study and a Long Run Marginal Cost Study. These studies were used to develop an improved rate design that allows for greater efficiency in its relative tariffs. Other relevant actions implemented by the company in this pursuit included; market assessment, grid modernization, and productivity improvement strategies to enhance service delivery. JPS is firmly of the view that given the current and evolving market dynamics, modern rate design must be part of its response to meeting the new demands of its customers.

In developing the COSS, JPS sought to address concerns expressed by the OUR in its 2014 Determination Notice. The Office indicated that in its view, "the company's submission was not sufficient to establish a cost-causation relationship among existing rate classes and functionalized cost to satisfy the requirements of the Office." In the related filing, JPS had presented changes to its rate structure, which were predicated on the load research parameters and the results of the COSS it had developed. These changes were not approved by the OUR.

JPS engaged the OUR throughout the process of developing the COSS presented in this chapter. The Regulator was asked to comment on the Terms of Reference (TOR) used to engage relevant expertise to assist JPS with developing the study, indicate its major concerns to the consultants at the inception phase and participate in meetings held to present the findings of the study. These meetings were critical to providing relevant clarifications in relation to the Regulator's concerns and identifying matters considered significant for incorporation in the outcomes of the study. JPS is therefore confident that the present study results comprehensively address the OUR's concerns, as well as the requirements of the Final Criteria. The COSS reports are provided as Annexes of the Rate Application.

The Final Criteria published by the OUR outlines specific requirements for JPS' tariff design inputs, inclusive of COSS and Load Characterization Study (LCS).

The following sections represents a summary of the robust analysis presented in JPS' COSS reports used to support its proposed rate design. The summary of the Load Characterisation Study is presented in section 16.2 followed by the Embedded Cost of Service Study and the Long Run Marginal Cost Study in sections 16.3 and 16.4 respectively.

Summary of Criteria

Criterion 7 established the general principles and guidelines for rate setting, which also accords with well-adopted economic theory as well as JPS' own processes and methodology for the development of tariffs.

In accordance with the requirements of the License, the OUR outlined the tariff requirements with respect to rate design in section 3.10 of the Final Criteria. This section states:

> *"As a part of its Rate Review application, JPS is required to conduct and submit a cost of service study. This study shall be used as the basis for establishing tariffs for each rate class which (with the possible exception of prepaid customers), shall at a minimum include customer charges and non-fuel energy charges. Standard and Time of Use (TOU) demand charges shall also be incorporated for applicable rate classes."*

Criterion 7 further stipulates, "The cost of service study shall form the basis of JPS' tariff design."

Additionally, Criterion 17 requires that "JPS shall submit as part of its 2019 – 2024 Rate Review application:

a) an embedded cost of service study based on the revenue cap for 2019 (Section 16.3)
b) a study done on a bottoms-up Long Run Marginal Cost basis with reconciliation to the revenue cap for 2019 (Section 16.4)
c) a load research study report detailing the sampling technique and methodology used in its programme as well as an analysis of the structure of demand over a typical day (weekdays, Saturday and Sunday) for each rate class (Section 16.2)

The criterion establishes the purpose of the Cost of Service Study (COSS) as to apportion the costs required to serve customers among each customer class in a fair and equitable manner and the study should be developed using the established Embedded Cost (EC) and Long Run Marginal Cost (LRMC) principles. It requires that the study details the cost functionalization, cost classification, and cost allocation for the major electricity system components outlined below.

It distinguishes the EC as a study allocating the total Revenue Requirement to customer classes, from the LRMC study which analyses how the cost of the system changes due to an incremental increase in demand. Further, it states that the LRMC of service study shall include:

a) The LRMC of generation, transmission by feeder type and distribution by feeder type and distribution medium voltage and low voltage and the supply of one unit of additional capacity to the power system at the peak period by main voltage levels.
b) The short-run marginal cost (SRMC) (energy and other variable O&M) at generation, transmission and at distribution and supply.
c) The economic cost of supply (covering customer service facilities and administration and general function), expressed as (a) capacity (cost/kW/year) or/and fixed charge per month, (b) energy and other variable O&M cost (cost/kWh), and (c) as a composite of (a) and (b) cost/kWh at generation, at transmission, at distribution and supply; and
d) The process for marking up the marginal cost to allow for full cost recovery

14.2 Load Characterization Study

The Final Criteria requires that JPS submit a Load Research Report that details various cost allocation factors based on at least twelve months of interval data from a representative sample. It further states that this sample should be selected to ensure a minimum statistical precision of peak hour demand estimate of ± 10% at a 90% confidence level. The cost allocation factors (methods as well) should be used to allocate both embedded and long run marginal costs to each rate class and thus ultimately lead to an initial tariff design based on fairness and equity (cost causality).

General Overview and Allocation Methodology

To develop cost allocation factors, technical expertise was sought through MacroConsulting to conduct a Load Characterization Study to support the Rate Review process, and in particular the development of the COSS. Load Characterization has two main uses in the determination of regulated rates, namely cost allocation and rate design. Load profile data provides information on user groups and customer class load characteristics including consumption patterns at a relatively high degree of resolution enabled by data collected from Smart AMI meters. These patterns are not observable in the regular billing database. This information is vital for the development of efficient cost allocation factors by customer class relative to a chronological system demand curve, as well as at a specific time of high system demand such as the peak. The load research analysis also informs the decision on rate structures, possible alternative rate designs, and revenue impact. The parameters estimated forms the basis for the allocation of system cost (revenue requirement) among the different ratepayers.

In order to allocate costs based on causation, various allocation factors and methods are utilized based on the type of cost (function and classification), system characteristics (planning principles, T&D network) and load characteristics (seasonality, load profile). Table 14-1 provides definitions of the allocation factors that were computed from the load research study. Table 14-2 contains the definition of allocation methods utilized based on classification.

Table 14-1: Definition of Allocation Factors and Load Parameters

Parameters	Definition and Comments
Class 1-CP	Definition: Class Peak at the time of the annual system peak.
Class 4 – CP	Average of the 4 highest Class Peak demands (not necessarily coincident with system peak)
Class 12 – CP	Average of the 12 monthly class peak demands in a year
Class NCP	Peak of the class which is not necessarily coincident with the system peak
Class NCP MD	Class non-coincident peak maximum demand- the sum of the individual customer maximum demand regardless of when each customer's maximum demand occurs.
Class LF	Class Load Factor - average class demand divided by class peak demand during a period
Average Demand	The average demand of a class during a particular period
Excess Demand	The difference between the Class NCP and average demand of a class during a particular period
Energy at Generation	Determined share (%) of energy supplied at generation caused by a particular rate class. Energy is sum of both sales and losses (net generation).
#Customers (#Cust)	Represents the number of customers in each rate class. The share is determined by dividing the number of customers (in a rate class) by the total number of customers.
Weighted #Customers (Weighted #Cust)	Calculates the weighted number of customers in each rate class. Weights are determined by metering costs for the different rate classes.
Class External Coincidence Factor (Class ICF)	The internal coincidence factor of the class is the ratio of the Class NCP and Class NCP MD
Class External Coincidence Factor (Class ECF)	The external coincidence factor of the class is the ratio of class demand during voltage level peak for a given TOU period and the Class NCP
Class External Coincidence Factor (Class TCF)	The product of the ICF and ECF of a class

Table 14-2: Definition of Allocation Methods

Classification	Method	Definition and Comments
Demand	Average-Excess Demand (AED)	Sums the weighted average of average demand and excess demand. Weights are system load factor (average demand) and 1 - system load factor (excess demand). Generation demand costs are allocated to each rate class using this method.
	12-CP	Average of the 12 monthly class peak demands in a year. Transmission demand costs are allocated to each rate class using this method
	ECF	Computes ECF (as defined above) to decompose energy cost for a particular rate class into costs for the three TOU periods.
	LOLP	Used to allocate generation demand cost to the three TOU periods. For details on computation see page xx of the LRMC report in annex XX.
Energy	Energy at Generation	Computes Energy at Generation (as defined above) to allocated energy costs to each rate class
	ECF	Computes ECF (as defined above) to decompose energy cost for a particular rate class into costs for the three TOU periods.
Customer	No. of Cust	Computed as defined above to allocate costs to each rate class
	Weighted No. of Cust	Computed as defined above to allocate costs to each rate class

Data Sources

Input data for the load characterization study was taken from JPS' billing and smart meter databases. The billing database contains billed and actual monthly readings for both energy (kWh) and demand (kVA) parameters on a per customer basis and therefore provides critical information on the entire customer base. The database was analysed from January 2008 through to December 2018 to provide insights into the change in consumption makeup of the customer base and within each existing rate class (tariff category). It also served to provide an invaluable check in determining the statistical significance of the sample selected for the load research analysis.

Table 14-3: Load Research Timetable[71]

Period	Status
Aug-2014 - Dec-2018	Complete billing database with energy consumption and power charges including billing in JMD per user.
Jan - 2008 – Jul -2014	Energy consumption and power charges per user.

[71] Source: *JPS Load Research Report, pp 20*

14.2.1 Sample Selection

As previously stated, the Final Criteria established that *"…the Load Research sample should be selected to ensure a minimum statistical precision of peak hour demand estimate of ± 10% at a 90% confidence level."* The emphasis on the representative nature or statistical accuracy of the sample is important as inferences will be drawn with respect to demand characteristics of the total population. The population *"N"* to be studied is the entire JPS customer base, which is subdivided into non-overlapping customer/ rate classes based on general demand and other technical characteristics. The total number of customers within each rate class forms the sampling frame from which the sample "*n*" will be selected. As an initial step, an assessment was performed to compute the sample that would at the minimum satisfy the criteria relative to the total customer population as per the billing database as at December 2018. The computation is summarized below in Table 14-4.

Table 14-4: Customer Sample Size[72]

Rate Class	Customers	Sample Size	
		90% - 10%	95% - 5%
R10	577,196	68	384
R20	66,446	68	382
R40	1,822	66	318
R50	157	48	112
R60	457	60	209
R70	23	6	6
Total	646,099	316	1,411

As can be seen, at the 90% confidence level (10% margin of error), the sample size would require 316 customer observations (cumulative sum). Given the wide availability of AMI interval meters (and data), increasing the statistical accuracy of the sample comes at minimal cost and the added benefit of increasing the robustness of the load characterization analysis. JPS adopted a significantly larger sample size than required by the Final Criteria.

Residential Sample MT10

The results from extensive sampling and analysis yielded a remarkable accuracy to within 2% variance of the annual mean consumption of the population of MT10 customers.

Small Commercial Customers: MT20

A similar sampling an analysis process was followed for the selection of the MT20 sample. Comparing the mean annual consumption of the selected sample relative to the mean consumption of the entire MT20 database, yielded a variance of only 0.26%.

[72] Source: JPS *Load Research Final Report 2019, pp 25*

Large Commercial and Industrial Customers: MT40, MT50 & MT70

The population of these customers is approximately 2,011 as of December 2018. AMI meter coverage within this group is almost universal, so a sampling exercise was not conducted. All available AMI data was utilized for these customers.

Final Sample

Table 14-5 shows the final sample size per rate class. This is compared to the minimum requirements outlined in the OUR's Final Criteria.

Table 14-5: JPS Final Sample Selection

Rate Class	Population Size	Final Criteria Sample Size (90% CI and 10% margin of error)	JPS Final Sample Selection
R10	577,196	68	10,000
R20	66,446	68	1,000
R40	1,822	66	1,555
R50	157	48	113
R60	457	60	
R70	23	18	21
Total	**646,099**	**328**	**12,689**

14.2.2 Results and Load Research Parameters

The following section presents the summarized results of the load research study having processed all available smart meter 15-minute interval data. The analysis allowed for the construction of load curves and determination of various allocation factors and allocation methods.

System Level Curves and Load Details

The construction of the typical curves included extrapolation (from sample data) to determine the aggregate demands of each class. Weekday and weekend curves are shown below for each rate class to facilitate comparison of demand patterns during a 24 hour period. The graph illustrating the demand on the day of system peak reveals a fairly high baseload of ~500MW with a plateau type peak of ~600MW between 9am and 4pm and system peak of ~654MW occurring at 7pm. During a typical weekend, the profile remains with the only change being the daytime demand being almost flat at ~500MW instead of 600MW.

Figure 14-1: System Level Peak Day Curves[73]

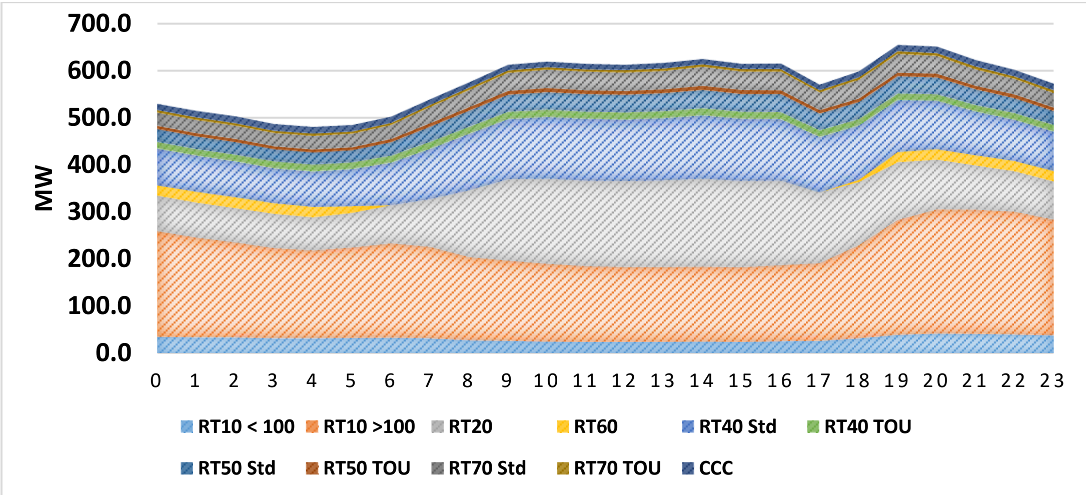
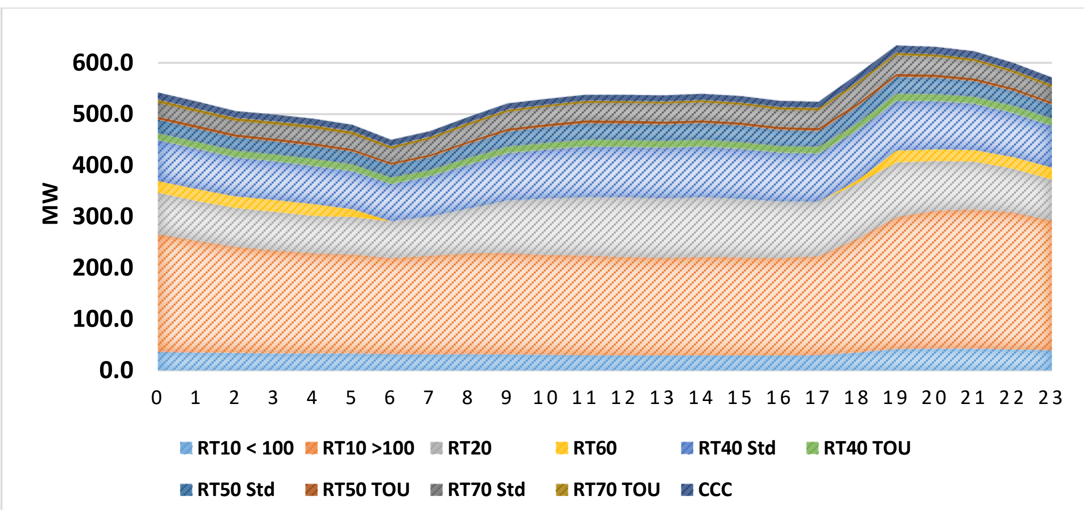


Figure 14-2: System Level Weekend Load Curves[74]



An analysis was done to investigate seasonal patterns by representing the energy sales for each class (by month and year) relative to its average monthly sales. The heat map below shows a clearly distinctive summer peak especially in the months of June, July, August, and September. Additionally, while residential customers peaked in August, commercial customers tended to peak in July.

[73] Source: *JPS Load Research Report, pp 86*

[74] Source: *JPS Load Research Report, pp 87*

Figure 14-3: Class and System Seasonality between 2015 and 2018[75]

2018													
Rate	January	February	March	April	May	June	July	August	Septembe	October	Novembe	Decembe	Year
MT10	0.97	0.95	0.92	0.97	1.00	1.03	1.07	1.11	1.01	0.99	1.01	0.97	1.00
MT20	0.90	0.91	0.97	0.97	1.01	1.05	1.09	1.06	1.05	1.01	1.01	0.96	1.00
MT40	0.93	0.90	0.98	0.97	1.00	1.05	1.10	1.07	1.02	1.00	0.99	0.99	1.00
MT50	0.94	0.86	0.96	0.95	1.03	1.05	1.10	1.04	1.00	1.01	1.07	1.00	1.00
MT60	0.94	1.08	1.06	1.06	1.06	1.00	0.99	0.96	0.97	0.97	0.97	0.96	1.00
MT70	0.94	0.85	1.02	1.02	1.01	0.98	1.03	1.07	1.08	1.02	1.02	0.98	1.00
Total	0.95	0.92	0.97	1.00	1.01	1.03	1.08	1.07	1.01	1.00	0.99	0.97	1.00

2017													
Rate Class	January	February	March	April	May	June	July	August	Septembe	October	Novembe	Decembe	Total
MT10	1.00	0.92	0.95	0.99	0.98	1.03	1.04	1.10	1.07	1.01	0.99	0.92	1.00
MT20	0.93	0.88	0.94	0.95	1.03	1.03	1.07	1.05	1.09	1.05	0.99	1.00	1.00
MT40	0.97	0.90	0.98	0.97	0.98	1.02	1.10	1.07	1.03	1.11	0.89	0.98	1.00
MT50	0.99	0.90	0.97	1.07	1.02	1.00	1.07	1.04	0.98	1.01	0.99	0.97	1.00
MT60	1.09	1.09	1.07	1.06	1.06	1.06	1.05	1.05	0.94	0.90	0.85	0.83	1.00
MT70													
Total	0.97	0.91	0.96	0.99	1.01	1.03	1.07	1.06	1.04	1.04	0.96	0.96	1.00

2016													
Rate Class	January	February	March	April	May	June	July	August	Septembe	October	Novembe	Decembe	Total
MT10	0.97	0.95	0.95	0.98	1.00	1.03	1.05	1.06	1.03	1.01	1.00	0.96	1.00
MT20	0.96	0.93	0.97	0.97	1.03	1.04	1.10	1.03	1.03	0.99	0.97	0.97	1.00
MT40	0.97	0.91	1.01	0.98	1.04	1.04	1.10	1.03	0.99	0.99	0.98	0.97	1.00
MT50	0.99	0.93	1.01	1.01	1.03	1.02	1.07	0.98	0.93	1.01	1.02	1.01	1.00
MT60	1.01	1.01	1.01	1.01	1.01	1.00	1.00	0.99	1.00	1.00	0.99	0.98	1.00
MT70													
Total	0.98	0.94	0.98	0.98	1.02	1.03	1.07	1.03	1.00	1.00	1.00	0.98	1.00

2015													
Rate Class	January	February	March	April	May	June	July	August	Septembe	October	Novembe	Decembe	Total
MT10	0.95	0.90	0.93	0.97	1.01	1.01	1.04	1.06	1.08	1.06	1.02	0.98	1.00
MT20	0.88	0.84	0.95	0.92	1.05	1.04	1.11	1.08	1.05	1.06	1.04	0.97	1.00
MT40	0.95	0.86	1.01	0.96	1.04	1.02	1.07	1.06	1.03	1.02	1.01	0.97	1.00
MT50	1.11	0.66	0.99	0.96	1.00	1.03	1.06	1.08	1.04	1.06	1.00	1.02	1.00
MT60	1.04	1.04	1.03	1.02	1.02	1.03	1.00	0.82	1.13	0.96	0.95	0.96	1.00
MT70													
Total	0.97	0.84	0.97	0.96	1.03	1.02	1.06	1.06	1.05	1.05	1.02	0.98	1.00

Average													
Rate Class	January	February	March	April	May	June	July	August	Septembe	October	Novembe	Decembe	Total
MT10	0.97	0.93	0.94	0.98	1.00	1.03	1.05	1.08	1.05	1.02	1.00	0.96	1.00
MT20	0.92	0.89	0.96	0.95	1.03	1.04	1.09	1.06	1.06	1.03	1.00	0.97	1.00
MT40	0.95	0.89	0.99	0.97	1.02	1.03	1.09	1.06	1.02	1.03	0.97	0.98	1.00
MT50	1.01	0.84	0.98	1.00	1.02	1.02	1.07	1.03	0.99	1.02	1.02	1.00	1.00
MT60	1.02	1.05	1.04	1.04	1.04	1.02	1.01	0.96	1.01	0.96	0.94	0.93	1.00
MT70	0.94	0.85	1.02	1.02	1.01	0.98	1.03	1.07	1.08	1.02	1.02	0.98	1.00
Total	0.97	0.90	0.97	0.98	1.02	1.02	1.07	1.06	1.03	1.02	0.99	0.97	1.00

75 Source: *JPS Load Research Report, pp 53*

Allocation Factors and Methods

Extensive data analysis allowed for the determination of several allocation factors and shares for allocation methods. These factors and methods were used in the ECS and LRMC tariffs. Tables 13-6 and 13-7 below shows the results for different allocation methods. Table 14-6 provides the coincidence and load factor results by rate class as per the Load Research Study while Table 14-7 presents external and total coincidence factor results by rate class.

Table 14-6: Coincidence and Load Factors – Summary[76]

Factors	Definition	MT10	MT20	MT40	MT50	70	MT60
Class 1-CP	Peak demand at the time of the annual system peak (kW)	205,373	85,799	107,165	34,049	41,158	15,747
Class 4-CP	Average of the class peaks at the times of the four highest peaks throughout the year	232,833	163,061	158,865	54,233	53,903	15,890
Class 12-CP	Average of the class monthly peaks	218,844	151,433	141,508	45,280	47,627	14,529
Class NCP	Peak of the class which is not necessarily coincident with system peak	226,816	162,311	143,871	41,016	47,750	15,747
Class NCP MD	Class non-coincident peak maximum demand - the sum of the individual maximum demand regardless of when each customer maximum demand occurs	406,408	220,508	162,622	46,784	52,220	15,747
Class LF	Class load factor	59.9%	47.1%	65.6%	69.3%	73.1%	41.7%
Class Internal Coincidence Factor	The internal coincidence factor of the class is the ratio of the maximum power of the class and the sum of all non-coincidental maximum powers of the customers in class	55.8%	73.6%	88.5%	87.7%	91.4%	100.0%
Class KonP	Percentage energy consumption of the class in the on-peak block	14%	11%	11%	12%	12%	22%
Class KpaP	Percentage energy consumption of the class in the partial peak block	36%	54%	48%	46%	44%	11%
Class KoffP	Percentage energy consumption of the class in the off-peak block	50%	36%	41%	42%	44%	67%

Table 14-7: External and total coincidence factors – Summary77

Rate	Coincidence factors											
MT10	External Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.91	0.91	0.91	0.97	0.65	0.65	0.65	0.65	0.99	0.99	0.99	0.99
	Total Coincidence Factor											

76 Source: *JPS Load Research Report, pp 54*

77 Source: *JPS Load Research Report, pp 55*

Rate	Coincidence factors											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.51	0.51	0.51	0.54	0.36	0.36	0.36	0.36	0.55	0.55	0.55	0.55
MT20	External Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.53	0.53	0.53	0.46	0.91	0.91	0.91	0.91	0.37	0.37	0.37	0.37
	Total Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.39	0.39	0.39	0.34	0.67	0.67	0.67	0.67	0.27	0.27	0.27	0.27
MT40	External Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.74	0.74	0.74	0.69	1.00	1.00	1.00	1.00	0.62	0.62	0.62	0.62
	Total Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.66	0.66	0.66	0.61	0.88	0.88	0.88	0.88	0.55	0.55	0.55	0.55
MT50	External Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.83	0.83	0.83	0.81	1.00	1.00	1.00	1.00	0.78	0.78	0.78	0.78
	Total Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.73	0.73	0.73	0.71	0.88	0.88	0.88	0.88	0.68	0.68	0.68	0.68
MT70	External Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.86	0.86	0.86	0.83	0.99	0.99	0.99	0.99	0.75	0.75	0.75	0.75
	Total Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.79	0.79	0.79	0.75	0.91	0.91	0.91	0.91	0.69	0.69	0.69	0.69
MT60	External Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	1.00	1.00	1.00	1.00	-	-	-	0.23	1.00	1.00	1.00	1.00
	Total Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	1.00	1.00	1.00	1.00	-	-	-	0.23	1.00	1.00	1.00	1.00

Consumption Patterns of Prepaid Customers

JPS currently offers prepaid service to residential customers as an alternative to the conventional post-paid service. There is a possibility that the change in how electricity costs are paid may result in some customers changing their consumption patterns to reduce electricity costs. The change in pattern can be a combination of a lowering of consumption as well as changes to the shape of their load profile. In order to determine if the consumption patterns of prepaid customers are different from post-paid customers, an analysis was done to compare the patterns of both groups of users.

MacroConsulting analysed the load characteristics of prepaid customers comparing it to the behaviour of the majority of post-paid MT10 customers. Overall, with limited available data, the study finds that prepaid customers behave very similarly to MT10 post-paid customers which consume 190 or less kWh a month (around 73% of all MT10 customers). Additionally, the study shows that after migrating to pre-paid service average consumption goes from 2,196 kWh/year to 1,947 kW/year a decrease of 10%. The limited data available does not allow for a robust conclusion to be made from the results of the study. JPS intends to make facilitations to increase the amount of prepaid load data and conduct future studies.

14.3 Embedded Cost of Service Study

In general terms, an Embedded Cost of Service study represents an assessment of the electricity value chain (generation, transmission, distribution, Management) and the various capital and operation & maintenance costs associated with the provision of each service. These costs are allocated to each customer class. JPS' 2018 (Jan-Dec) audited financial statements provided the basis for the Embedded Cost of Service Study and forms the base year. The costs were grouped into the categories of Operations and Maintenance (O&M), Taxes, Depreciation, and Return on Asset Base, the same categories which comprise the revenue requirement. The share of each category was applied to the 2019 Revenue Requirement in order to determine the corresponding amounts (in JMD) for 2019. Table 14-8 shows the different costs for both 2018 and 2019. The majority of costs (68.6%) are related to O&M expenses while 19.2% are attributed to asset depreciation, and 12.2% are attributed to return on asset base and taxes.

Table 14-8: Embedded Costs for 2018 and 2019

	2018 (JMD'M)	Share	2019 (JMD'M)
Operation & Maintenance (O&M)	33,111	68.6%	41,406
Asset Depreciation	9,245	19.2%	11,561
Return on Assets & Taxes	5,878	12.2%	7,351
Total (JMD'M)	**48,234**	**100.0%**	**60,319**

Despite the changes to a forward-looking tariff regime and the use of long run marginal costs for the base of tariffs, the embedded cost study is still relevant as it allows for comparative analyses. Additionally, it allows for an understanding of the cost caused by each customer for the provision of electricity service through an historical lens. This allows the opportunity for fair pricing judgment and alignment of revenue and cost structures. A key process of any cost of service study is cost allocation using outputs from the load research study.

Cost allocation is the process by which JPS' total revenue requirement (in this case 2018) is attributed to our various customer classes in a way that is consistent with their usage of the network, and other associated incurred O&M cost. The allocation process typically involves three major steps:

1. Cost Functionalization
2. Cost Classification
3. Cost Allocation

It is standard utility and regulatory practices to observe the principles of cost causality and transparency. *Cost causality* implies that all cost, revenues, and capital resources should be borne by the activity (or customer category) that causes them to be incurred. The principle of *transparency* requires us to attribute cost components, in a manner that is clear, identifiable, and traceable.

14.3.1 Cost Functionalization

The National Association of Regulatory Utility Commissioners (NARUC) Cost Allocation Manual defines *Functionalization* as the process of assigning company revenue requirements to specified utility functions: Production, Transmission, Distribution, Customer, and General Plant. JPS employs the use of Title 18 Code of Federal Regulations (18 CFR), published by the Office of the Federal Register National Archives and Records Administration, in its financial and accounting systems, policies, and procedures. These are commonly referred to as the FERC Uniform System of Accounts or FERC codes. This allows for the proper distinction of the assets and costs associated with the various functions of the utility. All assets and operation and maintenance (O&M) costs related to customer owned assets, JPS IPPs and the non-regulated business activities were excluded from the embedded cost study as these cost should not be borne by rate-payers. The following table shows the FERC codes for asset categories and O&M expenses categories.

Table 14-9: FERC Codes for Asset and O&M Expenses Categories

Utility Function Asset Category	FERC CODE	Operating & Maintenance Expense Category	FERC CODE
Production/Generation	310-348	Production Expenses	500 - 557
Transmission	350-359	Transmission Expenses	560 - 574
Distribution	360-374	Distribution Expenses	580 - 598
General Plant	389-399	Customer Accounts Expenses	901 - 910
-	-	Sales Expenses	913
-	-	Administrative & General Expenses	920 - 933

Functionalization of the revenue requirement is discussed in detail in Section XX of the ECSS report.

14.3.2 Cost Classification

The second major process involves the classification of cost and is considered the further separation of functionalized cost by the primary driver (demand, energy, and customer). The primary Cost Classification categories are described in Table 14-10.

Table 14-10: Categories for Cost Classification

Category	Definitions
Demand-Related Costs (aka Capacity-Related Costs)	Costs that vary with the kW of instantaneous demand (and therefore peak capacity needs)
Energy-Related Costs	Costs that vary with kWh of energy generated and or consumed
Customer-Related Costs	Costs that vary with the number of customers served by the system

The NARUC Cost Allocation Manual provides a guide for the classifications of costs under each function. Using this guide, JPS classified costs under each function as shown in Table 14-11.

Table 14-11: Classification Guide from the NARUC Cost Allocation Manual

Classification of Costs				
Activity	Voltage	Demand	Energy	Customer
Generation	High/Medium/Low	X	X	
Transmission	High/Medium/Low	X		
Distribution	High/Medium/Low	X		X
	Medium/Low	X		X
	Low			X
Management	High/Medium/Low	X		X
	Medium/Low	X		
	Medium	X		
	Low	X		

The capacity of the generation assets and transmission lines must be able to safely and reliably supply the simultaneous peak demand of the system at the very least. The operating and maintenance costs for the transmission network and JPS owned generation are primarily fixed by nature. Considering the nature of asset and O&M costs, all transmission costs and the majority of generation costs were deemed to be demand-related. There are other generation costs that vary with production and therefore were classified as energy-related (such as renewable power purchase cost and variable O&M). Management and Distribution asset and O&M costs were mainly recognized as being driven by demand and/or customer factors.

The table below shows the result of the functionalisation and classification steps. From a functional perspective, the majority of costs were due to the generation (54.8%) and distribution (26.8%) of electricity while transmission and management together accounted for 18.4% of costs. From a classification perspective, demand-related costs accounted for 43.1% of costs while energy and customer accounted for 35.5% and 21.4% respectively.

Table 14-12: Functionalization and Classification Results

Classification of 2019 Costs (JMD'M)						
Activity	Voltage	Demand	Energy	Customer	Total	**Total (%)**
Generation	High/Medium/Low	11,673	21,407	-	33,080	**54.8%**
Transmission	High/Medium/Low	3,182	-	-	3,182	**5.3%**
Distribution	High/Medium/Low	4,674	-	1,363	6,037	**26.8%**
	Medium/Low	3,885	-	1,232	5,117	
	Low	-	-	5,029	5,029	
Management	High/Medium/Low	1,026	-	5,261	6,287	**13.1%**
	Medium/Low	1,207	-	-	1,207	
	Medium	352	-	-	352	
	Low	27	-	-	27	
Total		**26,027**	**21,407**	**12,884**	**60,319**	**100.0%**
Total (%)		**43.1%**	**35.5%**	**21.4%**	**100.0%**	

14.3.3 Cost Allocation to Rate Classes Methodology

A rate class is defined as a relatively homogenous group of customers with similar energy, load, demand, end use, and connection characteristics. This implies that such groups of customers typically impose similar system cost and therefore should face similar prices. JPS' current rate classes as defined by certain common characteristics identified as follows:

- RT 10 LV – Residential Service
- RT 20 LV – General Service
- RT 60 LV – Street Lighting
- RT 40 LV - Powered Service
- RT 50 MV – Powered Service
- RT 70 MV – Powered Service

Allocation of functionalized and classified costs among these rate classes is based on the nature of cost causation. This recognizes the principle that different cost components have different drivers and therefore may require separate allocation treatment. As mentioned above, costs can be categorized into one of three groups namely *Demand-Related*, *Energy-Related*, and *Customer-Related*. The allocation methods are then also categorized in a similar manner i.e., based on the nature of the costs they apply to. The table below shows the allocation methods which were utilized in the ECS for allocation to rate classes and to TOU periods for each rate class.

Table 14-13: Definition of Allocation Methods by Function, Classification, and TOU Period.

Function	Classification		Method (Allocation to Rate Class)	Method (Allocation to TOU Period)
Management	Demand		Not Directly Allocated	ECF
	Customer		Weighted #Cust	
Generation	Demand		Average-Excess Demand	LOLP
	Energy		Weighted Energy at Generation	SRMC
Transmission	Demand		12-CP	LOLP
Distribution	Demand	High/Med/Low	ECF On Peak MV (All)	ECF MV On Share
		Medium/Low	ECF On Peak MV (All)	ECF MV On Share
		High	-	-
		Medium	-	-
		Low	-	-
	Customer	High/Med/Low	#Cust. for High/Med/Low	
		Medium/Low	#Cust. for Medium/Low	
		Low	#Cust. for Low	

Demand-Related Methods

Total demand-related costs for **Generation** were allocated to rate classes using the Average-Excess Demand (AED) method. This method considers both the average demand and excess demand in conjunction with the system load factor ($\frac{SysAvgDem}{SysNCP}$) to determine the share for each rate class.

$$FactorDemAvg_j = \frac{(NCP_j - AvgDem_j)}{\sum_j^n (NCP_j - AvgDem_j)} * \frac{SysAvgDem}{SysNCP}$$

$$FactorDemExc_j = \frac{AvgDem_j}{\sum_j^n AvgDem_j} * \frac{(SysNCP - SysAvgDem)}{SysNCP}$$

Allocation to TOU periods was achieved by using loss of load probability (LOLP) shares. For details on the computation of these factors, shown in the LRMC Report as an Annex to the Rate Case Filing.

Demand-related costs for **Transmission** were allocated using the 12-CP allocation method. This methods involved dividing the peak demand of each class by the sum of peak demands for all classes (not necessarily coincident with system peak). The resulting percentage share was then multiplied by the total demand-related transmission cost. Allocation to TOU periods was achieved by using LOLP factors.

$$12\ CP\ Allocation\ Factor = \frac{12\ CP\ for\ Class}{Sum\ of\ 12CP's\ for\ all\ Classes}$$

$$ECF_{OnPeak} Allocation\ Factor = \frac{ECF_{On}}{ECF_{On} +\ ECF_{Off} + ECF_{Partial}}$$

Demand-related costs for **Distribution** were grouped based on voltage level and then allocated to rate classes using the ECF On Peak MV (All) shares. This ECF value, for a particular rate class, was calculated by dividing the demand of the class during the On-Peak TOU period by the sum of the demands for all classes during the same TOU period.

$$ECF_{OnPeak}\ MV = \frac{On\ Peak\ Demand\ of\ Class}{System\ On\ Peak\ Demand}$$

Allocation to TOU periods was achieved by using ECF values for each TOU period for each rate class. The ECF shares were determined in a similar manner as discussed above for Generation.

Demand-related **Management** costs were not directly allocated to rate classes as was done for other functions. Instead, allocation was done directly to each TOU period (for each rate class) using ECF values at the Generation Level.

$$ECF\ On\ Peak\ Gen = \frac{On\ Peak\ Demand\ of\ Class}{Sum\ of\ all\ Demands\ for\ each\ Class\ in\ All\ TOU\ Periods}$$

Energy-Related Methods

Energy loads are also an important consideration in defining cost drivers, specifically **Generation** costs. The energy at generation method was employed to allocate total energy-related generation costs to each rate class. The energy supplied at the generation level, to satisfy load at the metering point for a particular rate class was divided by the total energy supplied at the generation level to determine the share for that rate class. This share (%) was then multiplied by the total energy-related costs to determine the energy-related costs for that particular rate class.

$$EneAtGenWeighted_{j,v} = \frac{(Factor_{j,v})}{\sum_j^n Factor_{j,v}}$$

Where:

$$Factor_{j,v} = (Energy_j * Costs_v * Energy.On.Share_j * Prod.Costs.On) + (Energy_j * Costs_v * Energy.Partial.Share_j * Prod.Costs.Partial) + (Energy_j * Costs_v * Energy.Off.Share_j * Prod.Costs.Off)$$

Allocation to TOU periods was achieved by using SRMC allocation factors for each TOU period for each rate class. For details on the computation of these factors, LRMC Report as an Annex to the Rate Case Filing.

Customer-Related Methods

The functions of **Management** and **Distribution** were the only two categories deemed to contain customer-related costs. The total customer-related costs for Management was allocated to rate classes using the weighted number of customers. The weights used were the relative metering costs of each rate class.

$$Weighted\ number\ of\ customers\ Factor_j = \frac{Number\ of\ customers_j * Metering\ Costs_j}{\sum_{j=1}^{n}(Number\ of\ customers_j * Metering\ Costs_j)}$$

Customer-related Distribution costs were allocated to rate classes in a similar manner but using the actual number of customers without any weights.

$$Number\ of\ Customers\ Factor_j = \frac{Number\ of\ customers_j}{\sum_{j=1}^{n}(Number\ of\ customers_j)}$$

To summarize, JPS adopted the allocation methods as follows:

- Demand-Related based on
  - 12 CP
  - AED – Average-Excess Demand
  - ECF – External Coincidence Factor (TOU periods)
  - LOLP – Loss of Load Probability (TOU periods)
- Energy-related based on
  - Weighted production costs
  - External Coincidence Factor (TOU periods)
- Customer-related
  - Number of customers
  - Weighted number of customers

Cost Allocation Results and Process Summary

The steps mentioned above for determining demand, energy, and customer-related costs were applied to the total costs for each function/activity to determine the allocated costs for each rate class. The results are shown in the table below. As was mentioned before, approximately 43% of all costs incurred can be attributed to demand-type drivers while ~36% and 21% can be attributed to energy and customer-type drivers.

From the perspective of rate classes, RT10 was allocated ~52% of all costs incurred even though this rate class was responsible for only 33% of energy consumption and 41% of NCP demand. This is primarily a result of the bulk of customer costs (89%) being attributed to RT10, a costs which does not vary with energy or demand. The next largest rate classes (in terms of allocated costs) were RT20 and RT40 which were allocated approximately 18% and 16% of overall costs respectively. All other rate classes were allocated 15% of all costs incurred.

Table 14-14: Allocated Costs Based on Classification

Tariff Category	Demand Costs	Energy Costs	Customer Costs	Total Costs
RT 10 LV Res. Service	11,552,267,413	8,495,574,199	11,621,647,937	31,669,489,549
RT 20 LV Gen. Service	4,781,472,170	4,565,092,359	1,339,506,390	10,686,070,919
RT 60 LV Street Lighting	953,491,522	350,981,883	9,485,897	1,313,959,302
RT 40 MV Power Service All	4,941,249,796	4,546,112,964	44,047,471	9,531,410,231
RT 50 MV Power Service All	1,469,587,461	1,401,372,860	2,260,623	2,873,220,943
RT 70 MV Power Service All	1,696,789,763	1,541,945,918	366,157	3,239,101,839
RT 20 LV Gen. Service (Other)	274,070,808	265,456,930	39,546	539,567,283
RT 50 MV Power Service (Cement Company)	626,902,210	461,395,384	15,920	1,088,313,514
Total	26,295,831,143	21,627,932,497	13,017,369,941	60,941,133,581

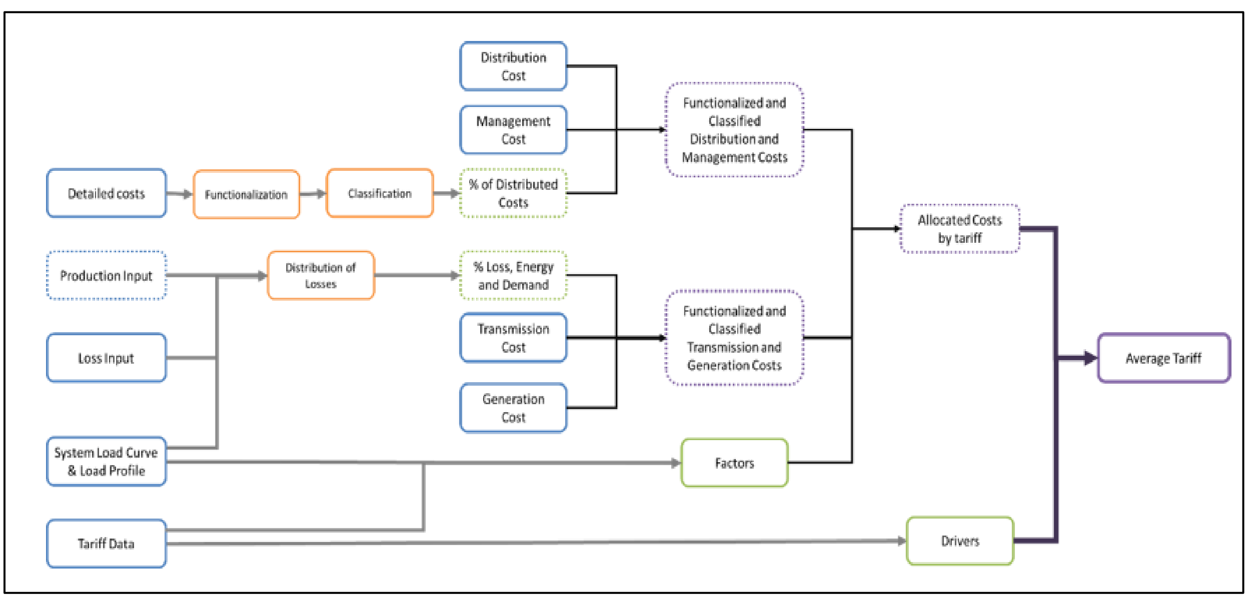
The overall costs for each rate class was divided by the energy consumption of each class to derive the embedded costs average tariff. As well, the existing tariffs (energy tariffs, demand and customer charges) were multiplied by the respective billing determinants for each rate class to compute revenue amounts. The results were then adjusted to equal the 2019 revenue requirement. Finally, the 2019 revenue by rate class was divided by energy consumption by rate class to yield adjusted existing average tariffs (i.e., existing tariffs adjusted to derive the 2019 revenue requirement). The results are shown in Table 14-15.

Table 14-15: Embedded Costs Average Tariffs

Tariff Category	Total Costs (JMD)	Total Energy (kWh)	Average Costs (JMD/kWh)	Adj Existing Average Tariff (JMD/kWh)
RT 10 LV Res. Service	31,669,489,549	1,066,621,238	29.69	28.35
RT 20 LV Gen. Service	10,686,070,919	600,743,680	17.79	23.64
RT 60 LV Street Lighting	1,313,959,302	62,362,528	21.07	29.08
RT 40 MV Power Service All	9,531,410,231	801,257,962	11.9	10.52
RT 50 MV Power Service All	2,873,220,943	267,274,115	10.75	9.80
RT 70 MV Power Service All	3,239,101,839	294,123,893	11.01	7.50
RT 20 LV Gen. Service (Other)	539,567,283	34,953,384	15.44	22.06
RT 50 MV Power Service (Cement Company)	1,088,313,514	88,261,194	12.33	7.39
Total	60,941,133,581	3,215,597,993	18.95	18.95

Average tariffs are calculated following the processes depicted in the figure below. The production input (net generation) and losses inputs (losses percentages) were used to determine the amount (MWh) of losses occurring at each function (and voltage level). The production and losses inputs in addition to the system load data were used to determine allocation factors for energy and demand-related costs. Tariff data was used to determine allocation factors for customer-related costs. Detailed costs represent those obtained from 2018 accounting records. These costs were functionalised and classified to determine the energy, demand, and customer-related costs for all four functions. The allocation factors mentioned previously were used to allocate costs to each rate class and also to each TOU period. Theses allocated costs were divided by billed consumption (drivers from tariff data) to derive average tariff values.

Figure 14-4: Embedded Cost Allocation Process Flow



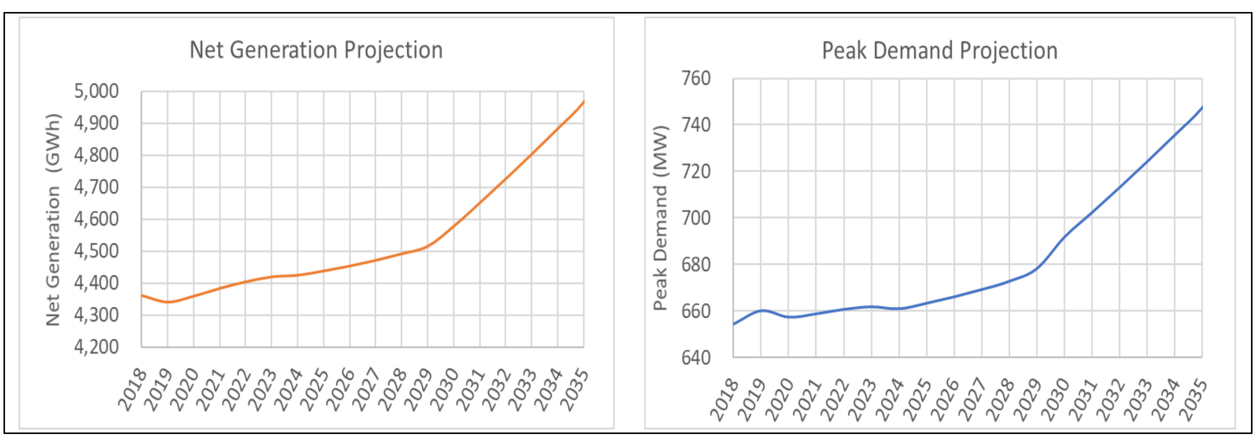
14.4 Long Run Marginal Cost Study

This study examined both the long run marginal and short run marginal costs and yielded the generation and network investment decisions that would be required given AC load flow, contingency and reliability constraints (N-1), system security along with co-optimized cost minimization economic analysis. The analysis was carried out using the Jamaican Power System Economic Dispatch (JPSED). JPSED is a long-term generation and transmission expansion planning tool premised on the four-hourly optimal economic dispatch to meet a given four-hourly demand for an entire year based on demand projections. The optimal economic investment decisions were confined to the functions of generation, transmission, and distribution. Additionally, only demand-related and energy-related costs were considered. When compared to the ECS, the marginal cost study did not include the management function and customer-related costs. For the period 2016-2035, the study examined four-time horizons: 2018, 2024, 2030, and 2035, and followed a chronological approach to sequentially evaluate system operational variables for every load level given a chronological demand function. The model represents a hierarchical time scope relevant to inform key decision within the power system.

14.4.1 Modelling Assumptions and Inputs

The computation of LRMC and SRMC require, among other parameters, inputs for demand projection, fuel prices, network topology, generation units' specifications, investments costs. The inputs are required in order to determine the optimal economic dispatch of generation units and transmission and distribution investment decisions to reliably satisfy demand. The projected demand (power and energy) utilized in the study are illustrated in the figure below. The period 2019 to 2024 showed little overall growth while the period 2024 to 2035 showed a modest growth of ~1% per year on average. See demand projection section of the LRMC Report as an Annex to the Rate Case Filing for further detail.

Figure 14-5: Forecasted Energy and Peak Demand 2016-2035



Generation and Transmission LRMC Approach

The estimation of LMRC generally follows two primary established approaches namely the Turvey or perturbation method and the incremental method. JPS utilized the incremental approach for the LRMC calculations.

The ***perturbation*** approach analyses the changes in capacity costs brought about when current forecasts of demand growth are perturbed by a fixed permanent increment. By running the different scenarios with a permanent increase in demand of 1MW, and using continuous investment decisions, the LRMC of both generation capacity and transmission capacity can be estimated as the discounted value of the change in future generation and transmission capacity investment costs respectively, over the discounted value of the change in demand.

For the ***incremental*** approach, JPS calculated the generation LRMC as the per MW annuity of the CAPEX for the expected future marginal generation technology during the peak hours for each of the four-time horizons being considered. The expected future marginal generation technology was identified from the results obtained with the optimization model. On the other hand, the LRMC of the transmission grid was obtained from the ratio of the discounted incremental network investments (obtained also from the expansion plan computed with the Economic Dispatch model and discrete investment decisions) over the discounted incremental demand during the planning period.

The process for calculating the LRMC, in summary, involved discounting both the increment in peak demand over the period as well as the capital expenditure required to support the investment decisions. The capex annuity represents a fixed payment that if received annually over the life of the project, would yield a return equal to the discount rate (WACC).

$$CAPEX\ annuity = CAPEX * Fixed\ Charge\ Rate$$

Where the *Fixed Charge Rate* is the proportion of the total investment paid annually and is calculated from the discount rate and the life expectancy of the asset.

$$Fixed\ Charge\ Rate = \frac{Discount\ Rate}{1 - (1 + Discount\ Rate)^{-Project\ Life}}$$

The discounted investment cost is calculated by determining the sum of the discounted capex annuities for each period (n).

$$Discounted\ Investment\ Cost = \sum \left(\frac{Capex\ Annuity}{(1 + Discount\ Rate)^{n}} \right)$$

The discounted incremental demand is calculated by dividing the increase in peak demand over a particular period by the discount factor at the end of the period.

$$Discounted\ Incremental\ Peak\ Demand = \frac{Peak\ Demand\ Increment_n}{(1 + Discount\ Rate)^n}$$

The estimation of the LRMC is simply the division of the discounted investment cost and the discounted incremental peak demand.

$$LRMC = \frac{Discounted\ Investment\ Cost}{Discounted\ Incremental\ Peak\ Demand}$$

Generation and Transmission LRMC Results

From the JPSED model, total investment and long-run marginal cost estimates were derived. Again, this is premised on the inputs and assumptions made in relation to the IRP process that is still ongoing, but nonetheless, the results are instructive in identifying the necessary system upgrades and investments required to meet the future demand for electricity. As requested by the OUR, JPS utilised the results of the LRMCS for this rate application. The resulting LRMC for Generation is shown in Table 14-16 and that for Transmission is shown in Table 14-17.

Table 14-16: Incremental Long Run Marginal Cost for Generation Technologies[78]

Year	On-peak generation	LRMC [USD/kW]
2018	Medium-Speed-Diesel	225.44
2024	CCGT-LNG	197.11
2030	OCGT-LNG	118.85
2035	CCGT-LNG	197.11
Average		**184.63**

Table 14-17: Incremental Long Run Marginal Cost for Transmission Capacity[79]

Voltage Level	Discounted Transmission Investment Costs	Discounted Incremental Peak Demand	Incremental LRMC for Transmission
	[MUS$]	[MW]	[US$/kW]
2018-2035	34.46	19.04	1,191.97
69 kV	3.51	19.04	183.06
138 kV	30.95	19.04	1,008.91

78 Source: JPS Cost of Service Study Report, pp 56

79 Source: JPS Cost of Service Study Report, pp 57

Generation and Transmission SRMC Approach

The SRMC of the combined generation and transmission systems was calculated by an economic dispatch that considered the marginal energy cost at each bus of the transmission network for each hourly demand level. This short-term optimization model was the same one used to calculate the expansion plan with the only difference being fixed investments. Consequently, only operational decisions were made to minimize system-operating costs. The resulting SRMC reflected the marginal cost of supplying one additional MWh of electricity at each transmission network bus and include the generation costs (fuel and O&M) for that MWh, the additional costs due to transmission losses, and the incremental dispatch costs caused by transmission network congestions. The weighted average price across all demand buses, i.e. the average cost of each MWh of demand, were also calculated.

Finally, the average nodal price across all demand buses per time of use period was calculated as well. Each category of consumers (residential, commercial, and industrial) can be charged according to the actual cost of their load profile (peak, partial-peak, off-peak), see Generation and Transmission LRMC Report for further details.

Generation and Transmission SRMC Results

Table 14-18 shows the non-fuel portion of the SRMC which was assumed to be 10% of the full SRMC.

Table 14-18: Generation and Transmission SRMC Results[80]

Cost	Total (average)	On-Peak	Partial-Peak	Off-Peak
SRMC (USD/MWh)	147.67	160.07	143.34	139.60
10%				
SRMC (USD/kWh)	0.01	0.02	0.01	0.01
SRMC Shares	100.0%	36.1%	32.4%	31.5%

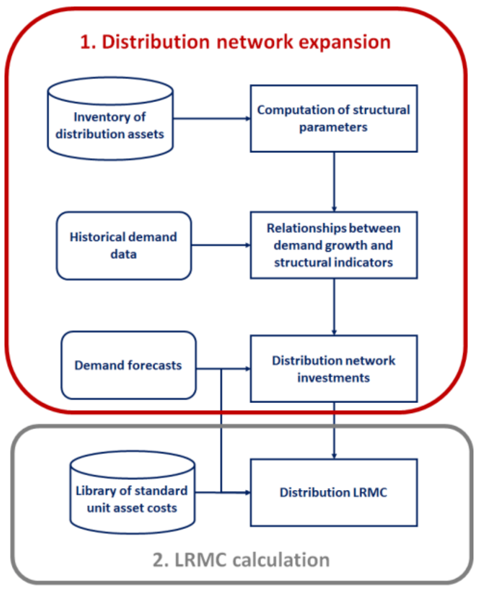
Distribution LRMC Approach

Distribution planning is considerably more data and resource intensive when compared to other elements within the electrical system. Distribution networks are very expansive, with a high number of individual network components, more frequent interruptions, and higher levels of energy losses (non-technical and technical).

[80] Source: *JPS Cost of Service Study Report, pp 58*

The estimation of the LRMC of distribution follows the Incremental Cost approach used for generation and transmission above. A Parametric CAPEX Model was developed to estimate the future network needs based on a set of key structural network parameters calculated from an inventory of network assets, the historical evolution of demand, and the forecasted load growth per the medium and low voltage distribution network. The model is premised on the assumption that the structural grid characteristics and their relation to demand remain relatively stable over time. Therefore, historical information is used to derive network indicators. For example, the line length per customer or transformer capacity per customer. These indicators along with the use of forecasted demand information allow for a reasonable estimate of the expansion of the medium and low voltage distribution network.

Figure 14-6: Overall Process for Computing Distribution LRMC[81]



LRMC estimation for each asset category and voltage level is derived using the equation below. The parameter IC represents incremental cost (IC) while ID represents incremental demand.

$$LRMC = \frac{PV\ \sum_i IC_i}{PV\ \sum_i ID_i}$$

Distribution LRMC Results

The resulting LRMC for Distribution is presented in Table 14-19. All costs were deemed to be demand-related. It should be noted that this section of the study was not updated since the July 2019 rate case filing.

[81] Source: *JPS Distribution LRMC Report, pp 6*

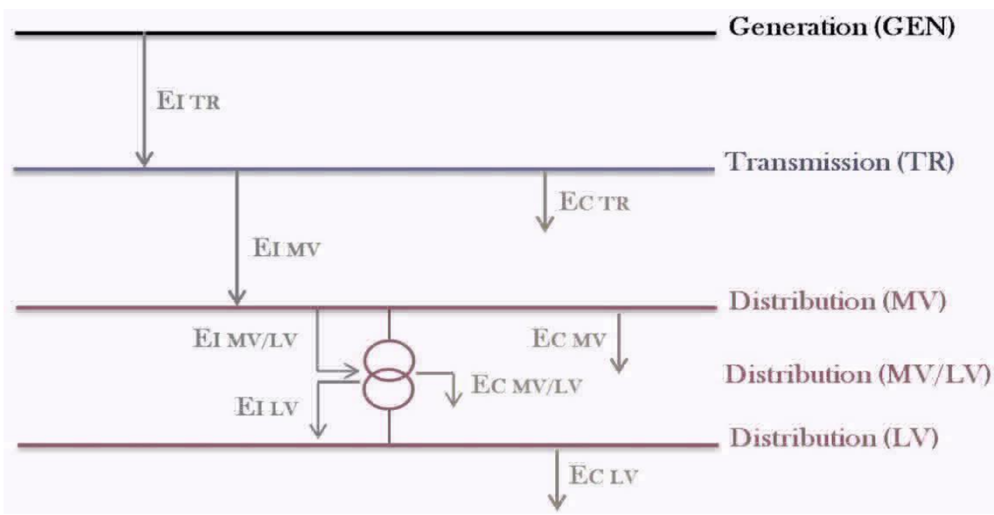
Table 14-19: Incremental Long Run Marginal Cost for Distribution Capacity[82]

LRIC LV (USD/kVA)	39
LRIC MV (USD/kVA)	195
LRIC MV/LV (USD/kVA)	121

Distribution SRMC Approach

The SRMC of the distribution activity corresponds to the cost of technical energy losses occurring at the distribution level. The calculation requires the costs of supplying energy at the transmission nodes (substations) as well as the amount of losses incurred in distributing power to a particular voltage level. Based on its current structure, the Jamaican system is divided into five layers: Generation (GEN), Transmission (TR), Distribution Medium Voltage (MV), Distribution Medium to Low Voltage (MV/LV), and Distribution Low Voltage (LV).

Figure 14-7: Overall Process for Computing Distribution LRMC[83]



The costs for supplying energy at transmission nodes (substations) were determined in the Generation and Transmission SRMC section above. Estimation of the losses at the different voltage levels required further calculations involving energy loss factors ELF_i' and ELF_i.

$$ELF_{LV}' = \frac{1}{1 - L\%_{LV}}$$

[82] Source: *JPS Distribution LRMC Report, pp 25*

[83] Source: *JPS Distribution LRMC Report, pp 8*

$$ELF_{LV} = ELF'_{MV} \cdot ELF'_{MV/LV} \cdot ELF'_{LV}$$

The ELF_{LV}' represents the amount of energy that must be injected into the LV network to yield an output of 1 unit of energy. The ELF_{LV} represents the amount of energy that must be injected at the substation to yield 1 unit of energy at the LV level. The ELF_{LV} is different from the ELF_{LV}' as it accounts for all losses from the substation to the LV level as opposed to just at the LV level.

Lastly, the energy loss factors ELF_i are multiplied by SRMC at the primary substations, to compute the distribution SRMC for each voltage level.

$$SRMC_{LV} = ELF_{LV} \cdot SRMC_{GEN-TR}$$

For more details on the SRMC calculations, assumptions, and modelling of the distribution system please see the see LRMC Report for further details.

Distribution SRMC Results

The calculated energy losses factors are presented in the table below. As energy is supplied at the generation level, the ELF' is 1 and since this level is before the substation, there is no ELF. The transmission ELF' of 1.027 accounts for the losses between the generation level and substations. The SRMC for Generation and Transmission factored in losses up to the transmission level. It can be seen how the energy that must be injected at the primary substations increases as the energy flows from the MV to the LV levels. The results indicate that in order to supply 1 kWh of energy at the LV level, 1.063 kWh must be injected into the MV from the substation.

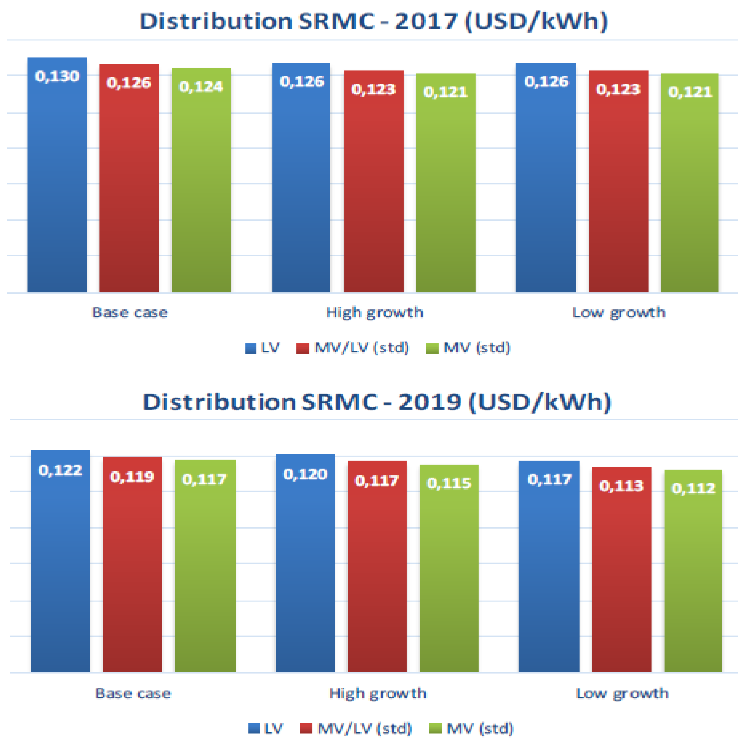
Table 14-20: SRMC Results for Distribution[84]

Network Layer	Energy Losses Factor (ELF')	Energy Losses Factor (ELF)
GEN	1.000	-
TR	1.027	-
MV	1.018	1.018
MV/LV	1.013	1.032
LV	1.03	1.063

The SRMC values obtained for 2017 and 2019 are presented in the figure below. Three scenarios were tested. For more details on the computation of these values, please see the Distribution LRMC report. It should be noted that these results, which were not used in any tariff computation, have not been updated since the July 2019 rate case filing.

[84] Source: *JPS Distribution LRMC Report, pp 27*

Figure 14-8: Distribution SRMC Results[85]



14.4.2 Marginal Cost Functionalisation and Classification Summary

The results of the functionalisation and classification process is shown in Table 14-21. The values represent pure marginal costs before any adjustments to the 2019 revenue requirement.

Table 14-21: Marginal Cost Functionalisation and Classification Results

Classification of Marginal Costs			
Activity	Voltage Level	Demand (USD/kW)	Energy (USD/MWh)
Generation	High/Medium/Low	184.63	147.67
Transmission	High/Medium/Low	1,191.97	
Distribution	Medium	195	
	Low	39	

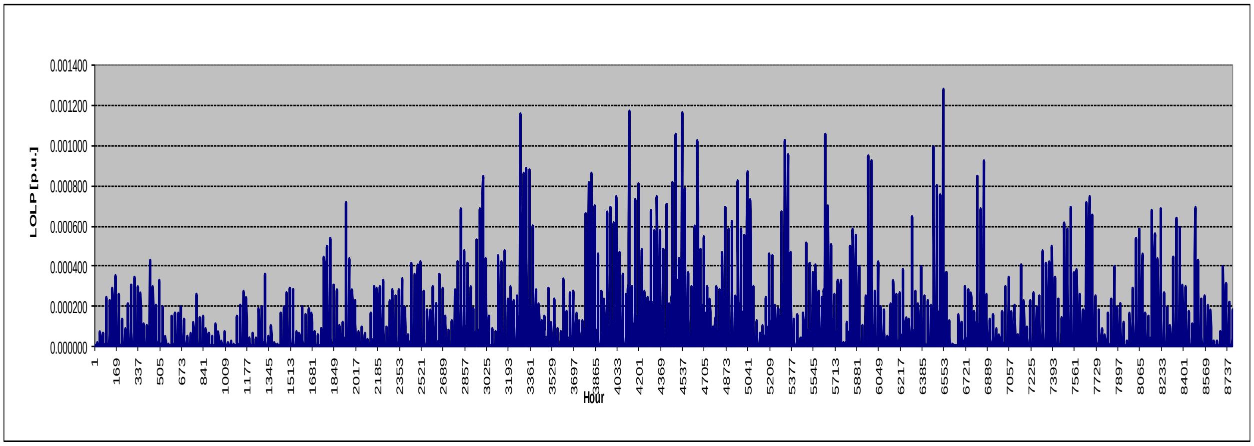
14.4.3 Loss of Load Probability

The loss of load probability (LOLP) determines the likelihood of a shortage in generation capacity to satisfy demand. Many utilities, including JPS, consider the LOLP when developing expansion plans for generation capacity. The LOLP then influences the generation type and capacity required to reliably supply power in the future. Consequently, it is often used as an allocation method for

85 Source: *JPS Distribution LRMC Report, pp 28*

apportioning generation investments across different time periods. The FLOP model (https://www.iit.comillas.edu/aramos/flop.htm) was used to calculate the LOLP as well as the Expected Energy Not Supplied (EENS) for 2024. The total capacity considered was 1,108.8 MW and an hourly demand between 357.4MW and 661.0 MW was modelled. Based on these numbers there was a large reserve margin and this yielded very low LOLP values. In the following figure, the time evolution of the LOLP for all hours of 2024 is presented. For 2024, the LOLP was 0.000043 and the EENS was 9,475 kWh.

Figure 14-9: LOLP Results for 2024[86]



The derived allocation shares for the TOU periods are presented in the table below. These factors were used to allocate generation demand-related LRMC to the different time periods.

Table 14-22: Loss of Load Probability Shares[87]

Method	On-Peak	Partial-Peak	Off-Peak
LOLP	44.19%	41.06%	14.75%

14.4.4 Marginal Cost Allocation to Rate Classes

The functionalised and classified LRMC were allocated to rate classes and TOU periods using (where possible) the same methods and factors presented in the EC section above. The key differences are due to embedded costs representing a total that can be divided into shares for each rate class. The LRMC obtained are in the form of rates and so it is not possible to divide the rates into pieces which when summed yields the original total.

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86 Source: *JPS Generation and Transmission LRMC Report, pp 36*

87 Source: *JPS Cost of Service Study Report, pp 44*

Demand

The average demand cost obtained from the LRMC over the period was divided by class capacity losses to achieve allocation to each rate class based on the function (transmission and distribution only). The capacity loss of a class represents the portion of demand at the functional level that is lost supplying the demand to the meter of customers. For example, generation capacity loss represents the portion of demand at the point of generation that is lost in supplying power to the meter of a customer. The use of this factor accounts for the fact that to satisfy 1MVA of demand at the meter of a customer requires more than 1MVA of supply at the point of generation due to losses in the transmission and distribution (T&D) network. The equation below shows how the transmission demand cost for a particular class was computed. The same approach was used for generation and the different voltage levels at the distribution layer.

$$Class\ Transmission\ Demand\ Cost = \frac{Average\ Transmission\ Demand\ Cost}{Class\ Transmission\ Capacity\ Losses}$$

Allocation to TOU periods, for the distribution function, was done using the appropriate ECF allocation factors. Allocation of demand-related generation and transmission LRMC to TOU periods was achieved using the loss of load probability (LOLP) and appropriate ECF factors. For more details, please see the LRMC tab in the LRMC Model (Excel).

Energy

The Generation and Transmission SRMC values obtained from the marginal cost study were allocated to rate classes using the class energy losses. The energy losses percentage were based on the voltage level at which the rate class received power from the grid. The energy losses accounts for the fact that 1MWh of consumption at the meter of a customer requires more than 1MWh of supply at the point of production due to losses in the T&D network. The average energy cost of a particular class is the simple mean of the costs in each TOU period for said class.

$$Class\ Energy\ Cost_{OnPeak} = \frac{Average\ Energy\ Cost_{On\ Peak}}{Class\ Energy\ Losses}$$

$$Class\ Avg\ Energy\ Cost = (Class\ Energy\ Cost_{OnPeak} + Class\ Energy\ Cost_{OffPeak} + Class\ Energy\ Cost_{PartialPeak})/3$$

14.4.5 Marginal Cost Allocation Results

Billing determinants, illustrated in Table 14-23, were applied to pure marginal cost charges determined from the procedures mentioned above to obtain revenues. An adjustment factor was then determined to reconcile the sum of said revenues with the 2019 revenue requirement. This adjustment factor was then applied uniformly to the pure marginal cost charges to determine the marginal cost charges in Table 14-24.

Table 14-23: Billing Determinants Used for Marginal Cost Charges[88]

Tariff Category	Demand (kVA)				Energy (kWh)
	Standard	On-Peak	Partial-Peak	Off-Peak	
RT 10 LV Res. Service	5,297,290				1,066,621,238
RT 20 LV Gen. Service	2,823,639				600,743,680
RT 60 LV Street Lighting	174,345				62,362,528
RT 40 MV Power Service All	2,343,690	240,434	295,407	300,782	801,257,962
RT 50 MV Power Service All	700,620	126,494	172,317	200,388	267,274,115
RT 70 MV Power Service All	600,571	123,054	142,421	151,403	294,123,893
RT 20 LV Gen. Service (Other)	86,524				34,953,384
RT 50 MV Power Service (Cement Company)		226,879	230,294	248,158	88,261,194

Table 14-24: Marginal Cost Charges[89]

Tariff Category	Demand (USD/kVA/month)				Energy (USD/kWh)			
	Standard	On-Peak	Partial-Peak	Off-Peak	Total	On-Peak	Partial-Peak	Off-Peak
RT 10 LV Res. Service	223.7	107.1	71.0	45.5	0.024	0.026	0.023	0.022
RT 20 LV Gen. Service	175.9	61.1	98.1	16.8	0.023	0.025	0.022	0.021
RT 60 LV Street Lighting	110.9	79.4	0.2	31.2	0.052[90]	0.018	0.016	0.016
RT 40 MV Power Service All	150.2	58.8	71.5	19.9	0.017	0.018	0.016	0.016
RT 50 MV Power Service All	132.5	52.0	63.2	17.3	0.016	0.017	0.015	0.015
RT 70 MV Power Service All	143.4	59.6	63.8	20.1	0.016	0.017	0.015	0.015
RT 20 LV Gen. Service (Other)	175.9	61.1	98.1	16.8	0.023	0.025	0.022	0.021
RT 50 MV Power Service (Cement Company)	167.3	73.3	70.9	23.0	0.016	0.017	0.015	0.015

The billing determinants were applied to the marginal costs charges above to determine revenues from each rate class. The resulting revenues were divided by the energy consumption to yield average marginal costs for each rate class.

88 Source: JPS Cost of Service Study Report, pp 62

89 Source: JPS Cost of Service Study Report, pp 62

90 The sum of the three periods do not add up to the total because an additional 0.03 USD/kWh was added to account for additional smart streetlight investments.

Table 14-25: Average Marginal Costs

Tariff Category	Average Marginal Cost (JMD/kWh)	Adj Existing Average Tariff (JMD/kWh)
RT 10 LV Res. Service	28.41	28.35
RT 20 LV Gen. Service	21.27	23.64
RT 60 LV Street Lighting	9.06	29.08
RT 40 MV Power Service All	12.71	10.52
RT 50 MV Power Service All	11.05	9.8
RT 70 MV Power Service All	9.38	7.5
RT 20 LV Gen. Service (Other)	11.47	22.06
RT 50 MV Power Service (Cement Company)	11.36	7.39
Total	18.95	18.95

15 Tariff Design

15.1 Introduction

This chapter presents JPS' tariff structure design for the 2019 to 2024 rate review period. The structure is the result of specifically commissioned studies, namely an Embedded Cost, a Long Run Marginal Cost of Service Study, and Tariff Structure Analysis. MRC Consultants were engaged to conduct the Long-Run Marginal Cost Study with a view to assess the results of the Integrated Resource Plan in 2016/2017. Gven the delay in the IRP results, this study was updated to reflect known Generation and Transmission system conditions as at December 2018. A Loss of Load Probability assessment was also conducted on the power system for the typical future system as at 2024. MRC also provided support in the development of JPS' proposed Power Wheeling Framework. MacroConsulting were our lead consultants for the Cost of Service Studies, and tariff design analysis. Combined, both teams provided expertise in the areas of Regulatory Economics, Tariff and Power System Design, with an accumulated experience of well over 50 years.

The breadth and rigour of the analysis presented throughout this chapter and accompanying reports is demonstrative of the level of effort embedded within the decision process in relation to JPS' tariff proposal. Given the many competing objectives (policy, regulatory and commercial) and potential customer impact, the proposed tariff design sought to develop outcomes that best satisfied these sometimes sensitive and conflicting goals of equity, causuality, efficiency, and sustainability.

Our Cost of Service Studies presents the results of the tariffs on a purely cost allocated basis, the details of which are found in Chapter 13 of this document, as well as in the Cost of Service models and reports attached as Annex to this rate application.

The pursuing sections presents the main highlights and results of these studies and JPS' tariff proposal having given due consideration to all the objectives stated above, customer impact, regulations and the broader electricity sector dynamics.

Table 15-1 presents a high-level summary of JPS' final non-fuel rate proposal. Table 15-2 provides the averate non-fuel tariff impact per proposed rate category.

Table 15-1: Summarizes JPS' 2019-2024 Tariff Proposal

		Energy Charge JMD? kWh				Demand Charge JMD/kVA			
	Customer Charge JMD/Month	STD	On-Peak	Partial-Peak	Off-Peak	STD	On-Peak	Partial-Peak	Off-Peak
RT 10 LV Res. Service First 50 kWh	853.74	8.95							
RT 10 LV Res. Service 50 - 500 kWh	853.74	29.33							
RT 10 LV Res. Service Over 500 kWh	853.74	27.78							
RT 20 LV Gen. Service First 150 kWh	1,488.71	17.5							
RT 20 LV Gen. Service Over 150 kWh	1,488.71	20.61							
RT 60 LV Street Lighting	2,818.88	12.01							
RT 60 LV Traffic Signals		12.01							
RT 40 LV Power Service (Std)	12,000	6.85				2,437.85			
RT 40 LV Power Service (TOU)	12,000	-	9.31	8.65	3.11	-	1,077.34	1,001.00	359.52
RT 40X LV Power Service (TOU)	12,000	-	7.70	7.16	2.57	-	891.50	828.33	297.5
RT 50 MV Power Service (Std)	12,000	6.5	-	-	-	2,315.96	-	-	-
RT 50 MV Power Service (TOU)	12,000	-	8.84	8.22	2.95	-	1,023.47	950.95	341.54
RT 50X MV Power Service (TOU)	12,000	-	7.20	6.69	2.40	-	701.31	651.61	234.03
RT 70 MV Power Service (Std)	12,000	4.95	-	-	-	2,141.35	-	-	-
RT 70 MV Power Service (TOU)	12,000	-	6.24	5.8	2.08		946.31	879.25	315.79

Table 15-2 provides an overall summary of the relative impact of the non-fuel tariff adjustment for each rate class as per JPS' tariff proposal and Cost of Service results.

Table 15-2: Non-Fuel Tariff Adjustment Relative Impact Summary

Tariff	Initial Average Tariff [J$/kWh]	Final Average Tariff [J$/kWh]	Variance
MT 10- Metered Residential	20.52	29.11	41.8%
MT 20- Metered Small Commercial	21.45	22.73	5.9%
MT 40 - Metered Large Commercial (STD)	13.68	15.08	10.3%
MT 50 - Meter Industrial (STD)	12.34	14.54	17.8%
MT 60 - Streetlighting	26.03	23.92	-8.1%
MT 70 - MV Power Service (STD)	9.01	10.18	13.0%
Electric Vehicles	-	26.17	
MT 40 - Metered Large Commercial (TOU)	11.76	14.56	23.9%
MT 50 - Meter Industrial (TOU)	12.26	13.43	9.5%
MT 70 - MV Power Service (TOU)	9.75	9.91	1.6%
MT10X_TOU	-		
MT40X_TOU	-	13.66	
MT50X_TOU	-	9.06	
Total	**17.21**	**20.39**	**18.5%**

Tariff Structure Objectives and Principles

Tariff systems, that is, the set of criteria, rules and procedures used to define the tariff level and structure, and the regulatory mechanisms that govern subsequent reviews. In the specific case of monopolistic public utilities, multiple objectives, namely: economic efficiency, revenue adequacy, cost reflectiveness, stability and predictability shown in Table 15-3.

Table 15-3: Regulatory Objectives

Objective	Definition
Revenue Adequacy/Sustainability	Cover economic costs of the service
Economic/Allocative Efficiency	Provide signals for efficient use of resources
Productive Efficiency	Create incentives for cost minimization
Equity	Protect poor users in terms of access and affordability
Cost reflectiveness	The cost causer pays
Stability & Predictability	Rates should not fluctuate unduly

Sustainability entails tariffs that generate enough revenues to cover the economic costs of the service. Economic costs include a return on invested capital, which attracts new capital resources to the industry, to help guarantee the future provision of the service while minimizing potential fiscal contributions.

Allocative efficiency is concerned, in a context of scarce resources and alternative uses for such resources, with tariffs reflecting the services' production costs. Strictly speaking, this would require having tariffs equal marginal costs.[91] When tariffs reflect costs, they serve as efficient signals for the allocation of resources in the economy, promoting efficient consumption whilst inducing efficient production and investment levels.

Productive efficiency has to do with the minimization of costs at a given output level or, alternatively, the maximization of output with a given level of inputs.

Lastly, the tariff system must also provide for certain basic aspects of fairness or equity. This, in turn, is a two-fold problem involving access and affordability. Access has to do with universal service goals: having the entire population connected to the service. Affordability has to do with having tariffs relate to payment capacity, particularly for the poorer strata of the population.[92]

[91] In natural monopolies, this condition would violate the sustainability objective, as marginal costs are below average costs. See Sharkey (1982), The Theory of Natural Monopoly – Cambridge University Press.
[92] For an analysis of the relationship between infrastructure reform and poverty in Latin America see Estache Foster & Wodon (2002) Accounting for Poverty in Infrastructure Reform.

In addition to the substantive goals discussed above, tariff systems must also achieve certain formal goals in order to guarantee the best possible results for tariff regulation. Usually, these include simplicity and public acceptance, transparency, non-controversy, price stability, fair allocation of total costs, and the exclusion of undue price discrimination.[93]

Summary of Criteria

Criterion 7 of the OUR's Final Criteria established the general principles and guidelines for rate setting, which also accords with well adopted economic theory and JPS' own processes and methodology for the development of tariffs.

In accordance with the requirements of the Electricity Licence 2016, the OUR outlined the tariff requirements with respect to rate design in section 3.10 of the Final Criteria. It emphasizes that rates ought to be cost reflective, economically efficient, non-discriminatory and transparent, compliant with applicable rules and regulations, as well as considerate of GOJ policy objectives with respect to the energy sector. The OUR suggested, for prudency, that the proposed rates should aim to achieve the often conflicting regulatory objectives of revenue adequacy, stability, predictability, and simplicity. These objectives were similarly identified in the background section of this chapter.

The Criteria requires that the rate proposal should clearly identify non-fuel tariffs for each customer category and shall include but not limited to tariffs for:

- Distributed generation
- Electric vehicles
- Wheeling
- Auxiliary Connections
- Stand-by-Service
- Prepaid electricity service

The Criteria also states that JPS may propose a social tariff and any special tariff in relation to economic development that is deemed necessary with supporting arguments and justification.

15.2 Assessment of JPS' Current Tariff Structure

JPS' current tariffs consist of a non-fuel charge and a fuel charge. The non-fuel tariff categories are:

- Rate 10 (Residential Service):
  - Residential households for Low Voltage domestic uses.
- Rate 20 (General Service):

[93] For a discussion of these formal regulatory objectives see Berg & Tshirhart (1988) Natural monopoly regulation: principles and practice.

- Customers other than residential households, with demand less than 25 kVA for all purposes in Low Voltage.
- Rate 40:
  - Customers other than residential household customers, with demand 25 kVA or more for all power and lighting purposes,
- Rate 50:
  - Customers other than residential household customers, with demand of 25 kVA or more for all power and lighting purposes. This is only applicable to customers with transformers that are not owned by JPS, in Medium Voltage.
- Rate 60:
  - Streetlights and traffic signals operated by Public Authorities, Local Municipalities, Statutory Organizations
- Rate 70:
  - Large customers who have a peak demand of at least two (2) MVA at a single location, in Medium Voltage. Service is provided at primary distribution voltages (6.9 kV, 13.8 kV and 24 kV) where applicable and available.

Non-fuel Tariffs are applied as approved by the OUR and is structured as follows. Rates 10, 20 and 60 are billed using a two-part tariff structure: a fixed customer charge, and a variable energy charge according to kWh consumption. For Rate 10 customers, the energy charge is applied to two different levels of consumption: up to 100 kWh/month and above 100 kWh/month. Rates 40, 50 and 70 are billed using a three-part tariff structure, with the following components: a fixed Customer Charge, a variable Energy Charge, and a Demand Charge for capacity according to power demand, kVA. Rates 40, 50 and 70 customers can choose between standard charge disregarding of the period of consumption, and time of use (TOU) tariff. The TOU tariffs differ according to the period of consumption and can be "on-peak", "off-peak" and "partial peak" hours as defined by existing regulations.

Table 15-4: JPS' Tariffs Structure – Current Charges (Existing 2018-2019)

			Demand Charge JMD/kVA			
	Customer Charge JMD/Month	Energy Charge JMD/kWh	STD	On-Peak	Partial-Peak	Off-Peak
RT 10 LV Res. Service First 100 kWh	445.39	9.66				
RT 10 LV Res. Service Over 100 kWh	445.39	22.49				
RT 20 LV Gen. Service	992.24	18.55				
RT 60 LV Street Lighting	2,818.88	24.19				
RT 40 LV Power Service (Std)	6,990.81	5.77	1,790.05			
RT 40 LV Power Service (TOU)	6,990.81	5.77		1,008.48	787.63	75.49
RT 50 MV Power Service (Std)	6,990.81	5.77	1,603.66			
RT 50 MV Power Service (TOU)	6,990.81	5.77		895.30	697.81	71.51
RT 70 MV Power Service (Std)	6,990.81	3.71	1,526.30			
RT 70 MV Power Service (TOU)	6,990.81	3.71		684.33	672.78	68.33

The tariff structure is predicated on both supply and demand criteria. The supply criterion is captured in the various types of tariffs charged for the service. These include time-of-use rates which are justified by the fact that the cost of generation varies throughout the day, and becomes most expensive during peaking periods. Differentiation between medium and low voltage recognizes the fact that the service connection type affects the cost of providing the service.

The demand criterion is captured in the four types of customers currently serviced by the grid, namely, residential, commercial (general service), street lighting and industrial. The objective is to assess the extent to which the current tariffs satisfy the economic rationale identified as necessary for appropriate tariff design. On completion of the analysis, the inferences developed and conclusions drawn informed the recommendation for the tariff structure proposed for the next regulatory period.

Table 15-5[94] summarizes the main elements of the tariffs for different customer types and the economic rationale for the existing structure.

Table 15-5: Economic Rationale for each Customer Type

Customer Category	Tariff Type	Objective	Economic Rationale
Residential	Increasing block	Equity	Higher consumption related to higher income
Commercial	Two-part tariff	Simplicity + allocative efficiency	Reflects cost structure (fixed / variable)
Industrial	Capacity + Energy TOU	Allocative efficiency	Reflects cost structure and time variation
Streetlight	Linear	Simplicity	Price inelastic – simplicity

15.2.1 Aggregated Level Analysis: Summary and Recommendations

Based on the results of its Cost of Service and Load Characterization Studies, tariff design principles, and existing market and regulatory dynamics, JPS reviewed its existing tariff structure with a view to manage any significant adverse impact to any single rate category while strictly adhering to the principle of non-cross subsidization. That is a customer contributes at least the marginal cost of the system. To achieve this, other considerations were introduced such as the Stand Alone Cost of self-generation for large industrial customers, the risk of grid defection, the allocation of low voltage non-technical losses, and the overall non-fuel rate increase observed for each rate class. Collectively, these sensitivities were repeated against the OUR's stated tariff design criteria, which JPS also observes, as well as with respect to the pure long-run marginal cost

[94] Source: *JPS' elaboration*

of service study. These were also compared to JPS existing tariff structure for cross-reference purposes, or what JPS considers in its analysis, "*the initial tariff position.*"

The full details of this analysis are presented in accompanying reports to this Tariff Application, chiefly, *JPS Tariff Structure Analysis Report, JPS Cost of Service Study,* and *JPS Load Characterization Study.* Notwithstanding a summary of the main approach taken in reviewing JPS' tariff structure is presented below.

Residential Customers – RT 10[95]

JPS analysed the consumption and revenue profile of its residential customers over a four-year period ending December 2018. From this, the impact of any structural change within the rate class could be assessed, beneficial or otherwise. The number of consumption blocks prescribed to residential customers as well the treatment of the fixed charges, especially with respect to the lifeline block was carefully weighed relative to the potential *negative or positive resulting* tariff changes.

On aggregate the rate class accounts for approximately 41 % of total revenues, 33% of billed kWh sales, and importantly, approximately 90% of JPS' customer base.

Based on the tariff structure analysis, JPS' concludes that having only 2 blocks for a residential tariff limits the possibility of improving the price signals contributing to the objectives of equity and allocative efficiency.

The proposed tariff structure maintains a uniform customer charge, but increases the number of blocks from the original two (2) to the now proposed three (3) block tariff. JPS maintains the lifeline, albeit at a reduced 50 kWh, but still keeps the principle of equity in mind with a lower energy charge, similar to what exists. All residential customers will benefit from this lifeline rate.

A third block is introduced for higher consumption households above 500 kWh per month and is priced as a declining block for the excess energy above 500 kWh. This recognizes the impact of distributed generation and the price elasticity of this group of customers.

JPS believes these changes achieves the objectives of simplicity, equity, allocative efficiency, as well as keeps the revenue of the residential class whole in line with the cost of providing their service.

RT 10 Lifeline Consideration

The current tariff schedule presents a lifeline block up to 100 kWh at a significantly low price/charge. This covers a significantly high percentage, approximately 45% of all residential

[95] See section 4.1.1 of the Tariff Structure Report for additional details

customers. In strict economic terms, the objective of the lifeline block is to improve the affordability of electricity service to low income households, therefore the applicable tariff for the first 100kWh/month was capped at a significantly low rate of J$9.66/kWh.

JPS found within its analysis that the current 100kWh was much too high, especially within the context of the observed average residential montly electricity consumption at approximately 150 kWh. Contiuning with this limit would be inefficient as all customer's benefit from the low energy charge in the first block, including relatively high-income households. This means that under the current tariff the average customers gets nearly 2/3 of their energy at a susbsidized rate.

JPS proposes a reduction of the lifeline block to 50kWh to improve the targeting to low income-households while still maintaining the subsidy with low variable charge for the first 50kWh per month. Improved targeting will allow for a further reduction in their variable charge and aligns with the principle of equity. Section 4.1.1.1.2 and Annex 3 of the Tariff Structure Analysis report provide further details of this analysis.

General Service – Rate 20[96]

Collectively Rate 20 accounts for approximately 25% of JPS' overall billed revenues, 20% of energy sales, and 10% of the total customer base. Notwithstanding the aggregate values, the rate class consists of a very heterogeneous (general services) group of customers that ranges from formal medium and small enterprises to local community-type business ventures. Notably, these local type businesses consume on average, a similar quantity of energy as residential households. Their load profiles are also more similar to that of Rate 10 than to the more established commercial businesses.

In particular, the analysis performed by JPS shows a very large group of users in this rate class (47.1% of the total) have an average consumption below 150 kWh/month explaining only 3% of the total energy consumption, while 3.7% of those with the highest consumption (over 6000 kWh/month) account for 50% of the total energy of the rate class. Applying a rate with a single fixed charge and a single block to such a dissimilar set of users makes it difficult to achieve the objectives of equity and allocative efficiency. JPS proposes a separation of this category into two consumption blocks with a uniform fixed charge to improve the tariff design for this customer category.

In analysing the consumption make-up of the rate class, sensitivity scenarios in relation to increasing block tariffs, and the impact of the fixed charge on groups of customers within the class, a second block was introduced, the first boundary reflective of the average monthly consumption of the class on aggregate.

[96] See section 4.1.2 of the Tariff Structure Report for additional details

The first block represents consumption up to 150 kWh per month and is billed at a variable charge in keeping with the principle of equity. The second block begins at the incremental kWh consumed above 150k kWh and is billed at a relatively higher tariff. All customers will pay the lower of the two for their first 150 kWh which ensures adherence to the principles of equity, and allocative efficiency.

JPS also recognised on review of the billing date that there are currently Rate 20 customers with kVA demand in excess of 25 kVA during 2018. JPS will transition these customers to RT 40 to improve the cost reflectiveness and price signals to these customers. These customers power consumption profile matches that of large commercial customers.

Large Commercial & Industrial (Metered Powered Service) Rate 40 & Rate 50[97]

Rate 40 on aggregate represents approximately 19% of JPS' billed revenues, 25% of kWh sales but less than 1% of overall customer base.

Rate 50 on aggregate represents approximately 8% of JPS' billed revenues, 11% of kWh sales but less than 1% of overall customer base.

JPS analysis finds that most of the users and the energy in these rate classes are concentrated in the Standard option. As most users have Smart AMI meters the continued proliferation of the STD options seems inefficient as it doesn´t provide the proper allocative efficiency signals. Addtionally, limiting the TOU signal to the demand charge only (as currently is the case) does not seem efficient as there are clear variations in energy cost over time. Thus differences in energy costs (measured in terms of the average 2017 cost) across time periods are of -10.5% when comparing on-peak and partial-peak and of -2.6% between partial-peak and off-peak. Therefore, JPS will introdue a TOU energy charge to improve the allocative efficiency signal.

Currently, customers are required to consume at least 50% of their energy requirements within the off-peak period in order to qualify for the Time-of-Use Option. The Tariff Structure Analysis find that the rule requiring users to consume at least 50% of their energy within the off-peak period in order to qualify for the TOU Option appears as inefficient and doesn´t seem to respond to any economic principle.

In principle, JPS intends to transition all customers to TOU, but recognizes that can better be managed on a phased basis as customers become more aware of the potential benefits of TOU. A time differentiated variable charge has been introduced in keeping with this objective as well as to improve allocative efficiency and responsiveness to price and cost of energy production throughout different periods of the day.

[97] See section 4.1.3 and Annex 5 of the Tariff Structure Report for additional details

These customers are also considered at risk given current market dynamics for grid defection. A scenario that has the rippling effect of increasing the price of electricity to unsustainable level. JPS proposes the introduction of a partial wholesale tariff (RT 40X and RT 50 X) for large commercial and industrial customer respectively that takes into account the cost of the next best alternative to self-generation.

Rate 70 – Wholesale Tariff[98]

JPS will maintain the Rate 70 tariff and believes there is even greater need for such a tariff especially given the market signals towards self-generation with CHP technology. This development significantly strains the competitiveness of the vertically integrated utility all in price, inclusive of network services.

The analysis indicates that rates of large users in some cases are above their stand-alone cost. This implies that incentives are created for inefficient defection from the network. The fuel charge being a key determinant of this result.

Overall Relative Tariff Structure

Allocative efficiency objectives require that tariffs be based on long-run marginal costs (LRMC). JPS has updated its Marginal Cost study to reflect known system changes and committed generation plants as at December 31, 2018. The Transmission marginal cost has also been updated to reflect planned investments in line with JPS' medium-term business plan. Notwithstanding, outstanding matters and concerns with Integrated Resource Plan (IRP), JPS accepts the results of this Long Run Marginal Cost of Service Study, and as such its proposed tariffs are established based on current LRMC results, adjusted to Revenue Requirement. Thus meeting the principles of allocative efficiency and long-term network sustainability.

Table 15-6 shows the relative tariff structure and weighting as at 2018, and the average tariff results as per the Cost Service Study post revenue requirement mark-up for the upcoming regulatory period. These results were derived from the results of the JPS Long Run Marginal Cost of Service Study, its Embedded Cost of Service Study, as well as an analysis of its existing tariff structure. A high correlation can be seen by examining the weights between the MC and EC average non-fuel tariffs, with a slight variation for RT 20 and RT 60. This variation is also carried over if one should review the weighting for the existing non-fuel tariff, with the distinction being a pronounced variation, primarily between RT 10, RT 20, and RT 60.

The impact of this would be a rebalance between RT 10, RT 20, and significantly so for RT 60. JPS is of the considered view that this rebalance has to be phased over time, especially given the likely impact on residential customers, should RT 60 be brought in line with the MC tariffs in a single adjustment.

[98] See section 4.1.3 of the Tariff Structure Report for additional details

Table 15-6: Relative Tariff Structure – LRMC & Embedded Cost[99]

Rate Category	Average Tariff	Average LRMC	Average Embedded Costs
MT10	18.95	28.41	29.69
MT20	19.80	21.27	17.79
MT40	11.82	12.71	11.90
MT50	10.74	11.05	10.75
MT60	24.83	9.06	21.07
MT70	7.55	9.38	11.01
Total	**15.5**	**18.95**	**18.95**

TOU Alignment to Loss of Load Probability

JPS also conducted a Loss of Load Probability (LoLP) Analysis to further refine the allocation of cost to the different TOU periods: OnPeak, Partial Peak, and OffPeak. The results of which were used in JPS' Cost of Service Studies (See Cost of Service Report for analysis). The proposed TOU rates are therefore reflective of this and reflects some change in the relative weights of the different TOU charges. Table 15-7 represents the results of the LoLP analysis.

Table 15-7: Loss of Load Probability

Method	On-Peak	Partial-Peak	Off-Peak
LOLP	44.19%	41.06%	14.75%

Section II 1.7 of the Cost of Service and Section 6 of LRMC Generation and Tranmission report provide additional details and computations.

15.3 Tariff Considerations

JPS proposed the following tariff schedule in line with the analysis presented in the previous sections and the Revenue Requirement as outlined for the 2019-2024 regulatory period, discussed in Chapter 13 and Chapter 16.

Inputs to the tariff design are as follows:

- The Revenue Requirement for the five-year tariff period 2019 – 2024 as per the Electricity Licence 2016, and OUR published Final Criteria.
- An analysis of the existing tariff structure and relative tariffs across rate classes. This was done in conjunction with results from the Long-Run Marginal and Embedded Cost of Service Studies.
- Results from JPS' cost of service studies, and the relative share of fixed and variable costs.
- A review of the options for revenue mark-up.

[99] See Table 17-33 in JPS' Cost of Service Report, sections III.3 and III.1.8

- Customer, energy and demand projections for the 2019-2023 period as per the OUR published Final Criteria.

15.3.1 User Class Definitions

The overall definition of rate classes remains relatively unchanged from the existing tariff schedule. JPS proposes to introduce two new rate classes for large commercial and industrial customers, MT 40X and MT 50X respectively. This serves as an intermediate measure seeking to reduce the incentives for inefficient grid or load defection for customer with demand above 1 MVA.

Current MT 20 customers who have demonstrated demand in excess of 25KVA for all months during 2018 will be migrated to RT 40.

RT 60 will be separated into two distinct categories, Street Lighting and Traffic Signals.

The Electric Vehicle tariffs is a new class for Jamaica and applicable to publicly available EV chargers. It is introduced as an interim tariff as EV demand-related data does not currently exist for Jamaica. As the market experiences growth, JPS will conduct an assessment in consultation with the OUR for a review and revision of the EV rate.

JPS proposes the immediate implementation of DER tariffs for new and existing customers with on-site generation, including customers on the Net Billing Programme. It is designed to reflect the changes in revenue and cost associated with providing network capacity and related services to these customers.

The rate categories proposed by JPS for this rate review period are presented in Table 15-8.

Table 15-8: Defined Rate Classes for Proposed Tariff Schedule

Existing Categories		
RT10		Residential Service
RT10 - Prepaid		Residential Service - Prepaid
RT20		General Service
RT20 - Prepaid		General Service - Prepaid
RT40	**STD**	Power Service Low Voltage – Standard
	TOU	Power Service Low Voltage – Time of use
RT50	**STD**	Power Service Medium Voltage – Standard
	TOU	Power Service Medium Voltage – Time of use
RT60S		Public lighting
RT60T		Traffic Signals
RT70	**STD**	Power Service Medium Voltage Large users – Standard
	TOU	Power Service Medium Voltage Large users – Time of use
New Categories		
RT40X	**TOU**	MT40 with Demand over 1MVA
RT50X	**TOU**	MT50 with Demand over 1MVA
EV	**TOU**	Electric Vehicles
DER	**TOU**	Distributed Energy Resources
RT10 TOU	**TOU**	Residential Service – Time of use

15.3.2 Demand Forecast

Table 15-9 presents the relevant values from the demand forecast to be used in the tariff design.

Table 15-9: Demand Forecast

Rate	Growth rate	Value (GWh)		
	2019-2024	2018	2019	2024
MT10	**1.72%**	**1,067**	**1,073**	**1,168**
MT10L	*5.12%*	*135*	*140*	*180*
MT10H	*1.17%*	*932*	*933*	*989*
MT20 (w/o others)	**-5.34%**	**601**	**604**	**459**
MT20L	*3.05%*	*10*	*11*	*12*
MT20M	*1.18%*	*195*	*202*	*201*
MT20H	*-9.80%*	*395*	*394*	*235*
MT40	**4.74%**	**801**	**809**	**1018**
MT50	**1.24%**	**356**	**364**	**387**
MT70	**1.56%**	**294**	**272**	**294**
MT60[100]	**-6.79%**	**62**	**58**	**41**
Electric Vehicles	**14.22%**	**-**	**0.07**	**0.19**

15.3.3 LRMC Adoption and Mark-up Adjustments101

As indicated, JPS adopts the results of the Long-Run Marginal Cost tariff structure as this improves allocative efficiency and price signals. To define a new tariff structure, JPS began by examining the the results of the LRMC study across all ratel classes. As seen in the LRMC model, the significant investment in the transmission network resulted in a higer than normal marginal cost. As such a uniform *mark-down* was applied to bring in line with JPS' actual Revenue Requirement forecast and thus ensuring the efficiency and marginal cost price signals were maintained in the resulting tariff structure. Table 15-10 and Table 15-11 shows the relative weights per rate class resulting from both cost of service studies, in comparison to the existing average tariffs.

[100] This projection embeds a GOJ customer house wiring policy that implies a yearly addition of 3,000 customers starting in 2020.
[101] Section 3.3.3 of JPS' Structure Analysis Report

Table 15-10: Relative Weights per Rate Class

Rate Category	Existing Average Tariff	Average LRMC	Average Embedded Costs
RT 10 LV Res. Service	1.20	1.50	1.57
RT 20 LV Gen. Service	1.26	1.12	0.94
RT 60 LV Street Lighting	1.53	0.48	1.11
RT 40 MV Power Service All	0.79	0.67	0.63
RT 50 MV Power Service All	0.72	0.58	0.57
RT 70 MV Power Service All	0.54	0.49	0.58
RT 20 LV Gen. Service (Other)	1.18	0.61	0.81
RT 50 MV Power Service (Cement Company)	0.67	0.60	0.65
Total	**1.00**	**1.00**	**1.00**

Table 15-11: Average Tariff per Rate Class

Rate Category	Existing Average Tariff	Average LRMC	Average Embedded Costs
MT10	18.95	28.41	29.69
MT20	19.80	21.27	17.79
MT40	11.82	12.71	11.90
MT50	10.74	11.05	10.75
MT60	24.83	9.06	21.07
MT70	7.55	9.38	11.01
Total	**15.5**	**18.95**	**18.95**

The results also indicate a high correlation between existing tariffs and the two cost structures (LRMC and Embedded) with exception to RT 20 and RT 60, relative to RT 10. While the existing RT 20 has the second highest average tariff, even slightly higher than RT10, the LRMC and embedded costs allocations result in RT 20 costs being substantially lower relative to residential customers. A second major difference can be observed in RT 60 – Street Lighting –which has a LRMC which is 68% lower than RT10 LRMC while the current tariff is 26% higher. Overall, a tariff rebalance is required as per the Cost of service study results, however a full rebalance within a single rate review period will create certain issues and adverse customer impact that needs to be addressed.

Firstly, this would result in an average residential tariff substantially higher than the existing tariff and will result in a rate shock to residential customer, especially the most vulnerable. JPS models indicated a 70-80% initial increase in residential rates. To mitigate against this, a cap of 30% increase was applied to RT 10 rates to limit this impact.

To account for the 30% limit in residential rates, two additional adjustments were factored. JPS imposed a 95% proportion adjustment of RT 60 relative to existing tariffs and in effect limits the rebalance of this tariff to no greater than a 5% reduction during this rate review period. Thirdly, a parital rate rebalance for RT 20 was adopted between the existing tariff and the LRMC results.

For large industrial users MT40, LRMC relative value plus a 10% adjustment was adopted as the initial relative tariff in order to avoid a larger increase for residential customers. MT50 in turn is defined as 95% of MT40 to reflect the fact that MT 50 customers own their own transformers and are connected to the MV network. Finally, MT70 relative tariff is based on the pure LRMC results. Table 15-12 summarizes the results of these adjustments:

Table 15-12: LRMC Results with Tariff Adjustments per Rate Class[102]

Tariff Category	Pure LRMC results	LMRC with Proposed Adjustments
RT10	28.41	26.68
RT20	21.27	21.36
RT40 STD	12.71	13.98
RT50 STD	11.05	13.28
RT60	9.06	24.72
RT70 STD	9.38	9.38

15.4 Proposed New Tariff Schedule

Rate design is a complex and sensitive exercise underlined by a myriad of competing objectives, including customer welfare, regulatory policies, and economic and market factors. JPS is confident that the approach adopted achieved an efficient balance between equity, sustainability, economic efficiency, and other stated objectives as per the Final Criteria.

This section outlines the tariff structure and rates proposed by JPS, considering the results of its Cost of Service Studies, and its intention to incrementally increase the share of fixed costs through fixed monthly charges. The tariffs also reflective of an overall increase of approximately 13.3% in JPS' Revenue Requirement over the course of the next five-years, and further broken down to recover the share of the revenue requirement per rate class as indicating in the Cost of Service Study.

15.4.1 Residential Service MT 10 – Low Voltage

As discussed in the Tarif Structure Analysis Report, the current structure of two consumption blocks seems insufficient, as it does not allow sufficient flexibility in terms of price signals. The definition of the optimal number of blocks is the result of a trade-off between improving price signals and maintaining a simple and easy to understand structure for users.

Bearing in mind these two opposing objectives, JPS proposes a three-tier tariff structure for residential customers and is confident that this will significantly improve economic signals of the tariff without unduly increasing the complexity of the tariffs for residential customers. The three-tier structure also satisfies the objectives of sustainability, efficiency, equity, and affordability.

The lifeline block has been reduced to 50 kWh and is sufficient to cover approximately 22 percent of all customers whose monthly consumption is strictly below or equal to 50 kWh. This is in keeping with the objective of improving equity, efficiency, and affordability as it reduces the

[102] Section 3.3.3 of the Tariff Structure Analysis Report provides the full details of this analysis.

volume of energy billed at the lower lifeline rate and therefore reduces the rate impact for customers above the lifeline. From an economic perspective, poor households are least likely to be able to pay the true cost of service, as such the energy charge for the first block has been reduced from J$9.66 to J$8.95/kWh, despite an increase in revenue requirement at his level of consumption. The supporting analysis and determination of the proposed limit at 50 kWh/month is provided in Section 4.1.1.1.2 of the Tariff Structure Analysis Report.

The second block 51-500 kWh per month consists of approximately 75 percent of all residential customers and is priced to ensure revenue sustainability of the class. A rate impact analysis was conducted to determine the energy charge required for revenue recovery while reducing rate impact. Rates have increased from the tariff of J$22.49 to J$29.33/ kWh.

Customers consuming above 500 kWh per month make up 3 percent of all residential customers and represents a reasonable frontier for a third block without the need for any significant revenue rebalance to other users, given the approximate 19 percent share of revenues under existing tariffs. The third block is priced in alignment with the long-run marginal cost which reduces the variable charge at that level of consumption. This is important in maintaining the sustainability of the network and signaling a disincentive to high-consumption households from exiting the network through use of roof-top solar panels or other technologies.

To improve allocative efficiency, the customer charge is increased to J$853.74 per month. To protect vulnerable households, the energy charge for the first block of 50 kWh has been reduced from the existing rate of J$9.66 /kWh to J$8.95/kWh – an approximate 7% reduction.

The average non-fuel tariff increase experienced by residential customers will be of the magnitude of approximately 41%, from an initial value of J$20.52/kWh to J$29.11/kWh.

All residential customers will benefit from the lower energy charge for their first 50 kWh. Table 15-13 represents JPS' proposed tariff structure for residential customers.

Table 15-13: RT 10 Proposed Tariff Grid

	Existing Rates			Proposed Rates		
	Block Limit (kWh/month)	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Block Limit (kWh/month)	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)
RT 10	0-100	455.39	9.66	0-50	853.74	8.95
	Above 100		22.49	51-500		29.33
	n/a			Increment above 500		27.78

15.4.2 General Service RT 20 – Low Voltage

JPS proposes a two-tier tariff structure for General Service Customers, where the first block is limited to 150kWh, and the second block begins at the kWh increment in excess of the first 150 kWh.

The General Service rate class consists of a very heterogeneous group of customers, and as a result their consumption patterns and demand characteristics are diverse. JPS records an approximate total of 66,000 customers within this rate class. Of this, 50% consume strictly below 150 kWh per month, accounting for only three (3) percent and six (6) percent of total class consumption and revenue respectively. These users are considered micro-business operators and demonstrate consumption characteristics typically associated with a residential user. Adding the 16.5 percent GCT on electricity adversely impacts the average tariff paid by these users, and thus results in an overall higher monthly bill. Table 15-14 outlines JPS' RT 20 proposed tariff.

Table 15-14: RT 20 Proposed Tariff Grid

	Existing Rates			Proposed Rates		
	Block Limit (kWh/month)	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Block Limit (kWh/month)	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)
RT 20	n/a	992.24	18.55	0-150	1,488.71	17.50
				Above 150		20.61

To improve equity and allocative efficiency within the rate class a lower energy charge for the first 150 kWh is proposed at J$17.50/kWh, which represents a reduction of 18 percent from the existing tariff and addresses equity and affordability concerns. The second block will begin at the increment in kWh above 150 and is priced at J$20.61/kWh to ensure revenue adequacy of the class. Users whose consumption is typically above 150 kWh will also benefit from the lower rate offered in the first block. Customer charges have been increased in order to achieve these objectives but is balanced by the overall decline in variable energy charges.

The results of the Long Run Marginal Cost Study indicated a realignment of the share of JPS' revenue requirement allocated to RT 20 customers. It was shown that the rate class receives a lower tariff increase relative to the existing tariff as their share or contribution to system shows a reduction. On average, Rate 20 customers will see a non-fuel tariff increase of approximately 5.9%, from an initial value of J$21.45 to J$22.73/kWh.

15.4.3 Street Lighting MT 60S – Low Voltage

JPS has deployed LED Smart Street Light system in accordance with its Licence. Significant capital expenditure has already been invested in carrying out this obligation, and a further US$13.5M is expected to be incurred during the rate review period for completion of the programme.

Cost causation is one the key pillars in tariff design, in that, system costs should be covered by the rate classes that are drivers for those costs being incurred. Street lighting assets and related infrastructure are one of few system assets that can be directly and solely associated to a specific user. Also relevant are the added new functionalities embedded within each lamp for monitoring and control purposes, the cost of which should not be borne by other ratepayers.

For purposes of improving allocative efficiency as discussed in Section 4.1.4 of the Tariff Structure Analysis report, JPS proposes a modification of the RT 60 Street light tariff to now include a customer charge per fixture of J$374.88monthly. The tariff will still include a variable energy charge for each kWh. Due consideration is also given to the projected reduction in demand from the more efficient lighting diodes. The table summarizes the proposed tariffs for RT 60 Streetlights as well as the bill impact for this class.

A per fixture charge is proposed given the additional functionality and maintaince requirements of the new lamps.

Table 15-15: Proposed MT60T Streetlight Tariff

MT 60 Streetlight	Energy Charge J$/kWh	Customer Charge J$/Fixture per Month
	12.01	374.88

Rate 60 will see a general non-fuel tariff of reduction of approximately 8.1%.

15.4.4 Traffic Signals – MT 60T – Low Voltage

JPS proposes to implement a distinct tariff for traffic signals in keeping with the principle of cost causation. The previous tariff had grouped two easily identifiable group of customers. The need for separation arises from the recognition that the cost associated with the two services vary. JPS will own, operate and maintain street lights and thus a higher level of cost is typically associated with this service. Traffic signals on the other hand are fully owned and maintained by the customer, and therefore a differentiated cost to serve can be observed. The tariff for streetlights recovers capital, O&M expenses and energy & demand charges. The tariff for traffic signals is only recovering energy and demand charges as the traffic signal customer owns and maintains its infrastructure. JPS is therefore of the view that the separation of traffic signals is justifiable and practical at this time. The move also aims to increase the level of transparency of the RT 60 tariff design, especially within context of the Smart Streetlight Replacement Programme.

The tariff will consist of two components, a variable energy charge, and a fixed customer charge to recover demand related system costs. JPS proposes an energy charge of J$ 12.01/kWh, similar to that associated with street lighting, and a customer charge of J$749.76 per month. Table 15-16 summarizes the proposed traffic signal tariff.

Table 15-16: Proposed MT60T Traffic Signals Tariff

MT 60 Traffic Signals	Energy Charge [J$/kWh]	Customer Charge [J$/Intersection/Month]
	12.01	749.76

15.4.5 Metered Powered Service Customers Standard VS. TOU Tariffs

With the modernization of JPS' metering infrastructure and other grid improvements, the general objectives are to improve price signals, maintain a reasonable level of allocative efficiency, and reduce the medium to long-term investments needed to maintain the reliability of the grid. This will require lowering network costs, and keeping customers connected by virtue of the inherent economies of scope and scale of an integrated network.

Time-of-Use tariffs are a more efficient rate structure in improving the utilization of network assets and can potentially lower the cost of electricity, benefiting both the utility and its customer. Generation capacity is engineered to satisfy system peak conditions and generation cost is highest during the times of highest demand as more flexible and higher variable cost peaking generation plants are brought online to respond to growing customer demand. TOU rates are designed to communicate the cost differential to customers by way of time-differentiated prices (Off-*Peak, Partial-Peak, and On-Peak*).

In previous years, a limiting factor was the availability and cost of meters capable of registering demand and energy usage at different time intervals. With the modernization of the network, including the wide-scale installation of smart meters, this issue will no longer be an impediment.

JPS recognizes that change has to be managed over time and as such proposes to retain its tariff structure without the mandatory introduction of time of use rates in the interim. It is expected that transitioning customers to TOU on an "Opt-in" basis will continue, and become accelerated as the benefits of TOU are realized by a greater percentage of the customer base. This transition will be an adjustment to both JPS and its customers in an effort to realize the vast medium to long-term benefits of time-differentiated tariffs, notwithstanding any potential short-term cost.

Standard (STD) tariffs will remain until the full transition to TOU has been implemented by the end of this regulatory period. To support this initiative, JPS is proposing to remove the existing eligibility requirement of 50 percent off-peak energy consumption for customer wishing to go TOU.

15.4.6 Metered Power Service MT 40 Standard (STD) – Low Voltage

JPS proposes to maintain the existing Standard three-part rate structure for large commercial clients, that will consist of a monthly customer charge, a demand charge per KVA, and a per kWh energy charge. Demand charges will continue to be applied in accordance with existing ratchet mechanisms. Table 15-17 illustrates JPS' proposed tariff for MT 40 (STD).

Table 15-17: Proposed MT40 STD Tariffs

	Existing Rates			Proposed Rates		
	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)
MT 40 STD	6990.81	5.77	1790.05	12,000	6.85	2,437.85

The average non-fuel RT 40 Std tariff will see an increase of 10.3%. Demand charges are proposed at J$2,437.85/kVA, an approximate 36% increase. Energy charges has a marginal growth.

15.4.7 Metered Power Service RT 40 Time of Use (TOU) - LV

JPS proposes to introduce a time varying energy charge for large commercial customers in an effort to improve the overall effectiveness of TOU rates. kWh consumption will be billed at varying energy charges and with respect to the specific TOU in which that energy is consumed. Demand charges will remain time differentiated and will be applied in accordance to the approved tariff schedule and existing six (6)-month ratchet mechanism. Table 15-18 illustrates JPS' RT 40 TOU proposed tariffs.

Table 15-18: Proposed RT 40 TOU Tariff Grid

		Existing Rates			Proposed Rates		
	Period	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)
RT 40 TOU	On Peak	6990.81	5.77	1,008.48	12,000	9.31	1,077.34
	Partial Peak			787.63		8.65	1,001.00
	Off Peak			75.49		3.11	359.52

The average non-fuel tariff for rate 40 customers on TOU will increase by approximately 23%. However, analysis of the relative increase in the individual tariff components shows a more modest increase. The proposal reflects an approximate increase in On-peak demand charges by 6.8%.

15.4.8 Metered Power Service RT 50 (STD) – Medium Voltage

JPS also proposes to maintain the existing Standard three-part rate structure for industrial customers. This will consist of a fixed customer charge, a demand charge per kVA, and a per kWh energy charge. Demand charges will continue to be applied in accordance with existing ratchet mechanisms. The proposed tariffs are given in Table 15-19:

Table 15-19: Proposed RT 50 Standard Tariffs

	Existing Rates			Proposed Rates		
	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)
RT 50 STD	6990.81	5.57	1,603.66	12,000	6.50	2,315.96

The proposed charges reflect an increase of approximately 17.8%, a marginal difference of less than J$1 per kWh. Demand charges intended to recover network capacity costs, have increased to J$2,315.96 per kVA, up from J$1,603.66/kVA, an increase of 44%. The overall non-fuel tariff increase is approximately 17.8%.

JPS also encourages RT 50 customers to take advantage of the TOU tariff available, as cost saving opportunities can be realized. Standard tariffs will also be phased out over the rate review period in keeping with JPS' medium and long-term objectives of improving price signals, which will lead to overall lower electricity cost.

15.4.9 Metered Power Service RT 50 (TOU) – Medium Voltage

JPS proposes to introduce a time varying energy charge for industrial customers. This is in keeping with the medium to long-term objectives of improved pricing. kWh consumption will be billed at the respective rates for the TOU period in which consumption occurred. Demand charges will remain time differentiated and will be applied in accordance to the approved tariff schedule and existing six (6)-month ratchet mechanism. The proposed non-fuel rates are show below:

Table 15-20: Proposed RT 50 TOU -MV

		Existing Rates			Proposed Rates		
	Period	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)
RT 50 TOU	On Peak	6990.81	5.57	895.30	12,000	8.84	1,023.47
	Partial Peak			697.81		8.22	950.95
	Off Peak			71.51		2.95	341.54

On-peak, and partial-peak demand charges increases by approximately 13%, and 33.7% respectively. Average non-fuel tariffs for a RT 50 (TOU) customer will see an estimated increase of approximately 8.8%, moving from an initial average tariff of J$12.26 to J$13.34/kWh

15.4.10 RT 70 Wholesale Tariff – Medium Voltage

JPS proposes to retain its RT 70 customer class for qualified customers with demand equal to or greater than two (2) MVA at a single metering point. The introduction of this rate class has been welcomed by customers, and represents one of the most significant rate development in recent years.

The introduction of Liquefied Natural Gas (LNG) to the Jamaican economy has sparked the development of a new gas sector that currently remains unregulated. JPS supports its introduction, and its role in Jamaica's progress towards fuel diversification and has been instrumental in the onboarding of LNG to the energy sector with its flagship project converting the Bogue Power Plant to be fueled by natural gas. The SJPC Combined Cycle 190 MW plant to be commissioned later in 2019 will also be fueled by natural gas.

Despite its welcomed benefits, LNG has also brought with it disruptive forces that have presented an alternative fuel source to customers seeking to optimize their energy costs and can utilise LNG in the build out of their own generation facilities. Experience has demonstrated that this may not always lead to the expected benefits that many customers anticipated. Additionally, the move is sub-optimal from an energy security and overall electricity price perspective.

JPS recognizes the drivers to which customers are responding but cautions that self-generation results in infrastructure duplication, inefficient capital deployment and an overall sub-optimal utilization and pricing of the grid. Continued inefficient partial or full-migration from the network will only serve to unnecessarily raise tariffs for remaining ratepayers, with a rippling effect that will further exacerbate price distortions.

Another impact worth mentioning is the current homogenous fuel rate applied across all rate classes.

There exists a real risk for the continued sustainability of the national electricity infrastructure, despite the introduction of RT 70. The proposed RT 70 tariff represents JPS' response to market forces as the sector becomes increasingly competitive in an unbalanced regulatory landscape. JPS has expended significant resources in refining the RT 70 tariff to reduce the perceived gaps in relation to the service-value being delivered to this increasingly price sensitive customer group. RT70 currently represent 0.0035% of the total customer base, but accounts for approximately 10% of energy sales.

15.4.11Metered Powered Service RT 70 Standard (STD)

Wholesale tariffs are applied in various international jurisdictions in recognition of their generally lower cost of service due to their connection characteristics, high demand and energy consumption.

To support grid retention, JPS proposes to adopt the strict results of the LRMC Cost of Service Study for this rate class. Sensitvity analysis was conducted with respect to an estimated stand alone cost for generation, which is considered their next best alternative option based on market research.The analysis revealed that customers have a strong incentive to self-generate, if estimates of their all-in cost of energy is achieved.

Importantly, the LRMC shows that the current tariff for RT70 is below their stand alone cost of self-generation. It is imperative that JPS maintains the LRMC tariff structure otherwise it will result in a significant economic and social welfare loss for all existing customers.

JPS will maintain the RT STD tariff during the rate review period, but encourages customers to transition to the TOU rate to optimize their load factor and maximize their potential cost savings. JPS' RT 70 rate proposal is shown below in Table 15-21.

Table 15-21: Proposed RT 70 Standard (STD) Tariff

	Existing Rates			Proposed Rates		
	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)
RT 70 STD	6990.81	3.71	1,526.30	12,000	4.95	2,141.35

The average non-fuel tariff for a RT 70 STD will increase by 13%, moving from J$9.01 in 2018 to J$10.18/kWh which results in a variance of J$1.17/kWh. Note that despite this increase, the tariffs are below the estimated stand alone cost of generation for Large Industrial customers. JPS proposal includes all network and generation related costs.

To improve fixed cost recovery, customer charges have increased to J$12,000 per month but remains neglible relative to a RT 70 customer electricity bill as they are high users of energy. Demand charges have been increased inline with JPS' long-run marginal cost of service study, and specifically related to the marginal cost of the transmission network.

15.4.12Metered Power Service RT 70 TOU – Medium Voltage

JPS proposes to improve the allocative efficiency of TOU tariffs by including a time varying energy charge. kWh consumption will be billed at the respective rates for the TOU period in which consumption occurred. Demand charges will remain time differentiated and will be applied in accordance to the approved tariff schedule and existing previous five (5) months ratchet mechanism. This structure represents an opportunity for customers to realize cost savings by improving their commercial and operational practices, and thus improving their energy utilization or load factor. The proposed non-fuel tariffs are outlined below have been aligned with JPS' Loss of Load Probability Study.

Table 15-22: Proposed RT 70 Time of Use (TOU)

		Existing Rates			Proposed Rates		
	Period	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)
RT 70 TOU	On Peak	6990.81	3.71	864.33	12,000	6.24	946.31
	Partial Peak			672.78		5.80	879.25
	Off Peak			68.33		2.08	315.79

On-peak, and partial-peak demand charges increases by approximately 9%, and 30% respectively. Off-peak demand charges have been aligned to the LoLP cost allocation and as result shows an increase to J$315.79/kVA, up from the prvious value of J$68.33/kVA. Average non-fuel tariffs will see an estimated increase of approximately 1.6%, moving from J$9.75 to J$9.91/kWh.

15.4.13Partial Wholesale Tariff

Unfortunately, high single point load characteristics advantage of the RT 70 limits the foregoing pricing strategy to that rate class. However large commercial and industrial customers below the two (2) MVA requirement for RT 70 have also strongly signaled to JPS their intention and or active plans to implement self-generation projects as the electricity sector continues to experience unprecedented change.

In an attempt to mitigate against this likely scenario, which will have an overall adverse impact on electricity prices, JPS is proposing the creation of two new rate classes for select customers within RT 40 and RT 50 with demand above one (1) MVA but less than two (2) MVA at a single metering point. This rate is available as an optional tariff for qualifying customers.

The new rates are proposed as TOU only in keeping with JPS' strategic objective to improve long-term utilization of network assets through appropriate time varying price signals.

Metered Power Service RT 40X TOU – Low Voltage

Table 15-23: MT 40X TOU - LV

	Period	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)
RT 40X (TOU)	On Peak	12,000	7.70	891.50
	Partial Peak		7.16	828.33
	Off Peak		2.57	297.50

This tariff structure has been aligned with the one proposed for RT 40 TOU customers with a differential in demand and energy charges. Customer charges will remain identical to the RT 40 tariff at J$12,000 per month.

Metered Power Service 50X RT TOU – Medium Voltage

Similar to the relative treatment of RT 40X and RT 40 TOU, RT 50X tariffs are adjusted relative to RT 50 TOU. Specifically, energy and demand charges are adjusted to reflect a 1.2 relative ratio between RT 50 TOU and RT 70 TOU. Table 15-24 highlights the proposed tariffs and the resulting average non-fuel and bill impact.

Table 15-24 : RT 50X TOU

	Period	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)
MT 50X TOU	On Peak	12,000	7.20	701.31
	Partial Peak		6.69	651.61
	Off Peak		2.40	234.03

15.4.14 Pre-Paid Tariffs

JPS proposes the retention of its pre-paid electricity tariffs for Residential (RT10) and General Service (MT20) customers. Its implementation has been a welcomed innovation to customers, and in line with the strategic initiative of improving service delivery, increasing the options available to customers, and providing them with greater control of their electricity usage.

JPS sought to improve the design of these tariffs, with due consideration for its tax obligations to the Government of Jamaica, customer value, and simplicity. A detailed analysis is presented in JPS Tariff Structure Report attached as an annex to this submission.

RT 10 Residential Prepaid

JPS proposes to retain the two-tier inclining block tariff structure for residential pre-paid customers. The first block, defined from 0 – 114 kWh is priced at J$24.57 for each unit of kWh consumed. The second block is the increment in consumption above 114 kWh, and is priced at J$35.37/kWh. Table 15-25 outlines the proposed tariff schedule.

Table 15-25: RT10 Residential – Prepaid Tariffs

Rate	Customer charge (JM$/Month)	Energy charge (JM$/kWh)	
RT10 PR	Not applicable	0-114 kWh	24.57
		+114 kWh	35.37

RT 20 General Service Prepaid

JPS proposes to retain the two-tier tariff structure for RT 20 prepaid service. The first block is defined from 0 – 10 kWh and is priced at J$119.68 for each unit of kWh consumed. The second block is the increment in consumption above 10 kWh, and is priced significantly lower at J$20.18 Table 15-26 outlines the proposed tariff schedule.

Table 15-26: RT20 General Service – Prepaid Tariffs

Rate	Customer charge (JM$/Month)	Energy charge (JM$/kWh)	
RT20PR	Not applicable	0-10 kWh	119.68
		+10 kWh	20.18

15.4.15 Residential Time of Use (TOU)

JPS proposes an optional TOU tariff for residential customers in keeping with its medium to long-term strategic initiative to improve its price signals and overall tariff design. The RT 10 TOU tariff is also in keeping with the expected development in the use of electric vehicles. With the appropriate TOU tariff, residential customers will be incentivized to charge their vehicles during the off-peak hours (10pm – 6am) as electricity rates are typically a fraction of that compared to peak and partial-peak hours. This will benefit both the customer and overall system through lowered costs.

This is proposed as an interim tariff, JPS will in consultation with the OUR seeks to improve its design during the rate review period.

The residential TOU tariff will include a time differentiated energy charge for the kWh consumption during the respective TOU defined periods. A non-time differentiated demand charge is applicable to the customer's maximum demand.

Table 15-27: Residential Time of Use Tariffs

	Period	Customer Charge (JMD/month)	Energy Charge (JMD/kWh)	Demand Charge (JMD/kVA)
RT 10 TOU	On Peak	380.75	9.86	2,091.23
	Partial Peak		9.15	
	Off Peak		3.29	

15.4.16 Public Electric Vehicle Charging – EV Tariffs

Electric Vehicles represents a new, promising and needed innovation in the Jamaican transportation sector. With global market trends, and appropriate policies, the transition toward the electrification of the local transportation fleet is anticipated by industry experts and key stakeholders.

JPS will invest approximately $1.5 Million USD over the next rate review period in support of the deployment of an island-wide electric vehicle charging infrastructure. These will be situated at various strategic, convenient and safe locations across the island that should provide adequate coverage for motor journeys across the island. JPS will be providing an integrated public charging service for electric vehicles in which specific assets will form part of the regulated asset base.

Given the non-existence of demand and load profile data associated with the use of electric vehicles in Jamaica, JPS proposes an interim tariff for public electric vehicle charging to enable market development in alignment with broader GOJ policy initiatives. As EV demand increases and relevant usage data becomes available, JPS will review, in consultation with the OUR, the applicable tariffs.

Table 15-28: Public EV Charging – Interim Tariff (Non-Fuel)

Public EV Charging	Tariff [J$/kWh]
Energy charge	26.17

While an average tariff is proposed at J$ 26.17/kWh, JPS would like to establish in principle that access to public charging infrastructure will usually vary in price according to the type of chargers being used. Public EV chargers are known within the industry as Level 2 and Level 3 and are generally priced differently, with a premium being applied to the latter. Level 3 chargers are high capacity rated and will typically get a battery from 0% to full charge usually within an hour. Level 2 chargers, on the other hand will typically take 3-4 hours to get to 100 % charge. Other jurisdictions surveyed including the US state of California demonstrated a price variance within the range of 2-3 times between L2 and L3 chargers.

15.4.17 Revenue Forecast under Proposed Tariffs

Section 13.9 of the Revenue Requrement chapter shows derivation of the annual revenue cap for 2019-2023 period. Revenue forecast (collected revenue) under the proposed tariffs will however differ from the annual revenue cap presented in section 13.9 of the Revenue Requrement chapter as shown in Table 15-29. As the the OUR is aware and following the guidelines stipulated by the 2016 License, new tariffs ought to have been implemented around approximately August 2019. The annual variation seen between the *Revenue Cap* and *Collected Revenue* is a result of the the delay in implementation of the tariffs in 2019, and as a result 2019 revenue collection is based on existing tariffs. Collected Revenue in Table 15-29 in essence represents adjusted annual revenue cap incorporating the delay in the implementation of the tariffs in 2019.

JPS now projects a tariff adjustment in May 2020 (partial) year, with the full effect on revenues beginning 2021, as seen in the increase in revenue collected. Overall, the Net Present value of the revenue cap equals the net present value of the toal revenue collected as outlined in the Final Criteria.

Table 15-29: Projected Revenue Requirement (J$'000)

Variable	Units	2019	2020	2021	2022	2023
Revenue Cap	M J$	60,923	61,444	62,249	63,011	63,783
Collected Revenue	M J$	54,220	61,162	65,114	65,771	66,426
NPV Revenue Cap	M J$	**262,274**				
NPV Collected Revenue	M J$	**262,274**				

Tables 14-30 through 14-32 provide a proof of revenue forecast by year for 2021 to 2023. Proof of revenue forecast tables were not prepared for 2019 and 2020, because proposed tariffs would not be in place for a full year in those years.

Table 15-30: Proof of Revenue Forecast under Proposed Tariffs - 2021

Class	Average 2021 Customer	Energy kWh	Demand - KVA	Customer Charge J$/month	Energy Charge J$/kWh	Demand Charge J$/KVA	Customer Revenue J$000	Energy Revenue J$000	Demand Revenue J$000	Total Revenue J$000
MT10 | Block: 1 | 0 - 50 kWh/month	614,410	313,686,361		853.74	8.95	-	6,294,554	2,807,493	-	9,102,047
MT10 | Block: 2 | 50 - 500 kWh/month		707,181,668		853.74	29.33	-	-	20,742,271	-	20,742,271
MT10 | Block: 3 | 500 and plus kWh/month		95,576,015		853.74	27.78	-	-	2,655,006	-	2,655,006
MT20 | Block: 1 | 0 - 150 kWh/month	67,724	84,783,849		1,488.71	17.50	-	1,209,863	1,483,717	-	2,693,581
MT20 | Block: 2 | 150 and plus kWh/month		362,982,133		1,488.71	20.61	-	-	7,482,122	-	7,482,122
MT40 | Block: 1 | 0 and plus kWh/month	2,101	640,702,914	2,039,120	12,000.00	6.85	2,437.85	302,533	4,386,723	4,971,069	9,660,326
MT40_TOU | Peak	775	80,942,009	747,673	12,000.00	9.31	1,077.34	111,569	753,580	805,495	1,670,644
MT40_TOU | Partial Peak		99,406,980	918,236	-	8.65	1,001.00	-	859,912	919,152	1,779,064
MT40_TOU | Off Peak		101,257,687	935,331	-	3.11	359.52	-	314,594	336,267	650,861
MT40X_TOU | Peak	25	18,929,361	229,334	12,000.00	7.70	891.50	3,563	145,836	204,452	353,851
MT40X_TOU | Partial Peak		23,247,639	281,651	-	7.16	828.33	-	166,413	233,301	399,714
MT40X_TOU | Off Peak		23,680,451	286,894	-	2.57	297.50	-	60,881	85,352	146,233
MT50 | Block: 1 | 0 and plus kWh/month	78	92,077,828	314,536	12,000.00	6.50	2,315.96	11,296	598,911	728,452	1,338,659
MT50_TOU | Peak	38	11,476,877	111,535	12,000.00	8.84	1,023.47	5,453	101,509	114,152	221,114
MT50_TOU | Partial Peak		15,634,324	151,937	-	8.22	950.95	-	128,481	144,485	272,966
MT50_TOU | Off Peak		18,181,216	176,689	-	2.95	341.54	-	53,662	60,346	114,009
MT50X_TOU | Peak	30	37,936,230	300,826	12,000.00	7.20	701.31	4,277	273,024	210,971	488,272
MT50X_TOU | Partial Peak		51,678,459	409,799	-	6.69	651.61	-	345,571	267,030	612,601
MT50X_TOU | Off Peak		60,097,078	476,557	-	2.40	234.03	-	144,333	111,530	255,863
MT70 | Block: 1 | 0 and plus kWh/month	15	182,004,444	443,446	12,000.00	4.95	2,141.35	2,153	901,239	949,571	1,852,964
MT70_TOU | Peak	8	28,696,842	219,795	12,000.00	6.24	946.31	1,201	179,056	207,993	388,249
MT70_TOU | Partial Peak		33,213,456	254,389	-	5.80	879.25	-	192,553	223,671	416,224
MT70_TOU | Off Peak		35,307,981	270,431	-	2.08	315.79	-	73,518	85,399	158,917
MT20O | Block: 1 | 0 - 100 kWh/month	2	2,400		1,074.01	20.08		26	48	-	74
MT20O | Block: 2 | 100 - 1681 kWh/month		37,940		1,074.01	20.08		-	762	-	762
MT20O | Block: 3 | 1681 and plus kWh/month		33,575,384		1,074.01	20.08		-	674,146	-	674,146
Electric Vehicles		83,842			26.17			2,194		2,194
MT60 | Block: 1 | 0 and plus kWh/month	517	40,430,217	109,286	-	12.01	4,539.07	-	485,399	496,057	981,456
TOTAL	**685,722**	**3,192,811,585**	**8,677,463**				**7,946,489**	**46,012,955**	**11,154,746**	**65,114,190**

Table 15-31: Proof of Revenue Forecast under Proposed Tariffs - 2022

Class	Average 2022 Customer	Energy kWh	Demand - KVA	Customer Charge J$/month	Energy Charge J$/kWh	Demand Charge J$/KVA	Customer Revenue J$000	Energy Revenue J$000	Demand Revenue J$000	Total Revenue J$000
MT10 | Block: 1 | 0 - 50 kWh/month	625,005	319,120,992		853.74	8.95	-	6,403,101	2,856,133	-	9,259,234
MT10 | Block: 2 | 50 - 500 kWh/month		717,628,616		853.74	29.33	-	-	21,048,689	-	21,048,689
MT10 | Block: 3 | 500 and plus kWh/month		96,472,095		853.74	27.78	-	-	2,679,898	-	2,679,898
MT20 | Block: 1 | 0 - 150 kWh/month	68,381	90,424,200		1,488.71	17.50	-	1,221,596	1,582,424	-	2,804,019
MT20 | Block: 2 | 150 and plus kWh/month		360,833,719		1,488.71	20.61	-	-	7,437,836	-	7,437,836
MT40 | Block: 1 | 0 and plus kWh/month	1,819	554,668,059	1,765,303	12,000.00	6.85	2,437.85	261,908	3,797,665	4,303,544	8,363,117
MT40_TOU | Peak	1,086	108,323,091	990,340	12,000.00	9.31	1,077.34	156,335	1,008,502	1,066,929	2,231,767
MT40_TOU | Partial Peak		133,034,396	1,216,262	-	8.65	1,001.00	-	1,150,803	1,217,476	2,368,279
MT40_TOU | Off Peak		135,511,161	1,238,906	-	3.11	359.52	-	421,015	445,407	866,421
MT40X_TOU | Peak	25	19,118,737	231,628	12,000.00	7.70	891.50	3,599	147,295	206,498	357,391
MT40X_TOU | Partial Peak		23,480,217	284,469	-	7.16	828.33	-	168,078	235,635	403,713
MT40X_TOU | Off Peak		23,917,359	289,765	-	2.57	297.50	-	61,490	86,206	147,696
MT50 | Block: 1 | 0 and plus kWh/month	69	79,750,589	272,427	12,000.00	6.50	2,315.96	9,910	518,730	630,928	1,159,568
MT50_TOU | Peak	50	14,965,167	141,364	12,000.00	8.84	1,023.47	7,233	132,361	144,682	284,277
MT50_TOU | Partial Peak		20,386,232	192,573	-	8.22	950.95	-	167,532	183,127	350,659
MT50_TOU | Off Peak		23,707,227	223,944	-	2.95	341.54	-	69,972	76,486	146,458
MT50X_TOU | Peak	30	38,333,616	303,977	12,000.00	7.20	701.31	4,378	275,884	213,181	493,443
MT50X_TOU | Partial Peak		52,219,797	414,092	-	6.69	651.61	-	349,191	269,828	619,019
MT50X_TOU | Off Peak		60,726,602	481,549	-	2.40	234.03	-	145,845	112,698	258,543
MT70 | Block: 1 | 0 and plus kWh/month	13	158,742,174	386,768	12,000.00	4.95	2,141.35	1,889	786,051	828,205	1,616,145
MT70_TOU | Peak	11	37,010,135	276,044	12,000.00	6.24	946.31	1,544	230,927	261,222	493,693
MT70_TOU | Partial Peak		42,835,184	319,491	-	5.80	879.25	-	248,334	280,913	529,247
MT70_TOU | Off Peak		45,536,480	339,639	-	2.08	315.79	-	94,816	107,255	202,070
MT20O | Block: 1 | 0 - 100 kWh/month	2	2,400		1,074.01	20.08		26	48	-	74
MT20O | Block: 2 | 100 - 1681 kWh/month		37,940		1,074.01	20.08		-	762	-	762
MT20O | Block: 3 | 1681 and plus kWh/month		33,155,652		1,074.01	20.08		-	665,719	-	665,719
Electric Vehicles		97,122			26.17			2,542		2,542
MT60 | Block: 1 | 0 and plus kWh/month	531	39,935,161	110,422	-	12.01	4,539.07	-	479,456	501,212	980,668
TOTAL	**697,022**	**3,229,974,119**	**9,478,962**				**8,071,519**	**46,527,997**	**11,171,431**	**65,770,947**

Table 15-32: Proof of Revenue Forecast under Proposed Tariffs - 2023

Class	Average 2023 Customer	Energy kWh	Demand - KVA	Customer Charge J$/month	Energy Charge J$/kWh	Demand Charge J$/KVA	Customer Revenue J$000	Energy Revenue J$000	Demand Revenue J$000	Total Revenue J$000
MT10 | Block: 1 | 0 - 50 kWh/month	635,580	324,825,655		853.74	8.95	-	6,511,436	2,907,190	-	9,418,626
MT10 | Block: 2 | 50 - 500 kWh/month		728,186,206		853.74	29.33	-	-	21,358,353	-	21,358,353
MT10 | Block: 3 | 500 and plus kWh/month		97,412,345		853.74	27.78	-	-	2,706,017	-	2,706,017
MT20 | Block: 1 | 0 - 150 kWh/month	69,044	99,601,800		1,488.71	17.50	-	1,233,440	1,743,031	-	2,976,471
MT20 | Block: 2 | 150 and plus kWh/month		355,399,919		1,488.71	20.61	-	-	7,325,830	-	7,325,830
MT40 | Block: 1 | 0 and plus kWh/month	1,531	466,820,713	1,485,717	12,000.00	6.85	2,437.85	220,439	3,196,198	3,621,956	7,038,593
MT40_TOU | Peak	1,403	136,236,075	1,237,717	12,000.00	9.31	1,077.34	201,987	1,268,375	1,333,437	2,803,799
MT40_TOU | Partial Peak		167,315,056	1,520,072	-	8.65	1,001.00	-	1,447,345	1,521,588	2,968,934
MT40_TOU | Off Peak		170,430,040	1,548,372	-	3.11	359.52	-	529,503	556,664	1,086,168
MT40X_TOU | Peak	25	19,308,894	233,932	12,000.00	7.70	891.50	3,635	148,760	208,551	360,946
MT40X_TOU | Partial Peak		23,713,754	287,298	-	7.16	828.33	-	169,750	237,978	407,728
MT40X_TOU | Off Peak		24,155,244	292,647	-	2.57	297.50	-	62,102	87,063	149,165
MT50 | Block: 1 | 0 and plus kWh/month	59	66,945,433	228,684	12,000.00	6.50	2,315.96	8,449	435,440	529,623	973,512
MT50_TOU | Peak	63	18,467,470	171,271	12,000.00	8.84	1,023.47	9,090	163,338	175,290	347,718
MT50_TOU | Partial Peak		25,157,229	233,313	-	8.22	950.95	-	206,740	221,868	428,608
MT50_TOU | Off Peak		29,255,438	271,320	-	2.95	341.54	-	86,348	92,667	179,015
MT50X_TOU | Peak	31	38,614,293	306,203	12,000.00	7.20	701.31	4,479	277,904	214,742	497,125
MT50X_TOU | Partial Peak		52,602,148	417,124	-	6.69	651.61	-	351,748	271,803	623,551
MT50X_TOU | Off Peak		61,171,239	485,075	-	2.40	234.03	-	146,913	113,523	260,436
MT70 | Block: 1 | 0 and plus kWh/month	11	134,510,454	327,729	12,000.00	4.95	2,141.35	1,610	666,061	701,781	1,369,452
MT70_TOU | Peak	13	45,573,668	333,961	12,000.00	6.24	946.31	1,901	284,360	316,029	602,290
MT70_TOU | Partial Peak		52,746,536	386,523	-	5.80	879.25	-	305,794	339,851	645,646
MT70_TOU | Off Peak		56,072,867	410,898	-	2.08	315.79	-	116,754	129,758	246,512
MT20O | Block: 1 | 0 - 100 kWh/month	2	2,400		1,074.01	20.08		26	48	-	74
MT20O | Block: 2 | 100 - 1681 kWh/month		37,940		1,074.01	20.08		-	762	-	762
MT20O | Block: 3 | 1681 and plus kWh/month		32,754,556		1,074.01	20.08		-	657,665	-	657,665
Electric Vehicles		124,558			26.17			3,260		3,260
MT60 | Block: 1 | 0 and plus kWh/month	546	40,365,910	111,364	-	12.01	4,539.07	-	484,627	505,490	990,117
TOTAL	**708,307**	**3,267,807,839**	**10,289,219**				**8,196,491**	**47,050,216**	**11,179,666**	**66,426,372**

15.4.18 Distributed Energy Resource Tariff (DER)

As the power sector continues to evolve, there is an increased presence of distributed generation. This represents a shift from the traditional model of large centralized generation plants, owned and operated by utility companies. The result of which is network migration. Despite the continued change in the generation segment of the industry, the transmission and distribution business has been left largely unchanged, especially in small island economies. The self-generator still has to interconnect to the T&D network for standby or back-up purposes, while centralized generation assets, included IPPs are called upon to serve the load of a self-generator at any given moment in time, and in some instances dependent on the size of the load – may have to be planned in advance.

Utilities world-wide are contending with this shift in the power market and the system related cost associated in maintaining sufficient capacity, reliability, and security. Jamaica is also experiencing this shift. Precedent established in various other jurisdictions, by utilities and regulators alike dictates a response through an appropriate rate design. Failure to do so will see customers who utilize on-site generation being subsidized by other customers who are least able to afford an alternative.

JPS proposes the implementation of the Distributed Energy Resource tariff for all customers with on-site generation - across all rate classes. The DER rate will replace existing Standby rates as they will no longer be applicable. All existing net-billing customers will be transitioned to DER. The DER rate is intended to recover demand and capacity related cost previously energized cost under the existing tariff structure. These costs are allocated throughout the rate design process described in Cost of Service chapter of this rate application.

The proposed DER tariff will consist of three time-of-use demand components as follows and is applicable regardless of the type of generation technology used by the customer:

- Peak demand charge
- Base demand charge
- Reliability capacity charge

The Peak-demand charge will be billed based on the maximum actual registered kVA for the month during the defined Peak TOU periods. Based demand charges will be billed on the customer's maximum actual registered kVA for all other hours not considered on-peak. If the customer does not take power from the grid at any given month, these charges will not be applied.

The reliability capacity charge will be billed based on the customer's maximum registered kVA, regardless of time of day. This component will be adjusted by a 12-month ratchet, and is intended to recover reserve generation capacity, transmission and distribution cost. This charge is applicable regardless of consumption from the grid in any given month.

JPS proposes the DER rate structure as seen in Table 15-33 in keeping with its Long Run Marginal Cost of Service Study, the results of which shows an approximate 95 – 98% fixed charge ratio and speaks to the significant investments in both transmission and distribution networks. The resultant variable/energy is predictable low.

Table 15-33: Proposed DER Rate Structure

Rate	Energy Charge J$/kWh	Customer Charge J$/month	Peak J$/kVA	Base J$/kVA	Reliability Capacity J$/kVA
DER 10 (LV)	0.43	853.74	1,539.96	1,443.44	2,367.13
DER 20 (LV)	0.59	1,488.71	2,038.20	1,910.44	3,061.43
DER 40 (LV)	0.45	12,000.00	880.39	825.41	1,419.87
DER 50 (MV)	0.44	12,000.00	1,242.53	1,200.54	2,103.72
DER 70 (MV)	0.39	12,000.00	774.10	842.96	2,362.20

15.4.19 Electric Power Wheeling

At the request of the OUR, JPS submitted a proposed Power Wheeling Regulatory Framework & Code, its position on a Use of System Charge, and a Draft Power Wheeling Contract in September 2018. These have also been recently published as part of the OUR's *Power Wheeling Tariff Methodology Consultation Document* on November 4th 2019. JPS maintains these positions and await further engagement with the OUR and other stakeholders within the power sector. The proposals were exhaustive and provides intricate details of the technical, commercial, and regulatory requirements that must be considered for the successful implementation of power wheeling in Jamaica.

The tariff mechanism is also reiterated in section 4.2.3 in the Tariff Structure Report attached as an annex to this Rate Application. Full cost allocation is conducted during the tariff design process for all rate classes - for which all tariffs are calculated and defined. Therefore, the Use of System Charge for any particular user, in this case, a Wheeler, will be computed in all cases using the applicable tariff approved by the OUR in JPS' rate schedule, less any defined avoidable cost. This is expressed as follows:

$$WC = FixedNC + VarNC + FECost + VECost\ (\delta^{T} + \ \delta^{NC})$$

where:

WC = *Monthly Wheeling Access Charge/Use of System Charge*
FixedNC = *Network Cost*
VarNC = *Variable Network Costs*
FECost = *Fixed Energy Costs*
VECost = *Variable Energy Costs*
δ^{T} = *Determined Technical Loss Factor*
δ^{NC} = *Non-controllable Loss Factor*

Following this methodology, JPS proposed Wheeling tariffs as seen in the table below. Wheeling charges will be adjusted monthly as per the prevailing fuel rate per the respective rate class.

Table 15-34: Non-Fuel Wheeling Charges per Rate Class

	Non- Fuel wheeling charges			Wheeling Fuel Charge [J$/kWh]
	Energy [J$/kWh]	Customer [J$/Month]	Demand [J$/kVA]	
RT 40 Wheeling	5.77	12,000.00	2,442.50	5.78
RT 50 Wheeling	6.50	12,000.00	2,315.96	5.78
RT 70 Wheeling	3.71	12,000.00	2,272.20	5.78

16 Decommissioning Cost

This chapter will lay out JPS' case for the reimbursement of decommissioning costs incurred in relation to steam generation plants that will be taken out of production during the next Rate Review period. Costs include plant dismantling, site restoration, redundancy and recovery of stranded investments in fixed assets. Much of the chapter will be an update of the information presented in the 2014 filing and should take account of the 2018 Annual Review Determination which permitted the recovery of accelerated depreciation costs related to the steam plants to be decommissioned.

16.1 Introduction

The completion of construction on the South Jamaica Power Company (SJPC) 194MW natural gas fired combined cycle power plant at OH is imminent, with a revised commercial operations date of December 2019. JPS has also executed a Power Purchase Agreement (PPA) with New Fortress Energy for the supply of 94 MW of power to the electric grid projected to commence in March 2020. These events bring the planned decommissioning of JPS' fleet of steam generation power plants sharply into focus as their displacement is marked by the completion of these projects. The construction of the 194MW gas fired power plant is the direct consequence of a sequence of activities that resulted in the Electricity Sector Enterprise Team granting approval to JPS on March 10, 2015 for the exercise of its right of first refusal (ROFR) for replacing generation capacity owned by the Company. This right is referred to in section 20(3) and 20(4) of the Electricity Act of 2015.

JPS supplies power to the electric grid from 626MW of generating capacity. Over 55% of this capacity was commissioned between 1967 and 1973, comprising 292 MW of steam powered generation plants at Old Harbour (OH) and Hunts Bay (HB) and 54MW of gas turbines also at HB, with a further 18% becoming operational between 1985 and 1992 comprising 40 MW of slow speed diesel at Rockfort and 73.5MW of gas turbine generation at Bogue. The remaining capacity was installed after the year 2000 mainly at Bogue.

These plants have operated well beyond their initial assigned useful lives, with major components approaching end of life. Advanced deterioration has been identified in certain structural components of some plants indicating that the risk of catastrophic failure could arise in the near to medium-term, failing major interventions. As the manufacturing of many of these plant models have been discontinued by original equipment manufacturers (OEMs) long ago, maintenance of the plants are bespoke engineering endeavors requiring great effort in planning and procurement of maintenance services. Critically, most of the generating plants commissioned during the period up to 1992 are technologically uncompetitive and generally rank very low in the dispatch merit order and are simply not suited for generating low-cost power. In instances, their heat conversion rates are twice as much as newer technology currently available, whose heat rates approximate 7,500 kJ/kWh.

In order to address this concern and to improve the cost efficiency of the generation function in the long run, JPS has made submissions to the Ministry of Energy (MOE) for the retirement and decommissioning of 473.5MW of generation capacity. Of this total, the replacement of 292MW of steam generation classified as Phase I was approved previously by the MOE and will be implemented during 2019 and 2020. Phase II, comprising the retirement of 40MW of slow speed diesel and 141.5 MW of gas turbine generation is slated to be implemented during year 2023, pending validation in the IRP and approval by the MSET operating in its capacity as System Planner. In addition, JPS had expressed its intention to exercise its Right of First Refusal (ROFR) to replace GT8's 14MW capacity (installed at Bogue power plant) and received a formal letter of notification from the Ministry of Energy on January 18, 2019, approving this action. This 14MW capacity will be replaced by 2021 however the physical removal (decommissioning) of the GT8 would be most economically beneficial to our customers to be done in 2023 along with other peaking units scheduled for removal at Bogue, reflecting the economies of scale.

Decommissioning activities are initiated after the retirement of an asset and refers to the process of dismantling the materials, equipment and structures comprising the asset, performing necessary environmental remediation and the restoration of the site. Decommissioning costs comprise three main components; i) demolition and site remediation, ii) staff separation, and iii) recovery of stranded asset costs. In response to requests made by JPS in its Annual Review Filing in 2018, the OUR approved the recovery of accelerated depreciation costs relating to the OH and HB steam generation plants in the amount of US$9.2M. The OUR agreed that no consideration would be taken of the residual scrap value of both plants in arriving at this decision. JPS proposes that the estimates of decommissioning costs presented in this rate review filing be adjusted by the actual scrap value derived from the disposal of the plant components. The OUR also approved US$2.3M related to the cost of separating staff currently engaged at the OH plant, which represents 50% of the total staff separation costs related to that location. The remaining 50% of staff separation costs relating to OH, in addition to the full cost relating to HB and Rockfort will be presented for recovery in this submission. Taking the OUR's approvals into account, JPS will include in this submission costs related to the three components for both phases of the decommissioning exercise.

JPS engaged Consultants, CL Environmental Company Limited, a Jamaican entity, who contracted Plan D Global, a Korean entity specializing in demolition engineering and possessing significant decommissioning expertise having executed over thirty three (33) such exercise worldwide, to develop a comprehensive decommissioning strategy along with updated cost estimates for both phases of the decommissioning exercise. While JPS provided a detailed decommissioning report for Phase I as a part of its 2014 rate review filing, those costs were model estimates and have changed significantly over the five-year period. JPS also wants to take the added precaution of engaging experienced professionals to assist the company in generating estimates that are comprehensive and have a high probability of being more representative of actual costs. This step is expected to assist in minimizing the possibility of having to propose significant revisions to the business plan as a result of cost omissions or other blatant errors after submission.

As an illustration, when the costs estimated for Phase I in 2014 are updated for necessary investments to maintain the operation of affected plants up to retirement and the approval of associated accelerated depreciation costs recovery in the 2018 annual review determination, the costs anticipated for recovery in the 2019 rate review filing is approximately $46.27M up from the US$20M estimated in 2014. The analysis of the 2019 costs are as follows:

1. Plant demolition and site remediation US$20.3M
2. Staff separation costs US$5.33M
3. Recovery of stranded assets, primarily consisting of incremental expenditure in 2018 and 2019 to keep plants running and stranded inventory associated with these plants - US$20.5M

The decommissioning cost for Phase II approximate $35M. Some of the costs affecting this may be impacted by the results of the IRP and so any delay in its finalization could affect the estimates presented in this filing. The costs are analyzed as follows:

Demolition and site remediation - US$10.9M

- Staff separation cost - US$3.05M
- Incremental depreciation, stranded assets and stranded inventory at 2023 - US$21M.
- Further details of these costs are broken down in table 16-1 below.

The total estimated decommissioning cost, net of scrap values, projected to be incurred in the 2019 to 2023 rate review period is US$81.28M. This chapter lays out the justification for the recovery of these costs to JPS. Given the materiality of the costs and the fact that this is the first time such an exercise is being conducted in the electricity sector in Jamaica, JPS took appropriate steps to ensure that tried and proven methodologies were considered and recommended best practices selected for the execution of the exercise. The company was also keen to ensure that the cost estimation methodologies were as robust and realistic as currently available information permitted given uncertainties around the timing such costs would actually be incurred, the impact of the IRP on Phase II of the exercise and the effect of market forces on labour and equipment costs and scrap values. The ensuing sections outline:

The Minister's Retirement Schedule;

- a summarized description of the decommissioning strategy;
- a description of contamination identified or anticipated at various sites and the associated environmental clean-up and monitoring requirements;
- timetables for the operation of the decommissioning exercises at the various sites; a summary of the cost estimates;
- proposal for cost recovery;
- the implementation plan;
- a proposal for the regulatory treatment of decommissioning costs in the future.

In essence, JPS' presentation not only lays out the cost estimate and the recovery proposal but presents the framework within which these proposals are generated. The detailed report from the Consultants advising on the execution of the exercise is presented at Annex of the Rate Case Filing.

The scope of works for demolition activity and various work approaches in bringing these plants to "Brown field" condition are outlined in the JPS Demolition and Closure Plan for phase I and II and a full description of work packages and work approaches can be examined in the Demolition and Closure Plan document – Annex I. The Plan goes on to outline in detail the activities that will achieve total demolition of the relevant plants. These high level descriptions are broken down into work packages on Demolition and Closure Plan document – Annex I.

16.2 Retirement Schedule

JPS proposes that the decommissioning exercise be carried out in two phases to minimize disruption to operations and ensure reliability of supply during the transitional period, as follows.

- Phase 1 comprises the decommissioning of 292MW of steam generation capacity operated by JPS at Old Harbor and HB. The replacement generating capacity will be provided by combined cycle gas turbine technology and the plant is already under construction and is expected to be completed prior to the scheduled decommissioning dates.
- Phase 2 comprises the decommissioning of 171.5 MW of slow speed diesel (40 MW at Rockfort) and gas turbine (131.5 MW) generating capacity located at Bogue and HB. This phase will be validated by the IRP currently being finalized by the MOE and research is currently ongoing in relation to the technology that will be used to replace these plants. Phase 2 will also include the decommissioning of GT8 (18MW) at Bogue.

Table 16-1: The Minister's Schedule

Single Buyer's Generation Sets		Installed Capacity (MW)	Commercial Operations Date	Letter of Notification	Minister's Retirement Deadline Year	Comments
Old Harbour 1	OH 1	30	1967	2008	2008	These five (5) plants add up to 292MW which should have been replaced in or around 2010. Through the Electricity Sector Enterprise Team, a Right of First Refusal (ROFR) in 2016 was granted for 190MW of the 292MW, via JPS' subsidiary, South Jamaica Power Company. The remaining 102MW may be available for ROFR depending on the results from subsequent Integrated Resource Plans.
Old Harbour 2	OH 2	60	1968	2016	2019	
Old Harbour 3	OH 3	65	1971	2016	2019	
Old Harbour 4	OH 4	68.5	1972	2016	2019	
Hunts Bay 6	HB 6	68.5	1976	2016	2020	
Bogue 8	GT 8	14	1992	2018	2020	ROFR - Letter of Notification Issued in August 2018
Hunts Bay 5	GT 5	21.5	1973	2019	2023	
Hunts Bay 10	GT 10	32.5	1993	2019	2023	
Rockfort 1	RF 1	20	1985	2019	2023	
Rockfort 2	RF 2	20	1985	2019	2023	
Bogue 6	GT 6	18	1990	2019	2023	
Bogue 7	GT 7	18	1990	2019	2023	
Bogue 9	GT 9	20	1992	2019	2023	
Bogue 3	GT 3	21.5	1972	2019	2023	171.5MW may be available for ROFR in 2019
Bogue 11	GT 11	20	2001	2032	2036	134MW may be available for ROFR in 2032
Bogue 12	GT 12	38	2003	2032	2036	
Bogue 13	GT 13	38	2003	2032	2036	
Bogue 14	ST 14	38	2003	2032	2036	
(Remainder of the 292MW)		102	n/a	2039	2043	102MW is the remainder of the 292MW (OH 1, OH2, OH3, OH 4 & B6) which should have been replaced approximately 8 years ago.

With respect to Phase 1, JPS has executed separate power purchase agreements (PPA) with South Jamaica Power Company Limited (SJPC) and Jamalco/New Fortress Energy (NFE) to supply power from combined cycle power generating plants projected to complete in December 2019 and March 2020, respectively, consequent on mandates issued by the Generation Procurement Entity and its predecessor, the Electricity Sector Enterprise Team, in 2015 and 2017, respectively. When both plants are completed, existing steam powered generation plants operated by JPS will be displaced and retired from the schedule of active generation plants. The cost of operating these steam generation plants are not considered economically feasible or operationally justifiable in the medium to long term. Additionally, current load growth forecasts in the medium term do not support maintaining these generation resources alongside the SJPC and NFE facilities.

Therefore, OH plant is expected to fully retire December 31st 2019 after the commercial operating date (COD) of the SJPC 194MW plant with the expectation that the plant will commence decommissioning works January 2021. Similar activities at HB are expected to commence within nine (9) months of the March 2020 COD of the Jamalco plant and the plant is expected to be fully retired by December 2020 and decommissioning works commence in 2022.

Based on the economic life of the electricity generating assets in Phase II (GT3,6,7,8 and 9) located at Bogue as well as HB (GT5 and 10), JPS had submitted a proposed retirement plan for these assets. The Company anticipated MSET's approval and notification for their planned retirement within the rate review period and as such engaged contractors for a decommissioning study to prudently determine the costs associated with this undertaking for the OUR's consideration. JPS is now in receipt of the Minister's Retirement Schedule, presented in Table 16-1, which clearly outlines the retirement schedule for these units and substantially confirms what JPS had presented. To allow proper planning to prepare for the disposal of these assets-which according to the Minister's Schedule- will come into effect in this rate review period, JPS requests that provisions be made even while we anticipate a directive from the Minister by means of the IRP for the technology that will replace them.

16.3 Decommissioning Strategy

The extent to which the decommissioning process is implemented may range from a baseline demarcated by legal requirements to a highpoint defined by the purpose for which the site is intended post decommissioning. Environmental regulations will define remediation necessary to meet air, groundwater and soil remediation standards. Given its plan to repower the decommissioning sites, JPS' objective is to restore the sites to "brownfield" conditions suitable for industrial applications. Brownfield means that the site may have the presence or potential presence of hazardous substances, pollutants or contaminants; however, remediation must meet environmental standards. The decommissioning strategy for each site will follow a basic framework while the actual sequencing of activities will understandably be unique to each location based on the type of plant being decommissioned and the method of deconstruction required. The environmental remediation and site restoration strategy will be largely the same for all locations except Rockfort, due to their similarity in environmental and geological characteristics and the intended post decommissioning use. Given its construct as a barge, and the ongoing direct threat to marine life, the Rockfort plant does not have significant scope for accommodating potential contamination due to rigorous environmental requirements.

The decommissioning process is broken down into four key steps, as follows:

1. Strategic planning and preparation,
2. Engineering and activity scheduling,
3. Project implementation, and
4. Project closure.

The scheduling of activities to be executed at each site will be developed as part of the engineering phase but activated only when transitioning of power supply to the new generating plant has been completed and efficient operation achieved, thereby signaling the redundancy of the retired plants. This coordinated period of operational overlap ensures continuity of reliable electricity supply and while scheduled for a fixed period will vary with the timeline within which operational efficiency is achieved at the new plant, at which time the decommissioning schedule can be finalized.

Step I: Strategic Planning and Preparation

The strategic planning aspect consists of the identification of plants for decommissioning and the development of suitable replacement generation to ensure continuity of supply to the grid. This phase will also include the procurement of relevant approvals for the development of suitable replacement plants. In relation to OH and HB these procedures have already been completed and were discussed in full in the introductory section to this chapter.

Preparation includes the physical inspection of the site and the gathering of historical information that may be relevant to the decommissioning exercise. The review of the schematic diagrams showing the layout of the plants, historical environmental monitoring records related to the site, and further investigations of the occurrence of environmental contamination are all part of this phase. JPS has mobilized this information and shared it with its consultants to assist with the development of the scope of works required to effect the decommissioning exercise.

A Request for Proposal was sent out to several international and local industry professionals in January 2018 for a Decommissioning Study to prudently determine the costs and steps to be taken to safely and efficiently decommission JPS power plants scheduled for retirement within the rate review period. The final report for this study was completed at the end of May 2019 at a cost of just under US$302,000. The decommissioning cost estimates by plant as per the study is shown in Table 16-14.

Step II - Engineering and Activity Scheduling

The second phase, which, is essentially the project planning phase consists of the identification of the various segments of the decommissioning exercise and scheduling them in the decommissioning plan for each plant. This exercise captures the broad framework for assessing environmental impacts and a plan for the development of suitable mitigation strategies to satisfy regulatory requirements, launching the decommissioning study, developing the engineering scope of works and the estimation of costs relating to each work segment. The estimation of costs may be generated from desktop models initially but must eventually be supported by actual market estimates obtained through requests for quotation or information from the market. JPS' initial decommissioning costs submission in 2014 was a desktop analysis using recommended estimation models.

This phase of the planning was completed and was primarily executed with the help of consultants, CL Environment Company Limited operating in collaboration with Plan D Global, hired by JPS to develop a decommissioning plan, which includes costing for the respective planned decommissioning sites. The consultants also developed individual closure plans for each site. The closure plans meet specific requirements of the Natural Resources Conservation Authority (NRCA), the environmental regulatory body in Jamaica, and are a part of the requirements necessary to obtain approvals for the implementation of decommissioning activities.

The decommissioning plan outlines the general process that will be used to execute decommissioning activities, provides a schedule of such activities with detailed descriptions of each activity that will be executed in each phase and segment of the decommissioning exercise and has as a subcomponent site specific closure plans. The closure plans include scheduled environmental monitoring procedures commencing several months before the physical decommissioning exercise is initiated and continuing well after completion, procedures for addressing necessary environmental remediation, recognizes health and safety requirements and regulatory requirements impacting the exercise. In relation to demolition and deconstruction activities, engineering estimates were developed for the volume of material and cost of various operations that will be required to decommission the specified plants. Engineering operations include the use of equipment such as cranes, wrecking balls, crushers and saws in the process of dismantling or demolishing various structures.

One of the most important components of this phase is the development of a comprehensive communication plan addressing all relevant stakeholders. The most important constituents will be employees, relevant regulatory bodies, the execution team and residents of the community in which the plants are located.

Step III – The project implementation phase will commence with the procurement of services for the execution of the decommissioning activities. This will include both the environmental monitoring, potential remediation and dismantling activities. Critical to the process will be securing the decommissioning site, mobilization of safety procedures, procurement of necessary equipment for deconstruction activities, securing salvage and the orderly management of waste removal and disposal. Given information already available, special provisions will have to be made for asbestos removal, and potential underground environmental remediation from oil or other chemical contamination.

Step IV – Project closure consists of the disposal of scrap metals garnered from the dismantlement of the plants, the implementation of grading and restoration activities and closure of the decommissioning process.

16.4 Environmental Cleanup

The Demolition and Closure Plan developed by CL Environmental provides a detailed description of each decommissioning site. The description comprises the location, area, current use, specification of each generating plant, an inventory and description of the structures and facilities, and inventories of chemicals and hazardous waste located at each site. With respect to hazardous waste, the report details the storage type, location, containment, quantity, period of generation, disposal method, fire prevention measures where applicable and risk category. These waste items include ammonium hydroxide, oil, sludge, and asbestos at OH and HB. All items are contained and considered to present a low to medium risk to the environment. The report describes the physical features of each site including the geology, hydrogeology and soils present, groundwater, climatology and meteorology where weather systems are installed, topography and water quality for each location. The biological environment around each site is described and the major sensitive faunal groups identified. It also details the findings of historical soil and water quality tests conducted at each site.

With the exception of soil contamination identified at the OH location in 2015, there are no indications at the other sites. The contamination identified at OH was completely remediated by the removal and safe disposal of affected soils which was replaced as considered necessary by appropriate fill material. Resulting from this experience and having cognizance of the exposures related to each site, as part of the closure parameters, soil analyses proposed for testing include RCRA 8 materials, iron, and vanadium and petroleum hydrocarbons. Soils tests conducted at OH in February 2017 did not indicate any contamination.

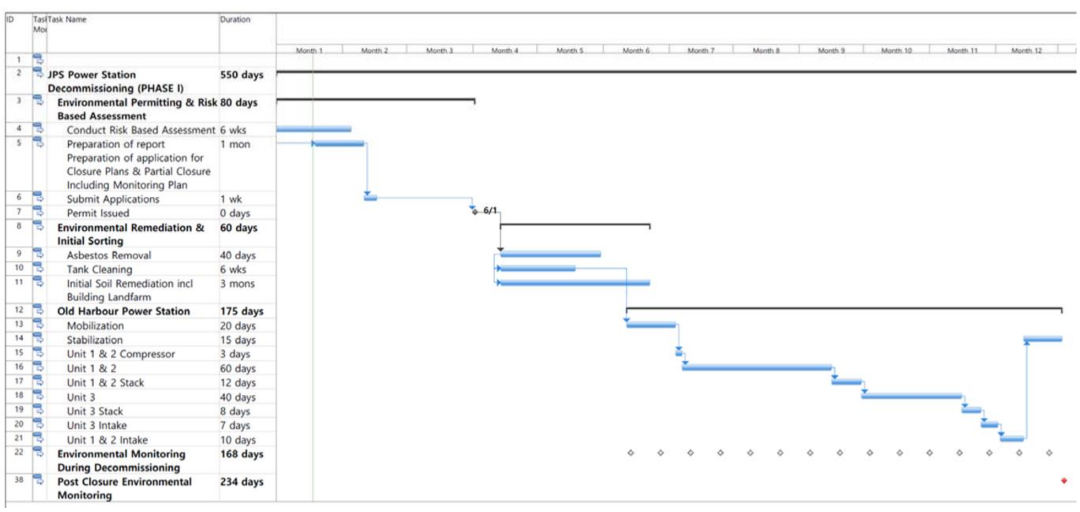
With respect to Asbestos Containing Material (ACM), NEPA has guidelines for its disposal and this is handled by the National Solid Waste Management Authority (NSWMA) within a designated cell of their disposal facility. The report also provides guidance for the disposal of such material outside of Jamaica if necessary. JPS currently disposes of polychlorinated biphenols (PCBs) overseas. With respect to other hazardous wastes, appropriate management and disposal procedures are detailed in the Demolition and Closure Plan – Annex I. The Plan details a risk assessment for the decommissioning process with the outcome that all risks were assessed as moderate or low, with the exception of adherence to safety and oil spill prevention procedures, which were determined to have a high risk. Risk mitigation measures to treat with these areas of potential risk were outlined in the report. The Plan details the planned decommissioning schedules and outlines an extensive environmental monitoring plan commencing before decommissioning activities are initiated, continuing through the exercise and extending well after completion to identify and remediate any potential contamination. The main areas identified for post closure monitoring are groundwater and asbestos monitoring.

Importantly, the Plan estimates the cost of remediating contamination at each plant site assuming 40% contamination of the soils comprising the footprint of each generating unit to a depth of 5 meters. The presence of contamination and resultant potential cost of cleanup depends on the extent of the remediation needs. The estimates are developed based on surface level inspection and prior experience in other locations and do not bear relation to the detailed findings at the respective sites. As the extent of contamination is unknown it is difficult to place a firm estimate on the cost of potential remediation. The full Plan for each site is provided in the Decommissioning Study.

16.5 Timetable

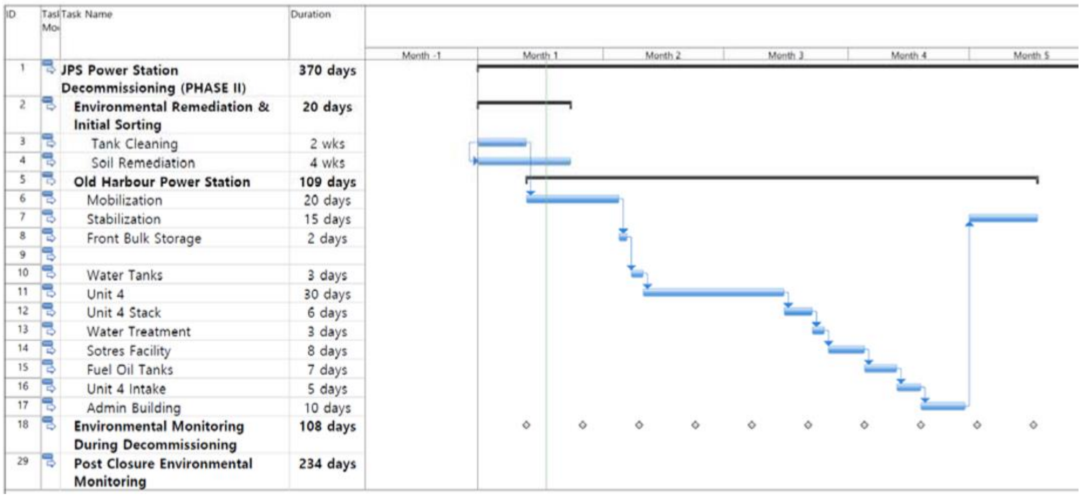
Phase I of the decommissioning exercise will comprise all the plants located at OH and the B6 unit at HB. Units 1, 2, and 3 at OH will be retired in 2019 with the exercise projected to commence in March 2020on the initiation of the compilation of the risk-based assessment. On completion, a report will be generated and submitted to NEPA to facilitate the issuance of a permit to activate the decommissioning exercise. The risk-based assessment and permitting segment of the exercise will take approximately 80 days and will be completed in June 2020 to facilitate the preparation for application for permits to NEPA. Environmental remediation and initial sorting is expected to commence in January of 2021 which will run for approximately 60 days. Approximately, 50 days into this process the deconstruction and demolition activities will commence and continue for approximately 175 days. This means that approximately 225 days into 2021 the deconstruction exercise will be completed. Post closure monitoring will continue for an additional 234 days after these activities will have been completed. The detailed decommissioning exercise is presented in Table 16-2.

Table 16-2: OH - Units 1, 2 & 3.



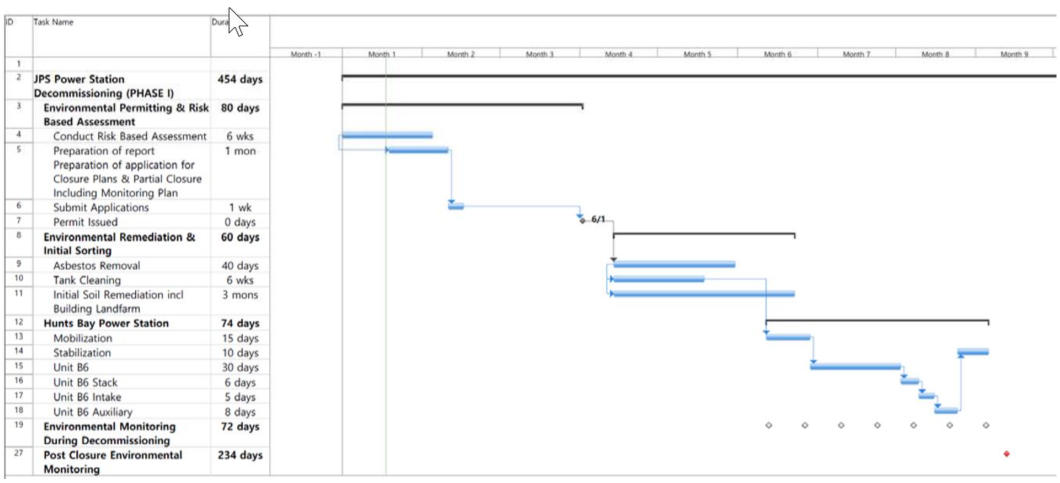
This process will be repeated in September of 2021 to facilitate the decommissioning of the Unit 4 at OH and January 2021 for HB B6. Table 16-3 and 16-4 present the details of the activities involved.

Table 16-3: OH - Unit 4



ID	Task Mode	Task Name	Duration
1		**JPS Power Station Decommissioning (PHASE II)**	**370 days**
2		**Environmental Remediation & Initial Sorting**	**20 days**
3		Tank Cleaning	2 wks
4		Soil Remediation	4 wks
5		**Old Harbour Power Station**	**109 days**
6		Mobilization	20 days
7		Stabilization	15 days
8		Front Bulk Storage	2 days
9			
10		Water Tanks	3 days
11		Unit 4	30 days
12		Unit 4 Stack	6 days
13		Water Treatment	3 days
14		Sotres Facility	8 days
15		Fuel Oil Tanks	7 days
16		Unit 4 Intake	5 days
17		Admin Building	10 days
18		**Environmental Monitoring During Decommissioning**	**108 days**
29		**Post Closure Environmental Monitoring**	**234 days**

Table 16-4: HB – Unit B6

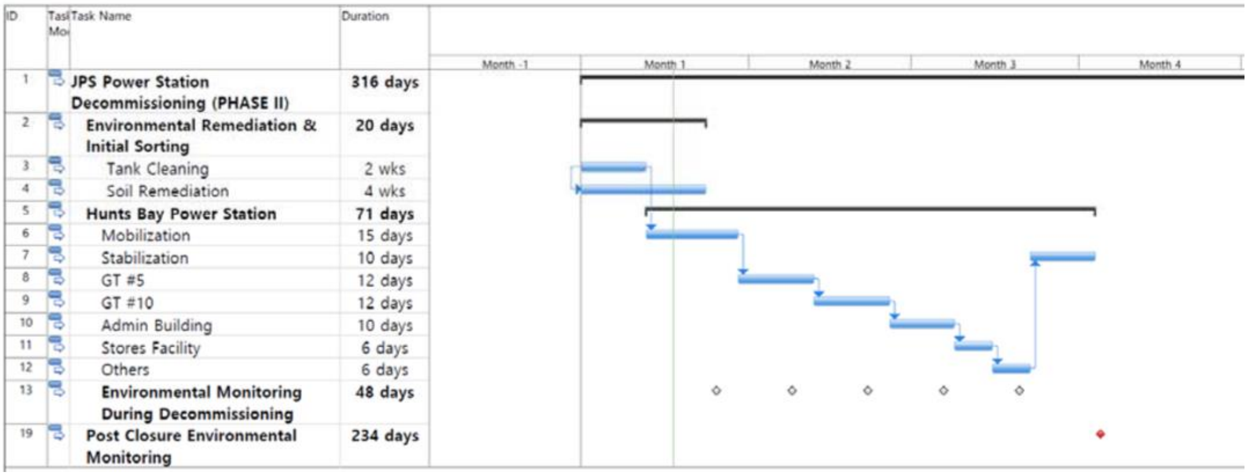


ID	Task Name	Dura
1		
2	**JPS Power Station Decommissioning (PHASE I)**	**454 days**
3	**Environmental Permitting & Risk Based Assessment**	**80 days**
4	Conduct Risk Based Assessment	6 wks
5	Preparation of report Preparation of application for Closure Plans & Partial Closure Including Monitoring Plan	1 mon
6	Submit Applications	1 wk
7	Permit Issued	0 days
8	**Environmental Remediation & Initial Sorting**	**60 days**
9	Asbestos Removal	40 days
10	Tank Cleaning	6 wks
11	Initial Soil Remediation incl Building Landfarm	3 mons
12	**Hunts Bay Power Station**	**74 days**
13	Mobilization	15 days
14	Stabilization	10 days
15	Unit B6	30 days
16	Unit B6 Stack	6 days
17	Unit B6 Intake	5 days
18	Unit B6 Auxiliary	8 days
19	**Environmental Monitoring During Decommissioning**	**72 days**
27	**Post Closure Environmental Monitoring**	**234 days**

Phase II of the decommissioning exercise will commence in 2021 for plants that will be retired in December 2023. Tables 15-4 to 15-6 below outline the detailed schedule of activities comprised in the exercise for each plant. Depending on the number and type of plant at each location, the length of the exercise will range from 316 days for the gas turbines at HB to 472 days for the diesel plants at Rockfort. Physical deconstruction and demolition activities will range from 91 days at HB to 200 days at Rockfort with Bogue consuming 194 days.

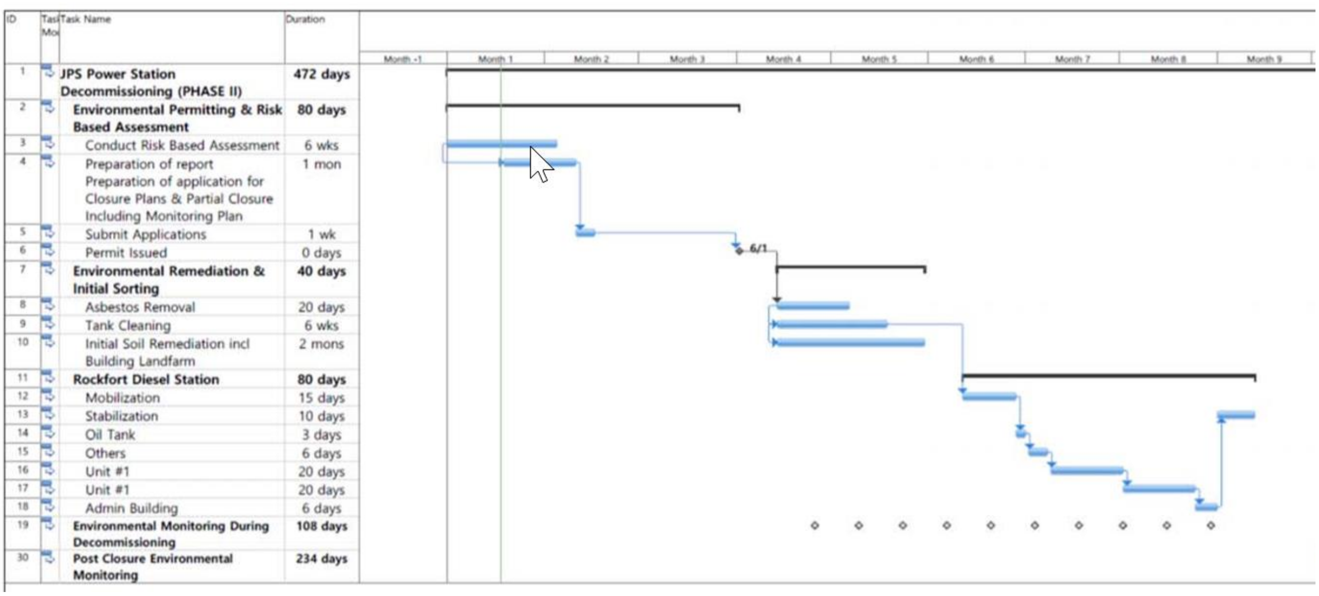
Table 16-7 provides comprehensive schedule of activities for Phase I (OH and HB plants). Table 16-8 provides similar comprehensive schedule of activities for Phase II, which includes OH, HB, and Bogue plants. These schedules indicate all the demolition required structures, equipment and objects. Further detail on the comprehensive schedules of tasks and activities can be found in the Decommissioning Study.

Table 16-5: HB - Units 5 & 10



ID	Task Mode	Task Name	Duration
1		**JPS Power Station Decommissioning (PHASE II)**	**316 days**
2		**Environmental Remediation & Initial Sorting**	**20 days**
3		Tank Cleaning	2 wks
4		Soil Remediation	4 wks
5		**Hunts Bay Power Station**	**71 days**
6		Mobilization	15 days
7		Stabilization	10 days
8		GT #5	12 days
9		GT #10	12 days
10		Admin Building	10 days
11		Stores Facility	6 days
12		Others	6 days
13		**Environmental Monitoring During Decommissioning**	**48 days**
19		**Post Closure Environmental Monitoring**	**234 days**

Table 16-6: Rockfort - Units 1 & 2



ID	Task Mode	Task Name	Duration
1		**JPS Power Station Decommissioning (PHASE II)**	**472 days**
2		**Environmental Permitting & Risk Based Assessment**	**80 days**
3		Conduct Risk Based Assessment	6 wks
4		Preparation of report Preparation of application for Closure Plans & Partial Closure Including Monitoring Plan	1 mon
5		Submit Applications	1 wk
6		Permit Issued	0 days
7		**Environmental Remediation & Initial Sorting**	**40 days**
8		Asbestos Removal	20 days
9		Tank Cleaning	6 wks
10		Initial Soil Remediation incl Building Landfarm	2 mons
11		**Rockfort Diesel Station**	**80 days**
12		Mobilization	15 days
13		Stabilization	10 days
14		Oil Tank	3 days
15		Others	6 days
16		Unit #1	20 days
17		Unit #1	20 days
18		Admin Building	6 days
19		**Environmental Monitoring During Decommissioning**	**108 days**
30		**Post Closure Environmental Monitoring**	**234 days**

Table 16-7: Bogue - Units 3, 6, 7, 8 & 9

ID	Task Mode	Task Name	Duration
1		**JPS Power Station Decommissioning (PHASE II)**	**454 days**
2		**Environmental Permitting & Risk Based Assessment**	**80 days**
3		Conduct Risk Based Assessment	6 wks
4		Preparation of report Preparation of application for Closure Plans & Partial Closure Including Monitoring Plan	1 mon
5		Submit Applications	1 wk
6		Permit Issued	0 days
7		**Environmental Remediation & Initial Sorting**	**40 days**
8		Asbestos Removal	20 days
9		Tank Cleaning	6 wks
10		Initial Soil Remediation incl Building Landfarm	2 mons
11		**Bogue Power Station**	**74 days**
12		Mobilization	15 days
13		Stabilization	5 days
14		GT #3	14 days
15		GT #6	10 days
16		GT #7	10 days
17		GT #8	10 days
18		GT #9	10 days
19		**Environmental Monitoring During Decommissioning**	**60 days**
26		**Post Closure Environmental Monitoring**	**234 days**

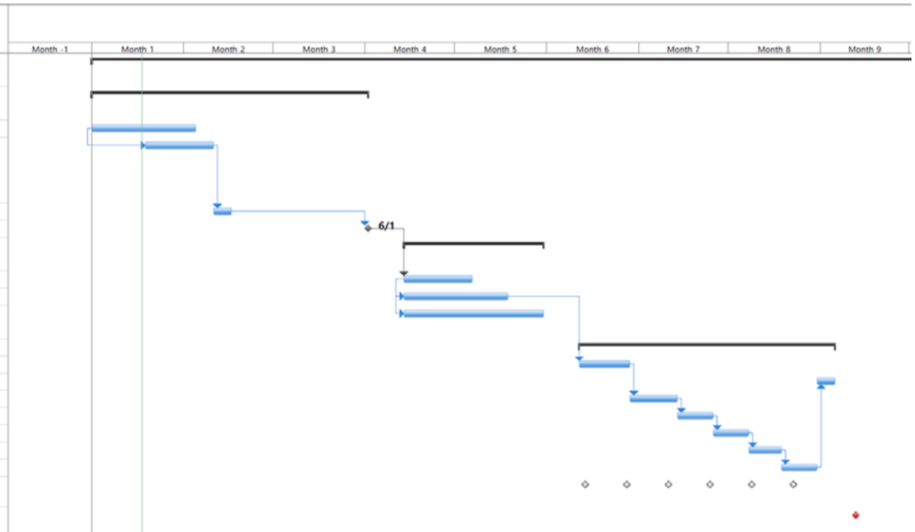


Table 16-8: Demolition Schedule Phase I

PHASE I

Task Name	Duration
JPS Power Station Decommissioning (PHASE I)	**280 days**
Old Harbour Power Station	**280 days**
Mobilization	20 days
Stabilization	20 days
Unit 1 & 2 Compressor	4 days
Unit 1 & 2	80 days
Unit 1 & 2 Stack	16 days
Unit 1 & 2 Intake	10 days
Unit 3	40 days
Unit 3 Stack	8 days
Unit 3 Intake	7 days
Unit 4	40 days
Unit 4 Stack	8 days
Unit 4 Intake	7 days
Front Bulk Storage	3 days
Water Tanks	4 days
Water Treatment	3 days
Stores Facility	8 days
Fuel Oil Tanks	8 days
Admin Building	12 days
Hunts Bay Power Station	**105 days**
Mobilization	20 days
Stabilization	20 days
Unit B6	40 days
Unit B6 Stack	8 days
Unit B6 Intake	7 days
Unit B6 Auxiliary	10 days

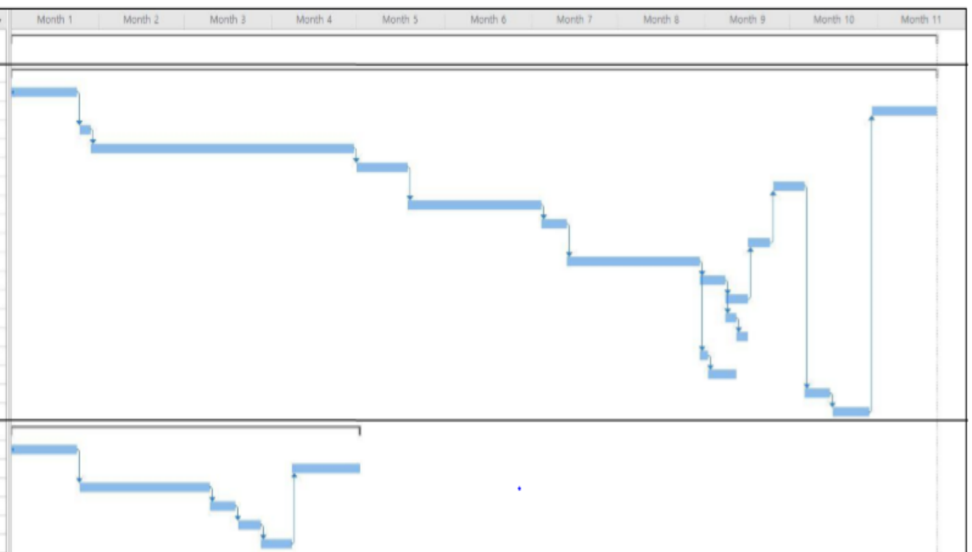
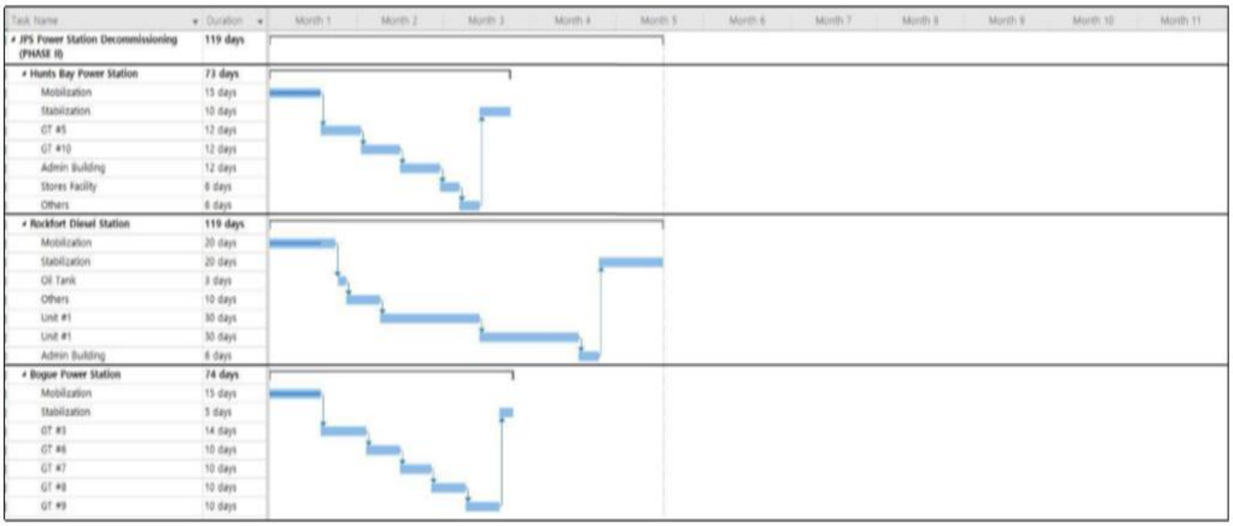


Table 16-9: Demolition Schedule Phase II

PHASE II



Further details can be found in Appendix C of the Decommissioning and Closure Plans.

16.6 Decommissioning Cost Estimate

Decommissioning costs comprise three main components, namely:

i) demolition and site remediation,
ii) staff separation, and
iii) recovery of stranded asset costs.

16.6.1 Demolition & Site Remediation Cost Estimate

JPS' consultants, CL Environment Company Limited and Plan D Global developed the cost estimates for the demolition and deconstruction component. The costing includes expenditure for extensive environmental site monitoring and estimates for site remediation costs based on the assumption that each site has 40% contamination of the soils comprising the footprint of each generating unit to a depth of 5 meters. Contamination costs are dependent on the extent of remediation required and may vary significantly based on requirements. The costing is therefore only indicative and will change based on detailed evaluation. The costing also outlines expenditure in respect of the disposal of hazardous material identified at each site, including asbestos, oil and sludge and ammonium hydroxide. The closure reports for each plant detail a list of hazardous material located at each site with comprehensive related material safety data sheets, providing suitable guidance on the safe handling of each substance. The details of the cost estimates are presented below.

Using a model predicated on studies of the physical plant location, conducted through site visits and the examination of schematic drawings showing the layout and major components of each generating plant to be decommissioned, Plan D Global, developed a quantities estimate of various types of material that will be decommissioned. The report, included in the Demolition and Closure Plan document, delineates the quantities and types of materials consisted in each major component of each generating plant, including the volume of concrete and various metals present in the construction. A schedule of engineering procedures appropriate for the demolition and dismantling of each material type was presented, with assignment to each major component. The necessary resource allocation required to complete the engineering procedures, including lifting equipment, tools, manpower, material and supplies including safety apparatus are assigned to each activity.

With respect to costs, the report considers labour rates, unit cost for certain demolition activities such as concrete crushing and separation, costs related to the acquisition of equipment including transportation, material and consumables, unit cost for dismantling different metal components, and waste management and disposal. In relation to methodology for demolition, the consultants considered the demolition work approach in the context of safety, effect on stakeholders, environment, effectiveness and economy. The salvage value for major subcomponents was also determined, as described in Appendix B of the Demolition and Closure plans.

Various demolition and deconstruction methods were also compared and the pros and cons outlined in the report along with the selection process for each method complete with a brief rationale for the selection. These factors were all taken into consideration in the model for estimating the cost of the decommissioning exercise. Tables 16-10 through 16-13 below summarizes the work approach, method selection considerations, method review and selection, and recommended decommissioning methods from the Consultant’s report. Table 16-14 captures an estimate of the decommissioning cost.

Table 16-10: Work Approach

Item	Approach	Remark
Method Selection	• Selection for feasible, Safe, Environment Friendly, and minimal public complaint method	
Public Complaint Minimizing	• Method to minimize public complaint while securing the efficiency and quality of the work	
Environment Friendly Method	• Demolition method with consideration of surroundings • Method to minimize waste generation and dust generation • Noise and vibration mitigating method	
Economical and Feasible Method	• Comparison and consideration of various demolition methods for economical and feasible plan • Review of stability of the method on predictable factors	

Table 16-11: Method Selection Considerations

Item	Details	Remark
Site Survey	• Site visit • Site condition survey • Structure & Equipment shapes and specification survey	
Safety	• Safety measures for work at height • Signal person and safety manager on job • Fire fighting measure	
Environmental Consideration	• Dust mitigation measure • Noise and Vibration mitigtion measure • Oil spill from equipments mitigation measure	
Cutting and Lifting	• Final cutting after wire holding • Worker falling prevention • Signal/Communication system in place for the final cutting and lifting work	

Table 16-12: Demolition Method Review and Selection

Method	Method and Equipment	Applied To
Crusher	• Fundamentals of the Method Hydraulic Crusher attachment on excavator presses or crushes concrete structure • Efficiency & Workability About 45~50m³ / day for concrete crushing Rebar cutting is required when doing crushing work • Characteristics · Noise and Vibration mitigation · Rebar cutting needed · Rebar removed after · Waste management is easier	· Concrete structure above Ground Level · Concrete Thickness (< 50cm)
Multi Crusher	• Fundamentals of the Method Hydraulic Crusher attachment on excavator presses or crushes concrete structure • Efficiency & Workability About 45~50m³ / day for concrete crushing Rebar is cut by multi crusher. -Rebar cutting is not required when doing crushing work • Characteristics · Noise and Vibration mitigation · Rebar cutting not needed · Waste management is easier	· Concrete structure above Ground Level · Foundation · Concrete Thickness (< 50cm)
Buster	• Fundamentals of the Method Applied on concrete retaining wall, foundation, girder, concrete wall. Insert busting element into drilled core and expand to break • Characteristics · No Vibration, No Noise, Almost No Dust · When Concrete foundation or retaining wall must be demolished without vibration and noise	· Foundation · Retaining Wall · Concrete Thickness (> 80cm)
Cutting + Lifting	• Fundamentals of the Method Lifting after cutting with wire saw or oxygen cutting • Characteristics · Most suitable for general demolition work at height · Fast and Simple · Requires crane mobilization/demobilization time	· Work at height where equipments cannot reach

Table 16-13: Recommended Decommissioning Methods

Power Station	Structure & Items	Roof	Column, Beam	Wall	Equipment	Foundation	Slab	Interior
OHPS & Hunts Bay B6	Turbine Building	Oxygen Cutting	Oxygen Cutting, Shear Cutter	Crusher, Multi Crusher	Oxygen Cutting, Shear Cutter	Breaker	Breaker, Crusher	Man Power
	Boiler	-	Oxygen Cutting, Shear Cutter	-	Oxygen Cutting, Shear Cutter	Breaker	-	-
	Stack	-	-	-	Oxygen Cutting, Shear Cutter	Breaker	-	-
	Office Building(OHPS)	Crusher, Multi Crusher	Crusher, Multi Crusher, Shear Cutter	Crusher, Multi Crusher	-	Breaker	Crusher, Multi Crusher	Man Power
	Storage Building	Crusher, Multi Crusher, Shear Cutter	Shear Cutter	Shear Cutter	-	Breaker	-	-
	Miscellaneous Building/Structure	Crusher, Multi Crusher, Shear Cutter	Shear Cutter	Crusher, Multi Crusher, Shear Cutter	Oxygen Cutting, Shear Cutter	Breaker	-	-
Rockfort	Stack	-	-	-	Oxygen Cutting	-	-	-
	Barge Body	Oxygen Cutting	Oxygen Cutting	Oxygen Cutting	-	-	-	-
	Equipment	Oxygen Cutting	-	-	Oxygen Cutting	-	-	-
	Office Building	Crusher, Multi Crusher	Crusher, Multi Crusher, Shear Cutter	Crusher, Multi Crusher	-	Breaker	-	Man Power
	Miscellaneous Building/Structure	Crusher, Multi Crusher, Shear Cutter	Crusher, Multi Crusher, Shear Cutter	Crusher, Multi Crusher	Crusher, Multi Crusher, Shear Cutter	Breaker	-	Man Power
Bogue & Hunts Bay GT	Gas Turbine	-	Shear Cutter	Shear Cutter	Oxygen Cutting, Shear Cutter	Breaker	-	-
	Office Building(HB)	Crusher, Multi Crusher, Shear Cutter	Shear Cutter	Shear Cutter	-	Breaker	Crusher, Multi Crusher	Man Power
	Miscellaneous Building/Structure	-	-	Shear Cutter	Oxygen Cutting, Shear Cutter	Breaker	-	-

Table 16-14: Decommissioning Cost Estimate

Decommissioning Costs (USD)						
Description	**Old Harbour**	**Hunts Bay (B6)**	**Hnts Bay GT10 & 5**	**Rockfort**	**Bogue**	**All Plants**
Decomissioning Works	6,814,213.00	1,400,239.00	714,749.00	4,716,746.00	779,129.00	14,425,076.00
Environmental Remediation	9,869,082.66	1,908,937.45	1,272,624.97	1,385,493.77	1,594,012.63	16,030,151.48
Project Management Costs	208,888.09	95,066.67		109,641.69	293,800.43	707,396.88
TOTAL	**16,892,183.75**	**3,404,243.12**	**1,987,373.97**	**6,211,881.46**	**2,666,942.06**	**31,162,624.36**
Phase I Total		**20,296,426.87**	**Phase II Total**		**10,866,197.49**	
Incremental Depreciation Stranded Asset Value	12,558,000.00	3,093,000.00	2,235,000.00	9,291,000.00	7,419,000.00	**34,596,000.00**
Phase I Total		**15,651,000.00**	**Phase II Total**		**18,945,000.00**	
Staff Seperation Cost (USD)	3,221,254.62	2,107,038.40	867,438.45	2,180,542.49	-	**8,376,273.96**
Phase I Total		**5,328,293.02**	**Phase II Total**		**3,047,980.94**	
Projected Value of stranded Inventory at Retirement	4,136,456.41	671,940.64	79,484.56	1,694,716.48	258,059.78	**6,840,657.87**
Phase I Total		**4,808,397.05**	**Phase II Total**		**2,032,260.82**	
Decommissioning Study	109,976.00	77,705.05		66,871.00	47,182.00	**301,734.05**
Phase I Total		**187,681.05**	**Phase II Total**		**114,053.00**	
Sub Total	**36,917,870.78**	**9,353,927.21**	**5,169,296.98**	**19,445,011.43**	**10,391,183.84**	**81,277,290.24**
Phase I Total		**46,271,797.99**	**Phase II Total**		**35,005,492.25**	
Grand Total (5 Yr.)	**81,277,290.24**					
Estimated Salvage Value (USD)	1,986,928.00	486,546.00	57,440.00	1,092,249.00	63,600.00	**3,686,763.00**
Phase I Total		**2,473,474.00**	**Phase II Total**		**1,213,289.00**	

*GCT not included

* Salvage value to be deducted from Decommissioning costs at the time of execution

The decommissioning cost estimate was developed using constant dollar values and does not assume inflation. Appropriate adjustments will therefore be made to reflect the inflationary effect during the periods of recovery. Given the closure schedule, the cost estimate for Phase 1 of the exercise should be highly representative of actual cost. In relation to Phase II, the differential of four years between estimation and actually incurring expenditure may present some material deviation. JPS will therefore have to update the estimate for that phase closer to the decommissioning date and present the amendments as a part of an extraordinary rate review submission.

16.6.2 Treatment of Salvage

The Decommissioning contractor's recommended method of treating salvage at this stage of planning was achieved by obtaining manufacturer's equipment specification details as input data in a computer model to determine the quantity and type of scrap and by applying the appropriate rates as submitted by the JPS' approved metal scrap contractor at the time of this study. The value of scrap was then estimated. All major and sub components were treated as scrap. Additional details for each salvage item is found on PDF Page 61-62 of the Demolition and Closure Plan document for Old Harbor and HB Plants, respectively. The rates used from JPS' approved metal scrap dealer contractor at the time of the study are provided in Table 16-15.

Substantially, all generation sub-assets would have been fully depreciated by the time of their scheduled retirement. For the period leading up to demolition works, JPS will seek to identify buyers on the local or international markets with interest in any salvageable sub-assets and at such time the highest value obtained will be added to the scrap value for decommissioning. The decommissioning study assumes each sub-asset to be at the end of its useful life and as such items are assessed at their scrap value. Considering the aforementioned, OH#3 unit transformer salvage being the most recent major sub-asset acquisition is the only sub-asset that had not yet been added to scrap value as the best value proposition for its disposal with due consideration for the possibility of its re-sale on the local or international market remains to be determined. This will be determined prior to demolition works and the value obtained treated accordingly. A full list of all items sold is to be submitted at the end of the demolition activities.

Therefore, at the time of this study, no acquisition arrangements for sale of equipment had been made. Given the age of most of the equipment (approaching 51 years), no buyers were readily identified. This approach for estimating decommissioning costs is industry practice for large power plants at this stage of planning. As we progress toward the dismantling operations and after all production activities on plant comes to a halt, expression of interest will be sought on the open market for components that may be perceived to have residual value.

The estimate of salvage value is based on metal prices generated from the market at the end of March 2019. The estimate was generated by applying open market metal prices to the estimated quantity of metals available for disposal. Being a point in time estimate, it is reflective of the possible recovery but not representative of actual revenues to be generated form the disposal exercise. The main metal component, steel, has seen significant volatility month on month since 2015 with average price falling precipitously from a high of US$450 per ton for steel scrap in some markets to a low of under US$180/ton in 2016. Prices have continued to vary since then, achieving a high of US$292 before losing 6% of value over the past twelve 12 months to June 2019 based on a review of data from the London Metal Exchange. Based on the decommissioning plan, the generation of cash from the sale of scrap metals is not anticipated to commence until March 2021 at best, a period almost 2 years from the date of this submission. It should be noted also, that the estimate includes Phase II for which the realization of revenues from scrap sales will not be experienced until 2024. This means that the estimate can only be taken as indicative.

Table 16-15: Metal Scrap Contractor Rates used at time of Study

MIJ INTERNATIONAL DMCC

Unit No. 2601 & 2609, Jumeirah Business Center 5, Plot No. W1,

Jumeirah Lakes Towers, Dubai, , UAE,

P.O. Box 125456 | TEL: +9714 4474224 | FAX: +9714 4474223
E-MAIL:mij@mijinternational.com

Updated Price List for March 2019

Description	Revised May 2nd MIJ	Prices for Jan 2019	Prices for March 2019
Pole Type Transformers	$460.00	$ 460.00	$ 460.00
Pad mount transformers	$560.00	$ 560.00	$ 560.00
Clean Copper	$4,800.00	$ 4,200.00	$ 4,800.00
Dirty Copper	$2,800.00	$ 2,500.00	$ 2,800.00
Clean Aluminum	$1,000.00	$ 750.00	$ 800.00
Clean Aluminum (wires)	$1,100.00	$ 1,000.00	$ 1,100.00
Meters(without glass covers) - received without glass	$700.00	$ 500.00	$ 550.00
Meters (without glass covers) - received with glass but shipped without		$ 450.00	$ 450.00
Meters (with glass covers)	$420.00	$ 350.00	$ 450.00
Insluted cu/alu cables	$850.00	$ 800.00	$ 850.00
Stainless Steel			$ 775.00
Misc. Substation eqpt.69 kv &138 kv circuit breakers	$225.00	$ 225.00	$ 225.00
Misc Substation eqpt. 24 kv reclosers	$225.00	$ 225.00	$ 225.00
Current & potential transformers with copper enclosed in a rubber casing	$400.00	$ 400.00	$ 400.00
Misc Generation eqpt composed mainly of steel &iron (Prepared)	$100.00	$ 80.00	$ 80.00
Misc Generation eqpt composed mainly of steel &iron (Unprepared	$70.00	$ 60.00	$ 60.00
Computer Eqpt	$300.00	$ 300.00	$ 300.00
Aluminum streetlight fixtures	$380.00	$ 380.00	$ 380.00

16.6.3 Market Based Cost Study

While the cost of this decommissioning exercise was developed using quotations from the local market, it was useful to see how it compares with undertakings of a similar nature in other jurisdictions within the regional or international energy space. Table 16-16 shows the cost of Decommissioning per Mega Watt for plants that have been decommissioned in the United States within the last 20 years. This study was conducted by Resources for the Future, a non-profit research organization based in the United States.

Table 16-16: Decommissioning Cost Estimates in the US[103]

TABLE 1. ISSIONING COST ESTIMATES PER MEGAWATT OF CAPACITY

Fuel type	No. of estimates	2016$ (thousands) Minimum	Mean	Maximum
Offshore wind	7	$123	$212	$342
Coal	28	$21	$117	$466
Concentrated solar power (CSP)	5	$24	$94	$138
Solar photovoltaic (PV)	22	–$89*	$57	$179
Onshore wind	18	$2	$51	$222
Petroleum/petroleum + gas	19	$2	$31	$103
Gas (various types)	28	$1	$15	$50

*Negative cost estimates indicate that the salvage value of plant materials exceeds decommissioning costs.

Table 16-17 shows JPS' Power plants' cost per Megawatt estimates for decommissioning work in Jamaica.

Table 16-17: JPS' Power plants' cost per Megawatt estimates

Plant/Technology	Capacity (MW)	Decom Cost Per Plant	US$ (,000)/MW	JPS Mean US$(,000)/MW
OHPS	230	$16,683,295.66	$72.54	**$67.12**
HBB6	68.5	$3,309,176.45	$48.31	
HBGT	54	$1,987,373.97	$36.80	
RFDS	40	$6,102,239.77	$152.56	
Bogue	93.5	$2,373,141.63	$25.38	

In addition to the foregoing, recent estimates were done in Trinidad for approximately 290MW of power plant assets at one location in the region of US$60,000 per megawatt. This is very similar to the JPS mean of $67,000 per MW with the environmental remediation costs being the main cost drivers. The units in Trinidad operate using natural gas as their main source of fuel while the comparable JPS 298.5 MW power plants at OH and HB B6 run on Heavy Fuel Oil. Environmental

[103] Raimi, Daniel. (2017, October). Decommissioning US Power Plants. https://www.rff.org/publications/reports/decommissioning-us-power-plants-decisions-costs-and-key-issues/

remediation for liquid petroleum products is much more expensive than that for natural gas (NG) as NG tends to evaporate overtime while more costly techniques must be employed for heavier liquid fuel products. It must also be noted that the total decommissioning effort at JPS spans four (4) separate locations that attracts individual costs for Environmental Remediation and environmental regulatory approvals, which in and of itself has additional cost implications.
The costs for JPS' decommissioning activities were developed using local market rates for services and labour under the guidance of experienced decommissioning and environmental practitioners and as such represents the best estimate at this time.

16.6.4 Staff Separation Costs

As JPS retire each generating unit in its retirement schedule, its requirement for staffing will diminish and the Company will incur separation costs. In accordance with the construction schedule and operations mandate for the 194MW plant, the OH and HB locations will be the first to be impacted by staff reduction commencing in November 2019, with the entire OH plant employees projected to be separated by January 2020 while the HB Unit 6 employees in its entirety to follow by January 2021.

The calculations used to derive these costs are as follows:

Years of service * annual basic pay * 8% (1-10years)

Years of service * annual basic pay * 10% (over 10 years)

A full list of employee positions up for redundancy are appended to this submission detailing their associated entitlements. In order to facilitate a full review of the redundancy exercise an Organizational Chart for affected plants is included.

This redundancy exercise is heavily dependent on the Commercial Operations Date (COD) of the new 194MW plant. As such, as the new plant goes through its commissioning and testing to prove its reliability while under EPC contract, uncertainties or delays in its final delivery date – which is not uncommon for large plants like these – impacts separation costs as notice costs may be required for some employees serving in critical areas of the Generation division. With due consideration for this current state and in balancing the nation's energy security needs while observing the relevant laws and labour agreement, JPS is constrained under section 3(1) of the Employee Termination and Redundancy Payment Act (ETRPA) in Part II: Minimum period of notice, and right to certain facilities, which states:

> *3. - (1) The notice required to be given by an employer to terminate the contract of employment of an employee who has been continuously employed for four weeks or more shall be -*
> *(a) not less than two weeks' notice if his period of continuous employment is less than five years;*
> *(b) not less than four weeks' notice if his period of continuous employment is five years or more but less than ten years;*

(c) not less than six weeks' notice if his period of continuous employment is ten years or more but less than fifteen years;
(d) not less than eight weeks' notice if his period of continuous employment is fifteen years or more but less than twenty years;
e) not less than twelve weeks' notice if his period of continuous employment is twenty years or more, and shall be in writing unless it is given in the presence of a credible witness."

JPS is duty bound to observe and abide by the relevant laws governing employee termination and redundancy payments and further notes the following with respect to the separation cost estimates:

I. Given the changes in the schedule for COD of the 194MW plant and in the interest of our customers, the separation of staff from legacy plants has been delayed due to delays in commissioning of the new plant. This delay resulted in the need for staff retention beyond the dates earlier projected and was punctuated by uncertainties from issues arising in the commissioning process.

II. JPS in observing the ETRPA found it more prudent to issue payment in lieu of notice rather than issuing an actual notice. A letter of notice allows the worker to have tenure over the period of the notice and benefit from monthly payments complete with basic pay and full benefits as well as any applicable at increased rates for salary and benefits based on the recently concluded labour union negotiations while payment in Lieu of notice considers basic pay only. Hence, given the current state it is more beneficial to customers for separation to be done for certain critical functions without notice.

In response to requests made by JPS in its Annual Review Filing in 2018, the OUR approved US$2.3M related to the cost of separating staff currently engaged at the OH plant, which represents 50% of the total staff separation costs related to that location. JPS is therefore seeking the approval of the recovery of the remaining 50% of staff separation costs relating to OH in addition to the full cost relating to the HB B6 unit to complete the recovery of such costs under Phase 1. The company will also be seeking approval for the recovery of the full staff separation costs related to Phase II. The full estimate of costs broken down by phase is presented below in "Decommissioning Cost Estimates" in Table 16-14. It must be noted that the figures presented for phase 1 will differ from what was presented in the 2018 Annual Review Filing for the following reasons:

1. Change in timeline for COD of the new 194MW plants which should replace the plants for which separation is necessary, affects the cost for separation in that there is an obvious increase in tenure.
2. Further adjustments have been made to accommodate the conclusion of the wage negotiations between JPS and some of its labour unions for the negotiating period January 1, 2018 to December 1, 2020.

However, JPS awaits a ruling from the Industrial Disputes Tribunal (IDT) on a matter concerning wage negotiations with the Union of Clerical Administrative Supervisory Employees (UCASE) expected in January 2020 which has not yet been included in this cost projection. The OUR should reasonably expect that the final cost for this separation exercise will be updated at such time as a ruling is delivered and JPS expects that this cost will be fully recovered through the tariff.

16.6.5 Recovery of Stranded Asset Costs

In its 2018 Annual Review and Extraordinary Rate Review Filing, JPS requested the recovery of the carrying value of assets slated for retirement, the recovery of which would not be facilitated by the normal depreciation rate up to the scheduled date of retirement of those assets. The Company made the case by citing the following arguments.

Excerpt from 2018 Annual Review Filing:

> "*Depreciation is a measure of the consumption of the utility value of an asset over its useful life. The recovery of asset values should reflect the pattern of usage of such assets to benefit customers over the period they remain in use. General ratemaking principles support the fair recovery of costs prudently incurred by a regulated business and the recovery of depreciation costs for approved assets is one such cost. As stated in previous determinations issued by the OUR, depreciation allowances preserve the "integrity of the investment" a regulated business makes in approved assets. JPS is also cognizant that the OUR supports the fair recovery of asset values over a reasonable period in cases where it is recognized that the actual useful life of an asset (or group of assets) approved by the regulator has changed because of advanced technology, shifts in market conditions or other justifiable reason."*
>
> *"Paragraph 5 of Condition 15 of the Electricity Licence lays out the methodology that shall be used to determine depreciation charges under the regulatory regime." It states:*
>
> "*Annual depreciation allowance shall be computed by applying reasonable annual straight line depreciation rates to the value of property, plant and equipment stated at book value. As a part of the Rate Review Process, the Office shall determine the adequacy of the depreciation rates based on a depreciation study conducted by a reputable firm of chartered accountants engaged by the Licensee*."

The Company also cited the IFRS requirements for recognizing depreciation costs as follows. "*Paragraph 6 of IAS 16 (of the International Financial Reporting Standards) defines depreciation ss "the systematic allocation of the depreciable amount of an asset over its useful life." The standard states that depreciable amount is the cost of an asset, or other amount substituted for cost, less residual value, and that useful life is the period over which an asset is expected to be available for use by an entity or the number of units of production expected to be obtained from an asset by an entity. It states further that useful life can be determined by considering factors such as, the expected usage of the asset, physical wear and tear, technological and commercial obsolescence, and legal and other similar limits on the use of an asset.*"

JPS estimated that extent to which the carrying values of assets slated for retirement as a result of the decommissioning exercise proposed in Phase I was US$9.2M. In its 2018 Annual Review Determination Notice, the OUR approved the recovery of accelerated depreciation costs as requested. The OUR agrees that no consideration would be taken of the residual scrap value of both plants in arriving at this determination. In this regard, the estimates of decommissioning costs presented in this rate review filing are adjusted to reflect the projected scrap value anticipated from the disposal of the plant components and associated specialized inventory spares.

In relation to ongoing capital expenditure required to keep plants running up to the proposed retirement dates, the OUR withheld its determination pending further clarification of the costs being requested for recovery. JPS presents its case for the recovery of such costs as follows.

Incremental maintenance costs of US$13.2M was presented for recovery in JPS' 2018 Annual Review Filing. Of this amount US $6M was incurred in 2017 with the remaining US $7.2M anticipated to be incurred between 2018 and 2020. While JPS agrees that on the surface it appears imprudent to incur the costs anticipated in 2018 to 2020 given that the plants are scheduled to be retired in 2019 and 2020, the matter of most importance in making the decision was the cost of unavailability of power supply should the expenditure not be incurred. Based on JPS' analysis, a failure to effect the maintenance would have increased the likelihood of power outages to customers due to increased forced outages on the generation assets.

The expenditures incurred in 2017 were principally directed at critical maintenance activities in relation to generating units at OH. While the interval to the next major overhaul would have been 4 years JPS will benefit from the expenditure for 3 years (i.e., only one year shorter than the expected period) and so in the Company's view the expenditure was justified. It should be noted that the company executed a limited maintenance routine in relation to these plants in order to save costs due to the pending retirement. Likewise, the expenditures related to 2018 to 2020 were deemed necessary to effect basic overhaul and statutory compliance to keep plants operable, reliable and compliant up to the time of retirement. The Company has sought extensions to its statutory certification instead of effecting major overhauls where possible in order to manage the assets to retirement.

In relation to the expenditure, in the 2018 Annual Review Determination Notice the OUR states that *"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;"* In JPS submits that there is a misunderstanding of the classification of costs. While the replacement of lubes and consumables are budgeted and recorded as O&M expenditure in the normal course of business, when such expenditures are incurred as a part of an overhaul exercise they are classified as capital expenditure along with the replacement of major spares. This is the requirement under IAS 16 as outlined in paragraphs 10, 13 and 14 of the standard. The capital budget for overhauls or major maintenance projects therefore includes these consumables, lube and other costs that appear to be O&M in nature. The O&M budget accounts for the fact that these costs will be capitalized and as such is reduced to account for this effect. There is therefore no double counting of these costs in the operating expenses budget.

Inventory Spares

Inventory spares represent specialized inventory unique to the operation of plants at each location. With the retirement of these plants the stock of inventory spares become obsolete as they cannot be used on the other plants operating in the fleet. Such inventory therefore become stranded assets, the cost of which must be recovered through the tariff. In managing these spares up to retirement JPS will ensure maximum efficiency in their application during normal maintenance activity. However, based on projected usage it is estimated that some items will remain at closure. The value the remaining inventory has been projected as Stranded Value of Inventory at retirement in Table 16-14.

Project Management Costs

It is anticipated that in order to effectively coordinate and manage the decommissioning projects across all plants, additional human resources will be needed in the form of project managers and administrative personnel to ensure compliance with regulatory requirements and the overall success of the project. Estimates are broken out by plant in Table 16-14.

16.7 Proposal for Cost Recovery

Consistent with paragraph 27 of Schedule 3 of the Licence, which permits the recovery of all prudently incurred expenses as a part of the Revenue Requirement, JPS submits that all expenses prudently incurred in connection with the decommissioning of plants, to the extent that recovery was not previously approved in the 2018 Annual Review Determination Notice, should be recovered through the tariff. Such costs must be recovered in a manner that is consistent with reasonable tariff and regulatory principles. In this regard, decommissioning costs should be recovered over a period that allows for timely recovery of the costs incurred by the Company while also preventing rate shocks. These considerations have been contemplated in the recommendations for cost inclusion in the tariff structure in the Revenue Requirement Chapter (Chapter 13).

JPS is also of the view that it should be permitted to recover only the cost it incurred in relation to this exercise. Consistent with the revenue cap principle the company is not permitted to benefit significantly from variations in actual expenditure from projections. Paragraph 46 d. (ii) of the Licence requires the initiation of an extraordinary rate review to return profits to customers if ROE exceeds 1% of the target rate, paragraph 46 d.(iii) of the Licencerequires the reconciliation of capital expenditure and the reimbursement of amounts not expended to customers during the next rate review period, and the annual adjustment formula requires the reconciliation of volumetric revenues differences to ensure that the Company does not over recover its revenue requirement or makes a greater profit than intended. As such, given the significance of decommissioning costs and the high level of estimation involved in the process the Company proposes the reconciliation of costs at the end of each phase of the exercise and that the difference between actual and estimated costs be returned to the party that has over expended on the exercise. In this regard, if actual expenditure were less than the amounts estimated, the excess recovery should be returned to customers, and vice versa, in an orderly and efficient manner. Since the costs are proposed to be collected from customers over the five-year rate review period, an adjustment in the tariff to reflect the difference related to Phase I commencing in 2022 would be appropriate. The adjustment for phase II will be effected in 2025 (the next rate review period) when actual expenditures are known.

16.8 Implementation

JPS' implementation strategy will be informed principally by the recommendations obtained from the Consultants' recommendations for developing its decommissioning strategy. Both consultants are leaders in their fields and bring a wealth of knowledge to the execution of the exercise. The strategy of seeking this guidance before implementing the process will assist the Company in avoiding some of the pitfalls that may be associated with the exercise especially since JPS does not currently possess the requisite experience within the organization. Additionally, given the magnitude and potential impact of the exercise it is necessary to invest resources appropriately to plan the execution of the process thoroughly and follow a prescribed set of principles and modalities that have proven successful in similar exercises.

In order to effectively execute on its decommissioning strategy, JPS will initiate the process of identifying suitably qualified contractors to carry out the contamination remediation and deconstruction and demolition exercises in March 2020. This process will run concurrent with the Environment Permitting and Risk-based Assessment identified as the first step in the schedule of activities included in Section 1.3.2 Timetable. JPS will use internal resources supported by the external consultant, CL Environment, to develop the risk-based analysis and pursue the permitting process in accordance with the schedule of activities identified in the closure plans and reproduced in Section 18.5 (Timetable).

In executing the strategy, the Company has four major objectives, as follows:

1. Restoration of the plant sites to environmentally sustainable conditions pursuant to the legal requirement from NEPA for operating industrial sites;
2. The safe execution of all aspects of the decommissioning exercise, from collecting samples to deconstructing and demolishing major plant components;
3. Executing the programme of activities at the lowest cost possible; and
4. Obtaining complete recovery through the tariff.

Achieving success in the first three objectives will be highly dependent on the effectiveness of the Company's planning and execution. To date, the Company has acted prudently and responsibly in addressing knowledge gaps in process development and execution by consulting the necessary expertise. The Company intends to build on this foundation in the execution process by following the best practice recommendations proposed by the consultants. The Company will also engage its experienced project management team, who will, with the requisite oversight by the Executive Leadership team, develop an effective project implementation strategy. The Company has very thorough procurement practices and these will be applied to this project to ensure that customers obtain the best value for the expenditure that will be incurred. Its safety practices are well understood but never taken for granted. In this regard, its safety management systems as a process mantra will be on display in the planning and execution of activities by both directly employed and third party contracted personnel. Weekly safety meetings and daily briefings will be implemented in the execution process.

With respect to tariffs, the Company has presented the case for decommissioning cost recovery in this chapter. JPS stands ready to provide the necessary clarification to enable the OUR to complete its assessment and approve the costs necessary for the successful implementation of the project. Such decommissioning costs include the recovery of all stranded assets, staff separation and demolition and deconstruction expenditure net of offsets generated from scrap sales.

16.9 Future treatment of Decommissioning Cost

As a component of the cost of an asset, IAS 16 requires the recognition of decommissioning costs in the carrying value of an asset. Subsection (c) of paragraph 16 describes the inclusion of cost estimates for the dismantling and removing of the item and restoring the site on which it is located as an item of the asset's cost. Such costs ought to be recognized on the date the asset is acquired and brought into service. As the cost is an estimate, modifications may be required to facilitate the fair representation of the item in the records over time. The approach not only results in a fair representation of the asset values, but it improves the cost recognition function and presents a more representative picture of the economic cost of using that asset in the production function. From a regulatory perspective, the principle of the cost causer pays and having tariffs that economically represent the cost of service delivery is only achieved when decommissioning costs are included as a component of the costs of assets.

The fact that decommissioning costs were excluded from the regulatory carrying value of large industrial assets, and therefore from the timely recovery of such costs from customers (depreciation charges), is an anomaly that must be corrected ogoing forward. The recovery of such costs after the asset is retired is not only a gross misallocation of costs but a violation of good regulatory principles. The practice results in asset costs being paid by customers who did not have the benefit of being served (receiving utility) by such assets. It also creates lumpiness in the tariff when large cost items are recovered over a relatively short period of time. This is economically and allocative inefficient. The superior approach is to recover such costs over the life of the asset, thereby allowing those who benefit from their operation to pay the cost over the asset's life.

While the current tariff exercise addresses an estimated 75% of the cost of JPS' assets, the remaining 25% needs to be addressed in a similar manner. Estimates of the cost of dismantling these assets and restoring the sites on which they are located should be developed and included in the regulatory cost structure so that recovery can be had from customers who benefit while they are in operation. If this is not accommodated in the current rate review period due to materiality of the costs being proposed in relation to the 75% portion of assets slated for retirement during the regulatory period, then JPS recommends that it should be implemented in the next regulatory period.

16.10 Conclusion

The recovery of decommissioning costs related to assets slated for retirement will add a further cost component to the revenue recovery function over the next five years. It is a component that the current regulatory structure failed to recognize heretofore (via absence of the necessary component in the depreciation rates), but a necessary cost that must be recovered to facilitate the efficient operation of the energy production function. JPS has taken the steps to ensure current best practices are followed in implementing the project and that both operating and cost efficiencies are achieved in its execution. It has contracted the requisite services and has developed a process for executing the decommissioning activities. It will also bring its strong project management and safety practices to deliver low-cost high-quality project outcomes. The Company believes that it has taken the necessary planning and preparatory steps toward the achievement of its four major objectives for the project and plans to build its execution on the modalities and recommendations presented in this chapter. To reiterate, these objectives are:

1. Restoration of the plant sites to environmentally sustainable conditions pursuant to the legal requirements from NEPA for operating industrial sites;
2. The safe execution of all aspects of the decommissioning exercise, from collecting samples to deconstructing and demolishing major plant components;
3. Executing the programme of activities at the lowest cost possible; and
4. Obtaining complete recovery through the tariff.

The Company also proposes the inclusion of decommissioning costs in the regulatory cost structure for all applicable assets to facilitate the efficient execution of the exercise in the future. Such an approach will avoid the need for the related rate adjustments to accommodate the execution of the exercise when the need arises.

17 Annexes

5 YR BUSINESS PLAN FOLDER

ANNEX I

1. Chapter 5 – Guaranteed Standards
    a. Barbados – Guaranteed Standards
    b. Trinidad & Tobago – Guaranteed Standards

2. Chapter 6 – Productivity Improvement Factor
    a. Productivity Improvement Factor Study
    b. Productivity Improvement Factor and OPEX projection
    c. TFP Model
    d. Database

3. Chapter 10 – Demand Forecast
    a. Demand Forecast Final Report
    b. Demand Forecast Model

4. Chapter 18 – Decommissioning Cost
    a. Addendum – MSDS
    b. Demolition Plan and Closure Plans
    c. Generation Organizational Chart
    d. Separation Cost Model

5. Cost of Unserved Energy
    a. COUE Final Report
    b. Jamaica COUE Updated Report
    c. Jamaica COUE Model

ANNEX II – Quality of Service (Q-Factor)

1. Appendix A – JPS' Customer, Transformer and Feeder Data
2. Appendix B – Reliability Improvement Projections Analysis
3. Appendix B-1 – JPS Transmission Reliability Models
4. Appendix C – Proposed 2019-20223 Q-Factor Targets
5. Appendix D – 2018 OMS Dataset
6. Appendix E – 2018 Outage Drivers
7. Appendix F – 2016 & 2017 Inclusions Exclusions Dataset

8. Appendix G – DigiSilent Inputs

ANNEX III – System Losses (Y-Factor)

1. 2018 Transmission Technical Losses Breakdown Folder
2. Audits Report YTD – Dec 31 2018
3. Benchmarking Analysis (OUR)
4. CB Hill Run – Twickenham 410 TL
5. Energy Loss Spectrum – Details (OUR)
6. JPS Transmission V3.2 – BVue-RR 69kV
7. Justification and Analysis for NTL Reduction 2.10%
8. Justification and Analysis for TL Reduction 0.20%
9. Loss Reduction Plan with Targets
10. Loss Spectrum Methodology – Updated
11. NTL Control and Responsibility
12. Optimal Transmission Technical Losses – 2024 & 2029
13. Proposed OH-HB 138kV Line
14. VSP Simulations

ANNEX IV – Fuel Recovery (H-Factor)

1. 2019-2024 Forecast Folder
2. Heat Rate Test Folder
3. T&D Maintenance
4. 2019 – 2024 Planned Outages (JPS & IPP)
5. CC Plant Heat Rate data for Gas Turbine Unit
6. Capacity Factor 2018
7. Demand & LDC – 2018
8. Existing Power Plant Capabilities
9. Generation Projects Due for Commissioning
10. Generation Retirement Schedule 2019 November
11. Generation Unit Performance 2018
12. Jamalco 94MW Heat Rate and Capacity Degradation
13. Jamalco 94 MW Heat Rate Data
14. OH 190MW Heat Rate and Capacity Degradation Data
15. Projected Variable Costs 2019-2024

ANNEX V – Financial Requirement

1. CAPEX
    a. Investment Costs Final Document Refiling-Unlinked

b. JPS Investment Plan- OUR Version-Refiling
c. 2019 Quotes & Invoices

2. Financial Requirement
    a. 2016-2018 Incremental Depreciation Folder
    b. 2018 Asset Register with Depreciation Forecast – 2023
    c. 2019-2023 Accelerated Depr Recovery
    d. ALRIM Offset
    e. Amortization of Debt issuance – 06 30 2019
    f. Amortization of Debt issuance – 12 31 2018
    g. CWIP Schedule 2018
    h. CWIP Schedule 2019-2023
    i. CWIP Depreciation Projection 2019-2023
    j. EEIF Tax Allowance
    k. Fixed Asset Depreciation Reconciliation with Financial Model
    l. Fixed Assets Summary as at December 2018
    m. Generation CAPEX Justification – OUR Nov 5
    n. JPS Asset Register Dec 2018
    o. JPS Asset Register Dec 2018_Cost Center Name
    p. JPS Depreciation Rate Study Final Report
    q. JPS EDF Report at December 31 2018
    r. JPS ROE Study
    s. JPSCO 2019_2023 Financial Model
    t. JPSCo FS 2018
    u. Revenue Lags Calculation
    v. User Manual
    w. WACC – 2019-2023 Rate Case
    x. Working Capital with Lead-Lag

3. O&M
    a. O&M Five Year Plan 2019-2023

ANNEX VI – Cost of Service & Tariff Design

1. Cost of Service & Load Research
    a. Cost of Service Report
    b. Embedded Cost Allocation Model
    c. Load Research Report
    d. Load Research Files
    e. Marginal Cost Model

2. LRMC
    a. 2019 LRMC Generation Transmission
    b. Distribution PCM Calculation
    c. FLOP JPS
    d. JPSED Base Case Study

3. Tariff Design
    a. 2018 Monthly Billing Data - CIS
    b. 2018 Monthly Data – Prepaid
    c. JPS DER Final Report
    d. JPS New Tariff Schedule Report
    e. JPS Tariff Structure Analysis Report
    f. 2018 AAF Tariff Basket
    g. Proof of revenue at proposed rates

ANNEX VII - Other

1. Deficiencies Clarification and Additional Information to JPS
2. Tariff Design Clarification (Response to Sept 10 letter)
3. Smart Streetlight Project
    a. JPS SSP Agreed Upon Procedure Report
    b. LED Streetlight Projections 2019-2021
    c. Streetlight Budget 2019-2021