Office of Utilities Regulation

REPORT ON INVESTIGATION OF

JAMAICA PUBLIC SERVICE COMPANY LIMITED MAJOR SYSTEM FAILURE

POWER SYSTEM ISLANDING AND WIDESPREAD OUTAGE 2016 APRIL 17 at 6:59 p.m.

Report

OFFICE OF UTILITIES REGULATION

DOCUMENT TITLE AND APPROVAL PAGE

1. DOCUMENT NUMBER:

2. DOCUMENT TITLE: Report on Investigation of Jamaica Public Service Company Limited Major System Failure, Power System Islanding and Widespread Outage 2016 April 17 at 6:59 p.m.

3. PURPOSE OF DOCUMENT

This Report contains the Office of Utilities Regulation's (OUR's) analysis and recommendations regarding the major system failure, power system islanding and widespread outage which occurred on 2016 April 17 at 6:59 p.m.

4. ANTECEDENT PUBLICATIONS

Publication Number	Publication Title	Publication Date
	JPS Major System Failure Technical Report Power System Islanding and Widespread Outage, April 17, 2016 at 6:59pm	

5. Approval

This Report is approved by the Office of Utilities Regulation and the recommendations therein become effective on 2016 November 8

On behalf of the Office:

………………………………………………

Joseph Matalon
Chairman

2016 November 10
Date

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Executive Summary

1. Introduction

On Sunday 2016 April 17th at 6:59 pm, the Jamaican electric power system experienced a major system failure which separated the power grid into two sub-systems namely; corporate and rural area sub-systems. The rural area sub-system eventually suffered a total blackout, while the corporate area survived after intermittently losing some of its customers.

Earlier in the day two (2) 69 kV transmission lines; Hunts Bay – Port Authority of Jamaica (PAJ) and Hunts Bay – Duhaney were taken out of service to facilitate road works being undertaken by the National Works Agency (NWA). These two (2) lines emanated from the Hunts Bay power station in the corporate area, the largest load centre on the island.

A total of 456 MW of generation was lost, affecting approximately 547,734 customers. Most customers were progressively restored within three (3) hours and full restoration of all customers was completed by 10:49 pm the same night.

The system operator Jamaica Public Service Company Limited (JPS), in keeping with section 45 (12) and (13) of the Electricity Act, 2015 (the Act) submitted to the Office of Utilities Regulation (OUR) an outage investigation report of the incident entitled 'Major System Failure Technical Report', 2016 April 17. This report provided an overview of the electric power system, the status of key elements of the system, conditions on the electric system that existed prior to the outage, events during the outage and sought to explain how and why the outage occurred. The measures and procedures to restore the system to normal operations were also described. The report concluded with a series of recommendations for actions that can and should be taken by JPS to prevent or minimize such occurrences in the future.

In keeping with its mandate the OUR carried out an investigation of the outage and provided its own review of the circumstances prior to, during and after the outage and highlighted its own analyses of the issues and causation leading to the outage event. Arising from this review a set of findings and recommendations geared to the prevention or minimization of such occurrences in the future is presented in this report.

2. OUR Findings

Investigation of the outage was undertaken by a team of OUR engineers. The OUR investigation was based on outage information and sequence of events recordings (SOE) provided in the JPS report. JPS provided further information pursuant to OUR's request.

The planned outage on 2016 April 17 of the two (2) 69 kV transmission lines Hunts Bay – PAJ and Hunts Bay – Duhaney was to facilitate road works being under taken by the National Works Agency (NWA). These two lines emanated from the Hunts Bay power station in the corporate area, the largest load centre on the island.

The taking out of service of these two lines puts the system in an N-2 contingency state which would compromise the system security. The low generating plant availability also compromised the security of the grid by reducing its ability to adequately respond to changes in demand.

The outage which was planned to start at 7am and be completed at 6pm the same day, before the onset of the evening peak did not start until 10:55 am, a delay of almost four (4) hours.

The initiating event occurred at 6:59:26 pm when the Hunts Bay – Three Miles line tripped while carrying in excess of 720 Amps or 86 MVA. At the time the system operators were erroneously seeing on the SCADA system a line loading on the Hunts Bay - Three Miles of only 600 Amps due to a faulty transducer.

The ensuing cascading events and resulting system separation occurred at 6:59:30 pm, within a total duration of four (4) seconds from the initiating event. During this short duration it was impossible for the system operators to take any corrective actions to prevent the system separation which occurred at 6:59:32 pm.

The resulting rural area system was unable to survive the resulting massive generation - load imbalance which was compounded by the failure of the under-frequency load shedding scheme to operate at a number of locations. This resulted in the loss of 335 MW of generation tripping off line due to low frequency in the sub-system. The blackout of the rural area system occurred within a duration from 19:00:12.078 pm to 19:00:25.188 pm or within thirteen (13) seconds. No manual corrective actions could be taken in this short period of time to avert the blackout.

The corporate area was able to survive the disturbance due to 122 MW of generators in the sub-system remaining online and the successful operations of the under-frequency load shedding scheme in the sub-system.

Over 547,734 customers were affected. The system restoration procedure started at 7:12 pm and over 98% of customers were restored within three (3) hours, with the remaining restored by 10:49 pm.

The OUR analysis of the conditions prior to outage, the events leading up to the outage, and the events during the outage revealed that the causes of the outage was a combination of poor outage organization, equipment failure, inadequate maintenance of equipment, failure to operate the transmission lines within their safe operating limits and most of all a serious lack of situational awareness on the part of the JPS operations and field staff.

Specifically these causes can be traced to:

- Inadequate outage planning, outage management and execution;
- Ineffective operations communication between system control, field personnel, management, and poor decision making. There were no updates on the outage status from the field personnel and the system operators;
- Inadequate contingency analyses which resulted in poor decision making, poor situational awareness on the part of JPS system operators and field staff .Lack of operator training and experience may have been a factor. In this regard the training and experience records of the operators on duty needs to be further investigated;
- Poor generation equipment maintenance resulting in low generating plant availability and hence low system spinning reserve margin, and equipment failures at critical times;
- Failure of system operations to adhere to the specific outage planning constraints/criteria;
- Violation of generating system spinning reserve margin requirement and violation of line loading limits;
- Faulty protection system design and equipment; and

- Faulty monitoring and communication equipment failure due to a lack of adequate and timely maintenance of defective equipment which negatively impacted on the operator visibility of the system.

Restoration

Restoration procedure commenced about twelve (12) minutes after the outage at 7:12pm and the last customer was restored at 10:49pm. Of the 547,734 customers affected over 98% of them were restored within three hours, with the remaining restored by 10:49 pm according to JPS' report.

The restoration was largely successful. JPS has a well-defined restoration process and the restoration was carried out according to this process and the black start procedure. There were however, a number of areas which failed to perform as expected. These included constraints such as:

- System Control Centre's stand by generator failed to automatic start;
- The late completion of planned outages on Hunts Bay – PAJ and Duhaney lines hampered the restoration process;
- Failure of the Remote Terminal Unit (RTU) causing communication issues at Parnassus and intermittent communication at Kendal, Spur Tree, Blackstonedge, Bellevue and North East coast substations;
- Reclosers failing to close at some substation; and
- Remote operation of field equipment a permanent failure of communication with Parnassus 138KV station and intermittent failures at Blackstonedge, Highgate and Oracabessa stations.

These above issues were encountered throughout the restoration process, and delayed the energizing of some customers in a timelier manner.

3. Recommendations

The following recommendations are based on the OUR assessments of the outage. The recommendations are geared at preventing or minimizing the recurrence of such events in the future.

System Operations and Outage Management

1. JPS is required to take immediate actions to correct the direct cause of the outage and provide to the OUR with evidence that specific actions were taken to fix the problems identified and that the system is being operated in a reliable manner. The direct causes shall be clearly stated and JPS shall present a solution for each cause along with an implementation schedule and costing where necessary.

2. JPS is required to review and update the SCADA database to reflect correct thermal operating limit settings of all transmission lines and other relevant system operating parameter limits.

3. JPS shall develop a set of criteria to identify facilities, the reliable operation of which are critical to system reliability and security.

4. JPS shall ensure that the communication issues identified are corrected, and equipment defects are addressed as a matter of priority.

5. JPS shall ensure that all major transmission outages are properly planned and coordinated to reduce the system exposure to undue security risks.

6. JPS shall ensure that system operators are properly trained and certified in outage management by industry recognized institutions in order to be able to prudently operate the system under contingencies and emergency conditions.

7. JPS shall ensure that system operators and controllers fully understand the system operating criteria and adhere to the requirements of the Generation Code to prevent violations of operating requirements under normal and abnormal conditions.

8. JPS shall ensure that outage managers and supervisors are properly trained and certified in outage management by industry recognized institutions and are able to understand the relationship between system reliability, and outage impact on system operations.

9. JPS shall ensure that the online and offline simulation tools are properly calibrated and personnel are properly trained to carry out extensive contingency analyses and are able to make informed decisions based on these analyses.

10. JPS is required to review communication protocol between field personnel and system operators and put in place adequate means of contacting outage managers and supervisors during outage situations.

11. JPS shall install time synchronized data recorders for the hydro units and other units which are not currently equipped with this facility.

12. JPS shall engage independent consultants to conduct a detailed review of its outage management systems, from planning to field execution and to develop plans to address the deficiencies identified.

Protection System

13. JPS shall carry out detailed review of under-frequency scheme and actions to be taken to address the persistent failure of the scheme in order to improve reliability of their operation.

14. JPS shall conduct detailed review of generator over and under frequency trip settings, to implement appropriate time delay tripping of generating units to prevent all plants from tripping at the same frequency in order to minimize the risks of rapid cascading of outages.

15. JPS shall take appropriate measures to improve the complement and competence of staff in the protection and control department.

16. JPS shall conduct a detailed review of the maintenance practice for protection equipment and take the necessary actions to improve maintenance of protection systems.

System Restoration

17. JPS shall ensure that all black start and standby generators are properly maintained and periodically tested and reported.

18. JPS is required to fix remote operating equipment that did not operate correctly during the restoration process.

19. Shall JPS ensure that the system control centre staff gets regular practice drills to improve the restoration process.

Long Term Planning.

20. JPS shall develop coordinated long term generation and transmission plans to address existing transmission system constraints.

Action Plan

21. **JPS is required to provide an action plan on the implementation of all of the above recommendations including specific time frame for their completion within thirty (30) days from receipt of this Report.**

Main Report

1. Introduction

On Sunday 2016 April 17th at 6:59 pm, the Jamaican electric power system experienced a major system failure which separated the power grid into two subsystems namely; corporate and rural area subsystems. The rural area eventually suffered a total blackout, while the corporate area survived after intermittently losing some of its customers.

A total of 456 MW of generation was lost, affecting approximately 547,734 customers. Most customers were progressively restored within three hours and full restoration of all customers was completed by 10:49 pm the same night.

The system operator JPS in keeping with section 45 (12) and (13) of the Electricity Act 2015 (the Act) submitted to the OUR an outage investigation report of the incident entitled 'Major System Failure Technical Report', 2016 April 17.

This report provided an overview of the electric power system, the status of key elements of the system, conditions on the electric system that existed prior to the outage, events during the outages and sought to explain how and why the outage occurred.

The measures and procedures to restore the system to normal operations were also described. The report concluded with a series of recommendations for actions that can and should be taken by JPS to prevent or minimize such occurrences in the future.

In keeping with its mandate the OUR carried out an assessment of the report and provided its own review of the circumstances prior to, during and after the outage and highlighted its own analyses of the issues and causation leading to the outage event. Arising from this review a set of findings and recommendations were made in order to support the prevention or minimization of such occurrences in the future.

2. OUR System Outage Assessment

2.1 Legislation and Regulatory Framework

Section 45 of the Act mandates that "*where there is a major system failure the System Operator shall*

a. as soon as practicable, inform the Minister and the Office of the status of the system;
b. seek to have the system restored to normal operating levels as soon as practicable, taking into account safety, reliability and economy; and

c. *coordinate the bringing back online of any apparatus forming part of the system that may have ceased to be available to the system."*

Section 45 (12) of the Act also requires that;

"Upon the system being restored to normal operating levels after a major system failure, the system operator shall carry out an investigation of the causes of the failure and produce a report thereon, which report shall also describe the measures and procedures to restore the system and the measures that should be taken to avoid a recurrence of the failure, and shall provide an assessment of the cost associated with the failure."

Section 45 (13) of the Act requires that;

"*The System Operator shall submit the report under subsection (12) to the Office and to the Minister within thirty days of the system being restored to normal operating levels*.

Condition 2 (3) of the JPS Electricity Licence, 2016 requires inter alia, the provision of an adequate, safe and efficient service. JPS in discharging its responsibility as an electric utility shall be required to operate the electric system reliably at all times, irrespective of contingency conditions.

2.2 Scope of Assessment

The purpose of OUR's assessment was to review the JPS investigation report to verify JPS' account as to what happened and the causes leading to the system outage, the events during the outage, the restoration procedures, make recommendations to reduce the likelihood of such recurrence in the future, and how to minimize the impacts of such recurrence.

The OUR focused its assessment on the technical and personnel issues including power system operations, planning, design, protection and control, maintenance and personnel resources.

2.3 Assessment Process

JPS was requested by the OUR to submit a preliminary report on the incident. The detail report was provided within thirty (30) days from the system restoration on 2016 May 18.

The OUR then formed a team of engineers to review and analyse the JPS report, in order to verify the prior conditions sequence of events during the outage, the restoration procedure in order to get an understanding of the incident and make its own assessment of the circumstances surrounding the incident and to make recommendations to prevent or minimize such occurrence in future.

The OUR conducted a preliminary review, and requested that JPS provide additional technical information.

The OUR detailed assessment was based on reviewing JPS data report, independently gathering data, carrying out system analyses and simulations to verify information included in the report in order to arrive at the causal factors contributing to the outage.

Arising from this detailed assessment and the additional information provided by JPS, the OUR was able to assess the system status and condition of key facilities prior to outage, during the outage to arrive at an understanding of the factors initiating the outage, and the ensuing cascading events which eventually lead to system separation and eventual black out of the rural area sub-system.

Based on the findings of its assessments the OUR has made recommendations, in addition to those made by JPS to prevent or minimize a recurrence in the future.

3. Overview of Electric System

This section provides a description of the electrical system major elements.

Jamaica's electric power system is an interconnected grid linking four (4) major generating stations in the west, south central and east areas of the island through138 kV and 69 kV transmission systems. Power is generated and transmitted at 50 Hz.

JPS operates the system under an exclusive licence for the transmission, distribution and sale of electricity. Independent Power Producers (IPPs) provide power to the grid under Power Purchase Agreements (PPAs) with JPS.

3.1 Generation

JPS currently owns and operates eighteen (18) thermal power generating units at four (4) sites (Rockfort, Hunts Bay, Bogue and Old Harbour), six (6) hydro-electric plants across the island and a wind plant making the total installed capacity of 640.62 MW as outlined in Table 1.

JPS Site	Generation Technology	Installed MCR (MW)
Old Harbour	Steam	223.5
Rockfort	Slow Speed Diesel	40.0
Hunts Bay	Steam	68.5
Hunts Bay	Gas Turbines	54.0
Bogue	GTs – Simple Cycle and Combined Cycle plants	225.5
Renewables* (seasonal)	Run of river hydro plants 3 MW wind farm (JPS-Munro)	29.1
Total		637.32

Table 1: JPS Generation Capacity by Location and Technology Type

3.2 Independent Power Producers

IPPs which are privately owned plants account for a total firm capacity of 262.16 MW of capacity, as shown in Table 2 below.

IPP Plant	Type	MCR (MW)
Jamaica Energy Partners (JEP)	Medium Speed Diesel	124.36
West Kingston Power Partners (WKPP)	Medium Speed Diesel	65.5
Jamaica Private Power Company (JPPC)	Slow speed Diesel	61.3
Jamalco Ropecon (Jamalco – St. Jago Road)	Cogeneration Conveyor Belt (non-firm)	11 0.5

Jamaica Broilers	Cogeneration (non-firm)	11
Wigton I	Wind (non-firm)	18
Wigton II	Wind (non-firm)	20
Firm Total		**262.16**

Table 2: Independent Power Producers Plant Capacity

3.3 Transmission

The JPS transmission system operates at two voltage levels, 138 kV and 69 kV. The 69kV system is linked to the 138 kV system through 837 MVA of 138/69 kV inter bus transformers. The system consists of sixty-one (61) individual transmission lines and fifty-three (53) substations. This transmission system transmits power from twelve (12) generating stations to fifty-three (53) distribution substations dispersed across the island.

The 138 kV lines (11 in total) are the bulk power transmission circuits in the network and spans 379 km in length.

The fifty-three (53) 69 kV circuits operate as the sub-transmission system spanning a total length of 826.5 km and provide the primary supply circuits for all the power distribution substations.

Figure 1 below gives the geographical layout of the JPS transmission power grid which comprise of a 69 kV and 138 kV transmission network, highlighted in red and blue respectively.

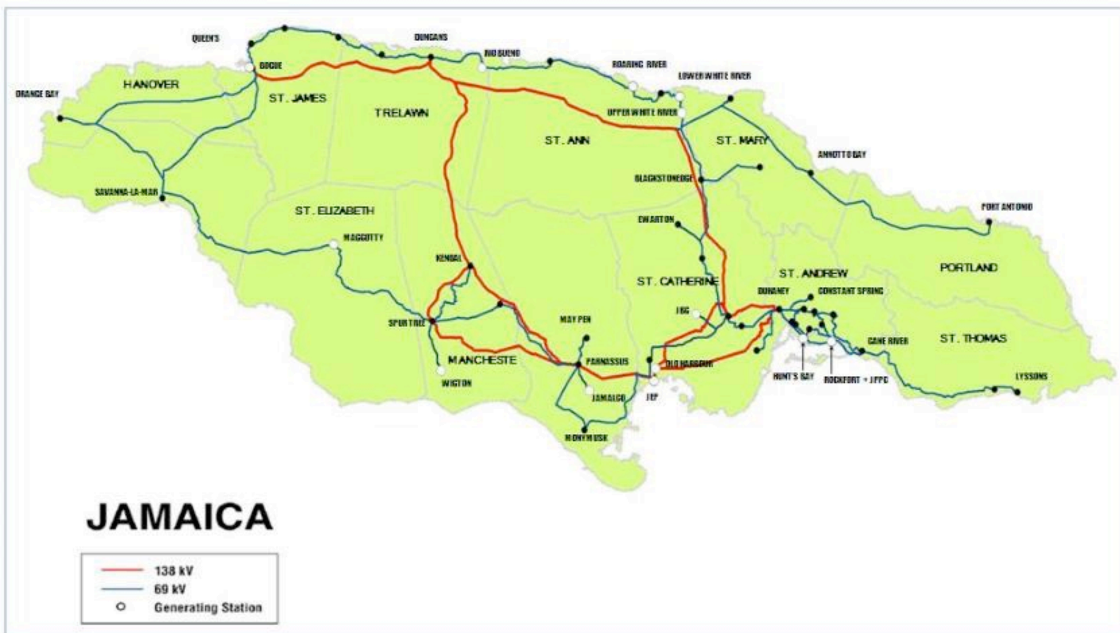

Figure 1: Geographical layout of the JPS 69 kV and 138 kV transmission network

3.4 Distribution

The distribution system consists of 110 feeders covering 14,000 cct. km of primary network operating at 24 kV, 13.8 kV, and 12 kV, and is primarily overhead bare conductors. The secondary distribution network provides service to the majority of customers at 110 V, 220 V and 415 V. The majority of the circuits are of wood pole construction (80%), which is being systematically replaced by concrete poles.

Capacitor banks are installed on distribution feeders to improve power factor and provide proper voltage to customers.

3.5 Protection and Control

The integrated JPS power system is comprised of Generation, Transmission and Distribution. Various subsystems are employed for protection, monitoring and control of the various elements of the system. JPS report summarised the protective relaying philosophy for generation, transmission and distribution systems.

3.6 Generator Protection

To protect the generators from abnormal and fault conditions, the following protection schemes are used:

- Differential protection: (1) High-speed unit protection that covers the generator; and (2) High-speed overall differential that covers both generator and step-up transformer.
- A combination of electromechanical relays and microprocessor-based relays are used for the older units while the combined cycle plant and the hydro plants utilize microprocessor-based relays.
- Ground faults in the generator windings are covered by a stator ground fault relay
- Generator over-speed protection is employed to protect the machine when there is a sudden loss of load; for the gas turbines, an over-frequency relay is used.
- Loss of excitation protection and exciter under-voltage protects against machine operating as an induction generator and absorbing reactive power from the grid.
- Other mechanical trips are employed for the boiler and turbines.

3.7 Transmission Line Protection

Three-zone distance protection is used for transmission lines protection. On the 138 kV system and some critical 69 kV lines, communication assisted trip is employed in a permissive overreaching transfer trip (POTT) scheme with reverse zone 3 and sensitive ground directional overcurrent function to detect high impedance faults and echo trip is employed for open circuit breaker condition. An accelerated zone 1 communication assisted tripping scheme is employed on all 138 kV line.

3.8 Under-frequency Load Shedding Scheme

In instances of generation-load imbalance when there is a sudden increase in load or a generator trips off-line, automatic under-frequency load-shedding is employed to restore the balance and maintain nominal frequency. The scheme also gives the operator enough time to respond and take corrective action. Five stages are employed as shown in Table 3 below. Each stage is delayed by 0.15 seconds.

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Stage	Frequency Threshold (Hz)
0	49.35
1	49.2
2	48.9
3	48.5
4	48.1

Table 3 Under-frequency load shedding scheme

3.9 SCADA/EMS

The SCADA/EMS is the main computer system that is used by the System Control Engineers and Planning Engineers in managing and controlling the power System on a daily basis. The basic SCADA (**S**upervisory **C**ontrol **A**nd **D**ata **A**cquisition) system is an integrated technology composed of the following four major components:

- Master Station: The Master Station is the collection of computers, peripherals and appropriate input and output (I/O) systems that enable the operators to monitor the state of the power system and control it.
- RTU: The remote terminal unit (RTU) serves as the eyes, ears and hands of the SCADA system. The RTU acquires all the field data (Volts, Amps, Watts, Vars, etc.) from different field devices, process the data and transmit the relevant system parameter data back to the master station.
- Communication System: This refers to the communication channels employed between the field equipment and the Master Station
- Human-Machine Interface (HMI): HMI refers to the interface required for the interaction between the Master Station and the operators or users of the SCADA system

The EMS supplies operational staff with a powerful suite of information management tools that allows them to visualize, anticipate, and respond to ever-changing system conditions.

3.10 Electronic Communication System

The JPS Communications Network consists of both a Digital Microwave Network (island-wide) and a fibre optic network in all parishes except St Mary, Portland and St Thomas. This provides the transmission medium for JPS's internal communications including SCADA, voice and data traffic. The SCADA System uses this network for communicating with the SCADA/EMS system at System Control. For the areas of the island where no fibre exists, the Digital Microwave system is used as the primary communication medium and a mixture of analog and PLC equipment is used as backup for SCADA.

4. Power Grid Operating Criteria

To ensure that the power grid operates in a safe and reliable manner under normal and contingency conditions, operation parameters limits for the system and the elements interconnected thereto have been established and codified.

4.1 Generation Dispatch

JPS is required to operate the generating system in an economic manner such that system load demand is met in a least cost manner subject to system safety and reliability constraints.

Generating units are committed into service based on their full load variable operating cost and dispatched using the equal incremental cost dispatch principle. The next increment of demand is served by the online generator that can provide it at least the incremental cost. There is provision for necessary adjustments to accommodate for plant and transmission limitations in a security constrained dispatch mode.

The system shall operate with a minimum spinning reserve margin of 30MW.

This has been established as the balance between economy and maintaining system security. The spinning reserve margin is the excess of online generating capacity and the system peak load at a point in time.

4.2 Frequency Range

4.3 System

The normal operating frequency of the System Grid shall be controlled by the System Operator to be within 50.0 Hz ± 0.2 Hz.

4.4 Generating Unit Operation

Generating units shall be design to operate between the frequency range between 48.0 Hz and 52.5 Hz.

4.5 System Voltage

The system voltage requirements under normal and contingency conditions are given below. The voltages will vary at different locations in the system but should be maintained within the limits prescribed by the Generation Code and set out below.

The Normal Operating voltages shall be within:

a) ± 5 % at the Generator Bus;
b) ± 5 % on the Transmission System;

The contingency (abnormal) operating voltages shall be within:

a) ± 5 % at the Generator Bus;
b) ± 10 % on the Transmission System.

4.6 Transmission Line Thermal Loadings

Under contingency conditions, transmission line loading of up to 110% of continuous rating for 30 minutes (Emergency Rating) may be used.

4.7 The Power Islands

The power system disturbances which occurred separated the power grid into two independent electrical power islands, the Eastern Power Island and the Western Power Island. JPS referred to the Eastern Power Island as the corporate area sub-system and the Western Power Island as the rural area sub-system.

The Eastern Power Island (EPI) comprises of the following Corporate area substations and all substations in St. Thomas. In their investigation JPS classified the following area as corporate area:

- West Kings House
- Hope

- Up Park Camp
- Cane River
- Cement Company
- Rockfort
- Greenwich Road
- Hunts Bay

The Western Power Island (WPI) comprises of the following Corporate area substations and all remaining substations for all the other parishes except St. Thomas:

- Three Miles
- Port Authority of Jamaica (PAJ)
- Washington Boulevard
- Constant Spring
- Duhaney

Figure 2 below gives a pictorial view of the two subsystems.

The corporate area power island survived after the loss of some generation and the load shedding of some customers.

A total of 456 MW of generation were lost, affecting approximately 547,734 customers. Most customers were progressively restored within three (3) hours.

The JPS report did not provide any assessment of the cost associated with the outage as required by section 45 (12) of the Act.

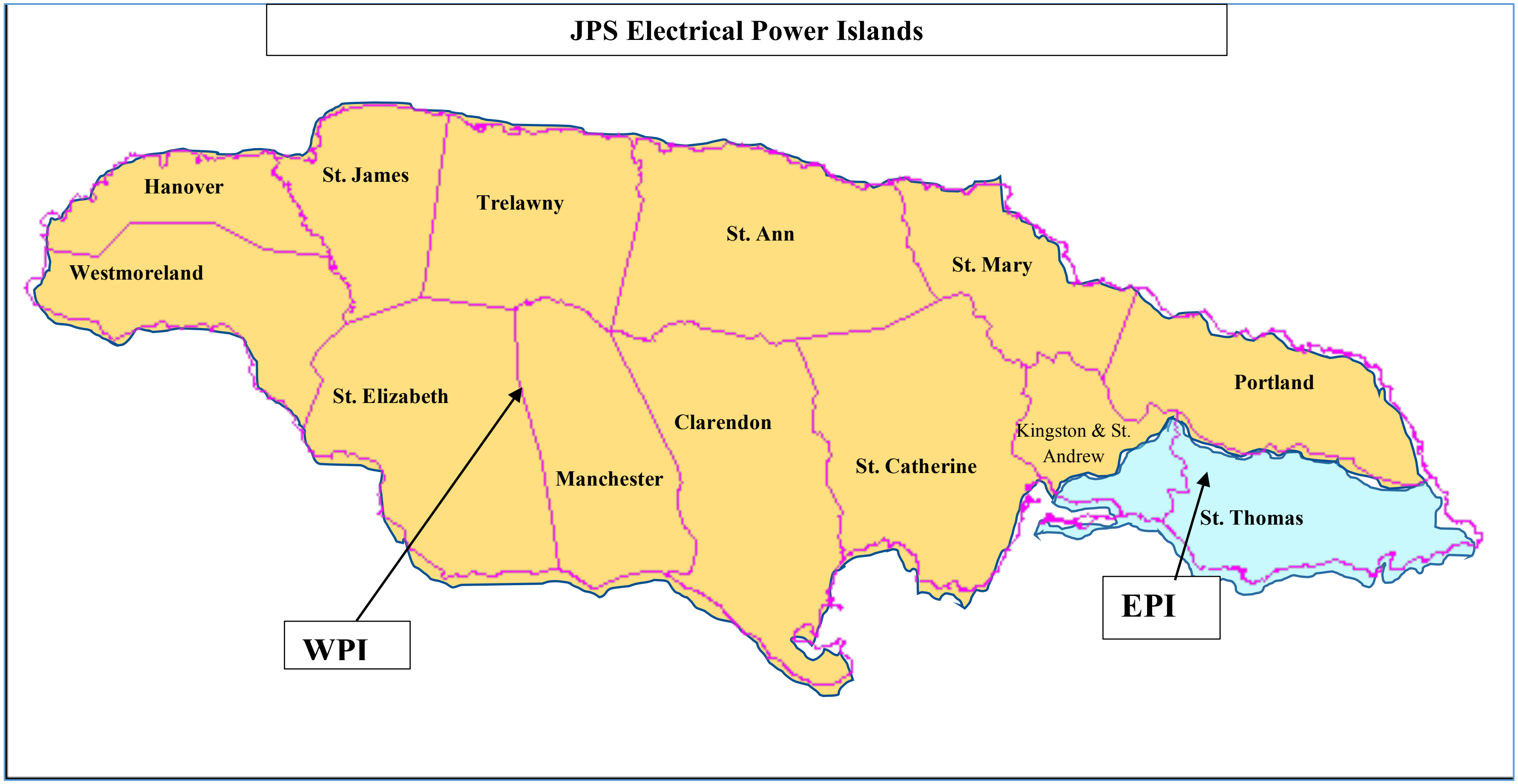


Figure 2: JPS Electrical Sub-Systems

5. System Conditions Prior to Failure

This section reviews and analyzes the status of the electric system prior to and leading up to the system failure. The analysis looked at the system prior conditions to see if they were abnormal in any way that may have contributed to the outage incident.

5.1 Weather Condition

According to the JPS investigation report fair weather conditions existed across most of the island. There were no meteorological projections for any onset of major inclement weather conditions that would have affected the performance of the outage.

OUR assessment

It can therefore be inferred that the prevailing weather conditions was not a negative factor in the execution of the planned maintenance outage, or a contributing cause of the subsequent system failure.

5.2 System Loads

5.3 System Load Projection on Day

Each day JPS prepares two gross plant capability reports (GPCR) for the generating system. One report is issued at 7am in the morning and the other at 3pm. These reports provided information on generating plant capability for each period and the expected system gross peak demand for both day and evening peak, and the actual peak demand for the previous day. Table A1 in the Appendix below provides the GPCR for 2016 April 17.

Based on the GPCR report for Sunday 2016 April 17 the projected day peak was 481.8 MW expected at 2:30 pm, and the evening peak 589.1 MW expected at 8 pm.
Figure 3 below gives the load profile for the previous Sunday of 2016 April 10. This shows the rapid load changes to be expected between 6:30 pm and 8:00 pm on a typical Sunday. The day of the outage was expected to follow this profile. The Jamaica Manufacturers Association (JMA) exhibition at the National Arena was not expected to have any impact on the load profile.

OUR Assessment

These load expectations were typical of the system Sunday demand profile and therefore not unexpected on the day, since there were no adverse weather conditions or any planned extraordinary event(s) which would have caused any meaningful changes to the load profile.

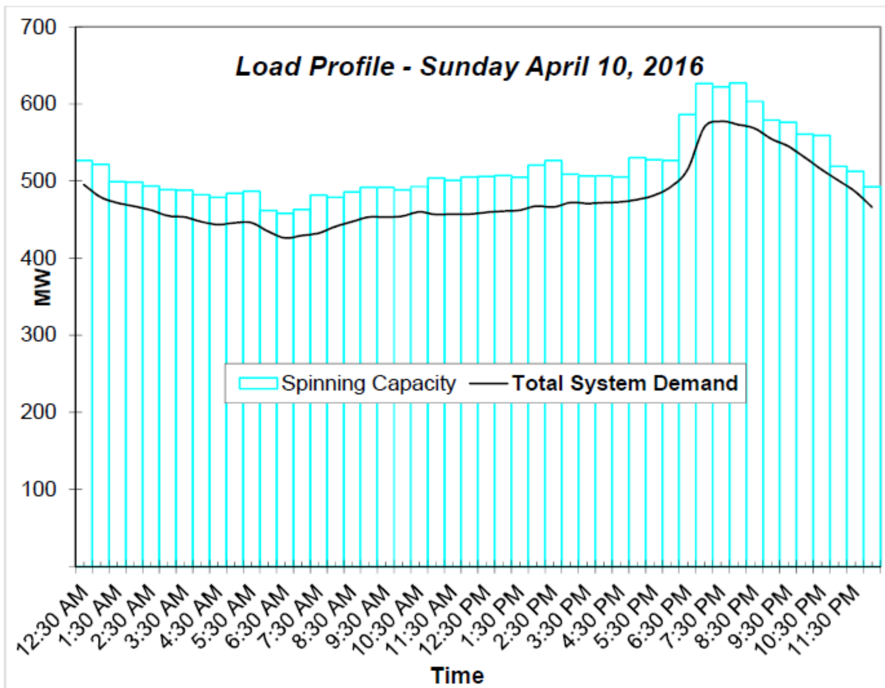


Figure 3: System Load Profile Sunday 2016 April 10

6. **Generating System Availability Status**

In order to ensure the safe and sustained operation of the generating system, generating units are removed from service for planned and routine maintenance on a scheduled basis. Generating units are also forced out of service by unplanned breakdown and the need to repair. In a properly planned and maintained generating system the installed plant capacity is sufficient to allow for units to be taken out for maintenance and be able to have available sufficient capacity to meet system peak demand and provide adequate spinning reserve to take care of unanticipated changes in load and generation.

6.1 Generating System Availability on 2016 April 17

From the 2016 April 17 Gross Plant Capability Report (GPCR) at 3:00 pm the available generating capacity was 573.66 MW. This capacity was available from a total installed capacity of 902.78 MW and a firm capacity of 861.78 MW. A total of 288.12 MW of generating plant capacity was unavailable, or 33.4% of firm installed capacity not available to meet demand.

This was the case due to a number of generating plants that were either taken out of service on planned and forced outages, or were de-rated over long period of time for various reasons. Table 4 below provides details of the generating system status.

Based on the load projection of 589.1 MW for the evening peak and the available generating capacity there would have been an expectation of a generation shortfall of about 15.5 MW to meet the expected system peak demand.

Generating Units	MCR (MW)	Output	
		MW	MVAR
HUNTS BAY B6	68.5	54.26	12.36
HUNTS BAY GT5	21.5	18.59	-0.78
HUNTS BAY GT10	32.5	29.37	-2.64
WKPP	65.5	66.3	5.60
JPPC	61.3	36.49	7.02
ROCKFORT RF1	20	18.48	1.75
ROCKFORT RF2	20	20.87	1.54
OLD HARBOUR #2	60	55.5	34.83
OLD HARBOUR #3	65	50.02	18.01
JEP	124.36	108.2	41.10
JA. BROILERS		2.02	-0.90
BOGUE GT3	21.5	19.25	1.75
BOGUE GT6	18	14.77	0.00

Generating Units	MCR (MW)	Output	
		MW	MVAR
BOGUE GT7	18	17.36	-0.14
BOGUE CC	57	52.92	18.13
ROARING RIVER	4.05	3.01	0.98
UPPER WHITE RIVER	3.19	1.14	0.00
LOWER WHITE RIVER	4.75	1.39	1.76
MAGGOTTY 1	3.15	3.02	0.02
MAGGOTTY 2	3.15	2.93	0.11
RIO BUENO A	2.5	2.24	0.91
RIO B	1.1	0	0.00
CONSTANT SPRING	0.77	0.5	0.00
WIGTON	38	0	6.18
JAMALCO	11	0.78	3.98
Total System Demand		**579.41**	**151.57**
Spinning Reserve		**22.11**	
Frequency		**49.98**	

Table 4 Generation Dispatch at 6:59 pm

OUR Assessment

The low generating capacity to meet the projected system peak load demand would have put the system security at risk by compromising the ability of the system to react to load increases and or sudden loss of generation.

6.2 Generation Spinning Reserve Margin

The spinning reserve is the difference between the generating plant capacity online and the load demand at any point in time.

To maintain a balance between system security and costs a minimum spinning reserve of 30 MW is required by the Generation Code. Table 5 below shows the spinning reserve margin distribution in each of the sub- system based on the system load and available generation just prior to the outage.

Generating Units	Generation (MW)		
	Availability	Dispatch	Spinning Reserve
Corporate area generation - EPI			
HUNTS BAY B6	68.50	54.26	14.24
HUNTS BAY GT5	21.50	18.59	2.91
HUNTS BAY GT10	31.00	29.37	1.63
ROCKFORT RF1	20.00	18.48	1.52
ROCKFORT RF2	20.87	20.87	0.00
WKPP	66.30	66.30	0.00
JPPC	36.49	36.49	0.00
Subtotal	**264.66**	**244.36**	**20.30**
Rural area Generation – WPI			
OLD HARBOUR #2	56	55.5	0.5
OLD HARBOUR #3	50.02	50.02	0
OLD HARBOUR #4	0	0	0
JEP	108.2	108.2	0
Subtotal	**214.22**	**213.72**	**0.5**
BOGUE GT3	20.5	19.25	1.25
BOGUE GT6	14.77	14.77	0
GT7	17.36	17.36	0
GT8	0	0	0
GT9	0	0	0
GT11	0	0	0
GT12	0	0	0
GT13	35	35	0
ST14	17	17	0
Subtotal	104.63	103.38	1.25
Rural area Total - WPI	**318.85**	**317.1**	**1.75**
Hydros & Co-gen	17.95	17.95	0
System Total	**601.46**	**335.05**	**22.05**

Table 5 Spinning Reserve Margin Distribution

OUR Assessment

Based on the generating system status as shown in the Generating Plant Capability Report (GPCR) of the available generating plant capacity as shown in Table A-1 of the Appendix

, and the system demand and dispatch as shown in Tables 4 and 5 there was a high probability that the system would be unable to meet the demand requirement and planned load shedding would have to be implemented to preserve system security. Given the load–generation balance in the sub-systems, as shown in Figures 4 and 5 approximately 59 MW from the corporate area sub-system would have to be exported to the rural area sub-system via the Duhaney – Washington Blvd 69 kV line for the day peak and 118 MW to meet the evening peak. The system would therefore be at risk of separation during the evening peak given the relatively high load level that would be encountered on this single line connecting the corporate and rural areas. The spinning reserve of 22 MW was inadequate to offer relief to the system in event of sudden reduction in generation and/or sudden load increases. The rural area was severely compromised due to the very uneven distribution of the little available spinning reserve with only 1.75 MW of spinning reserve.

Old Harbour Unit 4 was forced off line the previous day at 4:57 am and was planned for return to service on the 18 April at 10 am. This situation further compromised the system security which should have been evident to the system controllers and the outage planners. This brings to serious question as to the level of coordination between the system controllers and the outage planners and also their level of situational awareness. We would expect that risk assessment should have been carried out to understand the exposure to the system security by going into the outage with this low level of generating plant availability.

It is noted that a relatively large generating capacity was unavailable mainly in the rural areas. At Bogue a number of plants were on long term outages. This situation is reflective of issues in maintaining plant in reliable operating conditions. This in and of itself serves to reduce the ability of the system to respond to contingencies and hence reduce system reliability and security. The system operator has a responsibility to provide reliable service. It is therefore necessary to ensure plants are made available in a timely manner and an appropriate maintenance programme be put in place to improve the availability of the generating plant.

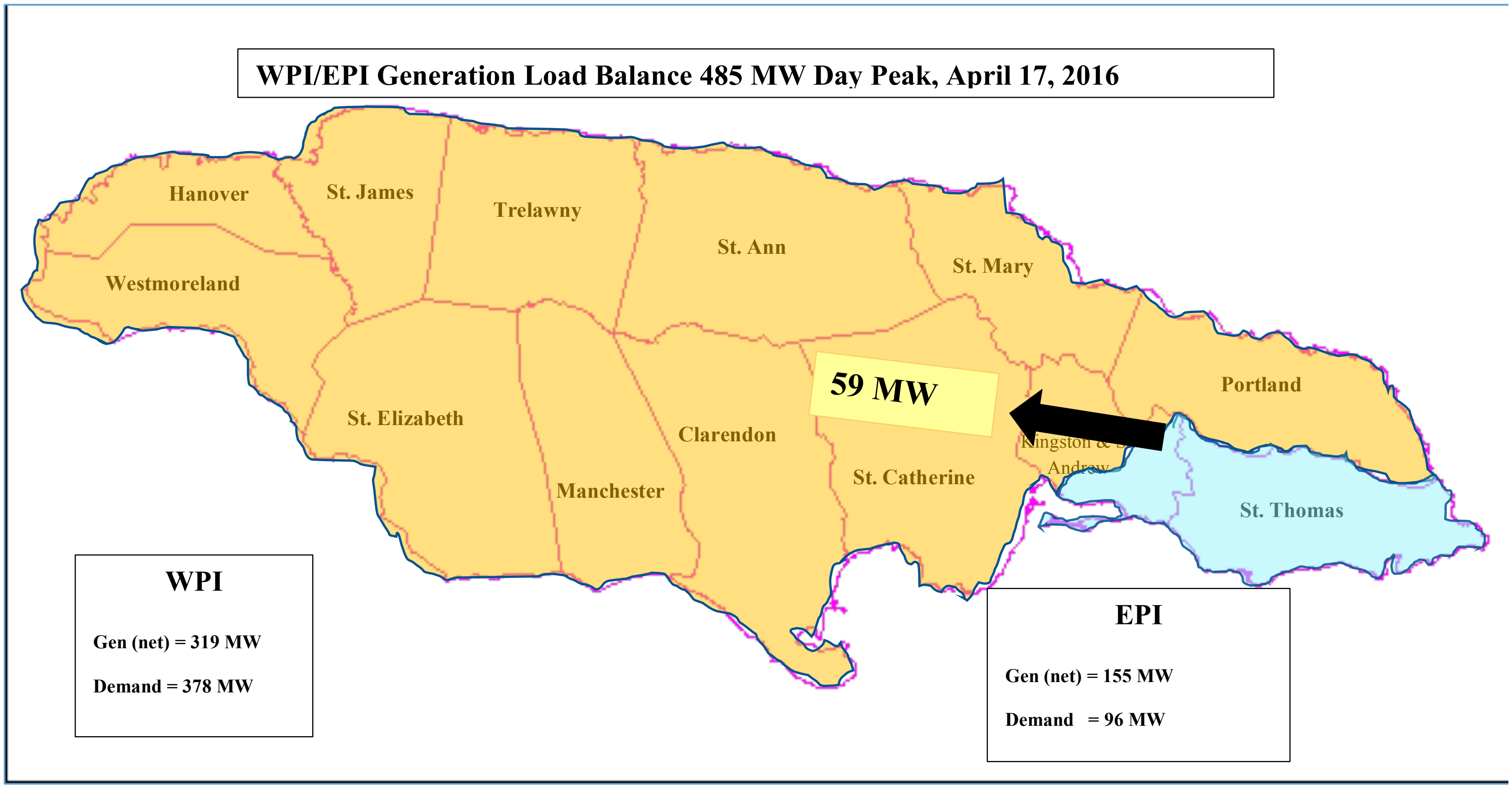


Figure 4: JPS Electrical Sub-systems load balance at 485 MW

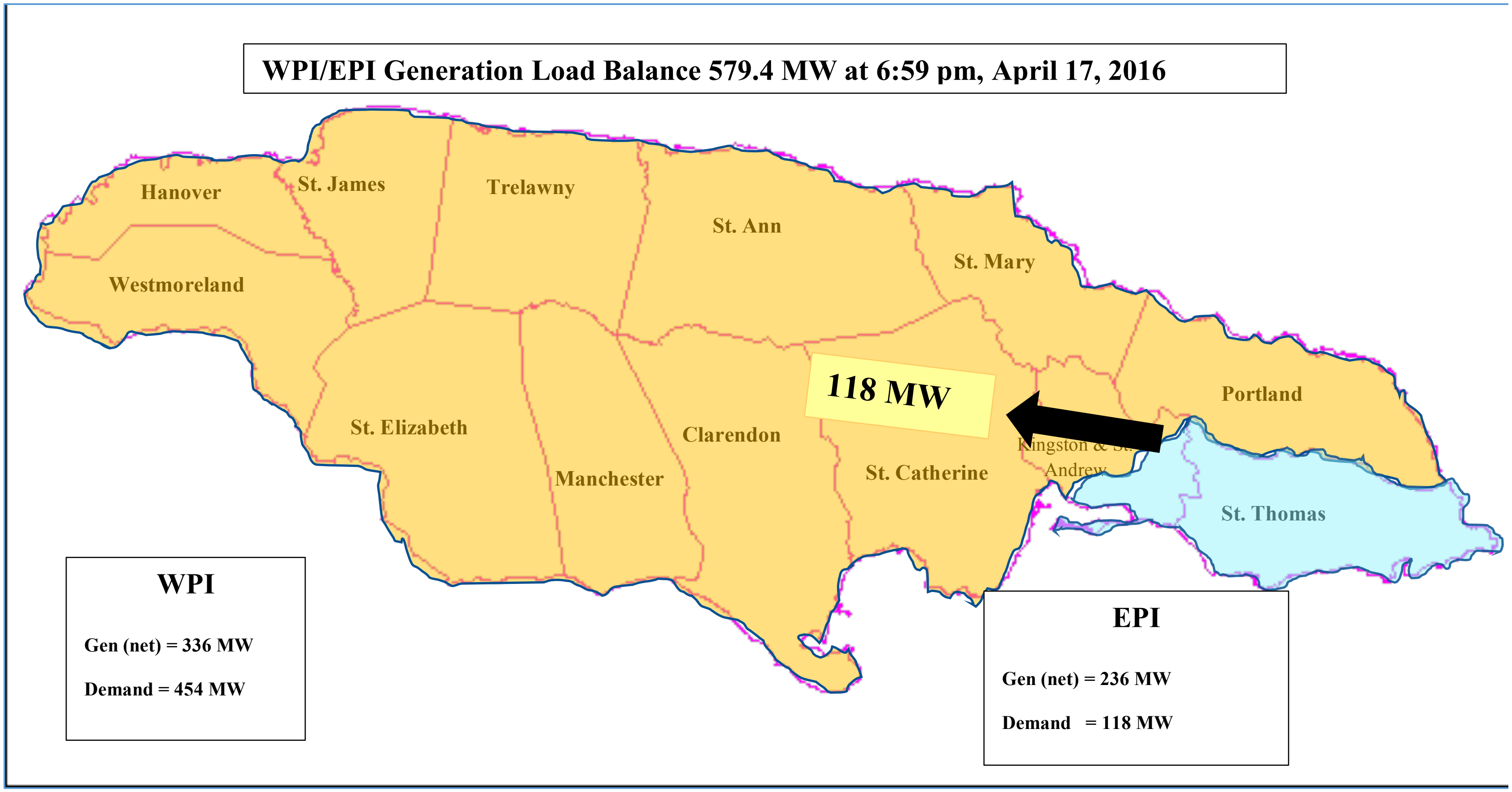


Figure 5: JPS Electrical Sub-systems load balance at 579.4 MW

7. Transmission System and Configuration

7.1 Transmission lines Planned Outages

The following 69 kV transmission lines were on planned outage.

Hunts Bay to PAJ 69 kV (Hunts Bay 'B' Line 2)

Hunts Bay to Duhaney 69 kV (Hunts Bay B Line 1)

Figure 6 shows the electrical single line configuration of the corporate area 69 kV transmission network and highlights the Duhaney – Hunts Bay and the PAJ – Hunts Bay lines.

The lines were planned to be taken out of service between 7:00 am to 6:00 pm for pole relocation work. No other transmission outages were planned for the day. However, the line outages were delayed and did not start until 10:55 am when the permit to work was issued.

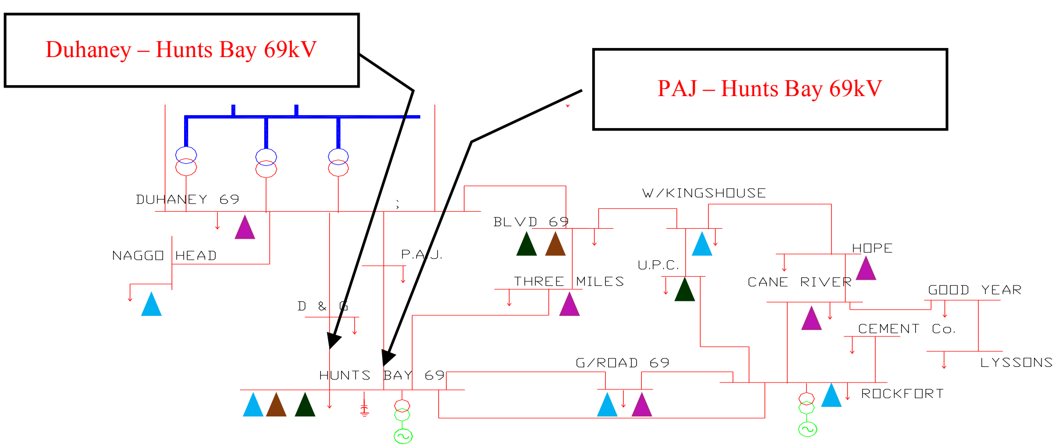


Figure 6: Corporate area 69 kV Transmission Network

OUR Assessment

Taking these lines out of service simultaneously would put the system in an N-2 line outage contingency. The situation was further compounded due to the fact that these lines emanated from the Hunts Bay power station which prior to the outage would be generating about 169 MW. This would put the Hunts Bay- Three Miles 69 kV line under severe loading stress.

The factors advanced by the system operator for the late start of the outage included;

- *No switchers were available at Hunts Bay to carry out the switching at 7:00 am as planned.*
- *Adjustment was made in the switching order at Hunts Bay to facilitate load transfer to the Three Miles substation.*

The above situation would indicate that there was a lack of management control of personnel resources and outage planning coordination. Given the nature and location of the line outages, both lines emanating from a major power station in the load centre and with the low availability of generating plant it would be expected that a more serious approach would have been adopted. This perhaps is a manifestation of the lack of awareness of the system operation issues on the part outage planners and system controllers. At best better contingency plans should have been put in place to protect the security of the system given the late start and the low generating plant availability.

In developing any transmission system outage plan it is the responsibility of the system operators to make themselves aware of all generating units that will not be available on that day. With this information, the system operator is required to carry out the appropriate contingency analyses study to identify any weaknesses such as equipment loading limits, line transfer capabilities, and voltage conditions on the system in order to make the correct decision to ensure grid security. Knowing the status of key facilities at all times is most critical to allow quick reaction to incipient conditions. On the face of the information provided in the JPS report contingency analyses were carried out for day peak period to determine loadings of critical lines. The contingency analyses identified the loading of the critical lines within the corporate area. However, a contingency analysis was not carried out for the expected load beyond 6pm even though the outage was delayed and the work scope was not adjusted. This clearly is a lack of proper planning and situational awareness on the part of outage planners, system controllers and operation managers.

Although JPS had established the outage planning criteria/constraints, it was very evident that they did not abide by these very constraints which they had established. This could have resulted from a lack of proper outage management and coordination on the part of outage planners, system controllers, and operation managers.

It is also a matter for serious concern that there was no clear distinction between the thermal rating of the transmission lines and the actual thermal overload trip setting for the lines as evidenced by the values provided in Table 3-11 and Table 4-1 of the JPS report.

8. **Planned Distribution Outage**

Distribution outages and load transfers for the day are given below.

8.1 Load Transfers

In order to facilitate the planned transmission outages, JPS indicated that a number of distribution system load transfers were necessary and these are listed below:

<table>
<tr><th colspan="2">From Substation</th><th colspan="2">To Substation</th></tr>
<tr><td rowspan="4">Hunts Bay</td><td>Feeder No.</td><td rowspan="4">Three Miles</td><td>Feeder No.</td></tr>
<tr><td>5-610</td><td>5-310 via Hunts Bay 5-710</td></tr>
<tr><td>5-710</td><td>5-310</td></tr>
<tr><td>5-810</td><td>5-510</td></tr>
</table>

Table 6: Load Transfers

*JPS did not indicate the amount of load transferred***.**

8.2 Other Planned Distribution Outage

Other planned distribution outages for the day were:

1. A section of the Kendal 237/6-310 feeder was planned for outage in the Scale community in Manchester.
2. Concurrently, a section of 237/6-310 from NCB Perth Road to Scale was transferred to the Spur Tree 64/6-310 feeder.

These works were scheduled to start at 9:00 am and end at 4:00 pm on 2016 April 17.

8.3 Unplanned Distribution Outages on Day of Outage

A major forced outage to correct hot joints on Queens Drive T2 transformer had several planning and logistical issues.

9. Equipment Outage and Error Readings Prior to System Outage

9.1 SCADA Electronic Communication

JPS provided a summary of the known communication issues prior to the grid disturbances as given in Table 7 below.

Site	Status
JEP2	Failed RTU
Catherine's Peak Repeater	Intermittent failure on radio identified on 2016 April 14 which affected SCADA circuits from Highgate, Port Antonio, Annotto Bay, and Oracabessa as this was a single point of failure. The cause of failure was an overheating RFU due to a failed A/C unit.
Greenwood	A/C powered router was identified as a vulnerability from a power audit done at the substation. Whenever this station lost power visibility would be lost as there was no inverter to power the AC router from the batteries. A DC power router was ordered to replace the existing router.
Martha Brae	A/C powered router was identified as a vulnerability from a power audit done at substation. Whenever this station lost power visibility would be lost as there was no inverter to power the AC router from the batteries. A DC power router was ordered to replace existing router

Table 7:Known defects on JPS communication system

OUR Assessment

The above communications issues served to reduce the visibility and data transfer of these points to the system controller. By reducing the means of monitoring system conditions, the ability of the system controllers to react in a timely manner to system operating issues in these locations was severely impaired.

The Old Harbour Digital Fault Recorder (DFR) was unavailable and this resulted in no fault events recorded for the outage events. This will negatively impact the availability of information for post outage analyses. JPS did not indicate the duration that this situation had existed.

It is critical that the maintenance of the communication system be given due priority and failures should be addressed as a matter of urgency

.

9.2 Contingency Analyses

Contingency analysis is a security application tool that is used by electric power utility operators to evaluate the security of the power network. This is necessary in order for the utility to develop ways to maintain system operation when one or more elements fail.

A contingency is the failure or loss of an element (e.g. generator, transformer, transmission line, etc.), or a change in the state of a device (e.g. the unplanned opening of a circuit breaker in a transformer substation) in the power system. Contingency analyses are utilized to analyze the power system operations in order to identify the equipment overloads, operating conditions and problems that can occur due to a "contingency". This analysis is useful to assist the system operator to look ahead and plan corrective actions to maintain system security and stability under various operating scenarios**.**

JPS system operators carried out the following base case and contingency analyses as a security assessment to determine the level of exposure that the network would be subjected to under the conditions tested, as well as to ascertain any violation of transmission line loadings and or voltage violations under the planned line outages.

These contingency cases included the following:

- A peak load of 485 MW which was the expected day peak. This was common to all the contingency runs.

1. Double Line outage of (base case N – 2 network condition);
    a. Hunts Bay – PAJ line and
    b. Hunts Bay – Duhaney

2. Duhaney – W/Blvd
3. Rockfort – Up Park Camp
4. W.K.H Rd - Up Park Camp
5. Hunts Bay –Three Miles
6. Hunts Bay – Rockfort

7. Washington Blvd – W.K.H. Rd

- The above included situations with and without Old Harbour Unit 4. Based on JPS's observation of the contingencies tested, the system would have been able to continue to operate within safe line loading limit for the above contingencies, except in the case of the Washington –Duhaney 69 kV line out which would result in a system separation.

9.3 Power Flows Prior to Outage

9.3.1 Key Transmission Line Loading

Table 3.3 of the JPS report gives the power flows on critical transmission lines at day peak load of 483.3 MW for two simulation scenarios and the actual and shown in Table 8 below.

Planned day peak - 485 MW with OH4				Without OH4 (Contingency) day peak - 485 MW			Actual day peak on April 17, 2016 - 483.1MW, No OH4			Trip setting
Corporate area Lines	**MW**	**Mvar**	**MVA**	**MW**	**Mvar**	**MVA**	**MW**	**Mvar**	**MVA**	**(MVA)**
Duhaney - W/Blvd.	-1.2	-8.7	8.8	-7.3	-8.7	11.4	-37.8	16.2	41.1	89.6
Rockfort - Up Park Camp	25.5	8.7	27.0	29.7	8.6	30.9	40.7	-0.17	40.7	95.6
Hunts Bay - Three Miles	45.4	15.8	48.0	45.8	16.2	48.6	63.4	1.9	63.4	86
WKH Rd. - Up Park Camp	-18.8	-8.5	20.6	-22.9	-8.3	-24.5	-32.1	0.6	32.1	95.6
WKH Rd. - W. Blvd.	1.3	0.9	1.6	7	-0.5	7	15.8	-4.9	16.5	71.7
Hunts Bay – Rockfort	11	11.6	16.0	1.3	12.8	12.8	15.8	7.2	17.4	95.6

Table 8: Loading on Key Transmission Lines in the Corporate area at Day Peak

OUR Assessment

Examination of the power flows on these critical lines shows significant differences between the actual and simulated values under similar system load and generation conditions. It therefore does not allow for decision making to rely on the simulated values and brings into question the reliance on this information to plan ahead. This is a matter of grave concern and would need further explanation from JPS.

9.4 Substations/Feeders Loading Data

JPS provided load data on 110 feeders derived from SCADA. On examination twenty two (22) of them as shown in Table A5 of the Appendix below are suspected to be in error for example;

- Radial feeders having negative MW.
- Substations/feeders where MW readings are zero with no mention of an outage on the respective substation/feeder.
- Feeders and substations where their MW loading is greater than the MVA capacity of the feeder and substation.

OUR Assessment

These discrepancies will require further explanation and/or verification on their impact on the system operations.

In addition, the Caribbean Cement Company Limited and PAJ substations were not included in the data provided and only the MW loadings were provided by JPS.

Table 9 below shows MW, MVAR and the limits for the branch flow as obtained from SCADA. These numbers do not represent the thermal capacity of the lines, but are the MVA equivalent of the pickup currents for the overcurrent protection of the respective lines.

BRANCH						
Name	**MW From**	**MW To**	**MVAR From**	**MVAR To**	**From Limits**	**To Limits**
BEL/TRE	-43.33	43.97	-14.44	16.28	71.71	114.73
BLK/SUN	-12.77	12.85	6.14	-5.97	43.02	71.70
BOG/BOG ST14	-52.58	52.61	-3.96	4.22	239.02	239.02
BOG/DUN	-22.25	22.41	-0.82	1.28	143.41	114.73
BOG/OBY	10.50	-10.39	0.76	-0.38	89.63	43.02
SPU/KEN	11.92	-11.91	4.72	-4.67	114.73	95.61
SPU/PAR	-34.12	34.29	-9.49	10.48	71.71	143.41
JEP/OHB	98.36	-98.24	54.46	-53.24	430.24	430.24

Table 9: SCADA Branch/Line flow data

9.5 Frequency Range

9.6 System

Prior to the outage the system frequency was 49.98 Hz which was within the normal operating frequency range 50.0 ±0.2 Hz.

9.7 Generating Units

There were no reports that any generating unit was operating outside the generator operating frequency range criteria limit of 52.5 Hz to 48 Hz. prior to outage.

9.8 Voltage Profile at Major Sub Stations

Figures 7 to 9 below depict major substations voltage profile and show that the voltages at the main 138 kV and 69 kV buses were well within the operating voltage criteria level prior to the system separation. Bus voltages were within the range of 144.9 -131.1 kV on the 138 kV bus and 72.45 – 65.55 kV on the 69 kV buses ie 0.95 – 1.05 p.u.

OUR Assessment

The slight reduction in voltage is due to the increasing load level over the duration. The generation power factor was 0.97 which would indicate that there were no requirement for additional reactive power support. System real power demand was 579.4 MW and reactive power requirement was 151.6 MVAr.

It can be concluded that voltage levels were not violated and voltage stability was not an issue prior to the outage and did not contribute to initiating the system outage.

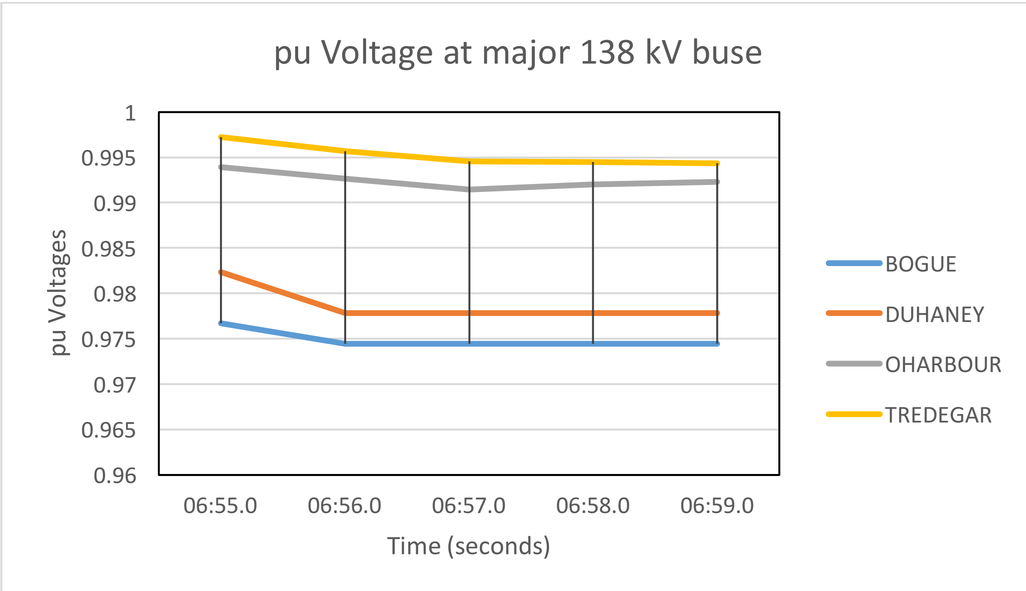
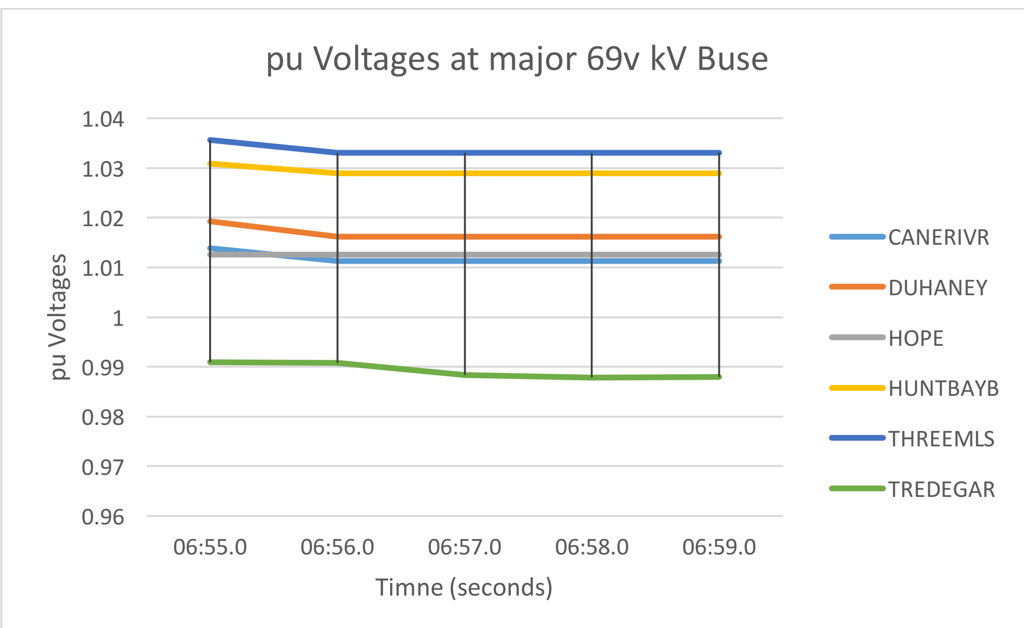


Figure 7: 138 kV substation bus voltage profile on April 17, 2016 at 6:59 pm



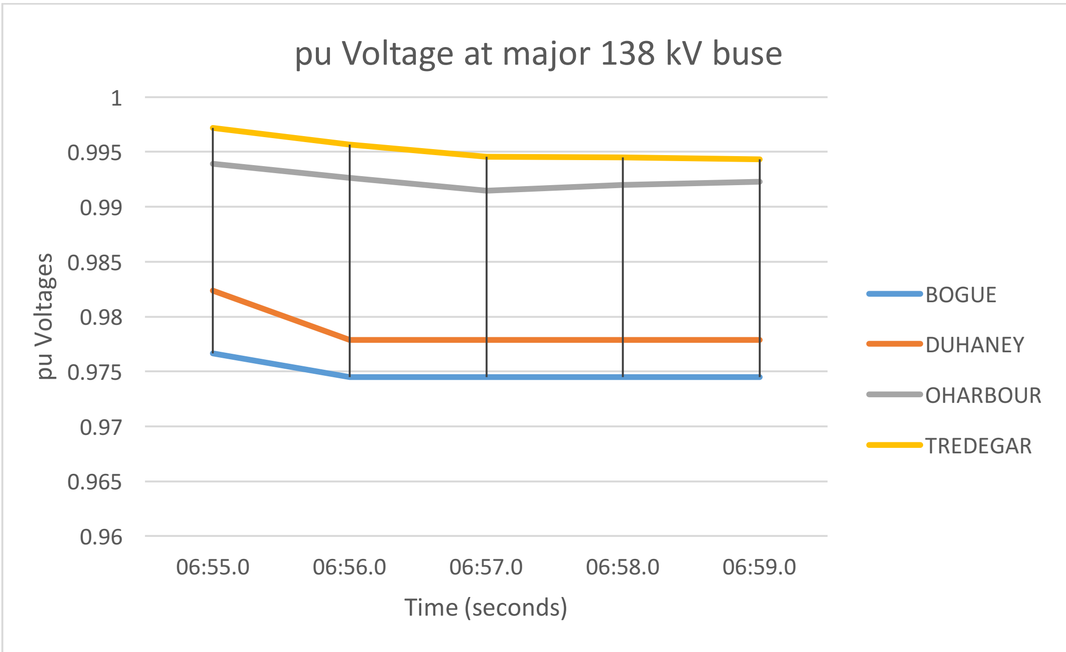


Figure 8: 69 kV substation bus voltage profile on 2016 Aprilat 6:59 pm

9.9 Transmission Lines Thermal Ratings and Pick Up Settings

Transmission lines are rated in terms of the maximum current capacity they can carry (thermal rating). Observing these ratings are of critical importance to ensure that the lines will not be at risk of losing either physical properties or reducing their economic lifetime. However, it is standard utility practice for lines to carry a certain percent overload for a short time and still maintain these properties. Protective systems are therefore necessary to ensure that lines do not operate outside of their limits for any extended period of time which are determined by manufacturers and system operators. Tables 10 and 11 below show the key transmission lines thermal ratings and line relay pick up settings provided by JPS.

Station	Circuit	Conductor		Relay Pick-up	
		Type	Thermal Rating (Amps)	Amps	% of Rating
Hunts Bay	Three Mile	394.5 MCM	532	720	135
Three Miles	Washington Blvd	394.5 MCM	532	720	135
Washington Blvd	Duhaney	559.5 MCM	663	752	113
West Kings House Rd	Washington Blvd	477 MCM	659	600	91

Table 10: transmission lines thermal ratings and relay pickup

Selected 69kV Circuit		Thermal Capacity		Loading at 18:59, April 17, 2016			
From S/S: (Relay Location)	To S/S: (Circuit Destination)	AMPS	MVA	MVA	MW	MVAR	AMPS
Duhaney	Washington Blvd.	720	79.2	77.12	-74.53	19.82	660.00
Rockfort	Up Park Camp	800	79.2	53.82	53.79	1.69	423.44
Hunt's Bay	Three Miles	720	63.6	72.06	72.00	3.03	600
Three Miles	Hunt's Bay	**720**	**63.6**	***95.27**	95.27	0.20	*** 771.67**
West Kings House Rd.	Up Park Camp	480	79.2	45.50	-45.50	0.35	359.20
West Kings House Rd.	Washington Blvd.	600	78.8	31.30	30.98	-4.43	244.35

Table 11: JPS SCADA transmission lines thermal ratings

10. Causal Events Leading to System Separation and Outage

10.1 Transmission Line Outage

This section provides an assessment of the causal events leading to the system outages.

The transmission line outages planned include;

- Hunts Bay to PAJ 69 kV (Hunts Bay 'B' Line 2)
- Hunts Bay to Duhaney 69 kV (Hunts Bay B Line 1).

The line outage was scheduled to last eleven (11 hours), between 7:00 am to 6:00 pm, in order to meet the day peak demand of 485 MW and to be completed before the evening peak load.

The start of the outage was delayed by nearly four hours.

OUR Assessment

The system security was, further compromised due to the late start of the outage programme, which was then expected to last beyond 6:00pm. At that time, the system load was expected to start increasing rapidly in order to reach the peak demand period which would occur between 6:30 pm and 8:00 pm.

JPS failed to adjust the work scope to account for the late start of the outage. It is not clear why contingency analyses were not performed at the expected evening peak load in order to advise on the system anticipated system performance and security issues beyond the day peak. A lack of situational awareness may have caused this omission, or personnel were not familiar with the system operations and the system load profile.

10.2 Personnel, Communication Issues

OUR Assessment

There were several personnel issues of concern going into the planned line outages, for example;

- *JPS report indicated that the system control 10 pm-8 am April 16 shift was very challenging for shift personnel due to the several outages which were all scheduled to start at 7am.*

- *It was also reported that the beginning of the 8am – 2pm April 17 shift was hectic due to the high volume of switching activities in progress.*

- *There was a concern by the shift supervisor who handed over the shift to the 2pm-10pm team about the contingency concerns, the work load and the late start of the outages.*

These issues may have had a negative impact on the efficiency and awareness of the shift personnel and their ability to perform effectively under the circumstances.

There were also communications issues which negatively affected the situation for example;

- *Futile attempts were made to contact the outage supervisor between 5:30 pm and 6:10 pm. The outage supervisor failed to inform the system controllers that the outage would have gone beyond 6:00 pm.*

- *Communication regarding the extension of the outage to the system controllers through a regional director was made after 6:15 pm indicating that the lines would be returned within an hour which would then be by 7:15 pm. Given this information and understanding the generation situation and the line loading limits, it would be expected that the system operator should have manually shed load to avert the oncoming load increases and reduce the line loadings.*

- *Based on the nature of the communications on the outage status it would seem that the approach to the outage was casual and the importance to return the lines on time was not properly understood by the regional personnel, outage supervisor and the system control personnel.*

- *JPS did not provide or indicate in their report that there was an outage organization which included clear lines of authorization, communication, management and functional responsibilities for the outage activities.*

- *From the information provided it was not evident that frequent and sufficient updates on the status of the outages were provided to the system operators, nor were such updates sought. There was no mention of the role and responsibilities of an outage manager, or if there was indeed an outage manager.*

- *No contingency analyses were carried out to determine the performance of the system under the increasing load conditions after 6 pm. An understanding of the importance of returning the lines before the onset of the evening peak or the lack thereof, was a crucial factor leading up to the subsequent events.*

10.3 Inadequate Contingency Analyses

JPS had carried out the following contingency analyses for the day peak demand of 485 MW. With the transmission network already in the N – 2 line outage state, these contingencies would represent a N – 3. Hence, the network could be very vulnerable under any of the contingencies.. These contingencies are as follows;

1. Duhaney – Washington Blvd 69 kV line out
2. Rockfort – Up Park Camp 69 kV line out
3. West Kings House Rd - Up Park Camp 69 kV line out
4. Hunts Bay – Three Miles 69 kV line out
5. Hunts Bay – Rockfort 69 kv line out
6. Washington Blvd – West Kings House Rd out

OUR Assessment

The above contingencies included situations with and without Old Harbour Unit 4 online. Based on JPS observation of the contingencies tested, the system would have been able to operate within safe line loading limits for the above contingencies, except in the case of the Washington –Duhaney 69 kV line out which would result in a system separation if tripping occurred.

The OUR noted that the contingency analyses were only carried out at a peak load of 485 MW . However, having known that the outage was delayed by nearly hours and with no reduction in scope, it would have been expected that additional contingency analyses would have been carried out at the expected system peak of about 580 MW. Sufficient time was available to do these contingency analyses which would have identified potential equipment overloads which would have provided the system operator with better situation awareness, and perhaps would have revealed the critical nature of the system security, thereby providing a better understanding of the generation load balance by the system controllers. With contingency information at 580 MW loading the operator might have taken action to reduce line loadings and may have avoided the system outage and separation.

JPS had planned to manually shed 25 MW of load from a combination of the following feeders;

- *Roaring River 4 – 210*
- *Rhodens Pen 4- 310*

- *Tredegar 6 – 210*

In all six contingency cases that JPS looked at for the 485 MW loading , the most severe case was the loss of the Rockfort – Up Park Camp 69 kV line, where the line loading was 105% of the thermal capacity of the conductor. JPS had anticipated an evening peak of about 589 MW and it was known that there would not be sufficient generating capacity to meet the demand and spinning reserve requirements. Under normal operating conditions with the two lines from Hunts Bay in service, the shedding of the 25 MW would have been sufficient for the safe operation of the system. However, with the two lines out of service and with the Hunts Bay – Three Miles taking out the bulk of the power from that area, the loading of this line and other critical circuits within the area became the determining factor.

Therefore, with regard to the outage and the fact that OH4 was out of service before the start of outage as well as the late start, JPS should have made either of two decisions;

- *Cancel the line outages for a day when more favorable conditions would have existed on the generation system.*
- *Limit the system demand to about 485MW, in light of the loading on the Rockfort – Up Park Camp 69 kV line. Hence, JPS would have to shed about 100 MW of the load. This would have been a more favourable outcome than risking the shut down of the system.*

JPS personnel cannot be excused for confusing the trip setting of the lines as their thermal ratings, because the information in the JPS report provided information for both the line ratings and the relay set pickup current of the lines.

The decision to bring GT #10 online at 6:30 pm was not a prudent decision, given that the Hunts Bay – Three Mile line was already heavily loaded and further increase in loading would risk tripping the line. This decision further aggravated the already marginal situation.

10.4 Violation of Planning Criteria/Constraints

After review and analysis of the outage plan, JPS established the following criteria which they indicated must be observed in order to maintain system security;

1) Load on the remaining one (1) transmission line in the corporate area (Duhaney – Washington Boulevard 69kV line) should be kept between (0-10 MW). If this wat done no other transmission violations would have resulted and the system would have been in a more stable state.

OUR Assessment

JPS violated the planning criteria it had established with regards to the flow on Duhaney – Washington Blvd. line into the Duhaney substation which at 6:00 pm was 40.10 MW. It should be noted that the Hunts Bay – Duhaney and the Hunts Bay-PAJ lines were still on outage because of the late start of the outage. This situation might have been as a result of poor outage communication with the outage stake holders or these criteria were not fully appreciated or communicated.

2) *If there were any unplanned changes on the transmission/generation system before or during the outage (e.g. Transmission Line or Generator force outage) then the outage plan/scope should have been re-assessed.*

Though it became obvious to JPS that the outage would have gone beyond 6:00 pm. It appears that no re-assessments were carried out for this situation. This calls into question the planning and management of the outage activities. It was not evident that there was an outage manager or if so, his responsibility in assessing the outage activities was not evident.

3) The scheduled outage must be completed at 6pm.

Given the late start of the outage it was clear this was not going to be possible. However, it appears that sufficient action was not taken to manage this contingency or that further analyses were not carried out to determine the impact of the delay in light of the expected rapid increase expected in system load after 6 pm.

*4) The available MW required in the corporate area should at least be **226.5 MW**.*

This is in order to have sufficient generation available in the corporate area, should there be a trip of B6 (68.5 MW, the largest available generator in the corporate area). This is *based on an expected **152 – 158 MW** of online corporate area generation required to keep the aforementioned monitored line within 0-10 MW during the day peak period.*

5) *The available MW in the rural area should be at least **395.5 MW**. This is to have sufficient generation available in the rural area, should there be a trip of OH4 (68.5 MW, the largest available generator in the rural area). This is based on an expected online rural area generation of **327 – 333 MW** required to keep the aforementioned monitored line within 0-10 MW during the day peak period.*

   *From the data provided in the GPCR of the day, the available rural area generation was 332 MW. It was reported in the GPCR that OH4 was unavailable from 4am on the previous day April 16, and not expected to return to service before April 18 at 10am. It is clear that in developing the planning constraints this was not taken into account. This again represent a violation of the outage criteri*a *established by JPS, and again points to a lack of outage planning, communications and effective operations management.*

10.5 Violation of Generation Spinning Reserve Margin

OUR Assessment

Based on the system load and the online generation capacity at 6:59 pm the spinning reserve margin was 22.11 MW. This is a violation of the existing Generation Code which mandates a minimum spinning reserve requirement of 30 MW at all times.

The spinning reserve status of the two subsystems is shown in Table 12.

Sub-system	**Generation (MW)**	
	Dispatch	**Spinning Reserve**
Corporate area Generation - EPI	244.36	20.30
Rural area Generation - WPI	317.10	1.75
Hydro & Co-gen	17.95	0.00
Total	**579.41**	**22.05**

Table 12: Distribution of spinning reserve

To compound the situation the spinning reserve allocation was far from evenly distributed with over 20 MW of the 22.1 MW spinning reserve available located in the corporate area. This would indicate that the stability of the rural area sub-system would be vulnerable to under frequency even with the smallest load increase.

11. Event Summary

This section describes the events leading to system separation and outage in a chronological format taken from the system control historian and historical recording system. The evaluation of the events and the impacts were assessed by the OUR and is included at each timeline.

At 6:00 pm, the scheduled time for the return to service of the outaged lines,

The power on the Hunt's Bay/Three Miles 69 kV line was 492.27 Amps/63.40 MW and the West Kings House/Washington Boulevard 69 kV line was 141.23 Amps/15.83 MW. The net export power to the Duhaney S/S was 40.10 MW, the total system demand was 481.66 MW.

OUR Assessment

The projected 3 pm day peak on the day of the line outage was expected to be 481.8 MW according to the JPS GPCR of that day 2016 April 17. With this demand projection, JPS would have had sufficient line capacity to withstand any other single line outage contingency in the corporate area, such as an outage on the Rockfort –Up Park Camp 69 kV line. An outage of this nature would not have compromised network stability. The loading on the Hunts Bay – Three Miles 69 kV line would be about 105% of its rated load carrying capacity, based on the 65.3 MVA thermal capacity of the conductor. If the outage had been completed at around 6:15 pm the network would most likely not be exposed to security risk since the system load would be at 481.66 MW.

It is important to note from JPS report that personnel seemed to have experienced some confusion in distinguishing between the line relay trip setting and the thermal rating of the conductor. Had the system controller demonstrated a clear understanding of the line thermal limit it is quite possible that he would have started to implement the manual load shedding of 25 MW of load as *previously planned to mitigate generation shortfall and to prevent any further increase in the line loadings. This might have prevented the ensuing outage incident.*

At 6:30 pm the power on the Hunt's Bay/Three Miles 69 kV line was 540.74 Amps/67.51 MW and the West Kings House/Washington Boulevard 69 kV line was 157.65 Amps/17.73 MW.

The net export power to the Duhaney substation was 40.50 MW, the total system demand was 511.62 MW; [GT10 came online at 6:05pm].

OUR Assessment

At 6:30 pm the system demand continued to increase reaching 511 MW with Hunts Bay – Three Miles 69 kV line now carrying 545 Amps (102% loaded). In light of the fact that the controller made the earlier decision to limit the current flow on the line to 500 Amps, the situation was further aggravated by the action taken by the controller to bring GT 10 online at 6:05 pm, which contributed to the increase in current flow along the line.

JPS continued to violate its own operating criteria of limiting the line flow on the Washington Boulevard - Duhaney 69 kV line to 10 MW. By that time the line was loaded at 40.5 MW and remained so for about thirty (30) minutes until the line tripped. This again violated JPS' line loading contingency of 110% for thirty (30) minutes.

The observation here is that JPS should have already implemented their load shedding plan of manually shedding the three selected feeder with an accumulated sum of 25 MW. Had this action been taken, it would quite likely have reduced the probability of a system separation.

At 6:45 pm the power on the Hunt's Bay/Three Miles 69 kV line was 600 Amps/72 MW,

As seen from the relevant SCADA monitoring point at Hunt's Bay, the West Kings House/Washington Boulevard 69 kV line was carrying 203.33 Amps/24.17 MW. The export power to the Duhaney substation was 63.80 MW, the total system demand was 554.23 MW [Hunts Bay GT5 came online at 6:33pm]

OUR Assessment

At 6:35 pm the loading on the Hunts Bay – Three Miles 69 kV line was 600 Amps, representing a 112% of rated loading. By that time the SCADA transducer had become saturated at 600 Amps. However, it should be noted that between 6:30 pm and 6:35 pm the system demand increased at a rate of 3 MW/minute to reach 526.5 MW. Still no attempt was made to manually load shed. By 6:45 pm the system demand had increased to 554.23 MW and Hunts Bay GT #5 was brought online thus further increasing the loading on the line, and comprising system security, with no attempt to manually shed load. The fact that no deliberate action was taken to mitigate the line loading situation would suggest there was a lack of situational awareness on the part of the system controllers in spite of having SCADA/EMS visual and simulation tools.

At 6:59 pm the power flow on the Hunt's Bay-Three Miles 69 kV line was observed to be 600 Amps/72 MW

As seen from the SCADA monitoring point at Hunt's Bay, the West Kings House -Washington Boulevard 69 kV line was carrying 248.48 Amps/31.50 MW. The net export power to the Duhaney S/S was 77.95 MW, the total system demand was 579.41 MW [GT6 at Bogue power station came online at 6:42pm]

At 6:59:30 pm the Washington Blvd-West Kings House Rd 69 kV line tripped

While carrying 600 Amps/75 MW the Washington Blvd-West Kings House Rd 69 kV line tripped resulting in a system islanding condition with the corporate area electrical system separating from the rural area electrical system and forming two separate sub-systems.

At 6:59:32 pm there was a rapid decline in the rural area frequency

This decline in frequency resulted in automatic under frequency load shedding in stages 0 to 4. However due to a massive demand/generation load imbalance in the rural area sub-system, all generators in that sub-system tripped resulting in a total blackout of that section of the rural area grid.

OUR Assessment

Prior to the separation the rural area was importing 118 MW and its separation resulted in a loss of 118 MW of generation, resulting in a 35% overload of the sub-system. A rapid frequency decline then occurred, *and due to the failure of some of the under frequency load shedding points within the sub-system sufficient loads were not shed, thereby causing a total collapse of the area.*

Only 97MW of the 172.5 MW of under frequency points in the scheme operated. Had the balance of 75.7 MW shed, it would have been likely that the sub-system would have survived the separation. This situation was further compounded by the lack of generation spinning reserve in the sub-system due to the low level of plant availability.

Simultaneously, there was a rapid increase in the corporate area system frequency that resulted in a trip of generators located at West Kingston, JPPC and Rockfort #2 due to over frequency/over speed. The loss of these generators resulted in automatic under frequency load shedding in stages 1 to 4 within the corporate area. There was not a total collapse of the corporate area, as units at Hunts Bay and Rockfort #1 remained online and supplied the remaining corporate area customers.

OUR Assessment

Prior to the separation the corporate area sub-system was exporting about 118 MW. Therefore, when the separation occurred there was excess generation within this sub-system, which caused a rapid increase in frequency. Upon reaching 52.5 Hz at number of generators at Rockfort and Hunt Bay tripped off line, causing 122 MW of generation to be lost simultaneously. This resulted in a generation shortfall in the sub-system, causing the operation of all under frequency load shedding points in the scheme to operate shedding 47.5 MW of load. The simultaneous loss of generation could have resulted in the collapse of the sub-system, had sufficient load not been shed. The tripping of a large proportion of generation at the same time is a cause of concern and an unacceptable design. A more coordinated scheme is required to be developed to prevent all generators from tripping off line at the same frequency. A well-co-ordinated generator tripping scheme would most not have been designed to trip all generators simultaneously. This would allow the corporate area sub-system to remain intact without the need to shed over 47 MW of customer load.

The total number of customers that lost supply all over the island at 6:59 pm were 547,734.

Restoration commenced at 7:12 pm and the number of customers without service was rapidly reduced until the last customer was restored at 10:49pm.

Table 13: Playback of the Event – Observed in SCADA by the Control Engineer

OPEN DDC – PLAYBACK FRAME RATE = 3S/FRAME					
		SYSTEM LOAD	HB/3MILES LINE		
FRAME #	TIME	(MW)	AMPS	% LOADING	NOTES
0	18:30:00	511	545	102.4	CALL RETURNED FROM LOGAN AT 6:25PM
100	18:33:00	520	570	107.1	
150	18:34:00	524	595	111.8	
165	18:35:00	526.5	600	112.8	
375	18:43:00	543.7	600	112.8	AMP VALUE NOT INCREASING
850	18:58:18	575	600	112.8	
883	18:59:24	579.2	600	112.8	
884	18:59:30	579.2	600	112.8	SEPARATION TIME
912	19:00:00		600	112.8	OH3 TRP

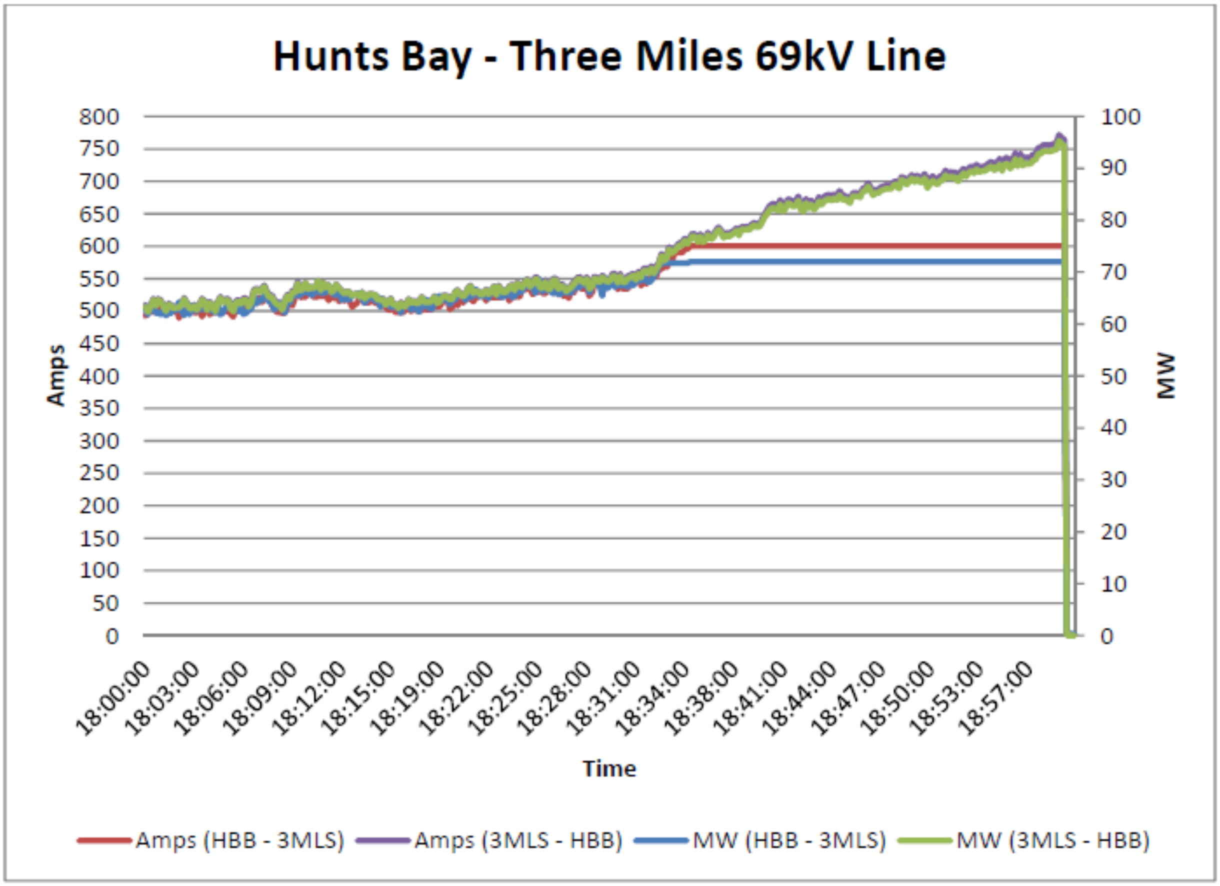


Figure 9 Power flow data on Hunts Bay – Three Miles 69kV line using SCADA

11.1 System Separation

This Section describes the phenomenon of 'Islanding' and the behaviour of the two sub-systems.

11.2 Electrical Power Islanding

Islanding is the occurrence of a separation of a single power grid into two or more independently operating power island grid (sub-system) in the event of a grid failure or fault on one or more critical elements.

A geographical layout of the JPS 69 kV and 138 kV transmission system is provided in Figure 11 below which shows the single line diagram along with the distribution of under-frequency load shedding scheme (UFLS) locations.

OUR Assessment

The tripping of the two 69 kV lines Hunts Bay – Three Miles and Duhaney – Washington Blvd separated the JPS power grid into two smaller electrical sub-systems;

EPI - Eastern Power Island and
WPI - Western Power Island

Figure 11 below also shows the boundary around the two subsystems which were formed subsequent to the separation namely; the corporate area sub-system (Eastern Power Island) and the rural area sub-system (Western Power Island).

The UFLS employed by JPS has five stages of varying frequency threshold and shed a total of approximately 220 MW. Ultimately the amount of load shed would depend on the system loading conditions. Table 14 below gives the approximated load to be shed by the scheme. It also gives the amount of load that failed to trip during the system separation.

.

Stage	Frequency Threshold (Hz)	Load to be Shed (9 MW)	Load that Failed to trip (MW)
0	49.35	29.4	0
1	49.2	13.6	0
2	48.9	45	14.
3	48.5	74.7	41.7
4	48.1	57.3	19.2
Total		**220**	**75.7**

Table 14: UFLS stages and load shed per stage

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JAMAICA PUBLIC SERVICE COMPANY LIMITED

Transmission Single Line Diagram and UFLS Point

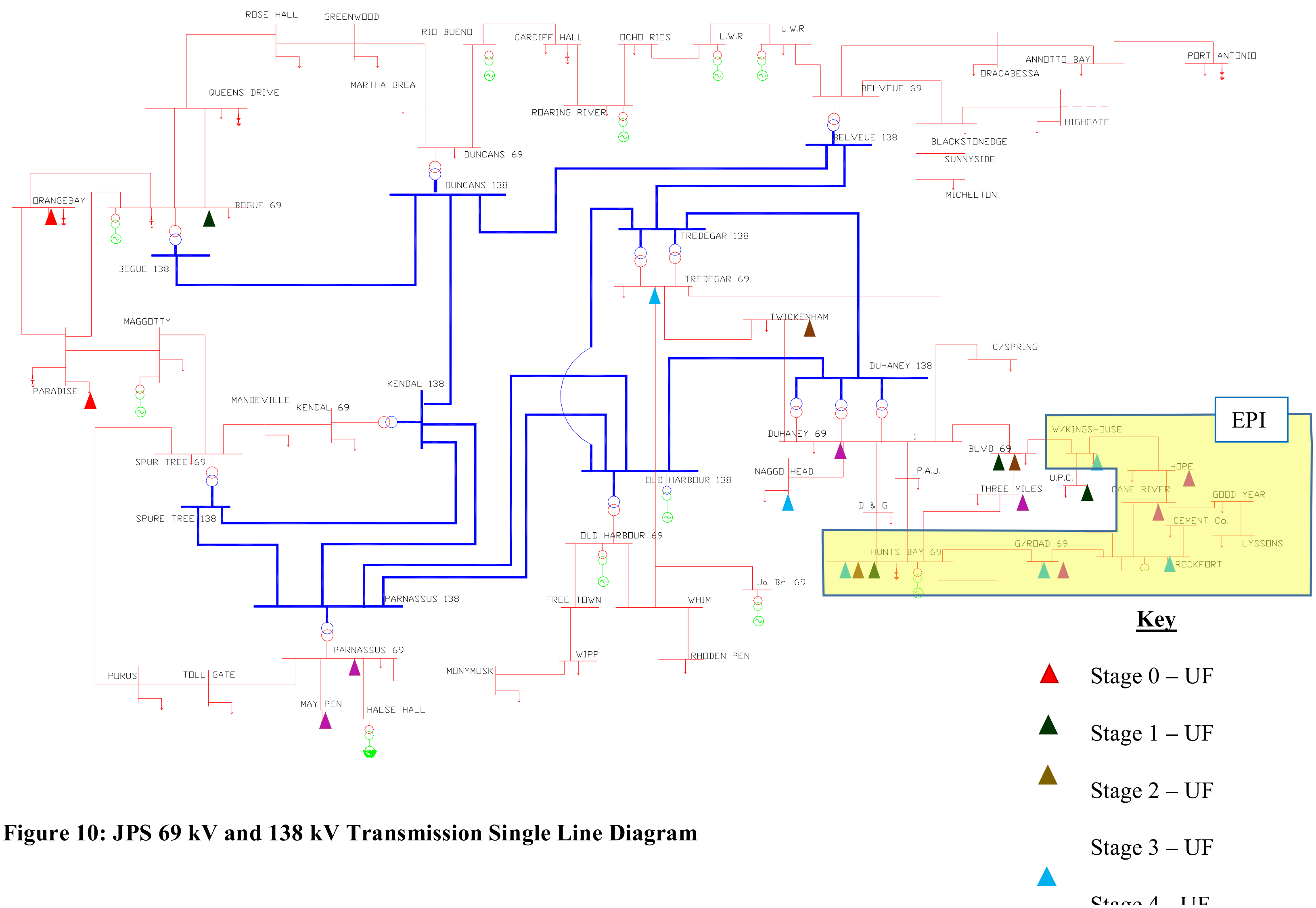
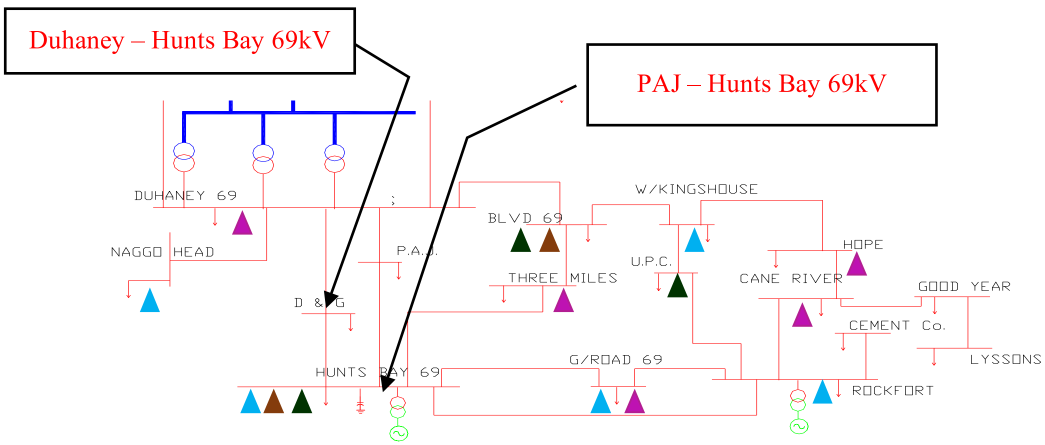


Figure 10: JPS 69 kV and 138 kV Transmission Single Line Diagram


Duhaney – Hunts Bay 69kV
PAJ – Hunts Bay 69kV
DUHANEY 69
NAGGO HEAD
D & G
P.A.J.
HUNTS BAY 69
BLVD 69
THREE MILES
W/KINGSHOUSE
U.P.C.
G/ROAD 69
CANE RIVER
HOPE
GOOD YEAR
CEMENT Co.
LYSSONS
ROCKFORT

12. Protection System Performance

12.1 Transmission Lines

The transmission lines that tripped during the event were tripped on overload condition by over current protection scheme as per design. Table 15 below shows the lines and the tripping sequence according to the sequence of events recorder (SOE).

No	Station	Breaker(s)	SOE Time	Elapsed Time (mm:ss:ms)	Comments
(0)	Hunts Bay	Three Miles 69kV Line	18:53:52.910 (SOE equivalent relay time)	0:00.000	Overcurrent Line relay initially picked-up, indicating line overload. Multiple events recorded before the eventual trip.
(1)	Hunts Bay	Three Miles (8-130)	18:59:26.247	5:33.337	Breakers tripped by Directional Overcurrent line relay 67RYB
(2)		Three Miles (8-150)	18:59:26.255	5:33.345	
(3)	West Kings House Rd.	W/Blvd (8-230)	18:59:30.258	5:37.348	Breaker tripped by Directional Overcurrent line relay 67RYB

Table 15: SOE data on transmission lines that tripped

12.2 Generation System

After the system separation the corporate area sub-system experienced over-frequency conditions as the power being exported was cut off. This resulted in a significant increase in the speed of the generators, causing about 122 MW of generation to trip off line. The rural area sub-system experienced under-frequency conditions as the power being imported was cut off and this created a shortage of generation to meet the load in the sub-system resulting in the generators in the rural Sub-system tripping off line on under-frequency.

OUR Assessment

Under extreme system fault conditions all generating units should have been disconnected at a frequency greater than 52.5 Hz. and less than 48.0 Hz. Where under and over frequency relays are installed, these relays shall be set for the automatic removal of the Generating System from the Transmission System. JPS however should specify slightly different tripping points for the various Generating Unit in order to avoid having all Generating Units on the Transmission System trip at the same time in a frequency constraint.

We note that the under-frequency and over-frequency protection scheme as designed did not provide high frequency and low frequency ride through capabilities in order to provide grid support under these fault conditions as shown in Tables 15 -16 and Figure 12 below.

No	Station	Breaker(s)	SOE Time	Elapsed Time (ms)	Comments
1.	Bogue	GT3 CB 4-320	19:00:12.078	41820	81U- Under-frequency (breaker time inserted from digital fault recorder)
2.	Bogue	GT6 CB 4-620	19:00:14.358	44100	81U suspected, 86G
3.	Bogue	GT7 CB 4-720	19:00:14.876	44618	81U, 86G
4.	Bogue	GT13 CB 4-1320	19:00:15.473	45215	24 Volts/Hz, 86G
5.	JEP	CB 88/ 4-380	19:00:15.537	45279	81U – Under-frequency relay operated on Barge #2 disconnecting JEP #9, 10 and 11.
6.	Bogue	ST14 CB 8-1490	19:00:16.546	46288	81U, 86G
7.	JEP	#6 Gen CB 4-620	19:00:17.682	47424	81U - Under-frequency
8.	JEP	#4 Gen CB 4-420	19:00:18.261	48003	81U - Under-frequency
9.	JEP	#1 Gen CB 4-120	19:00:18.621	48363	81U - Under-frequency
10.	JEP	#3 Gen CB 4-320	19:00:18.994	48736	81U - Under-frequency
11.	JEP	#7 Gen CB 4-720	19:00:19.068	48810	81U - Under-frequency
12.	JEP	#2 Gen CB 4-220	19:00:19.072	48814	81U - Under-frequency
13.	Old Harbour	Unit 3 CB 9-320A	19:00:19.230	48972	Loss of auxiliary power, 86G, 94T

No	Station	Breaker(s)	SOE Time	Elapsed Time (ms)	Comments
14.	Old Harbour	Unit 3 CB 9-320	19:00:19.247	48989	
15.	JEP	#8 Gen CB 4-820	19:00:19.591	49333	81U - Under-frequency
16.	JEP	#5 Gen CB 4-520	19:00:19.728	49470	81U - Under-frequency
17.	Old Harbour	Unit 2 CB 9-220A	19:00:21.063	50805	Loss of auxiliary power, 86B, B86V
18.	Old Harbour	Unit 2 CB 9-220	19:00:21.083	50825	
			Unsynchronized Times		
19.	Rio Bueno "B"	Hydro	18:58:**.***		81U- Under-frequency
20.	C. Spring	Hydro	18:59:**.***		81U- Under-frequency
21.	Lower White	Hydro	19:00:09.495		81U- Under-frequency
22.	Maggotty 1	Hydro	19:00:19		81U- Under-frequency
23.	Maggotty 2	Hydro	19:00:19		81U- Under-frequency
24.	Upper White	Hydro	19:01:08.642		81U- Under-frequency
25.	Rio Bueno "A"	Hydro	19:03:46.***		81U- Under-frequency
26.	Roaring River	Hydro	19:00:25.188		81U- Under-frequency

Table 16: Breaker operation for generators in the rural area sub-system

No	Station	Breaker(s)	SOE Time	Elapsed Time from Initiating Event (ms)	Comments
1.	JPPC	T1 HV 8-190	18:59:32.067	1809	81O - Over-frequency
					81O – Over-frequency
2.	JPPC	T1 HV 8-290	18:59:32.067	1809	(breaker time was inserted based on JPPC plant power flow data that

No	Station	Breaker(s)	SOE Time	Elapsed Time from Initiating Event (ms)	Comments
					highlighted that both units HV breakers tripped at the same time)
3.	Rockfort	Unit 2 generator breaker 5-220	18:59:32.250	1992	Critical Fault Over-speed Auto Emergency Stop Relays- 287GX and 286G (Breaker time was obtained from plant report and observing frequency plot on DFR, (see Appendix B)
4.	W. Kingston	#2 Gen CB 4-220	18:59:32.342	2084	81O - Over-frequency
5.	W. Kingston	#1 Gen CB 4-120	18:59:32.362	2104	81O - Over-frequency
6.	W. Kingston	#5 Gen CB 4-520	18:59:32.366	2108	81O - Over-frequency
7.	W. Kingston	#4 Gen CB 4-420	18:59:32.393	2135	81O - Over-frequency
8.	W. Kingston	#4 Gen CB 4-620	18:59:33.054	2796	81O - Over-frequency
9.	W. Kingston	#3 Gen CB 4-320	18:59:33.103	2845	81O - Over-frequency
10.	JPPC	JPPC1 Gen CB 5-120	18:59:34.381	4123	81O - Over-frequency

Table 17: Breaker operation for generators in the corporate area sub-system

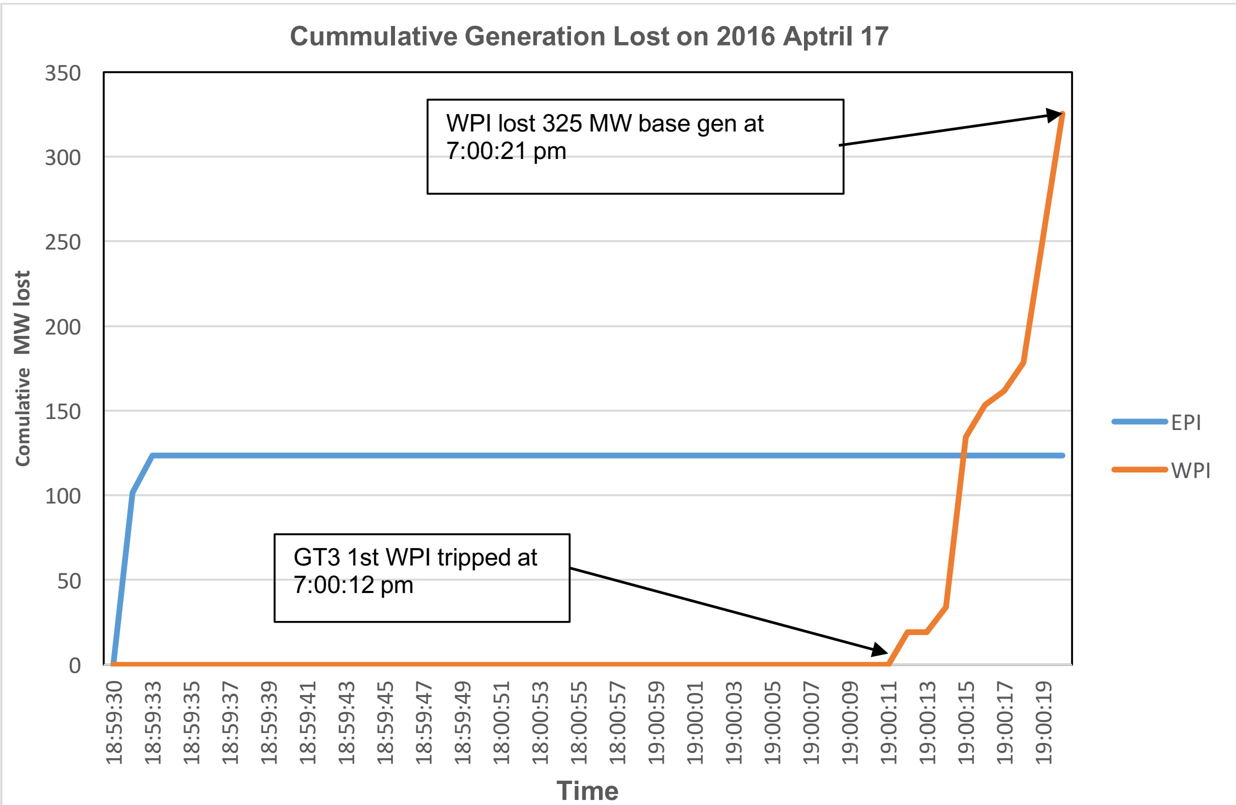


Figure 11: Cumulative generation lost for the two subsystems

12.3 Under-frequency Load Shedding

OUR Assessment

Failure of the UFLS during system disturbances on the JPS system has been a long standing issue. The majority of system blackouts has been precipitated by the failure of a number of the UFLS schemes to operate as designed. In this outage a major portion of UFLS points in the rural area failed to trip, with over 43.4 % or 75 MW from a total of 172 MW failed to operate as shown in Table 18 below.

OUR simulations have shown that had the UFLS points operated the system would have survived. Table 30 in section 15 gives the simulated maximum, minimum and settling frequency under the actual UFLS operating and under full operation of the scheme.
In contrast to the rural area the UFLS points in the corporate area operated as designed which allowed the system to recover and survived.

STAGE	Rural area Under Frequency Points Loading	
	Total demand available to be shed per stage (MW)	Total demand that actually failed to shed per stage (MW)
0	29.4	0.0
1	13.6	0.0
2	38.7	14.8
3	56.8	41.7
4	34.0	19.2
TOTAL	172.5	75.7

Table 18: Under-frequency stages loading in the rural area sub-system

13. System Restoration

The chief objective of a restoration process is to ensure that the rebuild of the electric system is done in a co-ordinated and safe manner, to minimize impact on critical loads (Hospital, security, etc) while restoring all unserved customers in the shortest possible time.

JPS restoration process allows for safe and timely restoration of customers. The process includes the following key activities.

1) System Assessment and Preparation

   Special note is taken of the pre-outage state of all components of the system in preparation for defining its restoration role. All critical operations and management personnel should be immediately informed of the occurrence and their participating role invoked or defined if not previously done. Operating crew should be called to attend at all critical 138/69 kV Substations.

2) Start-up Methodology in the event of a System Separation

   The JPS Primary Restoration Strategy in the event of a System Separation surrounds providing either power from black-start units or start-up power from the remaining online generation to the remote steam units at Old Harbour and other generating facilities that do not have black-start capability.

3) Customer Restoration Strategy

In developing the plan, priority in customer restoration is given to critical and sensitive loads. The classification used in categorizing and prioritizing feeders for restoration considers if they serve:

- Critical Loads – Hospitals, Airports, Water supply facilities, Control Centres (security forces), JPS and system critical loads (Under-frequency etc.), Telecommunication critical locations
- Industrial demand (Factories, Ports etc.)

- Hotel and Tourist sectors
- High Commercial Areas – Towns Squares, Critical roads
- High Security Risk Areas
- Other feeder loads will rank accordingly and will be restored after the critical loads.

JPS reported that their full restoration team was available (minimum requirement 6-8 Control Engineers) along with other staff from Operations Planning, Grid Performance, SCADA/EMS and Reliability Department, ensuring that the restoration was smooth and expeditiously as possible.

The JPS report documents the process details.

Restoration commenced about twelve (12) minutes after the outage at 7:12pm and the last customer was restored at 10:49pm. Of the 547,734 customers affected over 98% of them were restored within three (3) hours, with the remaining restored by 10:49 pm according to JPS report.

OUR Assessment

The restoration was largely successful. JPS has a well-defined restoration process and the restoration was carried out according to this process and the black start procedure. However, there were, a number of areas which failed to perform as expected. These included:

Some operational constraints were encountered throughout the restoration process, which delayed energizing customers expeditiously. These constraints included:

- *System Control Centre's stand by generator failed to start – automatic start, due to defective cable in the auto-start circuit;*
- *The late completion of planned outages on Hunts Bay – PAJ and Duhaney lines hampered the restoration process;*
- *Failure of the Remote Terminal Unit (RTU) caused communication issues at Parnassus and intermittent communication at Kendal, Spur Tree, Blackstonedge, Bellevue and North East coast substations;*
- *Reclosers failing to close at Porus and Monymusk substations.*
- *Voice services (hotline) at System Control was impacted. This was due to the separation of the PBX with Bogue; and*

- *Remote operation of field equipment was good except for a permanent failure of communication with Parnassus 138KV station and intermittent failures at Blackstonedge, Highgate and Oracabessa stations.*

OUR Assessment

The failure of the standby generator auto start is of serious concern. The consequences for the restoration and the sustained operation could be serious given that the system control centre is a major part of the grid operations infrastructure. The issue of lack of maintenance and periodic testing of such an important asset must be remedied as a matter of urgency.

It is still not clear when the planned outage was completed and the lines returned to service, and how their late return hampered the restoration process.

The failure of the remote terminal unit (RTU) caused communication failure at the key substations of Parnassus, Kendal, Spur Tree is of concern as this would have had negative implication on the restoration process by hampering the visibility of these critical areas to the system operators.

The failure of the abovementioned reclosure can be attributed to poor equipment maintenance. In general the failure of a number of critical field equipment is a cause for concern about the field maintenance practice for these equipment.

14. Power System Simulation Study by OUR

Power system simulations are used to predict and evaluate power systems performance under both steady state and fault conditions. These studies usually comprise load flow analysis, fault analysis and transient stability analysis. These studies are used to provide guidance to power system operators and analysts in their decision making.

The OUR utilized the DigSilent of power system software package which is a commercial internationally accepted power system simulation tool to carry out these analyses.

In order to analyse the performance of the power system during the outage event, and to examine the ability of the system to withstand certain contingencies, the OUR carried out a number of simulation studies to evaluate the power system and its components prior to, during and after the system separation and outage.

Parameter to be monitored	Limit
Voltage	+/- 5% of nominal voltage and +/- 10% for contingencies
System Frequency	50 +/- 0.2 Hz
Generator Frequency	Normal operating limit of 49.5 Hz to 50.5 Hz Operating range of 48.0 Hz to 52.5 Hz
Thermal Limit	Line loading should not be greater than 110% of thermal rating for 30 minutes.

Table 19: System operating limits

14.1 Steady State Load Flow Analyses

The following cases were carried out for both the day peak of 485 MW and the expected evening peak load of 579.4 MW. Also, it should be noted that the network was already in the N – 2 line outage contingency state, because the Hunts Bay – PAJ and Hunts Bay – Duhaney 69 kV lines were both out of service for the planned outage. This N – 2 condition was used as the base case for further network analysis.

In addition to the base case simulations for both day peak and evening peak demands, contingency load flow analyses were carried out for the following line outage condition, representing a N – 3 contingency state:

1. Hunts Bay – Three Miles 69 kV line
2. Three Miles – Washington Blvd 69 kV line
3. Rockfort – Up Park Camp 69 kV line

14.2 Load Flow Analysis at 579.41 MW

Tables 20 to 27 below summarises the power flow simulations for the system demand of 579. MW at 6:59 pm and gives the loadings on critical transmission lines in the Corporate area and also the bus voltages at some locations throughout the network. The tables also include information as provided by JPS for both line loadings and substation bus voltages. The OUR simulations output showed good correlation with SCADA data provided by JPS in most case. There however, was a fairly large difference in the line flow comparison for the Duhaney – Washington Boulevard 69 kV line.

		JPS SCADA		**OUR Simulation**		**Pickup Amps**
	Loadings on Critical Lines	**Amps**	**Loading (%)**	**Amps**	**Loading (%)**	
Base Case Load Flow with Hunts Bay - PAJ & Hunts Bay - Duhaney 69 kV lines out	Hunts Bay – Three Miles 69 kV	771.7	145.1	790.6	148.6	720
	Three Miles – Washington Boulevard 69 kV	673.7	126.7	657.0	123.5	720
	Rockfort – Up Park Camp 69 kV	449.9	67.9	436.3	65.8	N/A
	West Kings House Rd – Washington Boulevard 69 kV	271.9	41.0	272.8	41.4	600
	Up Park Camp – West Kings House Rd 69 kV	380.9	57.5	389.8	58.8	N/A
	Hunts Bay – Greenwich Rd 69 kV	276.6	52.0	309.1	58.1	N/A
	Duhaney - Washington Boulevard 69 kV	640.8	99.5	537.0	81	750

Table 20: Power flow base case Load Flow, 579.41 MW

Substation Bus	Rated Voltage (kV)	JPS SCADA		OUR Simulation	
		kV	Pu	kV	Per unit
Bogue	138	134.5	0.97	134.7	0.97
Duhaney	138	134.9	0.98	135.8	0.98
	69	70.1	1.02	70.2	1.02
Old Harbour	138	136.9	0.99	139.1	1.01
Tredegar	138	137.2	0.99	136.5	0.99
	69	68.2	0.99	68.5	0.99
Cane River	69	69.78	1.01	71.4	1.03
Hope	69	69.9	1.01	71.0	1.03
Hunts Bay	69	71.0	1.03	73.3	1.06
Three Miles	69	71.3	1.03	71.9	1.04

Table 21: Bus voltages, base case Load Flow, 579.41 MW

		JPS SCADA		OUR Simulation		Pickup Amps
	Loadings on Critical Lines	Loading (%)	Amps	Amps	Loading (%)	
N - 3 Hunts Bay - Three Miles 69 kV line out	Hunts Bay – Three Miles 69 kV	NP	NP	0.0	0	720
	Three Miles – Washington Boulevard 69 kV	NP	NP	144.2	27.1	720
	Rockfort – Up Park Camp 69 kV	NP	NP	1048.2	158.1	N/A
	West Kings House Rd – Washington Boulevard 69 kV	NP	NP	979.9	148.7	600
	Up Park Camp – West Kings House Rd 69 kV	NP	NP	999.1	150.7	N/A
	Hunts Bay – Greenwich Rd 69 kV	NP	NP	684.7	128.7	N/A
	Duhaney - Washington Boulevard 69 kV	NP	NP	516.5	77.9	750

Table 22: Contingency Case 579.41 MW, Hunts Bay – Three Miles 69 kV line out

NP: Not Provided

		JPS SCADA		OUR Simulation		Pickup Amps
	Loadings on Critical Lines	**Loading (%)**	**Amps**	**Amps**	**Loading (%)**	
N - 3 Washington Blvd - Three Miles 69 kV line out	Hunts Bay – Three Miles 69 kV	NP	NP	134.6	25.3	720
	Three Miles – Washington Boulevard 69 kV	NP	NP	0.0	0.0	720
	Rockfort – Up Park Camp 69 kV	NP	NP	944.8	142.5	N/A
	West Kings House Rd – Washington Boulevard 69 kV	NP	NP	849.5	128.9	600
	Up Park Camp – West Kings House Rd 69 kV	NP	NP	895.7	135.1	N/A
	Hunts Bay – Greenwich Rd 69 kV	NP	NP	685.7	128.9	N/A
	Rockfort - Greenwich Rd. 69 kV	NP	NP	599.6	112.7	750

Table 23: Base Cast 579.41 MW Washington Blvd – Three Miles 69 kV line out

NP: Not Provided

		JPS SCADA		OUR		Pickup Amps
N - 3 Rockfort – Up Park Camp 69 kV line out	Loadings on Critical Lines	Loading (%)	Amps	Amps	Loading (%)	
	Hunts Bay – Three Miles 69 kV	NP	NP	1052.8	197.9	720
	Three Miles – Washington Boulevard 69 kV	NP	NP	915.6	172.1	720

Table 24: Base case 579.4 M , Rockfort – Up Park Camp 69 kV line out

From these assessments the following conclusions are made with regards to line loading violations:

- *Base case analysis, two (2) violations.*
- *Contingency case Hunts Bay – Three Miles 69 kV line out, four (4) violations*
- *Contingency case Three Miles–Washington Blvd 69 kV line out five (5) violations*
- *Contingency case Rockfort – Up Park Camp 69 kV line out, two (2) violations.*

A number of these violations were above the overload trip settings of the direction overcurrent relays that are on these circuits. Therefore, any one of these could have resulted in major power system outages and as such the transmission grid was very exposed under the N-2-1 contingencies.

14.3 Load Flow Analysis for 485 MW

		JPS SCADA		OUR Simulation		Pickup Amps
Base Case Load Flow with Hunts Bay - PAJ & Hunts Bay - Duh 69 kV out	Loadings on Critical Lines	Loading (%)	Amps	Amps	Loading (%)	
	Hunts Bay – Three Miles 69 kV	76.4%	406.3	385.7	72.5	720
	Three Miles – Washington Boulevard 69 kV	52.3%	278.4	282.5	53.1	720
	Rockfort – Up Park Camp 69 kV	48.6%	258.3	311.6	47.0	N/A
	West Kings House Rd – Washington Boulevard 69 kV	9.0%	59.4	145.6	22.1	600
	Up Park Camp – West Kings House Rd 69 kV	38.5%	204.8	273.2	41.2	N/A
	Hunts Bay – Greenwich Rd 69 kV	21.2%	112.9	121.3	22.8	N/A
	Duhaney - Washington Boulevard 69 kV	17.9%	95.3	114.0	17.2	750

Table 25: Power flow, base case load flow, day peak 485 MW

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Substation Bus	Rated Voltage (kV)	JPS SCADA		OUR Simulation	
		kV	Pu	kV	pu
Bogue	138	133.3	0.97	136.3	0.99
Duhaney	138	135.3	0.98	137.4	0.99
	69	70.6	1.02	71.2	1.03
Old Harbour	138	138.1	1.00	140.2	1.02
Tredegar	138	135.4	0.98	138.3	1.00
	69	69.1	1.00	69.5	1.01
Cane River	69	71.1	1.03	71.8	1.04
Hope	69	70.8	1.03	71.6	1.04
Hunts Bay	69	72.3	1.05	73.1	1.06
Three Miles	69	71.6	1.04	72.2	1.05

Table 26: Bus voltages, base case load flow, day peak 485 MW

		JPS SCADA		OUR Simulation		Pickup Amps
	Loadings on Critical Lines	Loading (%)	Amps	Amps	Loading (%)	
Contingency Case Rockfort - Up Park Camp 69 kV line out	Hunts Bay – Three Miles 69 kV	105.4	561.0	559.1	105.1	720
	Three Miles – Washington Boulevard 69 kV	NP	NP	451.1	84.8	720
	Rockfort – Up Park Camp 69 kV	NP	NP	0.0	0.0	N/A
	West Kings House Rd – Washington Boulevard 69 kV	NP	NP	95.6	14.5	600
	Up Park Camp – West Kings House Rd 69 kV	NP	NP	39.8	6	N/A
	Hunts Bay – Greenwich Rd 69 kV	NP	NP	86.2	16.2	N/A
	Duhaney - Washington Boulevard 69 kV	NP	NP	78.9	11.9	750

Table 27: Power flow, day peak of 485 MW, Rockfort – Up Park camp line out

NP: Not provided

The only line loading violation for the contingency cases looked at for this system demand that resulted in a 105.1% loading on the Hunts Bay – Three Miles 69 kV line, which was within the 110% line loading criteria and would not have posed any security risk to the network at this load.

14.4 Load Flow Analysis for 526 MW Generation

In order to determine the additional increase in system load beyond 485 MW such that the network could be exposed to without gravely putting the network at risk, base case and line contingency Load Flow were done for 526 MW. The results of which are given in Tables 28 and 29 below.

		OUR Simulation		Pickup Amps
	Loadings on Critical Lines	**Amps**	**Loading (%)**	
526 MW Base Case Load Flow with Hunts Bay - PAJ & Hunts Bay - Duhaney 69 kV lines out	Hunts Bay – Three Miles 69 kV	538.4	101.2	720
	Three Miles – Washington Boulevard 69 kV	416.6	78.3	720
	Rockfort – Up Park Camp 69 kV	407.1	61.4	N/A
	West Kings House Rd – Washington Boulevard 69 kV	140.4	21.3	600
	Up Park Camp – West Kings House Rd 69 kV	314.9	47.5	N/A
	Hunts Bay – Greenwich Rd 69 kV	202.7	38.1	N/A
	Duhaney - Washington Boulevard 69 kV	274.5	41.4	750

Table 28: Power flow base case Load Flow, 526 MW

		OUR Simulation		Pickup Amps
	Loadings on Critical Lines	**Amps**	**Loading (%)**	
526 MW Base Case Load Flow with Hunts Bay – Three Miles 69 kV lines out	Hunts Bay – Three Miles 69 kV		0	720
	Rockfort – Up Park Camp 69 kV	808.9	122.2	N/A
	Up Park Camp – West Kings House Rd 69 kV	716.0	108	N/A
	Hunts Bay – Greenwich Rd 69 kV	532	100	N/A

Table 29: Peak load 579.41 MW, Hunts Bay – Three Miles 69 kV line out

Table 30 below lists the cases that were studied by the OUR in its time domain dynamic analysis of the system. The purpose of which was to analyze the system performance during the incident, identify any weaknesses that occurred and make the appropriate recommendations where necessary.

Case #	Description
1	System demand 579 MW. Hunts Bay – Three Miles 69 kV line tripped.
2	System demand 579 MW. Hunts Bay – Three Miles and West Kings House – Washington Boulevard 69 kV lines tripped. Including all generators that tripped and UFLS points that failed.
3	Case 2. With all UFLS in WPI operating
4	Case 3. With WKPP staying on line
5	Case 4. With JPPC1 staying online
6	System demand 526 MW. Hunts Bay – Three Miles 69 kV line tripped
7	System demand 526 MW. Hunts Bay – Three Miles 69 kV line tripped shedding and 70 MW by special protection scheme

Table 30 -: List of the stability study cases

Figure 13–15 below show the current flow and frequency plot prior to the system separation. Upon the loss of the two transmission lines, the Hunts Bay – Three Miles and the West Kings House – Washington Boulevard 69 kV lines, the power grid was divided into two electrical power islands, called the corporate area and rural area subsystems.

Prior to the separation the corporate area was exporting 118 MW to the rural sub-system and upon its occurrence (see Figure 6 above) this over generation caused corporate area frequency to increase rapidly and upon reaching 52.5 Hz, 122 MW of generation was lost due to the tripping offline of the WKPP plant, JPPC1 and Rockfort Unit 2. The resulting power swing that followed caused the sub-system frequency to fall to 48.0 Hz. This resulted in all four stages of the UFLS scheme shedding loads. The system was able to recover and settled at 50.86 Hz.

For the rural area there was a generation deficit of 118 MW. This generation/load balance caused a rapid decline in the sub-system frequency and resulted in all four UFLS operating. However, only 97 MW out of a total of 172.5 MW was shed. With the sub-system frequency already declining and this excess 22 MW of load. The sub-system suffered a frequency collapse and hence, the power outage as all of the generators tripped offline, as shown in Figures 16-18

The simulation results show that if all the UFLS points within the two sub-systems had operated, the sub-system would have recovered. This would result from the shedding stages 0, 1, and 3, after the frequency fall to 48.25 Hz, as shown in Figures 19-21below. The sub-system frequency then settled at a frequency of 49.99 Hz. Table 31 below shows the frequency performance in the corporate and rural area sub systems and indicates that had the under-frequency points in the rural area subsystem operated as designed the system would have recovered.

Case #	Description	Corporate area Frequency (Hz)			Comments	Rural area Frequency (Hz)			Comments
		Max	Min	Settling		Max	Min	Settling	
1	Hunts Bay -Three Miles 69 kV tripped	49.98	49.98	49.98		49.98	49.98	49.98	
2	Hunts Bay -Three Miles & West Kings House - Washington Blvd 69 kV tripped	52.66	48.00	50.86	Stages 1, 2, 3 & 4 operated	49.98	39.0	39.0	Stages 0, 2 & 3 & 4 of UFLS operated. 75.7 MW of UFLS fail to trip.
3	Hunts Bay -Three Miles & West Kings House - Washington Blvd 69 kV tripped	52.66	48.00	50.86	Stages 1, 2, 3 & 4 operated	49.98	48.25	49.99	All stages 0, 2 & 3 of UFLS operated, include those that failed
4	Case 2 plus WKPP stayed online tripping of WKPP	52.66	49.85	50.56	No UFLS operation	49.98	48.25	49..99	All stages 0, 2 & 3 of UFLS operated, include those that failed
5	Case 2 plus WKPP & JPPC1 stayed online	52.66	49.88	50.75	No UFLS operation	49.98	48.25	49.99	. All stages 0, 2 & 3 of UFLS operated, include those that failed

Table 31: Power Island frequency performance

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Figure 24 below gives the frequency plot for the corporate area sub-system, for the simulated condition of having the WKPP plant which was carrying 66.3 MW online throughout the simulation. In this case the frequency of the sub-system falls to 49.85 then recovered to 50.56 Hz.

Figure 27 below shows the frequency plot for the case where both WKPP and JPPC1 stayed online, the frequency falls to 49.88 Hz and settles at 50.75 Hz.

At 526 MW and not running GT #5 and GT #10, the current flow on the Hunts Bay – Three Miles 69 kV line would be 538.5 Amps, as shown in Table 17 above. However, in order to make preparation for the worst case contingency of losing this line, accommodation would have had to be made to shed approximately 70 MW, to prevent the loading on the Rockfort – Up Park Camp 69 kV line from reaching 856 Amps (129.1% loading) and keeping it at 678 Amps (102.3% loading), as is shown in Figures 28-31 below.. However, this shedding of load could not have been manually operated, but would have to be a special protection scheme designed for such or other similar situations.

Case 1: Hunts Bay – Three Miles 69 kV line tripped

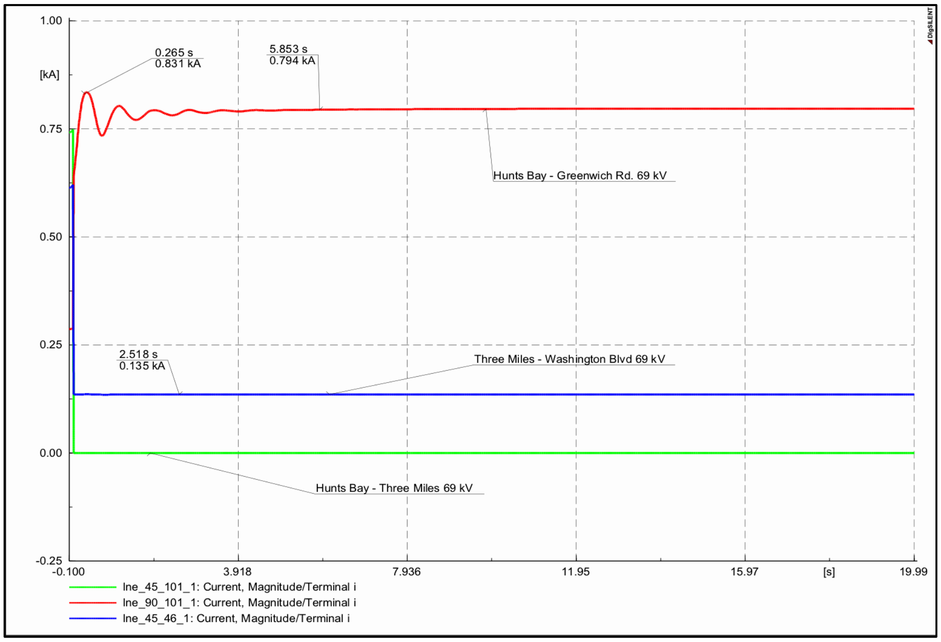

Figure 12: Case 1 - Power flow on major transmission lines in the corporate area

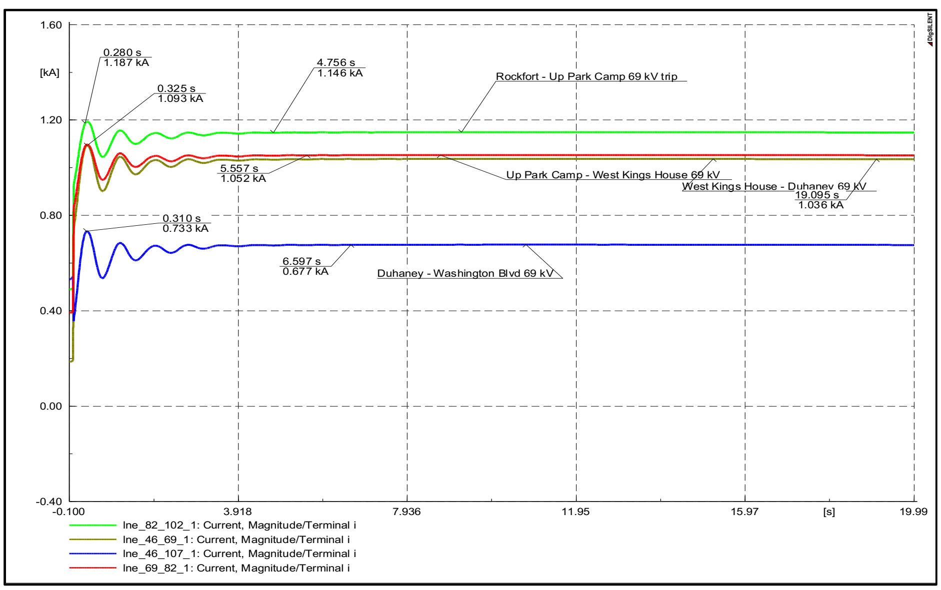

Figure 13: Case 1 - Power flow on major transmission lines in the corporate area

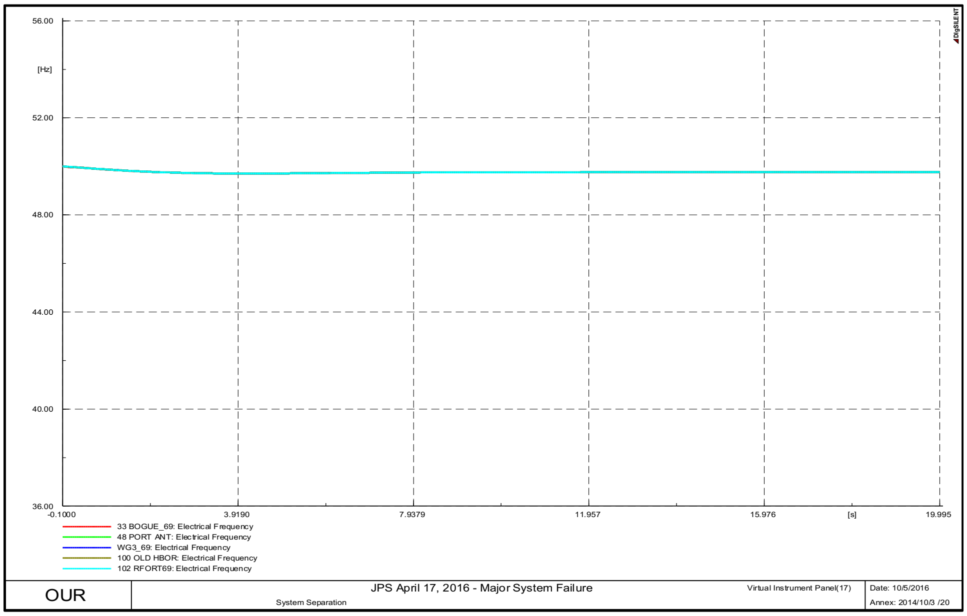

Figure 14: Case 1 – Frequency plot

Case 2: Hunts Bay – Three Miles and West Kings House Rd. 69 kV lines tripped.

This case simulated the system conditions as it occurred on 2016 April 17 at 6:59 pm

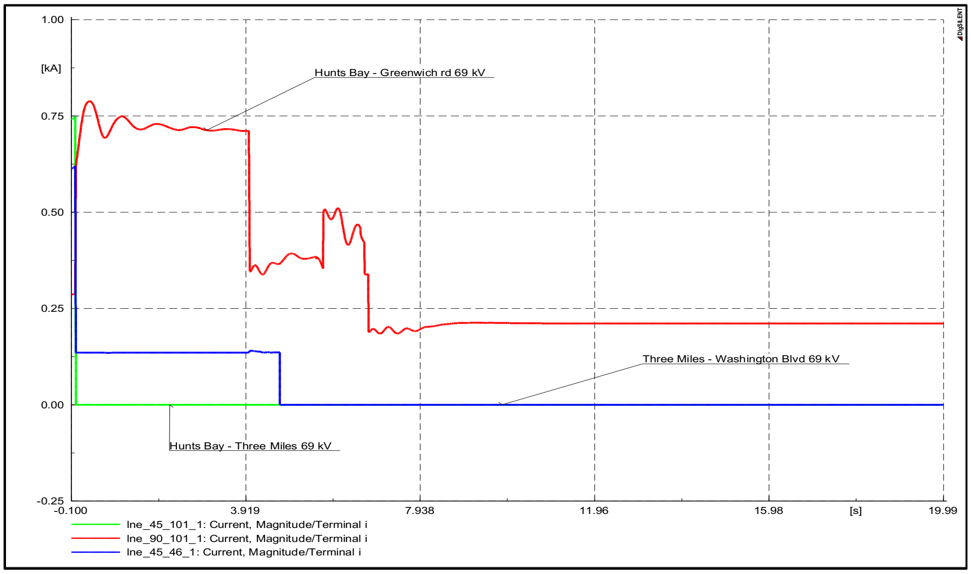

Figure 15: Case 2 - Power flow on major transmission lines in the corporate area

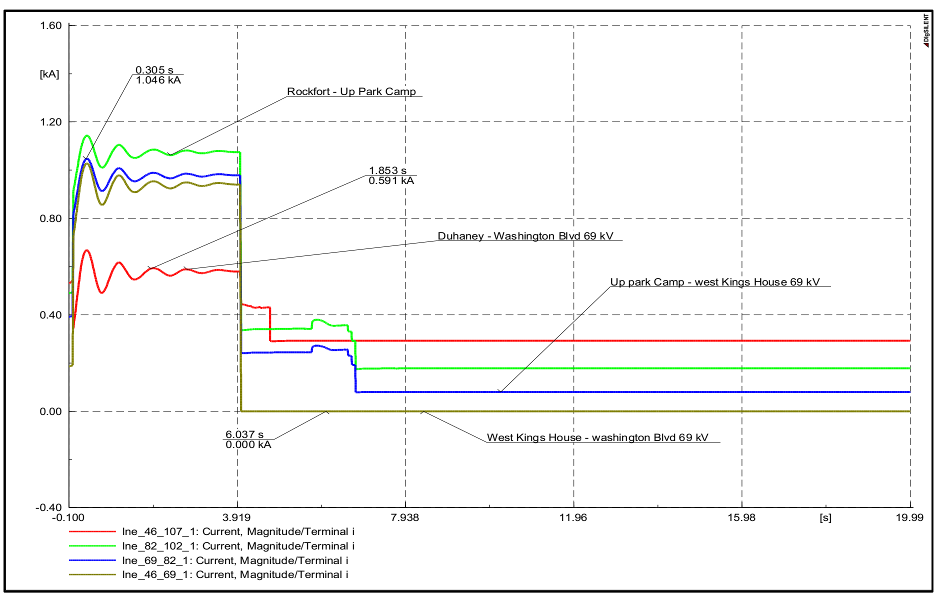

Figure 16: Case 2 - Power flow on major transmission lines in the corporate area

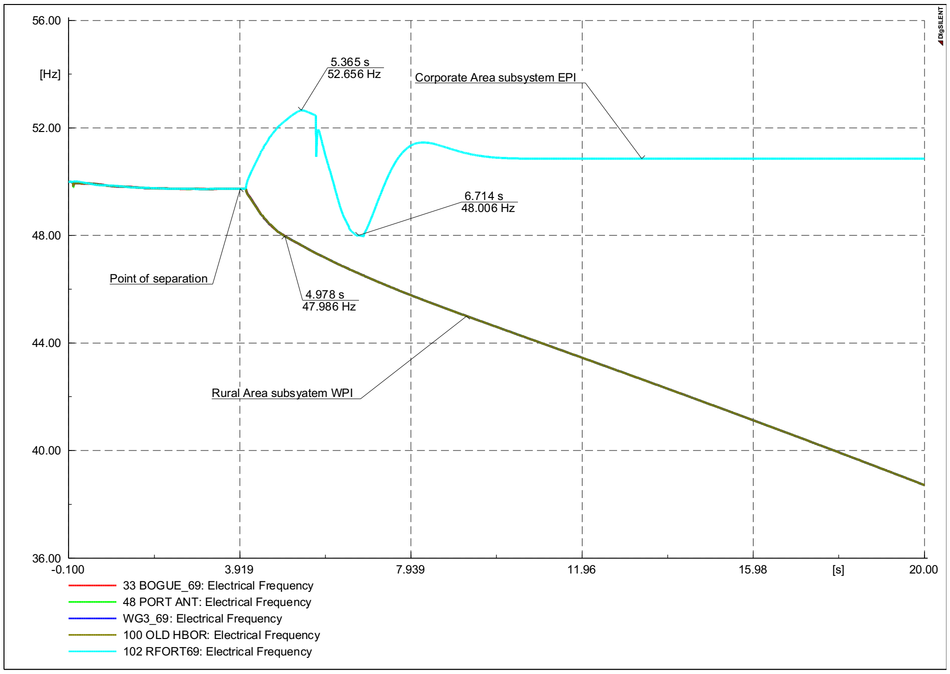

Figure 17: Case 2 – Frequency plot

Case 3: Hunts Bay – Three Miles and West Kings House Rd. 69 kV lines tripped.
This case simulated the system conditions similar to April 17th, 2016 at 6:59 pm, with the exception that all of the UFLS points in the rural area system operated.

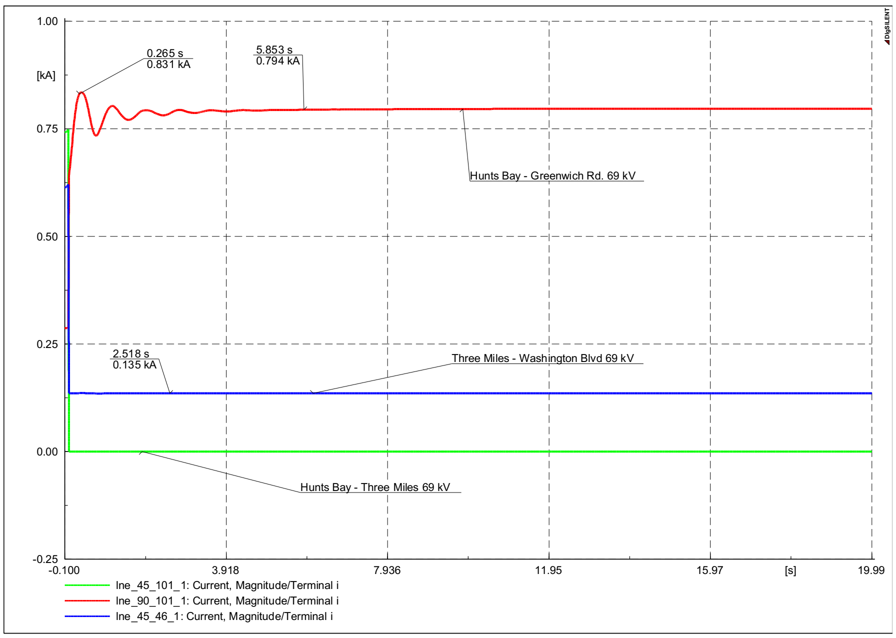

Figure 18: Case 3 - Power flow on major transmission lines in the corporate area

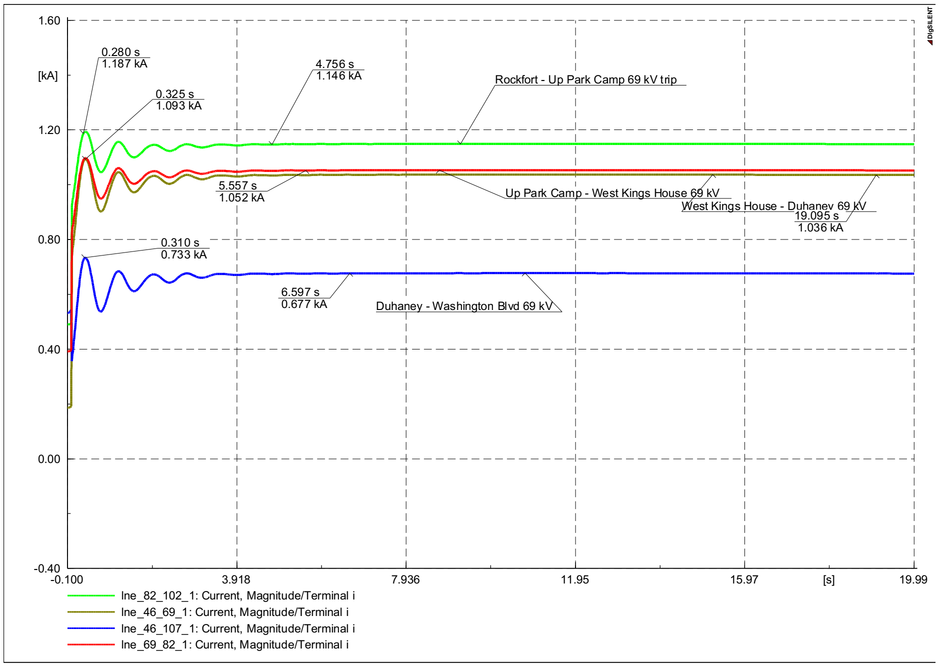

Figure 19: Case 3 - Power flow on major transmission lines in the corporate area

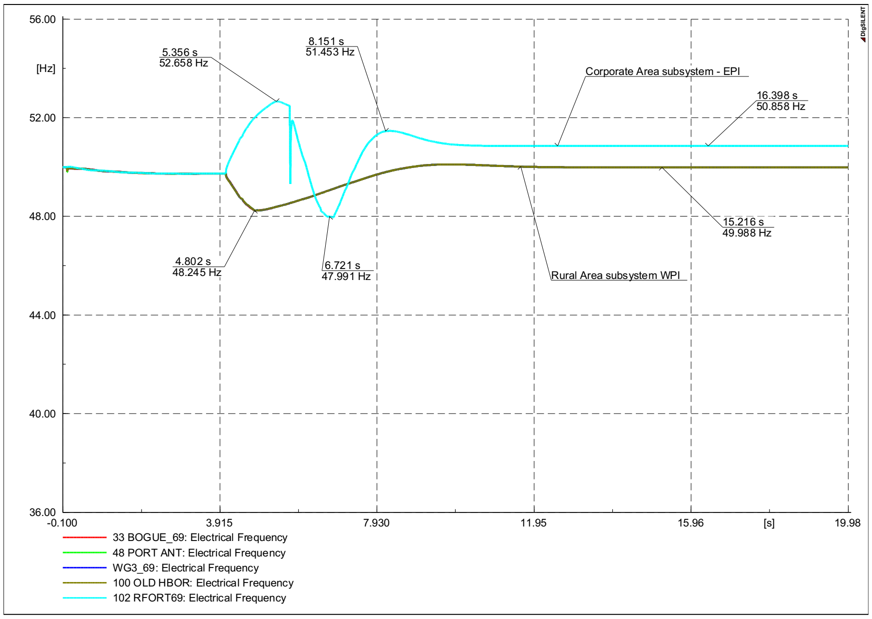

Figure 20: Case 3 – Frequency plot

Case 4:
Similar to case 3 with the exception that WKPP 66.3 MW stayed online.

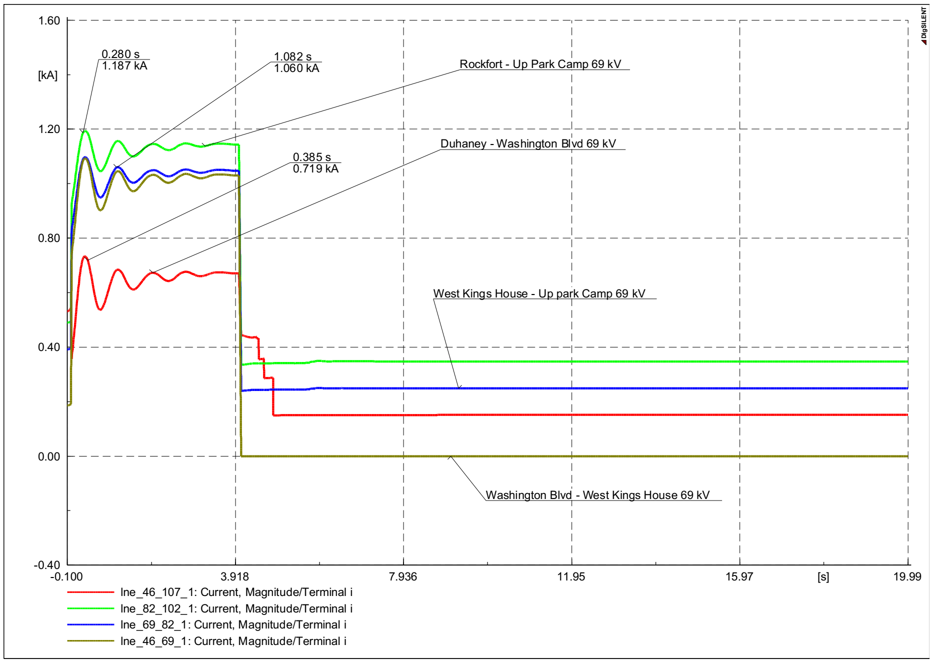

Figure 21: Case 4 - Power flow on major transmission lines in the corporate area

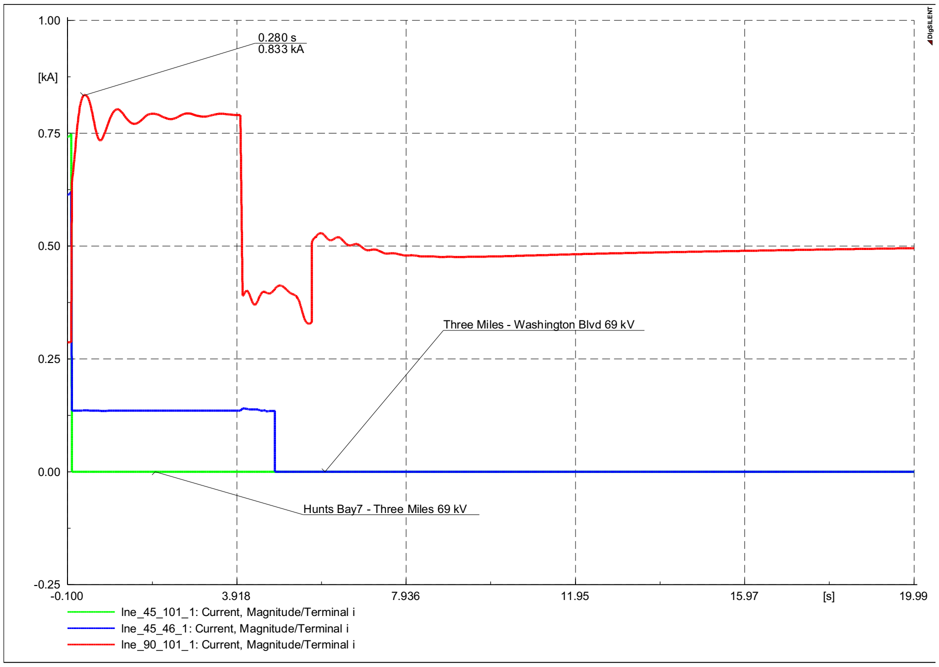

Figure 22: Case 4 - Power flow on major transmission lines in the corporate area

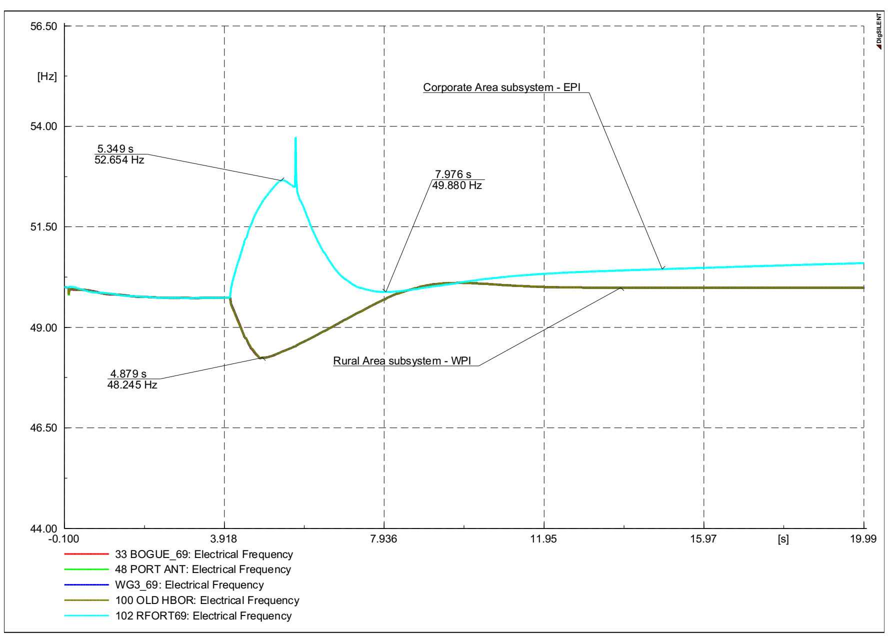

Figure 23: Case 4 – Frequency plot

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Case 5:

Similar to case 3 with the exception that WKPP and C1, a total of 85 MW stayed online.

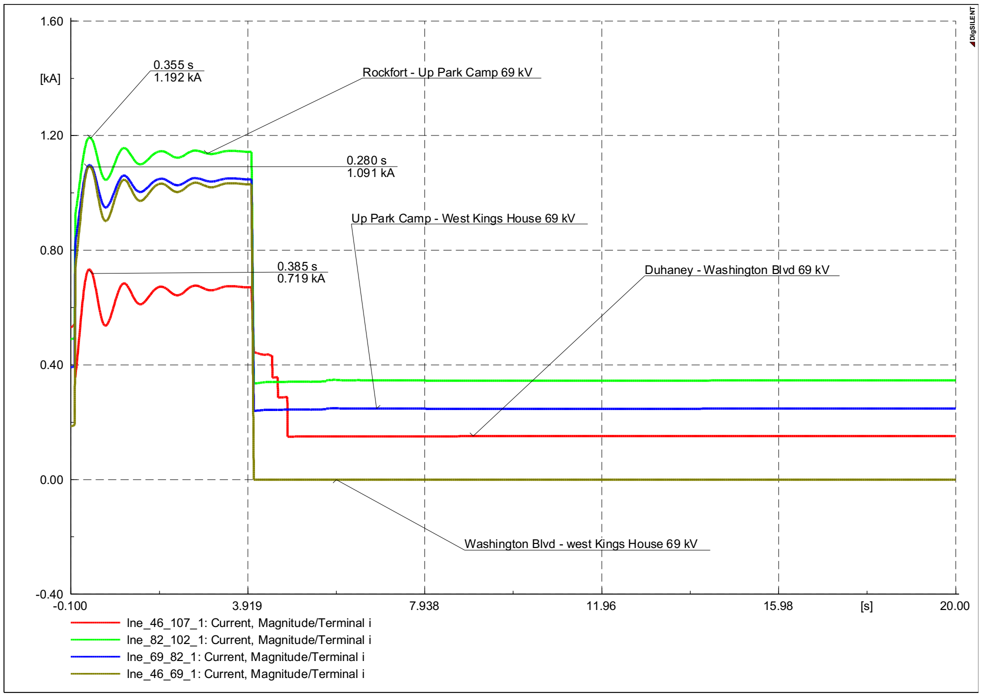

Figure 24: Case 5 - Power flow on major transmission lines in the corporate area

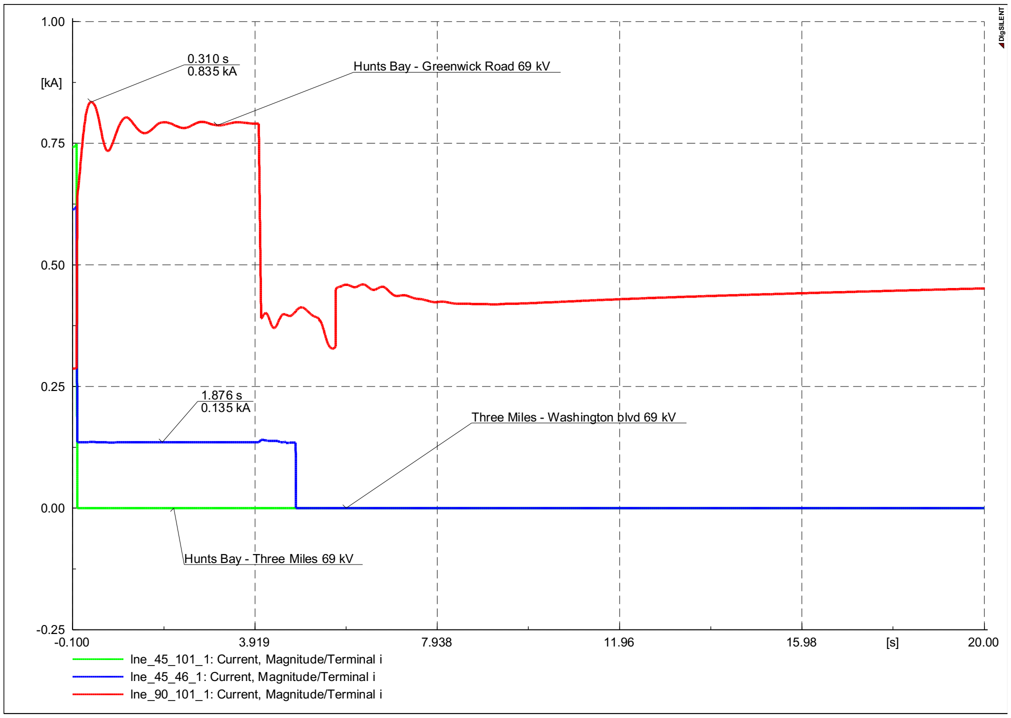

Figure 25: Case 5 - Power flow on major transmission lines in the corporate area

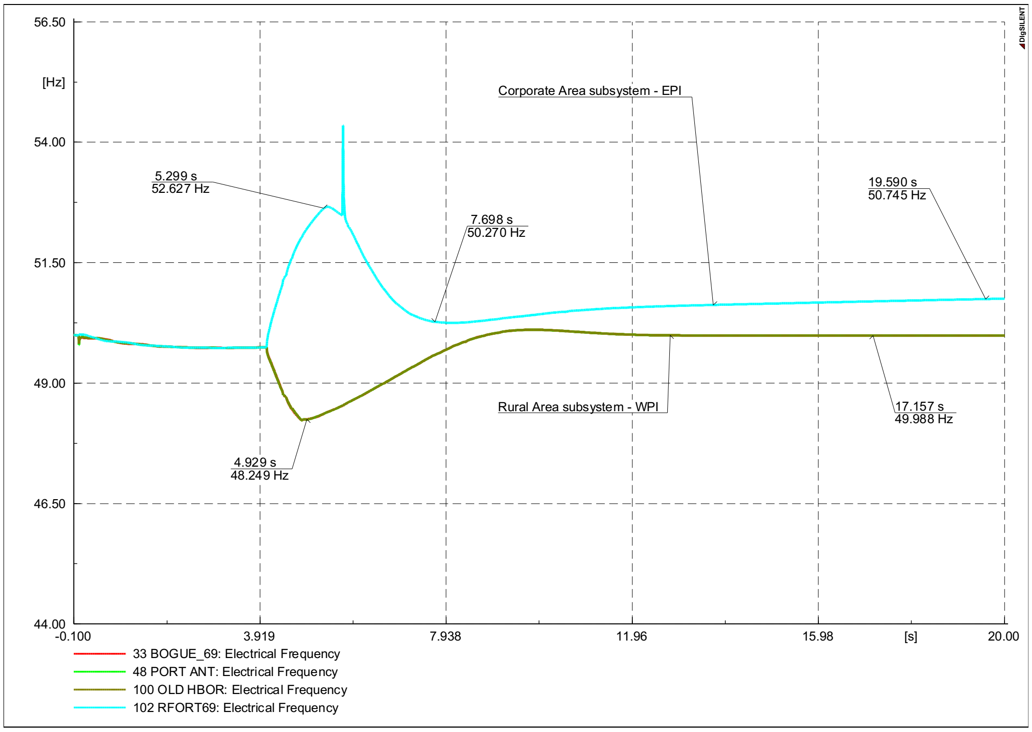

Figure 26: Case 5 – Frequency plot

Case 6: 526 MW, Hunts Bay - Three Miles 69 kV tripped

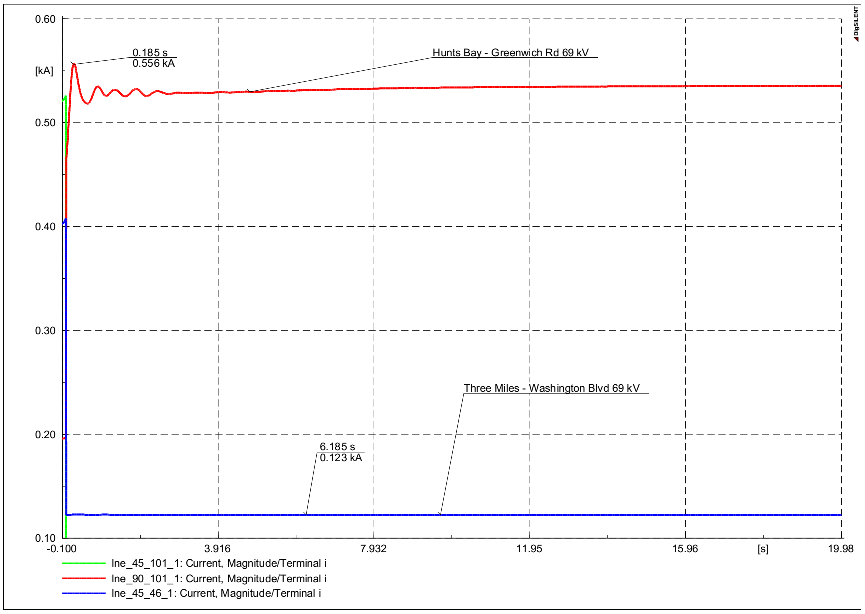

Figure 27: Case 6 - Power flow on major transmission lines in the corporate area

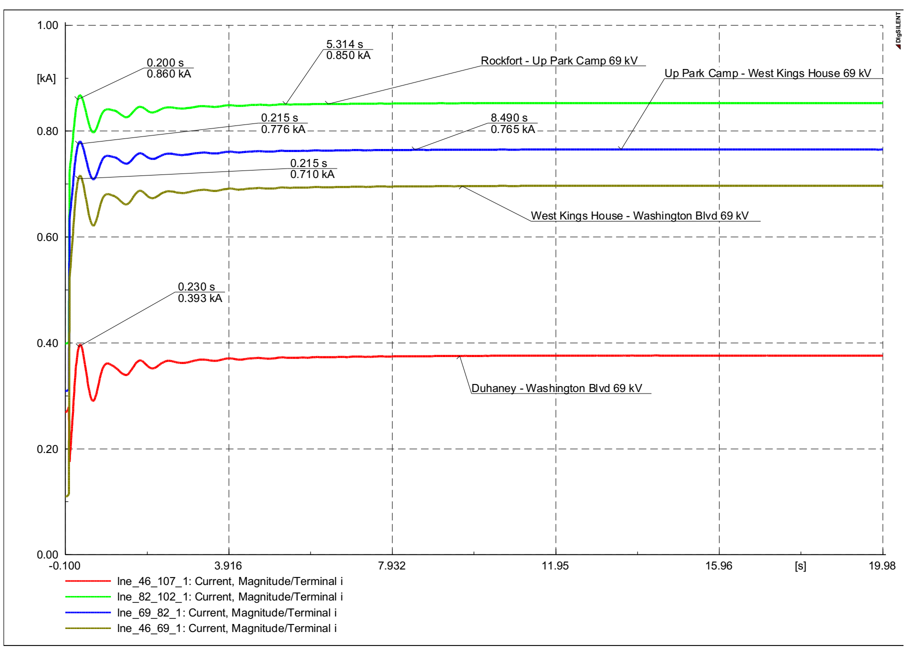

Figure 28: Case 6 - Power flow on major transmission lines in the corporate area

Case 7:526 MW, Hunts Bay - Three Miles 69 kV tripped. Automatic shedding of 70 MW

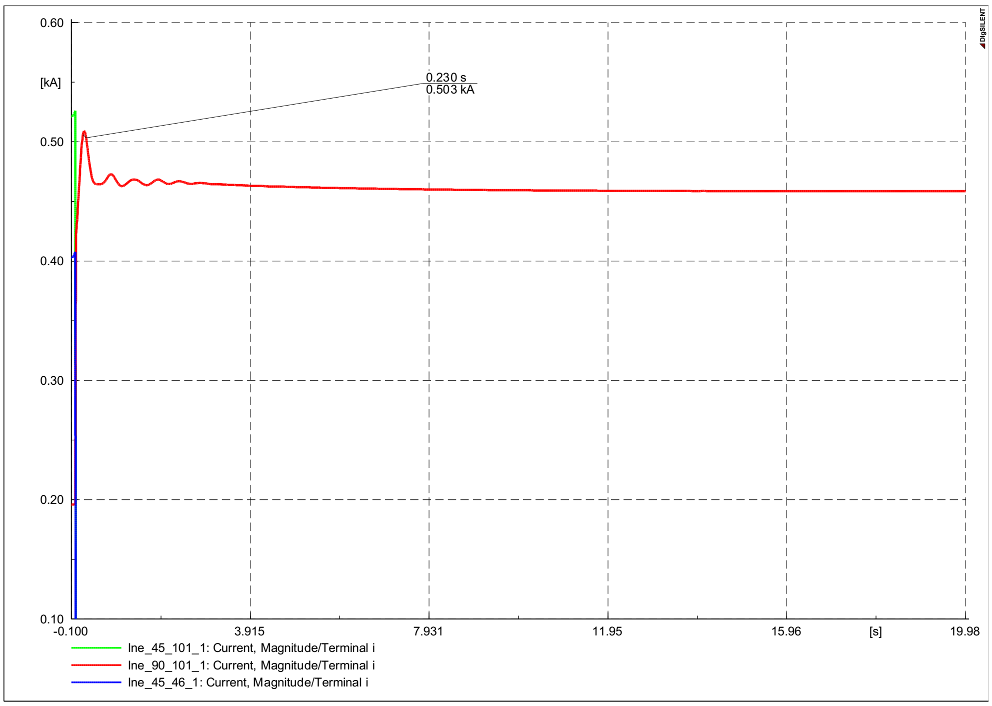

Figure 29: Case 7 - Power flow on major transmission lines in the corporate area

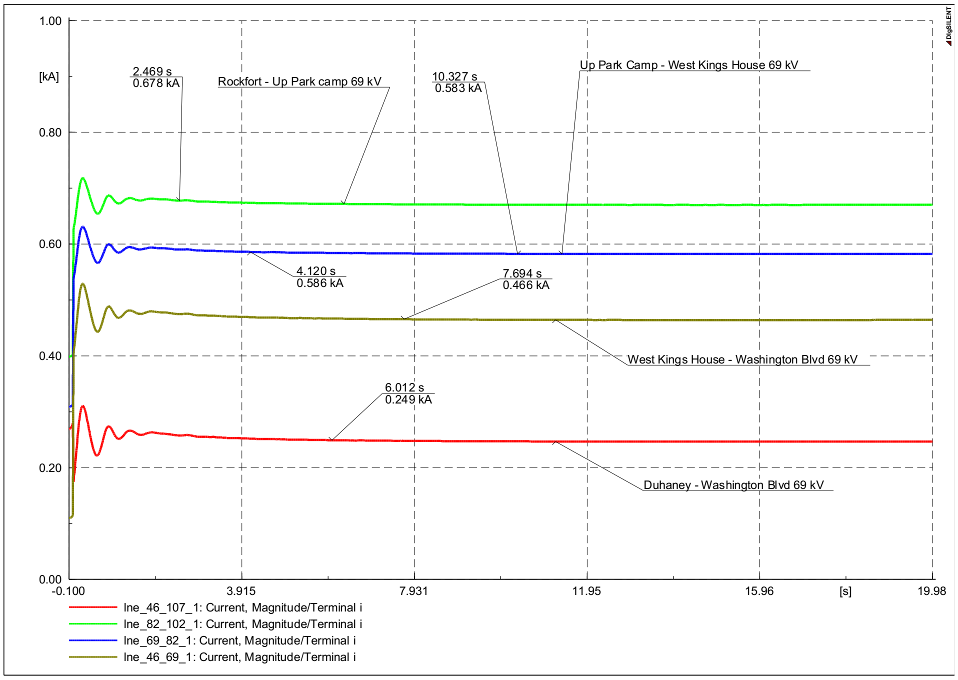

Figure 30: Case 7 - Power flow on major transmission lines in the corporate area

15. Conclusions and Recommendations

15.1 Outage Cause Analysis

This section discusses the cause of the system separation and blackout based on the OUR's assessment.

The OUR's assessment of the outage found that the sequence of events which led to the system separation and rural subsystem blackout was initiated by the inadvertent overloading and subsequent tripping of the HB- Three Mile 69 kV transmission line. However, the root cause of the outage was the culmination of several factors due to deficiencies (directly and indirect) in outage planning, personnel organization and management, decisions taken, failure of personnel to act and importantly a lack of situational awareness of personnel operating the system.

The cascading of the outage was as a result of several factors prior to the outage and during the event manifesting themselves the most notable of which was the failure of the under-frequency loading shedding protection system in the rural area.

The cascading of the outage was a result of several prior factors to the outage and during the event manifesting themselves and most notable the failure of the under-frequency protection system in the rural area.

Cause 1: Poor Situational Awareness by Stakeholders.

The main cause of the system outage was traced to a lack of situational awareness on the part of both outage management, operational and field personnel involved in critical aspects of the outage.

These include:

- Outage planners were either not aware of or did not factored in their planning the generation system plant availability situation.
- Insufficient risk assessments carried out prior to the planned outage. The generation situation increased the risk to the system of taking out the two lines which placed the system in an N-2 contingency state. The security of the system should be given greater

consideration than the facilitation of the road project as there were no imminent safety or other emergency risks. Given the low availability of generation, the outage could have been postponed to a more opportune time.

- Old Harbour Unit 4 was forced off line the previous day at 4:57 am and planned for return to service on April 18th at 10 am. This situation further compromised the system security and this should have been evident to the system controllers and the outage planners. This questions the coordination between the outage stakeholders as well as their level of situational awareness. We would expect that a risk assessment would have been carried out to understand the exposure to the system security under N-2 contingency and going into the outage with the low level of generating plant availability.

  Although the outage started nearly four (4) hours late, there was not an understanding that without a scope change the outage would go beyond the prescribed 6 pm completion time. There was a lack of understanding or awareness of the normal steep load increase going into the evening peak, which should have been well understood by the system operators

- There was a lack of understanding of the difference between line thermal limit and relay pick up setting. The Hunts Bay – Three Miles line had a thermal rating of 532 Amps, but the operator had thought that the thermal rating was 720 Amps, and as such no action was taken to reduce the loading on the line.

- System operators were unaware that line loading limits were violated and hence did not take actions to reduce the loading on the lines.

- Erroneous line loading reading on the Three Miles - Hunts Bay line due to transducer errors. This may have led to no action being taken by the system controllers to reduce the line loading.

- The system controllers did not run sufficient contingency analyses to alert operators to developing system conditions in a timely manner.

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Cause 2: Inadequate Outage Planning, Management and Execution

There were several personnel related issues of concern going into the planned outages, for example:

- JPS did not provide an outage organization including clear lines of authorization, communication, management and functional responsibilities for the outage activities.
  .
- The late start of outage and no commensurate scope adjustments. No switchers were available at Hunts Bay to carry out the switching at 7:00 am. The outage was delayed by nearly four (4) hours.

- JPS' report indicated that the system control 10pm - 8am April 16 shift was very challenging for shift personnel due to the several outages which were all scheduled to start at 7am.

- It was also reported that the beginning of the 8am – 2pm April 17 shift was hectic due to the high volume of switching activities in progress;

- There was a concern by the shift supervisor who handed over the shift to the 2pm-10pm team about the contingency concerns, the work load and the late start of the outages. It was not made clear what actions were taken to mitigate these issues.

These issues described may have had a negative impact on the efficiency and awareness of the shift personnel and their ability to perform effectively under these circumstances.

There were also communications issues which impacted the situation negatively for example;

- Futile attempts were made to contact the outage supervisor between 5:30 pm and 6:10 pm. The outage supervisor failed to inform system control that the outage would have gone beyond 6:00 pm. There was no evidence that periodic progress updates were provided to the system controllers nor were updates requested.

- Communication regarding the extension of the outage to the system controller through a regional director was made after 6:15 pm indicating that the lines would be returned within an hour, which would now be by 7:15 pm. Given this information and understanding the generation situation, the line loading limits and the expected load increase the system operator should have been prepared to manually shed load to avert the oncoming load increases and reduce the line loadings.

- Based on the nature of the communications on the outage status it would seem that the approach to the outage was casual and the importance of returning the lines on time was not properly understood by the regional personnel, outage supervisor and the system control personnel even though the system was in an N-2 contingency state going into the evening peak.

- From the information provided it was not evident that sufficient updates on the status of the outages were provided to the system operators, nor were such updates sought. There was no mention of the role and responsibilities of the outage manager, if there was indeed an outage manager.

Cause 3: Low Availability of Generating Plant

- The low generating capacity available to meet the projected system peak load demand would have put the already compromised system security at risk by reducing the ability of the system to react to load increases and or sudden loss of generation.

- In spite of a firm installed generating capacity of 862 MW only 587 MW was available to meet the evening peak and provide adequate spinning reserve margin.
.
- The low availability of plants have contributed to the lack of adequate spinning reserve to provide for load increase and generation loss. A code violation was evident as this was below the minimum 30 MW spinning reserve required by the Generation Code.

Based on the above generating system status there was a high probability that the system would be unable to meet the demand requirement and planned load shedding would have to be implemented to preserve system stability. Given the load–generation balance in the sub-systems, approximately 59 MW from the corporate area sub-system would have to be exported to the rural area sub-system via the Duhaney – Washington Blvd 69 kV line for the day peak and 118 MW to meet the evening peak. The system would therefore be at risk of separation given the relatively high load level that would be encountered on the single line connecting the corporate and rural areas during the evening peak. The spinning reserve was inadequate to offer relief to the system in event of sudden reduction in generation and/or sudden load increases as the rural area was severely compromised due to very uneven distribution of the little available spinning reserve.

It is noted that a relatively large generating capacity was unavailable mainly in the rural areas. At Bogue a number of plants were on long term outages. This situation is reflective of issues in maintaining the generating plants in reliable operating conditions. This compromises the ability of the system to respond to contingencies and hence reduces system reliability and security. The system operator has a responsibility to provide reliable service. It is therefore necessary to ensure plants are made available in a timely manner and that an appropriate maintenance programme be put in place to improve the availability of the generating plant.

Cause 4: Deficiencies in System Control Centre Operations

Personnel Issues

- This is the critical area for managing the operation of the power system. It was evident from the JPS investigation report that a number of incipient issues were present prior to, during the outage and during restoration.

- The report indicated that the personnel were challenged, as a result of the number of planned outages taking place on the system in the period. This would have affected the operators and controllers and may have contributed to their poor situational awareness and decision making.

Malfunctioning Communication Equipment

- A number of communication equipment failures were reported prior to and during outages. Communication is an integral part of system and outage management. Failure of any component can serve to compromise safety and security of operations.

- The controllers did not have access to a number of status information on the system due to malfunctioning equipment. The communications absence reduced the visibility and data transfer of these points to the system controller and reduced the means of monitoring the system conditions. This would impair the ability of system controllers to react timely to system operating issues arising in these locations.

- The Old Harbour Digital Fault Recorder (DFR) was unavailable hence no fault events were recorded. This negatively impacted the availability of information for post outage analyses. JPS did not indicate how long this situation existed.

It is critical that the maintenance of the communication system be given due priority and failures addressed as urgently.

The failure of the SCADA/EMS to indicate the true Ampere loading of the HB – Three Mile line is a significant risk to the system operations.

Inadequate Contingency Analyses

The delay in the start of the outage work programme, further compromised the security of the system, because the possibility now existed that the outage would go beyond 6:00pm, the time at which the system load would start increasing rapidly to reach the peak demand period which would occur between 6:30 pm and 8:00 pm. JPS failed to adjust the work scope to account for the late start of the outage.

No contingency analyses were carried out to determine the performance of the system under the increasing load conditions after 6 pm. Misunderstanding the importance of returning the lines before the onset of the evening peak was a crucial factor leading up to the subsequent events.

It is not clear why contingency analyses were not performed at the expected evening peak load in order to advise on the system anticipated performance and security issues beyond the day peak. A lack of situation awareness may have caused this omission, or personnel were not familiar with the system operations and the system load profile.

Violation of Planning Criteria/Constraints

JPS violated the planning criteria it had established with regards to the flow on Duhaney – Washington Blvd. line into the Duhaney substation which at 6:00 pm was 40.10 MW. It should be noted that the Hunts Bay – Duhaney and the Hunts Bay - PAJ were still out because of the late start of the outage. This situation may be a result of poor outage communication to the stake holders or these criteria were not fully appreciated or communicated.

System controllers did not manually shed the 25 MW load they had pre-selected to shed to mitigate the effects of a generation shortfall and relieve the loading on the transmission lines. This inaction may have caused some lines to become overload.

Protection System Failure

The protection system had several areas of failure due to inadequate design coordination, maintenance and testing. Design short coming negatively impacted the ability of the system to recover. These included a number of generators tripping at the same frequency. Normally, there should be some off-set increment to prevent all generators tripping at the same time.

- Under extreme system fault conditions all Generating Units should have been disconnected at a frequency greater than 52.5 Hz. and less than 48.0 Hz . Where under and over frequency relays are installed, these relays shall be set for the automatic removal of the generating system from the transmission system. The system operator however, should specify slightly different tripping points for the various generating units in order to avoid having all of them on the transmission system trip at the same time in a frequency constraint.

- The Rockfort No.2 Tripping well below the manufacturer's recommended overspeed tripping point is a significant factor. The Rockfort Unit No.1 was set at the manufacturer recommended overspeed tripping point. ,given that these are identical units had both been set at the manufacturer's recommended over speed trip stetting it is quite possible that unit 2 would have stayed online and may have reduced the extent of load shedding in the corporate area.

- Under-Frequency Relays (U/F)

  The significant failures of the U/F relays continue to be a major factor in the system failure over the years. These relays are usually the last line of defence to prevent system shutdown. The simulations carried out by the OUR showed that if these relays had properly operated in the rural sub-system then, the system collapse in the rural areas would not have occurred. Based on the amount of load under U/F control, had these operated the generator, the load imbalance would be corrected and the scale of the outages would be minimized.

16. Recommendations

The following recommendations are based on the OUR assessments of the outage. The recommendations are geared at preventing or minimizing the recurrence of such events in the future.

16.1 System Operations and Outage Management

System Operations and Outage Management

1. JPS is required to take immediate actions to correct the direct cause of the outage and provide to the OUR with evidence that specific actions were taken to fix the problems identified and that the system is being operated in a reliable manner. The direct causes shall be clearly stated and JPS shall present a solution for each cause along with an implementation schedule and costing where necessary.

2. JPS is required to review and update the SCADA database to reflect correct thermal operating limit settings of all transmission lines and other relevant system operating parameter limits.

3. JPS shall develop a set of criteria to identify facilities, the reliable operation of which are critical to system reliability and security.

4. JPS shall ensure that the communication issues identified are corrected, and equipment defects are addressed as a matter of priority.

5. JPS shall ensure that all major transmission outages are properly planned and coordinated to reduce the system exposure to undue security risks.

6. JPS shall ensure that system operators are properly trained and certified in outage management by industry recognized institutions in order to be able to prudently operate the system under contingencies and emergency conditions.

7. JPS shall ensure that system operators and controllers fully understand the system operating criteria and adhere to the requirements of the Generation Code to prevent violations of operating requirements under normal and abnormal conditions.

8. JPS shall ensure that outage managers and supervisors are properly trained and certified in outage management by industry recognized institutions and are able to understand the relationship between system reliability, and outage impact on system operations.

9. JPS shall ensure that the online and offline simulation tools are properly calibrated and personnel are properly trained to carry out extensive contingency analyses and are able to make informed decisions based on these analyses.

10. JPS is required to review communication protocol between field personnel and system operators and put in place adequate means of contacting outage managers and supervisors during outage situations.

11. JPS shall install time synchronized data recorders for the hydro units and other units which are not currently equipped with this facility.

12. JPS shall engage independent consultants to conduct a detailed review of its outage management systems, from planning to field execution and to develop plans to address the deficiencies identified.

Protection System

13. JPS shall carry out detailed review of under-frequency scheme and actions to be taken to address the persistent failure of the scheme in order to improve reliability of their operation.

14. JPS shall conduct detailed review of generator over and under frequency trip settings, to implement appropriate time delay tripping of generating units to prevent all plants from tripping at the same frequency in order to minimize the risks of rapid cascading of outages.

15. JPS shall take appropriate measures to improve the complement and competence of staff in the protection and control department.

16. JPS shall conduct a detailed review of the maintenance practice for protection equipment and take the necessary actions to improve maintenance of protection systems.

System Restoration

17. JPS shall ensure that all black start and standby generators are properly maintained and periodically tested and reported.

18. JPS is required to fix remote operating equipment that did not operate correctly during the restoration process.

19. Shall JPS ensure that the system control centre staff gets regular practice drills to improve the restoration process.

Long Term Planning.

20. JPS shall develop coordinated long term generation and transmission plans to address existing transmission system constraints.

Action Plan

21. **<u>JPS is required to provide an action plan on the implementation of all of the above recommendations including specific time frame for their completion within thirty (30) days from receipt of this Report.</u>**

‘

17. APPENDIX

2016 April 17 JPS System Outage Analysis

OUR Report

Plant	Unit	MCR	Avail	Non-avail	Reason for Non-availability		Effective		Expected Return	
						Event Type	Date	Time	Date	Time
JPS Plants										
Hunts Bay	GT #4	0	0		Inactive reserve	RS-Reserve shutdown	24-May-02			
	GT #10	32.5	31		Degradation of turbine compressor	D1-Unplanned (forced) derating - immediate	05-Mar-16	3:00pm		
Subtotal		**32.5**	**31**	**1.5**						
Old Harbour	OH #1	30	0		#2 JB bearing vibration (sheared Turbine shaft)	RS-Reserve shutdown	09-Aug-08	8:40pm		
	OH #2	60	56		Low vacuum	D1-Unplanned (forced) derating - immediate	13-Apr-16	11:03am		
	OH #3	65	50		Boiler flue gas outlet system problem	D1-Unplanned (forced) derating - immediate	12-Apr-16	9:47am		
	OH #4	68.5	0		Suspected boiler tube Leak	U1-Unplanned forced outage - immediate	16-Apr-16	4:57am	18-Apr-16	10:00am
Subtotal		**223.5**	**106.0**	**117.5**						
Bogue	GT #3	21.5	20.5		Worn Compressor	D1-Unplanned (forced) derating - immediate	10-Oct-15	8:00pm		
	GT #6	18	14		Smaller engine installed	D1-Unplanned (forced) derating - immediate	24-Feb-15	2:20pm		
	GT #8	14	0		Main exciter problems	U1-Unplanned forced outage - immediate	20-Dec-11	8:00am		
	GT #9	20	0		U1-Unplanned forced outage - immediate	U1-Unplanned forced outage - immediate	17-Mar-16	11:57am	25-Apr-16	6:00pm
	GT #11	20	0		Hot gas path damage	U1-Unplanned forced outage - immediate	19-Sep-12	6:30am		
	GT 12	38	0		Gas conversion project	PO-Planned outage	15-Mar-16	11:41am	30-Apr-16	5:00pm
	ST 14	38	19		GT12/HRSG#12 on planned outage	PD-Planned derating	15-Mar-16	1:29pm	30-Apr-16	9:00pm
Subtotal		**169.5**	**53.5**	**116.0**						

JPSCo's Total										
Independent Power Producers										
JEP		124.36	105.82	18.54	DG# 6 & # 4 on Forced	D1-Unplanned (forced) derating - immediate	16-Apr-16	12:26am	17-Apr-16	4:00am
JPPC		61.3	25	36.3	DG #1 on 12hr running in program	D1-Unplanned (forced) derating - immediate	17-Apr-16	1:04pm		
Subtotal		**185.66**	**130.82**	**54.8**						
Total		**611.16**	**321.32**	**289.84**						

Table A 1: GPCR of 2016 April 17 at 3pm

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Forecasted Unit Commitment Dispatch (MW)		
Generating Units	**Normal**	**Out of Merit**
Old Harbour OH2	56	56
Old Harbour OH3	50	50
Old Harbour OH4	59.3	0
Hunts Bay B6	40	42.3
Rockfort RF1	0	20
Rockfort RF2	20	20
Bogue CC	53	53
	0	20.5
BOGUE GT6	0	14
BOGUE GT7	0	18
JPPC	46	46
JEP	98.36	98.36
WKPP	46	30
JAMALCO	0	0
BROILERS	1.7	1.7
ROARING RIVER	3	3
UWR	1.1	1.1
LWR	1.4	1.4
MAGGOTTY 2	2.93	1.2
RIO A	1.2	1.2
Wigton 3	5	5
Total System Demand	**484.99**	**482.76**

Table A 2: Day peak Generation Dispatch for 2016 April 17

Generating Units	MCR (MW)	Output	
		MW	MVAR
HUNTS BAY B6	68.5	54.26	12.36
HUNTS BAY GT5	21.5	18.59	-0.78
HUNTS BAY GT10	32.5	29.37	-2.64
WKPP	65.5	66.3	5.6
JPPC	61.3	36.49	7.02
ROCKFORT RF1	20	18.48	1.75
ROCKFORT RF2	20	20.87	1.54
OLD HARBOUR #2	60	55.5	34.83
OLD HARBOUR #3	65	50.02	18.01
JEP	124.36	108.2	41.1
JA. BROILERS		2.02	-0.9
BOGUE GT3	21.5	19.25	1.75
BOGUE GT6	18	14.77	0
BOGUE GT7	18	17.36	-0.14
BOGUE CC	57	52.92	18.13
ROARING RIVER	4.05	3.01	0.98
UPPER WHITE RIVER	3.19	1.14	0
LOWER WHITE RIVER	4.75	1.39	1.76
MAGGOTTY 1	3.15	3.02	0.02
MAGGOTTY 2	3.15	2.93	0.11
RIO BUENO A	2.5	2.24	0.91
RIO B	1.1	0	0
CONSTANT SPRING	0.77	0.5	0
WIGTON	38	0	6.18
JAMALCO	11	0.78	3.98
Total System Demand		**579.41**	**152.98**
Spinning Reserve		**22.11**	
Frequency		**49.98**	

Table A3: Generation Dispatch at 6:59 pm for 2016 April 17

SCADA Line Flow Data

Table A 4: SCADA Line Flow Data

BRANCH						
Name	**MW From**	**MW To**	**MVAR From**	**MVAR To**	**From Limits**	**To Limits**
ANN/HGT	-5.56	5.57	0.08	-0.04	19.10	35.90
ANN/PTO	8.30	-8.19	1.28	-1.03	28.70	35.90
BEL/BLK	5.27	-5.23	7.56	-7.47	43.02	43.02
BEL/ORA	11.90	-11.82	3.49	-3.31	43.02	21.50
BEL/TRE	-27.01	27.31	-15.63	16.48	71.71	114.73
BLK/SUN	-8.53	8.57	5.11	-5.03	43.02	71.70
BOG/BOG GT13	0.00	0.00	-0.02	0.00	215.12	215.12
BOG/BOG ST14	-52.59	52.62	7.11	-6.85	239.02	239.02
BOG/BOG GT3 BUS	-52.19	52.21	-4.87	5.14	215.12	215.12
BOG/DUN	6.85	-6.84	-2.15	2.19	143.41	114.73
BOG/OBY	13.78	-13.60	0.48	0.16	89.63	43.02
BOG/PDS	11.12	-10.92	-3.81	4.25	89.63	35.85
BOG/QDR L1	19.46	-19.35	1.54	-1.27	86.05	57.37
BOG/QDR L2	26.60	-26.50	6.02	-5.63	86.05	57.37
CRV/GYR	8.34	-8.24	1.17	-0.95	28.68	28.68
CRV/HOP	7.81	-7.79	2.17	-2.10	57.37	57.37
CAR/RVR	1.95	-1.95	-0.48	0.49	64.54	57.37
D&G/HBB	0.00	0.00	0.00	0.00	86.05	86.05
DUH/CON	20.03	-19.84	4.80	-4.33	57.37	57.37
DUH/D&G	0.00	0.00	0.00	0.00	89.63	89.63

DUH/NAG	14.09	-14.00	6.44	-6.25	57.37	57.37
DUH/PAJ	1.12	-1.12	-4.32	4.33	89.63	89.63
DUH/TRE	-6.80	6.80	1.43	-1.42	114.73	143.40
DUH/TWK	29.87	-29.53	13.43	-12.78	89.63	71.71
DUH/WBL	-7.30	7.31	-8.70	8.75	86.05	89.63
DUN/BEL	6.54	-6.52	3.54	-3.49	114.73	114.73
DUN/KEN	-15.98	16.10	-8.06	8.39	114.73	114.73
DUN/RIO	15.14	-15.05	-1.76	1.98	68.10	57.37
GYR/LYS	4.19	-4.19	0.53	-0.52	28.68	28.68
GWD/MAR	9.48	-9.43	-5.16	5.26	64.54	71.71
HAL/PAR	-0.03	0.04	2.94	-2.94	43.00	43.02
HGT/BLK	-10.73	10.79	-0.74	0.88	19.10	35.90
HOP/WKH	-6.81	6.82	-4.94	4.97	57.40	71.71
HBB/GRD	10.99	-10.96	7.77	-7.71	86.05	71.71
HBB/RFT	1.31	-1.29	12.77	-12.70	95.61	95.61
HBB/3ML	45.77	-45.48	16.20	-15.56	86.05	71.71
HBB/HBA North	0.00	0.00	0.00	0.00	86.05	86.05
HBB/HBA South	0.00	0.00	0.00	0.00	86.05	86.05
JBR/SPV	1.67	-1.67	2.95	-3.00	25.10	25.10
JPC 1/RFT	22.98	-22.97	6.54	-6.49	215.12	215.12
JPC 2/RFT	22.98	-22.97	6.54	-6.49	215.12	215.12
ALK/KEN	-2.52	2.52	0.38	-0.40	57.37	59.76
LWR/UWR	-15.81	15.84	-4.87	4.94	50.19	71.71
MAG/PDS	-4.98	5.03	-1.55	1.67	53.78	71.71
RFT/CMT	15.04	-15.02	9.38	-9.32	28.68	28.68
MAR/DUN	4.57	-4.55	-5.19	5.22	64.54	71.71

MIC/TRE	-21.91	22.16	0.18	0.36	43.00	71.71
SPU A & B 69	25.50	-25.49	1.74	-1.70	130.00	130.00
OCH/LWR	-17.16	17.23	-6.21	6.35	50.19	64.54
OHB/DUH L4	50.73	-50.34	19.97	-17.88	215.10	100.40
OHB/PAR L6	37.00	-36.81	12.36	-11.79	172.10	57.37
OHB/PAR L7	37.00	-36.81	12.36	-11.79	172.10	57.37
OHB/TRE L5	58.11	-57.59	21.43	-19.19	215.12	100.39
OHB/MON	2.77	-2.75	-3.09	3.12	86.00	50.20
OHB/RHO	18.10	-18.04	-0.84	1.00	86.00	53.78
ORA/ANN	4.79	-4.77	2.11	-2.06	43.00	21.50
PAJ/HBB	0.00	0.00	0.00	0.00	86.05	86.05
PDS/OBY	2.91	-2.90	3.12	-3.08	50.19	77.44
PAR/KEN	27.17	-26.99	8.07	-7.50	143.41	57.37
PAR/MAY	12.34	-12.27	3.73	-3.61	14.30	14.30
PAR/MON	1.61	-1.61	2.37	-2.35	57.37	71.71
PAR/TOL	3.76	-3.74	0.74	-0.72	71.71	57.40
POR/SPU	0.90	-0.90	0.73	-0.73	50.20	71.71
QDR/ROS	29.68	-29.42	0.83	-0.28	77.44	68.12
RIO/CAR	16.24	-16.10	-1.73	2.05	68.10	57.37
RVR/OCH	-7.29	7.31	-2.58	2.62	64.54	57.37
RFT/CRV	24.66	-24.49	6.94	-6.57	71.71	57.37
RFT/GRD	3.94	-3.93	-4.76	4.79	71.71	86.00

RFT/UPC	29.69	-29.59	8.62	-8.27	95.61	43.00
ROS/GWD	20.76	-20.60	-2.65	3.01	71.71	68.12
SPV/WHM	-3.64	3.72	6.45	-6.35	53.78	86.00
SPU/KEN	4.49	-4.49	4.08	-4.07	114.73	95.61
SPU/MAG	6.70	-6.65	-2.04	2.17	71.71	53.78
SPU/ALK	-2.51	2.52	0.39	-0.38	57.37	59.76
SPU/PAR	-22.52	22.59	-8.82	9.28	71.71	143.41
TOL/STJ	0.20	-0.20	0.02	-0.02	71.70	71.70
SUN/ALC	0.00	0.00	0.00	0.00	71.71	43.02
SUN/MIC	-8.57	8.58	5.03	-5.01	43.02	71.71
TOL/POR	3.54	-3.54	0.70	-0.69	71.71	57.40
TRE/SPV	-5.31	5.31	3.46	-3.45	53.78	86.05
TRE/TWK	-12.45	12.48	-6.05	6.11	86.00	89.63
UWR/BEL	-16.23	16.27	-5.20	5.30	50.19	71.71
JEP/OHB	98.36	-98.20	84.18	-82.56	430.24	430.24
WBL/3ML	-29.65	29.82	-15.12	15.49	71.71	86.05
WKH/UPC	-22.94	23.02	-8.28	8.51	57.37	95.61
WKH/WBL	7.00	-6.99	0.53	-0.51	71.71	89.63
WHM/RHO L2	-3.72	3.72	6.35	-6.34	57.37	57.37
ANN T1	2.03	-2.03	0.70	-0.67	12.50	12.50
BEL INT	33.53	-33.45	19.11	-16.35	60.00	60.00
BLK T1	2.98	-2.98	1.48	-1.35	10.00	10.00
BOG INTBUS T1	-6.85	6.86	2.15	-2.07	100.00	100.00
BOGUE T2	26.96	-26.86	-4.37	7.55	40.00	40.00
BOG CC1 XFMR	0.00	0.00	0.00	0.00	69.00	69.00
BOG CC12 XFMR	0.00	0.00	0.00	0.00	145.00	145.00
BOG CC2 XFMR	53.00	-52.62	-3.12	6.85	69.00	69.00
BOG GT11 XFMR	0.00	0.00	0.00	0.00	33.30	33.30

BOG GT12 XFMR	0.00	0.00	0.00	0.00	50.00	50.00
BOG GT13 XFMR	0.00	0.00	0.00	0.00	50.00	50.00
BOG GT3 XFMR	-20.42	20.50	-2.00	3.83	28.50	28.50
BOG GT6 XFMR	-13.93	14.00	2.25	-1.50	26.00	26.00
BOG GT7 XFMR	-17.87	18.00	-5.38	6.69	26.00	26.00
BOG GT8 XFMR	0.00	0.00	0.00	0.00	26.00	26.00
BOG GT9 XFMR	0.00	0.00	0.00	0.00	30.00	30.00
JBR GEN XFMR	-1.67	1.68	-2.95	3.00	60.00	60.00
CRV T1	4.04	-4.04	1.86	-1.73	12.50	12.50
CRV T2	4.30	-4.30	1.37	-1.22	15.00	15.00
CAR T1	14.15	-14.06	-1.57	3.17	15.00	15.00
CON T1	19.84	-19.76	4.33	-2.42	33.25	33.25
D&G T1	0.00	0.00	0.00	0.00	25.00	25.00
DUH INT T1	20.69	-20.67	5.97	-5.32	100.00	100.00
DUH INT T2	20.69	-20.67	5.97	-5.32	100.00	100.00
DUH INT T4	15.76	-15.75	4.51	-4.01	80.00	80.00
DUH T3	-0.72	0.73	2.99	-2.95	25.00	25.00
DUN INT	16.28	-16.25	2.32	-1.53	40.00	40.00
DUN T2	5.66	-5.64	-1.93	2.20	10.00	10.00
GYR T1	4.04	-4.04	0.42	-0.31	10.00	10.00
GRD T1	6.13	-6.12	0.50	-0.34	25.00	25.00
GRD T2	8.77	-8.75	2.42	-2.06	33.00	33.00
GWD T1	11.12	-11.06	2.14	-1.17	15.00	15.00
HIGHGATE T1	5.16	-5.14	0.78	-0.51	6.25	6.25
HOPE T1	10.56	-10.54	6.02	-5.36	33.00	33.00
HOPE T2	4.02	-4.01	0.90	-0.79	10.00	10.00

HUNTS BAY B6 GE	-42.17	42.25	-12.31	15.30	80.00	80.00
HUNTS BAY GT10	0.00	0.00	0.00	0.00	42.66	42.66
HUNTS BAY GT4 G	0.00	0.00	0.00	0.00	30.00	30.00
HUNTS BAY GT5 G	0.00	0.00	0.00	0.00	28.50	28.50
HUNTS BAY T1	7.99	-7.98	1.80	-1.52	33.00	33.00
HUNTS BAY T2	6.10	-6.09	-1.39	1.57	30.00	30.00
HUNTS BAY T3	0.00	0.00	0.00	0.00	25.00	25.00
JAMALCO GEN TF	0.03	-0.03	-2.94	2.98	30.00	30.00
JPPC GEN TF1	-23.16	23.18	0.98	0.03	80.00	80.00
JPPC GEN TF2	-22.79	22.82	-14.05	15.49	80.00	80.00
KENDAL INTBUS T	15.38	-15.37	3.18	-2.70	80.00	80.00
KENDAL T2	12.85	-12.82	3.09	-2.29	25.00	25.00
LOWER WHITE HYD	-1.41	1.42	-1.48	1.56	6.00	6.00
LYSSONS T1	4.19	-4.17	0.52	-0.29	6.25	6.25
MAGGOTTY HYDRO	0.00	0.00	0.00	0.00	12.50	12.50
MAGGOTTY T1	12.79	-12.76	2.02	-1.25	33.00	33.00
MARTHA BRAE T1	4.87	-4.84	-0.07	0.22	15.00	15.00
MAY PEN T1	12.27	-12.24	3.61	-2.39	15.00	15.00
MICHELTON T1	13.33	-13.29	4.83	-3.93	25.00	25.00
MONYMUSK T1	4.36	-4.35	-0.76	0.92	12.50	12.50
NAGGO HEAD T1	0.00	0.00	0.00	0.00	12.00	12.00
NAGGO HEAD T2	14.00	-13.96	6.25	-5.22	25.00	25.00
OCHO RIOS T1	9.86	-9.84	3.59	-3.13	33.00	33.00
OH#1 GEN TF	0.00	0.00	0.00	0.00	37.50	37.50
OH#2 GEN TF	-57.44	57.67	18.24	-11.58	80.00	80.00
OH#3 GEN TF	-49.88	50.00	-2.29	6.39	80.00	80.00

OH#4 GEN TF	2.94	-2.94	1.36	-1.34	80.00	80.00
OHB INT T1	19.74	-19.70	-0.89	1.92	37.50	37.50
ORACABESSA T1	7.03	-6.98	1.20	-0.64	10.00	10.00
ORANGEBAY T1	16.50	-16.44	2.92	-1.64	25.00	25.00
PARADISE T1	-3.20	3.25	-9.77	10.23	33.00	33.00
PARADISE T2	6.18	-6.17	0.73	-0.31	10.00	10.00
PARNASUS INTBUS	23.85	-23.82	6.23	-5.06	80.00	80.00
PARNASUS T3	6.07	-6.05	1.15	-0.87	15.00	15.00
PORT ANTONIO T1	8.19	-8.16	1.03	-0.56	10.00	10.00
PAJ T1	0.02	0.01	-9.45	9.96	25.00	25.00
PAJ T2	1.09	-1.09	5.13	-4.97	25.00	25.00
PORUS T1	2.63	-2.63	-0.04	0.09	13.30	13.30
QUEENS DRIVE T1	5.12	-5.12	1.72	-1.58	25.00	25.00
QUEENS DRIVE T2	11.04	-11.02	4.36	-3.74	25.00	25.00
RF1 GEN TF	-18.95	19.02	1.45	0.15	25.00	25.00
RF2 GEN TF	-18.95	19.02	2.21	-0.60	25.00	25.00
RHODENS PEN T1	14.31	-14.27	5.34	-4.30	25.00	25.00
RIOBUENO HYDRO	-1.20	1.20	-0.25	0.27	5.00	5.00
RVR GEN XFMR	-3.00	3.01	-0.53	0.68	5.00	5.00
RVR T1	12.23	-12.20	2.62	-2.03	25.00	25.00
ROCKFORT T1	11.81	-11.78	1.83	-1.22	25.00	25.00
ROSE HALL T1	8.67	-8.63	2.93	-2.32	15.00	15.00
SPUR TREE T1	19.69	-19.61	4.47	-2.63	25.00	25.00
SPUR TREE T2	18.02	-18.00	4.75	-4.07	80.00	80.00

THREE MILES T1	15.66	-15.62	0.07	1.00	25.00	25.00
TRED INT T1	11.78	-11.75	2.07	-1.49	30.00	30.00
TRED INT T2	11.70	-11.67	2.06	-1.48	30.00	30.00
TREDEGAR T3	19.02	-18.94	5.20	-3.49	25.00	25.00
TWICKENHAM T1	17.06	-17.00	6.68	-5.14	33.25	33.30
UP PARK CAMP T1	6.57	-6.56	-0.24	0.43	33.25	33.25
UPPER WHITE HYD	-1.09	1.10	-1.90	2.00	6.00	6.00
UPPER WHITE T1	1.48	-1.47	2.16	-2.10	6.00	6.00
WASH BLVD T1	8.80	-8.79	1.99	-1.63	25.00	25.00
WASH BLVD T2	13.93	-13.90	2.46	-1.52	33.00	33.00
WASH BLVD T3	6.60	-6.58	2.44	-2.08	15.00	15.00
WKH T1	9.12	-9.11	2.79	-2.36	33.00	33.00
SPU/WIG	0.00	0.00	0.00	0.00	46.55	46.55
WIG T1	0.00	0.00	0.00	0.00	40.00	40.00
PSUEDO1/PSUEDO2	0.00	0.00	0.00	0.00	46.55	46.55
PSUEDO3/PSUEDO4	0.00	0.00	0.00	0.00	46.55	46.55
MUN/MAG	0.00	0.00	0.00	0.00	30.00	30.00
WKPP/HBB	30.00	-29.99	24.90	-24.85	430.24	430.24
MAGG HYD GSU 2	-1.16	1.17	-2.64	2.72	6.00	6.00
WIG3 T1	-4.99	5.00	1.92	-1.69	999.90	999.90
SPU/WIG3	-4.98	4.99	1.94	-1.92	999.90	999.90

Table A5: SCADA Substation/Feeder loading

Substation Name	**Feeder**			
	No.	**Name**	**Load (MW)**	**Load (MVAR)**

Bogue	6-410	HOSP	9.24	
	6-310	MoBay	8.90	
	6-210	Lucea	14.94	
		Total	**33.08**	
Queens Drive	6-710	Queens Drive	10.4928331	
	6-310	Flankers	2.32689428	
	6-510	Airport	1.51499987	
	6-810	Hotel	4.48413706	
		Total	**18.8188643**	
Rose Hall	6-110	COR GARDEN	9.82789993	
	6-210	Rose Hall	0	
		Total	**9.82789993**	
Greenwood	6-110	G/WOOD	2.70000005	
	6-210	ROS/ALL	-3.1000001	
		Total	**10.88**	
Duncans	4-110	DUNCAN	5.78	
Cardiff Hall	6-310	B/TOWN	7.85017967	
	6-210	SALEM	6.76267767	
		Total	**14.6128573**	
Roaring River	4-210	B/TOWN	0	
	4-310	O/RIOS	0	
	4-410	S/ANNBY	6.04797363	
		Total	**6.04797363**	
Ocho Rios	4-510	FRANKFRT	3.48600006	
	4-410	MAIN ST	3.03600025	
	4-310	O RIOS	3.6388042	
		Total	**10.1608045**	
Oracabessa	4-210	R/NUEVO	3.90537262	
	4-110	P/MARIA	1.11240005	
		Total	**5.01777267**	
UPRWHITE	4-110	O/RIOS	1.47700012	
	4-210	EXCHANGE	0.87400001	
		Total	**2.35100013**	
Port Antonio	6-410	TOWN FDR	5.992064	

	6-310	SAN SAN	2.45588207	
		Total	**8.44794607**	
Annotto Bay	6-210	DOVER	0.85776806	
	6-310	ANOT BAY	1.36092806	
		Total	**2.21869612**	
Highgate	4-210	PT MARIA	3.25440001	
	4-110	HIGHGATE	1.90170002	
		Total	**5.15610003**	
Blackstonedge	4-110	GUYSHL	0	
Mitchelton	4-110	EWARTON	7.90739965	
	4-210	BOG WALK	5.7420001	
		Total	**13.6493998**	
Tredegar	6-210	ENSOM	6.47459793	
	6-310	ELTHAM	5.22144985	
	6-410	SP TWN	7.48287773	
		Total	**19.1789255**	
Constant Spring	6-410	STONYHL	32.7670021	
	6-310	LONG LANE	16.3830013	
	6-210	MANNING	16.3830013	
		Total	**65.5330048**	
Washington Blvd	6-510	CSPRNG	7.77436256	
	6-810	RED HILLS	11.2498741	
	6-610	SHORTWD	6.30809975	
	6-410	HWT RD	2.83233881	
	6-710	MOLYNES	5.64935207	
	6-310	WALTHAM	5.6358614	
		Total	**39.4498887**	
West Kings House	210	LV MW	4.16432524	
	310	LV MW	3.42533588	
	410	LV MW	2.46596909	
		Total	**10.0556302**	

Hope	6-310	UWI	4.44837904	
	6-410	LIGUANEA	7.05990458	
	6-510	EAST	8.20961952	
		Total	**19.7179031**	
Cane River	6-410	H/VIEW	3.49303794	
	6-610	AIRPORT	2.59992194	
	6-310	BULL BAY	2.26876497	
		Total	8.36172485	
Goodyear	6-110	GOODYEAR	0.04399962	
	6-210	MORANT BAY	3.89799976	
		Total	**3.94199938**	
Lyssons	6-410	MORANT BAY	**-2.500025**	
Rockfort	6-210	ROLLTWN	3.37773871	
	6-310	FLOURMIL	1.38998604	
	6-410	DOWNTWN	6.90213394	
		Total	**11.6698587**	
Up park Camp	6-310	N/KGN	2.60712123	
	6-410	OXFORD	0	
	6-510	MT VIEW	2.85920286	
		Total	**5.46632409**	
Hunts Bay	5-810	SP TWN RD	0	
	6-110	B.O.J.	1.92779326	
	5-610	ESSO	0	
	6-210	HBR ST	6.87415648	
	5-710	M GARV DR	0	
	6-510	NORTH ST	0	
	6-410	ORANGE ST	1.27800131	
	6-310	X RDS	5.00578451	
		Total	**15.0857356**	
Greenwich Rd.	6-310	CROSS RD	3.77363014	
	6-710	MAXFIELD	2.64325356	
	6-410	OLD HOPE RD	-0.014412	
	6-510	NEW KGN	-0.014412	
		Total	**15.31**	

Three Miles	5-510	M GARV	4.85456848	
	5-310	FREEZONE	4.71961451	
	5-410	SPTWN RD	5.83923578	
		Total	**15.4134188**	
Naggo Head	6-510	B/LODGE	7.72054386	
	6-610	G/PMORE	7.10837412	
		Total	**14.828918**	
Twickenham	6-210	P/MORE	10.4278955	
	6-410	G/DALE	6.45263195	
		Total	**16.8805275**	
Rhodens Pen	6-210	SPRVIL	5.4000001	
	310	INDEST	3.45596886	
	410	OHBAY	5.25603199	
		Total	**14.1120009**	
Monymusk	4-210	L/TOWN	1.4322083	
	4-310	FACTORY	0.42179403	
	4-410	MILK RV	2.60000014	
		Total	**4.45400247**	
Parnassus	6-210	MAYPEN	0	
	6-310	HAYES	0	
		Total	**0**	
Kendal	6-210	CHRISTIANA	8.32144547	
	6-310	MILE GULLY	4.79160023	
		Total	**13.1130457**	
May Pen	6-110	CHAPELTON	7.30000019	
	6-210	MAYPEN	4.70000029	
		Total	**12.0000005**	
Porus	6-210	BROADLEAF	1.37161911	
	6-310	PORUS	2.81163549	
		Total	**4.1832546**	
Spur Tree	6-310	NEWPORT	8.96675205	
	6-210	S/CRUZ	32.7669983	
		Total	**41.7337503**	
Maggotty	6-110	MAGGOTTY	2.614326	

	6-210	BLACK RVR	10.6157475	
		Total	**13.2300735**	
Paradise	6-310	NEGRIL	5.99499941	
	6-210	FERRIS	7.39099932	
	6-110	FROME	6.12999964	
		Total	**19.5159984**	
Orange Bay	6-210	NEGRIL	10.1449995	
	6-310	LUCEA	6.15499973	
		Total	**16.2999992**	
Martha Brae	4-110	**Total**	0	
Duhaney	6-210	FERRY	7.90206432	
	6-310	PEMBROKE	8.372715	
	6-410	SP TWN RD	1.2096014	
		Total	**17.4843807**	

18. References

1. **JPS MAJOR SYSTEM FAILURE TECHNICAL REPORT POWER SYSTEM ISLANDING AND WIDESPREAD OUTAGE, APRIL 17, 2016 at 6:59PM**

2. **ELECTRICITY ACT, 2015**

3. **JPS ELECTRICITY LICENCE**