Jamaica Public Service Company Limited

CHANGING LIVES WITH OUR ENERGY

PRELIMINARY TECHNICAL REPORT
POWER SYSTEM SHUTDOWN – JULY 3, 2007

EXECUTIVE SUMMARY

On Tuesday, July 3, 2007 at approximately 5:11 a.m., an All-Island electric system shut down occurred. This resulted in customers experiencing power outage for periods of time varying from just under an hour to eleven and a half hours. Subsequent investigations and inspections carried out immediately following the event revealed the location of the initiating fault to be in the proximity of the generator step-up transformer for unit #2 at Old Harbour power station. Evidence of the fault was seen as flashed-over lightning arresters on the HV side of Unit # 2 generator step-up transformer (GSU) and a dislodged B-phase down-dropper associated with the line-side of disconnect switch 9-227.

JPS has launched an internal investigation of the event. This Preliminary Report is prepared as part of the JPS internal investigation as well as in response to a directive by the OUR. It provides a technical assessment of the performance of the power system protection as well as other pertinent technical and operational information and data requested by the OUR. A final report will be issued after the completion of the internal investigation.

Jamaica's electric power system is an interconnected grid linking four major generating stations in the west, south central and east areas of the island through 138 kV and 69 kV transmission systems. The general philosophy applied to protecting the JPS power system is to provide main and back-up protection schemes that will detect most of the faults which occur and clear them discriminatively. When the situation of a given fault is such that this is not possible, the indiscriminate fault clearance may result in the loss of a major section but not the entire system. The basic design objectives of JPS protective relaying system are, among other things, to maintain dynamic stability; prevent or minimize equipment damage; minimize the system outage area. To accomplish the design objectives, four criteria for protection are considered: speed, selectivity, sensitivity and reliability.

The design criteria for the protection of generators and generator transformers (GSU) at Old Harbour Unit # 2, require that for any fault in the Generator/GSU zone, the two primary protection breakers will trip in addition to tripping the generator. If there is any failure of either of these primary protection breakers, then all adjacent breakers feeding into the failed breaker will be required to operate via breaker-fail (backup) protection, thereby isolating the fault. If the breaker-fail scheme for either breaker fails, then local backup including the inter-bus transformer and all generators on-line at Old Harbour will be required to trip in addition to breakers at the remote ends of all 138 kV transmission lines connected to the Old Harbour Station (Parnassus, Duhaney and Tredegar substations) effectively isolating the Old Harbour Station.

In response to the fault on the GSU the primary protection and breaker-fail protection schemes failed to operate as designed due to the slow operation of breakers. The primary protection relays operated correctly to trip the associated breakers. However, one of these breakers (9-220) failed to operate within the required time; it took more than 4000 ms to operate, instead of 100ms, due to a stuck breaker pole. *(Subsequent test result of breaker timing for breaker 9-220: Pole 1 - >4000 ms; Pole 2 - 226.2 ms; and Pole 3 - 227.1 ms)*. The stuck breaker pole was still facilitating the flow of fault current, thus completing the logic for operation of the breaker-fail scheme for 9-220. This breaker-fail scheme is designed to trip the other south bus breakers in addition to re-tripping breaker 9-220A within 330 ms. These breakers took between 983 and 1051 ms to open. Given the duration of the breaker operation, which was well outside the time allotted for local breaker-fail protection to clear the fault, remote zone 2 or directional over-current relays at Duhaney, Tredegar and Parnassus were required to operate, as well as the local inter-bus transformer back-up protection at Old Harbour, all within 470 ms (zone-2) to 730 ms (directional over-current). The zone-2 protection operated correctly at Duhaney substation. Parnassus breakers tripped on ground directional over-current relays in a time of approximately 730 ms. Tredegar breakers tripped on zone-2 distance protection in a time of 709 ms.

Routine maintenance of the protection relays at the Old Harbour switchyard was last performed June 26, 2007 as scheduled. Major preventative maintenance to the 138 kV oil circuit breakers is done every three years. Maintenance is on schedule for all the breakers in the schemes associated with this event. The defective breaker (9-220) was last maintained in April 21, 2006 and was within its maintenance cycle.

At the time of the fault there were 20 generators online carrying 445MW of load. The delayed fault clearance at Old Harbour significantly affected the operation of the generators online. JEP Barge-II, JEP Barge-I, Old Harbour Unit-4 and Unit-1, JPPC, Bogue Combined Cycle units, Rockfort Unit-2 and Hunts Bay B-6 generators tripped in that sequence within 14 seconds of the occurrence of the fault. This resulted in a loss of approximately 260MW or 58% of the total load on the system.

The JPS power system operates at 50 Hz frequency and is typically achieved when the active power generated is matched exactly by the load being served. In instances of loss of active power generating capacity without a corresponding loss of active load, system frequency will decline commensurate with the level of system overload. In order to maintain the load/generation balance, the system relies on automatic under-frequency load shedding to reduce the loads. Four stages of automatic under-frequency totalling 45% of the load (approximately 200MW) were shed during the shutdown. These loads were shed after generating units tripped at Old Harbour, 1.671 seconds after the fault started. The last stage 4 point was shed 2.179 seconds after fault inception.

The under-frequency load shedding scheme was not able to maintain the load generation balance due to the significant loss of generator units relative to the load/demand. The resulting instability resulted in the cascade of the power system to total shutdown.

System restoration started approximately 20 minutes after shutdown with the restart of generators and supply of power to customers in two separate sub-systems, Montego

Bay and Kingston. GT10 black-started and energized the bus at Hunts Bay (Kingston) at 6:04am. Rockfort substation was energized at 6:31am. At this time both Rockfort and JPPC units were requested on line. GT7 (Bogue) black-started and energized Montego Bay subsystem at 6:43am. Two feeders from the Hunts Bay substation were the first to be energized between 6:18 and 6:22 am. From Bogue, the Cornwall Regional Hospital feeder supply was restored followed by the Donald Sangster International Airport at 6:46am. The Kingston and Montego Bay subsystems were synchronized at 8:26am and supply restored to the Old Harbour switchyard at 8:35am to facilitate dispatch of all available generators at this station. The transmission grid was fully energized at 10:19am with just over 50% of total system demand restored. Full restoration of customers' supply was hampered by delays encountered as various generating plants had problems returning the units to service. The last feeder was energized at 4:59pm.

Subsequent to the event, the damaged lightning arresters were replaced on GSU #2 the defective breaker (9-220) has been replaced with a new SF-6 unit. All other breakers are being tested. Scheduled preventative maintenance has also been accelerated for the Old Harbour switchyard.

Detailed technical analysis as well as the internal investigations into the event continue and are scheduled to be completed by August 31, 2007. JPS is in the process of engaging international consultants to review the investigation and final report on the event as well as to review and implement any necessary improvements to the design, maintenance and operations of the protection and control, substation and transmission lines subsystems.

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1.0 INTRODUCTION

1.1 Event Description

On Tuesday, July 3, 2007 at approximately 5:11 a.m., an All-Island electric system shut down occurred. This resulted in customer island wide experiencing power outage for varying period of time spanning eleven and a half hours.

Subsequent investigations and inspections carried out on the morning of July 3, 2007 revealed evidence of:

- Flash-over lightning arresters on C-Phase HV side of Unit No. 2 generator step-up transformer (GSU)
- Burnt arrester ground connector for the H3 (C-phase) bushing lightning arrester
- Pitting and outright burn-through of corona rings for H3 (C-phase) and H2 (B-phase) bushing lightening arresters; and
- Dislodged B-phase down-dropper associated with line-side of disconnect switch 9-227

An immediate assessment of the network was done and the fault was determined to be isolated to the Old Harbour Unit 2 GSU zone, accordingly, restoration activities commenced at 5:32 am. Full restoration of power to customers was achieved at 5:00 PM

1.2 Shutdown History

Prior to the event of July 3 outlined above, the JPS power system experience a similar all island shut down on July 15, 2006. This event was comprehensively investigated by an internal JPS team, the Office of Utilities Regulation (OUR) and an external Power Outage Review Team (PORT).

Arising from these investigations several recommendations have been made and are being implemented under the supervision of the OUR. Appendix A shows the recommendations made and the implementation progress to date.

1.3 Investigation

JPS has launched an internal investigation to determine precisely what led to this all Island electric system shutdown of July 3, 2007.

This report will document the work of the investigating team subsequent to their review of the sequence of events and all relevant system data and reports inclusive of the JPS internal reports, the OUR Information and Questions for Enquiry and the PORT report of 2006. It will:

- Compare the actual performance of the system during the shutdown with the design criteria
- Identify the cause of the event
- Highlight any new recommendations not previously identified to prevent any similar reoccurrence.

2.0 JPS ELECTRIC POWER SYSTEM

2.1 System Topology

Jamaica's electric power system is an interconnected grid linking four major generating stations in the west, south central and east areas of the island through a 138 kV/69 kV transmission system. Power is generated and transmitted at 50 Hz. The Jamaica Public Service (JPS) operates the system under an exclusive license for distribution and sale of electricity. Independent Power Producers (IPP) provide power to the grid under Power Purchase Agreements. The Electric system topology is shown in Figure-2.1 and Figure-2.2, which give the geographical layout and single line diagram of the network respectively.

2.1.1 Generation

JPS currently owns and operate eighteen (18) thermal power generating units at four (4) sites (Rockfort, Hunts Bay, Bogue and Old Harbour), and six (6) hydro electric plants across the island making a total installed capacity of 664.2 MW and 621.1 MW (MCR) as shown in table 2.1 below. The plant mix by type comprising the 621 MW is outlined in table 2.2.

Table 2-1 Generation Capacity by Type and Location

Site	**Type**	**Name Plate (MW)**	**Maximum Continuous Rating (MW)**
Old Harbour	Steam	230.0	223.5
Rockfort	Diesel	40.0	36.0
Hunts Bay	Steam	68.5	68.5
Hunts Bay	GTs	55.0	54.0
Bogue	GTs	247.8	217.5
Hydros*	Hydro	22.9	21.6
Total		664.2	621.1

**The six plants are independently sited across the island*

Table 2-2 JPS Generation Capacity by Plant Type

Technology	# of Units	Average Age (yrs)	Total (MCR) Capacity (MW)	% of Capacity	% of 2006 JPS Production
1. Slow Speed Diesel	2	22	36.0	6	9
2. Oil Fired Steam	5	35	292.0	47	49
3. Combined Cycle	1	4	114.0	18	28
3.Combustion Turbines Frame 5*	2	34	43.0	7	2
4. Combustion Turbine Frame 6	1	14	32.5	5	4
5. Combustion Turbines FT4	4	16	62.0	10	3
6. Combustion Turbine FT8	1	6	20.0	3	0
7 Hydroelectric	6	47	21.6	3	6
TOTAL	22		621.1	100	100

Privately owned plants account for a total MCR of 196.7 MW of contracted capacity for an overall system generating MCR of 817.75 MW.

Table 2-3 Independent Private Power Plant Capacity

Plant	Type	Name Plate (MW)	Maximum continuous Rating (MW)
Jamaica Energy Partners	Medium Speed Diesel	124.36	124.36
Jamaica Private Power Company	Slow speed Diesel	61.30	59.2
Jamalco	Cogeneration	11.00	11.00
Wigton	Wind	20.00	As available
Firm Total		216.66	196.66

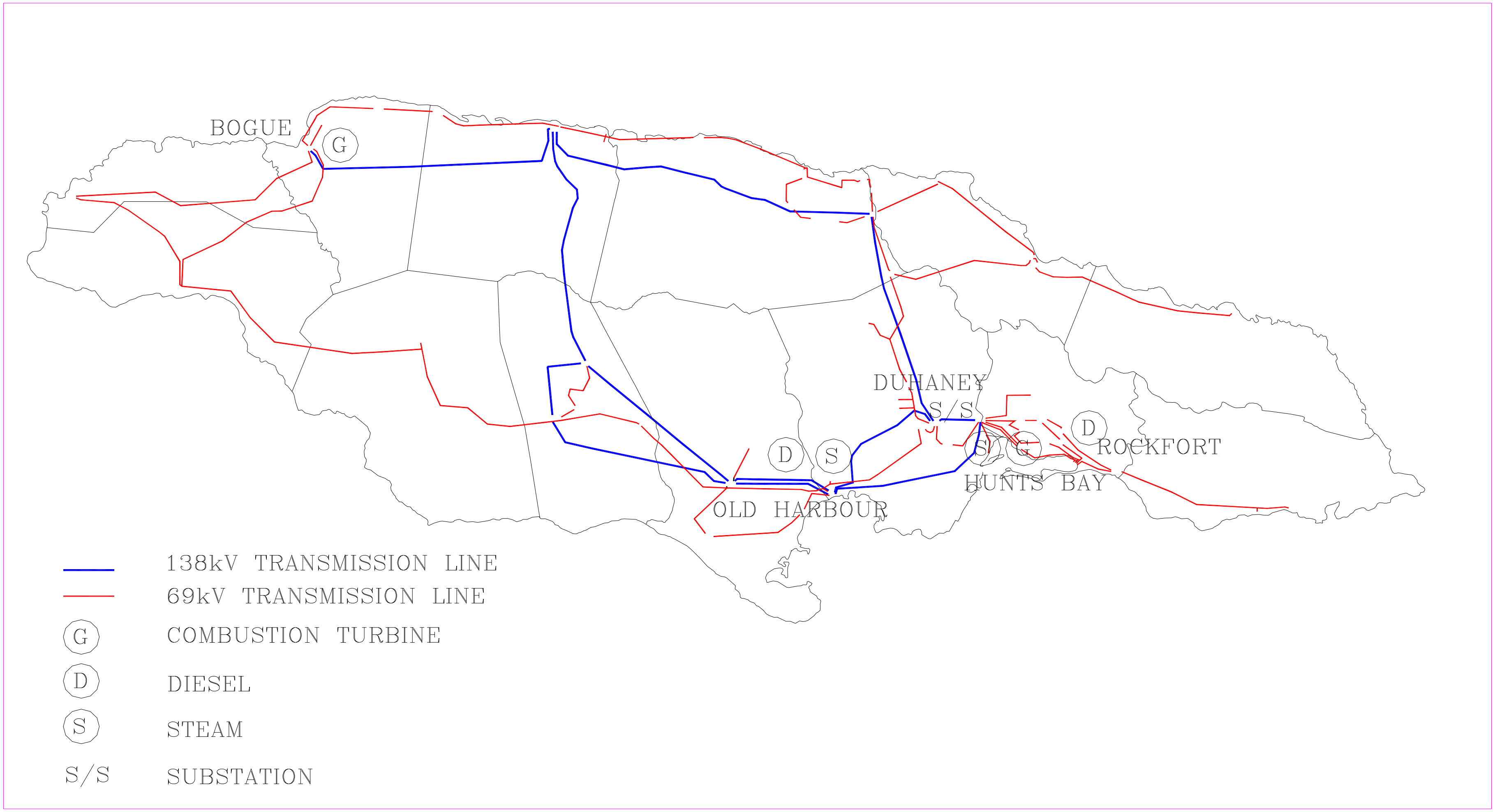


Figure 2-1: Electricity System Layout

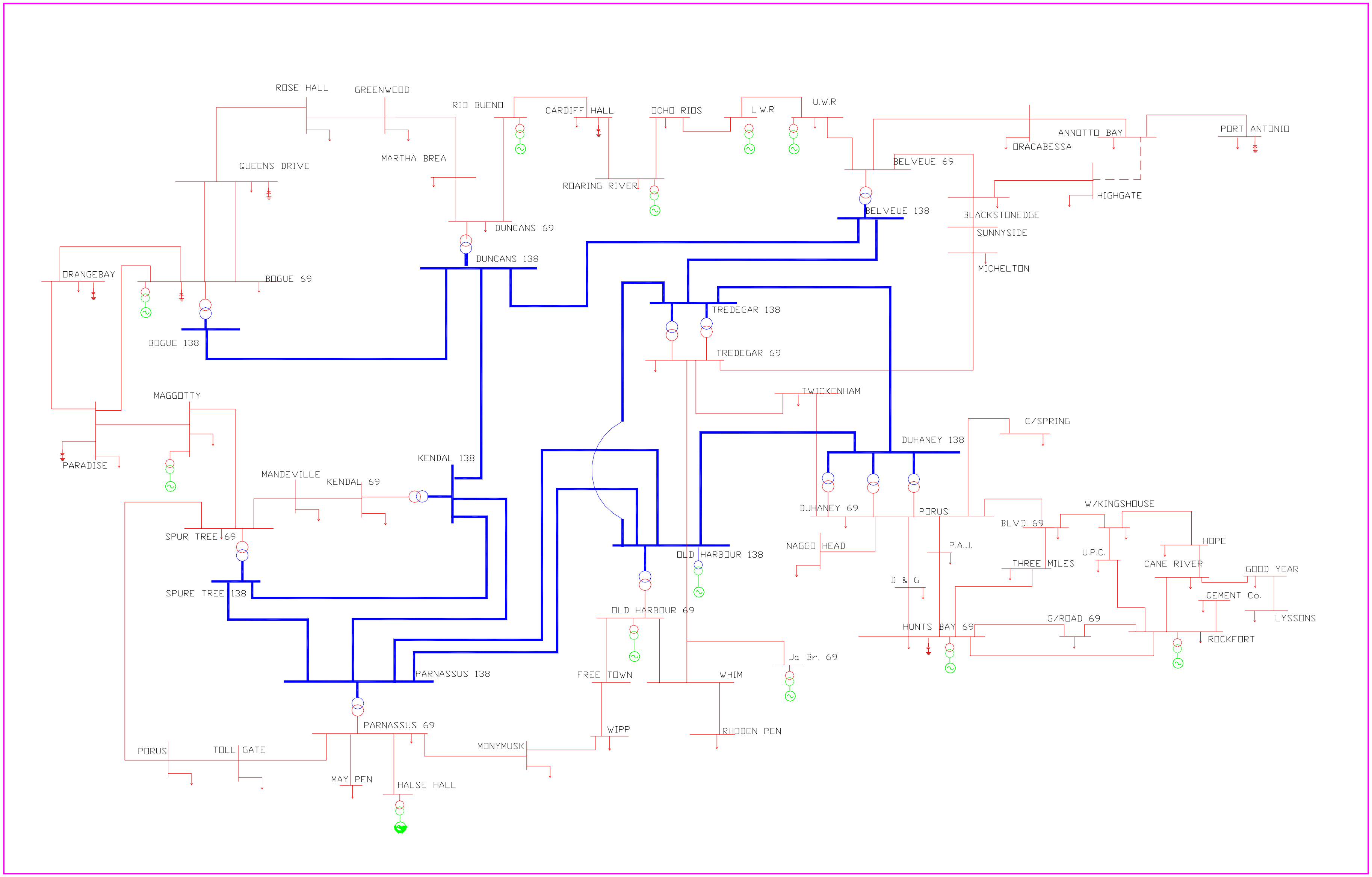


Figure 2-2: One line diagram of the existing transmission system.

2.1.2 Transmission and Distribution System

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.

The majority of the 69 kV transmission circuits are primarily of wood pole with some tubular/lattice steel and concrete structures. The 138 kV circuits are constructed of steel lattice towers and wood pole structures.

Distribution System

The distribution system consists of 106 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.

2.2 Protection and Control System

Relaying Operational Philosophy

All protection systems employed by JPS operate with at least one level of redundancy, hence the existence of both high-speed primary and time-delayed backup protection for all major equipment. The general philosophy applied to protecting the JPS system is to provide main protection which will detect most of the faults which occur and clear them discriminatively, while allowing the faults which cannot be detected by the main protection, usually of relatively low amplitude, to be detected and cleared by the back-up protection. This may in some instances require that the power system be divided into self contained sections, for which the back-up protection may be able to provide discriminative fault clearance, or when the fault is such that this is not possible, the indiscriminate fault clearance may result in the loss of a section but not the entire system.

The primary distance relays have 100% equipment redundancy (A&B) and perform the dual function of providing main protection for the line circuit by means of its first and second zone reach elements and remote back-up for faults on the next in line circuit by means of its second and third zone elements.

Primary A distance relay is supplied by separate CTs while primary B distance and back-up protection schemes are fed from the same CT core. Metering and other equipment are provided with separate CT cores where possible otherwise they are fed from CTs associated with the primary B and back-up protection. The primary A & B protection auxiliary dc supplies are 100% separated to minimize the likelihood of failure on both relays.

The same voltage transformer is used for A and B circuits except the primary A scheme is supplied by separate secondary windings while primary B share secondary windings with the back-up protection. Where only one secondary winding exists each protection is separately fused. Electromechanical directional earth fault relays are polarized using auxiliary PTs connected open delta.

Back-up protection is divided into two groups: (a) local backup where secondary protective devices on the faulted circuits operate to interrupt the fault following non-operation of the main protection and/or its associated circuit breakers; and (b) remote backup, where faults are cleared from the remote busbar.

2.2.1 Protective Relaying Practices

<u>DESIGN OBJECTIVES</u>

The basic design objectives of JPS protective relaying system are to:

- Maintain dynamic stability;
- Prevent or minimize equipment damage;
- Minimize equipment outage time;
- Minimize system outage area;
- Minimize system voltage disturbances;
- Allow the continuous flow of power within the emergency ratings of equipment on the system.

2.2.2 Design Criteria

To accomplish the design objectives, four criteria for protection are considered: speed, selectivity, sensitivity and reliability (dependability and security).

Speed

Speed is defined as the high-speed tripping of all terminals of a faulted circuit to isolate the faulted electric system element(s). This normally requires the application of a pilot relay scheme on transmission lines and high-speed differential relaying on generators, buses and transformers. For schemes employing high-speed protection, the total clearing time consists of (a) the relay operating times, which are considered to have no intentional time delay and would be in the order of one cycle including other auxiliary devices and signal propagation time and (b) the circuit breaker operating time of three to five cycles depending on the breaker design specifications.

Selectivity

Selectivity is the ability of the protective relaying to trip the minimum number of circuits or equipment to isolate the fault. Coordination is required with the adjacent circuit protection including breaker failure, generator potential fuses and station auxiliary protection.

Sensitivity

Sensitivity demands that the relays be capable of sensing minimum fault conditions without imposing limitations on circuit or equipment capabilities. The settings must be investigated to determine that the relays will perform correctly during transient power swings from which the system can recover.

Reliability

Reliability is a measure of the protective relaying system's certainty to trip when required (dependability) and not to trip falsely (security). Dependability is based on a single contingency, such that the failure of any one component of equipment, e.g., relay, current transformer, circuit breaker, communication channel, etc., will not result in failure to isolate the fault. The primary and backup schemes necessary to accomplish this are established for the JPS power system. The following design considerations must be adhered to.

2.2.3 Scheme Types

Generator Protection

Generators are among the most critical elements of the JPS, or any, electric power system and as such require a high degree of protection to ensure that damage due to faults is minimized. Generators on the JPS grid are provided with the following protective relay functions:

Primary Protection

- Generator Differential – for phase faults in stator windings. In gas turbine and diesel engine units, the protection zone includes the generator LV circuit breaker.
- Stator Ground Fault – for earth faults in stator windings and output connections up to the step-up transformer LV terminals.
- Overall Differential – for faults in the generator/step-up transformer zone inclusive of the HV circuit breaker(s)

Redundant Protection

- Voltage-Restrained Over-current – for system fault backup protection. Pickup setting is typically 110 % of generator full-load current rating.
- Negative Phase Sequence – for unbalanced loading protection
- Rotor Ground Fault – for earth faults in the rotor windings
- Loss of Excitation, Reverse Power, Over/Underfrequency, Over/Under-Voltage – for miscellaneous abnormal operating conditions
- Generator Transformer HV Neutral Ground Over-current – for system ground-fault backup protection

<u>Transformer Protection</u>

Power transformers 10 MVA and above are provided with the following protective relay functions:

Primary Protection

- Transformer Differential – primary protection for internal faults. For generator step-up transformers and interbus (138-69 kV) transformers, the zone of protection typically extends up to and includes the associated HV and LV circuit breaker(s).
- Buchholz/Sudden Pressure – complements the transformer differential protection.

Backup Protection

- Phase/Ground Over-current – backup protection for transformer internal/external faults. The phase relays (or relay elements) are typically set to pick up at 150-250 % of transformer oil natural, air natural (ONAN) current rating. The ground relay (or element) is set more sensitively (20-30 %) of the phase-fault pickup setting).
- Winding/Oil Temperature – for transformer overload

Busbar Protection

Major substations/switchyards are provided with busbar protection schemes as outlined below:

Primary Protection:

- High-Impedance Bus Differential – for phase/ground bus faults at stations with 1½ breaker and/or single-busbar configuration. At Bogue, the 69 kV north bus is included in the interbus transformer differential protection zone. Note that at mesh (ring) bus stations, the bus zones are included in circuit (line/transformer) protection zones; hence bus differential is not required.

Backup Protection:

- Directional Over-current – for phase/ground bus and line faults at single-busbar stations. This scheme exists only for Tredegar 69 kV bus #1 and bus #2.
- Neutral Displacement Voltage – for 69 kV ground faults at stations with interbus transformers. This protection is required in the event that the station becomes isolated from a 69 kV ground source.

Transmission Line Protection

At each line terminal (i.e. substation or switchyard), the following protective relaying systems are provided, with relay settings as indicated:

Primary A (Pilot or Communication-Aided) Distance Protection

A primary distance relay is utilized in conjunction with a digital-microwave communication channel and POTT (permissive overreaching transfer-trip) logic for high-speed fault clearance over 100% of the protected line. Overreaching of the remote line terminal is prevented by communication between the pilot relays at both line terminals. The communication path is a redundant communication link of either fibre optic or digital microwave.

The primary distance relay also provides time-stepped backup protection, independently of the communication channel as outlined below:

Zone 1: High-speed clearance for 80-90 % of the protected line. For 138 kV lines terminating into Interbus or distribution power transformers, the zone 1 reach setting is modified to 110 % of the protected line.

Zone 2: Delayed protection for 100 % of the protected line plus 50 % of adjacent line, with operating time delay of 0.4 second. For 138 kV lines terminating into Interbus transformers, the zone 2 reach setting is modified to 100 % of the protected line plus 50% of the transformer impedance.

Zone 3: The zone –3 element in the primary A distance relay is a reverse-looking element required for the permissive overreaching transfer trip (POTT) scheme logic – it is not utilised for tripping

Zone 4: Delayed protection for 100 % of protected line plus 120 % of adjacent line, with operating time delay of 0.8-1.0 second. For 138 kV lines terminating into Interbus transformers, the zone 4 reach setting is modified to 100 % of the protected line plus 120 % of the transformer impedance.

Note also that pilot protection is not applicable to radial transmission (or 69 kV sub-transmission) lines; therefore, for these lines, only the duplicate primary or backup distance relay is provided.

Redundant Primary B (Non-Pilot/pilot 3-Zone) Distance Protection:

A redundant (or duplicate primary) distance relay is utilized to provide 3-zone time-stepped distance protection independently of a communication channel or with communication channel, as outlined below. The primary and backup distance relays are of different make to ensure that both relays do not fail at the same time due to any common design deficiency. The communication path is a redundant communication link of either fibre optic or digital microwave

Zone 1: High-speed clearance for 80-90 % of the protected line. For lines terminating into transformers (Interbus or distribution), the zone 1 reach setting is modified to 110 % of the protected line.

Zone 2: Delayed (0.4 second) backup protection for 100 % of protected line plus 50 % of adjacent line. For lines terminating into transformers (Interbus or distribution), the zone 2 reach setting is modified to 100 % of the protected line plus 50 % of the transformer impedance.

Zone 3: is used as a reverse looking element in the POTT scheme and is not used for tripping

Zone 4: Delayed (0.8-1.0 second) backup protection for 100 % of protected line plus 120 % of adjacent line. For lines terminating into transformers (Interbus or distribution) the zone 4 reach setting is modified to 100 % of the protected line plus 120 % of the transformer impedance.

Backup (Non-Pilot) Directional Over-current Protection:

Directional over-current relays with both instantaneous and time-delayed characteristics are provided for backup fault clearance. At some locations, this function is obtained via the backup distance relay. Setting criteria are as follows:

- The instantaneous pickup setting is typically 125% of maximum fault current flow from the relay location for a fault at the remote busbar, to prevent overreaching and hence mis-coordination.
- The time-delayed phase-fault pickup setting ranges between 90-110% of line rating.

- The pickup setting for the time-delayed ground-fault element is 20-30% of the corresponding phase-fault pickup setting.
- A minimum coordination time of 0.4 seconds is the benchmark requirement for relay pairs (i.e., for two relays in series).

Breaker Failure Protection

Breaker fail back-up protection is divided into two groups: (a) local backup where secondary protective devices on the faulted circuits operate to interrupt the fault following non-operation of the main protection; (b) remote backup, where faults are cleared from the remote busbars.

Breaker fail schemes are employed at all major 138 kV and 69 kV stations such as Old Harbour, Hunts Bay and Bogue. Breaker fail time delay of 0.25 seconds is used and for some locations where the flexibility of microprocessor based relays exist, a re-trip time of 0.15 seconds is used to trip the failed breaker.

The breaker fail logic Is such that on fault inception, the first in-line protection sense and issue a command to trip the circuit breakers, also issue a permissive start to the breaker fail timing scheme. Providing the fault persist beyond 0.25 seconds, the scheme interprets this to be a failed breaker and issues trip commands to the adjacent breakers via lock-out relays to isolate the failed breaker and the fault.

Remote zone 2/3 distance protection and time delayed directional over-current protection also provide back-up protection for busbar faults and failed circuit breakers.

Distribution Feeder Protection

Distribution feeders are provided with basic phase and ground over-current protection, which takes the form of hydraulic reclosers or non-directional over-current relays that trip vacuum breakers directly. Separate reclosing relays are used or in some cases, the over-current relay incorporates reclosing features. Three shots to lockout is used in the feeder reclosing sequence, one fast and two slow trips.

Underfrequency Protection

In instances of generation-load imbalance when there is a sudden increase in load or a generator trips off-line, automatic underfrequency load-shedding is employed to restore the generation/load balance and maintain nominal frequency by disconnecting equal or more load than the equivalent of the excess demand. Loads are shed in four stages at 49.2, 48.9, 48.5 and 48.1 Hz and a time delay setting of 0.15 seconds is used to override transients. The scheme also gives the operator enough time to respond and take corrective action by facilitating a temporary recovery in frequency, this recovery may manifest in two ways: (1) If there is an overshed and the settling frequency is too high then the operator is required to add load; and (2) if insufficient load is shed and the settling frequency is low, the operator is required to shed additional loads. Table 2.4

shows the under frequency load shedding scheme currently employed. Other considerations that form the basis of the scheme design are:

1. A thorough appreciation for the load/generation balance
2. The operating times of relays and breakers
3. The set and reset frequencies for different stages as well as the amount of load shed per stage, and the frequency at which the system settles down
4. The reliability of the scheme as it relates to the dispersion of the under frequency relays
5. The safe operating frequency of generators

Table 2-4 Percentage Shed Underfrequency Stage by design

Stage1		**Stage 2**		**Stage 3**		**Stage 4**	
Substation	% Of total Load Shed	Substation	% Of total Load Shed	Substation	% Of total Load Shed	Substation	% Of total Load Shed
Bogue	2.47%	Hunts Bay	2.52%	Three Mile	3.22%	Greenwich Road	2.04%
Hunts Bay	0.26%	New Twickenham	4.99%	Cane River	0.45%	Hunts Bay	0.73%
Orange Bay	1.38%	Washington Blvd	4.8%	Duhaney	1.73%	Naggos Head	3.51%
Paradise	1.1%	Hope	1.1%	Greenwich Road	2.05%	Rockfort	1.16%
Spur Tree	4.3%			Hope	1.55%	Tredegar	4.49%
Up Park Camp	1.26%			Kendal	1.12%	West Kings House	3.95%
Washington Blvd	1.74%			May Pen	1.64%		
				Parnassus	3.11%		
Total % per Stage	**12.5%**		**13.41%**		**14.89%**		**16.34%**

Total % Shed 57.14%

Protection Performance History due to Faults

Protection system performance is measured by the total number of fault disturbances on the system and those that are cleared by the operation of the correct circuit breakers.

JPS power system is subjected to a number of system faults on a yearly basis and it is the function of the protective schemes in place to operate correctly to maintain system stability, minimize damage to equipment and property and to prevent injuries or fatalities.

Records of the system performance between 2003 and 2007 year-to-date June, show that for the period 2003-2006, the primary protection system operate correctly on average 97% with the back-up system covering the remaining 3% of faults.

The 2007 June year-to-date figure for disturbances is 150 and of these, 98.6% or 148 disturbances were cleared by primary protection.

2.3 SCADA

The SCADA system provides real-time monitoring and control of the transmission grid and it consists of a master station at System Control and multiple Remote Terminal Units (RTUs) at remote stations island wide.

The RTUs collect analog and status data from field equipment such as breakers and transformers automatically and stores it in a buffer until the master station interrogates these remote units via the communications link to acquire the data.

At the master station, the data is stored and a predefined set of data is displayed graphically and in tabular form. The operators are able to open or close circuit breakers and switches and to read telemetered data from the Control Room. The critical components of the system are duplicated to provide a high level of reliability.

2.4 Communication System

The JPS Communications Network consist of a Digital Microwave Network (all island) and a Fibre Network in Kingston and St. Catherine. This provides the transmission medium for JPS's internal communications, SCADA, voice and data traffic.

The SCADA System in Kingston and St. Catherine uses Digital Microwave for primary communication and Fibre as backup.

In the rest of the island, the Digital Microwave system is use for primary communication and a mixture of analog and PLC equipment is used as back up for SCADA.

Digital channels provide communication services for the following:

- SCADA (Supervisory Control & Data Acquisition)
- Teleprotection (transmission lines)
- Relay Monitoring
- WAN (Wide Area Network) Data Services
- PPMS (Power Plant Monitoring System)
- Revenue Metering / Substation Metering
- Internal Telephone (Telephone Network)

All Digital Microwave radios outside of Kingston and St Catherine are over 10 years old and plans are in place to gradually install fibre at these substations and use the Digital Microwave radios as backup for the SCADA System.

There are Twenty-Eight (28) Substations that have both SCADA prime and backup circuits, Eighteen (18) substations that have only prime communications and Ten (10) Substations that have no communication as per Appendix D.

2.4.1 System Demand and Supply

JPS provides electricity to approximately 570,000 customers island-wide with a total consumption of over 3,050 GWh for year ending 2006. The main load centre is concentrated in the Greater Kingston, Portmore and Spanish Town area, which accounts for approximately 50 percent of total system load. Remaining loads are dispersed across the island. A total of 53 distribution substations supply these loads.

System peak demand reached 625.7 MW in November 2006. In 2007 a peak of 629.4 MW was achieved on February 15 and April 10, 2007, at about 7:30 pm. A new trend is being observed with regards to the day peak, and on July 10, 2007 at about 1:30 pm the day peak equal the traditional evening system peak of 629.4 MW.

The system installed generation reserve now stands at 34.8% with an approximate load factor of about 76.1%. The light load demand is about 356 MW which typically occurs at night and on weekends.

Generally, the daily peak demand is dominated by an evening demand that normally exceeds the day peak by some 34 MW. Figure 2.3 and shows a typical daily load profile.

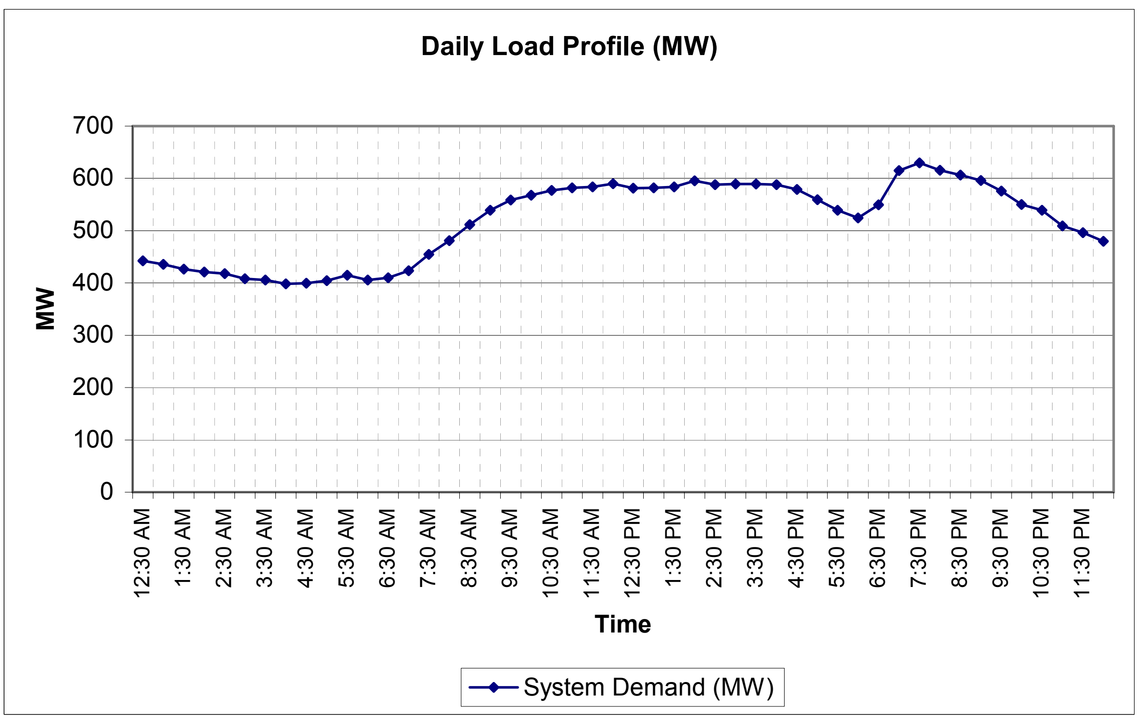


Figure 2-3: Typical Daily Demand

2.5 Plant Operations

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 incremental cost. There is provision for necessary adjustments to accommodate for plant and transmission limitations in a security constrained dispatch mode.

The system operates with a spinning reserve margin criterion of 30MW. This has been established as the balance between economy and maintaining system security.

System voltages are maintained at 1.0 per unit ± 5%, frequency is maintained at 50 Hz ± 0.2 Hz.

Voltage regulation is provided by controlling generator reactive power output by automatic voltage regulator, application of fixed and switched capacitor banks on the distribution system, bulk 24kV capacitor banks at some substations and transformer tap changers. Frequency is maintained by matching generator real power output to load and by governor droop settings.

Four major generating stations (JEP, Bogue, JPPC, and Hunts Bay) have black start capability either through gas turbines or diesel generating units on site. These units are essential for re-establishing the generating system in a timely manner after a system shutdown by providing electrical supply to the generator unit's auxiliary equipment while the main generating plants are prepared for start up.

3.0 SYSTEM OPERATING AND MAINTENANCE CONDITIONS PRIOR TO SHUTDOWN

3.1 Generator Availability and Loading at 5:00 am July 3, 2007

The Gross Plant Capability Report (GPCR) and the System Control Generation Log indicate that at 5:00 am available generation capacity was 673 MW.

Only four of the five base-load steam plants were available and online. These are, Old Harbour units 1, 2, 4 and the Hunts Bay B6 unit. Old Harbour unit 3 was out on forced maintenance.

Table 3.1 below gives the MW output of these units, and all others that were online prior to the shutdown, along with they respective online spinning capacity. The online capacity was 516 MW serving a demand of 445 MW with a spinning reserve of 71 MW. The system was operating at a frequency of 50 Hz

Table 3-1 Generation Available and online at 5:00 am, July 3, 2007

Units	MCR Capability (MW) Available	Loading at 5:10 A.M. (MW)	Spinning Reserve MW	COMMENTS
Rockfort 1	0.0	0.0		
Rockfort 2	18.0	18.0	0.0	
Hunts Bay B6	68.5	47.9	20.6	
Hunts Bay GT 4	0.0	0.0		
Hunts Bay GT 5	21.5	0.0		
Hunts Bay GT 10	32.5	0.0		
Old Harbour 1	25.0	20.6	4.4	
Old Harbour 2	56.0	45.5	10.5	
Old Harbour 3	0.0	0.0		
Old Harbour 4	63.5	57.4	6.1	
Bogue GT 3	20.5	0.0		
Bogue GT 6	14.0	0.0		
Bogue GT 7	14.0	0.0		
Bogue GT 8	14.0	0.0		
Bogue GT 9	20.0	0.0		
Bogue GT 11	20.0	0.0		
Bogue GT 12	33.0	28.2	4.8	
Bogue GT 13	33.0	28.3	4.7	

Units	MCR Capability (MW) Available	Loading at 5:10 A.M. (MW)	Spinning Reserve MW	COMMENTS
Bogue ST 14	34.0	28.6	5.4	
Roaring River	4.1	4.1	0.0	
Upper White River	3.4	3.4	0.0	
Lower White River	4.8	4.8	0.0	
Rio Bueno ‘A’	2.0	2.0	0.0	
Rio Bueno ‘B’	0.9	0.9	0.0	
Maggotty	4.1	4.1	0.0	
Jamalco	3.2	3.2	0.0	
Wigton	5.9	5.9	0.0	
JEP	98.0	83.5	14.5	
JPPC	59.0	58.9	0.1	
Jamaica Broilers	0.0	0.0	0.0	
System	**672.9**	**445.3**	**71.1**	

3.1.1 System Load Profile at 5:00pm

The available generating capacity at 5:00 am was 673 MW. The online capacity was 516 MW serving a load demand of 445 MW with a spinning reserve of 71 MW. The system was operating at a frequency 50.0 Hz.

Table 3-2 Generation Dispatch by Location at 5:00 am

Station	MW	Percent of Total
Corp. Area	125	28.0
Old Harbour	207	46.5
Bogue	85	19.1
Hydros	19	4.3
Wigton	6	1.3
Jamalco	3	.7
Total	**445**	**100**

3.2 Transmission & Distribution Systems Status

3.2.1 Planned T&D Outages

The transmission and distribution system was fully intact, prior to the shutdown, and the power system was operating within the normal operational limits.

Tables 3.3 provide the loading of transmission lines emanating from the Old Harbour switchyard.

Table 3-3 Critical 138 KV and 69 KV line loading Prior to Fault

Circuit	Capacity (MVA)	Loading	
		MW	MVAR
Old Harbour - Duhaney 138kV	215	54	20
Old Harbour - Tredegar 138kV	215	59	21.6
Old Harbour - Parnassus L6 138kV	155	27.6	14.4
Old Harbour - Parnassus L7 138kV	155	27.1	13
Old Harbour - Tredegar 69Kv	61	15.8	3.52
Old Harbour Inter-bus Transformer	37.5	10.5	-0.57

3.2.2 Power Flows and Bus Voltages prior to Shutdown

Figure 3.1 below gives the Generation/Load imbalance for the system, outlining the generation and loads in the rural areas and also the corporate area (CA). The figure also shows the importation of 66 MW into the CA via the Duhaney substation due to the deficiency of generation in to the CA relative to load.

Tables 3-4 gives the bus voltage at major generating substation

Table 3-4 Recorded Voltage level at the Generating Substation - July 3rd, 2007 (5:00 A.M.)

Substation	Recorded Volts (kV)
Old Harbour 138kV Bus	140.7
Old Harbour 69kV Bus	71.43
Rockfort 69kV Bus	71.9
Hunts Bay 69kV Bus	72.3

The megawatt imports into the Corp. Area measured at Duhaney S/S was 67 MW and 9.7 MVars respectively.

July 3, 2007, 5:00 am, Prior to System Shutdown

Figure 3-1: Generation/Load Balance Diagram

3.3 SCADA & Communication Systems

SCADA systems supported by the telecommunication systems provide control, status and telemetry data to support remote operation of the system from the System Control Center (SCC).

Table 3.5 give the status report on SCADA visibility during island wide power failure, and there was ninety percent visibility for the first three hours following the shutdown.

Table 3-5 : Status report on SCADA visibility during island wide power failure

Time	**% SCADA Visibility**	**Substations Affected**	***Description of failure***
5:11			Power System Shutdown Time
5:45	90%	Rio Bueno	Defective radio
		Orange Bay	Theft of communication batteries at the substation resulted in no battery backup power for the communication system.
		JEP # 1 and #2	No SCADA availability from Private Power.
		Kendal “B”	Low Battery Voltage causing Voltage Protection System to Trip
		Port Antonio	Low Battery Voltage causing Voltage Protection System to Trip
8:00 AM	69%	Hope	RTU failed due to low DC Battery Voltage. Voltage Protection System was bypassed temporarily to restore power to the RTU.
		Roaring River	Failed transmitter on Granger radio.
		Old Harbour	Battery disconnect breaker tripped due to overload condition.
		Duncans	Low DC battery voltage.
		Jamaica Broilers	Due to failure of Old Harbour radio.
		Annotto Bay	Low DC battery voltage.
		Kendal “A”	Low DC battery voltage.
		West Kings House	Low DC Battery Voltage activated 48 Volts DC Surge Protector.
		Up Park Camp	Substation Maintenance Department Charger Tripped resulting in a loss of power to the RTU.
9:00 AM	94%	Rio Bueno	Defective radio at Rio Bueno.
		Roaring River	Defective Radio Transmitter at Roaring River. No output from Granger Microwave radio transmitter. Communication restored via Digital Microwave on 6th July, 2007 at approximately 12:00PM.
		Port Antonio	Restored at 10:13 AM when the line between Bellevue, Annotto Bay and Port Antonio was restored.

Resulting from the July 15, 2007 shutdown recommendations by JPS, OUR and PORT, the following SCADA improvements are currently being implemented:

- Battery capacity at locations need to be increase (by doubling capacity)

- 0.5 M US$ project to come online within 3 weeks , to provide a more reliable backup circuit from the SCADA using the FLOW fibre optic cable
- SCADA primary will be upgraded using microwave radios, this project will be starting shortly
- Backup communication will be provided by JPS and FLOW network

3.4 Substation & Protection Maintenance Condition – Old Harbour

The objective of the JPS maintenance programme is to ensure the integrity and maximum availability of substation and Protection & Control equipment.

This will be achieved by:

i) Prevention of failures through periodic checks and tests.
ii) Early detection of failures through continuous remote monitoring.
iii) Efficient fault correction through provision of necessary resources.

While conforming to JPS documents:

- Maintenance Standard and Procedure, Protection & Control
- Substation Equipment

3.4.1 Protection & Control

Periodic checks and test are carried out conforming to established frequencies. These tests are described in detail in Appendix C.

- **Verification checks:** To ensure the existence of correct source input to the subsystem.
- **Calibration Test:** To verify relay settings calibrations and configuration.
- **Integrity Test:** To verify that the intent of the subsystem is carried out.

Protection and Control – Relay Calibration

Old Harbour substation protection schemes are comprised of electromechanical as well as microprocessor based relays. The Unit 2 transformer differential as well as the breaker-fail relaying scheme is comprised of electromechanical relays. The last maintenance calibration for these relays was carried out in May 2006 and the records indicate that the relays were in good working order and within calibration. Re-verification of the breaker fail timers for the Old Harbour south bus relays was performed on July 3, 2007 and they operated within specification.

Routine maintenance was performed on June 26, 2007 and inputs of AC voltages and currents were verified for all relays. DC trip supply voltage was also verified. All relay calibration and routine maintenance records are provided in Appendix B.

3.4.2 Substation Equipment

Old Harbour138/69 kV switchyard is comprised of switches and circuit breakers that require routine interventions to insure their operability under any operating conditions. Owing to the nature of our operations, the maintenance of equipment and devices at a station such as Old Harbour does not always coincide; accordingly, the last maintenance and inspection date for major substation equipment at Old Harbour are summarized in the table below

Equipment	Maintenance dates	Status
Battery	May 22, 2007	Complete
Station Inspection	July 2, 2007	Require intervention due to level of contamination
Breaker 9-930	July 31, 2005	Complete
Breaker 9-830	May 11, 2004	Complete
Breaker 9-730	August 22, 2003	Due for servicing
Breaker 9-630	May 13, 2004	complete
Breaker 9-530	August 19, 2004	complete
Breaker 9-520	July 31, 2005	complete
Breaker 9-430B	April 20, 1998	complete
Breaker 9-430A	June 21, 2006	complete
Breaker 9-420A	May 17, 2004	Due for servicing
Breaker 9-420	June 7, 2004	complete
Breaker 9-320A	April 26, 2006	complete
Breaker 9-320	February, 2006	complete
Breaker 9-220A	July 2006	complete
Breaker 9-220	April 21, 2006	complete
Breaker 8-330	June 21, 1997	complete
Breaker 8-240	June 12, 2006	complete
Breaker 8-140	July 14, 1998	complete
Breaker 8-120	March 1, 1999	complete
Unit 2 transformer	January 2006	Complete
Unit 3 transformer	February 2006	Complete
Unit 4 transformer	September 2006	Complete
Unit 1 transformer	September 2005	Complete
Interbus transformer		

A more detailed report on these maintenance activities is included in Appendix C

Subsequent tests and inspections carried out at Old Harbour were as follows:

- Breaker timing tests were carried out on the failed breaker 9-220 as well as other breakers at Old Harbour. The results of these timing tests along with the maintenance history of Old Harbour is provided in Appendix C.

- Cleaning of the JEP bay on July 5, 2007

- Cleaning of breaker bushings for all breakers that timing tests were carried out on

- Breaker 9-220 was replaced as the stuck pole defect was not repairable

3.5 Weather

Fair weather was reported across the island.

4.0 FAULT EVENT ANALYSIS

The system black-out was precipitated by a two phase to ground fault as a result of a flashover on the high voltage lightning arresters associated with Unit # 2 at Old Harbour. Based on relay event reports obtained from Duhaney and Tredegar substations, it appears that the fault started as a single line to ground (A-G) and evolved into a two phase to ground (A-C-G).

Inspection of Unit 2 transformer and arresters revealed evidence of pitting and outright burn- through of the corona rings for the H3 (C-phase) and H2 (B-phase) lightning arresters. There is also a burnt ground lead connector on the C-phase arrester, as well as, and other signs of scorching.

A burnt B-phase down-dropper was observed on the line side of disconnect switch 9-227. Disconnect switch 9-227 is used to isolate Unit 2 and its GSU from the 138 kV grid.

Figure 4-1 Burnt ground conductor connector at base of outer phase arrester

Figure 4-2 Burnt outer phase arrester base (same arrester as in figure 3.1)

Figure 4-3 Scorching on middle phase arrester

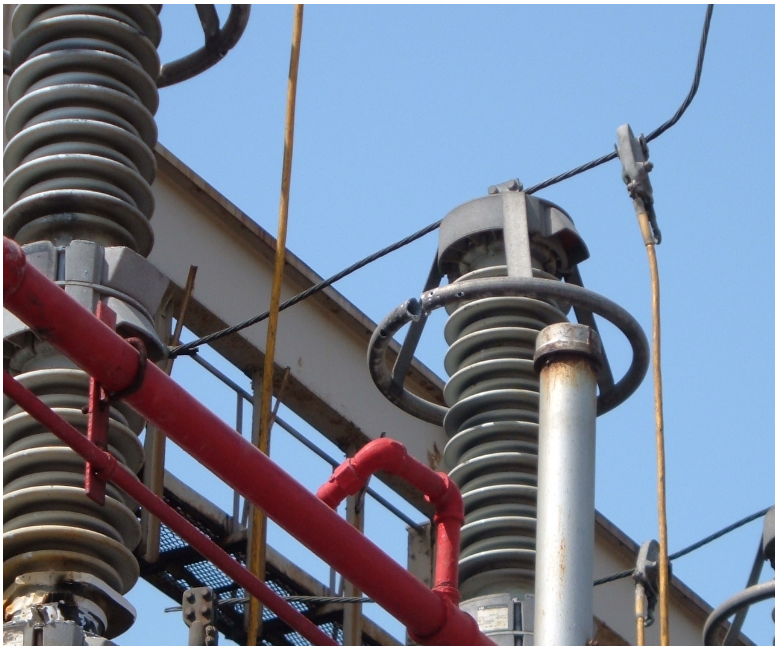


Figure 4-4 Burn-through of corona ring at top of arrester – middle phase


Figure 4-5 Dislodged down dropper on middle phase of switch 9-227

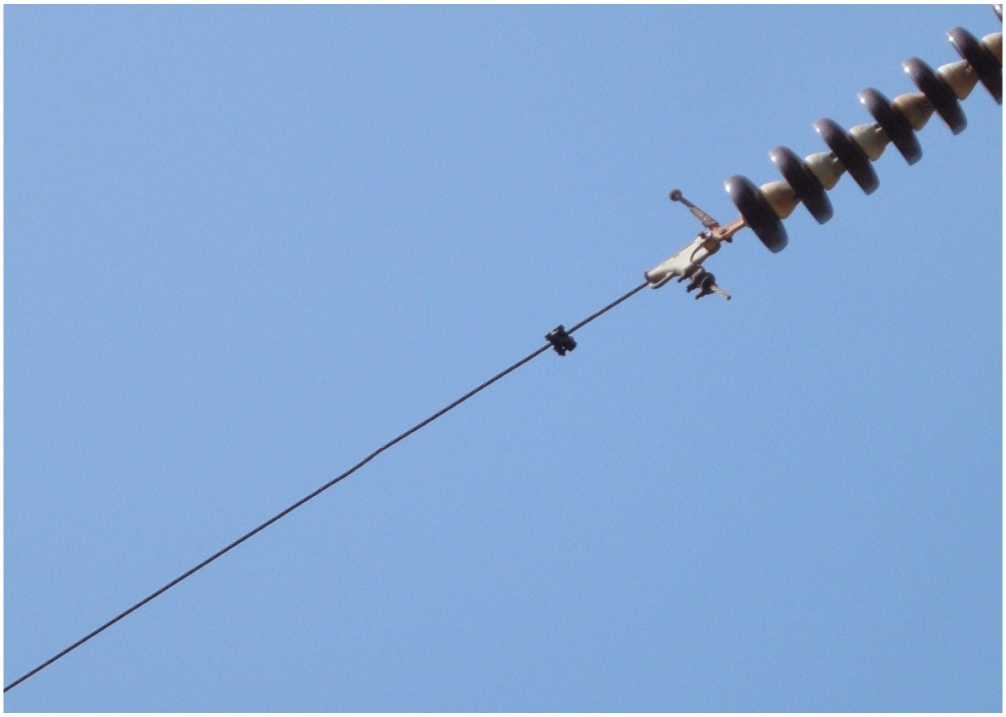


Figure 4-6 Connector for the dislodged down dropper for switch 9-227

4.1 Sequence of Events and analyses

The Sequence Of Events (SOE) record was compiled from reports generated by System Control and relay event records from Duhaney and Tredegar substations (Old Harbour lines)

Fault inception was obtained from the fault record stored by the Old Harbour relay at Duhaney. This relay recorded an event from fault trigger to tripping of the breaker of duration 471 ms. When subtracted from the actual breaker operating time recorded by SCADA, the fault inception time was estimated to be at about 5:11:05.608 on the day in question.

4.2 SOE

Initial Breaker Operations for Fault Isolation

No	Station	Breaker(s)	SOE Time	Elapsed Time (ms)	Comments
(0)	Old Harbour		5:11:05.608	0.00	Fault inception
(1)	Old Harbour	Unit 2 (9-220A) Old Harbour #2	5:11:05.820 5:10:41	212	87T-B, A86V, B86V. Relay with no intentional time delay
(2)	Duhaney	Old Harbour (9-830)	5:11:06.079	471	Zone 2 AC, 23.64 mls Relay with time delay of 0.4 sec
(3)	Tredegar	Old Harbour (9-930)	5:11:06.306	698	Z2 AC 15.76 mls Relay with time delay of 0.4 sec
(4)	Tredegar	Old Harbour (9-430)	5:11:06.317	709	Z2 AC 15.76 mls Relay with time delay of 0.4 sec
(5)	Parnassus	Old Harbour L7 (9-1230)	5:11:06.371	763	67N
(6)	Parnassus	Old Harbour L7 (9-250)	5:11:06.372	764	67N
(7)	Parnassus	Old Harbour L6 (9-730)	5:11:06.376	768	67N
(8)	Parnassus	Old Harbour L6 (9-150)	5:11:06.378	770	67N

Initial Breaker Operations for Fault Isolation (cont'd)

No	Station	Breaker(s)	SOE Time	Elapsed Time (ms)	Comments
(9)	Old Harbour	South Bus (9-520)	5:11:06.591	983	50BF-G2, 86BF-G2, 86SBUS
(10)	Old Harbour	South Bus (9-430B)	5:11:06.613	1005	50BF-G2, 86BF-G2, 86SBUS
(11)	Old Harbour	South Bus (9-320)	5:11:06.655	1047	50BF-G2, 86BF-G2, 86SBUS
(12)	Old Harbour	South Bus (9-420)	5:11:06.659	1051	50BF-G2, 86BF-G2, 86SBUS

Generator Trips

No	Station	Breaker(s)	SOE Time	Elapsed Time (ms)	Comments
(13)	JPPC	JPPC3CB 5-320	5:11:06.104	496	1 MW auxiliary boiler
(14)	JEP DBII	138 kV breaker 9-290	5:11:06.141	533	50N
(15)	JEP	#9 GenCB 4-920	5:11:06.471	863	Generator overspeed
(16)	Old Harbour	Unit 4 (9-420A)	5:11:07.089	1481	Turbine overspeed, 86G, 94T
(17)	Old Harbour	Unit 1 (8-120)	5:11:07.157	1549	Low Drum Level, 86B
(18)	JPPC	Unit 2 (8-290)	5:11:07.917	2309	27
(19)	JPPC	Unit 1 (8-190)	5:11:07.920	2312	27
(20)	Old Harbour	Unit 2/South bus (9-220)	5:11:09.958	4350	87T-B, A86V, B86V
(21)	Bogue	GT 12	5:11:10		51, 81, plant time
(22)	Bogue	GT 13	5:11:10		51, 81, plant time
(23)	Bogue	ST 14 (8-1490)	5:11:10.786	4966	51, 81
(24)	Riobueno	Gen A Cb 3-120	5:11:12.831	7011	51, 59, 81
(25)	Riobueno	Gen B Cb 3-220	5:11:12.831	7011	Loss of Incoming
(25)	Rockfort	Unit 2	5:15		127L, 27B, 227L, 286T, Plant time
(26)	Hunts Bay	Unit B6 (8-650)	5:11:19.916	14308	86G, 94T, 86SV
(27)	Hunts Bay	Unit B6 (8-120)	5:11:19.919	14311	86G, 94T, 86SV
(28)	Roaring River	Hydro			51, 59
(29)	Maggotty	Hydro			51, 59
(30)	Upper White	Hydro			51, 59, 81
(31)	Lower White	Hydro			51, 59, 81

Automatic Underfrequency Load shedding Points

	Station	Feeders	SOE Time	Elapsed Time (ms)	Relay(s) Operating/ comments
(32)	Paradise	Frome Fdr 6-110	05:11:07.279	1671	81-Stage 1
(33)	Huntbayb	Sp Twn Rd Fdr 5-810	05:11:07.298	1690	81-Stage 1
(34)	Washblvd	Molynes Fdr 6-710	05:11:07.332	1724	81-Stage 1
(35)	Spurtree	Newport Fdr 6-310	05:11:07.389	1781	81-Stage 1
(36)	Washblvd	Red Hills Fdr 6-810	05:11:07.389	1781	81-Stage 1
(37)	Washblvd	Csprng Fdr 6-510	05:11:07.417	1809	81-Stage 2
(38)	Hope	Liguanea Fdr 6-410	05:11:07.430	1822	81-Stage 2
(39)	Twicknam	G/Dale Fdr 6-410	05:11:07.456	1848	81-Stage 3
(40)	Twicknam	P/More Fdr 6-210	05:11:07.460	1852	81-Stage 4
(41)	Washblvd	Hwt Rd Fdr 6-410	05:11:07.464	1856	81-Stage 4
42)	Duhaney	Ferry Fdr 6-210	05:11:07.490	1882	81-Stage 3
(43)	Washblvd	Shortwd Fdr 6-610	05:11:07.496	1888	81-Stage 2
(44)	Washblvd	Waltham Fdr 6-310	05:11:07.496	1888	81-Stage 2
(45)	Huntbayb	North St Fdr 6-510	05:11:07.499	1891	81-Stage 2
(46)	Parnasus	May Cb 8-410	05:11:07.502	1894	81-Stage 3
(47)	Duhaney	Sp Twn Rd Fdr 6-410	05:11:07.508	1900	81-Stage 3
(48)	Parnasus	T3 Cb 8-170	05:11:07.556	1948	81-Stage 3
(49)	Threemls	Main Fdr 5-110	05:11:07.588	1980	81-Stage 3
(50)	Hope	East Fdr 6-510	05:11:07.593	1985	81-Stage 3
(51)	Kendal	C/Tiana Fdr 6-210	05:11:07.628	2020	81-Stage 3
(52)	Canerivr	Bull Bay Fdr 6-310	05:11:07.653	2045	81-Stage 3
(53)	Tredegar	Main Fdr 6-110	05:11:07.653	2045	81-Stage 4
(54)	Rockfort	Downtwn Fdr 6-410	05:11:07.668	2060	81-Stage 4
(55)	Tredegar	Main Fdr 6-110	05:11:07.668	2060	81-Stage 4
(56)	Rockfort	Downtwn Fdr 6-410	05:11:07.677	2069	Contact Bounce
(57)	Rockfort	Downtwn Fdr 6-410	05:11:07.693	2085	Contact Bounce
(58)	Grwichrd	Maxfield Fdr 6-710	05:11:07.697	2089	81-Stage 3
(59)	Grwichrd	X Rds Fdr 6-310	05:11:07.705	2097	81-Stage 3
(60)	Tredegar	Main Fdr 6-110	05:11:07.712	2104	Contact Bounce
(61)	Tredegar	Main Fdr 6-110	05:11:07.723	2115	Contact Bounce
(62)	Tredegar	Main Fdr 6-110	05:11:07.733	2125	Contact Bounce
(63)	Westkhrd	W/Loo Rd Fdr 6-410	05:11:07.748	2140	81-Stage 4
(64)	Grwichrd	New Kgn Fdr 6-510	05:11:07.766	2158	81-Stage 4
(65)	Westkhrd	Hope Rd Fdr 6-310	05:11:07.767	2159	81-Stage 4
(66)	Grwichrd	Ohope Rd Fdr 6-410	05:11:07.776	2168	81-Stage 4
(67)	Westkhrd	N/Kgn Fdr 6-210	05:11:07.776	2168	81-Stage 4
(68)	Grwichrd	New Kgn Fdr 6-510	05:11:07.778	2170	81-Stage 4
(69)	Grwichrd	New Kgn Fdr 6-510	05:11:07.787	2179	Contact Bounce

4.3 Operation Design of System at Old Harbour Substation

The design criteria for the protection of generators and generator transformers (GSU) such as Old Harbour Unit 2, require that for any faults in the Generator/GSU zone, the two 138 kV switchyard breakers are required to trip in addition to tripping of the generator and a sequential shutdown of the turbine and boiler

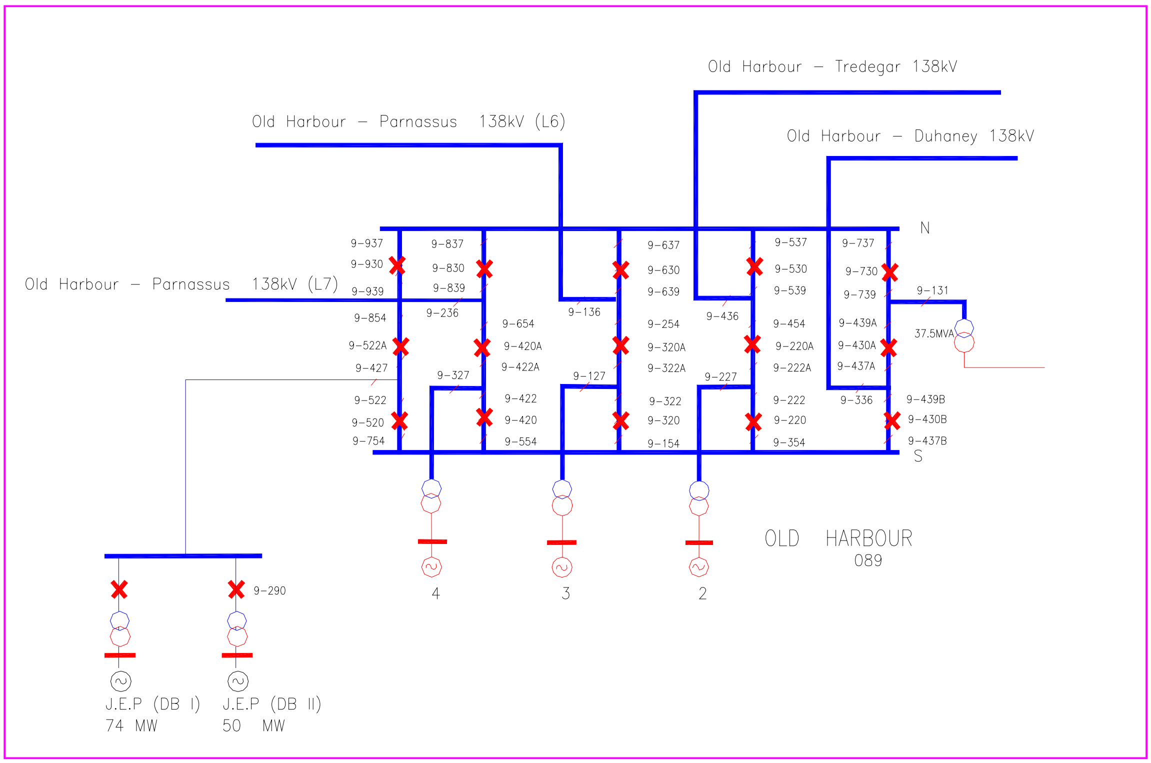
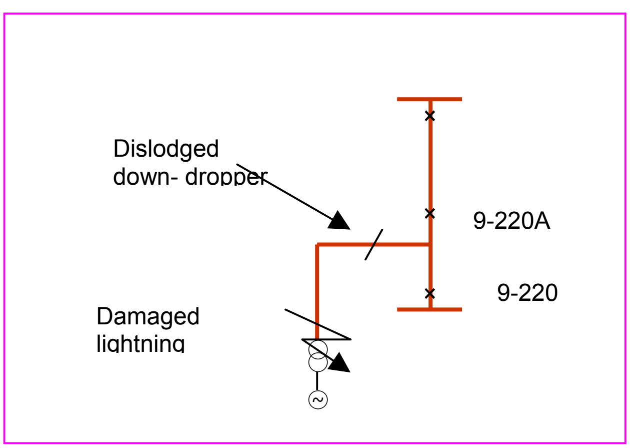


Figure 4-7 Old Harbour Single Line Layout Diagram



For the damaged lightning arresters and the dislodged down-dropper on disconnect switch 9-227, breakers 9-220 and 9-220A are required to trip along with the generator.

If there is any failure on the part of either breaker, then all adjacent breakers feeding into the failed breaker will be required to operate via breaker fail protection as follows:

(a) Failure of 9-220

All the south bus breakers (9-520, 9-420, 9-320 & 9-430B) at Old Harbour would be required to trip in addition to 9-220A. No additional generator is required to trip for this contingency.

(b) Failure of 9-220A

Breakers 9-220 and 9-530 are required to trip in conjunction with the Old Harbour line breakers at Tredegar (9-430 & 9-930).

If the breaker fail scheme for either breaker fails, then local back-up to include the interbus transformer and all generators on-line at Old Harbour will be required to trip in addition to remote line breakers at Parnassus, Duhaney and Tredegar substations.

5.0 EXPLANATION OF SOE

5.1 Fault Events

5.1.1 Old Harbour Substation

5:11:05.608

Oscillographs from Old Harbour line distance relays at Duhaney and Tredegar revealed that an A-G fault developed on the system and quickly evolved into an A-C-G fault as shown in figures 5-2 to 5-5. This fault was the result of flashover on Old Harbour Unit 2 GSU transformer high voltage (HV) lightening arresters.

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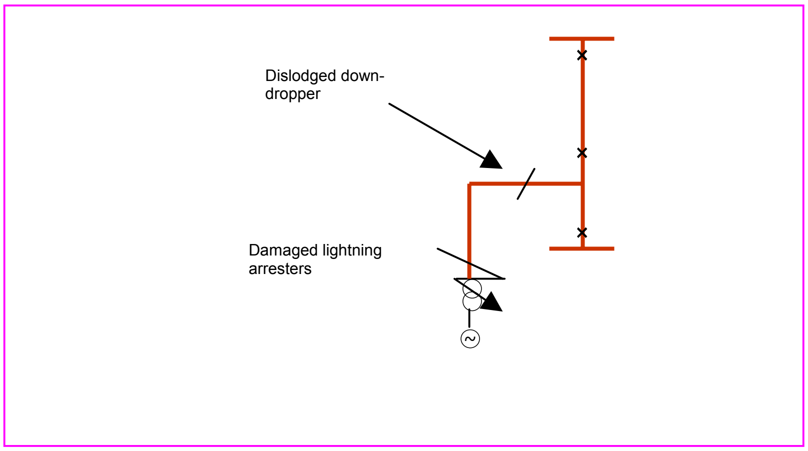


Figure 5-1 Section of the Single Line diagram

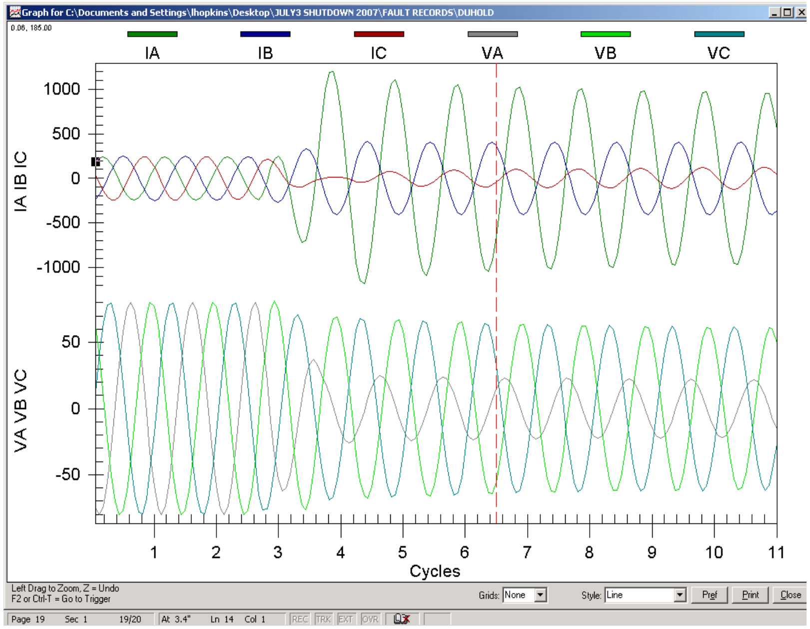
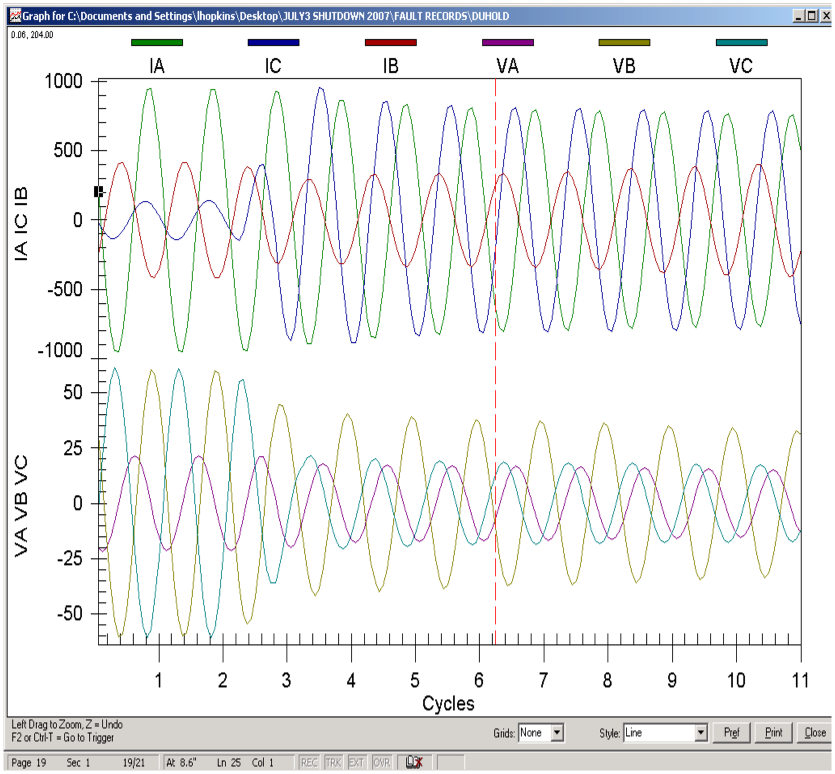


Figure 5-2 Duhaney-Old Harbour SEL321 Relay Fault Record 1

Duhaney-Old Harbour relay event record 1:

Oscillograph for the first event showing A-phase current much greater than the other two phases

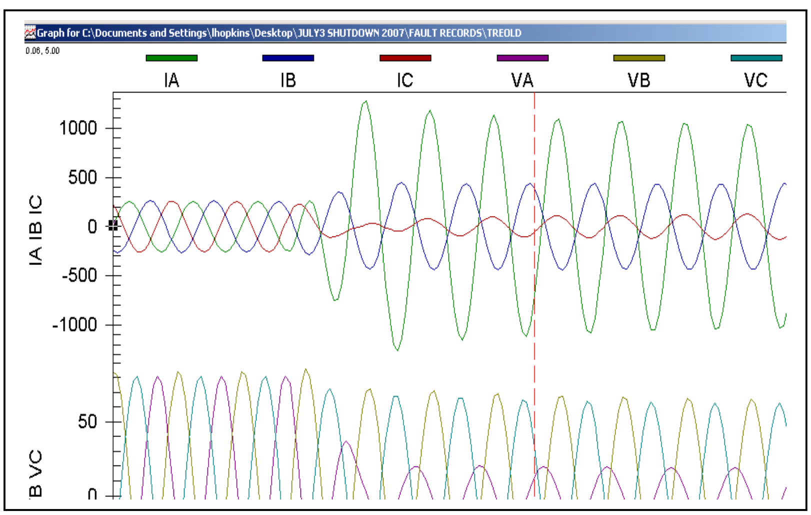
The time of fault inception was calculated to be 5:11:05.608



Duhaney-Old Harbour relay event record 2:

Second event record from the Old Harbour line distance relay at Duhaney shows A-C-N fault

Figure 5-3 Duhaney-Old Harbour SEL321 Relay Fault Record 2

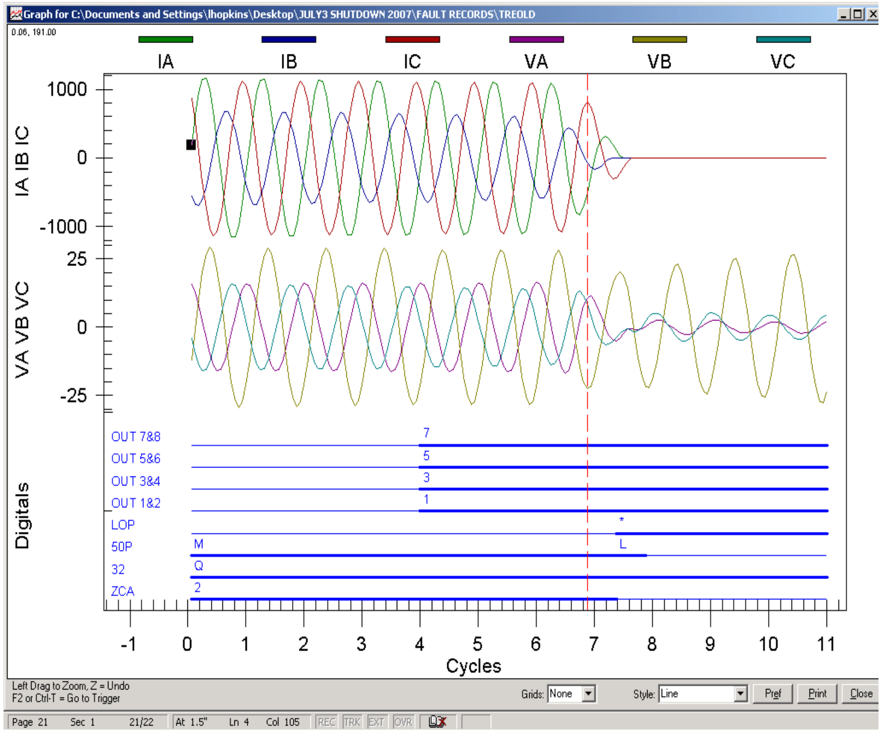


Tredegar-Old Harbour relay event record 1:

Oscillograph for the first event showing A-phase current much greater than the other two phases

The time of fault inception was calculated to be 5:11:05.608

Figure 5-4 Tredegar-Old Harbour SEL321 Relay Fault Record 1



Tredegar-Old Harbour relay event record 2:

Relay picked-up on zone 2 CA

Note A & C currents are much greater than the B-phase current

Figure 5-5 Tredegar-Old Harbour SEL321 Relay Fault Record 2

<u>5:11:05.820 [1]</u>

Approximately 212 ms from the start of the fault, breaker 9-220A tripped at Old Harbour when the Unit 2 GSU transformer differential protection operated. At this time however, the other breaker required to trip for this fault, 9-220, did not open.

Expected trip time for this scheme is in the order of 70ms with a 60 ms breaker operating time. [Cause 1]

5.2 Remote Breaker Operations

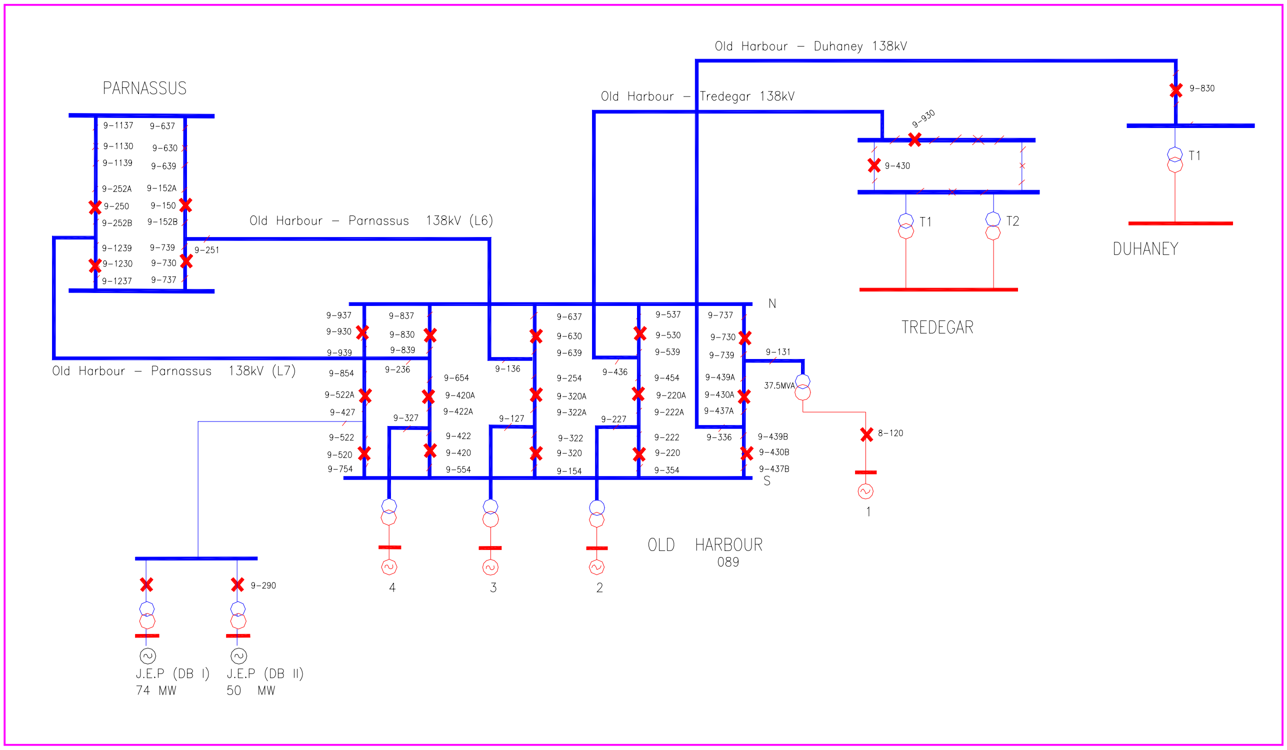


Figure 5-6 Single Line Layout Diagram of Old Harbour and adjacent substations

5.2.1 Duhaney Substation

<u>5:11:06.079 [2]</u>

The Old Harbour line distance relay detected a Zone 2 A-C fault at 23.64 miles from Duhaney in approximately 471 ms after the fault inception, this compares well with the in-service setting of 400 ms for the zone 2 timer and was in response to a breaker fail condition on 9-220. [Cause 1]

The “B” distance relay at Duhaney (Old Harbour line) recorded A-G for 232 ms and A-C-G for 244.5 ms as shown in figures 4.6

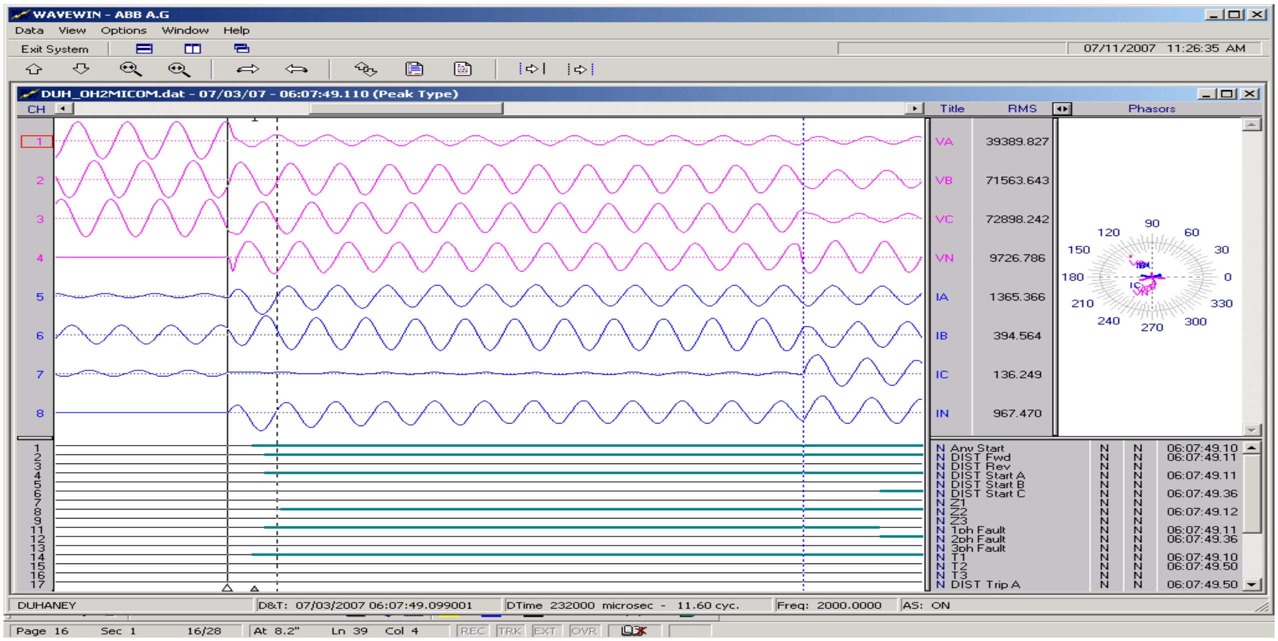


Figure 5-7 Duhaney-Old Harbour Micom P441 Relay Fault Record A-G 232 ms

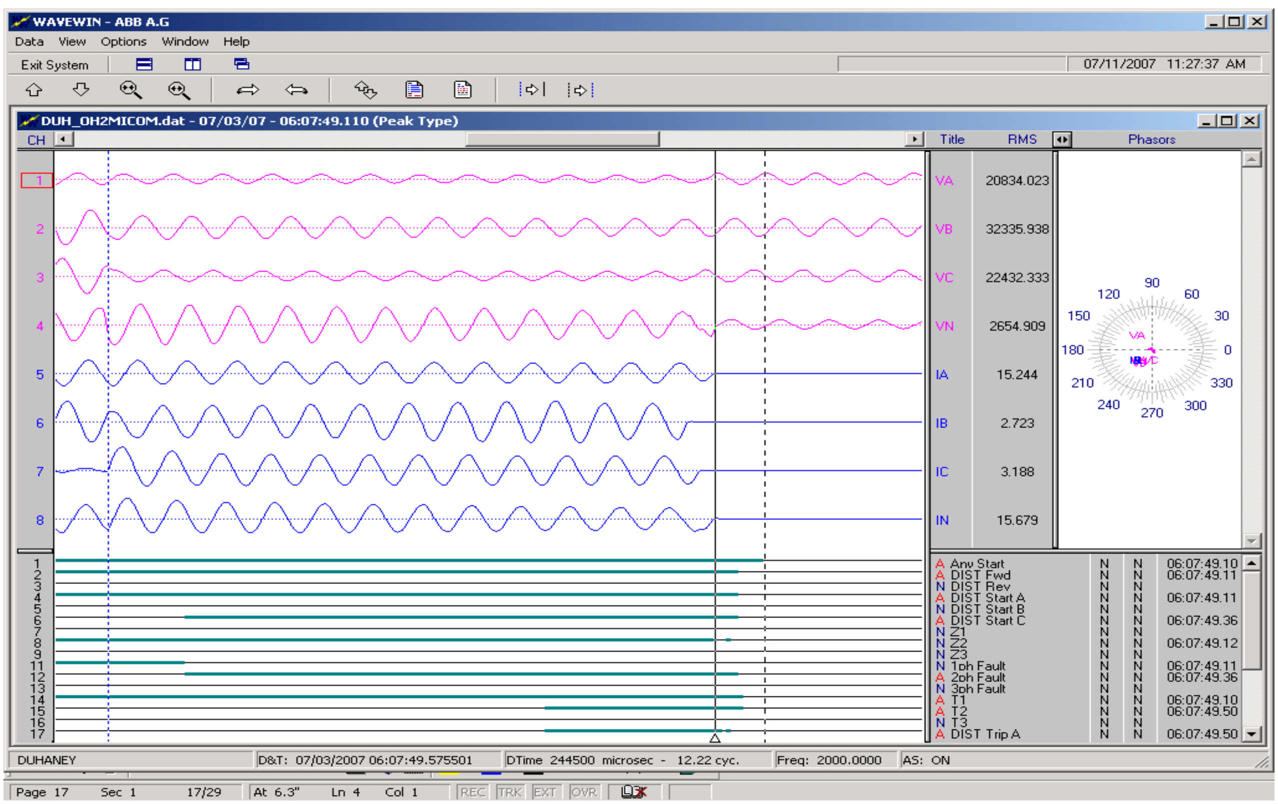


Figure 5-8 Duhaney-Old Harbour Micom P441 Relay Fault Record A-C-G 244.5 ms

5.2.2 Tredegar Substation

5:11:06.306 [3]

Similar to the protection system response at Duhaney, the Old Harbour line distance relay at Tredegar operated on zone 2 A-C distance element tripping breaker 9-930 approximately 698 ms after fault inception [Action 1 perform timing test]

Expected trip time for this scheme is in the order of 470ms with a 60 ms breaker operating time.

5.2.3 Parnassus Substation

5:11:06.371 [4 & 5]

At this time and approximately 763 ms after fault inception, the first recorded breaker trip at Parnassus occurred and by 770 ms after fault inception the two lines, lines 6 & 7 were completely isolated from Old Harbour. The relay data from Parnasssus indicate tripping was via three phase to ground directional over-current protection.

5.2.4 Old Harbour Substation – Breaker Failure

5:11:06.591[6]

983 ms after fault inception and 771 ms after the first breaker operation, breakers on the south bus at Old Harbour (9-520, 9-420, 9-320, 9-430B) commenced tripping in response to a breaker fail condition on breaker G2 or 9-220. This breaker subsequently tripped 4.35 sec after fault inception at 5:11:09.958 [7].

The trip times of breakers at Old Harbour in response to the fault condition were much greater than the design expectation. Accordingly, the cumulative effect on the system was severe as the local back-up protection provided by the breaker fail scheme turned out to be slower than the remote back-up protection provided by remote zone 2 distance elements and directional over-current protection. [Cause 1]

5.3 GENERATOR TRIPS

The delayed fault clearance at Old Harbour significantly affected the operation of generators online at 5:11 am on July 3, 2007:

5.3.1 JPPC

[5:11:06.104][13]

The first generator trip occurred on the JPPC plant at Rockfort when the 1 MW steam turbine tripped.

5.3.2 JEP Generators/Tie line

5.3.3 Barge II

JEP step-up transformers are able to supply ground fault current due to the grounded wye connection of the HV transformers. The delayed fault clearance on Unit 2 GSU caused ground instantaneous protection on Barge II to operate tripping breaker 9-290 approximately 533 ms after fault inception, this trip was a correct response based on the set time delay of 500 ms established for that circuit.

The generators on Barge II (DG 9, 10 & 11) subsequently tripped on overspeed protection due to loss of load.

5.3.4 Barge I

Generators on Barge I (DG1, 3, 4, 6 & 7) tripped due to over-current relay action as a result of the units trying to supply loads above their design rating.

5.3.5 Old Harbour Unit 4 & 1

[5:11:07.089-5:11:07.157][16, 17]

The tripping of 138 kV line breakers at Duhaney, Tredegar and Parnassus in-turn resulted in isolation of Old Harbour unit 4 generator from the 138 kV grid, however, the unit was still connected to Unit 1 on the 69 kV system via the 138/69 kV interbus transformer.

5.3.6 ROCKFORT POWER BARGE

Rockfort Unit 2 tripped on undervoltage protection, this response is typical if the voltage on the system is sufficiently suppressed by a fault or if there is an imbalance between the reactive generation and reactive load.

5.3.7 Hunts Bay Unit B6

[5:11:19.916][26]

Sequence of Event record from Hunts Bay indicate a flame failure on unit B6 which led to the sequential shutdown of the unit.

The tripping of this unit was the last of the generator trips as recorded by the SOE

5.4 AUTOMATIC UNDERFREQUENCY LOADSHEDDING

The JPS power system operates at 50 Hz frequency and is typically achieved when the active power generated is matched exactly by the load being served. In instances of loss of active power generating capacity without a corresponding loss of active load, system frequency will decline commensurate with the level of system overload. In order to maintain the load/generation balance, the system relies on automatic underfrequency load shedding to reduce the loads.

Four stages of automatic underfrequency were shed during the shutdown, these loads were shed after generating units tripped at Old Harbour and 1671 ms after the fault started. The last stage 4 point was shed 2179 ms after fault inception.

Table 5-1 Percentage Shed per Underfrequency Stage on July 3, 2007

Stage1		Stage 2		Stage 3		Stage 4	
Substation	% Of total Load Shed	Substation	% Of total Load Shed	Substation	% Of total Load Shed	Substation	% Of total Load Shed
Bogue	-	Hunts Bay	1.30%	Three Mile	3.22%	Greenwich Road	2.04%
Hunts Bay	0.26%	New Twickenham	4.99%	Cane River	0.45%	Hunts Bay	-
Orange Bay	1.38%	Washington Blvd	4.8%	Duhaney	1.73%	Naggos Head	-
Paradise	1.10%	Hope	1.1%	Greenwich Road	2.05%	Rockfort	1.61%
Spur Tree	1.46%			Hope	1.55%	Tredegar	4.49%
Up Park Camp	-			Kendal	1.12%	West Kings House	3.95%
Washington Blvd	1.74%			May Pen	1.64%		
				Parnassus	3.11%		
Total % per Stage	5.93%		12.19%		14.89%		12.10%

Total % Shed 45.11%

5.4.1 PROTECTION SYSTEM PERFORMANCE

The performance of the protection system is assessed based on the design criteria of speed, selectivity, sensitivity and reliability. Table 5.2 below is a comparison of the trip times for various circuits versus the design trip times and includes breaker times.

The expected time of operation of the breaker fail scheme is 330 ms and is broken down as follows:

- Initial relay (87TB, A86V & B86V) operates with no intentional time delay – approximately 10ms
- Breaker fail overcurrent relay 50BF-G2 should also operate with no intentional time delay – approximately 10 ms
- Breaker fail timer 62BF-G2 set time delay is 250 ms
- Circuit breaker design operating time is approximately 60 ms

- Total breaker fail from fault inception should be approximately 330 ms.

The total design delay time for zone 2 distance protection is 470 ms and is broken down as follows:

- Circuit breaker trip time approximately 60 ms
- Relay zone 2 delay time 400ms
- Relay operating time approximately 10ms

Directional over-current relays are less predictable as the operating times are based on the available short circuit currents during faults.

Table 5-2 comparison of the trip times versus the design trip times

No	Station	Breaker(s)	SOE Time	Elapsed Time (ms)	
				Actual	Design
(0)	Old Harbour		5:11:05.608	0.00	Fault inception
(1)	Old Harbour	Unit 2 (9-220A)	5:11:05.820	212	80
(2)	Old Harbour	Unit 2 (9-220)	5:11:09.958	4350	80
(3)	Old Harbour	South Bus (9-520)	5:11:06.591	983	330
(4)	Old Harbour	South Bus (9-430B)	5:11:06.613	1005	330
(5)	Old Harbour	South Bus (9-320)	5:11:06.655	1047	330
(6)	Old	South Bus (9-420)	5:11:06.659	1051	330

	Harbour				
(7)	Duhaney	Old Harbour (9-830)	5:11:06.079	471	470
(8)	Tredegar	Old Harbour (9-930)	5:11:06.306	698	470
(9)	Tredegar	Old Harbour (9-430)	5:11:06.317	709	470
(10)	Parnassus	Old Harbour L7 (9-1230)	5:11:06.371	763	470, 730 *
(11)	Parnassus	Old Harbour L7 (9-250)	5:11:06.372	764	470, 730 *
(12)	Parnassus	Old Harbour L6 (9-730)	5:11:06.376	768	470, 730 *
(13)	Parnassus	Old Harbour L6 (9-150)	5:11:06.378	770	470, 730 *

Complete fault isolation occurred when breaker 9-420 tripped 1051 ms after fault inception.

Note *:

- 470 ms for back-up distance relay
- 730 ms for directional over-current relay

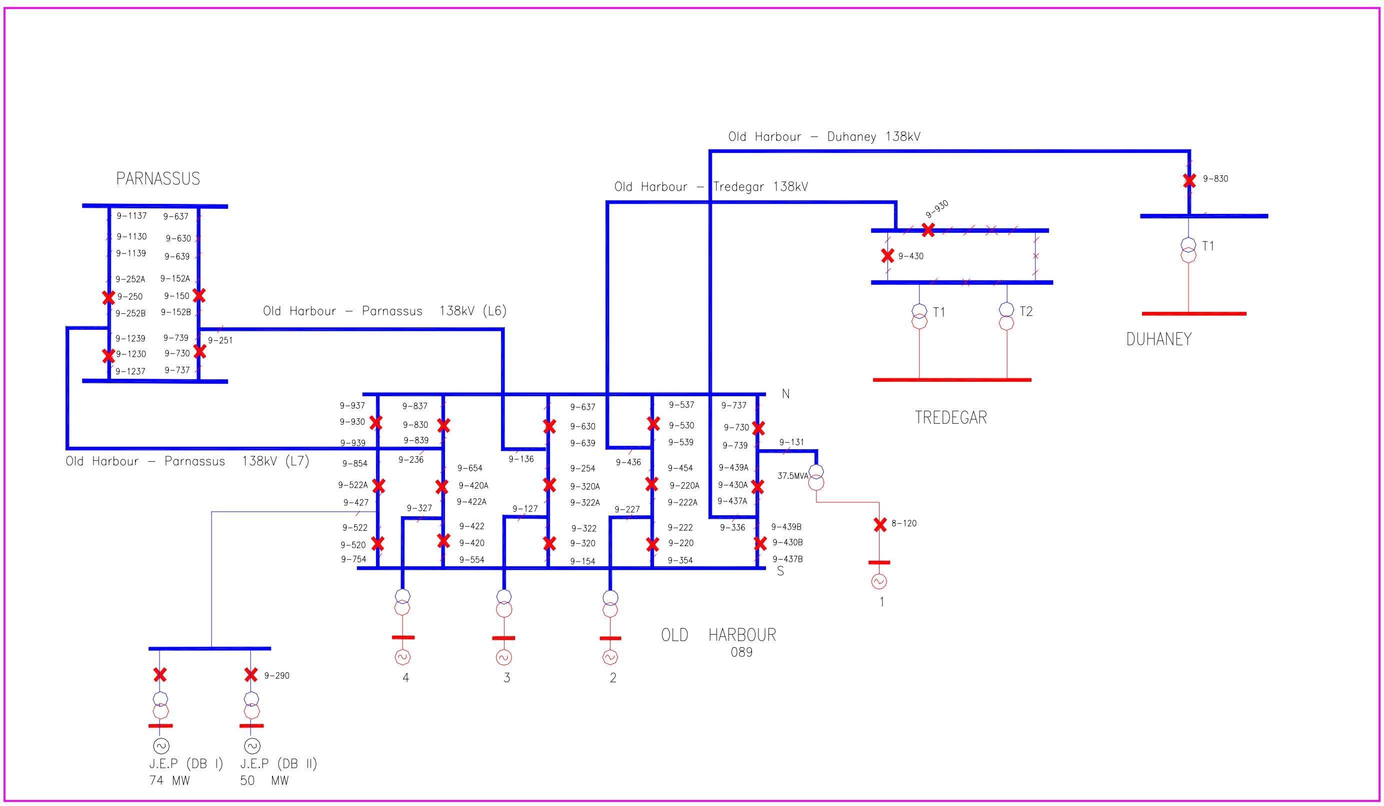


Figure 5-9Single Line Layout Diagram of Old Harbour and adjacent substations

5.4.1.1 Old Harbour Relay Operation

For the fault in the Unit 2 GSU protection zone, transformer differential protection, device 87B operated correctly to trip breakers 9-220A and 9-220. Breaker 9-220 however, tripped greater than 4000 ms after the fault due to a stuck breaker pole. *(Subsequent test result of breaker timing for breaker 9-220: Pole 1 - >4000 ms; Pole 2 - 226.2 ms; and Pole 3 - 227.1 ms)*. The stuck breaker pole was still facilitating the flow of fault current, thus completing the logic for the breaker fail scheme for 9-220. This breaker fail scheme is designed to trip the other south bus breakers in addition to re-tripping breaker 9-220A. .

Given the duration of the stuck breaker pole, which was well outside the time allotted for local breaker fail protection to clear the fault, remote zone 2 or directional overcurrent relays at Duhaney, Tredegar and Parnassus were required to operate as well as the local interbus transformer back-up protection at Old Harbour.

This section will focus on the response of these systems to the failed breaker.

5.4.1.2 Old Harbour Interbus Transformer Protection

For the failed breaker at Old Harbour, 9-220, the interbus transformer phase and ground over-current protection schemes are required to operate. The design operating time for this protection is dependent on the magnitude of the fault current. The actual trip time based on the predicted fault current of 554A is 3.67 seconds.

The operating time of 1051 ms recorded for the last south bus breaker, 9-420 is less than the 3.67 seconds for the interbus over-current relay, as such, this protection did not time out, and the interbus breakers were not required to trip.

Observation

Subsequent inspection of the transformer panel at Old Harbour, it was observed that the transformer differential had operated, however, the sequence of operation record does not show any operation of the associated breakers.

5.4.1.3 Parnassus Relay Operation

Given the slow breaker operations at Old Harbour, zone 2 distance relays are required to operate as a first line of defence at Parnassus, however, the trips at Parnassus were attributed to the ground directional over-current relays in a time of approximately 730 ms. Expected operating time is 470 ms based on zone 2 distance relay operation.

The non-operation of the distance relay was caused by a loss of potential block (LOPB) due to the low voltage and low fault current experienced at the station and requires a revision of the LOPB logic. The oscillographs below show the LOPB active at 4 cycles.

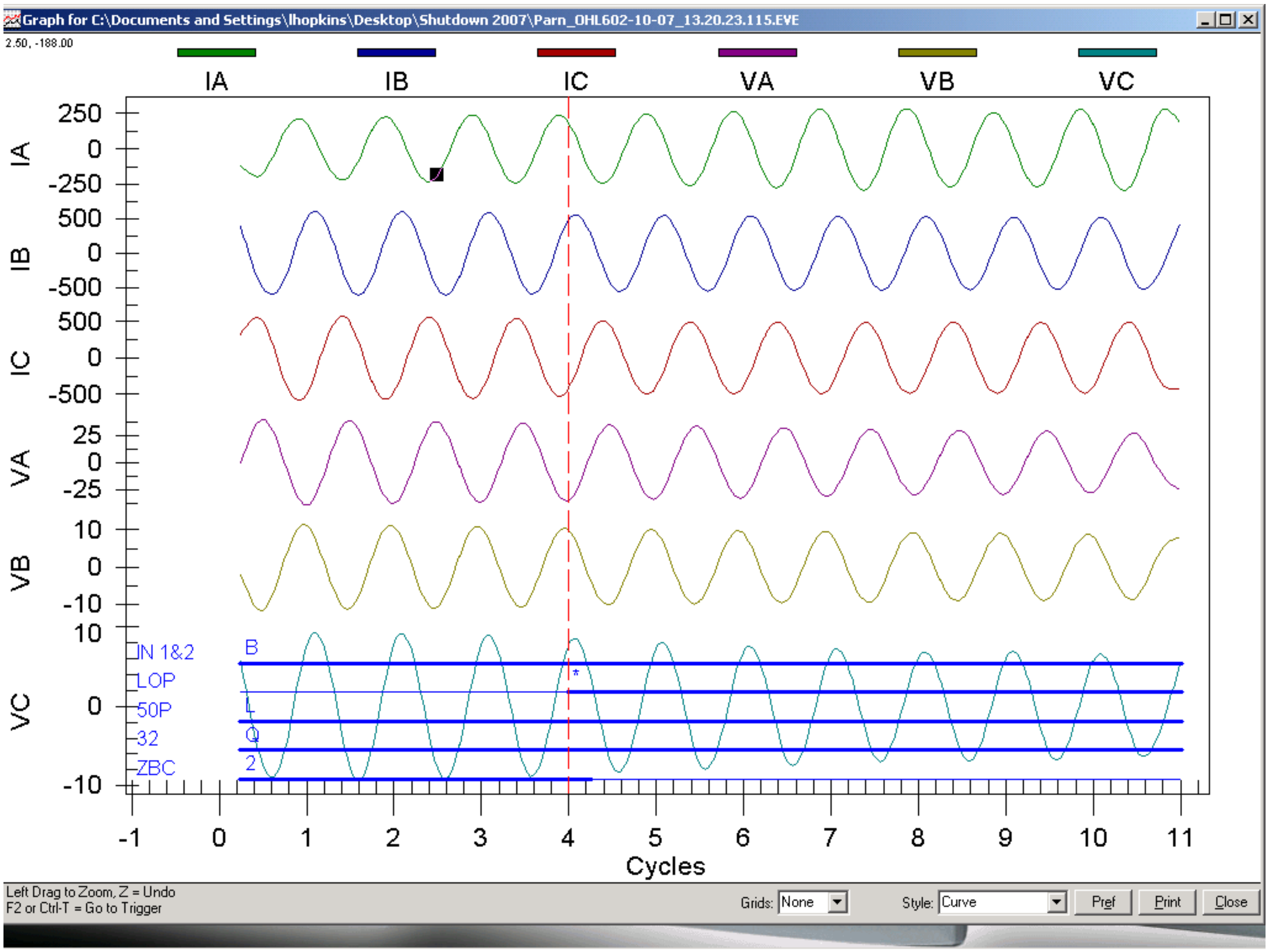


Figure 5-10 Parnassus – Old Harbour 138 kV Line 6

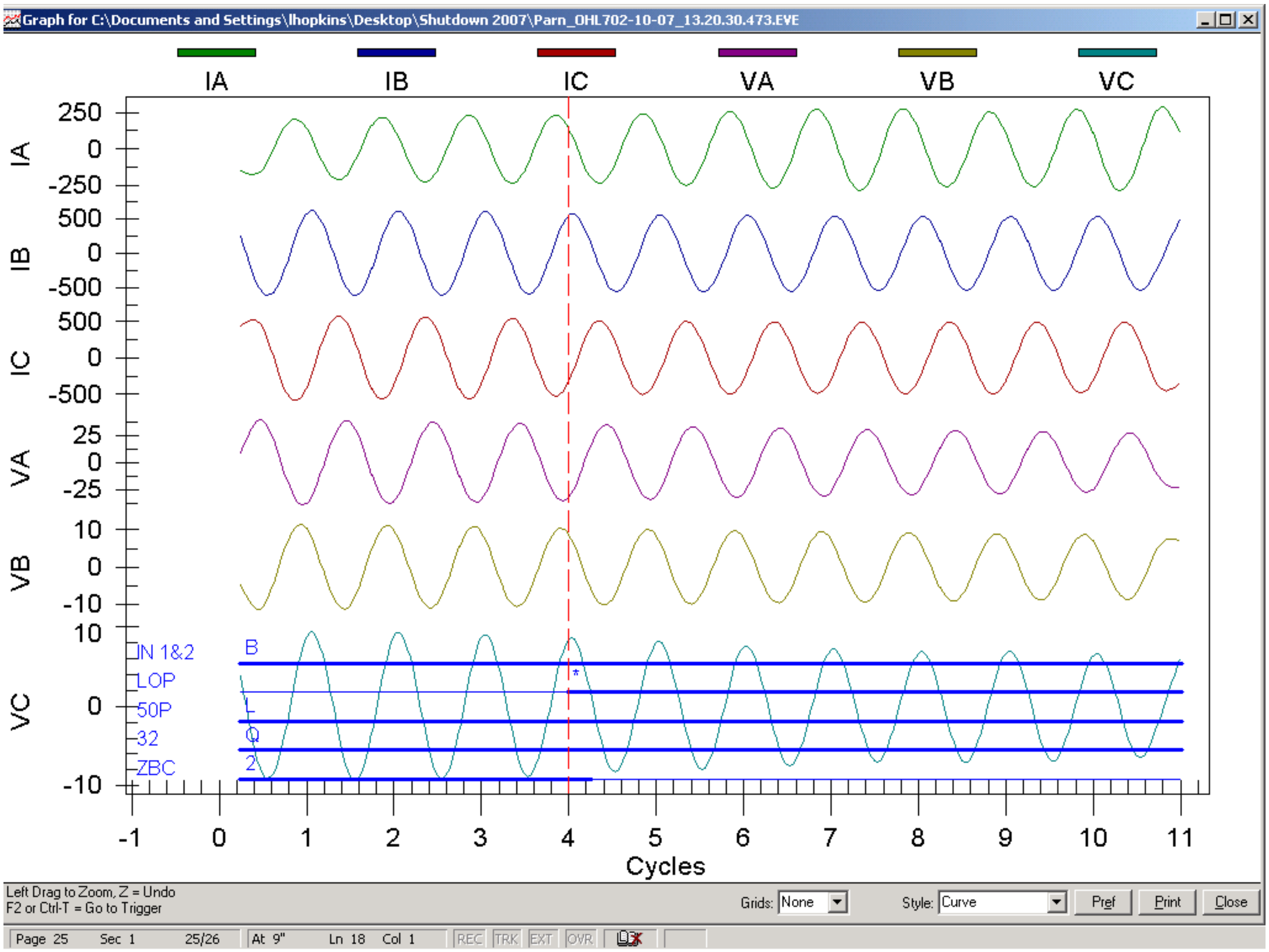


Figure 5-11 Parnassus – Old Harbour 138 kV line 7

6.0 SYSTEM RESPONSE

In instances of power system disturbances such as a fault on the Old Harbour Unit 2 transformer zone, generators near the fault tends to speed up as a result of not being able to supply the load while generators farthest from the fault tends to slow down from trying to pick-up the additional system load. These dynamic changes are reflected in the frequency and voltage response of the system at various busbars.

The system frequency recorded by SCADA at the Rockfort busbar is shown in Figure 6-1 below. Bus voltages in the Corporate Area and on the 138 kV system islandwide are shown in Figures 6-2 and 6-3.

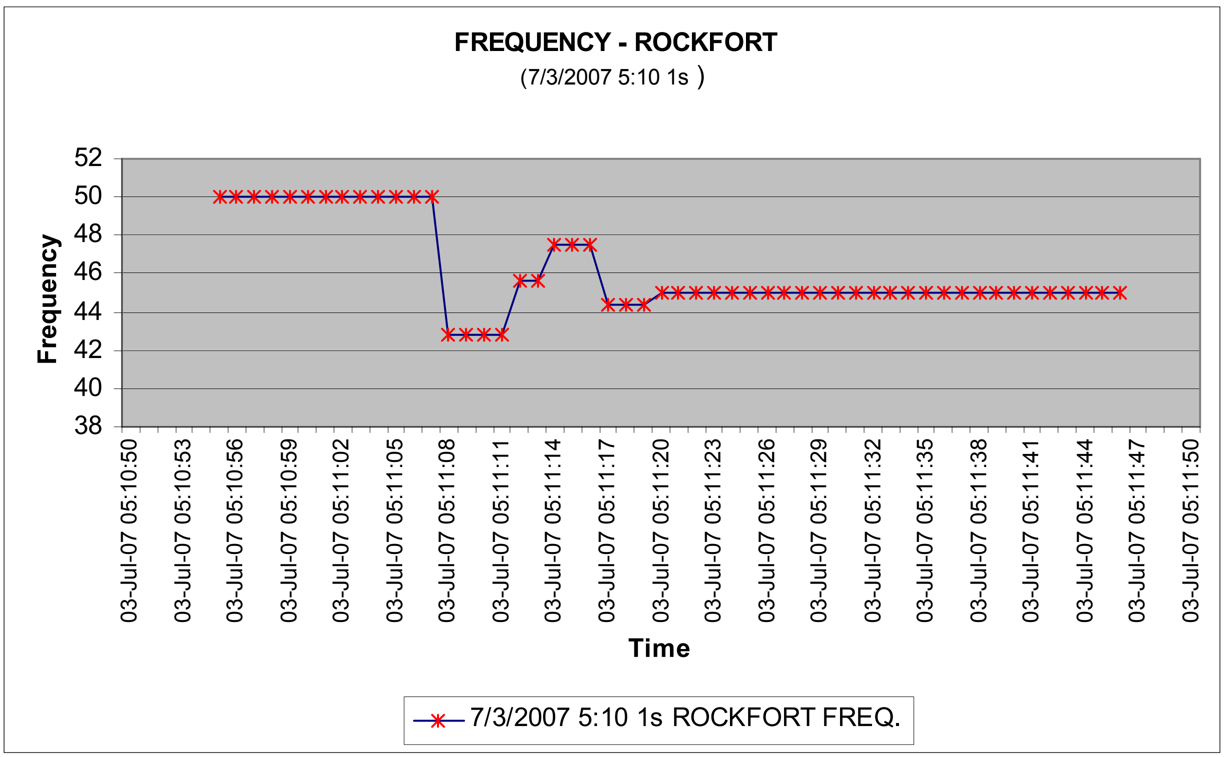


Figure 6-1 Frequency at the Rockfort busbar

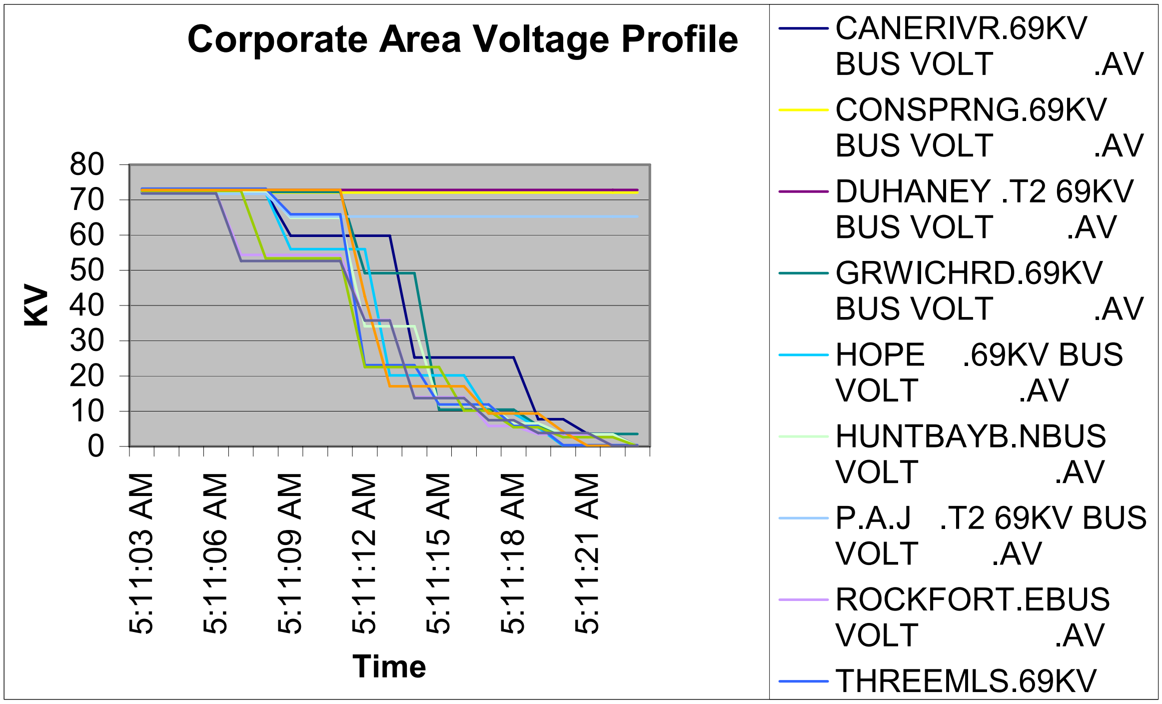


Figure 6-2 Corporate Area 69 kV bus voltage profile

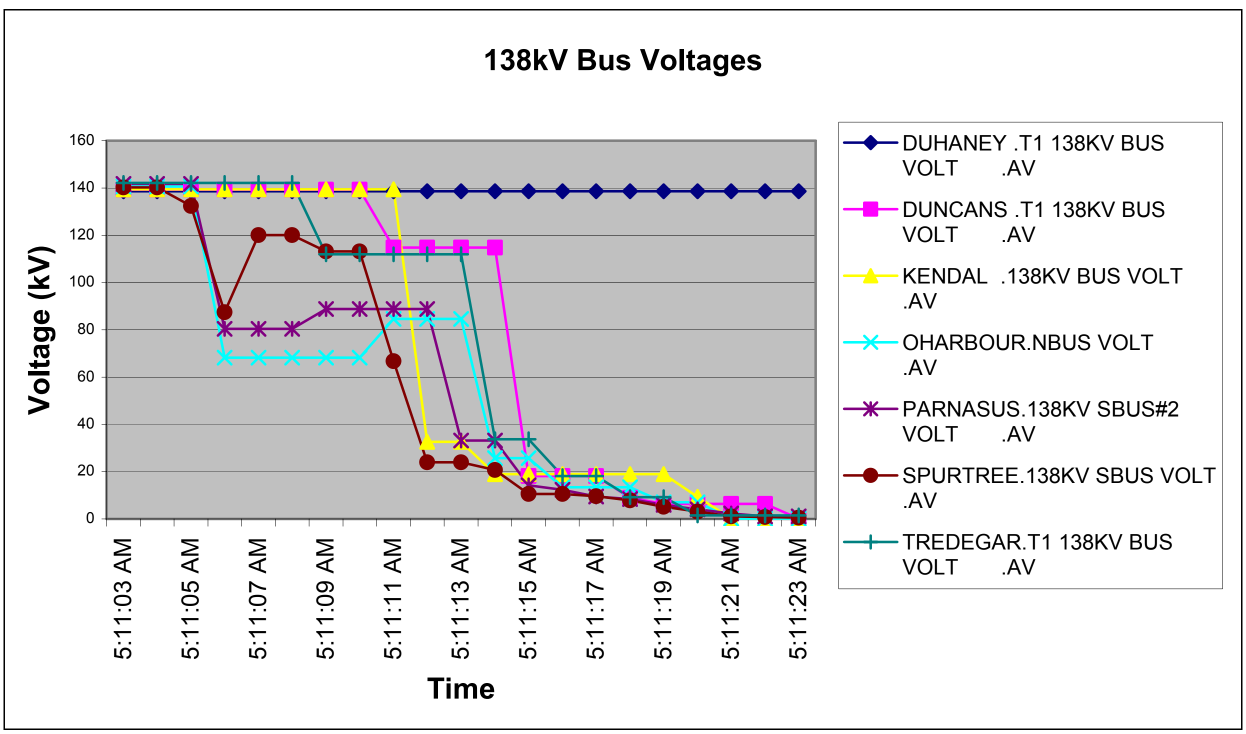


Figure 6-3 138 kV bus voltage Profile

7.0 SYSTEM RESTORATION

7.1 RESTORATION PRINCIPLES

The foundation of a good Restoration Plan is the establishment of clear, strategic, goals and that takes into consideration the specific local conditions of a particular Power System. These specific goals may vary widely across Systems and are influenced by such factors as the generation mixes, types and location of loads present and contractual obligations. The goal must be listed and prioritised to ensure that the actions taken result in optimal restoration, maximizing energy restored while minimizing restoration time.

Despite the nature of the power system, the general and fundamental goals in restoration should be to:

1. Rebuild a stable electric system
2. Restore all un-served loads

These prime goals can only be effectively achieved if other critical factors are taken into consideration while we pursue them. These factors include:

1. Maintaining a safe operating environment
2. Taking careful, calculated and decisive actions
3. Achieving maximum restoration in minimum time
4. Minimizing any adverse impact to the public
5. Maintaining enough flexibility to vary the approach

In the restoration of power networks after a complete collapse, two basic strategies or combinations of both are adopted. The “build-up” and “build down” strategies contain the fundamental principles that will guide any restoration process.

In preparing the network for the application of any of the fundamental strategies however, a few critical issues have to be addressed. Firstly, an assessment of the system status must be carried out. This includes acquiring knowledge of breaker and switch states, power plant conditions and the status of local energy storage and backup systems (compressed air, batteries, stand-by generators, Uninterruptible Power Supplies etc.) to name a few. This is crucial in deciding which restoration plan of action to initiate or how to modify recommended approaches.

While the initiating cause of most blackouts is not usually a major factor in the restoration effort, information on the systems and equipment affected by blackouts that are caused by catastrophic events is very important. This could prevent energization of a faulted system preventing further network damage or a further collapse of the system.

Management personnel and operation teams must be notified of the occurrence of a blackout, the status of the system and what is required of them to support the restoration efforts. With due consideration for the state of the system, restoration options should be evaluated and the best one under the circumstances chosen for implementation. The formulation of the restoration action plan must proceed in tandem with other restoration preparatory activities to minimize downtime.

7.1.1 Build-Up Strategy

The build up strategy is internationally the more common of the two approaches. The basic approach of the build up strategy is to restore the system in “islands that will subsequently be interconnected. The application of the build up strategy predicates that parallel restoration actions are possible. While this approach can significantly reduce restoration time, its application is limited by the extent of sectionalization possible due to lack of adequate operating teams or monitoring, control and communications systems to effect the efficient and effective co-ordination of the efforts.

The critical steps/tactics and sequence of the build-up approach are as follows:

1. Sectionalization of the system into subsystems to maintain at least one unit with blackstart capability in each subsystem
2. Simultaneously commence in each subsystem the process of supplying cranking blackstart power to drum type steam electric units before hot restart time elapses and/or to other critical systems before backup power “runs down”.
3. Interconnect generating stations within each subsystem after minimum loading achieved on each generator but before full restoration of subsystem loads.
4. Coordinate load pickup sequence to control system frequency. Add load in small amounts when system frequency is above nominal and generation when frequency is sub-nominal. Allow sufficient settling time before each increment of load addition.
5. Restore smaller radial loads before larger, low voltage AC network loads. Utilize loads with good VAR components and proximity to generators to clamp voltage rise and to maintain system stability.
6. Maintain a good real-reactive power balance by under-exciting generators where possible within stability limits and initially energizing only one circuit of double-circuit lines
7. Establish firm transmission and generating capability by interconnecting subsystems and having sufficient generation in each subsystem.

7.1.2 Build-down Strategy

The build down strategy is primarily applied to small systems that have relatively low voltage transmission systems characterized by short transmission lines. The build-down approach applies a sequential restoration approach and is based on firstly restoring the bulk power network followed by restoring load and generation in a step by step approach at all times ensuring system stability is maintained and frequency controlled.

The application of the build-down strategy can be very slow and challenging if lightly the loaded transmission system produces reactive power that exceeds the absorption capability of the available generation, resulting in sustained over-voltages on the system at remote locations where synchronization is being attempted. This over-voltage could also result in damage to equipment if not prevented.

The key steps/tactics to be applied in the execution of a build–down strategy are as follows:

1. Preparing black-start generator to provide cranking power and initiating restart sequence.
2. Establish a transmission path to the next generator requires cranking power to start-up. Transmission path selection will include some or all of the following actions:
    a. Avoiding faulted transmission paths
    b. Consideration for the location of loads critical for restoration and/or sensitive loads
    c. Finding a suitable starting load based on the capability and limits of the connected starting generator
    d. Taking steps to mitigate sustained over-voltages or during switching operations. Remove or deactivate switched capacitors.
3. Once the black-started generator is stabilized, utilize the chosen transmission path to provide cranking power to the next non-black-start generator be started or to critical loads. Give priority to drum type steam powered units to ensure that maximum hot restart time doesn’t expire.
4. The choice of next generator is dependent on:
    a. Generator restart limits
    b. Their real and reactive power capabilities
    c. Grid location with respect to both loads and the cranking source
5. Synchronize new generator, to the same transmission grid from which it received start-up power to establish parallel generator operation with the blackstart generator
6. Establish minimum stable loads on online generators, picking up loads in as large an increment as to prevent frequency decline. Choose major critical loads first such as communication circuit power sources and major switching stations. Avoid frequency sensitive loads or loads on underfrequency schemes in the early phase.

7. Strengthen the transmission connectivity and continue linking other generating stations and as much generation as practical followed by loads and vice versa. Delay load additions as long as is necessary to ensure that a stable integrated bulk power network has first been established.
8. Once a stable system has been achieved, continue load restoration as quickly as possible, continuously monitoring frequency and keeping within the online generators' ramp rates.
9. Choose radially fed, lagging power factor loads first to help manage voltage rise.
10. Monitor real and reactive power balance and adjust strategy accordingly to maintain steady state and transient stability. Continue process until all loads are restored

7.2 JPS RESTORATION APPROACH

Traditionally, the approach taken in the restoration of the JPS System has been more akin to the build down strategy. The characteristic of the JPS System (small, relatively low transmission voltages and short transmission lines) and the occurrence of high voltages while restoring the system after the 2001 blackout identified the need to carefully evaluate how best to apply this approach.

Given this and the load generation balance across the subsystems of the electric network, a hybrid build-up and build-down approach has been adopted as the preferred option to speed up the restoration while still creating a stable transmission backbone and providing black-start power to critical steam powered generators as quickly as possible.

If all generators are available in the Corporate Area and Northwest Regions of the island, then a substantial portion of the system load can be restored very quickly. The Southern Area of the island has good capacity reserve margin but black-start facilities only at JEP. Self-Restoration in this area is thus impaired if JEP blackstart fails and is dependent on the remote black-start of the generators at Old Harbour from Hunts Bay or Bogue. The Northeast Area primarily comprises of load with only small hydro generators so this area will normally be one of the later regions to be restored

Transmission Synchronization Points exist between the Northwest and Southern Areas at Magotty, and between Southern and Corporate Area via the 138kV link at Old Harbour. There are also synchronization facilities between the Southern and Northeast Areas at Bellevue

7.2.1 System Assessment and Preparation

Immediately upon the occurrence of a System Shutdown several steps must be taken in preparation for a restart of the System. The first task involves doing an assessment of the state of the system and the extent of functioning sub-systems available and/or the extent of damage if any. In this assessment phase, SCADA information should never be relied on solely but confirmed by field verification checks.

Special note must be 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. Some or all of these stations are most likely to be critical nodes in any start-up path and may require manual intervention in the event SCADA control and monitoring fail at any time. Other stations or locations which are not SCADA remote capable but which will form part of the restoration strategy must have attendant operations personnel on location.

Protection System status must be determined and restored to normalcy prior to the start of re-energization efforts, particularly checking for lockout relays that have operated and resetting them. Some Distance Relays may have been activated also due to power swings caused by an out-of step condition. Checks should also be made on lines that may have been overloaded in the cascade and possibly developed faults.

Generating Unit status should be evaluated to declare their availability and rule out any suspicions of damage that may have occurred in the shutdown process. The existence of any generator that has tripped to local load should be determined and steps taken to stabilize any such machine since local load may be below the stable minimum MW for that generator. After conducting the generator status assessment, a black-start unit must be selected and a suitable start-up load identified to stabilize the generator at about half-load. This load should preferably be connected to the distribution transformers at the generating station location selected (Bogue or Hunts Bay) to minimize voltage rise.

Having assessed the system status, a system restoration action plan must be initiated based on the constraints or advantages that exist at the time. In preparation for black-starting the Steam Powered Generators at Old Harbour, all bulk capacitor banks and other VAR sources must be switched off from the grid and a preferred restoration start-up path selected. All loads connected to this path should be stripped or disconnected. The black-start generator identified should be connected to the grid to feed the selected start-up load.

7.2.2 Subsystem Black-start and Build-up

The JPS Primary Restoration Strategy surrounds providing black-start power to the remote Steam units at Old Harbour utilizing the quick-start Gas Turbines either at Bogue (GT’s 3,6,7,8,9,11) or Hunts Bay (GT’s 10 and 5) or the hydro unit at Magotty. From the viewpoint of maximizing demand restoration, restoring loads in Corporate Area (50% of the system demand) is crucial. To this end, the early start-up of the Hunts Bay and Rockfort generators is imperative. GT 10, GT5 and JPPC are the Corporate

Area based black-start units and hence must provide primary support for Rockfort and their own Hunts Bay Power Station

Bogue should be simultaneously black-started and operated to supply the North-West Region of the island. Attempts should be made to provide cranking power to Old Harbour and/or the black-starting of the 120MW Combined Cycle. The Combined Cycle is critical since such a large generator can contribute significantly to full load restoration in the North-West Areas. Like the units at Old Harbour however, it will be some time before the steam generator of the Combined Cycle is restored to service after a blackout.

All attempts must be made to interconnect all the Generating Stations via the transmission network and as much generators restarted and synchronized as soon as possible. Loadings on the generators should be advanced to at least their minimum stable MW levels by restoring loads to the system, taking into consideration the load characteristic. The bulk power network will be strengthened while loads are restored.

When the system is robust enough, Generation and Demand must be added step by step keeping the frequency excursions of the system minimal.

7.2.3 Customer Restoration Strategy

The JPS strategy outlines the stages that lead to the restoration of all available generators that can be restarted in two hours or less after a shutdown (Gas turbines, Diesel and Hydro units) interconnected by a stable transmission grid and the provision of black-start power to the major steam plants at Hunts Bay and Old Harbour. At the end of those stages, over 50% of the original demand on the system is restored with the remainder awaiting the return to service of the steam plants.

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:

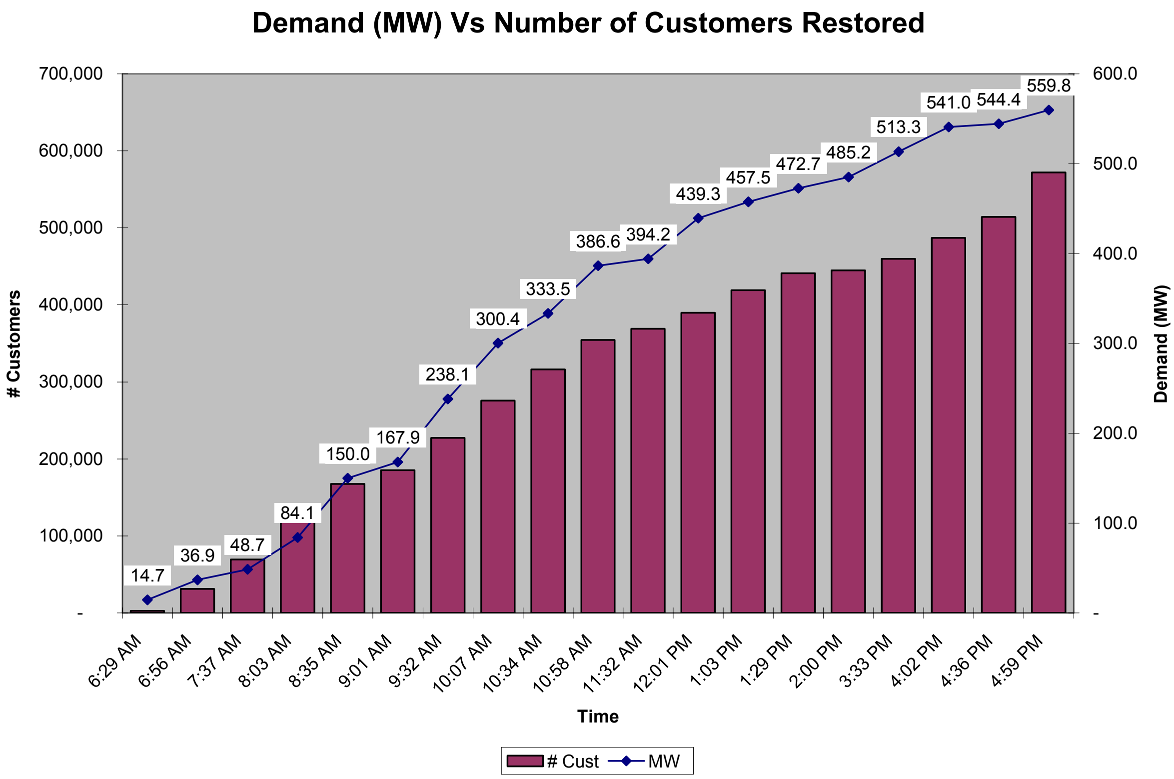
- Critical Loads – Hospitals, Airports, Water supply facilities, Control Centers (Army and Police), JPS and system critical loads (Underfrequency etc.), Telecommunication critical locations
- Industrial demand (Factories, Ports etc.)
- Hotel and Tourist sectors
- High Commercial Areas – Towns Squares, Critical roads
- High Security Risk Areas

7.3 System Restoration of July 3, 2007

The early assessment of the events of the morning of July 3rd 2007 indicated that some event related to electrical network and equipment connected to the Old Harbour Power Station had initiated the All-Island power failure.

Subsequent to this assessment, the decision was taken to isolate Old Harbour and its associated interconnections to the system for inspection while blackstarting generators at Bogue and Hunt's Bay immediately. Thereafter, both the North West and Corporate Area subsystems would be operated as separate subsystems and synchronize later in the morning.

Authorized switching personnel were dispatched to various substations island wide. Necessary switching commenced at 5:32am in preparation for generators blackstarting, isolation of the Old Harbour substation and subsequent restoration of the grid. Appendix E outlines the full generation-load restoration sequence which lasted for just under twelve hours



7.3.1 Successful Blackstart and Grid Interconnection

GT10 blackstarted and energized the bus at Hunts Bay at 6:04am, stabilized and supplied station service loads. H/Bay 6-710, H/Bay 6-410 were the first feeders to be energized between 6:18 and 6:22am in preference to 6-310(hospital feeder), which could not be closed. It was later discovered that the hospital feeder recloser had a defective closing coil that was subsequently replaced.

GT7 blackstarted and energized northwestern subsystem at 6:43am, Bogue 6-410 (Cornwall Regional Hospital feeder) supply was restored followed by the Donald Sangster International Airport at 6:46am.GT5 and GT9 synchronized to their respective subsystems at 6:48am and 7:10am respectively. GT5 had a failed start earlier at 6:21am while coming up, delaying the restoration process.

Rockfort s/s was energized at 6:31am. At this time both Rockfort and JPPC units were requested on line. As generators synchronized to the respective subsystems, transmission line redundant paths were created in the subsystems, loads added accordingly and transmission path created to facilitate synchronizing of the two subsystems that were operating independently. Care was taken not to load any generator more than 50% full load. This would allow generators to pick up load suddenly if another online generating unit should trip, preventing system to collapse.

Switching was carried out isolating faulted bus section at Old Harbour and prepare Old Harbour station to receive power via the Old Harbour to Duhaney 138kV line (Line 4). Patrol of both Old Harbour line 4 and line 5 (Old Harbour – Tredegar 138kV) was carried out by the transmission line crew to assess the state of these assets for re-energization. The patrols found no faults on these lines

The Hunt’s Bay and Bogue subsystems were synchronized at 8:26am and supply restored to Old Harbour switchyard at 8:35am. Entire transmission grid was fully energized at 10:19am with just over 50% of total system demand restored.

7.3.2 FAULT AT OLD HARBOUR

Inspection of the Old Harbour substation revealed burnt off middle phase/ pulled out of clamp of generator # 2 isolator switch (89/9-227), damaged corona ring on #2 unit transformer and damaged surge arrester for same transformer. The faulted area was isolated and the station was energized at 8:35am. Available units at Old Harbour were requested on line as well as JEP units.

Added isolation of the Old Harbour south bus was effected to provide additional clearance for fault to be corrected. It must be noted that correcting the fault on the OH unit 2 bay area did not prevent Old Harbours1 and 4 or JEP’s units from synchronizing and supplying the grid. The earlier return of these generators was affected by burner problems and limited station service capacity at Old Harbour, and cooling system problems at JEP.

7.3.3 SOME OTHER FACTORS TAKEN INTO CONSIDERATION DURING RESTORATION

- Forecasted loads for the day 617mw at 2:30pm and 630mw at 8:00pm will be difficult to serve if generators were delayed in coming on line
- Priority was given to feeders considered to be critical supplying loads such as hospitals, morgues, airports, factories, hotels etc
- In the infancy of the restoration, generators were made to stabilize and loaded not more than 50% full load capacity.
- Redundancy in transmission interconnections was ensured to prevent collapse resulting from possible line faults.
- Special attention was paid to systems parameters in particular voltage, maintained within statutory limitations.

7.4 SOME OBSTACLES DURING RESTORATION PROCESS

- The following breakers at Old Harbour could not be closed due mainly to charging air problem: 89/9-530, 9-630, 9-830 and 8-130
- The following breakers at Parnassus were unable to close remotely: 26/8-170, and 26/8-410
- Generators (JPPC, ROCKFORT, OLD HARBOUR) took longer than normal to come on line from time the stations were energized
- GT3 tripped, GT12 & 13 restricted to 25mw to facilitate ST14 coming on line, JEP sets tripped at various times during the process
- JPPC took longer than normal to ramp up to full load

7.5 CONCLUSION

Full restoration of customers' supply was hampered by delays encountered as various generating plants had problems returning the units to service. The last feeder was energized at 4:59pm.

No collapse of system encountered especially in the early segment of the restoration when individual islands was most fragile, as steps were taken to create redundancies for generators and transmission line routes while reasonable balancing of load to generator was done. No equipment experienced overloading condition and system voltages were kept within statutory limitations.

8.0 ACTIONS SINCE SYSTEM SHUTDOWN OF JULY 3, 2007

OLD HARBOUR

- Replaced lightning arresters for Unit 2 GSU
- Timing verification performed for breakers 9-220, 9-520, 9-320, 9-830, 9-630, 9-420A & 9-320A
- Perform timing tests on breaker fail timers for 9-220, 9-320, 9-420, 9-520 and 9-430B
- Repair jumper for disconnect switch 9-227
- Accelerated contamination mitigation programme (insulator clearing)
- Accelerated general maintenance of Old Harbour switchyard
- Replaced breaker 9-220 with SF-6 type breaker

PARNASSUS

- Review and implement 50M (LOP block) distance relay settings at Parnassus for Old Harbour lines 6 & 7.

Appendix A

OFFICE OF UTILITIES REGULATION

Information and Questions for Enquiry – JPS System Shutdown of July 3, 2007

1. The system status prior to the commencement of the system shutdown incident.
2. Operating sequence of the system shutdown with indication of circuit breakers which operated and at what time.
3. Generators which came off-line, including IPP units, at what time and the reason for the separation from the system grid.
4. Any partitioning of the transmission system, location and time.
5. In respect of Old Harbour switchyard, all circuit breakers and relays which operated, in what sequence, inclusive of times.
6. Remote backup relays external to Old Harbour switchyard which operated and time alignment with the Old Harbour switchyard incident.
7. Any SOE recordings from the System Control Center or generating plants relevant to the incident which would serve as confirmation of items (2) to (6) above.
8. Any eye witness account pertinent to the event.
9. Information on currents, voltages and frequencies which may have been recorded on bus-bars across the island, particularly at Old Harbour.
10. The cause attributed to the delayed or non-tripping of any circuit breaker at Old Harbour switchyard.
11. Cause attributed to flash-over of two (2) 138 KV lightning arrestors on Old Harbour generator Unit #2 step up transformer.
12. Cause attributed to damage to the Old Harbour switchyard isolating switches for generator Unit #2 step up transformer, including burning of jumpers.
13. Whether any circuit breaker, switch, protective relay or any other major item of equipment in the Old Harbour switchyard was found defective or otherwise out of service.
14. Whether there is any indication that a fault occurred at any point on the 138 KV system external to the Old Harbour switchyard.
15. The date or dates of the last general service carried out in relation to Old Harbour switchyard.
16. Specifically, the date or dates when the switchyard insulators, including lightning arrestors and transformer and circuit breaker insulator bushings were last cleaned (of dust and saline contamination).
17. Specifically, the date or dates when the relevant circuit breakers involved in this incident at the Old Harbour switchyard was last inspected and maintained.
18. Specifically, the date or dates when the key protection relays involved in this incident at the Old Harbour switchyard were last inspected and maintained.

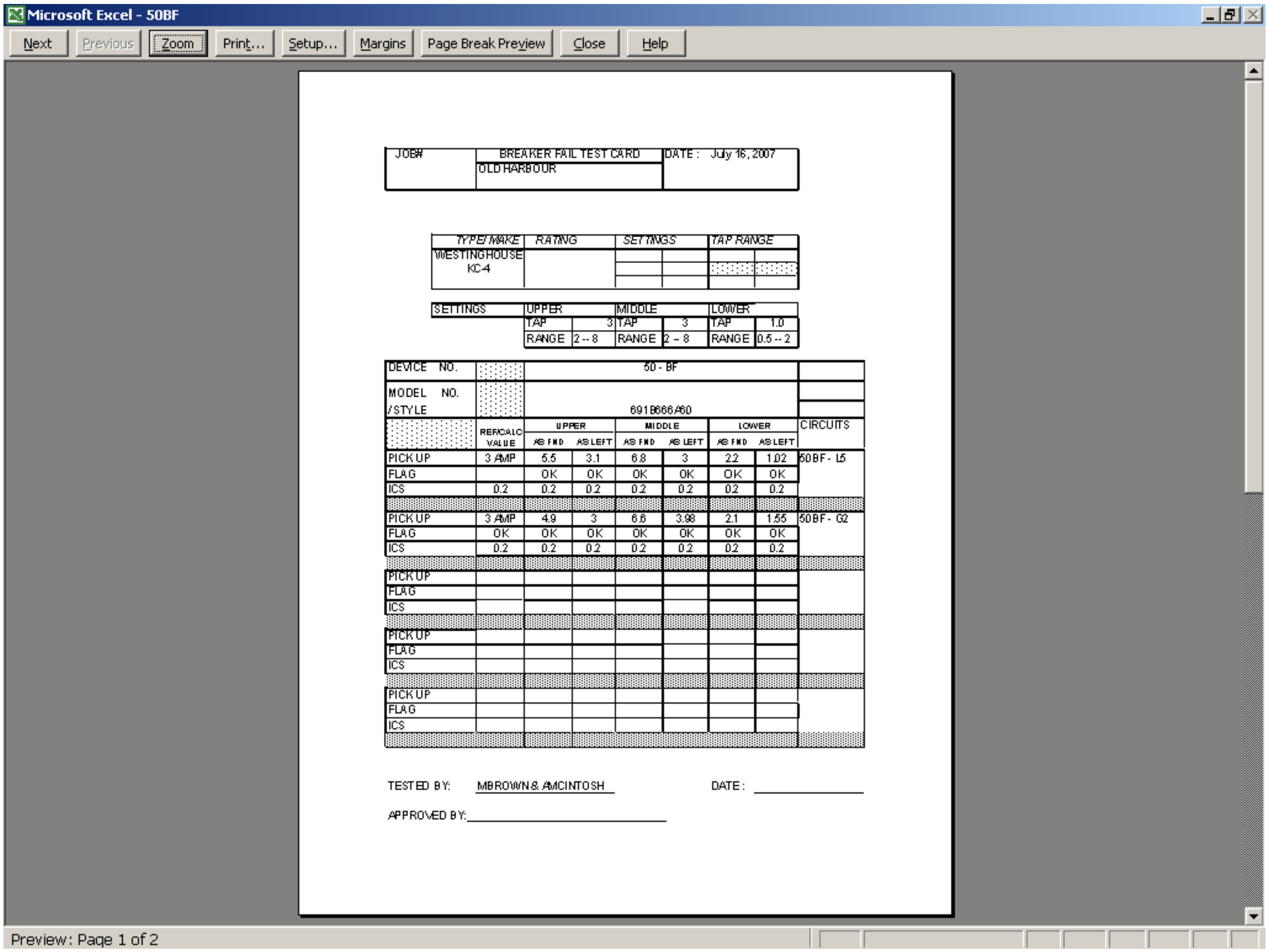
19. Availability of the SCADA remote monitoring and control and telecommunication systems.
20. Black-start capability of generating units.
21. Information on the sequence of system restoration, time lines and any incidents or issues resulting from the close-up exercise.
22. Single line diagram for Old Harbour switchyard.
23. Electrical diagram of Old Harbour switchyard, showing protective relay types and locations.
24. Tripping logic for Old Harbour switchyard.
25. Island transmission grid net-work.
26. JPS' opinion as to the primary initiating event leading to the system collapse.

JAMAICA PUBLIC SERVICE COMPANY LIMITED
JULY 15 2006 SYSTEM SHUTDOWN
RECOMMENDATIONS IMPLEMENTATION STATUS SUMMARY
TO BE UPDATED

No.	Description	Schedule	Status	Responsibility
	JPS RECCOMMENDATIONS			
1.	Replace failed REL 512 backup 138kV line protection relay at Duncans substation and re-commission remote monitoring point.	Nov. 30	Completed using SEL Relays. (Temporarily) New REL Relays ordered, scheduled for implementation Q1 – 07. 15 SEL received on 4/12/06, testing in progress. Relays installed, refer to 1B. 10 MICOM not yet received. To be located by shippers/suppliers. Remote monitoring reverification completed (2/11/06) Shipment not received. Procurement being finalized for purchase of new relays from Areva and GE	L. Hopkins
1B.	System wide replacement plan	Mar. 07	Relays replaced with SEL 321 at Roaring River (1), Ocho Rios (1), Duncans (1), Annotto Bay (3), Cane River (1), Kendal (1), Old Harbour (4). Retrofit of SEL321 primary relays at Tredegar (138 kV lines) scheduled for May 07. Procurement being finalized for purchase of new relays from Areva and GE	

Appendix B

PROTECTIVE RELAY VERIFICATION AND CALIBRATION RESULTS



JOB#	BREAKER FAIL TEST CARD	DATE : July 16, 2007
	OLD HARBOUR	

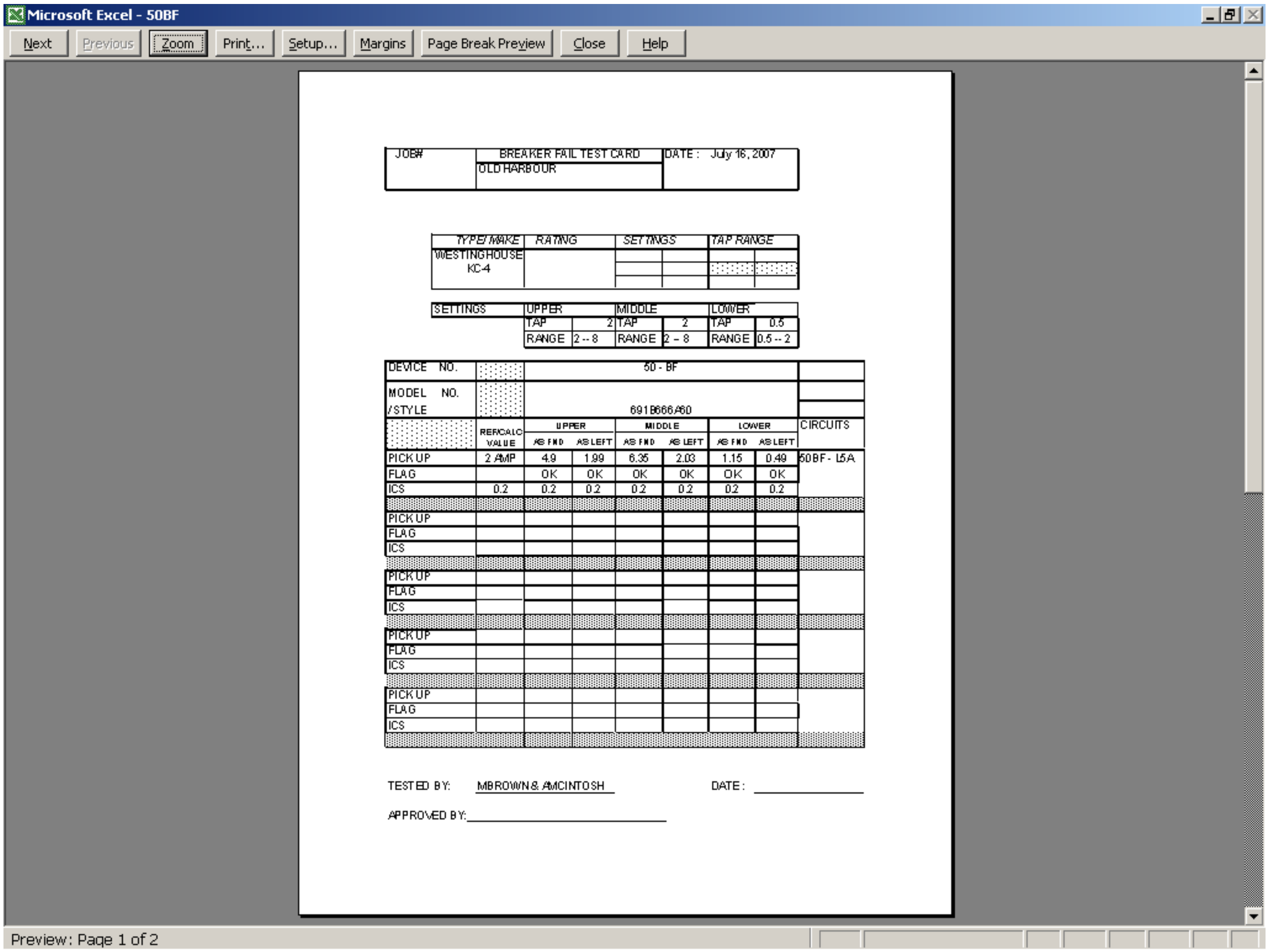
TYPE/ MAKE	RATING	SETTINGS	TAP RANGE
WESTINGHOUSE KC-4			

SETTINGS	UPPER		MIDDLE		LOWER	
	TAP	3	TAP	3	TAP	1.0
	RANGE	2 -- 8	RANGE	2 – 8	RANGE	0.5 -- 2

DEVICE NO.		50 - BF						
MODEL NO. /STYLE		691B666A60						
	REF/CALC VALUE	UPPER		MIDDLE		LOWER		CIRCUITS
		AS FND	AS LEFT	AS FND	AS LEFT	AS FND	AS LEFT	
PICK UP	3 AMP	5.5	3.1	6.8	3	2.2	1.02	50BF - L5
FLAG		OK	OK	OK	OK	OK	OK	
ICS	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
PICK UP	3 AMP	4.9	3	6.6	3.98	2.1	1.55	50BF - G2
FLAG	OK	OK	OK	OK	OK	OK	OK	
ICS	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
PICK UP								
FLAG								
ICS								
PICK UP								
FLAG								
ICS								
PICK UP								
FLAG								
ICS								

TESTED BY: MBROWN & AMCINTOSH DATE : ______________

APPROVED BY: ______________________



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JOB#	BREAKER FAIL TEST CARD	DATE : July 16, 2007
	OLD HARBOUR	

TYPE/ MAKE	RATING	SETTINGS		TAP RANGE	
WESTINGHOUSE KC-4					

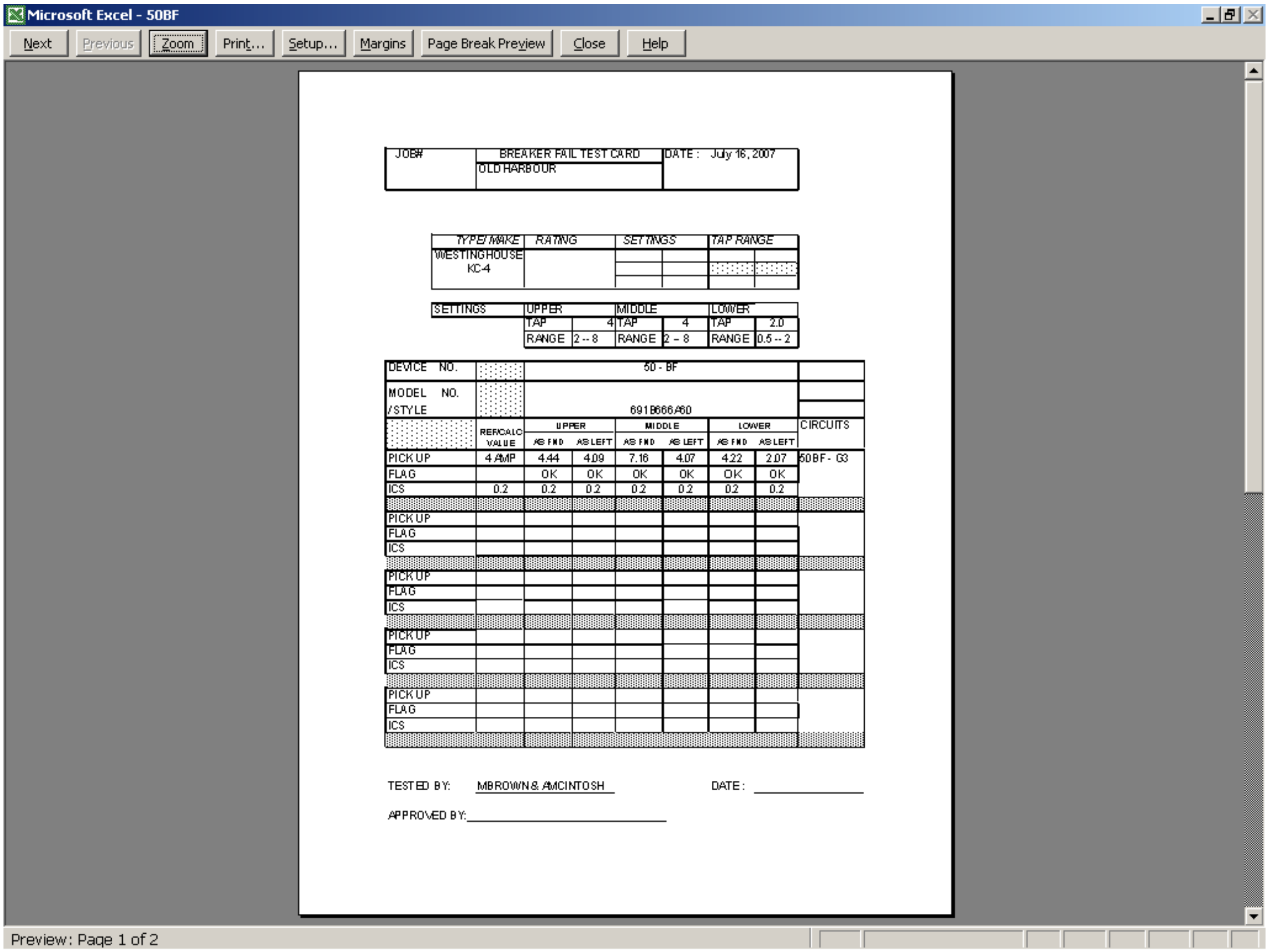
SETTINGS	UPPER		MIDDLE		LOWER	
	TAP	2	TAP	2	TAP	0.5
	RANGE	2 -- 8	RANGE	2 – 8	RANGE	0.5 -- 2

DEVICE NO.		50 - BF						
MODEL NO. /STYLE		691B666A60						
	REF/CALC VALUE	UPPER		MIDDLE		LOWER		CIRCUITS
		AS FND	AS LEFT	AS FND	AS LEFT	AS FND	AS LEFT	
PICK UP	2 AMP	4.9	1.99	6.35	2.03	1.15	0.49	50BF - L5A
FLAG		OK	OK	OK	OK	OK	OK	
ICS	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
PICK UP								
FLAG								
ICS								
PICK UP								
FLAG								
ICS								
PICK UP								
FLAG								
ICS								
PICK UP								
FLAG								
ICS								

TESTED BY: MBROWN & AMCINTOSH DATE : ______________

APPROVED BY: ______________________

Preview: Page 1 of 2



JOB#	BREAKER FAIL TEST CARD	DATE : July 16, 2007
	OLD HARBOUR	

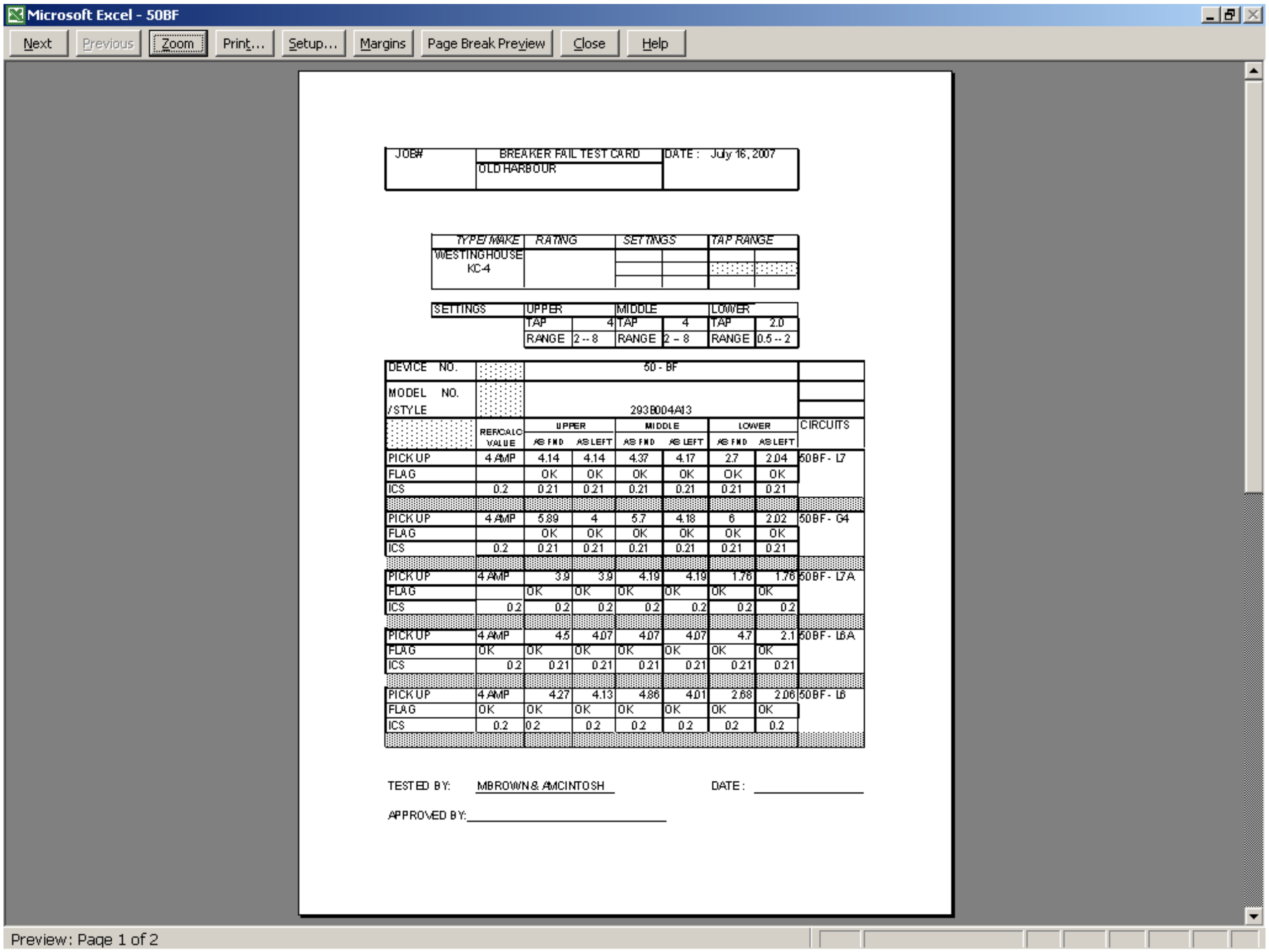
TYPE/ MAKE	RATING	SETTINGS	TAP RANGE
WESTINGHOUSE KC-4			

SETTINGS	UPPER		MIDDLE		LOWER	
	TAP	4	TAP	4	TAP	2.0
	RANGE	2 -- 8	RANGE	2 – 8	RANGE	0.5 -- 2

DEVICE NO.		50 - BF						
MODEL NO. /STYLE		691B666A60						
	REF/CALC VALUE	UPPER		MIDDLE		LOWER		CIRCUITS
		AS FND	AS LEFT	AS FND	AS LEFT	AS FND	AS LEFT	
PICK UP	4 AMP	4.44	4.09	7.16	4.07	4.22	2.07	50BF - G3
FLAG		OK	OK	OK	OK	OK	OK	
ICS	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
PICK UP								
FLAG								
ICS								
PICK UP								
FLAG								
ICS								
PICK UP								
FLAG								
ICS								
PICK UP								
FLAG								
ICS								

TESTED BY: MBROWN & AMCINTOSH DATE : ______________

APPROVED BY:__________________________



JOB#	BREAKER FAIL TEST CARD	DATE : July 16, 2007
	OLD HARBOUR	

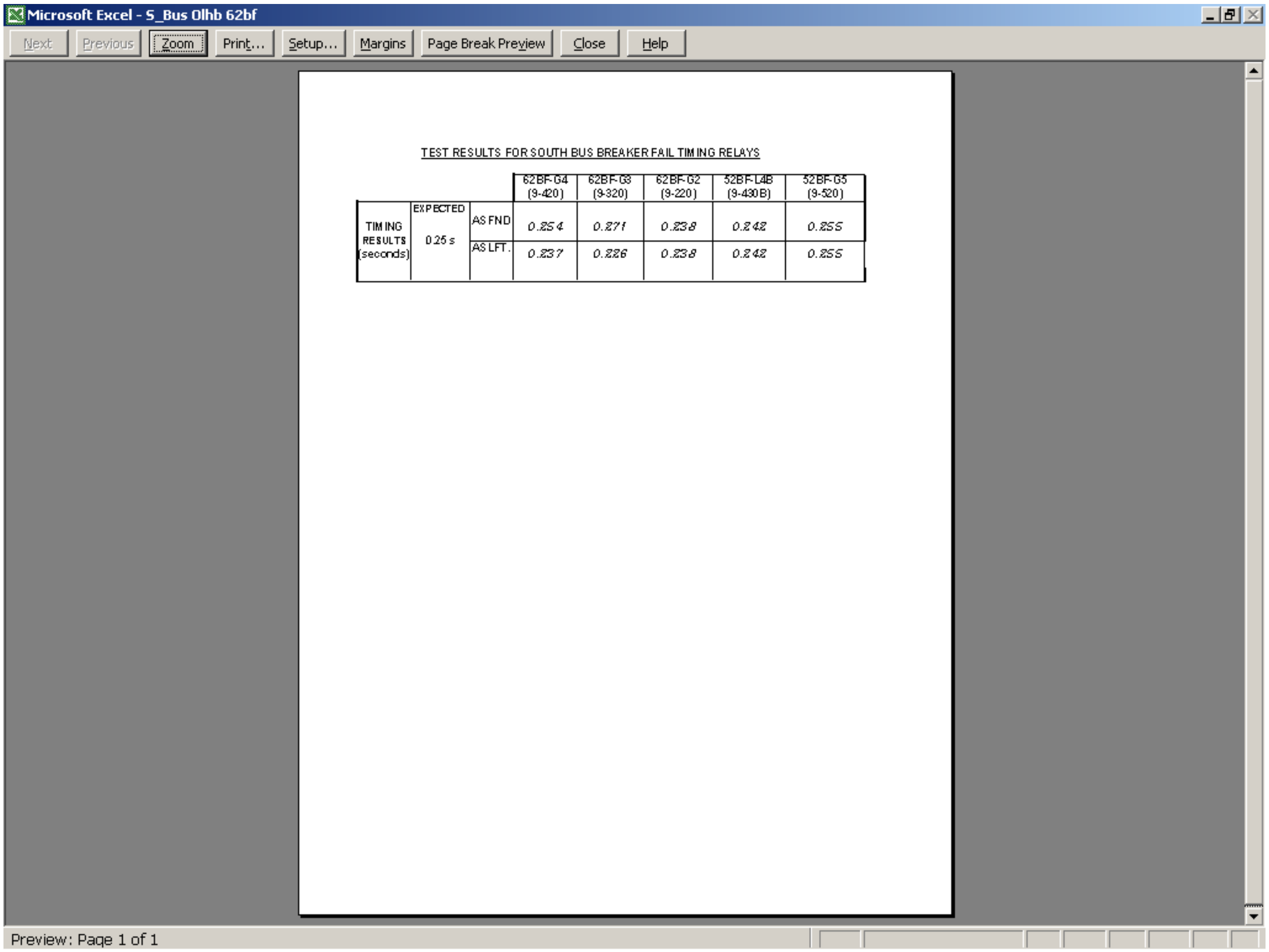
TYPE/ MAKE	RATING	SETTINGS		TAP RANGE	
WESTINGHOUSE KC-4					

SETTINGS	UPPER		MIDDLE		LOWER	
	TAP	4	TAP	4	TAP	2.0
	RANGE	2 -- 8	RANGE	2 – 8	RANGE	0.5 -- 2

DEVICE NO.		50 - BF						
MODEL NO. /STYLE		293B004A13						
	REF/CALC VALUE	UPPER		MIDDLE		LOWER		CIRCUITS
		AS FND	AS LEFT	AS FND	AS LEFT	AS FND	AS LEFT	
PICK UP	4 AMP	4.14	4.14	4.37	4.17	2.7	2.04	50BF - L7
FLAG		OK	OK	OK	OK	OK	OK	
ICS	0.2	0.21	0.21	0.21	0.21	0.21	0.21	
PICK UP	4 AMP	5.89	4	5.7	4.18	6	2.02	50BF - G4
FLAG		OK	OK	OK	OK	OK	OK	
ICS	0.2	0.21	0.21	0.21	0.21	0.21	0.21	
PICK UP	4 AMP	3.9	3.9	4.19	4.19	1.76	1.76	50BF - L7A
FLAG		OK	OK	OK	OK	OK	OK	
ICS	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
PICK UP	4 AMP	4.5	4.07	4.07	4.07	4.7	2.1	50BF - L6A
FLAG	OK	OK	OK	OK	OK	OK	OK	
ICS	0.2	0.21	0.21	0.21	0.21	0.21	0.21	
PICK UP	4 AMP	4.27	4.13	4.86	4.01	2.68	2.06	50BF - L6
FLAG	OK	OK	OK	OK	OK	OK	OK	
ICS	0.2	0.2	0.2	0.2	0.2	0.2	0.2	

TESTED BY: MBROWN & AMCINTOSH DATE : ____________

APPROVED BY: ______________________



TEST RESULTS FOR SOUTH BUS BREAKER FAIL TIMING RELAYS

			62BF-G4 (9-420)	62BF-G3 (9-320)	62BF-G2 (9-220)	52BF-L4B (9-430B)	52BF-G5 (9-520)
TIMING RESULTS (seconds)	EXPECTED 0.25 s	AS FND	0.254	0.271	0.238	0.242	0.255
		AS LFT.	0.237	0.226	0.238	0.242	0.255

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JAMAICA PUBLIC SERVICE Co. LTD

RELAY CIRCUIT VERIFICATION REPORT SHEET

SUBSTATION Old Harbour

DATE June 26, 2007

CIRCUIT NAME	PRIMARY PROTECTION						BACK-UP						OTHER			REMARKS
	V Y-B IR	V R-B IY	V R-Y IB	VN IN	DC	TYPE	V Y-B IR	V R-B IY	V R-Y IB	VN IN	DC	TYPE	VAC I AC	DC	TYPE	
PARNASSUS	69.5	69.5	69.4		129.8	SEL	116	116	116		130	CDD	2	129	CDD	
L1	69	64	67			21P-L1	0.5	0.5	0.5			67	0.02		67N	
TREDEGAR	69.4	69.6	69.3		124	SEL	116	116	116		130	CDD	0	129	CDD	
	330	324	325			21P-L2	2.8	2.8	2.7			67	0.02		67N	
T2 W1	0.1	0.1	0.1		129						129	GE				
Station Service W2	0.1	0.1	0.1			87	0.00	0.00	0.00			50/51				
NORTH BUS					130	PVD										
DIFFERENTIAL	0.00	0.00	0.00			87										
SOUTH BUS					130	PVD										
DIFFERENTIAL	0.00	0.00	0.00			87										
INTER BUS W1	77	74	74		130	SEL					128	PB02	0.01	129	50/51-1BLV	
XFMR W2	149	151	146			87	1.9	1.9	1.9			50/51	0.09	129	50/51-1BHV	
DUHANEY	136.10	135.80	136.00		129	SEL	62	51	75		130	NPO2	0	129		
L4	375.000	378.000	375.000			21P-L4	1.5	1.5	1.5			67	0.1		67N	
DUHANEY							78.72	77.76	78.72		129	ABB				
L4							0.36	0.36	0.36			21B - L4				

TESTER L.BARNES / M BROWN

CHECKED BY: ____________

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JAMAICA PUBLIC SERVICE Co. LTD

RELAY CIRCUIT VERIFICATION REPORT SHEET

SUBSTATION Old Harbour DATE JUNE 26,2007

CIRCUIT NAME	PRIMARY PROTECTION						BACK-UP						OTHER			REMARKS
	V Y-B IR	V R-B IY	V R-Y IB	VN IN	DC	TYPE	V Y-B IR	V R-B IY	V R-Y IB	VN IN	DC	TYPE	V AC I AC	DC	TYPE	
TREDEGAR	136.60	135.30	135.40		129	SEL	78.24	77.76	77.76		129	ABB				
138KV-L5	359	356	355			21P-L5	0.36	0.36	0.36			21B-L5				
PARNASSUS	78.72	78.72	78.72		129.6	ABB	114	114	114		129.5	WEST	0.1	129	WEST	
L6	0.096	0.096	0.096			21B-L6	0.9	0.9	0.8			67	0.1		67N	
PARNASSUS	78.72	78.72	78.72		129	ABB	114	114	114		129	WEST	1	129		
L7	0.096	0.108	0.096			21B-L7	0.8	0.8	0.8			67	0.1		67N	
UNIT # 4	3.2	3.2	3.2		129	CO-8										
INTER TRIP						50/51										
GENERATOR #3	443	443	446		129.6	SEL311					129	KCGG				
LINE	221	221	220			87	435	432	436	6.8		50/51N				
PARNASSUS	137	136.4	136.9		129	SEL										
L6	104	105	102			21P-L6										
PARNASSUS	136.6	136.2	136.6		129	SEL										
L7	101	103	102			21P-L7										
TREDEGAR							75	73	76		129	NP02	0	129		
138KV - L5							1.5	1.5	1.5			67	0		67N	

TESTER L.BARNES / M.BROWN CHECKED BY: ______________

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RELAY TEST CARD

PROTECTION & CONTROL DEPARTMENT

Mod. No. DT12AF231A OLD HARBOUR Sta. On Kv Cir.Name UNIT AUX. XFMR

Make: ENGLISH ELEC. Type DDT Style P.T. Ratio C.T. Ratio

Tap Range (Ph)FIXED

Relay Rating 5 Amps 125 Volts Relay Location:

RELAY SETTING			SECONDARY INJECTION TEST										
						AS FOUND			AS LEFT			AUXILIARY	
ELEMENT	AS FOUND	AS LEFT			CALC.	R	Y	B	R	Y	B		
PLUG	50%	50%										T - Flag	OK
			PICK UP TST		2.5A	1.80	2.3	2.00	1.83	2.3	2.10	Inst.FLAG	N/A
TD	1.5	1.5	ICS		30V DC	33.2	36.8	29.3	33.2	36.8	29.3	DISC	OK
K2	20%	20%	SLOPE TEST	I_1		10	10	10	10	10	10	SPRING	OK
K3	20%	20%		I_2		12.50	12.60	12.85	12.45	12.50	12.65	MAG	OK
				%SLOPE	20%	22%	23%	25%	21.8%	22%	23%		

Tested by: Mbrown & Okelly Date: July 6, 2006 Approved: Date:

jps_2004

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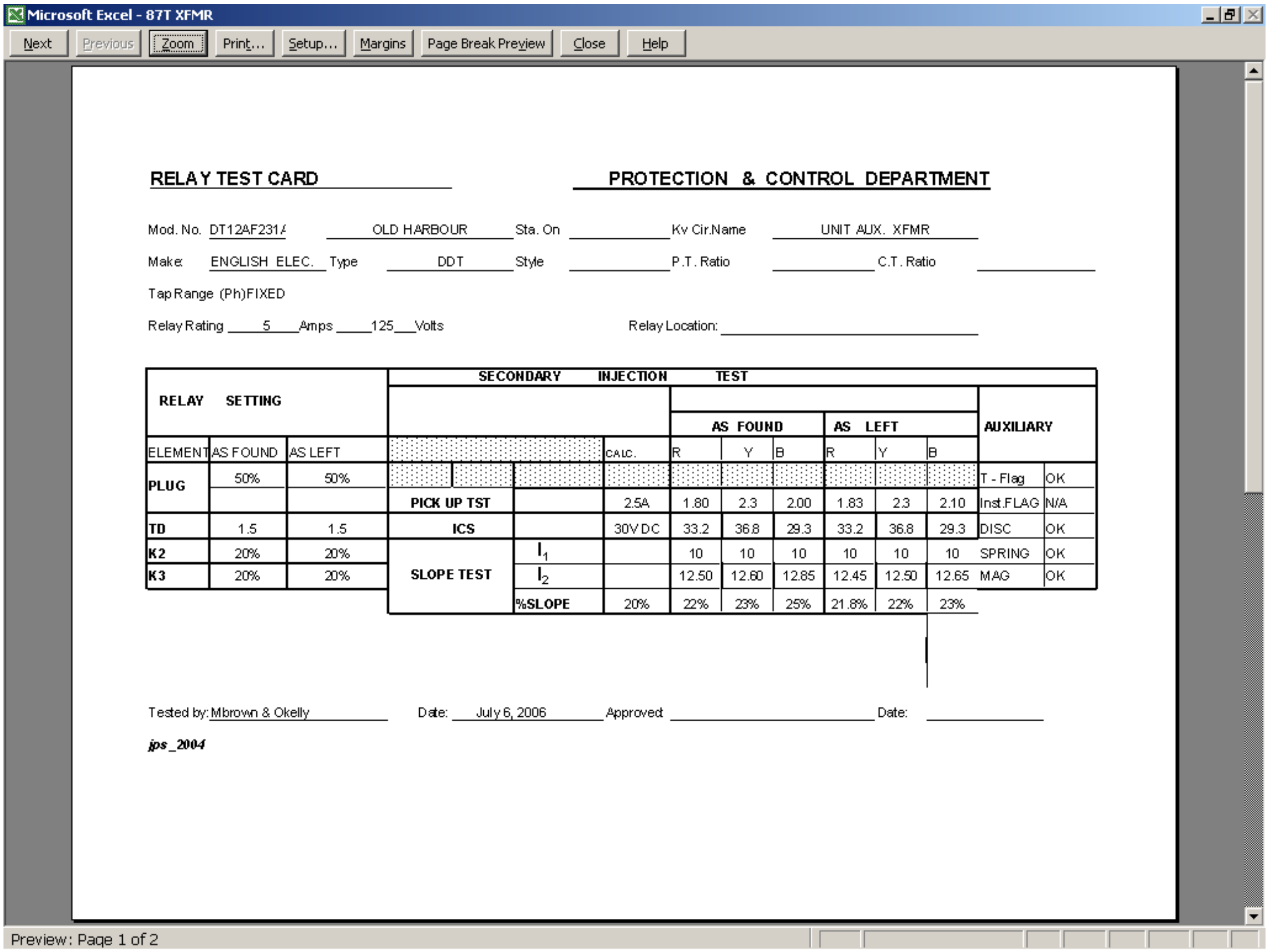


RELAY TEST CARD — **PROTECTION & CONTROL DEPARTMENT**

Mod. No. DT12AF231A — OLD HARBOUR Sta. On ______ Kv Cir.Name UNIT AUX. XFMR

Make: ENGLISH ELEC. Type DDT Style ______ P.T. Ratio ______ C.T. Ratio ______

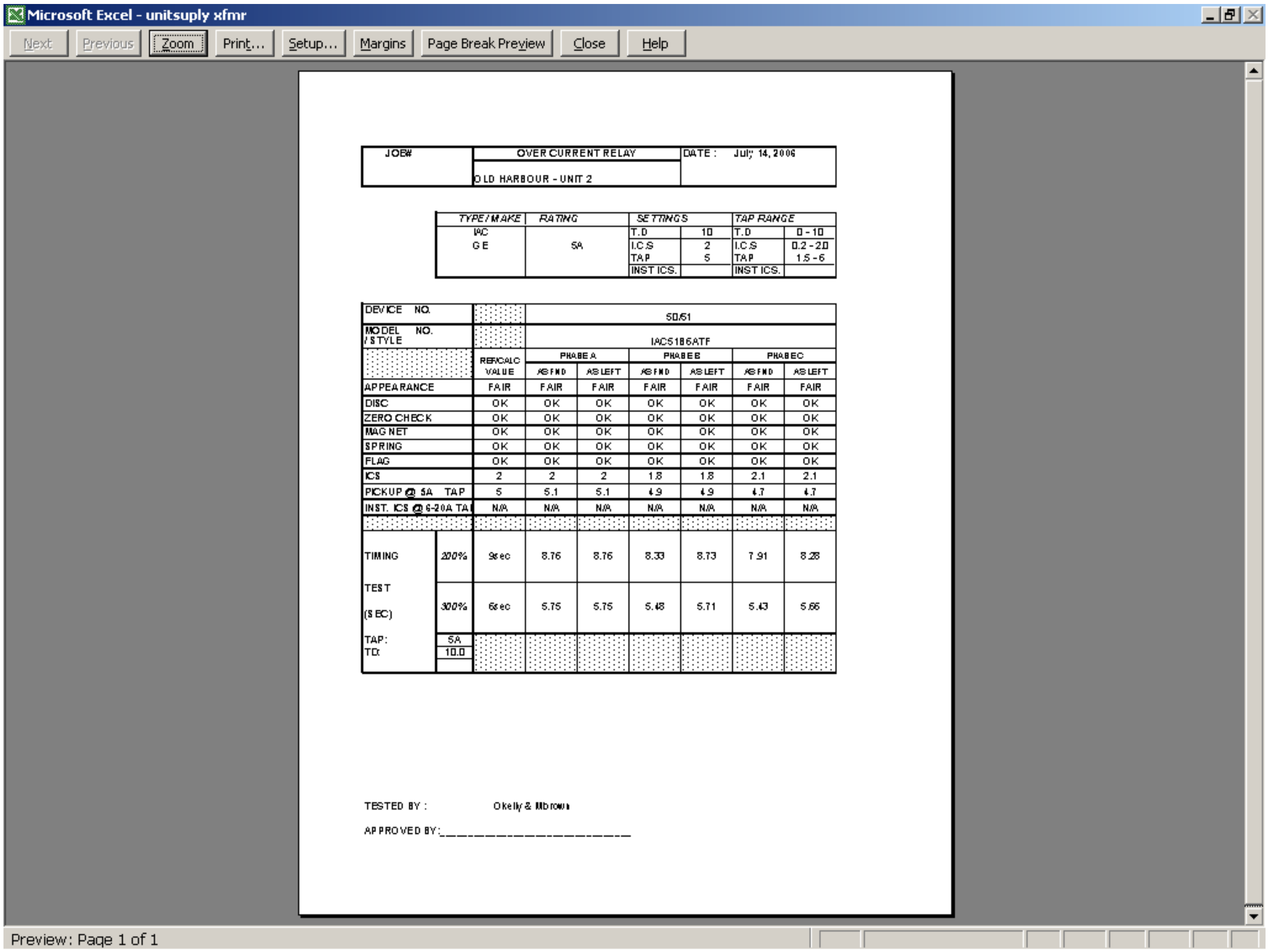
Tap Range (Ph)FIXED

Relay Rating 5 Amps 125 Volts — Relay Location: ______

RELAY SETTING			SECONDARY INJECTION TEST									AUXILIARY	
						AS FOUND			AS LEFT				
ELEMENT	AS FOUND	AS LEFT			CALC.	R	Y	B	R	Y	B		
PLUG	50%	50%										T - Flag	OK
			PICK UP TST		2.5A	1.80	2.3	2.00	1.83	2.3	2.10	Inst.FLAG	N/A
TD	1.5	1.5	ICS		30V DC	33.2	36.8	29.3	33.2	36.8	29.3	DISC	OK
K2	20%	20%	SLOPE TEST	I_1		10	10	10	10	10	10	SPRING	OK
K3	20%	20%		I_2		12.50	12.60	12.85	12.45	12.50	12.65	MAG	OK
				%SLOPE	20%	22%	23%	25%	21.8%	22%	23%		

Tested by: Mbrown & Okelly — Date: July 6, 2006 — Approved: ______ Date: ______

jps_2004



JOB#	OVER CURRENT RELAY	DATE : July 14, 2006
	OLD HARBOUR - UNIT 2	

TYPE / MAKE	RATING	SETTINGS		TAP RANGE	
IAC		T.D	10	T.D	0 - 10
G E	5A	I.C.S	2	I.C.S	0.2 - 2.0
		TAP	5	TAP	1.5 - 6
		INST ICS.		INST ICS.	

DEVICE NO.			50/51					
MODEL NO. / STYLE			IACS186ATF					
		REF/CALC VALUE	PHASE A		PHASE B		PHASE C	
			AS FND	AS LEFT	AS FND	AS LEFT	AS FND	AS LEFT
APPEARANCE		FAIR	FAIR	FAIR	FAIR	FAIR	FAIR	FAIR
DISC		OK	OK	OK	OK	OK	OK	OK
ZERO CHECK		OK	OK	OK	OK	OK	OK	OK
MAGNET		OK	OK	OK	OK	OK	OK	OK
SPRING		OK	OK	OK	OK	OK	OK	OK
FLAG		OK	OK	OK	OK	OK	OK	OK
ICS		2	2	2	1.8	1.8	2.1	2.1
PICKUP @ 5A TAP		5	5.1	5.1	4.9	4.9	4.7	4.7
INST. ICS @ 6-20A TA		N/A	N/A	N/A	N/A	N/A	N/A	N/A
TIMING TEST (SEC)	200%	9sec	8.76	8.76	8.33	8.73	7.91	8.28
	300%	6sec	5.75	5.75	5.48	5.71	5.43	5.66
TAP:	5A							
TD:	10.0							

TESTED BY : Okelly & Mbrown

APPROVED BY:__________________________

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RELAY TEST CARD

PROTECTION & CONTROL DEPARTMENT

Mod. No. DT12AF231A OLD HARBOUR Sta. On Kv Cir.Name UNIT AUX. XFMR

Make: ENGLISH ELEC. Type DDT Style P.T. Ratio C.T. Ratio

Tap Range (Ph)FIXED

Relay Rating 5 Amps 125 Volts Relay Location:

RELAY SETTING			SECONDARY INJECTION TEST											
						AS FOUND			AS LEFT			AUXILIARY	
ELEMENT	AS FOUND	AS LEFT			CALC.	R	Y	B	R	Y	B		
PLUG	50%	50%										T - Flag	OK
			PICK UP TST		2.5A	1.8	2.3	2.0	1.83	2.3	2.1	Inst.FLAG	N/A
TD	1.5	1.5	ICS		30V DC	33.2	36.8	29.3	33.2	36.8	29.3	DISC	OK
K2	20%	20%	SLOPE TEST	I_1		10	10	10	10	10	10	SPRING	OK
K3	20%	20%		I_2		12.50	12.60	12.85	12.45	12.50	12.65	MAG	OK
				%SLOPE	20%	22%	23%	24.2%	21.8%	22%	23.4%		

Tested by: Mbrown & Okelly Date: July 6, 2006 Approved: Date:

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Microsoft Excel - LOST OF FIELD

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RELAY TEST CARD

Mod. No. /CGF11AF1/ At ______ Old Harbour ______ Kv Cir.Name ______ GEN. LOSS OF FIELD

Make: ENGLISH ELECTRIC Type ______ YCGF ______ P.T. Ratio ______ - ______ C.T. Ratio ______ - ______

Tap Range (Ph)________ IT Range (Ph)______ - ______ Performance Cu

Relay Rating ____5____Amp

RELAY SETTING			SECONDARY INJECTION TEST				
				AS FOUND	AS LEFT	AUXILIARY	
ELEMENT	AS FOUND	AS LEFT	ANGLE 1	251	251	T - Flag	N/A
K_1	0.89	0.89	ANGLE 2	296	296	Inst.FLAG	N/A
K_2	2	2	MTA	273.5	273.5	DISC	N/A
K_3	0	0.0	OUTER LIMITS	68V	66V	SPRING	N/A
K_4	2	2	INNER LIMITS	12.5V	12.5V	MAG	N/A
K_5	36	36	PICK UP	1.7A	1.7A		

MTA =(ANG.1 + ANG 2)/2 +/- 5deg

Tested by: O KELLY & M BROWN Date: JULY 2006 Date: ______

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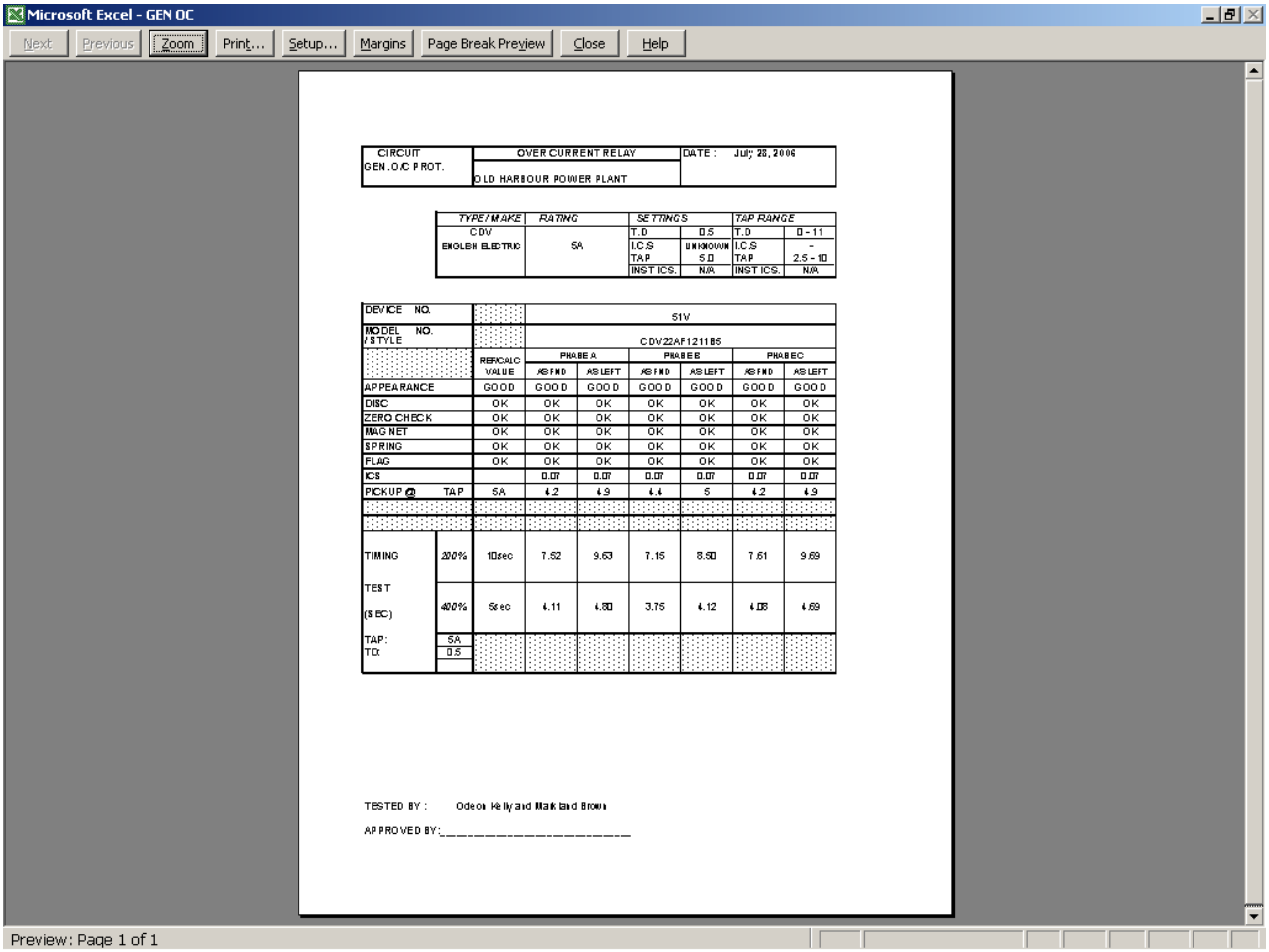

CIRCUIT GEN.O/C PROT.	OVER CURRENT RELAY OLD HARBOUR POWER PLANT	DATE : July 28, 2006

TYPE / MAKE	RATING	SETTINGS		TAP RANGE	
CDV ENGLISH ELECTRIC	5A	T.D	0.5	T.D	0 - 11
		I.C.S	UNKNOWN	I.C.S	-
		TAP	5.0	TAP	2.5 - 10
		INST ICS.	N/A	INST ICS.	N/A

DEVICE NO.			51V					
MODEL NO. / STYLE			CDV22AF121185					
		REF/CALC VALUE	PHASE A		PHASE B		PHASE C	
			AS FND	AS LEFT	AS FND	AS LEFT	AS FND	AS LEFT
APPEARANCE		GOOD	GOOD	GOOD	GOOD	GOOD	GOOD	GOOD
DISC		OK	OK	OK	OK	OK	OK	OK
ZERO CHECK		OK	OK	OK	OK	OK	OK	OK
MAGNET		OK	OK	OK	OK	OK	OK	OK
SPRING		OK	OK	OK	OK	OK	OK	OK
FLAG		OK	OK	OK	OK	OK	OK	OK
ICS			0.07	0.07	0.07	0.07	0.07	0.07
PICKUP @ TAP		5A	4.2	4.9	4.4	5	4.2	4.9
TIMING TEST (SEC)	200%	10sec	7.52	9.63	7.15	8.50	7.61	9.69
	400%	5sec	4.11	4.80	3.75	4.12	4.08	4.69
TAP:	5A							
TD:	0.5							

TESTED BY : Odeon Kelly and Markland Brown

APPROVED BY:_______________________

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CIRCUIT GEN.O/C PROT.	OVER CURRENT RELAY	DATE : July 28, 2006
	OLD HARBOUR POWER PLANT	

TYPE / MAKE	RATING	SETTINGS		TAP RANGE	
CDV ENGLISH ELECTRIC	5A	T.D	0.5	T.D	0 - 11
		I.C.S	UNKNOWN	I.C.S	-
		TAP	5.0	TAP	2.5 - 10
		INST ICS.	N/A	INST ICS.	N/A

DEVICE NO.			51V					
MODEL NO. / STYLE			CDV22AF121185					
		REF/CALC VALUE	PHASE A		PHASE B		PHASE C	
			AS FND	AS LEFT	AS FND	AS LEFT	AS FND	AS LEFT
APPEARANCE		GOOD	GOOD	GOOD	GOOD	GOOD	GOOD	GOOD
DISC		OK	OK	OK	OK	OK	OK	OK
ZERO CHECK		OK	OK	OK	OK	OK	OK	OK
MAGNET		OK	OK	OK	OK	OK	OK	OK
SPRING		OK	OK	OK	OK	OK	OK	OK
FLAG		OK	OK	OK	OK	OK	OK	OK
ICS			0.07	0.07	0.07	0.07	0.07	0.07
PICKUP @ TAP		5A	4.2	4.9	4.4	5	4.2	4.9
TIMING TEST (SEC)	*200%*	10sec	7.52	9.63	7.15	8.50	7.61	9.69
	400%	5sec	4.11	4.80	3.75	4.12	4.08	4.69
TAP: TD:	5A 0.5							

TESTED BY : Odeon Kelly and Markland Brown

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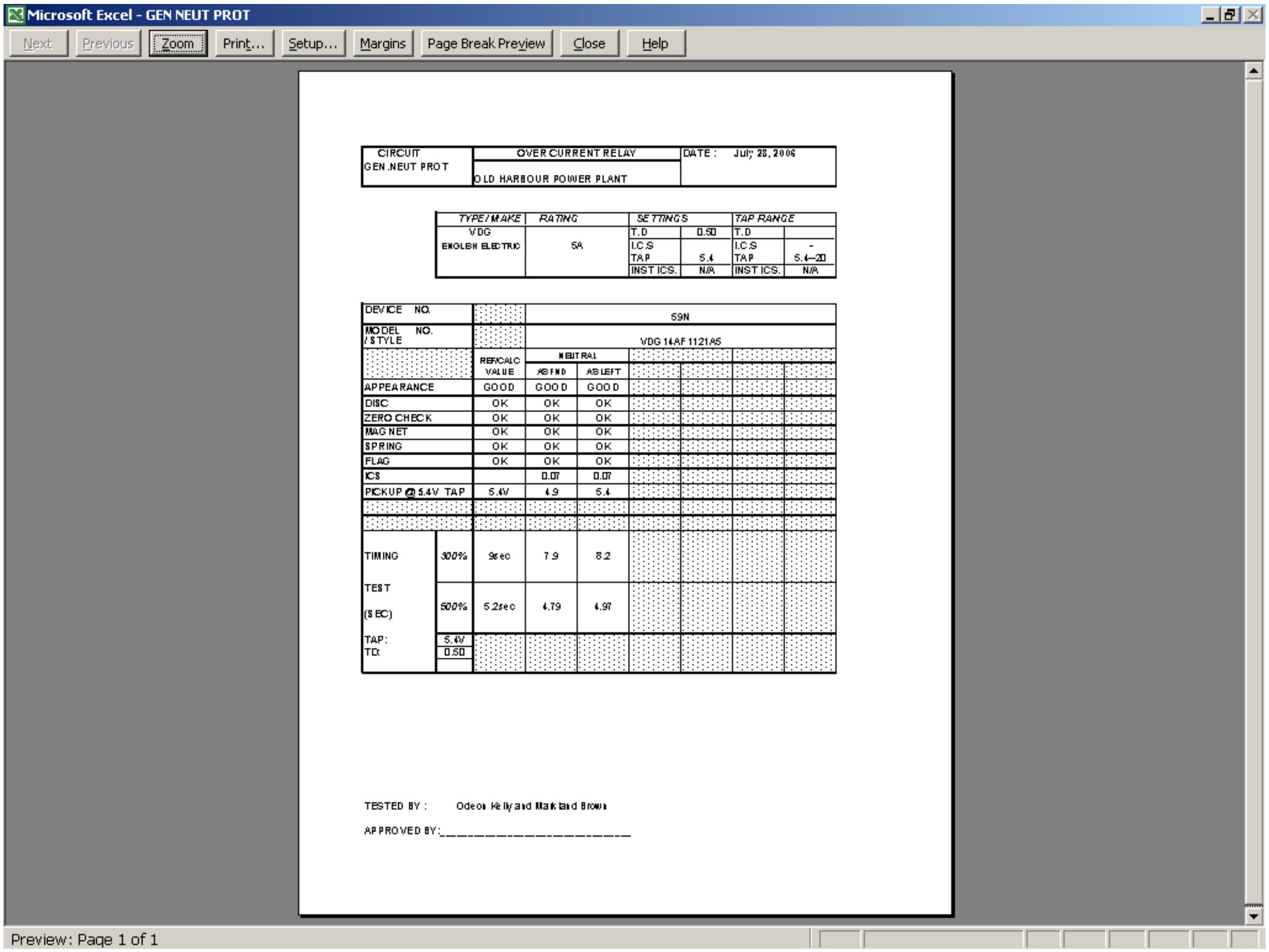

CIRCUIT GEN.NEUT PROT	OVER CURRENT RELAY OLD HARBOUR POWER PLANT	DATE : July 28, 2006

TYPE / MAKE	RATING	SETTINGS		TAP RANGE	
VDG ENGLISH ELECTRIC	5A	T.D	0.50	T.D	
		I.C.S		I.C.S	-
		TAP	5.4	TAP	5.4–20
		INST ICS.	N/A	INST ICS.	N/A

DEVICE NO.			S9N					
MODEL NO. / STYLE			VDG 14AF 1121A5					
		REF/CALC VALUE	NEUTRAL AS FND	NEUTRAL AS LEFT				
APPEARANCE		GOOD	GOOD	GOOD				
DISC		OK	OK	OK				
ZERO CHECK		OK	OK	OK				
MAGNET		OK	OK	OK				
SPRING		OK	OK	OK				
FLAG		OK	OK	OK				
ICS			0.07	0.07				
PICKUP @ 5.4V TAP		5.4V	4.9	5.4				
TIMING TEST (SEC)	*300%*	9sec	7.9	8.2				
	500%	5.2sec	4.79	4.97				
TAP: TD:	5.4V 0.50							

TESTED BY : Odeon Kelly and Markland Brown

APPROVED BY:________________________

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RELAY TEST CARD **PROTECTION & CONTROL DEPARTMENT**

Mod. No. ________ OLD HARBOUR Sta. On ________ Kv Cir.Name GENERATOR DIFF

Make: ENGLISH ELEC. Type DDG(87G) Style ________ P.T. Ratio ________ C.T. Ratio ________

Tap Range (Ph)FIXED

Relay Rating ___5___Amps ___125___Volts Relay Location: UNIT 2 CONTROL ROOM

RELAY SETTING			SECONDARY INJECTION TEST										AUXILIARY	
						AS FOUND			AS LEFT					
ELEMENT	AS FOUND	AS LEFT			CALC.	R	Y	B	R	Y	B			
PLUG	5%	5%	THROUGH CURR		OK	OK	OK	OK	OK	OK	OK	T - Flag	OK
			PICK UP TST		0.25	0.34	0.29	0.35	0.34	0.29	0.35	Inst.FLAG	N/A
TD	5	5	ICS		30V DC	29	35.4	34.3	29	35.4	34.3	DISC	OK
BIAS	10%	10%	SLOPE TEST	Ir	5A	5	5	5	5	5	5	SPRING	OK
				Iop	.5A	0.56	0.53	0.56	0.56	0.53	0.56	MAG	OK
				%SLOPE	10%	10.7%	10.1%	10.7%	10.7%	10.1%	10.7%		

Tested by: Mbrown & Okelly Date: July 6, 2006 Approved: ________ Date: ________

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Microsoft Excel - CWP2A

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CCT # CWP 2A	OVER CURRENT RELAY OLD HARBOUR - UNIT 2	DATE : July 14, 2006

TYPE/ MAKE	RATING	SETTINGS		TAP RANGE	
UC GE	5A	T.D	10	T.D	0 - 10
		I.C.S	1	I.C.S	
		TAP	1	TAP	
		INST ICS.		INST ICS.	

DEVICE NO.								
MODEL NO. / STYLE			UC51B5ATF					
		REF/CALC VALUE	PHASE A		PHASE B		PHASE C	
			AS FND	AS LEFT	AS FND	AS LEFT	AS FND	AS LEFT
APPEARANCE		GOOD	FAIR	FAIR	FAIR	FAIR	FAIR	FAIR
DISC		OK	OK	OK	OK	OK	OK	OK
ZERO CHECK		OK	OK	OK	OK	OK	OK	OK
MAGNET		OK	OK	OK	OK	OK	OK	OK
SPRING		OK	POOR	POOR	OK	OK	OK	OK
FLAG		OK	OK	OK	OK	OK	OK	OK
ICS		1	0.9	0.9	1.7	1.7	0.8	0.8
PICKUP @ 1A TAP		1	1.8	1.5	1.1	1.1	2	1.3
INST. ICS @ TAP								
TIMING TEST (SEC)								
	800%	2.50	2.97	2.56	2.61	2.50	2.61	2.54
TAP: TD:	1A 10.0							
SLOPE TEST	I_1	6.25	6.2	6.2	6.2	6.2	6.4	6.4
	I_2	5	5	5	5	5	5	5
	%	25	24	24	24	24	28	28

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Microsoft Excel - CWP 2B

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CCT # CWP 2B	OVER CURRENT RELAY OLD HARBOUR - UNIT 2	DATE : July 14,2006

TYPE/ MAKE	RATING	SETTINGS		TAP RANGE	
UC GE	5A	T.D	10	T.D	0 - 10
		I.C.S	1	I.C.S	
		TAP	1	TAP	
		INST ICS.		INST ICS.	

DEVICE NO.		51					
MODEL NO. / STYLE		UC51B5ATF					
	REF/CALC VALUE	PHASE A		PHASE B		PHASE C	
		AS FND	AS LEFT	AS FND	AS LEFT	AS FND	AS LEFT
APPEARANCE	GOOD	FAIR	FAIR	FAIR	FAIR	FAIR	FAIR
DISC	OK	OK	OK	OK	OK	OK	OK
ZERO CHECK	OK	FAIL	OK	FAIL	OK	OK	OK
MAGNET	OK	OK	OK	OK	OK	OK	OK
SPRING	OK	OK	OK	OK	OK	OK	OK
FLAG	OK	OK	OK	OK	OK	OK	OK
ICS	1	0.8	0.8	1.2	1.2	0.9	0.9
PICKUP @ 1A TAP	1	1	1	1.8	1.4	1.8	1.2
INST. ICS @ TAP							
TIMING TEST (SEC) 800%	2.50	2.55	2.53	2.47	2.53	2.62	2.55
TAP: 1A TD: 10.0							
SLOPE TEST I_1	6.25	6.4	6.4	6.53	6.53	6.66	6.66
SLOPE TEST I_2	5	5	5	5	5	5	5
SLOPE TEST %	25	28	28	30.6	30.6	33.2	33.2

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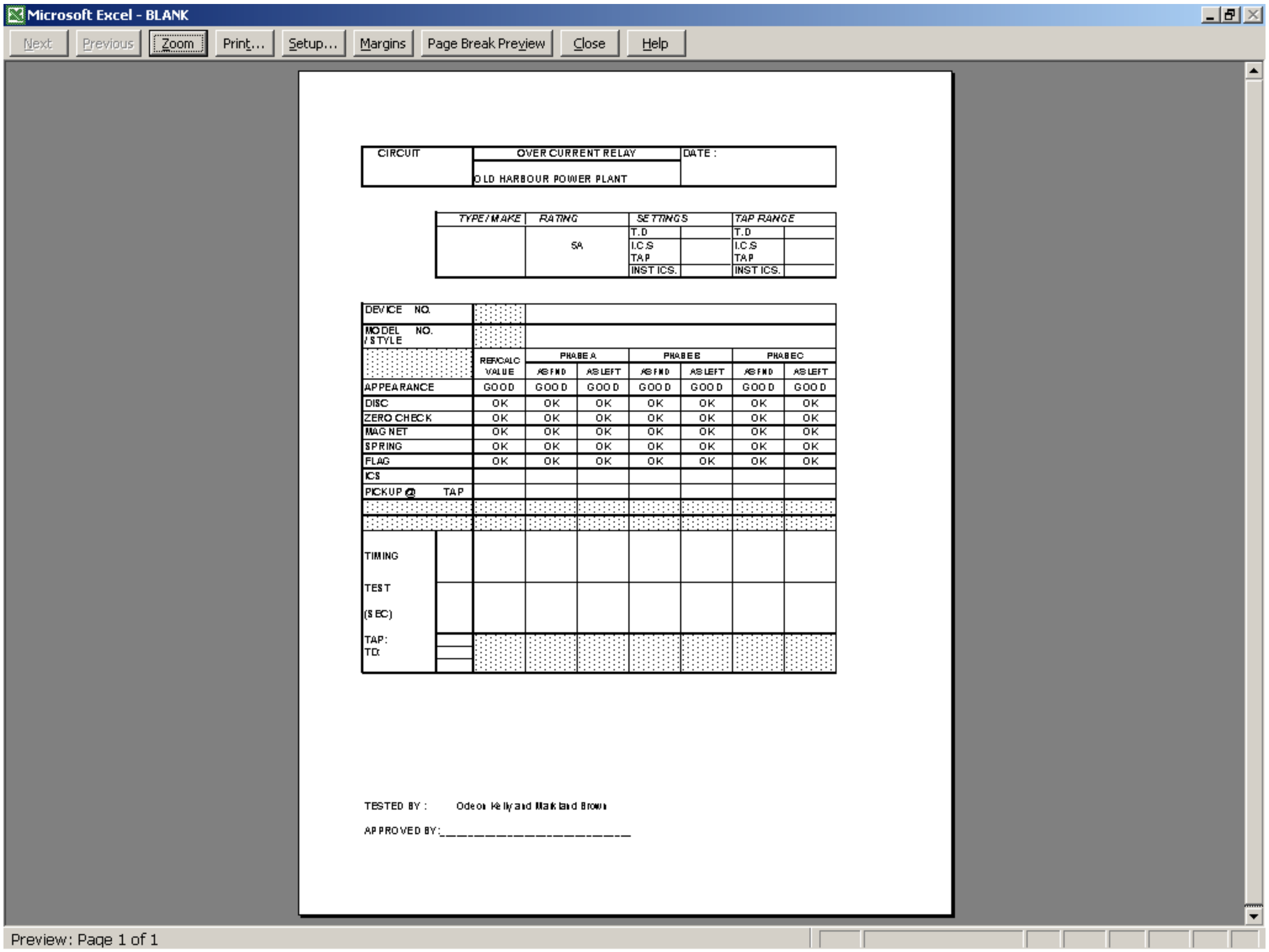


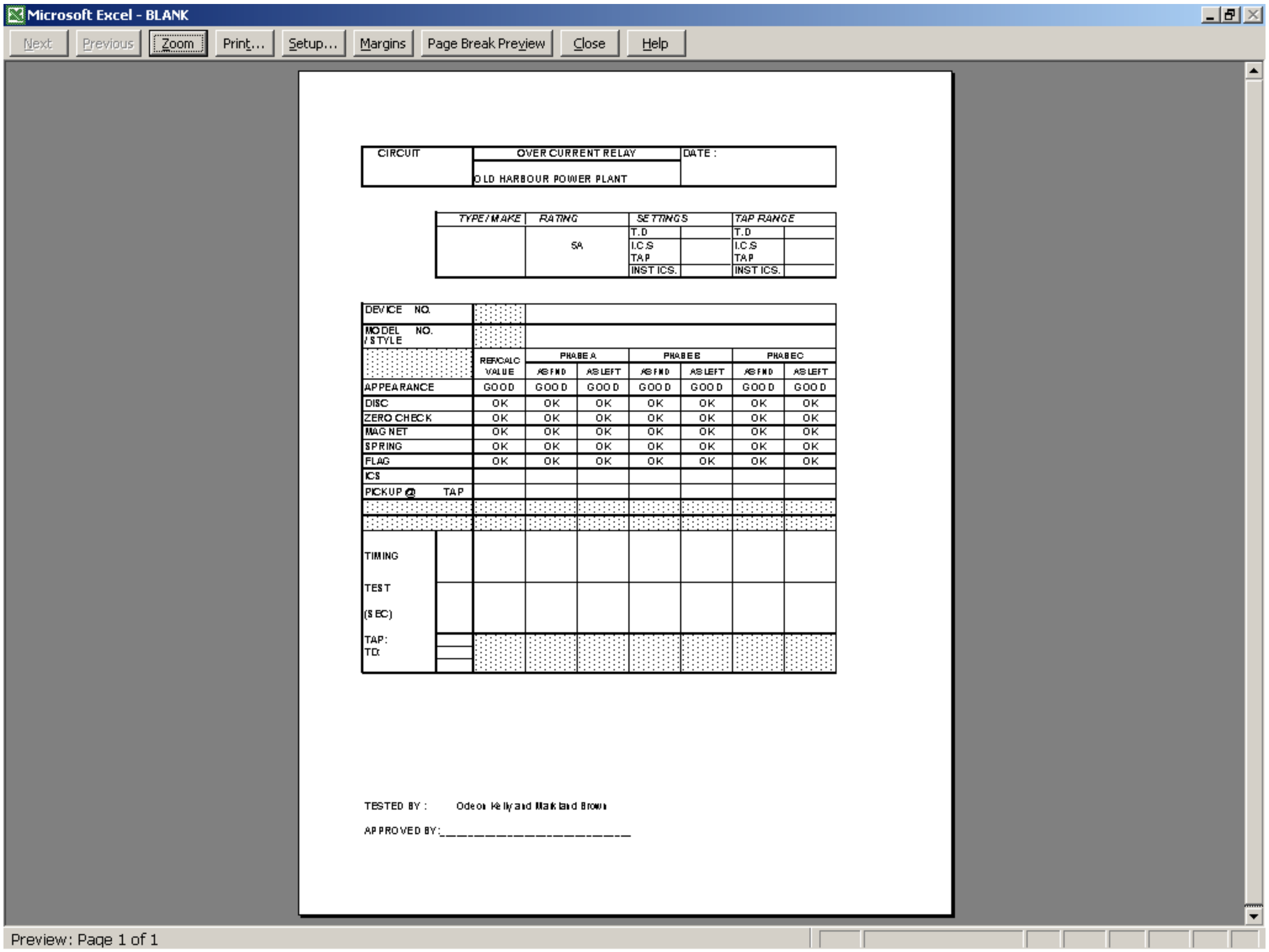
CIRCUIT	OVER CURRENT RELAY	DATE :
	OLD HARBOUR POWER PLANT	

TYPE / MAKE	RATING	SETTINGS		TAP RANGE	
	5A	T.D		T.D	
		I.C.S		I.C.S	
		TAP		TAP	
		INST ICS.		INST ICS.	

DEVICE NO.							
MODEL NO. / STYLE							
	REF/CALC VALUE	PHASE A		PHASE B		PHASE C	
		AS FND	AS LEFT	AS FND	AS LEFT	AS FND	AS LEFT
APPEARANCE	GOOD	GOOD	GOOD	GOOD	GOOD	GOOD	GOOD
DISC	OK	OK	OK	OK	OK	OK	OK
ZERO CHECK	OK	OK	OK	OK	OK	OK	OK
MAGNET	OK	OK	OK	OK	OK	OK	OK
SPRING	OK	OK	OK	OK	OK	OK	OK
FLAG	OK	OK	OK	OK	OK	OK	OK
ICS							
PICKUP @ TAP							
TIMING TEST (SEC)							
TAP: TD:							

TESTED BY : Odeon Kelly and Markland Brown

APPROVED BY:________________________



CIRCUIT	OVER CURRENT RELAY	DATE :
	OLD HARBOUR POWER PLANT	

TYPE / MAKE	RATING	SETTINGS		TAP RANGE	
	5A	T.D		T.D	
		I.C.S		I.C.S	
		TAP		TAP	
		INST ICS.		INST ICS.	

DEVICE NO.							
MODEL NO. / STYLE							
	REF/CALC VALUE	PHASE A		PHASE B		PHASE C	
		AS FND	AS LEFT	AS FND	AS LEFT	AS FND	AS LEFT
APPEARANCE	GOOD	GOOD	GOOD	GOOD	GOOD	GOOD	GOOD
DISC	OK	OK	OK	OK	OK	OK	OK
ZERO CHECK	OK	OK	OK	OK	OK	OK	OK
MAGNET	OK	OK	OK	OK	OK	OK	OK
SPRING	OK	OK	OK	OK	OK	OK	OK
FLAG	OK	OK	OK	OK	OK	OK	OK
ICS							
PICKUP @ TAP							
TIMING TEST (SEC)							
TAP: TD:							

TESTED BY : Odeon Kelly and Markland Brown

APPROVED BY:________________________

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RELAY TEST CARD **PROTECTION & CONTROL DEPARTMENT**

Mod. No. DT12AF231A OLD HARBOUR Sta. On Kv Cir.Name UNIT AUX. XFMR

Make ENGLISH ELEC. Type DDT Style P.T. Ratio C.T. Ratio

Tap Range (Ph)FIXED

Relay Rating 5 Amps 125 Volts Relay Location:

RELAY SETTING			SECONDARY INJECTION TEST									AUXILIARY	
						AS FOUND			AS LEFT				
ELEMENT	AS FOUND	AS LEFT			CALC.	R	Y	B	R	Y	B		
PLUG	50%	50%										T - Flag	OK
			PICK UP TST		2.5A	1.80	2.3	2.00	1.83	2.3	2.10	Inst.FLAG	N/A
TD	1.5	1.5	ICS		30V DC	33.2	36.8	29.3	33.2	36.8	29.3	DISC	OK
K2	20%	20%	SLOPE TEST	I_1		10	10	10	10	10	10	SPRING	OK
K3	20%	20%		I_2		12.50	12.60	12.85	12.45	12.50	12.65	MAG	OK
				%SLOPE	20%	22%	23%	25%	21.8%	22%	23%		

Tested by: Mbrown & Okelly Date: July 6, 2006 Approved: Date:

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Appendix C

Verification Check - This ensures the existence of correct source inputs to the subsystems.

Equipment	Procedure
Electromechanical and Solid State Relays	Measure and record CT and PT source input values, and verify presence of trip voltage(s).
Microprocessor Based Relays	Record CT and PT source input values, and verify presence of trip voltage(s).
Transducers	Analyze telemetered data (real and archived) for consistency.

Calibration Test -This is required to verify relay setting calibrations, configurations.

Equipment	Procedure
Electromechanical and Solid State Relays	Remove relay from service. Record as found settings. Bench test relay operation as per manufacturers procedure Restore operational settings Restore to service
Microprocessor Based Relays	N/A
Transducers	Analyze telemetered data (real and archived) for consistency.

Integrity Test **-**Integrity testing is required to verify that the intent of the subsystem is being carried out.

System	Procedure
Protection circuits with electromechanical, solid state or microprocessor based relays.	Conduct insulation, resistance and mag-curve test on source CTs and cables. Conduct remote and local trip/close check on circuit breaker(s). Conduct protection trip check on circuit breaker(s).
Transducers	Analyze telemetered data (real and archived) for consistency
RTU	Status of RTU I/O modules, wetting voltage, analog calibration monitored continuously via SCADA. Checked daily by department.
Relay/RTU communication channel	Status of communication channels monitored continuously via SCADA. Checked daily by department.

Frequency Of Periodic Checks And Tests – Protection & Control

In addition to installation testing, protection and control systems will be periodically tested as follows:

Frequency of Checks and Tests – P&C equipment

Protection & Control System	**Verification Check Frequency**	**Calibration Test Frequency**	**Integrity Test Frequency**
Transmission Protection Relays Electromechanical & Solid State	2 Months	2 Years	5 Years
Microprocessor Based	2 Months	(Note 1)	5 Years
Distribution Protection Relays Electromechanical & Solid State	2 Months	2 Years	5 Years
Microprocessor Based	2 Months	(Note 1)	5 Years
Generator Protection Relays Electromechanical & Solid State	(Note 5)	(Note 5)	(Note 5)
Microprocessor Based	(Note 5)	(Note 5)	(Note 5)
Frequency Load Shedding Relays Electromechanical & Solid State	2 Months	2 Years	5 Years
Microprocessor Based	2 Months	(Note 1)	5 Years
Remote Terminal Units (RTU) Microprocessor Based	N/A	N/A	(Note 2 & 3)
Transducers Electronic	Monthly (Note 4)	Monthly (Note 4)	Monthly (Note 4)
Analog	Monthly (Note 4)	Monthly (Note 4)	Monthly (Note 4)
Relay Communication JPS Communication Network	N/A	N/A	Daily (Note 2)
Dedicated Fibre Optic	N/A	N/A	Daily (Note 2)
RTU Communication JPS Communication Network	N/A	N/A	Daily (Note 2)

Notes:

1 - Microprocessor based relay – Periodic Calibration Testing does not apply. These relays are self-monitoring. Bi-monthly verification tests and regular retrieval and analysis of fault data verify calibration and operability.

2 – RTU/Communication – These systems are monitored continuously via SCADA.

**3 – RTU – ** Integrity is verified by regular operation.

4 – Transducers - Calibration verified by consistency checks of data.

5 – Statutory – Scheduled by Generation Division.

Frequency Of Periodic Checks And Tests – Substation

In addition to installation testing, substation equipment will be periodically tested as follows:

Frequency of checks and tests – Substation Equipment

Substation Equipment	**Verification Check Frequency**
Substation Inspection	3 Months
Battery servicing	6 weeks
Switch servicing	1 year
Transformer servicing to include electrical tests, cleaning & inspection of bushings	1 year
Circuit breaker servicing	3 years
Infrared scan	2 Months

Property	Asset	Description	JobID	Status
Old Harbour Substation				
	SW_89/8-122			
		Top right phase of the switch has a class C hot joint	2006-Nov-Z1-1028	COMPLETE
		Service 69 kV isolator	2006-Oct-Z2-948	COMPLETE
		Service 69 kV isolator	2006-Oct-Z2-949	COMPLETE
		Service 69 kV isolator	2006-Oct-Z2-950	COMPLETE
	CB_089/8-140			
		breaker need chip and paint		NEW
		Back of breaker panle need to be patched		NEW
		breaker needs chip and paint	2007-Apr-Z3-1583	COMPLETE
	CB_089/8-230			
		rusty nuts snd bolts, breaker needs painting, due service		NEW
		Service/test OCB	2006-Jun-Z2-711	COMPLETE
		Test/service circuit breaker	2006-Sep-Z2-885	COMPLETE
		rusty nuts and bolts, breaker needs painting	2007-Apr-Z3-1583	COMPLETE
	CB_089/8-240			
		needs lock, panel have holes, breaker needs chipping and panting.		NEW
		Service/test OCB	2006-Jun-Z2-658	COMPLETE
		Service OCB	2006-Jun-Z2-666	COMPLETE
		Service/test oil circuit breaker	2006-May-Z2-643	COMPLETE
		Assist with the replacement of #1 station service transformer	2007-Apr-PRJ-1628	COMPLETE
		Assist with the replacement of #1 station service transformer	2007-Apr-PRJ-1667	COMPLETE

Property	Asset	Description	JobID	Status
		Apply flash band on top of OCB cabinet	2007-Apr-Z2-1677	COMPLETE
		Repair breaker cabinets, 089/9-420 and 089/9-420A	2007-Apr-Z3-1572	COMPLETE
		need lck,panel have holesbreaker need chipping and painting	2007-Apr-Z3-1583	COMPLETE
		Assist with the replacement of #1 station service transformer	2007-May-PRJ-1708	COMPLETE
	CB_089/8-330			
		breaker needs chip and paint		NEW
		breakers need chip and paint	2007-Apr-Z3-1583	COMPLETE
	CB_089/9-220			
		Facing 089/9-220, R phase switch bottom and close to 089/9-220.		NEW
		breakers need chip and paint		NEW
		grounding of circuit breaker 089/9-220		Approved
		Facing 089/9-220, R phase switch bottom end close to 089/9-220.		NEW
		breaker needs chip and paint		NEW
		Service circuit breaker 089/9-220	2006-Apr-Z2-558	COMPLETE
		Service circuit breaker 089/9-220	2006-Apr-Z2-560	COMPLETE
		Replace circuit breaker	2007-Jul-PRJ-1978	COMPLETE
		Electrical tests on breaker	2007-Jul-PRJ-1986	COMPLETE

Property	Asset	Description	JobID	Status
		Change breaker OCB 089/9-220	2007-Jul-Z2-1964	Assigned
		Remove OCB 89/9-220 breaker from Old Harbour switchyard to Boulevard Stores.	2007-Jul-Z2-1965	Assigned
		Perform electrical test on Siemens SF6 breaker to replace OCB 89/9-220 at Old Harbour switch yard.	2007-Jul-Z2-1966	COMPLETE
		Perform electrical test on Siemens SF6 breaker to replace OCB 89/9-220 at Old Harbour switch yard.	2007-Jul-Z2-1967	COMPLETE
		Electrical tests on breaker	2007-Jul-Z2-1968	COMPLETE
		Electrical test on breaker 089/9-220.	2007-Jul-Z2-1985	Assigned
		Assist contractor with RTV Spraying of SF6 breaker 89/9-220.	2007-Jul-Z2-1999	Assigned
	CB_089/9-220A			
		breaker needs chip and paint		NEW
		Service/test OCB	2006-Jul-Z2-724	COMPLETE
		Service/test OCB	2006-Jul-Z2-725	COMPLETE
		Service/test OCB	2006-Jul-Z2-726	COMPLETE
		Service/test OCB	2006-Jul-Z2-727	COMPLETE
		breaker need chip and paint	2007-Apr-Z3-1583	COMPLETE
		breaker needs chip and paint	2007-Apr-Z3-1583	COMPLETE
		Correct pipe leak on breaker.	2007-May-Z3-1789	COMPLETE
	CB_089/9-320			
		breaker needs chip and paint,due service		NEW
		Service circuit breaker	2006-Feb-Z2-390	COMPLETE

Property	Asset	Description	JobID	Status
		Conduct electrical test on circuit breakers	2006-May-Z3-637	Assigned
		breakers need chip and paint,	2007-Apr-Z3-1583	COMPLETE
		Battery charger needed for Old Harbour	2007-Apr-Z3-1583	COMPLETE
	CB_089/9-320A			
		breaker needs chip and paint	2007-Apr-Z3-1583	COMPLETE
		breaker need chip and paint	2007-Jun-Z2-1856	COMPLETE
	CB_089/9-420			
		breaker need chip and paint,		NEW
		Key broken for interlock switch		NEW
		Replace compressor pulley bearing for 089/9-420	2006-May-Z2-610	COMPLETE
		Replace compressor pulley bearing for 089/9-420	2006-May-Z2-613	COMPLETE
		breaker needs chip and paint	2007-Apr-Z3-1583	COMPLETE
	CB_089/9-420A			
		breaker needs chip and paint,panel has holes.due service		NEW
		breaker need chip and paint, panel has holes	2007-Apr-Z3-1583	COMPLETE
		Troubleshoot closing problem with breaker 089/9-420A	2007-Mar-Z3-1535	COMPLETE
		Replace defective switch in breaker cabinet	2007-May-Z2-1715	COMPLETE

Property	Asset	Description	JobID	Status
	CB_089/9-430A			
		breaker needs chip and paint, valves sweating,oil indicator on the middle phase craked		NEW
		Service/test OCB	2006-Jun-Z2-683	COMPLETE
		Service/test OCB	2006-Jun-Z2-686	COMPLETE
		Service/test OCB	2006-Jun-Z2-687	COMPLETE
		Service/test OCB	2006-Jun-Z2-688	COMPLETE
		Service/test OCB	2006-Jun-Z2-689	COMPLETE
		Service/test OCB	2006-Jun-Z2-693	COMPLETE
		Service/test OCB	2006-Jun-Z2-708	COMPLETE
		breaker need chip and paint	2007-Apr-Z3-1583	COMPLETE
		Replace oil indicator glass on OCB 089/9-430A	2007-Mar-Z2-1470	Assigned
	CB_089/9-520			
		Clean circuit breaker bushings	2007-Jul-Z2-1969	Assigned
	CB_089/9-530			
		breaker needs chip and paint,AC in cntrl panel		NEW
		breaker need chip and paint, no AC in cntrl panel	2007-Apr-Z3-1584	COMPLETE
	CB_089/9-630			
		breaker need chip and painting		NEW
		Trouble fault with circuit breaker	2006-Jul-Z2-773	COMPLETE
		Trouble fault with circuit breaker	2006-Jul-Z2-775	COMPLETE
		Trouble fault with circuit breaker	2006-Jul-Z3-771	COMPLETE
		Trouble fault with circuit breaker	2006-Jul-Z3-772	COMPLETE

Property	Asset	Description	JobID	Status
		breaker needs chip and painting	2007-Apr-Z3-1584	COMPLETE
		Perform timing Test on Breakers, 089/9-630	2007-Jul-Z2-2010	Assigned
	CB_089/9-730			
		breaker needs chip and paint		NEW
		Due service		NEW
		Service/test OCB	2006-Nov-Z2-1014	COMPLETE
		Service/test OCB	2006-Oct-Z2-1004	COMPLETE
		Service/test OCB	2006-Oct-Z2-1005	COMPLETE
		Battery maintenance	2006-Sep-Z2-901	COMPLETE
		breaker needs chip and paintin	2007-Apr-Z3-1584	COMPLETE
		Service & test OCB 089/9-730 at Old Harbour	2007-Feb-Z1-1322	COMPLETE
	CB_089/9-830			
		breaker need chip and paint, counter defective		NEW
		breaker needs chip and paint,counter detective	2007-Apr-Z3-1584	COMPLETE
		Timing test on breaker 089/9-830 & 089/9-630.	2007-Jul-Z2-1994	Assigned
	CB_089/9-930			
		Middle phase bushing clamp, facing breaker has a class C hot joint.		NEW
		panel need a lock	2007-Apr-Z3-1584	COMPLETE
		panel need a lock	2007-Apr-Z3-1584	COMPLETE
		Wash circuit breaker	2007-Jul-Z2-1972	Assigned

Property	Asset	Description	JobID	Status
	SW_089/8-239			
		R-phase, switch top, facing 089/8-239 has a class C hot joint		NEW
	SW_89/8-132			
		M-phase, switch top, facing 089/8-132 has a class C hot joint		NEW
		Service switches	2006-Sep-Z2-935	COMPLETE
	SW_89/9-127			
		Due for servicing	2006-Feb-Z2-407	COMPLETE
	SW_89/9-154			
		Switch as major rotten bolts		NEW
	SW_89/9-222			
		Service switches and clean insulators	2007-May-Z3-1780	COMPLETE
		Service switches and clean insulators	2007-May-Z3-1780	COMPLETE
		Service switches and clean insulators	2007-May-Z3-1780	COMPLETE
	SW_89/9-222A			
		Left phase, end close to circuit breaker facing 089/9-222A has a class D hot joint.		NEW
		Switch has many rotten bolts		NEW
	SW_89/9-320			
		Additional lightening protection needed for 69kv & 138kv bus		NEW
	SW_89/9-322			
		Due for servicing	2006-Feb-Z2-404	COMPLETE

Property	Asset	Description	JobID	Status
	SW_89/9-422A			
		Service switches	2006-Sep-Z2-892	COMPLETE
		Service switches and clean insulators	2007-May-Z2-1726	Assigned
	SW_89/9-439			
		Shield wire rusting at anchor points on sturcture, needs to be replaced		NEW
		Lighting correction in Old Harbour relay building	2006-Jul-Z2-758	COMPLETE
	SW_89/9-439B			
		Middle phase end further away from circuit breaker facing 089/9-439B has a class C hot joint.		NEW
	SW_89/9-554			
		Remove interlock from switch 089/9-554	2007-Jul-Z2-2015	Assigned
	SW_89/9-639			
		Service switches and clean insulators	2007-Feb-Z1-1364	COMPLETE
	SW_89/9-739			
		Rotten bolts		NEW
	TR INT OHB			
		Rusted bolts throughout all structure		NEW
		Rotten shield wires above 138kv and 69kv structure, needs urgent attension		NEW

Property	Asset	Description	JobID	Status
		one fan not working Defective temperature gauge Nitrogen meter shows Zero		
		Rusted bolts		NEW
		R-phase, switch top, facing 089/8-122 has a class C hot joint		NEW
		Damaged 3 core cables for lightening in yard		NEW
		Relay room building needs repair & AC unit		NEW
		Inspect Substation	2005-Dec-PRJ-272	COMPLETE
		Inspect and service battery at Old Harbour s/y	2005-Dec-Z2-256	COMPLETE
		Inspect and service battery at Old Harbour s/y	2005-Dec-Z2-261	COMPLETE
		Inspect Substation	2005-Dec-Z2-266	COMPLETE
		Continue inspection of Old Habour.	2007-Jul-Z2-1952	COMPLETE
		Live Line Washing of Substation	2007-Jul-Z2-1963	Assigned
		Dewasp station structure	2007-Jul-Z2-2021	Assigned
		Battery maintenance	2007-Mar-Z3-1423	COMPLETE
	TR Unit 1 OHB			
		Proper fence bonding needed for grounding system		NEW
		Trench cover needed, trench edge broken-some repalced		NEW

Property	Asset	Description	JobID	Status
		Additional danger signs needed for fence		NEW
		Rusted arrester bracket and bolts on station service 2 transformers		NEW
		Check unit one fan control circuit and adress if possible. Tap up H.V Bushing (middle phase). Check oil sweats on radiators	2005-Sep-Z3-46	COMPLETE
		Test Transformer. Do PI test on Transformer. Do dielectric on T1 transformer at JEP (S#: 5800941). See what connection needed to do DGA sample.	2005-Sep-Z3-47	COMPLETE
		Transformer damaged	2006-May-Z2-634	COMPLETE
		Test transformer	2006-Oct-Z2-959	COMPLETE
		Correct oil leak	2006-Sep-PRJ-934	COMPLETE
		Correct oil leak on Transformer	2006-Sep-Z2-878	COMPLETE
		Correct oil leak on Transformer	2006-Sep-Z2-879	COMPLETE
		Test Transformer	2006-Sep-Z2-936	COMPLETE
		Oil Sampling	2007-Jan-Z2-1221	COMPLETE
		Inspect substation.	2007-Jun-Z2-1950	COMPLETE
	TR Unit 2 OHB			
		DGA sampling and substation inspection	2006-Jan-Z2-336	COMPLETE
		DGA sampling and substation inspection	2006-Jan-Z3-310	COMPLETE

Property	Asset	Description	JobID	Status
		Check propblem unit two transformer	2006-Jul-Z2-728	COMPLETE
		Check and test transformer	2006-Jun-Z2-699	COMPLETE
		Check and test transformer	2006-Jun-Z2-702	COMPLETE
		Check and test transformer	2006-Jun-Z2-703	COMPLETE
		Test Unit two transformer	2006-Jun-Z2-709	COMPLETE
		Inspect Substation	2007-Feb-Z3-1382	COMPLETE
		Cable Splicing and Testing at Old Harbour	2007-Jun-Z1b-1943	Assigned
		Tap up SF6 gas on breaker 089/8-130	2007-Mar-Z1-1534	COMPLETE
		Process the oil in the transformer	2007-May-PRJ-1779	COMPLETE
	TR Unit 3 OHB			
		Test Auxilliary xfmr associated with Unit 3 main xfmr	2006-Aug-PRJ-840	Assigned
		Checks	2006-Feb-Z2-360	COMPLETE
		Test and check transformer	2006-Feb-Z2-410	COMPLETE
		Checks	2006-Feb-Z2-429	COMPLETE
		Process unit #3 transformer	2007-Jul-PRJ-1980	COMPLETE
		Process unit #3 transformer	2007-Jun-PRJ-1850	COMPLETE
		Process unit #3 transformer	2007-Jun-PRJ-1881	COMPLETE
		Conduct PI test on both Unit # 3 main and auxillary transformer.	2007-Jun-Z2-1837	COMPLETE
		Inpection and electrical test of Unit 3 main transformer.	2007-May-Z2-1821	COMPLETE
	TR Unit 4 OHB			
		Test Transformer	2006-Sep-Z2-891	COMPLETE
		Test Transformer	2006-Sep-Z2-902	COMPLETE

Sub-Station	Equipment	Last Date Serviced	Maintenance History (2006-2007)					
Old Harbour	Battery	22-May-07	5-Mar-07	19-Dec-06	12-Sep-06	13-Jul-06	30-May-06	13-Feb-06
	Station Inspection	2-Jul-07	26-Feb-07	18-Dec-06	2-Aug-06	24-May-06	6-Mar-06	
	SF6 Breaker '089/9-930	31-Jul-05						
	OCB '089/9-830	11-May-04						
	OCB '089/9-730	22-Aug-03						
	OCB 089/9-630	13-May-04						
	OCB '089/9-530	19-Aug-04						
	SF6 Breaker '089/9-520	31-Jul-05						
	SF6 Breaker 089/9-430B	20-Apr-98						
	OCB '089/9-430A	21-Jun-06						
	OCB '089/9-420A	17-May-04						
	OCB 089/9-420	7-Jun-04						
	OCB 089/9-320A	26-Apr-06						
	OCB '089/9-320	30-Apr-03						
	OCB '089/9-220A	Jul-06						
	OCB 089/9-220	21-Apr-06						
	SF6 Breaker '089/8-330	21-Jun-97						
	OCB '089/8-240	12-Jun-06						
	OCB 089/8-230	11-Sep-03						
	OCB 089/8-140	21-Dec-01						
	SF6 Breaker '089/8-130	14-Jul-98						
	SF6 Breaker '089/8-120	1-Mar-99						

Appendix D

REPORT ON THE

INSPECTION

OF THE CONTAMINATION

LEVELS AT THE OLD HARBOUR

SWITCH YARD

PREPARED BY: Adanaka Patterson
TITLE: Zone Engineer

LOCATION: JPS Substation Department
DATE: July 9, 2007

INTRODUCTION

This report looks at contamination on the Old Harbour substation equipment, particularly on suspension and pilot insulators, circuit breakers and transformer bushings. A recent visit to the Old Harbour switchyard on July 4, 2007 revealed significant flashover due to contamination on suspension insulators and breaker bushings at some sections of the switchyard. The effect of the contamination was monitored throughout the day and into the morning, of July 5th, 2007.

PROCEDURE

A physical inspection of all sections of the Old Harbour station was done to identify the areas of heavy contamination.

OBSERVATION:

On July 4, 2007 at approximately 6pm I visited the Old Harbour Switch yard to check on the contamination level of the insulators as well as to assist in the supervision of the removal of OCB 089/9-220 and the spotting of the new SF6 breaker. When I got there the evidence of tracking in the switch yard was quite minimal. However, as night approached, flashovers were noticed on some insulators and bushings and the tracking activity grew more pronounced especially in the JEP 138kV and Old Harbour 69kV bay areas. As early morning approached and the morning dew increased, the flashovers in these sections got violent especially on the 138kV suspension insulators and potential transformers in the JEP bay area. The most aggressive period was between 2am and 5am. The flashover slowly dissipated as the sun rose.

CONCLUSION

Tracking and flashovers increases as the morning dew gets heavier, with the period of most intense activity being between the hours of 2 and 5am when the dew is at its heaviest. The tracking and flashover activity occurred as a result of high contamination level of the insulators in the Old Harbour switch yard and therefore urgent cleaning of all insulators is necessary.

Appendix E

Generator	AVAIL MW	TOT CAPACITY	Blackstart / Start	Synchronize	Trip	Feeder/SS/Xmission Line	Feeder Time	Sensitive Load	# Cust	Sum of Cust	% Demand
GT10	32.5	32.5	5:30 AM	6:04 AM		Hunts Bay 710	6:18 AM		549	549	
GT5		32.5	6:11 AM		6:21 AM	Hunts Bay 110	6:21 AM		233	782	
		32.5				Hunts Bay 410	6:22 AM		16	798	
		32.5				Hunts Bay 210 - Harbour Street FDR	6:22 AM		657	1,455	
		32.5				Hunts Bay 510 - North Street FDR	6:23 AM		823	2,278	
		32.5				Hunts Bay 610	6:25 AM	Esso/Petrojam	4	2,282	
		32.5				Rockfort 310	6:25 AM	Flour Mills	1	2,283	
		32.5				Bogue 410	6:29 AM	Cornwall Regional Hosp.	418	2,701	2.5%
		32.5				Rockfort SS	6:31 AM			2,701	
		32.5				Rockfort 210	6:36 AM	St. Joseph's Hospital	3027	5,728	
		32.5				Q/Drive SS	6:41 AM			5,728	
GT7	14.0	46.5	6:43 AM	6:43 AM		Q/Drive 610 - Airport B Feeder	6:46 AM	Sangster International Airport	1	5,729	
		46.5				Q/Drive 710 - Flankers Feeder	6:48 AM		11572	17,301	
GT5	21.5	68.0	6:37 AM	6:48 AM		Duhaney SS	6:56 AM			17,301	6.0%
		68.0				Duhaney 6-310	6:56 AM	System Control & Frequency Monitoring	13957	31,258	
GT9	20.0	88.0	7:10 AM			W/Blvd SS	7:12 AM			31,258	
		68.0				Orange Bay 6-310	7:18 AM	Stage 1 U/F Loads	13071	44,329	
GT3	20.5	108.5	7:31 AM	7:31 AM		Paradise 210	7:32 AM		11489	55,818	8.1%
		108.5				Paradise 110	7:37 AM	Stage 1 U/F Loads	13651	69,469	
		108.5				Bogue 310 - Mobay Feeder	7:40 AM		16031	85,500	
GT6	14.0	122.5	7:41 AM	7:41 AM						85,500	
RF2	18.0	140.5		7:42 AM		Paradise 310	7:43 AM		6680	92,180	
B6	68.5	209.0	6:55 AM	7:44 AM		Duhaney 410	7:45 AM		1426	93,606	
		209.0				Hunts Bay 810	7:48 AM	Stage 1 U/F Loads	1823	95,429	
		209.0				Magotty SS	7:50 AM			95,429	
		209.0				PAJ SS	7:51 AM		11	95,440	

Generator	AVAIL MW	TOT CAPACITY	Blackstart / Start	Synchronize	Trip	Feeder/SS/Xmission Line	Feeder Time	Sensitive Load	# Cust	Sum of Cust	% Demand
		209.0				W/BLvd 810	7:57 AM		3471	98,911	
		209.0				Bogue 210	7:58 AM		13266	112,177	
		209.0				W/Blvd 710	7:58 AM	Stage 1 U/F Loads	6776	118,953	
GT13	25.0	234.0		7:59 AM		Orange Bay 210 - Negril Feeder	8:03 AM		2837	121,790	14.0%
		234.0				Const. Spring 210 - Manning's Hill Feeder	8:08 AM	Stage 1 U/F Loads	9685	131,475	
		234.0				Queens Dr. 810	8:10 AM	Montego Bay Hip Strip	2507	133,982	
		234.0				W/Blvd 510 - Const, Spring Feeder	8:12 AM	Stage 2 U/F Loads	2868	136,850	
		234.0				W/Blvd 310 - Waltham Feeder	8:12 AM	Stage 2 U/F Loads	6441	143,291	
		234.0				Duhaney - Bogue Transmission	8:16 AM			143,291	
		234.0				W/Blvd 410 - HWT Feeder	8:17 AM	Stage 2 U/F Loads	1969	145,260	
		234.0				W/Blvd 610 - Shortwood Feeder	8:17 AM	Stage 2 U/F Loads	5797	151,057	
		234.0				Duhaney 210 - Ferry Feeder	8:18 AM		3871	154,928	
		234.0				Const. Spring 410 - Stony Hill Feeder	8:18 AM		12737	167,665	
		234.0				Hunts Bay - Bogue synchronized	8:26 AM			167,665	
JPPC1	29.5	263.5	5:23 AM	8:29 AM		Old Harbour SS & OH - L4	8:35 AM			167,665	25.0%
		263.5				Rhodens Pern 410 - O/H Bay feeder	8:56 AM	Water Pumps for OH PStn	8051	175,716	
		263.5				Rhodens Pern 210	8:56 AM		2870	178,586	
		263.5				Rhodens Pern 310	8:56 AM		3191	181,777	
		263.5				WKHouse 210 - N/KGN Feeder	8:58 AM		564	182,341	
		263.5				WKHouse 310 - Hope Rd Feeder	9:01 AM	Andrew's Hospital	3133	185,474	
		263.5				Hope 310	9:01 AM	UWI Hospital	510	185,984	
GT3	-20.5	243.0			9:02 AM	Parnassus SS from O/H	9:02 AM			185,984	
		263.5				Porus 210	9:09 AM	Water Pumps for Manchester	5157	191,141	
JEP9	17.0	260.0	7:52 AM	8:51 AM		Porus 310	9:09 AM	Water Pumps for Manchester	777	191,918	

Generator	AVAIL MW	TOT CAPACITY	Blackstart / Start	Synchronize	Trip	Feeder/SS/Xmission Line	Feeder Time	Sensitive Load	# Cust	Sum of Cust	% Demand
JEP10	17.0	277.0		9:07 AM		Kendal SS & Spur Tree SS	9:10 AM			191,918	
JEP11	17.0	294.0		9:13 AM		Spur Tree 110 - Main	9:21 AM			191,918	
		294.0				Spur Tree 210	9:21 AM	Stage 1 U/F Loads	14394	206,312	
		294.0				WKHouse 410 - Waterloo Rd Feeder	9:24 AM		2625	208,937	
JPPC2	29.5	323.5	9:04 AM	9:24 AM						208,937	
GT12	25.0	348.5		9:26 AM		Hunts Bay 310 - Cross Roads Feeder	9:26 AM	Kingston Public Hospital	3061	211,998	39.7%
		348.5				Spur Tree 310 - Newport Feeder	9:27 AM		15218	227,216	
		348.5				Monymusk SS	9:32 AM			227,216	
		348.5				Monymusk 210	9:32 AM		2191	229,407	
		348.5				Monymusk 310	9:32 AM		4	229,411	
		348.5				Monymusk 410	9:32 AM		2963	232,374	
		348.5				Cane River 610	9:33 AM	Norman Manley Airport	651	233,025	
		348.5				Cement company SS	9:36 AM	Cement Company	6	233,031	
		348.5				Goodyear 210	9:38 AM		11301	244,332	
		348.5				Lyssons 410	9:38 AM		6419	250,751	
		348.5				Three Miles 110 - Main	9:46 AM			250,751	
		348.5				Three Miles 410 - Spn Twn Rd. Feeder	9:46 AM		211	250,962	
		348.5				D&G Energized (transferred to three miles 410)	9:46 AM		2639	253,601	
		348.5				Up Park Camp 310 - N/KGN Feeder	9:46 AM		1094	254,695	
		348.5				Up Park Camp 410 - Oxford Rd. Feeder	9:47 AM		2262	256,957	
		348.5				North Coast SSs Energized	9:48 AM			256,957	
		348.5				Martha Brae 110	9:48 AM		3805	260,762	
		348.5				Duncans 110	9:48 AM		5577	266,339	
JEP1	9.3	357.8		9:59 AM						266,339	50.0%

Generator	AVAIL MW	TOT CAPACITY	Blackstart / Start	Synchronize	Trip	Feeder/SS/Xmission Line	Feeder Time	Sensitive Load	# Cust	Sum of Cust	% Demand
JEP7	9.3	367.0		10:06 AM		Michelton Halt 110	10:07 AM		9588	275,927	
		367.0				Upper White River 110	10:07 AM		5053	280,980	
JEP3	9.3	376.3		10:11 AM		Tredegar 310 - Eltham Feeder	10:19 AM		6214	287,194	
		376.3				Highgate 110	10:19 AM		4061	291,255	
		376.3				Highgate 210	10:19 AM		6569	297,824	
		376.3				Oracabessa 110	10:19 AM		3367	301,191	
		376.3				Oracabessa 210	10:19 AM		4039	305,230	
		376.3				North East Coast SSs Energized	10:22 AM			305,230	
		376.3				Entire Transmission Grid Energized	10:22 AM			305,230	
JEP6	9.3	385.5		10:28 AM		Naggos Head 610 - B/Lodge Feeder	10:34 AM		11252	316,482	
		385.5				Ocho Rios 310 - Ocho Rios Feeder	10:35 AM		5040	321,522	
		385.5				Q/Drive 510 - Airport A Feeder	10:37 AM		1	321,523	
		385.5				Parnassus 210	10:38 AM	Stage 3 U/F Loads	10353	331,876	
		385.5				Kendal 310 - M/Gully Feeder	10:48 AM	Mandeville Hospital	6712	338,588	
JEP4		385.5		10:49 AM	11:02 AM	Cardiff Hall 110 - Main	10:56 AM			338,588	
		385.5				Twickenham 210 - Portmore Feeder	10:58 AM		15903	354,491	
		385.5				Greenwich Rd. 510	11:22 AM	Stage 2 U/F Loads	1933	356,424	
		385.5				Hope 410	11:22 AM	Stage 1 U/F Loads	6037	362,461	
		385.5				Roaring River 210	11:32 AM		6638	369,099	
		385.5				Roaring River 310	11:32 AM		55	369,154	
		385.5				Roaring River 410	11:32 AM		4886	374,040	
OH1	25.0	410.5		11:28 AM		Three Miles 510 - M Garv Dr. Feeder	11:36 AM		488	374,528	
		410.5				Q/Drive 310 - Queens Drive Feeder	11:38 AM		6295	380,823	
		410.5				Hope 510	11:40 AM	UTECH	6304	387,127	

Generator	AVAIL MW	TOT CAPACITY	Blackstart / Start	Synchronize	Trip	Feeder/SS/Xmission Line	Feeder Time	Sensitive Load	# Cust	Sum of Cust	% Demand
		410.5				Greenwood 210 - Rosehall Feeder	11:57 AM		1254	388,381	
JEP2	9.3	419.8		11:55 AM		Ocho Rios 410 - Main St. Feeder	12:01 PM		1293	389,674	67.7%
		419.8				Port Antonio 410	12:14 PM		13496	403,170	
		419.8				Greenwich Rd. 410	12:16 PM	Stage 2 U/F Loads	1388	404,558	
GT3	20.5	440.3		12:13 PM		Greenwood 110 - Greenwood Feeder	12:18 PM		5245	409,803	
		440.3				Rockfort 410 - Downtown Feeder	12:19 PM		6574	416,377	
ST14 & CC FL	50.0	490.3		12:54 PM		CONSPRNG LONG LANE FDR 6-310	1:03 PM		2670	419,047	
		490.3				CARDHALL B/TOWN FDR 6-310	1:04 PM		15239	434,286	
		490.3				CARDHALL SALEM FDR 6-210	1:04 PM		4324	438,610	
		490.3				ANOTOBAY A/BAY FDR 6-310	1:29 PM		674	439,284	
		490.3				ANOTOBAY DOVER FDR 6-210	1:29 PM		1765	441,049	
		490.3				Greenwich Rd. 310	1:51 PM	Stage 3 U/F Loads	987	442,036	
		490.3				Greenwich Rd. 710	2:00 PM	Stage 3 U/F Loads	2771	444,807	
		490.3				OCHORIOS FRANKFURT FDR 4-510	2:03 PM		1791	446,598	
OH4	63.5	553.8		3:17 PM		TWICKNAM G/DALE FDR 6-410	3:24 PM		5122	451,720	
		553.8				Parnassus 310	3:33 PM		8257	459,977	
		553.8				TREDEGAR SP TWN FDR 6-410	3:40 PM		11951	471,928	
		553.8				UPPKCAMP MTVIEW FDR 6-510	3:43 PM		3893	475,821	
		553.8				May Pen 110	4:02 PM	Stage 2 U/F Loads	11157	486,978	
		553.8				May Pen 210	4:02 PM	Stage 2 U/F Loads	2539	489,517	
		553.8				BLKSTONE GUYSHL FDR 4-110	4:23 PM		2492	492,009	
		553.8				MICLETON BOGWLK FDR 4-210	4:23 PM		4672	496,681	
		553.8				MAGGOTTY B/RIV FDR 6-210	4:36 PM		17722	514,403	
		553.8				MAGGOTTY MAGTY FDR 6-110	4:36 PM		5187	519,590	
		553.8				CANERIVR BULL BAY FDR 6-310	4:38 PM		3809	523,399	

Generator	AVAIL MW	TOT CAPACITY	Blackstart / Start	Synchronize	Trip	Feeder/SS/Xmission Line	Feeder Time	Sensitive Load	# Cust	Sum of Cust	% Demand
		553.8				CANERIVR H/VIEW FDR 6-410	4:38 PM		2837	526,236	
		553.8				KENDAL C/TIANA FDR 6-210	4:39 PM		16937	543,173	
		553.8				TREDEGAR ENSOM FDR 6-210	4:40 PM		7104	550,277	
		553.8				NAGOHEAD FDR 6-510	4:41 PM		10968	561,245	
		553.8				Port Antonio 310	4:50 PM		5617	566,862	
		553.8				MAGGOTTY MAGTY FDR 6-110	4:50 PM		5187	572,049	
						All Customers Restored	**4:59 PM**			572,049	100.0%