Entergy Operations, Indian Point Energy Center, Unit 2

Root Cause Evaluation Report

IP2 Turbine Trip/Reactor Trip Due to 21 Main Transformer Fault

CR-IP2-2010-6801; Event Date: 11-07-2010

REPORT DATE: 10-27-2011, Rev 1

Position	Name	Date
Evaluator	Theresa Motko	12/8/10
Reviewer	Joe Reynolds	12/8/10
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CARB Chairperson	Mark Cox	12/8/10

Problem Statement

At 18:39 on 11/7/10, with Indian Point Unit 2 at 100% power, a fault occurred in the 21 Main Transformer which resulted in a Unit 2 automatic trip.

Event Narrative

The problem statement addresses the following Condition Reports (CR):

CR-IP2-2010-06801:

"Unit 2 tripped due to a fault in 21 Main Transformer"

This CR also addresses CR-IP2-2010-06803:

"An Alert was declared at Indian Point unit 2 at 1849 due to main transformer explosion. EAL 8.2.3 was selected."

On November 7, 2010, at 18:39, while Unit 2 was at approximately 100% power, a fault occurred on 21 Main Transformer which resulted in a Unit 2 automatic trip.

An Alert was declared in accordance with EAL 8.2.3 at 1849 due to the 21 Main Transformer explosion. A 1-hour event notification was made for entry into EP classification. EAL 8.2.3 was selected because the explosion could have damaged Safeguards Equipment. However, no Safeguards Equipment was damaged by the event.

Event Timeline:

11/7/2010:

1838 Reactor Operator leaving Turbine Building near the 138KV yard hears a loud hum coming from the Transformer Yard, then hears an explosion and sees a fireball coming from the yard.

1839 CCR feels concussion, receives first out indications coincident with reactor trip/turbine trip

1840 Entered 2-E-0, "Reactor Trip or Safety Injection"

Fire brigade dispatched to the transformer yard. Deluge system was active, and no fire was noted.

1845 Entered 2-ES-0.1, "Reactor Trip Response"

Fire brigade felt and heard second explosion in transformer yard while mobilizing equipment. Simultaneously, the CCR felt a large concussion. Visual inspection after the second explosion noted that the B-Phase W95 feeder bus section from 21 Main Transformer was broken away and resting over the radiator.

1849 Alert Emergency declared – EAL 8.2.3 (21 Main Transformer explosion).

1900 Entered 2-POP-3.2, "Plant Recovery from Trip, Hot Standby"

2218 Terminated Alert Emergency

2317 Initiated plant cooldown to Cold Shutdown per 2-POP-3.3

Description of Event and Actions Taken:

At 18:39 on 11/7/10, with the plant at approximately 100% power, a fault occurred on 21 Main Transformer which resulted in a Unit 2 automatic trip. Primary and Back-up Pilot Wire Relays 87L1/345 and 87L2/345 for Feeder W95 actuated, initiating a turbine trip/reactor trip via Main Generator Primary and Back-up Lockout Relays 86P and 86BU. An Alert was declared in accordance with EAL 8.2.3 at 18:49 due to the 21 Main Transformer explosion.

All safety related plant systems and equipment functioned per design. The Station Auxiliary Transformer (SAT) tap changer hung up stuck at step 16 (Ref CR-IP2-2010-6802 Troubleshooting was performed to correct condition under WO: 255953). This occurred during the attempted "fast transfer" of the IP2 6.9 KV buses 1, 2, 3 and 4 from the Unit Auxiliary Transformer (UAT) to the SAT on a loss of the main generator output, which feeds the UAT. Also, 21 RCP experienced a lower bearing high oil level.

Following the failure of 21 Main Transformer, oil (from 21 Main Transformer) mixed with water from the fire deluge system, overflowed the transformer's containment structure and penetrated the east wall of the Turbine Building. This oil/water mixture flowed onto the 15 ft elevation of the Turbine Building, near the 6.9 KV switchgear, and into the 5 ft elevation. All Turbine Building sump pumps were immediately secured, and cleanup activities of the oil/water mixture commenced. The discharge canal was monitored for any signs of oil or oil sheen. Initially, there was no oil detected in the discharge canal or the river. On 11/8/10, an oil film was observed on the water in the discharge canal. The oil was observed along the entire discharge canal and the visible portion of the outfall. No means to quantify the oil was available. No means was available to determine whether or not oil was being transferred to the Hudson River from the discharge canal. The oil was reported to station management. The New York State DEC was informed of the spill of transformer oil that may have been the source of oil in the canal. The oil sheen in the discharge canal was contained. Clean Harbors and Miller Environmental were called in to assist in the containment and cleanup of the oil.

The event was initiated when the 21 Main Transformer experienced a low impedance ground fault on the 345kV 'B' Phase bushing. The fault initiated from inside of 21 Main Transformer. This was confirmed with relay targets and digital fault recording readings provided by Con Edison, see Attachment I. URS (an independent contractor) also verified that relay protection schemes operated as designed for a fault that originated inside 21 Main Transformer on high voltage 'B' Phase and propagated to 'C' Phase, see Attachment II.

Event Narrative

The transformer experienced a rapid increase in pressure due to the failure of the 'B' phase high voltage bushing. This sudden increase caused the tank to fail. Combustible gases, from arcing, built up in the transformer as the insulating oil leaked from the tank breach. After several more minutes, enough oxygen combined with the hot gases causing a secondary explosion. A cooling valve cracked 360° resulting in most of the oil draining from the tank. See Attachment III for photos of damage to bushings and ruptured transformer tank.

The unit trip occurred right after a noticeable 60 cycle humming noise, consistent with an overload, was noticed by more than one person.

The trip occurred within a minute of receiving a main generator high RF Alarm. It should be noted that this alarm had been coming in following increases in lagging MVARs, but this time the alarm occurred without a corresponding change in MVARs.

Primary and Back-up Pilot Wire relays 87L1/345 and 87L2/345 for Feeder W95 actuated, initiating a turbine trip/reactor trip via Main Generator Primary and Backup Lockout Relays 86P and 86BU. The B Phase failure was evident by protective relays actuation. Overall Unit Differential Phase B Relay 87/GTB, and Main Transformer Differential Phases B and C Relays 87/T21B and 87/T21C all actuated.

A summary of the generator/22KV/345KV relay actuations (tripped) is shown below:

- 87/T21B - B-phase Main Xformer Differential
- 87/T21C - C-phase Main Xformer Differential
- 87/GT - B-phase overall Differential
- 87L2/345 - Backup Pilot Wire on W95
- 87L1/345 - Primary Pilot Wire on W95
- 50BU/345 - 345kV Backup Phase Fault Detector
- 50P/345 - 345kV Primary Phase Fault Detector
- 50NBU/345 - 345kV Backup Ground Fault Detector
- 50NP/345 - 345kV Primary Ground Fault Detector
- 81P/1 - Generator Overfrequency
- 81BU/2 - Generator Overfrequency
- 87/T21B - B-phase Main Transformer Differential
- 87/T21C - C-phase Main Transformer Differential
- 87/GTB - B-phase Overall Differential

The 21 Main Transformer was replaced, like-and-kind, with a spare transformer that was available on site, tested, and put in service. Inspections and testing of the 22 Main Transformer, Unit Auxiliary Transformer (UAT), and the isophase bus were completed, along with necessary repairs. Unit 2 was restarted and returned to full power operation on 11/24/10.

Inspections Performed on Failed 21 Main Transformer:

Based on initial internal inspection, the fault originated from the ‘B’ phase high voltage bushing. The ‘B’ phase high voltage link was broken at the stand-off insulator above the radiators. Internal to the transformer housing, the epoxy-resin insulator on the lower end of the bushing disintegrated, with pieces found outside of the transformer. The epoxy-resin on the ‘C’ phase bushing was also detached.

An internal visual inspection of the internals of the 21 Main Transformer was performed on 11/10/10 to look for evidence of arcing or conductor separation, especially on the ‘B’ phase bushing area and inside the corona shield enclosure. The inspection confirmed that the high voltage B phase bushing was the source of the failure, and that the internals of the transformer showed physical damage from the explosion. A summary of the 21 Main Transformer internal tank inspection is provided below:

> The transformer windings and connections were found to be in good condition with no evidence of damage or overheating. The bushing flanges were found cracked on all 3 high voltage bushings.
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> The inboard end (oil side) of the ‘B’ phase high voltage bushing was found severely damaged. The inboard end housing (epoxy-resin insulator) was found completely shattered and ejected from the bushing with pieces both inside and outside of the main tank. Most of the conductive and insulating paper was torn, unraveled, removed from the bushing conductor and scattered throughout the transformer internals and outside of the transformer. Excessive arc striking was noticed at the bushing bottom terminal and on the transformer main tank wall and turret. The arc strike out of the bushing has been located at the highest section of the bushing conductor at the top of the turret. A hole through the center conductor of the bushing was observed. The bushing lower corona shield was found shifted downward, exposing the bushing bottom terminal. The corona shield winding was in good condition with no evidence of arcing and all connections were intact. The shield support bracing was broken due to the shockwave from the initial explosion, which caused the shield to shift / drop down. The porcelain insulator of the bushing external to the top of the transformer tank was intact.
>
> The ‘C’ phase high voltage bushing sustained some damage but not as severe as the ‘B’ phase. The epoxy-resin was shattered off of the bushing. Most of the insulating paper was found intact still on the bushing conductor. The corona shield was slightly shifted downward due to some damage to the shield bracing. The bottom terminal of the bushing was exposed. The shield winding was in good condition with no evidence of arcing and all connections were intact. The damage to the ‘C’ phase high voltage bushing appears to have been caused by the shock wave from the failure of the ‘B’ phase high voltage bushing.
>
> The ‘A’ phase bushing sustained little visible damage. The corona shield winding was in good condition with no evidence of arcing and all connections were intact. There was arcing noted on the base of the conductor, however, this is an expected response as the dielectric properties of the oil medium were compromised due to the failure of the ‘B’ phase bushing.

> There was some overall corona shield bracing damage in the lower portion of the transformer in the vicinity of the 'B' and 'C' phase winding, below the 'B' phase high voltage bushing. The damage included cracked bracing and bracing that was ejected or dropped to the bottom of the transformer. There did not appear to be any bracing or wedging damage or looseness on the windings. All transformer winding leads were in good condition and intact.

Based on the internal inspection and KT analysis, one of the possible causes was the failure of the supports for the corona shield, allowing the base of the bushing to be exposed. Upon further review by Siemens personnel, it was concluded that this was not the failure mode due to the construction of the corona shield assembly and there was no evidence of partial discharge in the online gas monitoring system prior to the fault. Reference Attachment V for Siemens Technical report issued on HV bushing and corona shielding.

Entergy T&D Technical Support Group also performed a visual inspection and concurred that the 'B' phase high voltage bushing initiated this failure.

<u>21 Main Transformer Dissolved Gas in Oil Review:</u>

The dissolved gases in oil sample results from the 10/29/10 laboratory sample of 21 Main Transformer were evaluated by System Engineering. The sample results do not show any sudden or significant increases in any of the key combustible gases. The key combustible gases being Hydrogen (H2), Methane (CH4), Carbon Monoxide (CO), Ethane (C2H6), Ethylene (C2H4) and Acetylene (C2H2). The trend in the combustible gases was stable and consistent with the transformers operating history. The sample results show that an electrical fault (partial discharge or arcing) was not present as there were no traces of Acetylene.

A review of the on-line gas monitor (Serveron) sample results was also performed. The sample results also do not show any sudden or significant increases in any of the available key combustible gases, including the last sample which was taken a couple of hours prior to failure. It should be noted that the Oxygen (O2), Methane (CH4) and Ethylene (C2H4) channels have not been included in the graph due to not reading correctly and required calibration, which was completed under WO: 206484. Acetylene (C2H2) has not been included in the graph due to frequent spiking of the channel. Graphically the spiking makes it appear that Acetylene is present. If Acetylene were present the value should be constant as the gas would remain dissolved in the oil and only be removed by reconditioning of the oil. In addition no traces of Acetylene have ever been observed in any of the laboratory sample results. In the absence of spiking the Serveron shows Acetylene to be zero. Spiking in Acetylene is seen on all four of the Serveron units installed on site, and thus has not demonstrated consistent reliability for analysis.

An evaluation of the dissolved gases in oil for 21 Main Transformer was performed using the guidance of IEEE Std C57.104-2008 (IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers). Both the Doernenburg and Rogers ratio methods were employed for the evaluation. These methods use the ratio of certain key combustible gases to determine the presence and type of fault within a transformer. The types of faults that can be present in a transformer are thermal (overheating), partial discharge (PD) and arcing. Both methods indicated the presence of low energy (< 300 ^{o}C) thermal activity within the transformer. This combined with the presence of CO and CO2 point to overheating of the cellulose (paper insulation). The presence of Ethylene in the oil indicates that there may also be some overheating of the oil. This aligns with the evaluation of the 10/29/10 sample results performed by Doble Engineering. The 10/29/10 sample results document the following: "Overheating of oil and cellulose, condition is of no immediate concern. Resample in 3 months."

The transformer gassing was brought to the attention of the transformer manufacture (Siemens) in both 2006 and 2008. The gassing occurring in 2006 was attributed to the winding hot spot going above allowable limits due to inadequate cooling setpoints (CR-IP2-2006-04602). As a result the setpoints were revised. In 2008, it was noted that gassing was elevated within the transformer (CR-IP2-2008-00948). The condition was similar to past transformer operating history. The vendor and several industry peers and experts were contacted about the condition. Both the vendor and Doble indentified that the gassing was typical for a generator step up transformer (GSU) of this size and loading. The vendor identified the probable cause of the gassing to be due to cellulosic parts in contact with structural steel parts, and that PD was not present since there were no traces of Acetylene in the oil.

Based upon the laboratory gas in oil samples, data available from the on-line gas monitor, expert and vendor input, it can be concluded that the gassing in 21 Main Transformer up until the time of failure was normal for the transformer and that there were no immediate or near term concerns for the health of the transformer.

<u>High Voltage Bushing Failure Investigation</u>

The failed 'B' phase high voltage bushing was a Trench Type COTA with a fixed copper conductor rated at 345kV and 2000A (Style: 1175-F020-23-AG3-02).

Investigation in to the failure included teardown and analysis of the following bushings, all of the same make and style as the failed bushing:

- All three bushings from the failed 21 Main Transformer
- Two bushings from 22 Main Transformer
- One bushing from 32 Main Transformer

Representatives from Trench, Siemens, Entergy, Lucius Pitkin, Inc. (LPI) were present for the teardown of the bushings. Entergy contracted LPI to assist in the failure analysis. The analysis performed by LPI and their conclusions are contained in Attachment III. A summery of the findings from the teardowns and failure analysis is contained in the follow paragraphs.

The teardown of the failed 'B' phase bushing from 21 Main Transformer revealed a puncture hole in the inboard end of the bushing that radiated outward to the bushings ground flange. When the bushing was unwound electrical treeing was observed in the paper at the high stress edges of the foil layers.

Electrical treeing compromises the axial and radial breakdown strength of the paper layers since these are three-dimensional structures. As the insulation quality breaks down, the electrical withstand strength decreases between adjacent paper layers. At some point, dielectric breakdown between layers will occur. Breakdown between layers results in an avalanche condition wherein full-scale breakdown progresses rapidly and without significant warning.

Event Narrative

With electrical treeing, the insulation structure of the bushing can not withstand its normal voltage stresses.

While it is possible that there was an initial defect in the bushing that started the insulation breakdown, the presence of the electrical treeing is what lead to the rapid and complete breakdown of the insulation system.

It appears that the electrical treeing is being caused by the manufacturing/design of the foil edges. The foil edges are cut with a device similar to a standard office paper cutter. This results in “sharp” edges that do not control the electrical stresses at the foil/paper interface. These stresses cause the electrical treeing in the paper. The analysis of the paper, foil and oil did not reveal any other anomalies that would have lead to the treeing.

Other manufactures use precision cutting techniques to cut the foil and fold over the edges. These techniques result in smooth rounded edges that control and minimize the electrical stresses. It was also observed during bushing assembly that the foils are manually placed into position using only a template for alignment (other manufactures may use devices such as laser alignment). This method could result in misplaced foils, if even by fractions of an inch, which could alter the capacitive grading; thus potentially further weakening the already treed insulation system.

The foil cutting and placement process described above is used for the assembly of all bushings at the Trench manufacturing facility.

When the other two bushings from 21 Main Transformer (MT) were unwound the same electrical treeing phenomenon was also observed.

The electrical treeing phenomenon was also observed in two of the bushings removed from 22 Main Transformer that were unwound and the one Trench bushing from 32 Main Transformer. The third bushing from 22MT is being held for future testing, if needed.

The service life of the bushings torn down was:

21MT (failed unit) – 4 years 6 months

22MT – 5 years 0 months

32MT – 2 years 0 months

None of the laboratory testing to date (impulse, hi-pot, PD, Doble, oil samples) has been able to identify the presence of the treeing. The treeing is only detectable upon bushing teardown. The bushing that failed was successfully Doble tested 2 years 6 months prior to failure, with no anomalies noted.

Based on these findings we believe that all Trench Type COTA 345kV bushings (copper and aluminum core) are susceptible to the electrical treeing phenomenon and potential failure.

Position of Trench

As of this date we have not received a complete formal root cause evaluation of the bushing failure from Trench, or the cause of the treeing in the bushings torn down. However at this time, it appears Trench is of the opinion that the treeing is being caused by copper migration. This is a problem they have seen in the past in their bushings (Reference 19). They believe that copper is migrating from the copper center conductor and creating copper trees within the paper structure. The mechanism of how the copper migrates off of the center conductor has not been determined. Based on this position they feel that bushings with aluminum center conductors would not be susceptible to the failure mechanism (electrical treeing).

The bushings in 22MT have aluminum center conductors while the bushings in 21MT have copper center conductors.

As stated above, Entergy (using an independent failure analysis from LPI) has not found evidence to support the copper migration theory. In addition while at the Trench manufacturing facility, for the tear down of the 22MT bushings, another major bushing manufacture was present. During the tear down this bushing manufacture noted the process used by Trench for cutting the foil edges. The manufacture discussed with Trench on how their process uses lasers to cut the foils and then the edges are folded over, thus preventing an increase in the electrical stress concentration caused by sharp edges.

Evaluation of Main Generator High RF Monitor/Alarm Prior to Event:

The main generator high RF alarm was received approximately one minute prior to the event. This alarm has been coming in following increases in lagging MVARs, but this time the alarm occurred without a corresponding change in MVARs.

A review of the operating history of the IP2 main generator RF (radio frequency) monitor alarm since 1/1/2009 has determined that this alarm is unreliable. For example, the alarm had previously actuated on 1/28/09 with generator parameters such as stator cooling discharge temperatures and hydrogen cooler discharge temperatures verified as normal. Discussions with GE representatives on 2/12/2009 indicated that GE does not specifically recommend the use of RF monitors on their generators. It was recommended to either install a partial discharge monitoring system or to perform regular flux probe testing to trend generator degradation.

IP2 has performed flux probe testing every refueling outage since 1994 and this testing has indicated no change in the state of the rotor since the documentation of shorted turns in the first test. This coupled with steady state indication of other generator parameters indicated that the information from the RF monitor was either not reliable, or that the monitor needed to be fully calibrated during the next available shutdown.

The generator RF monitor physically monitors for "radio frequency interference" from the main generator all the way to the main transformers, and is not a localized monitoring device, so the location of RF interference could be anywhere in that line of connection. Therefore, testing was performed on the iso-phase bus to ensure that no damage occurred due to this event. The alarm may have been caused by the event, but it is not used as an indication that there is a fault in either of the Main Transformers.

Conclusions:

In summary, the direct cause of the 21 Main Transformer failure was a fault at the B phase high voltage bushing. There was evidence of a catastrophic failure of the bushing. The root cause is a vendor design/manufacturing deficiency associated with the Trench Electric B phase high voltage bushing.

There were no precursors to this event, or indications of impending failure. The most recent power factor testing, dissolved gas analysis and thermography of the transformer were satisfactory.

The rate at which the 21MT 345kV 'B' phase bushing deteriorated is not known. The current monitoring and testing results document the bushing tested satisfactory on 4/7/08 and failed on 11/7/10. If the bushing deteriorated slowly over this time period, then it could be reasonably concluded that a degraded bushing can be indentified prior to failure using a 2 year test frequency. The bushings and transformers are on a 4 year test frequency IAW the EN-Transformer-Oil Immersed PM Basis Template, Rev 1. The next scheduled test for the Unit 2 Main Transformers in 2012 (2R20), less than 2 years from now. The next scheduled test for 32 Main Transformer, which is included as Extent of Cause, is in 2013 (3R17), 4 years after its last test. Based on this the following actions will be pursued and tracked via the Root Cause Analysis:

1. Submit scope testing of the 32 Main Transformer into 3R16. The transformer is scheduled for power factor tip up testing, but the bushings are not scheduled to be tested, CA: 023.

   Action Completed: This Trench bushing was replaced in 3R16 with an ABB bushing under WO 267273, EC 27984.

2. Evaluate the need to revise the PM frequency for bushing/transformer testing from every 4 years to every 2 years, CA: 024.

   Action Completed: As an enhancement the PM frequency for transformer electrical testing has been change to a 2 year frequency under PMCR 109519.

3. Evaluate the need to install bushing monitors for 21 and 22 Main Transformers. If the failure was caused by rapid or sudden deterioration then periodic testing would not be able to detect a degraded bushing prior to failure. In this case, only a continuous bushing monitor may be able to give enough warning to remove the transformer from service prior to failure. Careful consideration must be employed if bushing monitoring devices are to be installed since industry OE has uncovered that these devices have led to false positive identification of imminent bushing failure and in some cases, unit trips, CA: 025.

   Action Completed: The evaluation concluded that while bushing monitors would be enhancement, they are not required to be installed as a corrective action to this event.

4. Post mortem cause analysis of the HV bushings from 21 Main Transformer will be performed, CA: 026.

   Action Completed: Analysis has been completed and is summarize in this event narrative.

All testing performed on 22 Main Transformer and the Unit Auxiliary Transformer demonstrate that the transformers were not damaged or degraded by the 21 Main Transformer fault. These transformers are acceptable to return to service. Both Doble and Siemens Engineering have reviewed the power factor, excitation current and SFRA testing data for 22 Main Transformer and verified the results are satisfactory.

As further confirmation of the condition of the High Voltage Trench COTA style bushings on 22 MT, oil samples were taken from the bushing for DGA, under instructions from Trench. The results were satisfactory and received on 11/22/10. It should be noted that these bushings were subsequently replaced in May of 2011 under WO 271017.

There were no grid disturbances prior to the event.

There was no industry OE related to the Trench Electric COTA high voltage bushings installed on the 21 Main Transformer.

DIRECT CAUSE

The **Direct Cause** for the failure of the 21 Main Transformer was a low impedance fault of the 'B' phase high voltage bushing. Ancillary effects from this failure caused damage to the 'C' phase bushing, arcing on the bottom conductor of the 'A' phase bushing and extensive damage to the corona shields of the 'B' and 'C' phase bushings.

A. ROOT CAUSE(S)

Based on the inspections performed, KT Problem Analysis, and the evaluation of this event, the root cause is:

RC_1: Vendor Design/Manufacturing Deficiency (ES1C) – Trench Electric Type COTA Bushings

Electrical treeing in the paper at the high stress edges of the foil layers lead to a rapid and complete breakdown of the bushings insulation system.

It appears that the electrical treeing is being caused by the manufacturing/design of the foil edges. The foil edges are cut with a device similar to a standard office paper cutter. This results in "sharp" edges that do not control the electrical stresses at the foil/paper interface. These stresses cause the electrical treeing in the paper. The analysis of the paper, foil and oil did not reveal any other anomalies that would have lead to the treeing.

Other manufactures use precision cutting techniques to cut the foil and fold over the edges. These techniques result in smooth rounded edges that control and minimize the electrical stresses. It was also observed during bushing assembly that the foils are manually placed into position using only a template for alignment (other manufactures may use devices such as laser alignment). This method could result in misplaced foils, if even by fractions of an inch, which could alter the capacitive grading; thus potentially further weakening the already treed insulation system.

There were no human performance issues identified for this event because all recommended testing and analyses were being performed on the 21 Main Transformer prior to the event, with no adverse trends or abnormalities. Also, the new 21 Main Transformer installed in 2006 was specified correctly for its application, and there was no known OE that identified deficiencies associated with the Trench Electric high voltage bushings supplied with the 21 Main Transformer by the transformer vendor. It is documented in the industry (EPRI and INPO) that bushing failures are unpredictable and typically can only be detected at the point of failure. This high voltage bushing had a good history of operation and no thermography issues. Doble testing and physical inspections did not reveal any abnormalities.

B. <u>CONTRIBUTING CAUSE(S)</u>

There are no contributing causes identified for this event.

<u>Evaluation of Failure and Potential Causes:</u>

The original Westinghouse 21 and 22 Main Transformers were replaced in 2006 due to aging and increased generation from power up-rate in 2004. The 21 and 22 Main transformers were replaced under modification ER-04-2-059, and attachment 9.1.4 of the mod write-up provides a comparison of characteristics between the old and replacement transformers. Electrically, the transformers are very similar with the same voltage ratios, winding connections, taps, basic impulse levels (BIL), and temperature ratings. Electrical differences are as follows;

- Maximum MVA capacity of the new transformers is a little higher than the old units, with ratings of 629MVA versus the old rating of 607MVA. This provides additional load carrying capacity at the same temperature rating.
- Impedance values for the new transformers are slightly higher. This provides less fault current contribution at 345kV buses, and less reduced fault current on the isolated phase bus.

The modification determined that the replacement 21MT &22 MT transformers were correct for installation at Unit 2, based on the electrical ratings and transformer design. As part of the procurement plan for the new 21 and 22 Main Transformers both IPEC and Entergy T&D personnel were sent to the manufacturing facility to witness fabrication, test and inspection of the transformers.

The new transformers are Siemens type transformers, with Trench Electric type COTA style number 1175-F020-23-AG3-02 high voltage bushings. These bushings are fixed conductor, condenser type oil impregnated bushings. There is no known industry issues associated with these type bushings. A Doble test was completed at the factory in 2005, after installation in 2006, and again in 2008. There has been no adverse trending in the Doble test results for these bushings. Discussions with the bushing manufacturer (Trench Electric) indicated that they have not had any failures of these bushings from their factory. There have been other industry failures attributed to Trench Electric bushings of different design (i.e., draw lead bushings), different voltage levels, and manufactured location (France), but no design issues have been identified for the specific type bushings used on IP2 21 & 22 Main Transformers.

The evidence found during the internal inspection is indicative of a bushing failure. When a high voltage bushing is transmitting high voltage (345,000 volts) to the bus, the bushing insulation and seals are vital to prevent internal bushing gassing / overheating and current tracking. This type of failure mode typically results from a breakdown in the insulation or gassing due to moisture intrusion or loss of insulating oil via the bushing seals. The conductive layers (foils) of the condenser are separated by the (insulation) oil impregnated paper. In the event where insulating paper is compromised, either by moisture intrusion, oil loss, or gassing (gas bubbles formed between the paper layers due to heat or arcing), the conductive layers are essentially shorted allowing current tracking across the condenser layers. Voltage can no longer be contained within the bushing and will flashover or strike out of the bushing to the closest grounded metal surface, causing total destruction of the bushing. This describes an internal failure of the bushing insulating properties resulting in a sudden bushing explosion. This is evident of the tank rupture in the vicinity of the ‘B’ phase bushing and having no prior dissolved gas issues up to 2 hours prior to the failure. Examination of the B phase bushing detected an arc strike from the bushing center conductor through the bushing insulating paper.

Since the bushing had excellent power factor and capacitance test values as early as 2008, this type of bushing failure is a low probability. Typically, Doble test values are trended during maintenance periods and increases in the power factor indicate that the bushing is degraded and replacement is recommended. Bushings degrade throughout service life and level of degradation is reflected in Doble test values. The values are trended and at end of life the values should indicate a need for replacement. This bushing was only 4 years old and had no Doble power factor test value concerns since installation.

Based on the internal inspection and KT analysis, one of the possible causes was the failure of the supports for the corona shield, allowing the base of the bushing to be exposed. The arcing patterns found on the bottom terminal of the bushing indicate evidence of both low and heaving arcing. It is possible the arcing developed as a result of the shield dropping to expose the bushing bottom terminal. The corona shield is necessary to equally distribute the stresses that are developed from the high voltage. Without the corona shield, the voltage stresses would not be controlled and the bushing bottom terminal would be subject to arcing. Upon further review by Siemens personnel, it was concluded that this was not the failure mode due to the construction of the corona shield assembly and there was no evidence of partial discharge in the online gas monitoring system prior to the fault. Reference Attachment V for Siemens Technical report issued on HV bushing and corona shielding.

The largest arc strike was found to the left of the ‘B’ bushing (looking from the high voltage side of the transformer) at the turret. Based on this arc strike, the ‘B’ phase blast was directed to the left of the bushing causing a pulse wave / damage of the epoxy-resin on the ‘C’ phase bushing. This is evidence of the epoxy-resin falling straight down since there were no signs of fragment impact on the ‘C’ phase bushing adjacent walls.

No loose connections were found on the ‘B’ phase high voltage bushing conductors. This eliminates loose connections as a potential cause of arcing inside of the bushing.

Semi-annual thermography is performed on these bushings, in addition to daily operator rounds to check the bushing oil sight glasses and to check for oil leaks. No adverse trends or abnormalities were observed prior to the failure.

A root cause analysis of this event was performed IAW EN-LI-118 section 5.5.4, using KT Problem Solving and Why Staircase. A root cause could not definitely be determined, because the failure destroyed most of the direct evidence. The bushing thermography and Doble values were acceptable prior to the event, so there were no precursors. Based on the root cause analysis performed, the most probable root cause is a vendor design/manufacturing deficiency, specifically, internal insulation failure of the ‘B’ phase high voltage bushing, resulting in a catastrophic failure of the bushing.

The failure of the 21 Main Transformer B phase high voltage bushing was catastrophic, without any adverse precursors (Doble testing, on-line gas monitoring, and DGA analysis). In order to best determine the specific cause of the bushing failure, an independent equipment failure analysis of the failed bushing is being performed by an outside vendor. Following completion of this independent failure analysis, Entergy will review the findings and identify further corrective actions as needed.

Organizational and Programmatic Weakness Evaluation:

As part of this root cause analysis, this event was reviewed for organizational and programmatic (O&P) weaknesses using the guidance in EN-LI-118, Attachment 9.5. The root cause of this event is a vendor design/manufacturing deficiency associated with Trench Electric type COTA bushings. There were no organizational and programmatic issues identified for event, because the Trench Electric bushings were selected and supplied by the transformer vendor, Siemens, as suitable for their the transformer they were supplying. The transformer was correctly specified by Entergy for its application, with respect to its size, rating and other technical parameters. The transformer purchase specification, which identified the Trench Electric high voltage bushings, was reviewed by the Entergy T&D Group, who concurred with the selection. There was no known industry OE that identified design deficiencies associated with these Trench Electric type COTA bushings. Also, there were no Entergy human performance issues associated with this event, because all industry and vendor recommended preventive maintenance, inspections and analyses were being performed on these transformers.

C. Safety Culture Evaluation

A Safety Culture Evaluation of the most probable root cause was performed, using EN-LI-118, Attachment 9.6, Table 1, “Safety Culture Comparison”, and Table 2, “Detailed Safety Culture Component Review”. The completed tables are documented in Attachment VIII of this root cause analysis. Note that there were no significant contributing causes identified for this event, so only the root cause was evaluated.

Results:

The root cause identified for this event was a vendor design/manufacturing deficiency associated with Trench Electric type COTA transformer high voltage bushings. There were no safety culture issues identified for this cause.

In this event, personnel work practices supported human performance expectations. Personnel involved did perform their activities per approved procedures and expected work practices. There was no human performance issue associated with this event.

Generic Implications: Extent of Condition and Extent of Cause

Extent of Problem/Condition:

The extent of problem/condition (EOC) performed for this event included components electrically connected to 21 Main Transformer and may have been impacted by the fault. This includes 22 Main Transformer, Unit Aux Transformer, and the Iso-phase Bus. The Main Generator was excluded from the EOC due to a discussion with General Electric Engineering which indicated that the fault value was within IEEE limits and therefore it is unlikely the Generator was affected.

External visual inspections of the 22 Main Transformer high voltage bushings were performed. There were no signs of cracks or damage to the bushing flanges. No chips or cracks were found on the porcelain insulators. The 'A' and 'C' phase bushings have no signs of oil leaks and oil levels were satisfactory. The 'B' phase bushing has a small oil leak in the vicinity of the flange plug near the nameplate side. No other anomalies were found and oil level was satisfactory. CR-IP2-2010-06918 was generated to document the oil leak. Siemens identified the source of the leak to be the vent plug, which was tightened and the minor leakage stopped.

External visual inspections were completed satisfactorily on both the Unit Aux Transformer and Iso-phase Bus.

EOC Testing and Analysis of Results

Testing was performed to confirm that electrical components in close electrical proximity to the faulted transformer are still functional. A summary of the testing performed, IAW recommendations from Entergy Fleet Engineering Guide EN-EE-G-001, is provided below:

- In addition to the minimum tests required to perform on a close-in fault on a transformer the following tests were also selected (1) sweep frequency response analysis, and (2) infrared thermography.
- Lightning arrestors are connected to the high voltage bus near the faulted transformer. Testing of these components is considered important since they perform an electrical protective function, and there's recent history of component failures.
- The isolated phase bus is connected to the low voltage side of the faulted transformer. As a result of the fault, the bus experienced higher than normal loading (amperes) and testing will ensure that no damage has occurred.
- Protective relays that operated during the fault will be checked to ensure adequate calibration and settings are maintained.
- Corona and thermography testing of electrical components in the transformer yard will be performed to detect any defects or flaws that are not obvious to the naked eye, but could lead to operational issues.

Main Generator testing was not considered necessary, since the fault was on the high side of 21 Main Transformer. Fault current contribution from the main generator was limited due the impedance of the transformer itself. No Generator protective relays activated, except over-frequency which was expected for a simultaneous trip (sudden loss of load). Relaying and circuit breakers isolated the fault within milli-seconds, therefore the generator experienced only minimal stress.

The following testing was performed to assess the condition of 22 Main Transformer, the Unit Auxiliary Transformer, and Iso-phase Bus are electrically connected to 21 Main Transformer and may have been impacted by the fault. The testing performed is varied due to different transformer types.

22 Main Transformer- Siemens:

- Transformer Power Factor Test
- Transformer Capacitance Test
- Bushing Power Factor Test (High Voltage Bushings)
- Bushing Capacitance Test (High Voltage Bushings)
- Bushing Hot Collar Test (Low Voltage Bushings)
- Excitation Current Test
- Leakage Reactance Test
- Transformer Turns Ratio (TTR)
- Winding Resistance Test
- Winding Insulation Resistance Test (Megger)
- Sweep Frequency Response Analysis (SFRA)
- Dissolved Gas Analysis (DGA)
- High Voltage Bushing DGA

Unit Auxiliary Transformer-Westinghouse:

- Transformer Power Factor Test
- Transformer Capacitance Test
- Bushing Hot Collar Test
- Excitation Current Test
- Winding Insulation Resistance Test (Megger)
- Dissolved Gas Analysis (DGA)

IP2 22kV Isolated Phase Bus

- Visual inspection of areas affected by fire & heat
- Electrical Megger testing of the bus to ensure electrical integrity

Generic Implications: Extent of Condition and Extent of Cause

All testing on 22 Main Transformer and the Unit Auxiliary Transformer was completed satisfactory, see Attachment IV for Testing and Results Matrix for 22 MT and UAT. Results were reviewed by Entergy Engineering, Doble, and Siemens.

During Doble testing of 22 MT, Siemens technicians also identified an oil leak within the core ground terminal box, located on the top of the transformer. This terminal box is a “feed through” penetration used for accessing internal ground connections during testing and was repaired by Siemens.

The 22 Main Transformer and the Unit Auxiliary Transformer show no signs of degradation with the current gas in oil analysis. Additional testing has determined that no degradation has occurred due to the failure of 21 Main Transformer. Based on the results of this testing, an internal inspection of the 22 Main Transformer was not deemed necessary.

Visual inspections and Megger testing of the 22kV Iso-phase Bus were completed satisfactorily on 11/19/10. There was one anomaly noted regarding a change on ‘A’ phase meggar reading being lower than the ‘B’ and ‘C’. ‘A’ phase measured 4 Gigaohms in comparison to ‘B’ and ‘C’ phase which measured 33 Gigaohms. Although the value was within the specified acceptance criteria, this is a change from the last time the test was performed in 2006, and all three phases were 30 Gigaohms. CA: 022 of CR-IP2-2010-6801 has been issued to perform a full ‘A’ phase inspection next outage.

All three lightening arrestors were inspected and tested satisfactory. A visual inspection of the 345KV W95 line was performed. The inspection identified the need to replace the ‘B’ phase cable drop from the Turbine Building to the transformer fire wall. The cable was replaced under WO 257043, EC 26055. All protective relays that actuated were calibrated satisfactory.

Extent of Cause:

RC1:

The root cause as described in the Root Cause section is a design/manufacturing weakness associated with the Trench Electric Type COTA high voltage bushings. At IPEC, the extent of cause is limited to main transformer high voltage Trench Electric type COTA bushings, which are installed on IP2 21 and 22 Main Transformers. There are no other Trench type COTA bushings installed at IPEC, or at any other Entergy Nuclear facility.

To prevent potential future failures of Trench Type COTA bushings it is recommended that they are replaced with another manufactures bushing. It is recommended that the bushings are replaced at the next opportunity during 2R20 (2012). This is based on the following facts:

- There is no warning of an incipient catastrophic failure.
- The failure mechanism (electrical treeing) cannot be detected via non-destructive test methods.
- Although our failure occurred after 4 years of service, there is no way to evaluate that this failure mechanism requires that much time to cause a failure. (we currently only have one data point)
- All six Trench bushings torn down to date have shown the presence of the failure mechanism (electrical treeing).
- The failure mechanism (electrical treeing) has been seen in a bushing with as little as two years of service life. If the existing bushings are left in-service until 2R21 (2014) they will have approximately three years of service life; increasing the risk for a catastrophic in-service failure.

Service Life of In-service Trench Type COTA Bushings

	2R20 (2012)	2R21 (2014)
21MT	1 year 4 months	3 years 4 months
22MT	0 years 10 months	2 years 10 months

- IPEC currently does not have a spare main transformer. A subsequent failure would be a large economic impact to Entergy.
- A failure of a Main Transformer has the potential to cause collateral damage to the Isophase Bus, Main Generator and/or Station Auxiliary Transformer.
- IPEC has recently had two main transformer failures. A subsequent failure could adversely affect public relations.

Generic Implications: Extent of Condition and Extent of Cause

The risk significance of the most probable root cause discussed above is medium, because this cause would not be expected to impact nuclear safety, or result in the plant being operated outside its design basis. Also, as discussed above, the consequences from this cause could be managed with some effort.

The risk significance, which is the combined considerations of probability and consequences, of a plant auto trip due to a failure of a main transformer is medium. During the operating life of both IP2 and IP3, there have been two previous instances of transformer bushing failure on-line, resulting in plant trips. IP3 had the event of April, 2007 documented in CR-IP3-2007-01834 for which a root cause analysis was performed, while IP2 was purported to have a catastrophic bushing failure in the 1980's due to oil vapor spraying on the bushings from the main turbine lube oil vapor extractor. However, no documentation could be found on this event. Both IP2 and IP3 safety systems performed as required in the 2007 IP3 event and the current IP2 event being evaluated in this root cause analysis. Also, the consequences can be managed with some effort, which supports the risk category of "Medium".

The Main Transformer low voltage bushings have been excluded from the extent of cause as they are Siemens type T model T2700209. These bushings have no history of failure and are a reliable design which utilizes transformer main tank oil for cooling and dielectric properties.

Previous Occurrence Evaluation

The failed 'B' phase high voltage bushing was a Trench Type COTA with a fixed copper conductor rated at 345kV and 2000A (Style: 1175-F020-23-AG3-02), manufactured in Canada.

There is no industry OE relevant to Trench COTA style bushings that are manufactured in Canada. There is OE on the Trench Draw Lead bushings and those manufactured in France, but none on the specific style that are installed on 21MT and 22MT.

The purpose of this section is to determine how effective preventive actions for similar events have been so that these lessons learned can be applied to the preventive/corrective actions for this event.

Operating experience (OE) from within the IPEC site, Entergy fleet, and the nuclear industry (via INPO, WANO, and Doble databases) was searched and evaluated for applicability to the IP2 main transformer failure and automatic shutdown evaluated by this CR. They were researched, applicable events identified and reviewed. This review focused on determining whether past corrective actions for applicable events were inadequate and contributed to this event.

Internal:

A search of internal operating experience data was performed for main transformer failures to determine if the same or similar conditions had previously occurred at IPEC or other Entergy sites. The searches covered the time period of 1/1/2005 to present and resulted in 291 hits that were related to CRs. The causes and corrective actions from pertinent CRs in the search results were considered during this root cause evaluation.

The CRs were reviewed and one CR of note was CR-IP3-2007-01834.

CR-IP3-2007-01834 documented that on April 6, 2007, while the unit was at approximately 91% power, a fault occurred on 31 Main Transformer which resulted in a Unit 3 automatic trip. A root cause analysis was performed for this CR. The direct cause for the failure was a fault at the B phase bushing. The most probable root causes were determined to be original design weaknesses associated with GE U type bushings.

Main Transformers 21 and 22 are new Siemens type transformers. The high voltage bushings on these new transformers are manufactured by Trench Electric and are type COTA. These bushings are constructed of oil impregnated paper with layers of aluminum foil. There are no industry issues associated with these type bushings. The design is greatly different from the original GE U type bushing design and does not have the design weaknesses that were found with the U type. Therefore, this OE is not specifically applicable to the event of this CR.

In summary, there were no ineffective corrective actions from internal OE nor were there any missed opportunities that could have prevented the event being evaluated under this root cause analysis.

External:

A search of external operating experience data was performed for this event using the INPO web. Transformer, electrical distribution system/grid, and switchyard failures were included in the searches, which covered the time period of 1/1/2005 to present and returned 238 hits. Three of these OE were considered pertinent and reviewed to determine if any actions could have been implemented that could have prevented or mitigated this event. That review is summarized below:

SEN 256, Rev. 1(OE21916): Catastrophic Main Transformer Failure Resulting in Fire and Unplanned Outage

On June 27, 2005, a phase-to-ground fault on the Turkey Point Nuclear Power Plant Unit 4 main transformer caused an automatic trip from 100 percent power and resulted in a fire. The new transformer had been in operation for approximately 14 days when it suffered a catastrophic failure. Subsequent investigation found that the transformer suffered an internal fault. The event began as a high side B phase fault to ground and propogated into a short between all three phases. The cause was determined to be a manufacturing defect involving laminations in the upper B phase compression ring, which resulted in electrical tracking on the underside of the ring.

Although the event scenario has similarities to the IP2 event of this CR, the inspections and failure analyses if the IP2 21 Main Transformer failure suggest that the most likely cause was an internal insulation failure of the 'B' phase bushing.

SEN 275: Catastrophic High-Voltage Bushing Failure Results in Transformer Fire and Unplanned Outage

On August 16, 2008, the Diablo Canyon Unit 2 reactor automatically scrammed from 100 percent power because of an electrical fault on a high-voltage bushing on one of the main, single-phase 500 KV transformers. Oil from the bushing and transformer ignited in the vicinity of the failed bushing, causing a fire at the transformer. The entire porcelain portion of the bushing was ejected by the energy from the electrical fault. The presumed cause of the catastrophic bushing failure was either an internal degraded ground connection at the C phase high-voltage bushing test tap, or an accelerated internal oil loss that resulted in a partial discharge and subsequent bushing degradation. Because of damage, the specific reason for the bushing failure could not be determined. The bushing was no longer connected to the generator via the transformer. This was because the failure caused an internal pressure wave that lifted the bushing with enough force and distance to pull the lugs off the four multi-conductor leads connecting the transformer secondary winding to the bottom of the bushing conductor. The causes were presumed to be either an internal degraded ground connection at the C phase high voltage bushing test tap, or an accelerated internal oil loss in the bushing that resulted in a partial discharge and subsequent degradation of the bushing insulation. The organizational weakness identified during the investigation included those in the area of performance monitoring of the bushing, procedure guidance for oil-filled transformer maintenance, and control of forensic evidence following the bushing failure.

For the main transformer bushings at IPEC, the performance monitoring exceeds recommended practices and includes quarterly thermography, monthly DGA testing, and daily operator rounds to check bushing sight glass levels and to check for oil leaks. Also, there were no deficiencies identified in the maintenance practices for the IPEC transformers, and the failed bushings were being sent out for independent failure analysis. Therefore, there are no corrective actions from SEN 275 that would have prevented the IP2 21 Main Transformer failure.

SOER 02-3 investigates large power transformer reliability in nuclear power stations. It was identified that despite industry attention, transformer events were on the increase. Investigation into the events revealed that degraded conditions frequently were not recognized in time for stations to take appropriate actions in order to prevent catastrophic failure. As identified in the root cause analysis performed for CR-IP3-2007-01834, IPEC System Engineering has reviewed SOER 02-3 in detail and has determined that IPEC is meeting or exceeding the recommended contingencies, training and expertise levels that each station should have available.

INPO has issued SOER 10-1 Large Power Transformer Reliability, which replaces SOER 02-3 in its entirety. The SOER was issued because of the unacceptably high number of large power transformer failures over the past several years. For over 10 years, the rate of scrams as a result of transformer failures has not improved, and forced losses have increased over the same interval. Transformer failures challenge operators by causing electrical power system transients, equipment unavailability, scrams, fires, and emergency plan entries. The industry has taken steps to improve transformer reliability by implementing SOER 02-3, Large Power Transformer Reliability, and other industry guidance. Technology and maintenance strategies have been improved, and inservice transformer failures have been avoided through better performance monitoring and trending of adverse transformer conditions. SOER 10-1 provides recommendations that represent the advances in technology and transformer management strategies.

IPEC has responded to SOER 10-1 under CR-IP2-2010-01985 and is implementing the SOER recommendations.

In addition to the above three OE, the nuclear industry has had many occurrences of transformer bushing failures. The following OE is a sample of bushing failure/degradation events:

OE#6750 – Beaver Valley Unit 1: While at 100% power on 6-01-1994 Beaver Valley Unit 1 experienced a high voltage bushing failure which caused porcelain debris to enter into the main oil tank and also caused damage to the phase B & C lighting arrestors. LER 94-005-00 listed the only cause as “insulating bushing failure”.

OE#14594 – Browns Ferry Unit 2: While at 100% power on 7-27-2002 a phase to ground fault occurred in a low-side main transformer bushing. LER 05000260 specifically links this to thermal degradation of the condenser bushing paper internal to the bushing. No bushing type was listed in the LER. The IP2 21 Main Transformer bushing that failed was on the high voltage side, however, it is being sent out for an independent failure analysis to determine if there were any signs of internal degradation.

OE#9951 – Pilgrim Power Station: on 5-18-1999 while refueling, the C phase bushing on the generator step-up transformer failed during electrical testing. It is currently believed that this failure was a result of performing electrical testing while the transformer was drained of oil, and not as a result of degraded bushings. Therefore, this OE is not applicable to this event.

OE#24201 – Grand Gulf Station: on 1-09-2007 power factor testing was performed on a 34.5kV transformer. Testing on the GE Type U bushings returned a power factor value greater than 1.5%. Based on the Doble criteria for testing of these bushings, Grand Gulf Engineering made the decision to replace all the Type U bushings with bushings from PCORE electric. The higher power factor is being attributed to thermal cycling of the bushings, which can create gas voids within the bushing condenser and over time allow partial discharge to break down the insulation of the bushing. The IP2 21 Main Transformer high voltage bushings are Trench Electric type COTA, and not the GE type U bushings, so this OE is not directly applicable to this event.

<u>Review of OE on Trench COTA bushing failures:</u>

A review of the available OE on Trench COTA bushing failures has been performed. This included review of the Doble website, discussions with the Transformer manufacturer (Siemens), discussions with a former Trench Bushing Project Manager (that has his own consulting company now), direct discussions with Trench and discussions with the Entergy Energy Delivery Department.

The overall results indicate a lack of any indicated failure data for this particular type of Trench bushings manufactured in Canada. Other types having the draw lead have had past performance issues but the type that failed at IPEC is a bottom terminal type. An oil interaction on certain voltage range bushings was reported that has been corrected in the manufacturing process which did not apply to this type bushing (French facility using Shell Diala D oil).

Contact with Trench Electric confirmed the OE search results in that Trench was not aware of any failures of this specific style (345 kV,2000A) Trench bushing anywhere. Trench indicated that our failure was the first case ever reported.

<u>Trench COTA OE Results</u>

June 2011 – A Trench Type COTA fixed aluminum conductor bushing failed in a 500kV transformer in the FirstEnergy system. This is a recent event in the non-nuclear industry; as such minimal information exists on the event. The bushing was manufactured in 2009.

May and June 2006 – Two Trench Type COTA fixed copper conductor bushings failed in separate transformers in the Southern Company System. Upon bushing teardown it was found that the bushings had signs of electrical treeing. The sister bushings were also found to have signs of electrical treeing, with one bushing having a puncture hole at the bottom of the first foil layer. A paper presented by Trench at the 2010 Doble Client Conference concluded that the electrical treeing was being caused by copper migration. The copper migration was attributed to the type of oil (Shell Diala D) being used in the bushings. The bushings were manufactured in 1999 and 2001 in the Trench France facility. (Reference 19)

June 2009 – A Trench Type COTA aluminum draw lead bushing failed in a 353kV transformer in the Duke Energy system. Upon bushing teardown it was found that a layer of foil was omitted during winding of the bushing. Trench concluded that the missing foil was the probable cause for the failure, with external factors (i.e. switching surges) as possible contributors. The bushing was manufactured in 2001 in the Trench France facility.

2001 – 2009 – Thirteen related or suspect Trench Type COTA draw lead bushings have failed through out the US in 230kV systems. A paper presented by Trench at the 2011 Doble Client Conference concluded that the bushing failures were not related to bushing design, materials or quality issues. They concluded that the bushing failures seem to be the result of external factors, mainly related to very fast transients and the arcing between the draw lead cable and the bushing tube due to such transients. It was also concluded that the phenomenon will and likely has impacted other bushing manufactures and it is not limited to Trench COTA bushings. The bushings were manufactured at all three Trench facilities. (Reference 20)

In summary, there were no ineffective corrective actions from external OE nor were there any missed opportunities that could have prevented the event being evaluated under this root cause analysis.

Nuclear Safety

This event was an automatic reactor trip caused by a turbine generator trip which occurred due to a fault in the 21 Main Transformer, and subsequent high differential current on the 345KV side of the transformer. Automatic reactor trips do present a challenge to nuclear safety systems, however all plant safety systems functioned properly and within design basis and the UFSAR. The resultant loss of power from the Unit 2 trip is bounded by the UFSAR Section 14. An Alert was declared due to 21 Main Transformer explosion. EAL 8.2.3 was selected.

Radiological Safety

There is no impact on radiological safety because this event occurred in the transformer yard, which is not a radiologically controlled area. This event did not cause any radiation exposure to workers, nor did it involve any equipment, processes or procedures related to radiological work.

Environmental Safety

Following the failure of 21 Main Transformer, oil (from 21 Main Transformer) mixed with water from the fire deluge system, overflowed the transfomer's containment structure and penetrated the East wall of the Turbine Building. This oil/water mixture flowed onto the 15 ft elevation of the Turbine Building near the 6.9KV Switchgear and into the 5 ft elevation, as well. All Turbine Building sump pumps were secured. The oil leak was contained in the transformer yard moat area and the turbine building, and did not meet the reportability requirements of SMM-EV-101. The oil sheen that was seen in the discharge canal was being contained. The DEC was notified and the area was investigated and cleaned by Fire Protection and Safety. CR-IP2-2010-7244 was issued to track the remediation of the Unit 2 Transformer Yard, the Site Discharge Canal, and shore line south of the Algonquin Gas Line

Industrial Safety

There is no impact on industrial safety because there were no personnel injuries or accidents associated with this event. The industrial safety significance was the catastrophic failure of the bushing that resulted in a fire and explosion in the transformer yard. There were no personnel present in the yard at the time of the initial event, so there were no injuries involved. Any personnel in the yard at the time of the failure could have been struck by the projected debris resulting in possible personnel injury. There were fire brigade personnel in the transformer yard at the time of the second explosion. CR IP2-2010-06809 was initiated by the IPEC training department to capture debrief comments from the fire brigade members following the response to the 21 main transformer event. Corrective actions were assigned from this CR to the Operations department. CAs 1 & 2 of this CR are in place to ensure that the issues identified by the fire brigade are resolved. This event did not create any new industrial safety hazards, nor were there any instances identified where personnel worked in an unsafe manner.

Corrective Action Plan

All root and contributing causes, and generic implications must have corrective actions or a documented basis why no action is recommended.

Identified Cause	Corrective Actions	Responsible Dept.	Due Date
	Immediate Actions		
DC-1: Fire developed on 21 Main Transformer due to the fault.	Fire was extinguished, area cleaned.	Safety	Complete
DC-1: 21 Main Transformer fault resulted in a Unit 2 trip.	PTRG Committee was assembled to evaluate plant effects- CA: 008.	Operations	Complete
DC-1: 21 Main Transformer explosion	Alert Notification was declared in accordance with EAL 8.2.3.	Operations	Complete
DC-1: Oil from 21 Main Transformer found in Discharge Canal	Notification to NYS DEC of oil from 21 Transformer in discharge canal.	Operations	Complete
DC-1: Oil/water intrusion in Turbine Bldg. due to 21 Main Transformer fire and deluge activation.	Open and inspect 6.9 KV Switchgear panels due to oil/water intrusion- CA: 009.	Maintenance	Complete
RC-1: 21 Main Transformer bushing fault.	Complete replacement and acceptance testing of 21 Main Transformer- CA: 010.	Projects Management	Complete
EOC-1: 21 Main Transformer explosion possibly damaged equipment in close proximity.	Complete appropriate testing of 22 Main Transformer, Main Generator and Iso-Phase Bus, as required- CA: 011.	System Engineering	Complete

Corrective Action Plan

Identified Cause	Corrective Actions	Responsible Dept.	Due Date
RC-1: 21 Main Transformer failure.	Develop and implement a monitoring plan for 21 Main Transformer- CA: 018.	System Engineering	Complete
	Interim Actions		
N/A	None		
	Short & Long Term Actions		
Enhancement	Evaluate the installation of bushing monitors.	System Engineering	2/20/11
RC-1	Perform failure analysis of all three HV bushings on failed 21 MT.	System Engineering	4/27/11
Extent of Cause	Submit scope testing of 32 Main Transformer into 3R16. The transformer is scheduled for power factor tip up testing, but the bushings are not scheduled to be tested. The 'B' phase HV bushing is a Trench Electric Type COTA.	System Engineering	1/20/11
Extent of Cause	Evaluate the need to revise the PM frequency for bushing/transformer testing from every 4 to 2 years as a result of recent failure of 21 MT, which tested SAT in 2008.	System Engineering	1/21/11
RC-1	Revise the Root Cause with CAPRs as necessary, issue Effectiveness Review Plan, and Equipment Failure Evaluation as necessary, based on results of the failure analysis of the HV bushings.	System Engineering	5/3/11

Corrective Action Plan

Identified Cause	Corrective Actions	Responsible Dept.	Due Date
CAPR RC-1	Replace the Trench type COTA bushings in 21 and 22 Main Transformers with another manufactures bushing.	System Engineering	5/1/12

Effectiveness Review Plan

This section should contain an Effectiveness Review strategy that includes the following:

Method – Describe the method that will be used to verify that the actions taken had the desired outcome.

Attributes – Describe the process attributes to be monitored or evaluated.

Success – Establish the acceptance criteria for the attributes to be monitored or evaluated.

Timeliness – Define the optimum time to perform the effectiveness review.

1. Effectiveness review actions are required for all CAPRs.

CAPR: Replace the Trench type COTA bushings in 21 and 22 Main Transformers with another manufactures bushing.			
	Action	**Resp. Dept**	**Due Date**
Method:	Review bushing replacement EC 31512 to ensure another manufactures bushing is being specified.	System Engineering	6/1/12
Attributes:	Monitor bushing replacement work orders 289104 and 289102 and their schedule for the next outage (2R20)	System Engineering	6/1/12
Success:	The bushings are replaced in 21 and 22 Main Transformers with another manufactures bushings	System Engineering	6/1/12
Timeliness:	Upon competition of bushing replacements	System Engineering	6/1/12

1. **Repeat the above for each CAPR, as required.**
2. **Similar MAST criteria may also be shown for other important corrective actions.**

References

Documents reviewed:

1. CR-IP2-2010-06803
2. CR-IP2-2010-06806
3. CR-IP2-2010-06810
4. CR-IP3-2007-01834
5. Post Transient Evaluation for CR-IP2-2010-06801
6. Event Recollection Forms for this event
7. 9321-LL-3130, Rev. 32, Generator Primary Lockout Relay 86/P
8. IP-SMM-EV-101, Rev. 3, IPEC Spill/Release Response Plan
9. IP2 System Description 27.1, Electrical Systems
10. VM# 2932, Siemens 629MVA 345/20.3KV Three Phase GSU Xfmr Operating Instruction Manual
11. Modification ER-04-2-059, Replacement of Main Transformers MT21 and MT22
12. EN-EE-G-001, Rev. 1, Large Power Transformer Inspection Guidelines
13. 2-XFR-006-ELC, Rev. 4, Main Transformer Preventive Maintenance
14. 0-XFR-403-ELC, Rev. 6, station or Unit Auxiliary Transformer Preventive Maintenance
15. 2-BKR-007-ELC, Rev. 1, General Electric, Type AKR-NB-50-D Low Voltage Breaker Maintenance
16. SEN 256, Rev. 1(OE21916), Catastrophic Main Transformer Failure Resulting in Fire and Unplanned Outage
17. SEN 275, Catastrophic High Voltage Bushing Failure Results in Transformer Fire and Unplanned Outage
18. SOER 02-3, Large Power Transformer Reliability in Nuclear Power Stations
19. Investigation of Failures of [Trench] 230-KV OIP Copper Conductor Bushings, 2010 Doble Engineering Company -77th Annual International Doble Client Conference
20. Investigation on Failures of Trench Draw Lead COTA Bushings, 2011 Doble Engineering Company -78th Annual International Doble Client Conference

References

Personnel contacted:

Richard Burroni – System Engineering Manager

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Charlie Braun – System Engineering

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Eddie Hester – Entergy T&D Support Group

Herb Robinson – Design Engineering-Electrical

Marcello Mastropietro – Security

Mike Spagnuolo – Security

Konrad Mann – Operations

Ross Rohla – Operations

Tom Alexander – Operations

Mike Cosentino – Operations

Luke Hedges – Operations

Kevin McKenna – Operations

Mike Ruh – Operations

Pete Campbell – Operations

Don Dewey – Operations Shift Manager

George Keller – Operations

Seth Tell - Operations

Team Members:

Steve Manzione – Programs and Components Engineering Supervisor - Team Lead (RCA Qualified)

Robin Daley – System Engineering

Ovidio Ramirez – System Engineering

Theresa Motko – System Engineering (RCA Qualified)

Lou Lobrano – Programs & Components Engineering

Vincent Andreozzi – System Engineering Supervisor

References

Chris Ingrassia – System Engineering (RCA Qualified)

Mike Vasely – System Engineering Supervisor

Bob Sergi – Design Engineering – (RCA Qualified)

Joe Raffaele – Design Engineering-Electrical Supervisor

Mike Tumicki – CA&A (RCA Mentor)

Paul Bode – CA&A

Carl Smyers – Operations

Rick Johnson – Maintenance-I&C

Tom Dempsey - Training

<u>Analysis Methodologies employed:</u>

1. Why Staircase Analysis
2. KT Problem Solving Analysis

<u>Attachments:</u>

I. Digital Fault Recorder (DFR) data provided by Con Edison system operator

II. URS Engineering Analysis of IPEC Relay Protection

III. Final Report Transformer Bushing Root Cause Assessment 21 Main Transformer Fault of November 7, 2010 , Rev 2, Lucius Pitkin, Inc.

IV. Testing Matrix of 22MT & UAT

V. Siemens Technical Report to date, March 16 2011

VI. Why Staircase

VII. KT Problem Solving Chart

VIII. Safety Culture Evaluation EN-LI-118, Attachment 9.6, Table 1 and Table 2

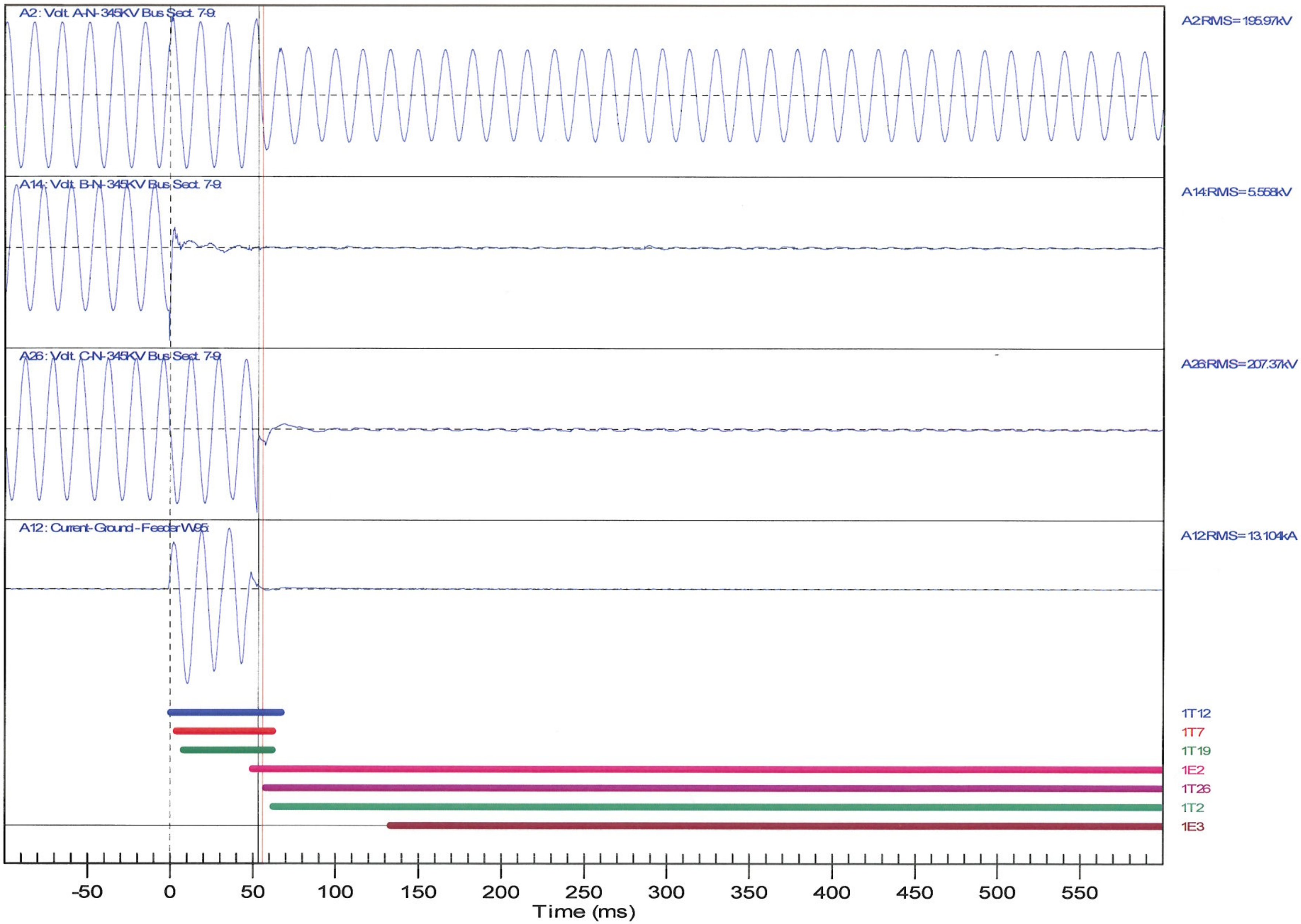
IX. Event Recollection Forms

X. Equipment Failure Evaluation Form

Attachment I

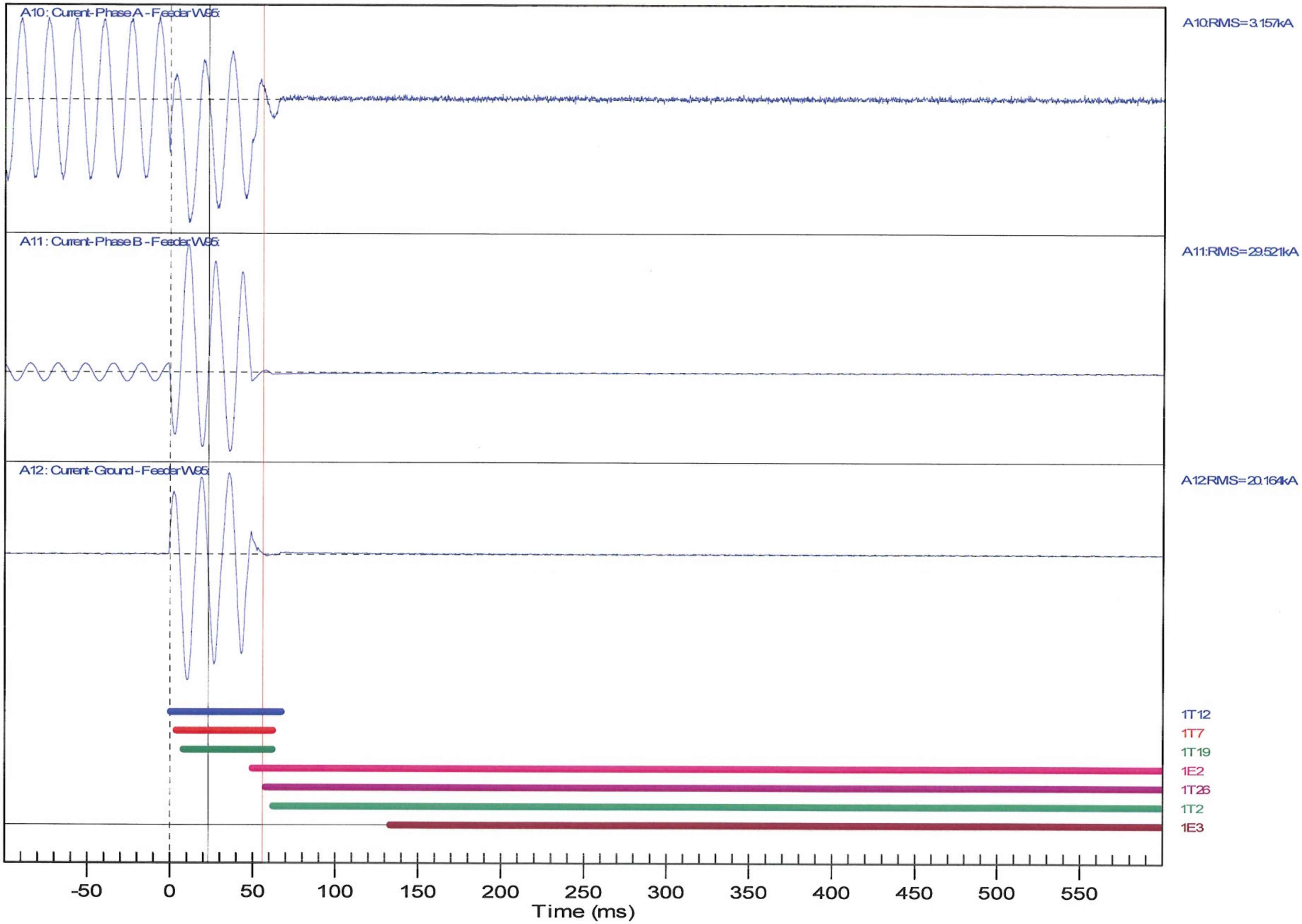
R03F0392 : Buchanan 345kV (DFR)

Fault Time : 11/07/2010-18:39:36.197710



R03F0392 : Buchanan 345kV (DFR)

Fault Time : 11/07/2010-18:39:36.197710



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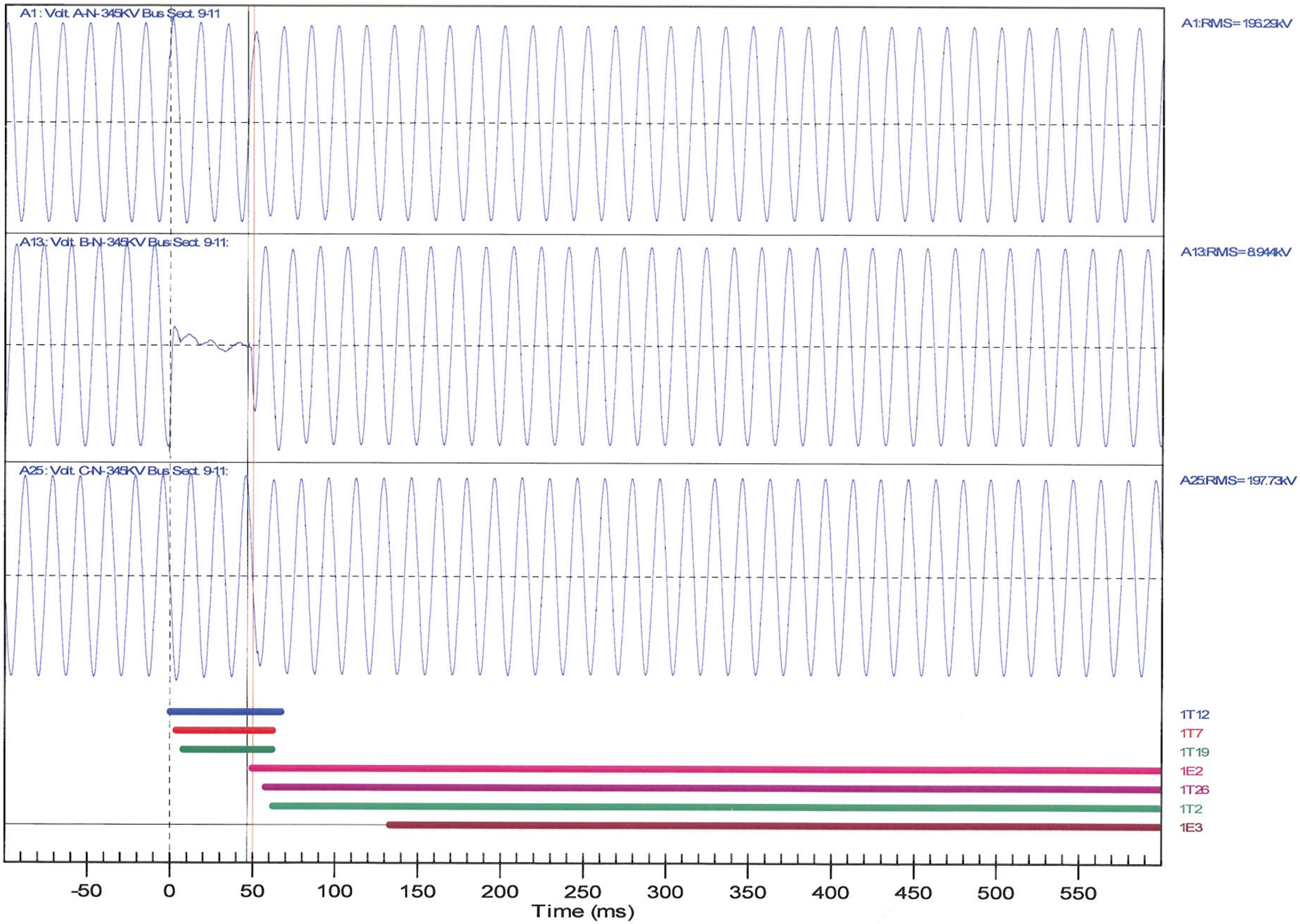
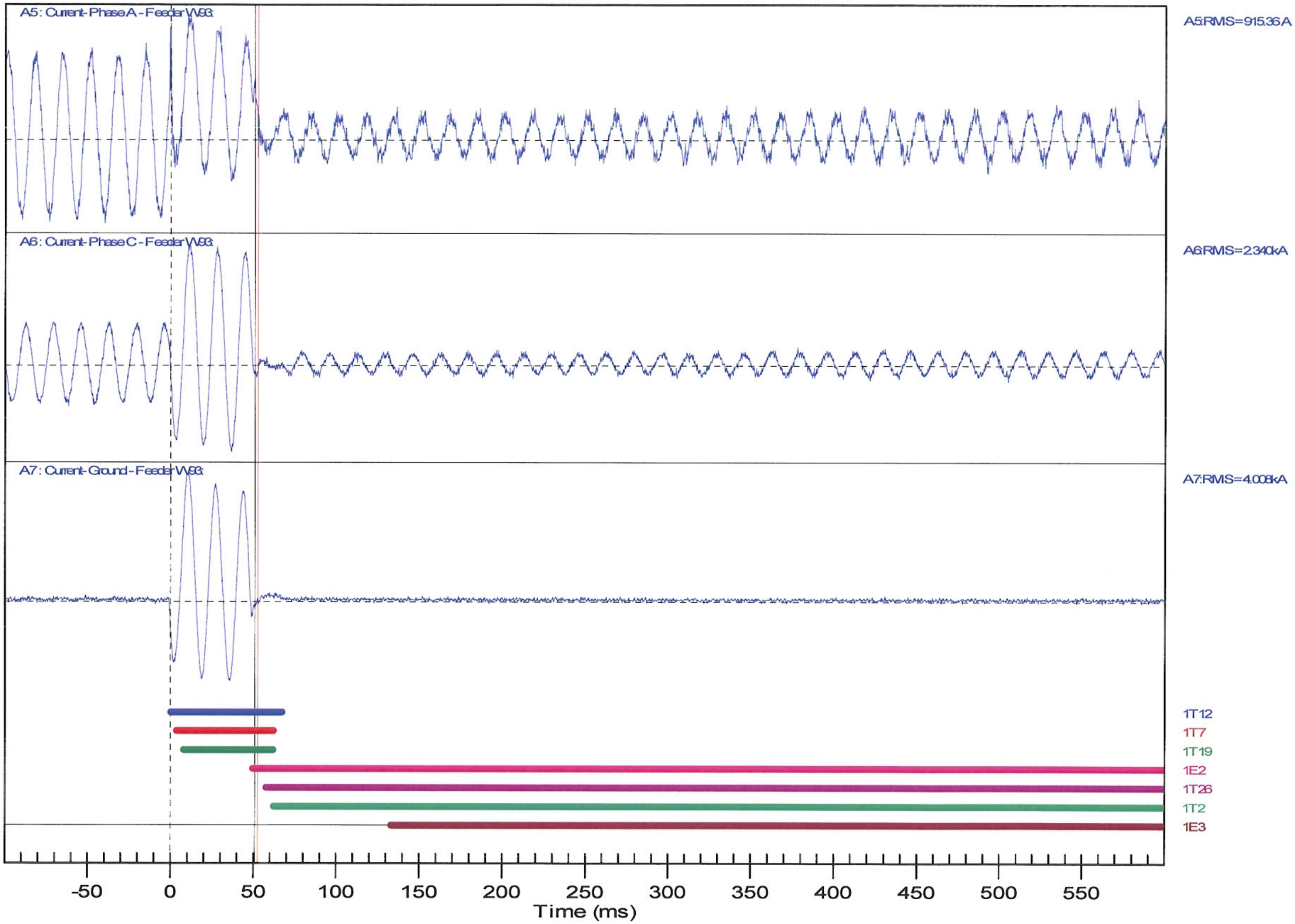
Fault Time : 11/07/2010-18:39:36.197710



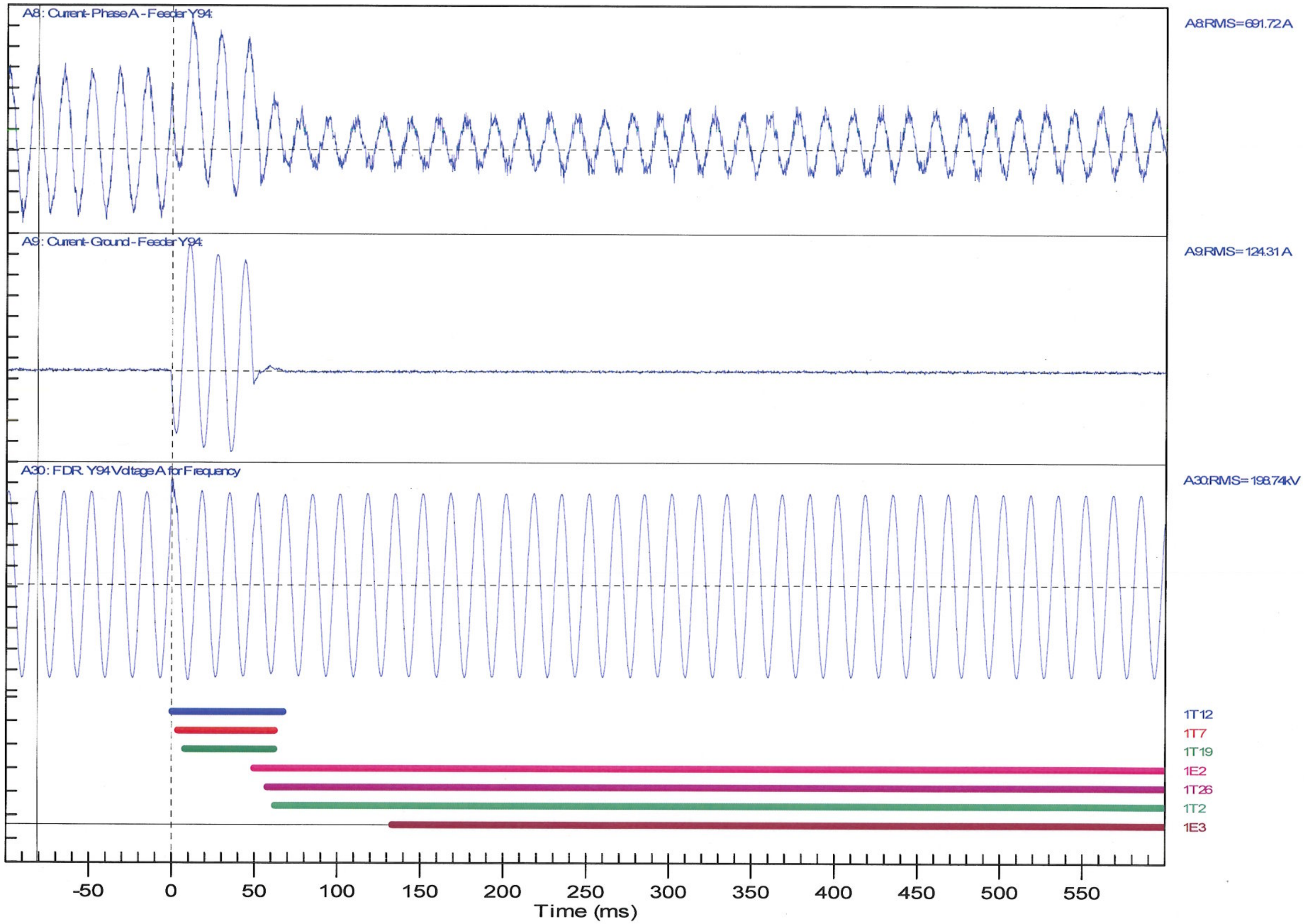
R03F0392 : Buchanan 345kV (DFR)

Fault Time : 11/07/2010-18:39:36.197710



R03F0392 : Buchanan 345kV (DFR)

Fault Time : 11/07/2010-18:39:36.197710



Attachment
II

Entergy

ENTERGY NUCLEAR
Engineering Report Cover Sheet

Engineering Report Title:
Main Transformer 21 Fault Study

Engineering Report Type:

New ☒ Revision ☐ Cancelled ☐ Superseded ☐
Superseded by: ______

Applicable Site(s)

IP1	☐	IP2	☒	IP3	☐	JAF	☐	PNPS	☐	VY	☐	WPO	☐
ANO1	☐	ANO2	☐	ECH	☐	GGNS	☐	RBS	☐	WF3	☐	PLP	☐

EC No. 26267

Report Origin: ☐ Entergy ☒ Vendor
Vendor Document No 30362-001.17.01 Rev. 0

Quality-Related: ☐ Yes ☒ No

Prepared by: See Study Revision Page — Responsible Engineer (Print Name/Sign) Date: N/A

Design Verified: N/A — Design Verifier (if required) (Print Name/Sign) Date: N/A

Reviewed by: See Study Revision Page — Reviewer (Print Name/Sign) Date: N/A

Approved by: Joseph Raffaele/ Joe Raffaele — Supervisor / Manager (Print Name/Sign) Date: 12/01/2010

Entergy

ENTERGY NUCLEAR MANAGEMENT MANUAL
EN-DC-149

VENDOR DOCUMENT REVIEW STATUS

☒ FOR ACCEPTANCE ☐ FOR INFORMATION

☒ IPEC ☐ JAF ☐ PLP ☐ PNPS ☐ VY ☐ ANO ☐ GGNS ☐ RBS ☐ W3 ☐ NP

Document No.: IP-RPT-10-00046	Rev. No.0
Document Title: Main Transformer 21 Fault Study	
EC No.: 26267 (N/A for NP)	Purchase Order No.N/A

STATUS NO:
1. ☐ ACCEPTED, WORK MAY PROCEED
2. ☒ ACCEPTED AS NOTED RESUBMITTAL NOT REQUIRED, WORK MAY PROCEED
3. ☐ ACCEPTED AS NOTED RESUBMITTAL REQUIRED
4. ☐ NOT ACCEPTED

Acceptance does not constitute approval of design details, calculations, analyses, test methods, or materials developed or selected by the supplier and does not relieve the supplier from full compliance with contractual negotiations.

	Print Name	Signature	Date
Responsible Engineer	F. Bloise	/ Fred Bloise	12/01/2010
Engineering Supervisor	J. Raffaele	/ Joe Raffaele	12/01/2010

INDIAN POINT UNIT 2

Project Number

Study Number 30362-001.17.01

MAIN TRANSFORMER 21 FAULT STUDY

PREPARED FOR

ENTERGY

URS Corporation
510 Carnegie Center
Princeton, NJ 08540

Revision: 0 Status: Final

STUDY REVISION PAGE

Project Name:	INDIAN POINT UNIT 2 MAIN TRANSFORMER 21 FAULT STUDY	Discipline:	ELECTRICAL
Client:	ENTERGY	Project Number:	30362

Latest Revision:

Revision Signatures KK. FOR R.C.

Kaz Kolodziej K.K.	11/23/10	Richard Casalaina (PDE)	11/23/10
Prepared by	Date	Approved by (title)	Issue Date
Ajoy Das	11/23/10		
Checked by	Date	Approved by (if required) (title)	Date

Status	Rev. No.	Date	Prepared By	Pages	Description of Changes
Final	0	11/23/10	KK	All	Initial Issue

Table of Contents

I. Background

On Sunday, November 7, 2010, at approximately 6:39PM, Indian Point Unit 2 tripped off line as a result of a failure of one of the two generator step-up transformers (T21). The failure resulted in an explosion and a resultant transformer tank rupture in the vicinity of the phase B high-voltage bushing. Entergy contacted URS for the primary purpose of reviewing the relay protection schemes and accident operations of the relays to assess relay schemes' operation as designed. At the same time URS assisted Entergy in review of Con Edison Buchanan switchyard data to assess the events of the failure.

II. Discussion

Following the Unit 2 trip a Disturbance Fault Recorder (DFR) at Buchanan 345kV substation automatically recorded Buchanan 345kV station various bus section voltage magnitudes and various 345kV feeder current magnitudes. Also, Buchanan Sequence of Events Recorder (SER) at Control House #2 automatically recorded various 345kV system protection equipment operating times in a chronological order with recorded time of each event. Similar Sequence of Events Recorder (SER) at Indian Point Unit 2 automatically recorded various plant equipment operating times in a chronological order. Also, following Indian Point Unit 2 trip the operator manually recorded all plant operated relay targets on Relay Operations Following a Trip and Prior to Startup sheets The above documents were given to URS for review/evaluation and results/findings to be summarized in this report.

Buchanan 345kV (DFR) reports generated by Con Edison consisted of two (2) sets of hard copies. Report numbered R03F0392 dated 11/07/2010-18:39:36.197710 depicts sixteen (16) 345kV current and voltage wave forms starting 100 milliseconds before the event and continuing 600 msec after the event, see Attachment 1. Report numbered R03F0391 dated 11/07/2010-18:39:36.197710 depicts sixteen (16) 345kV current and voltage wave forms starting 500,000 milliseconds before the event and continuing 500,000 msec after the event, see Attachment 2.

345kV DFR shows various 345kV bus section phase to neutral voltages and 345kV bus feeder Amps. Typically three (3) phases to neutral voltages are shown for each 345kV bus section and two (2) phase currents and ground current are shown for various 345kV feeders. It must be noted that the plots were setup for automatic graphical scaling of all plotted wave forms. Automatic scaling sets the maximum value of the recorded current or voltage wave as plot's full scale. Each plot also contains a tracer (a vertical line where the cursor intercepts the wave) for which the RMS value of corresponding voltage or current is shown on the right side of the plot.

Based on the facilities One Line, Attachment 6, Indian Point Unit 2 is connected to Buchanan 345kV bus section 7-9 by 345kV feeder W95. Thus plots relating to Indian Point Unit 2 were evaluated. Sheet 1 of the Attachment 2 shows 345kV feeder W95 phase A, phase B and ground currents for Indian Point Unit 2 prior to the event. From the DFR plot it has been noted that prior to the event 345kV feeder W95 phase B current was recorded at 2,517A. Since the Indian Point Unit 2 turbine-generator rated output reflected to 345kV is well below the DFR recorded current it has been suspected that DFR 345kV feeder W95 currents were not properly calibrated/set. A meeting with Con Edison personnel responsible for DFR calibration/setting was arranged to investigate the matter. Also, request to verify DRF 345kV feeder W95 calibration/setting had been sent by email. Attachment 12, is a reply from Con Edison which states that the 345kV feeder W95 currents were calibrated for 3000/1 while 2000/1 was required. Thus, it must be noted that any DFR current value shown for 345kV feeder W95 is required to be scaled by 3000/2000=1.5. 345kV feeder W95 phase B pre-event current shown on Sheet 1 of the Attachment 2 is then 2,517A/1.5 = 1,678A

Page 1 of the Attachment 1 shows 345kV feeder W95 phase A, phase B and ground currents for Indian Point Unit 2. From the DFR plot it is apparent that 345kV feeder W95 phase B current rises from pre-fault level and peaks at 29.521kA and after approximately 3.5 cycles it levels at zero. Again, it must be noted that any DFR current value shown for 345kV feeder W95 is required to be scaled by 3000/2000=1.5 thus 29.521kA/1.5 =19.680kA. Thus, it is stated that phase B experienced a fault and the breakers interrupted the fault in approximately 3.5 cycles. From the DFR plot it is also apparent that 345kV feeder W95 phase A current during the phase B fault experienced a shifted neutral and after 3 cycles it levels at zero. It can be stated that phase A has not experienced a fault and the current levels at near zero following a breaker opening. Phase C has not been plotted but feeder W95 ground fault has been plotted from which it can be seen that feeder W95 ground fault current level peaks at 20.164kA/1.5=13.442kA while feeder W95 phase B fault current peaks at 29.521kA/1.5=19.680kA. Since feeder W95 phase A has not developed a fault then phase C had to be faulted to balance the ground fault current values shown on the plot.

Page 2 of the Attachment 1 shows 345kV bus section 7-9 phase voltages A-N, B-N, and C-N which are 345kV voltages for Indian Point Unit 2. From the DFR plot it is seen that 345kV bus section 7-9 phase B-N voltage collapses to almost zero at the time 0 which is the origin of the event and levels near zero for the duration of the 600msec scan time. Phase C-N voltage shows some reduction in voltage magnitude especially a cycle and a half before breakers are opened. Following breaker opening, phase C-N voltage levels to near zero for the rest of the 600msec plot. From the DFR plot it can be seen that 345kV bus section 7-9 phase A-N voltage does not show any reduction in magnitude at the time of fault. However, 345kV bus section 7-9 phase A-N shows significant reduction in voltage magnitude following the breakers opening and shows slight continuous decrease the rest of the 600msec scan time. Since the plot only contains 345kV section 7-9 phase A-N voltage the plotted voltage characteristic needs to compared with another 345kV phase A-N voltage. Sheet 3 of Attachment 1 contains 345kV bus section 9-11 bus voltage phase A-N. Upon closer examination of the two sheets it becomes apparent that the two (2) phase A-N voltages stay in-synch up to the time the breakers open but, after breakers open, 345kV bus section 7-9 phase A-N frequency is increasing. Sheet 2 of Attachment 1, 345kV bus section 7-9 phase A-N voltage plot shows 37 cycles following breaker opening while Sheet 3 of Attachment 1 345kV bus section 9-11 phase A-N voltage shows 36 cycles following breaker opening.

Thus it is concluded that 345kV bus section 7-9 voltage A-N is showing accelerating generator voltage reflected on the 345kV side of the main transformer following breakers open and turbine trip. Since generator phase A has not contributed to the main transformer fault current then generator phase A voltage slowly decayed following breakers opening and generator excitation trip and the residual magnetism in the spinning generator provided excitation.

The second set of DFR plots (Attachments 2) were difficult to read as the plots represented total of 100,000msec. The electronic DFR file was used to zoom in on the time of the event. It must be noted that the electronic DFR file contains 32 channels and the channels are arranged by phase voltage and feeder current and the hard copies were sorted to show 17 channels related to the transformer fault. To put all 345kV events in perspective all 32 channels were plotted from the 600msec file, see Attachment 3. Also, all 32 channels from the 100,000msec files were zoomed in to 1,000 msec and were plotted, see Attachment 4. After evaluating the two (2) plots showing all 32 channels it must be noted that the 100,000 msec file is of lower resolution or sampling rate but all items lineup with the 600 msec plot. When all 345kV phase A-N were shown in sequential order as shown on Attachment 3 or 4 then it becomes clear that the bus section 7-9 phase A-N is not connected to the other 345kV phase A section 9-11 which is connected to the system. Thus it can be stated that the DFR 345kV bus section 7-9 A-N voltage represents generator phase A voltage when separated from the system.

It must be noted that prior to the transformer fault none of the captured current or voltage wave forms exhibit any abnormalities.

From the plots it can be seen that following the event (Main Transformer T21 fault) the phase B-N voltage is reduced to almost zero thus phase B fault is a very low impedance fault. Following the event, Phase C-N voltage shows small reduction in magnitude approximately two (2) cycles after Phase B-N voltage collapsed to zero. Thus phase C fault is at least two (2) cycles later and it is a high impedance fault as the phase voltage is not reduced to zero but is only slightly reduced.

Buchanan Sequence of Events Recorder (SER) at Control House #2 automatically recorded various 345kV system protection equipment operating times in a chronological order with recorded time of each event, see Attachment 5. The recorded events, 345kV feeder W95 relay operated, followed by 345kV feeder W95 lockout operated and then 345kV feeder W95 breaker 7 and breaker 9 operated as designed. These events also match the Buchanan DFR plots except that the clock has not been adjusted for EST.

Since the Indian Point Unit 2 One Lines are broken up by equipment thus no single drawing depicts all relays that operated during the main transformer 21 fault. Based on equipment one line diagrams a Simplified Indian Point Unit 2 Single Line Diagram has been developed, see Attachment 9, to depict all relays that operated during the main transformer 21 fault. Each of the main transformers is protected by a transformer differential relay (87T) connected to the transformer high and low voltage bushing CT's. Main transformer differential relaying consists of three (3) single phase relays. Three (3) single phase differential relays (87GT) are also utilized for unit differential protection (generator plus main transformers). Unit differential zone of protection starts at the generator neutral CT's and extends to the high side of the main transformers and iso-phase bus tap to the Unit Auxiliary Transformer. Main transformer overcurrent protection and line differential protection (87L) is by redundant relays connected to main transformers' high voltage CT's. Overcurrent protection consists of three (3) single phase overcurrent relays (50) and single overcurrent relay (50N) connected to residually connected phase CT's for transformer ground fault protection.

All protection relays are equipped with targets to flag the operators that they have operated. Indian Point Unit 2 operator manually recorded all plant operated relay targets on Relay Operations Following a Trip and Prior to Startup sheets, see Attachment 7. The first item marked on the list shows two (2) generator over-frequency 81 relay trip. Over-frequency relay trip is consistent with the above DFR wave capture from which it is seen that the generator frequency had increased following breaker 7 and 9 opening. It must be noted that targets are not indicative of time log but only a list that the relays operated. The checked off relays could have operated during the main transformer 21 fault or following breaker 7 and 9 opening. Over-frequency trip is one of the relays that operated following the unit trip. Both relays 81P and 81B operated as designed.

Next item on the relay target list is "main transformer phase B and phase C operated." Again this is consistent with the DFR wave capture which shows phase B carrying a fault current and Phase C, although not plotted, had to carry fault current as the ground current was indicative of phase C contributing to the ground fault. Both relays operated as designed.

Overall differential relays show only phase B operated. Per the DFR it can be seen that phase B was a low impedance ground fault. Thus phase B relay operated as designed. Based on the DFR it was concluded that phase C experienced a high impedance ground fault thus it is possible that the phase C fault level was too low to operate the overall differential relay. Since the DFR is not setup to capture phase C it is difficult to calculate the exact phase C current magnitude.

Next items on the list include line differential relays which indicate that (1) or more phases operated for faults as the relay is equipped with (1) common trip flag for all (3) phases. Line differential relays are connected to transformer CT's and will operate only for faults above the main transformer bushing differential CT's. Since these relays operated and it is known that the transformer tank ruptured near the phase B bushing, we concluded that the arc started on the inside of the transformer and propagated to the outside of the transformer following the tank rupture and made contact with one of the transformer high voltage bushing or bus work above the transformer.

Final items on the flag list are for overcurrent relay targets. Per the flag list both primary and backup overcurrent relays on phase B and C operated in addition to ground overcurrent relays. Overcurrent relays connected to the transformer bushings will operate for fault current above the CT or below the CT. Since both primary and backup relays operated then it is consistent with the transformer differential relays and the relays operated as designed. Both primary and secondary ground fault relay targets operated. Again it is consistent with DFR report which shows two (2) phases faulting to ground thus the ground fault relays operated as designed.

Based on the DFR fault currents none of the other generator or main transformer relays should need to have operated. Per the relay target list no other relay targets operated.

Indian Point Unit 2 Sequence of Events Recorder (SER) automatically recorded various plant equipment operating times in a chronological order with recorded time of each event, see Attachment 8. Per the recorded events, High Turbine Vibration trip operated first followed by Generator Lockout relay trip one (1) cycle later. The trips are consistent with DFR plots which show 345kV bus section 7-9 phase B voltage collapsing to very small magnitude during the first cycle of the event. As the 345kV bus section 7-9 phase B voltage collapsed to near zero it also had to very significantly reduce Indian Point Unit 2 generator Phase B voltage resulting in very large imbalance on turbine load. Thus, turbine load imbalance resulted in High Turbine Vibration trip. Generator Lockout relay trip is also consistent with the event as it typically takes one (1) cycle to operate electrical-mechanical relay and trip a lockout relay.

It must be noted that none of the above provided documents are showing a trip time for the Indian Point Unit 2 excitation system.

Main Transformer 21 is equipped with a conservator oil tank and is provided with sudden pressure relay (63) which is wired to alarm only. Tripping or alarm with sudden pressure relay (63) is owners preference.

III Conclusions

Based on the review of the data the following conclusions are made:

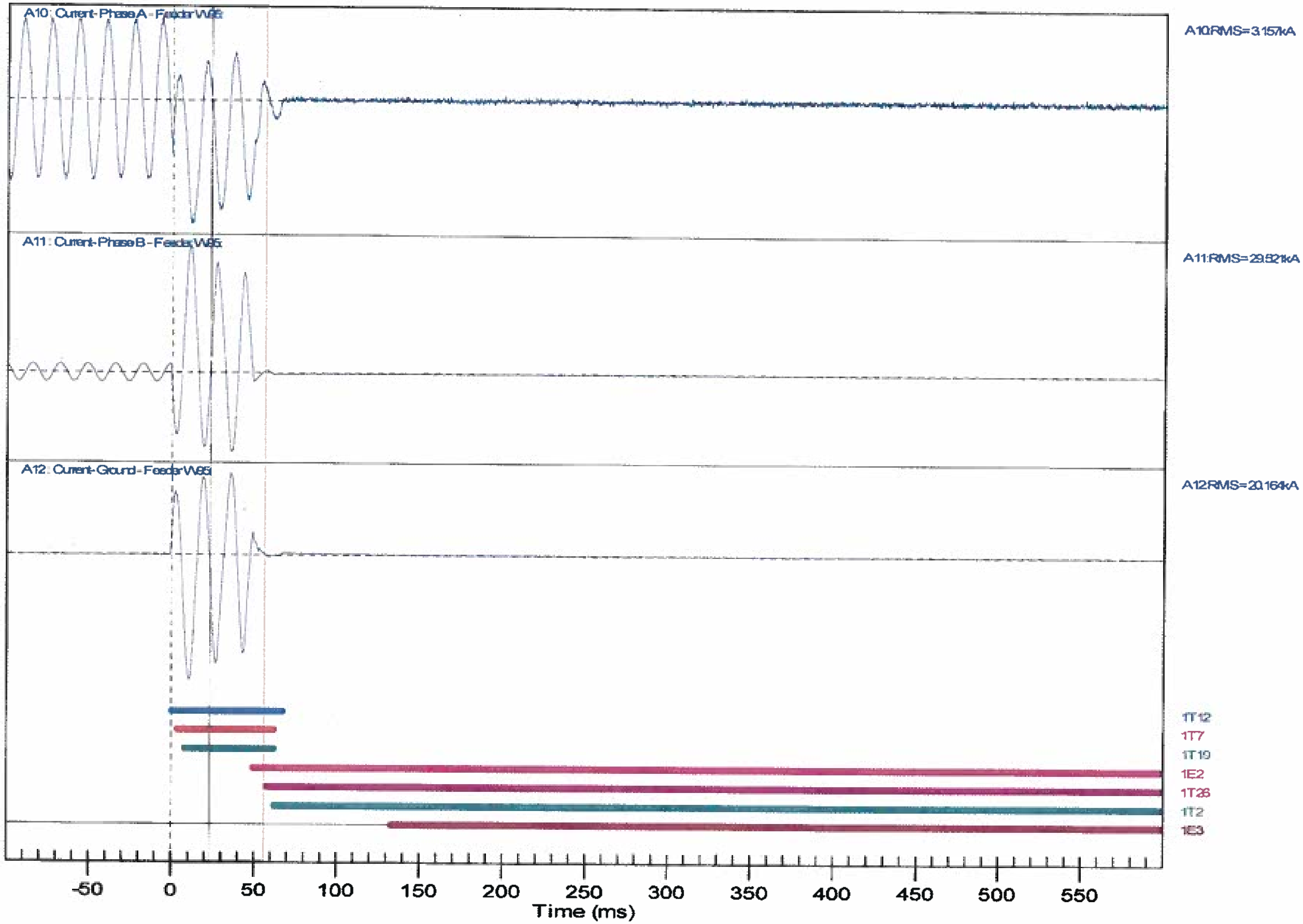
- Prior to the fault there were no system anomalies.
- The fault originated inside the main transformer 21 on the high voltage side of phase B and propagated to transformer phase C.

- Phase B fault was a low impedance fault resulting in high level fault current and high level of turbine/generator vibration.
- Phase C fault was a high impedance fault resulting in lower level fault currents.
- As the main transformer tank ruptured the fault propagated to the main transformer high voltage line connections.
- As the transformer fault propagated more main transformer and line protection relays operated and all operated protective relays were racing to open main transformer high voltage breakers and to shut down the unit.
- The DFR waveforms are consistent with the event.
- The relays operated as expected for the event.

ATTACHMENT 1 SHT 1

R03F0392 : Buchanan 345kV (DFR)

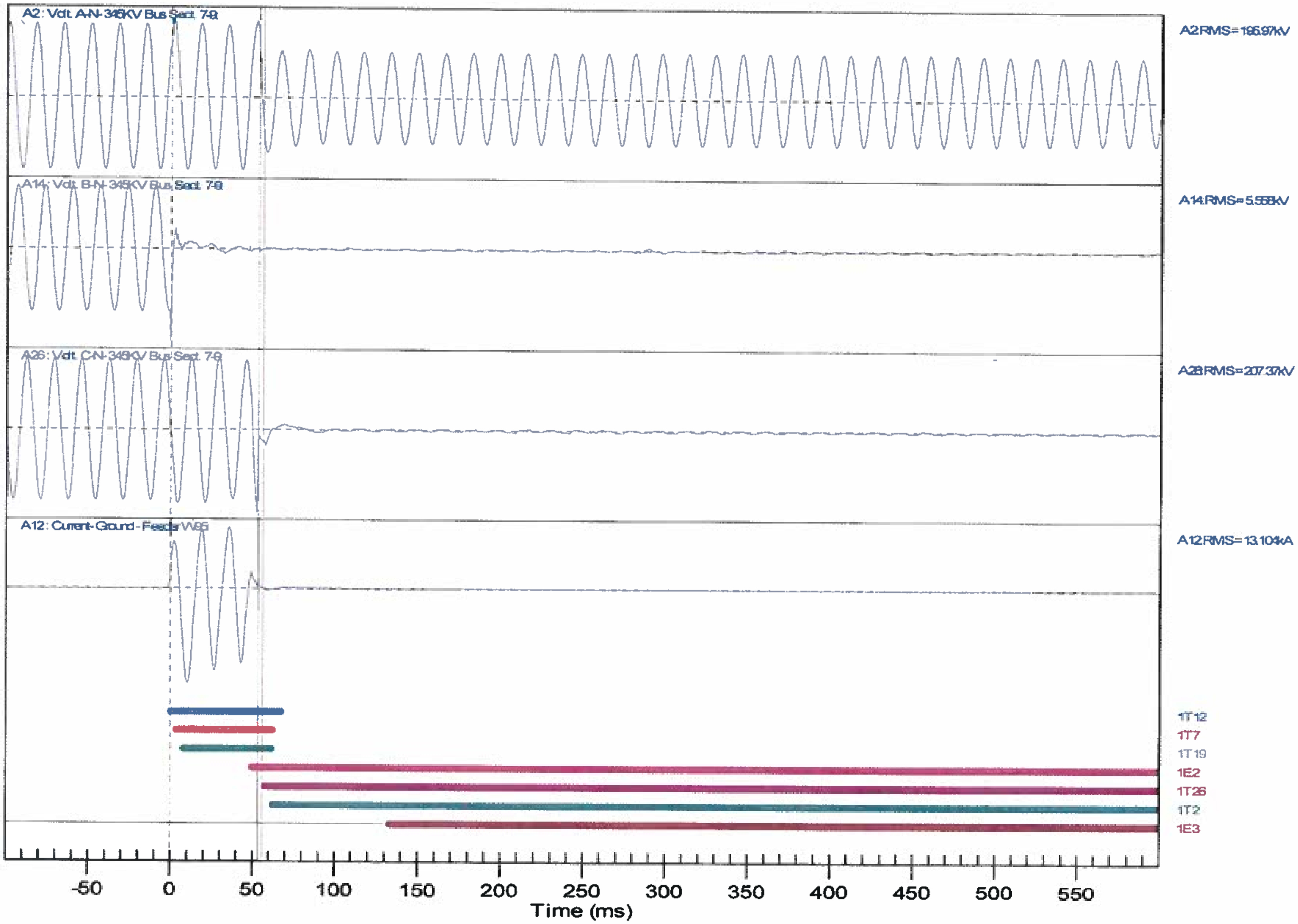
Fault Time : 11/07/2010-18:39:36.197710



ATTACHMENT 1 SHT 2

R03F0392 : Buchanan 345kV (DFR)

Fault Time : 11/07/2010-18:39:36.197710



ATTACHMENT 1 SHT 3

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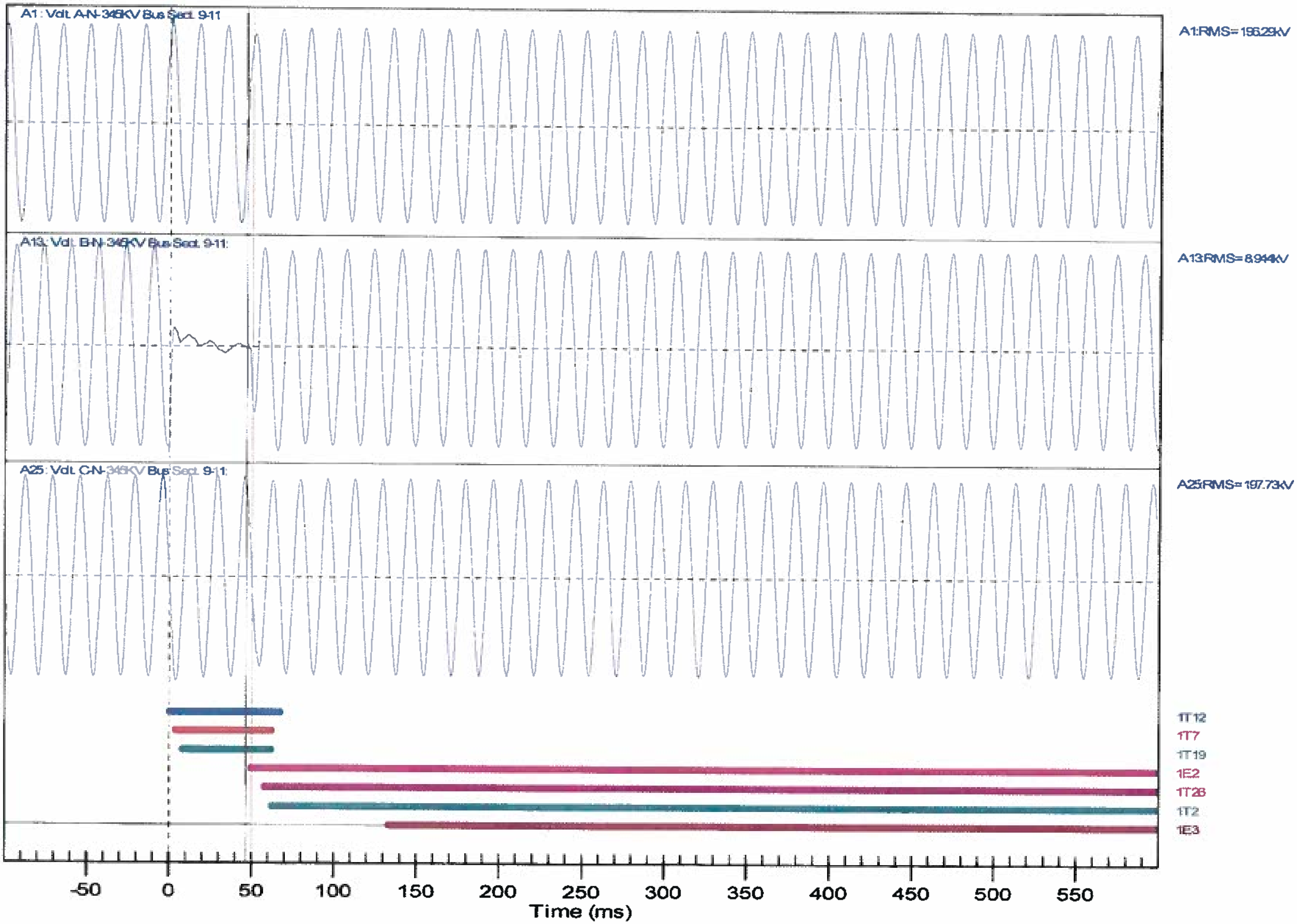

ATTACHMENT 1 SHT 4

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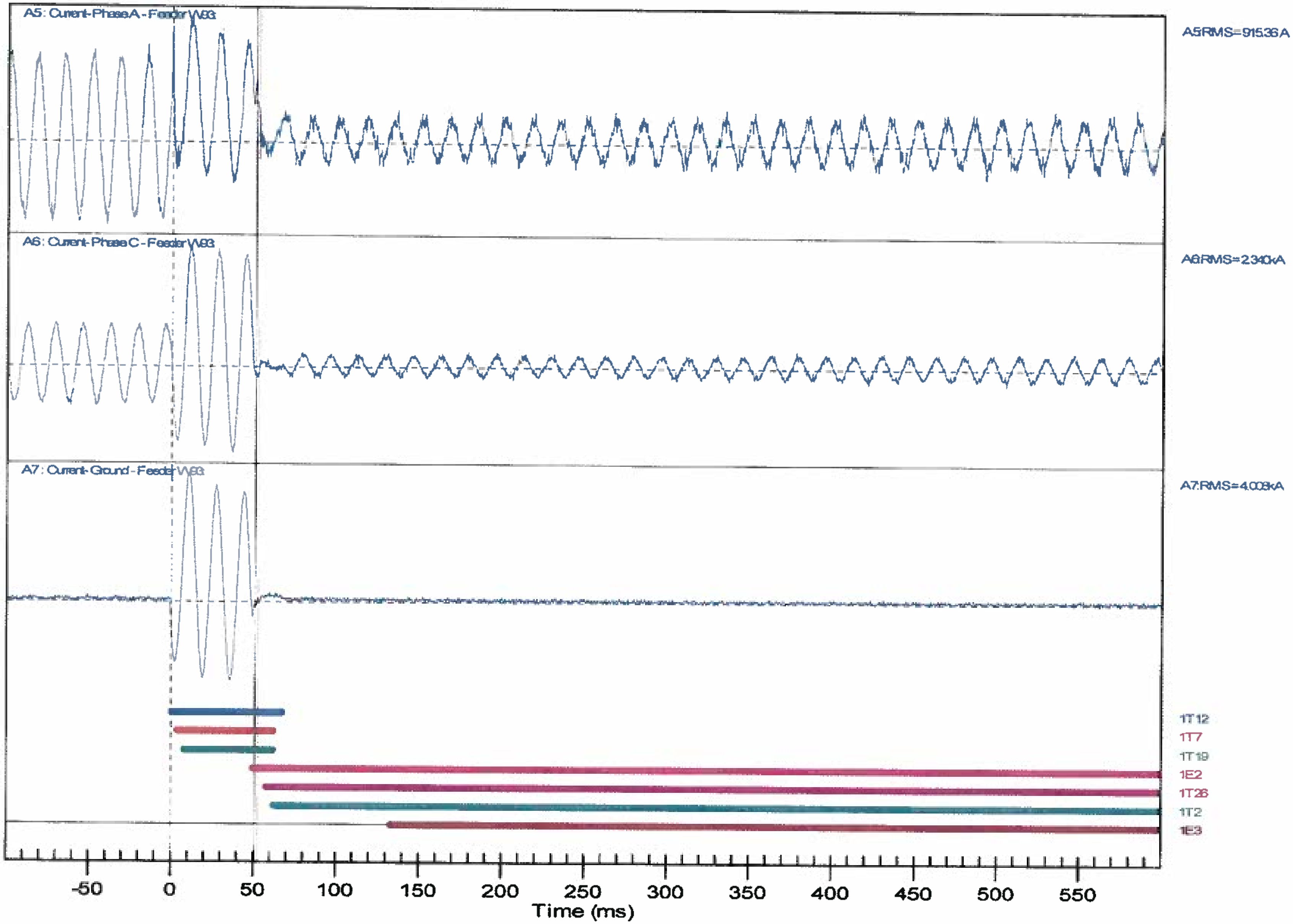

ATTACHMENT 1 SHT 5

R03F0392 : Buchanan 345kV (DFR)

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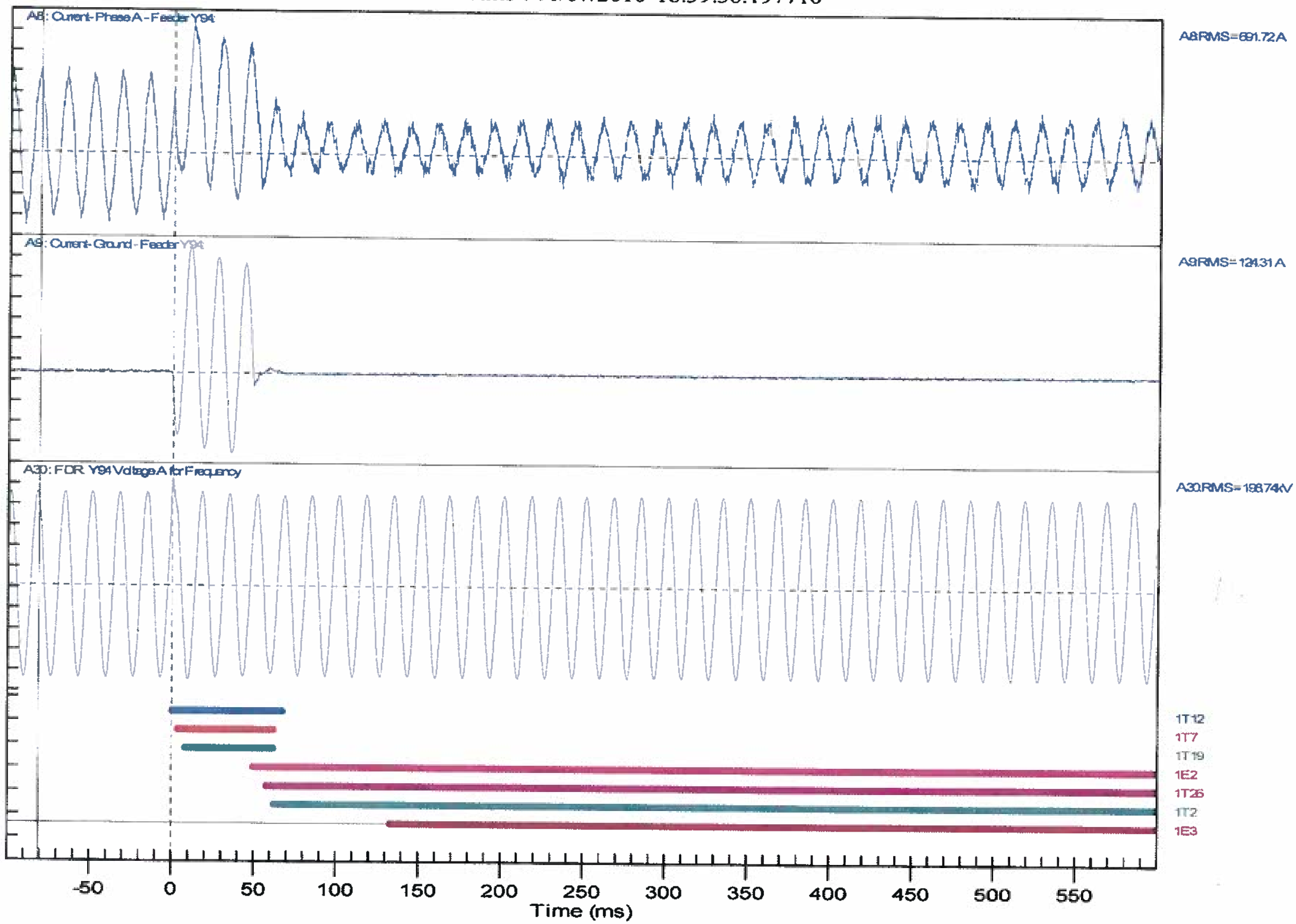
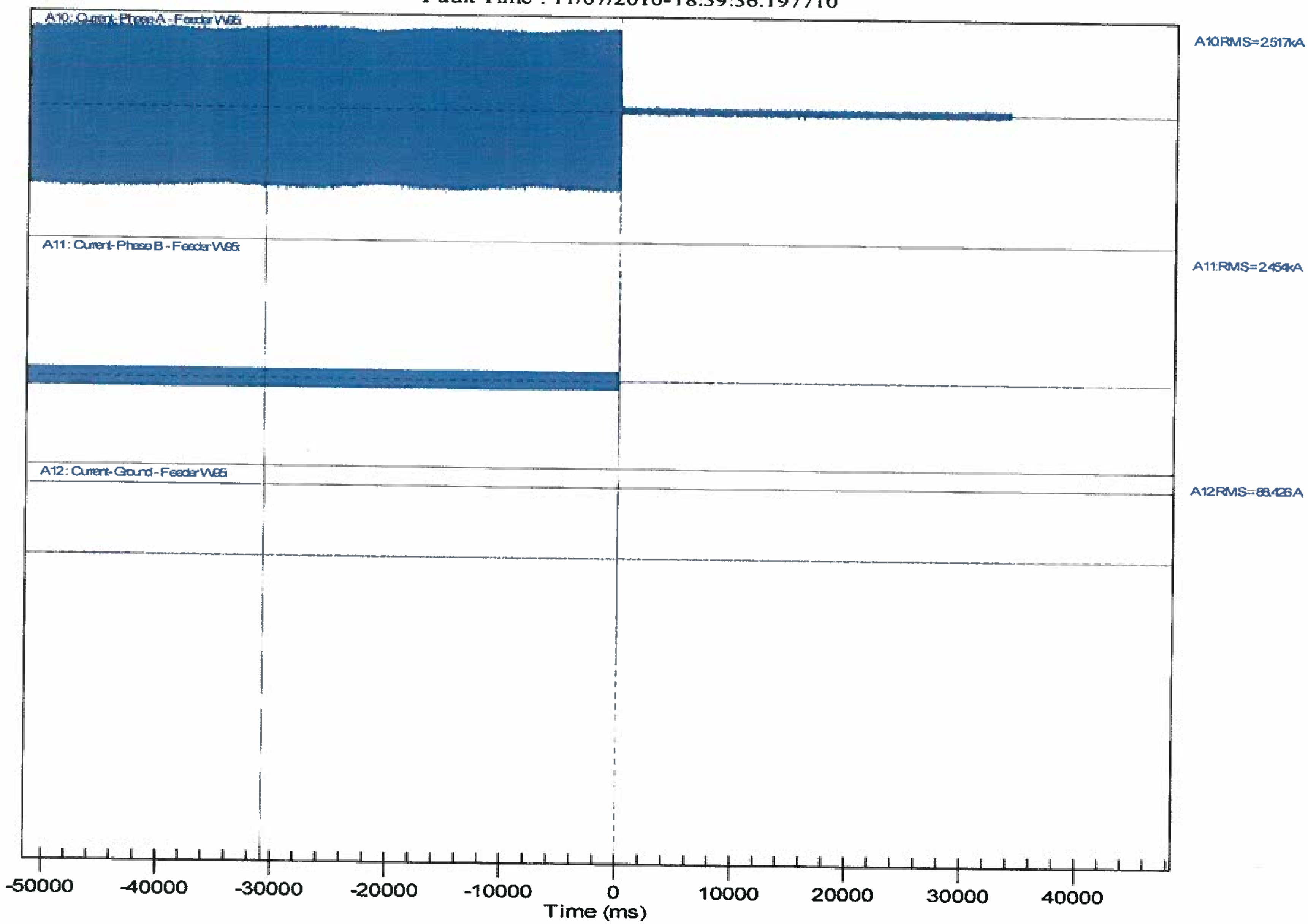


ATTACHMENT 2 SHT. 1

R03F0391 : Buchanan 345kV (DFR)

Fault Time : 11/07/2010-18:39:36.197710



ATTACHMENT 2 SHT. 2

R03F0391 : Buchanan 345kV (DFR)

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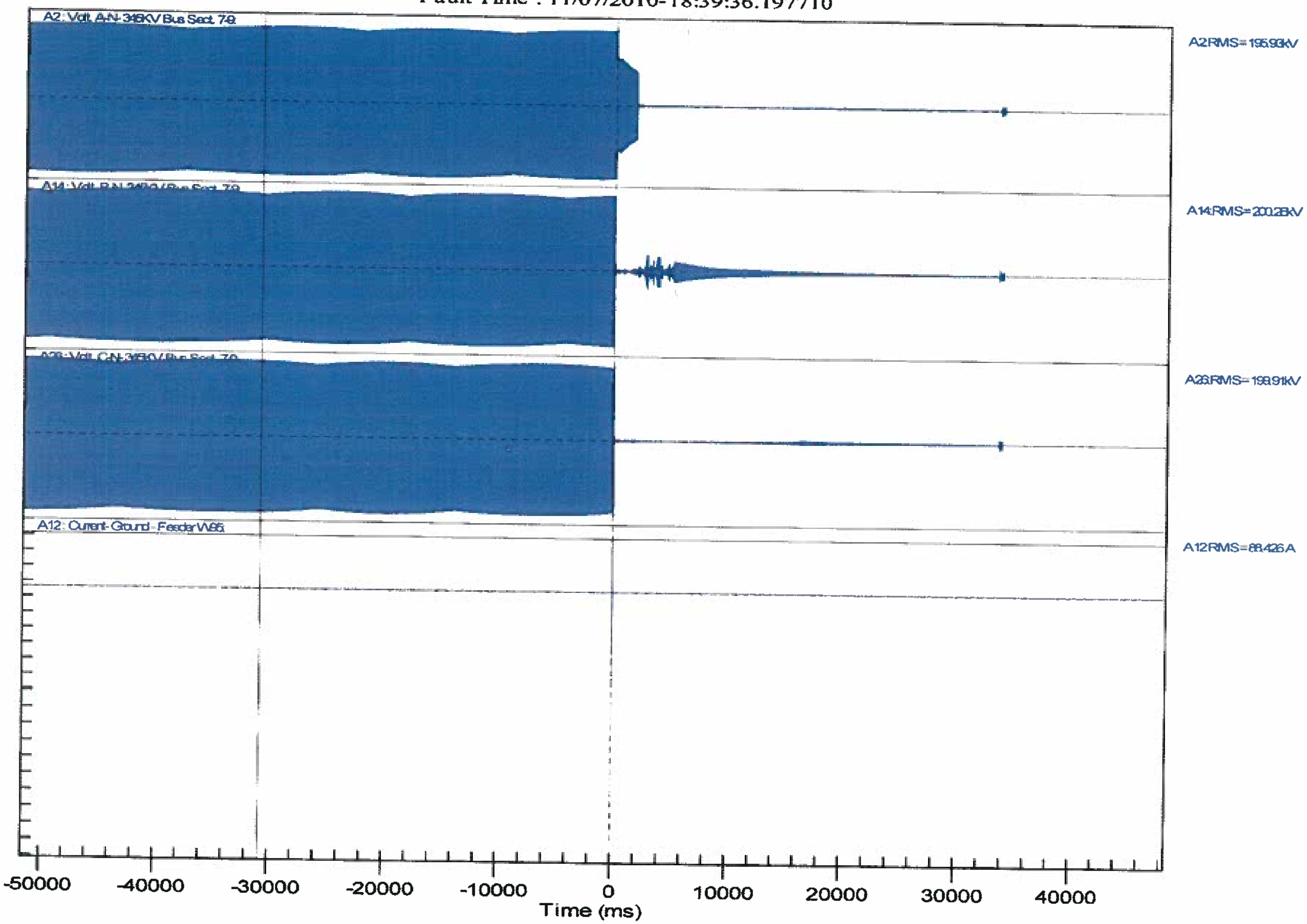

ATTACHMENT 2. SHT 3

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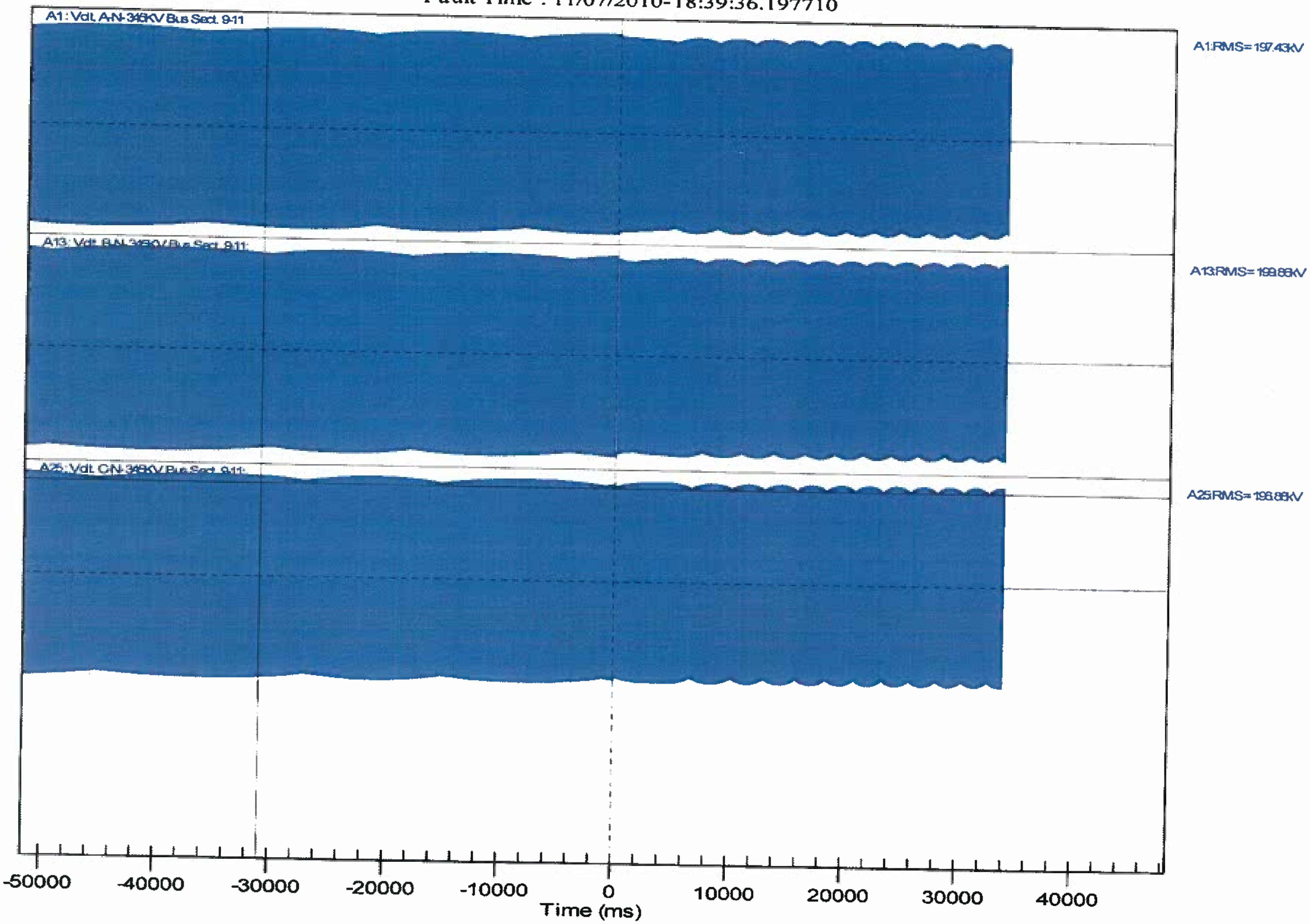

ATTACHMENT 2 SHT. 4

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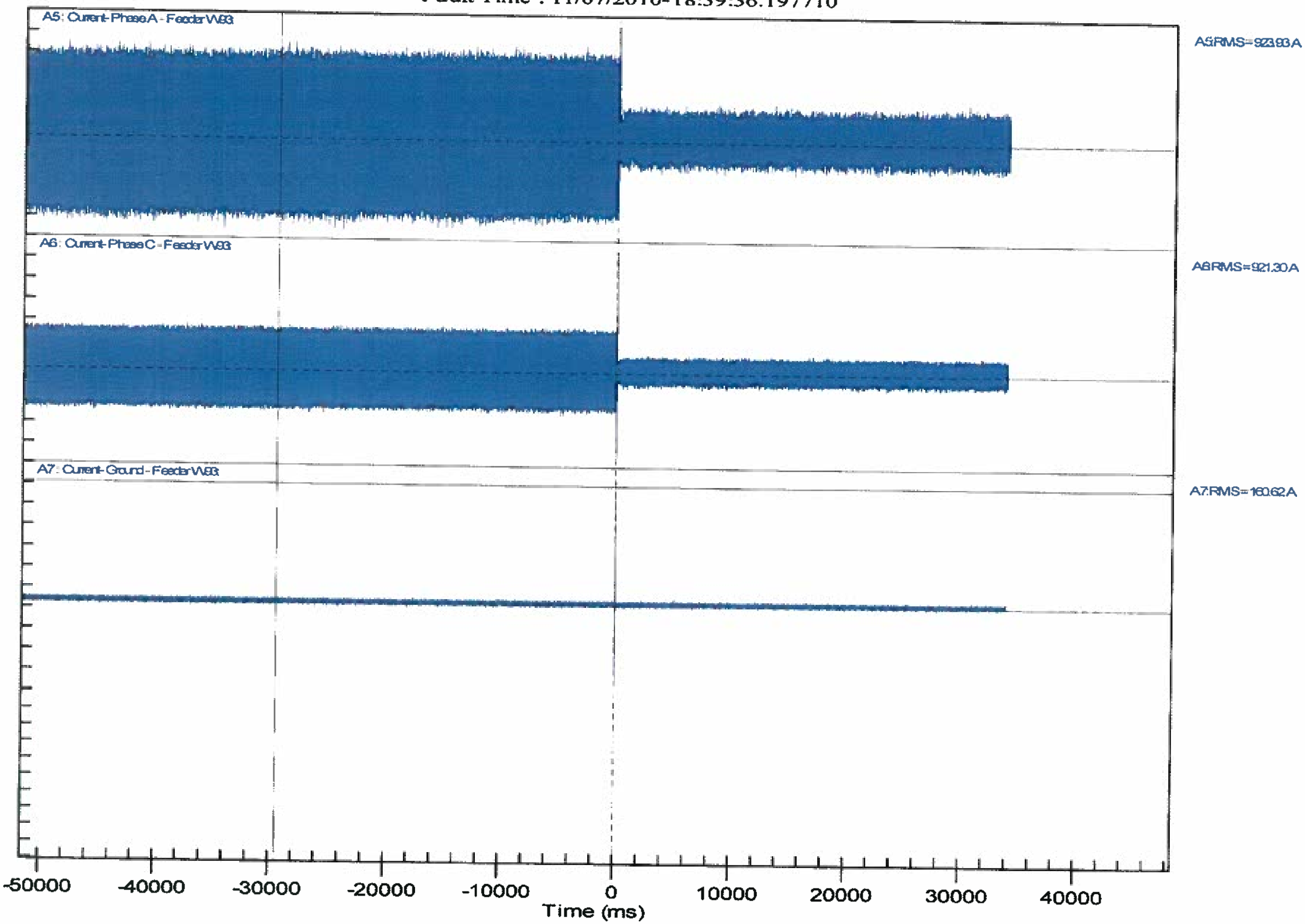
Fault Time : 11/07/2010-18:39:36.197710



ATTACHMENT 2 SHT. 5

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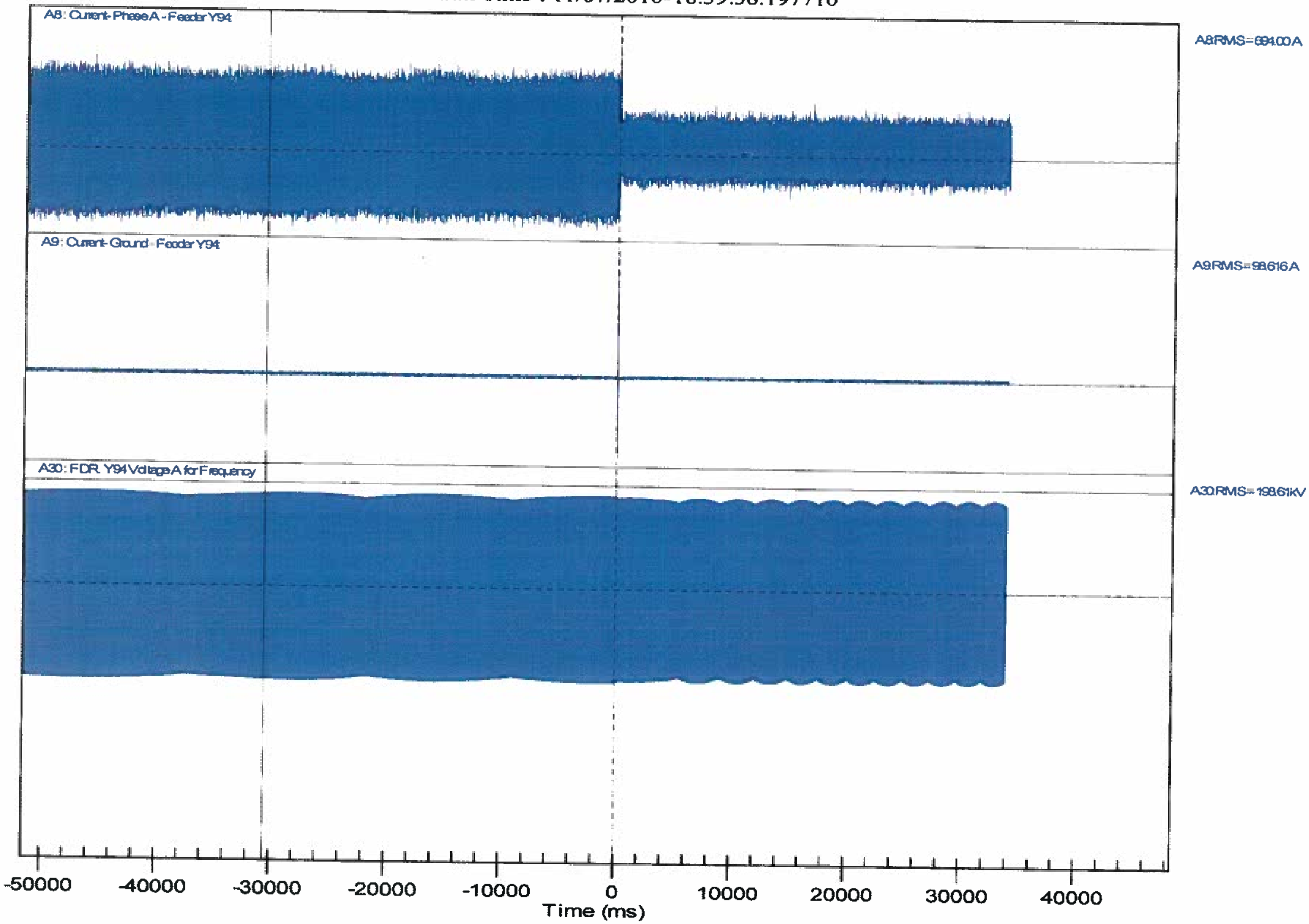
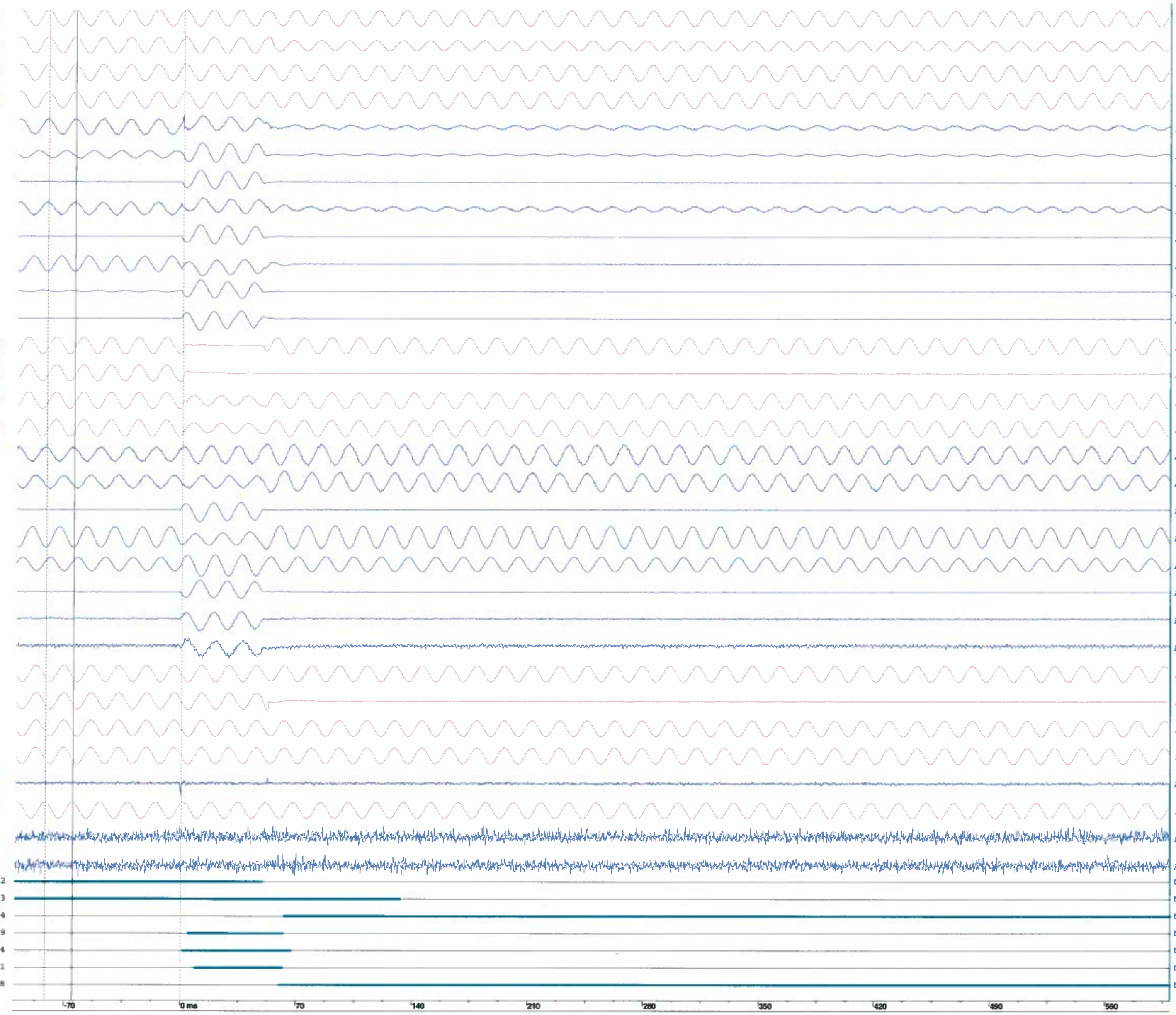


101107,183936198,-5td,Buchanan 345kV (DFR),USI_2002,(null),R03F0392.dat - 07/11/2010 - 18:39:36.197 - Primary - (Peak Type) ATTACHMENT 3



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2	A2 Volt. A-N- 345KV Bus Sect. 7-9:	196054.383	276684.766
3	A3 Volt. A-N- 345KV Bus Sect. 5-6:	198728.057	282064.371
4	A4 Volt. A-N- 345KV Bus Sect. 4-6:	199762.830	282574.982
5	A5 Current- Phase A - Feeder W93:	899.669	1314.197
6	A6 Current- Phase C - Feeder W93:	917.627	1453.189
7	A7 Current- Ground - Feeder W93:	153.253	187.479
8	A8 Current- Phase A - Feeder Y94:	691.446	1207.232
9	A9 Current- Ground - Feeder Y94:	136.096	-11.737
10	A10 Current- Phase A - Feeder W95:	2517.045	-3594.859
11	A11 Current- Phase B - Feeder W95:	2454.921	3556.302
12	A12 Current- Ground - Feeder W95:	86.949	-81.986
13	A13 Volt B-N- 345KV Bus Sect. 9-11:	199967.039	-280227.403
14	A14 Volt B-N- 345KV Bus Sect. 7-9:	200233.951	-283731.939
15	A15 Volt B-N- 345KV Bus Sect. 5-6:	197503.901	-280703.692
16	A16 Volt B-N- 345KV Bus Sect. 4-6:	199892.354	-284090.737
17	A17 Current- Phase A - Feeder Y88:	646.681	854.871
18	A18 Current- Phase C - Feeder Y88:	648.738	925.523
19	A19 Current- Ground - Feeder Y88:	155.375	93.682
20	A20 Current- Phase A - Feeder W96:	2552.795	-3503.395
21	A21 Current- Phase C - Feeder W96:	2543.657	-3463.354
22	A22 Current- Ground - Feeder W96:	74.453	23.434
23	A23 Current- Ground - Feeder W97:	123.204	81.960
24	A24 Current- Ground - Feeder W98:	91.973	176.099
25	A25 Volt. C-N- 345KV Bus Sect. 9-11:	196953.855	282955.206
26	A26 Volt. C-N- 345KV Bus Sect. 7-9:	199866.257	286474.216
27	A27 Volt. C-N- 345KV Bus Sect. 5-6:	199369.767	281651.412
28	A28 Volt. C-N- 345KV Bus Sect. 4-6:	199768.368	283756.924
29	A29 (SPARE)	159.751	-181.262
30	A30 FDR. Y94 Voltage A for Frequency	198756.028	281689.112
31	A31 (SPARE)	134.803	60.437
32	A32 (SPARE)	128.499	211.208

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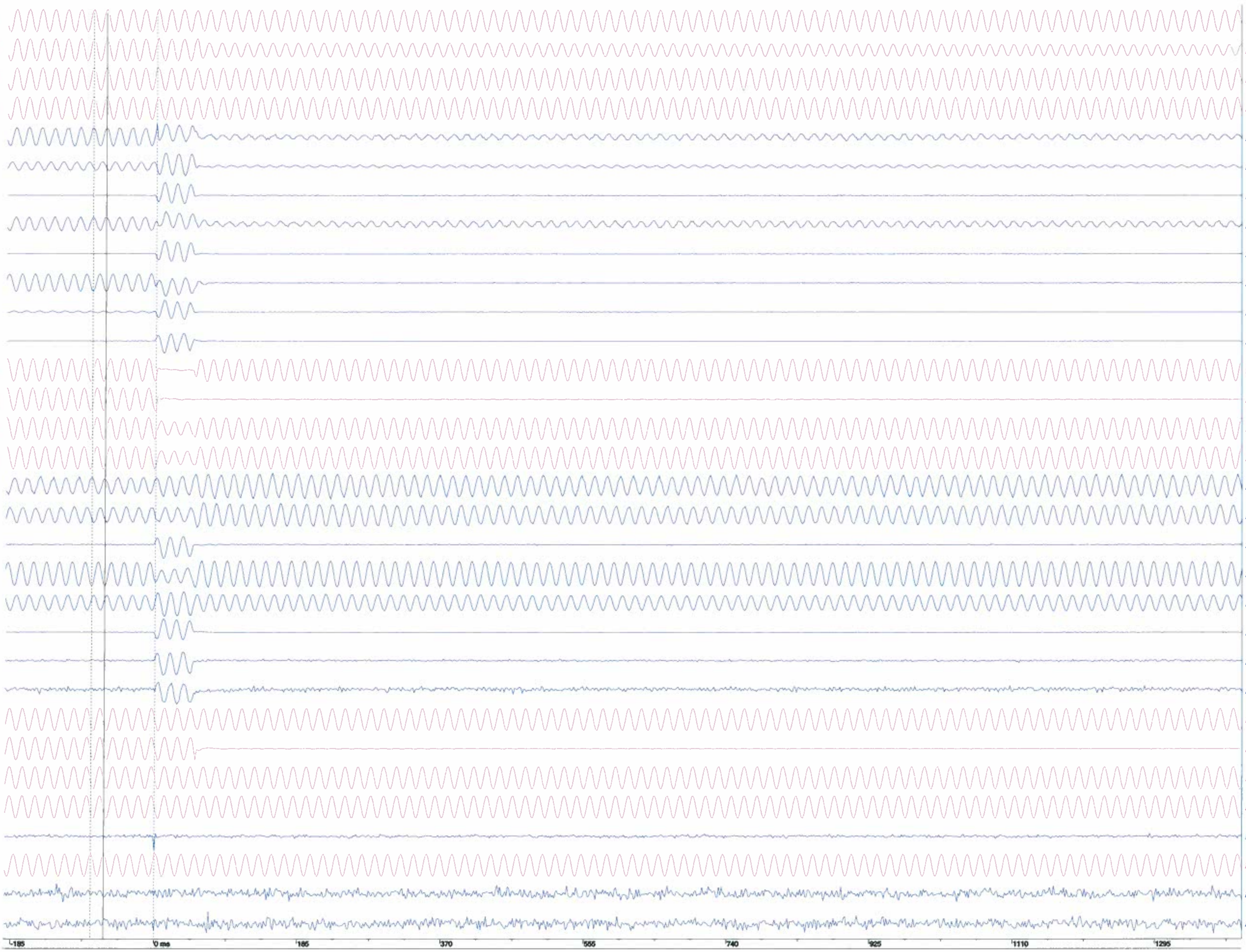
2	N	E2 Breaker 9 Operation	N A 18:39:36.247293		001
3	N	E3 Breaker 7 Operation	N A 18:39:36.330834		001
34	N	T2 (A2)Volt. A-N- 345KV Bus Sect. 7-9:	N A 18:39:36.260001		001
39	N	T7 (A7)Current- Ground - Feeder W93:	N N 18:39:36.201251	18:39:36.259793	002
44	N	T12 (A12)Current- Ground - Feeder W95:	N N 18:39:36.197918	18:39:36.265001	002
51	N	T19 (A19)Current- Ground - Feeder Y88:	N N 18:39:36.205626	18:39:36.259584	002
58	N	T26 (A26)Volt. C-N- 345KV Bus Sect. 7-9:	N A 18:39:36.255418	18:39:36.257084	003

Buchanan 345kV (DFR) DT: 07/11/2010 18:39:36.132710 Dt: 65000 microsec - 3.90 Cvc 4800.0000 AS: ON

101107,183936198,-5td,Buchanan 345kV (DFR),USI_2002,(null),R03F0391.d03 - 07/11/2010 - 18:39:36.197 - Primary - (Peak Type)

ATTACHMENT 4



CH	Title	RMS	InstPeak
1	A1 Volt. A-N- 345KV Bus Sect. 9-11	197836.392	277874.994
2	A2 Volt. A-N- 345KV Bus Sect. 7-9:	196079.890	275524.662
3	A3 Volt. A-N- 345KV Bus Sect. 5-6:	198856.101	281339.643
4	A4 Volt. A-N- 345KV Bus Sect. 4-6:	199813.959	281705.743
5	A5 Current- Phase A - Feeder W93:	909.214	1278.995
6	A6 Current- Phase C - Feeder W93:	930.284	1335.997
7	A7 Current- Ground - Feeder W93:	152.236	257.783
8	A8 Current- Phase A - Feeder Y94:	669.415	937.656
9	A9 Current- Ground - Feeder Y94:	119.403	82.157
10	A10 Current- Phase A - Feeder W95:	2549.393	-3594.859
11	A11 Current- Phase B - Feeder W95:	2466.901	3391.984
12	A12 Current- Ground - Feeder W95:	80.466	35.137
13	A13 Volt. B-N- 345KV Bus Sect. 9-11:	199871.462	-279066.140
14	A14 Volt B-N- 345KV Bus Sect. 7-9:	200212.521	-280906.213
15	A15 Volt B-N- 345KV Bus Sect. 5-6:	197634.906	-278674.334
16	A16 Volt B-N- 345KV Bus Sect 4-6:	200044.399	-283221.515
17	A17 Current- Phase A - Feeder Y88:	611.769	796.318
18	A18 Current- Phase C - Feeder Y88:	654.108	948.954
19	A19 Current- Ground - Feeder Y88:	158.326	292.755
20	A20 Current- Phase A - Feeder W96:	2535.818	-3585.414
21	A21 Current- Phase C - Feeder W96:	2547.647	-3276.146
22	A22 Current- Ground - Feeder W96:	105.064	23.434
23	A23 Current- Ground - Feeder W97:	133.240	199.045
24	A24 Current- Ground - Feeder W98:	85.870	70.440
25	A25 Volt C-N- 345KV Bus Sect. 9-11:	196879.788	271790.691
26	A26 Volt. C-N- 345KV Bus Sect. 7-9:	199830.879	270611.294
27	A27 Volt. C-N- 345KV Bus Sect. 5-6:	199471.275	267278.479
28	A28 Volt. C-N- 345KV Bus Sect. 4-6:	199617.953	272235.639
29	A29 (SPARE)	154.635	-151.052
30	A30 FDR Y94 Voltage A for Frequency	198841.292	281181.564
31	A31 (SPARE)	126.051	181.311
32	A32 (SPARE)	108.369	150.863

Buchanan 345kV (DFR) DT: 07/11/2010 18:39:36.132711 Dt: 65000 microsec - 3.90 Cvc 600.0000 AS: ON

ATTACHMENT 5

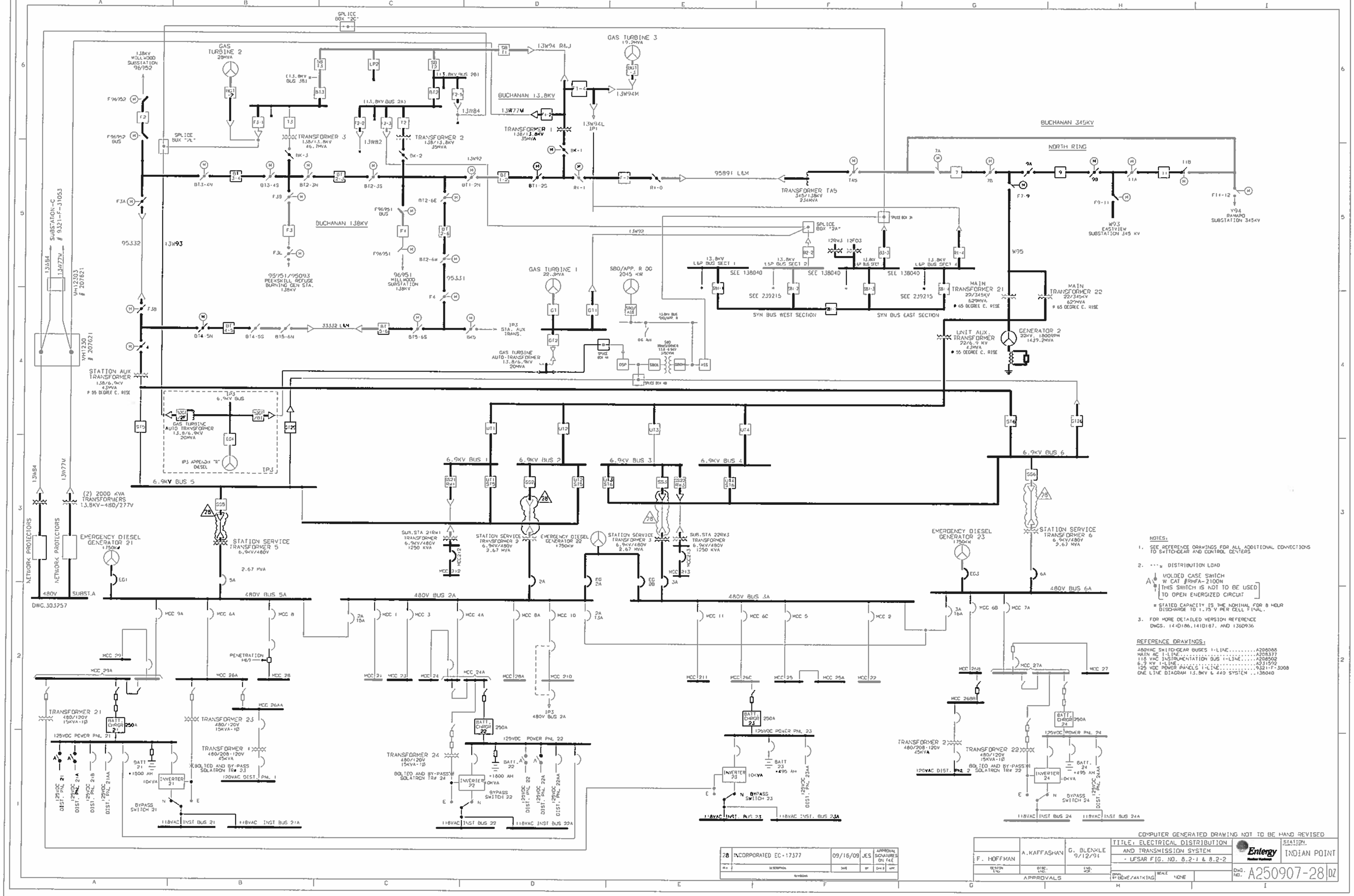
CompanyName **Sequence of Events Recorder Report** 11/8/2010

Station Name : Buchanan (SER) Control House #2
Remote ID : 16

Sequence of Events

Date-Time	Event	Now	Normal	SYNC	Description
11/07/2010-20:56:54.644375	E21	O	N	S	Control House #2 - BREAKER 9
11/07/2010-20:56:41.657500	E20	O	N	S	Control House #2 - BREAKER 7
11/07/2010-20:56:41.653333	E33	O	N	S	CTRL HOUSE 2 - W95 DTT SENT VIA BRKS 7&9 OPEN
11/07/2010-20:02:53.617917	E10	O	N	S	Control House #2 - FDR W95 2ND LINE PM-23 (86-2A)
11/07/2010-20:00:35.780834	E5	O	N	S	Control House #2 - FDR W95 1ST LINE PM-23 (86-1A)
11/07/2010-19:40:16.572292	E32	C	A	S	CTRL HOUSE 2 - W95 DTT SENT VIA DISCO F7-9 OPEN
11/07/2010-19:39:41.683333	E4	O	N	S	Control House #2 - FDR W95 1ST LINE L.O. RELAY 86-1B
11/07/2010-19:39:41.682709	E33	C	A	S	CTRL HOUSE 2 - W95 DTT SENT VIA BRKS 7&9 OPEN
11/07/2010-19:39:39.856875	E9	O	N	S	Control House #2 - FDR W95 2ND LINE L.O. RELAY 86-2B
11/07/2010-19:39:36.352292	E5	C	A	S	Control House #2 - FDR W95 1ST LINE PM-23 (86-1A)
11/07/2010-19:39:36.352292	E10	C	A	S	Control House #2 - FDR W95 2ND LINE PM-23 (86-2A)
11/07/2010-19:39:36.253959	E21	C	A	S	Control House #2 - BREAKER 9
11/07/2010-19:39:36.247500	E20	C	A	S	Control House #2 - BREAKER 7
11/07/2010-19:39:36.226459	E9	C	A	S	Control House #2 - FDR W95 2ND LINE L.O. RELAY 86-2B
11/07/2010-19:39:36.226459	E6	O	N	S	Control House #2 - FDR W95 2ND LINE HCB
11/07/2010-19:39:36.226459	E4	C	A	S	Control House #2 - FDR W95 1ST LINE L.O. RELAY 86-1B
11/07/2010-19:39:36.226459	E1	O	N	S	Control House #2 - FDR W95 1ST LINE HCB
11/07/2010-19:39:36.217292	E6	C	A	S	Control House #2 - FDR W95 2ND LINE HCB
11/07/2010-19:39:36.217292	E1	C	A	S	Control House #2 - FDR W95 1ST LINE HCB

ATTACHMENT 6



ATTACHMENT 7 SHT. 1

ELECTRICAL RELAY POSITIONS FOLLOWING A TRIP AND PRIOR TO STARTUP	No: 2-COL-27.1.13 Rev: 13
	Page 9 of 37

				Trip		Init	Date	NT
②	81P/1	Generator Overfrequency	ON	✓		fo	11/7/10	
②	81BU/1	Generator Overfrequency	ON			fo	11/7/10	
②	81P/2	Generator Overfrequency	ON			fo	11/7/10	
②	81BU/2	Generator Overfrequency	ON	✓		fo	11/7/10	
	87/T21	A θ Main Trans. Diff.				fo	11/7/10	
	87/T21	B θ Main Trans. Diff.		✓		fo	11/7/10	
	87/T21	C θ Main Trans. Diff.		✓		fo	11/7/10	
	87/T22	A θ Main Trans. Diff.				fo	11/7/10	
	87/T22	B θ Main Trans. Diff.				fo	11/7/10	
	87/T22	C θ Main Trans. Diff.				fo	11/7/10	
	87/GT	A θ Overall Diff.				fo	11/7/10	
	87/GT	B θ Overall Diff.		✓		fo	11/7/10	
	87/GT	C θ Overall Diff.				fo	11/7/10	
	87/UT	A θ UAT Diff.				fo	11/7/10	
	87/UT	B θ UAT Diff.				fo	11/7/10	
	87/UT	C θ UAT Diff.				fo	11/7/10	
①	87/G	Gen. Diff	ON			fo	11/7/10	
	40	Loss of Field				fo	11/7/10	
	60A	Voltage Balance				fo	11/7/10	
	51/NT	Main Trans. Neut. O.C.				fo	11/7/10	
	59N	Gen. Neut. O.V.				fo	11/7/10	
	46	Neg. Sequence				fo	11/7/10	
①	62UT	Unit Aux. B.U. Timer	OFF			fo	11/7/10	
	51N/UT	Neut. O.C.				fo	11/7/10	
	51/UT	A θ Overcurrent				fo	11/7/10	
	51/UT	B θ Overcurrent				fo	11/7/10	
	51/UT	C θ Overcurrent				fo	11/7/10	

① Listed light indication represents tripped OR monitor in failed condition
② Orange display in 3 shutter window indicates tripped (SEE Example 3)

				Trip	Init	Date	NT
1.3	**Back of Unit 2 Flight Panel FB**						
	87 ST	A θ SAT. Diff.			Ro	11/7/10	
	87 ST	B θ SAT. Diff.			Ro	11/7/10	
	87 ST	C θ SAT. Diff.			Ro	11/7/10	
	87 L2/345	P.W. Diff.		✓	Ro	11/7/10	
	32 NBU/345	B.U. Dir. Grd.			Ro	11/7/10	
	87 L1/345	P.W. Diff.		✓	Ro	11/7/10	
	51 ST	A θ SAT. O.C.			Ro	11/7/10	
	51 ST	B θ SAT. O.C.			Ro	11/7/10	
	51 ST	C θ SAT. O.C.			Ro	11/7/10	
	50 BU/345 B.U. & FAULT			✓ ✓	Ro	11/7/10	
	50NBU/345BU Ground Fault			✓	Ro	11/7/10	
	Station Aux. Trans. Neut O.C.				Ro	11/7/10	
	85L2/345	PWM & TT			Ro	11/7/10	
	85L1/345	PWM & TT			Ro	11/7/10	
	345 85/PM-23				Ro	11/7/10	
①	Unit Aux.	86UT (86P & 86 BU)	OFF		Ro	11/7/10	
①	Sta. Aux.	86 STP	OFF		Ro	11/7/10	
①	Sta. Aux.	86 ST B.U.	OFF		Ro	11/7/10	
	32 NP	Pri Dir. Grd.			Ro	11/7/10	
	50 NP/345 Primary Ground Fault			✓	Ro	11/7/10	
	50 NP/345 Primary Phase Fault			✓ ✓	Ro	11/7/10	
①	62 STP	Sta. Trans. B.U. Timer	OFF		Ro	11/7/10	
①	62TI-BT4-5	Bus 5 B.U. Timer	OFF		Ro	11/7/10	
1.4	**Back of Unit 2 Flight Panel FC**						
	87 L2/138	P.W. Diff.			Ro	11/7/10	
	87 L1/138	P.W. Diff.			Ro	11/7/10	
	85 L2/138	PWM & T.T.			Ro	11/7/10	
	85 L1/138	PWM & T.T.			Ro	11/7/10	
	138kv Line	B.U. PH. Fault Det.			Ro	11/7/10	
	138kv Line	PRIM. PH. Fault Det.			Ro	11/7/10	

① Listed light indication represents tripped OR monitor in failed condition

ATTACHMENT 8 SHT. 1

ENTERGY CORP - INDIAN POINT UNIT 2
DATE: 7-NOV-2010 TIME: 18:40

SEQUENCE OF EVENTS LOG

INITIATED TIME: 18:39:36.175 TRIGGER: (YD9038) HIGH VIBRATION CAUSE TURBINE

TIME	POINT-ID	DESCRIPTION OF POINT ID	MESSAGE	QUALITY	DELTA (msec)
18:39:36.175	YD9038	HIGH VIBRATION CAUSE TURBINE	TRIP	ALM	0
18:39:36.191	YD9039	GENERATOR 86BU LOCKOUT RELAY CAU	TRIP	ALM	16
18:39:36.191	YD9040	GENERATOR 86P LOCKOUT RELAY	TRIP	ALM	16
18:39:36.197	YD9036	LOW BEARING OIL PRESSURE CAUSE T	TRIP	ALM	22
18:39:36.296	YD9038	HIGH VIBRATION CAUSE TURBINE	NOT TRI	GOOD	121
18:39:36.336	YD9036	LOW BEARING OIL PRESSURE CAUSE T	NOT TRI	GOOD	161
18:39:36.340	PD0399	TURB HYD OIL LOW PRESSURE CAUSE	TRIP	ALM	165
18:39:36.406	YD0007	REACTOR MAIN TRIP BREAKER B	TRIP	ALM	231
18:39:36.412	YD0006	REACTOR MAIN TRIP BREAKER A	TRIP	ALM	237
18:39:36.757	FD0407	STM LINE 21 HI FLOW CHNL 2 SI PA	TRIP	ALM	582
18:39:36.913	FD0407	STM LINE 21 HI FLOW CHNL 2 SI PA	NOT TRI	GOOD	738
18:39:37.473	ND0021	INTERM RANGE CHNL 2 HI POWER CAU	NOT TRI	INHB	1298
18:39:37.481	ND0020	INTERM RANGE CHNL 1 HI POWER CAU	NOT TRI	INHB	1306
18:39:37.489	ND0010	POWER RANGE CHNL LOW POWER CAUSE	NOT TRI	INHB	1314
18:39:37.759	FD0426	STM LINE 22 HI FLOW CHNL 1 SI PA	TRIP	ALM	1584
18:39:37.775	FD0466	STM LINE 24 HI FLOW CHNL 1 SI PA	TRIP	ALM	1600
18:39:37.779	FD0446	STM LINE 23 HI FLOW CHNL 1 SI PA	TRIP	ALM	1604
18:39:37.785	FD0406	STM LINE 21 HI FLOW CHNL 1 SI PA	TRIP	ALM	1610
18:39:37.879	FD0407	STM LINE 21 HI FLOW CHNL 2 SI PA	TRIP	ALM	1704
18:39:37.903	FD0427	STM LINE 22 HI FLOW CHNL 2 SI PA	TRIP	ALM	1728
18:39:38.021	FD0446	STM LINE 23 HI FLOW CHNL 1 SI PA	NOT TRI	GOOD	1846
18:39:38.027	FD0406	STM LINE 21 HI FLOW CHNL 1 SI PA	NOT TRI	GOOD	1852
18:39:38.039	FD0427	STM LINE 22 HI FLOW CHNL 2 SI PA	NOT TRI	GOOD	1864
18:39:38.110	FD0426	STM LINE 22 HI FLOW CHNL 1 SI PA	NOT TRI	GOOD	1935
18:39:38.131	FD0466	STM LINE 24 HI FLOW CHNL 1 SI PA	NOT TRI	GOOD	1956
18:39:38.330	FD0407	STM LINE 21 HI FLOW CHNL 2 SI PA	NOT TRI	GOOD	2155
18:39:43.327	LD0424	SG 22 LOW LOW LEVEL CHNL 2 PARTI	TRIP	INHB	7152
18:39:43.344	LD0464	SG 24 LOW LOW LEVEL CHNL 2 PARTI	TRIP	INHB	7169
18:39:43.347	LD0425	SG 22 LOW LOW LEVEL CHNL 3 PARTI	TRIP	INHB	7172
18:39:43.347	LD0426	SG 22 LOW LOW LEVEL CAUSE REACTO	TRIP	INHB	7172
18:39:43.438	LD0421	SG 22 LOW LEVEL CHNL 2 PARTIAL R	TRIP	INHB	7263
18:39:43.447	LD0461	SG 24 LOW LEVEL CHNL 2 PARTIAL R	TRIP	INHB	7272
18:39:43.473	LD0465	SG 24 LOW LOW LEVEL CHNL 3 PARTI	TRIP	INHB	7298
18:39:43.473	LD0466	SG 24 LOW LOW LEVEL CAUSE REACTO	TRIP	INHB	7298
18:39:43.495	LD0463	SG 24 LOW LOW LEVEL CHNL 1 PARTI	TRIP	INHB	7320
18:39:43.521	LD0460	SG 24 LOW LEVEL CHNL 1 PARTIAL R	TRIP	INHB	7346

ATTACHMENT B SHT. 2

ENTERGY CORP - INDIAN POINT UNIT 2
DATE: 7-NOV-2010 TIME: 18:40

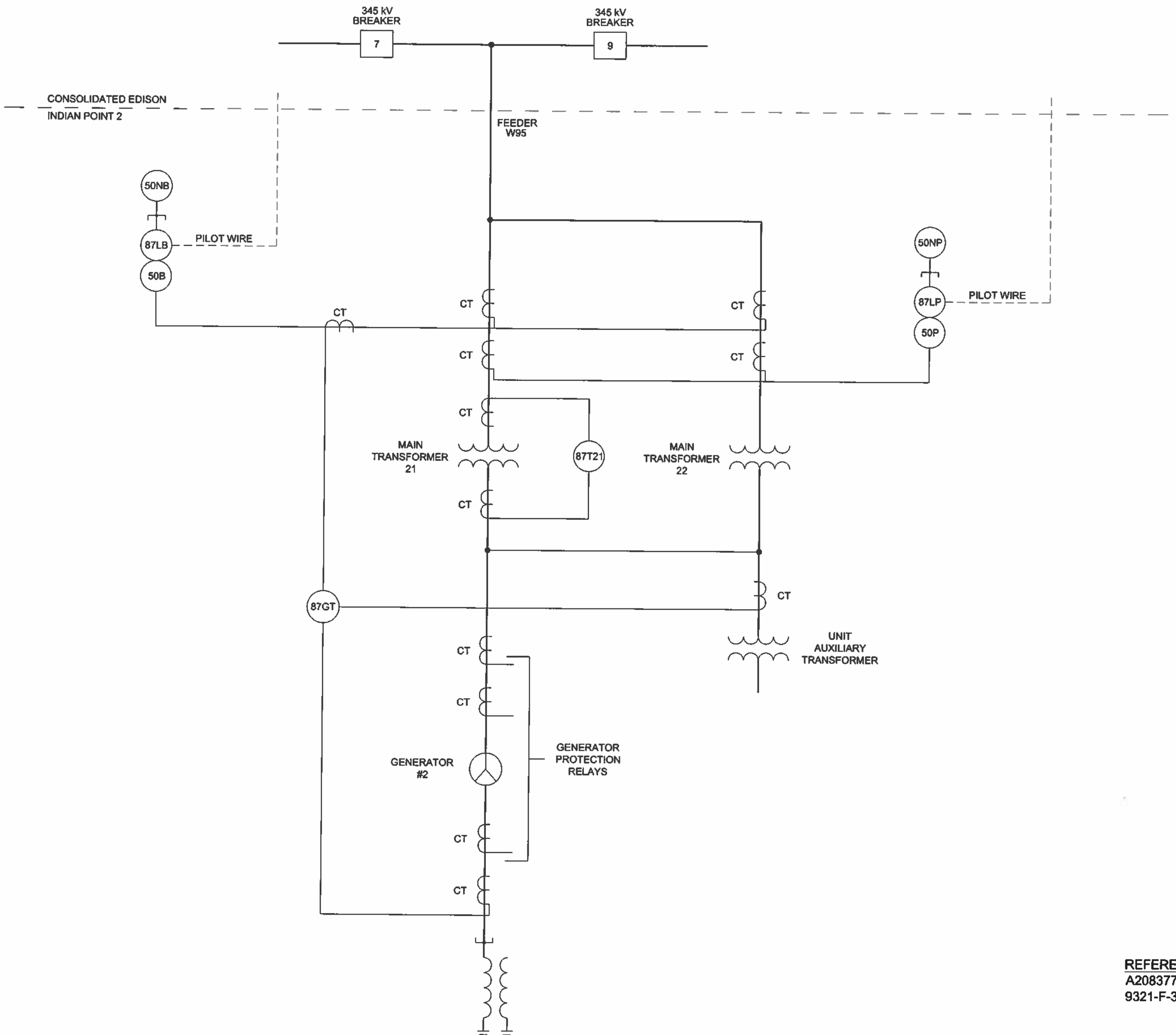
SEQUENCE OF EVENTS LOG

INITIATED TIME: 18:39:36.175 TRIGGER: (YD9038) HIGH VIBRATION CAUSE TURBINE

TIME	POINT-ID	DESCRIPTION OF POINT ID	MESSAGE	QUALITY	DELTA (msec)
18:39:43.538	LD0420	SG 22 LOW LEVEL CHNL 1 PARTIAL R	TRIP	INHB	7363
18:39:43.553	LD0423	SG 22 LOW LOW LEVEL CHNL 1 PARTI	TRIP	INHB	7378
18:39:43.686	LD0404	SG 21 LOW LOW LEVEL CHNL 2 PARTI	TRIP	INHB	7511
18:39:43.780	LD0401	SG 21 LOW LEVEL CHNL 2 PARTIAL R	TRIP	INHB	7605
18:39:43.800	LD0440	SG 23 LOW LEVEL CHNL 1 PARTIAL R	TRIP	INHB	7625
18:39:43.815	LD0406	SG 21 LOW LOW LEVEL CAUSE REACTO	TRIP	INHB	7640
18:39:43.830	LD0405	SG 21 LOW LOW LEVEL CHNL 3 PARTI	TRIP	INHB	7655
18:39:43.888	LD0443	SG 23 LOW LOW LEVEL CHNL 1 PARTI	TRIP	INHB	7713
18:39:43.939	LD0445	SG 23 LOW LOW LEVEL CHNL 3 PARTI	TRIP	INHB	7764
18:39:43.961	LD0444	SG 23 LOW LOW LEVEL CHNL 2 PARTI	TRIP	INHB	7786
18:39:43.989	LD0400	SG 21 LOW LEVEL CHNL 1 PARTIAL R	TRIP	INHB	7814
18:39:44.022	LD0441	SG 23 LOW LEVEL CHNL 2 PARTIAL R	TRIP	INHB	7847
18:39:44.088	LD0403	SG 21 LOW LOW LEVEL CHNL 1 PARTI	TRIP	INHB	7913
18:39:44.113	LD0400	SG 21 LOW LEVEL CHNL 1 PARTIAL R	NOT TRI	INHB	7938
18:39:44.273	LD0400	SG 21 LOW LEVEL CHNL 1 PARTIAL R	TRIP	INHB	8098
18:39:44.317	YD9060	ATWS MITIGATION SYS. ACT. CIRC	TRIP	INHB	8142
18:39:44.318	LD0403	SG 21 LOW LOW LEVEL CHNL 1 PARTI	NOT TRI	INHB	8143
18:39:44.449	LD0444	SG 23 LOW LOW LEVEL CHNL 2 PARTI	NOT TRI	INHB	8274
18:39:44.473	LD0403	SG 21 LOW LOW LEVEL CHNL 1 PARTI	TRIP	INHB	8298
18:39:44.593	LD0444	SG 23 LOW LOW LEVEL CHNL 2 PARTI	TRIP	INHB	8418

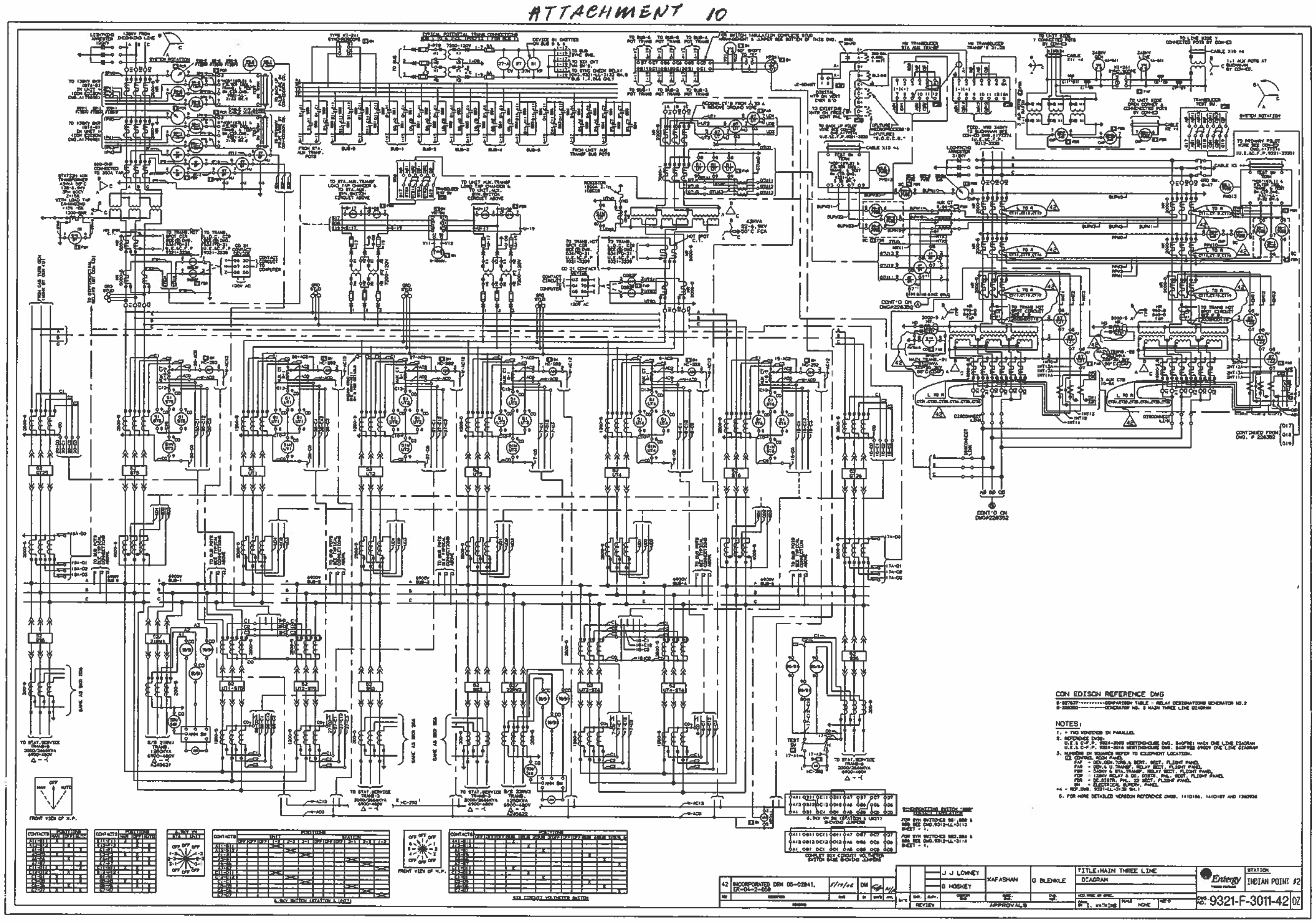
ATTACHMENT 9

SIMPLIFIED INDIAN POINT UNIT 2
SINGLE LINE DIAGRAM

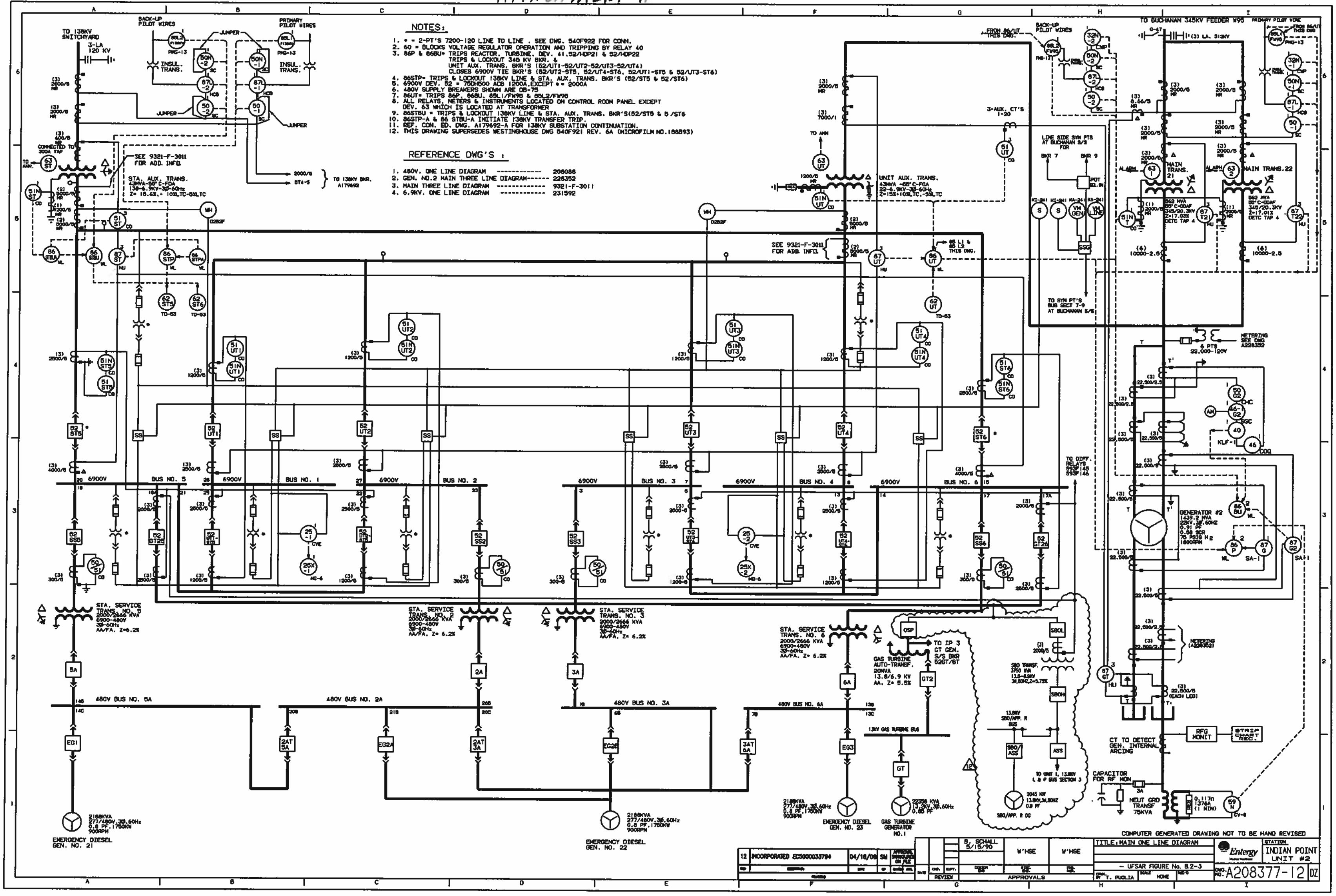


REFERENCE DRAWINGS:
A208377-12 - MAIN ONE LINE DIAGRAM
9321-F-3011-92 - MAIN THREE LINE DIAGRAM

ATTACHMENT 10



ATTACHMENT II



NOTES:

1. • = 2-PT'S 7200-120 LINE TO LINE . SEE DWG. 540F922 FOR CONN.
2. 60 = BLOCKS VOLTAGE REGULATOR OPERATION AND TRIPPING BY RELAY 40
3. 86P & 86BU= TRIPS REACTOR, TURBINE, DEV. 41,52/HDP21 & 52/HDP22
   TRIPS & LOCKOUT 345 KV BKR. &
   UNIT AUX. TRANS. BKR'S (52/UT1-52/UT2-52/UT3-52/UT4)
   CLOSES 6900V TIE BKR'S (52/UT2-ST5, 52/UT4-ST6, 52/UT1-ST5 & 52/UT3-ST6)
4. 86STP= TRIPS & LOCKOUT 138KV LINE & STA. AUX. TRANS. BKR'S (52/ST5 & 52/ST6)
5. 6900V DEV. 52 = 75DH500 ACB 1200A,EXCEPT •• = 2000A
6. 480V SUPPLY BREAKERS SHOWN ARE DB-75
7. 86UT= TRIPS 86P, 86BU, 85L1/FW95 & 85L2/FW95
8. ALL RELAYS, METERS & INSTRUMENTS LOCATED ON CONTROL ROOM PANEL EXCEPT DEV. 63 WHICH IS LOCATED AT TRANSFORMER
9. 86STBU = TRIPS & LOCKOUT 138KV LINE & STA. AUX. TRANS. BKR'S(52/ST5 & 5 /ST6
10. 86STP-A & 86 STBU-A INITIATE 138KV TRANSFER TRIP.
11. REF. CON. ED. DWG. A179692-A FOR 138KV SUBSTATION CONTINUATION.
12. THIS DRAWING SUPERSEDES WESTINGHOUSE DWG 540F921 REV. 6A (MICROFILM NO.188893)

REFERENCE DWG'S :

1. 480V. ONE LINE DIAGRAM ------------ 208088
2. GEN. NO.2 MAIN THREE LINE DIAGRAM------ 228352
3. MAIN THREE LINE DIAGRAM ------------- 9321-F-3011
4. 6.9KV. ONE LINE DIAGRAM ------------ 231592

Kolodziej, Kazimierz ATTACHMENT 12 SHT 1

From: Zografos, Andromahe [azograf@entergy.com]
Sent: Monday, November 22, 2010 3:55 PM
To: Kolodziej, Kazimierz
Cc: Raffaele, Joseph J; Casalaina, Richard; Bode, Paul; Das, Ajoy
Subject: FW: 2.5kA vs 1.7kA for W95

Kaz,

I just got this information from Con-Ed.

Andrea

From: Jacques, Patricia L [mailto:JACQUESP@coned.com]
Sent: Monday, November 22, 2010 3:50 PM
To: Zografos, Andromahe; Raffaele, Joseph J
Cc: Jacques, Patricia L; Vasco, John; Chu, Howard
Subject: RE: 2.5kA vs 1.7kA for W95

Good Afternoon,

The Buchanan DFR is currently calibrated at a 3000/1 ratio for Feeder W95. This will be corrected to reflect 2000/1.

Thanks,

Patricia Jacques
Relay Protection Engineering
212-460-3066

From: Zografos, Andromahe [mailto:azograf@entergy.com]
Sent: Monday, November 22, 2010 9:49 AM
To: Jacques, Patricia L
Cc: Raffaele, Joseph J
Subject: FW: 2.5kA vs 1.7kA for W95

Pat,

I've been asked to forward you this email. Can you please answer the question per the below that is related to the DFR?

Thank you,

Andrea

From: Kolodziej, Kazimierz [mailto:Kazimierz.Kolodziej@wgint.com]
Sent: Monday, November 22, 2010 9:16 AM
To: Zografos, Andromahe; Bode, Paul; Das, Ajoy; Casalaina, Richard; Raffaele, Joseph J
Subject: RE: 2.5kA vs 1.7kA forr W95

Andromahe,

Can you forward this email to Patricia at CON ED working with Howard Chu.

Reviewing IP and Con Edison dwgs it appears that the 345kV breakers are equipped with 3000/5A MR CT. What is the CT ratio tap used for the circuits that IP Unit 2 and 3 is connected. It appears that 2000/5A CT tap might be used but the DFR might be set for 3000/5A full ratio thus DFR shows 2500A not 1700A?

Kaz

ATTACHMENT 12 SHT, 2

From: Bode, Paul [mailto:PBode@entergy.com]
Sent: Monday, November 22, 2010 8:21 AM
To: Kolodziej, Kazimierz; Das, Ajoy
Subject: RE: 2.5kA vs 1.7kA forr W95

OK. I looked at all the traces and I see that the U3 feeder is also sitting at about 2500 so must be a systemic issue?

From: Kolodziej, Kazimierz [mailto:Kazimierz.Kolodziej@wgint.com]
Sent: Friday, November 19, 2010 12:50 PM
To: Das, Ajoy; Bode, Paul
Subject: 2.5kA vs 1.7kA forr W95

We could not get in touch with you but just to note that Con ED DFR's are typically connected to 3000/5 CT except for W95 which is connected to 2000/5. If they put the 3000/5 ratio vs 2000/5 then they display the 2.5kA vs 1.7kA.

Minutes of Meeting with Con Edison and URS, Washington Division at Con Edison Office on November 19, 2010

Date: November 19, 2010
Time: 10AM
Place: Con Edison Office

Present:

Con Edison	**URS, Washington Division**
Howard Chu	Ajoy Das
Patricia Jacques	

1. Indian Point #2 Main generator step up transformer developed a fault on Sunday, November 7, 2010. Purpose of the meeting was to analyze relay operations and related DFR records.

2. It was concluded that relays responded according to the protection scheme and the breakers at Buchanan substation cleared the fault.

3. It was indicated by Entergy that Indian Point #2 recorded 1060MW and 260 MVAR output before the fault developed at the main generator step up transformer.

4. Considering the above data, plant output current was 1826A (feeder W95)

5. It was noted that W95 feeder DFR at Con Edison Buchanan substation registered 2518A instead of approximately 1826A.

6. It was agreed that DFR calibration would be checked by Con Edison.

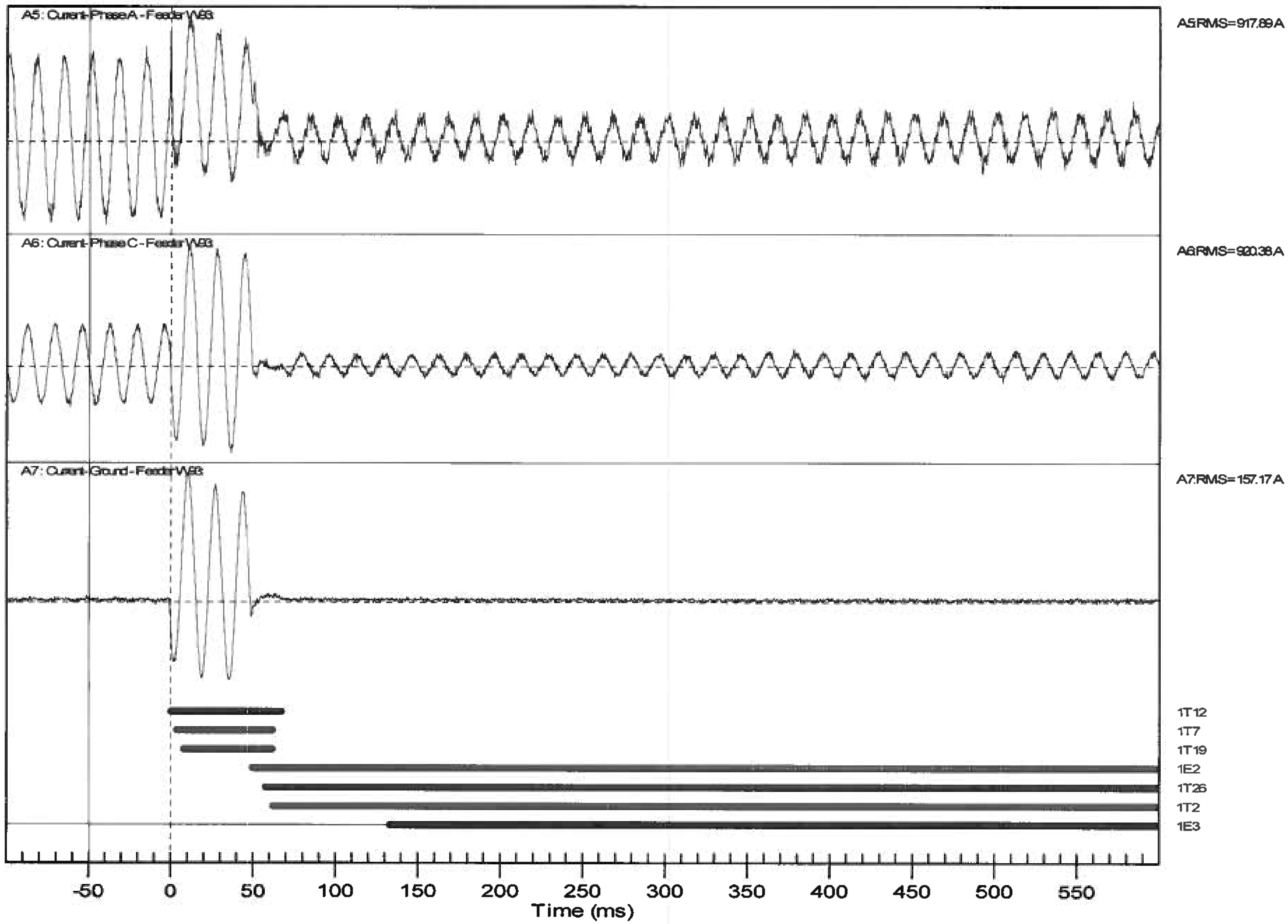
7. Current traces at W95 and W93 are attached.

(Subsequently, Con Edison checked the DFR calibration on November 22, 2010. They confirmed that DFR calibration was based on 3000:5 breaker CT ratio. Actual CT ratio is 2000:5. DFR calibration will be corrected by Con Edison).

Attachment 13, Sht. 2

R03F0392 : Buchanan 345kV (DFR)

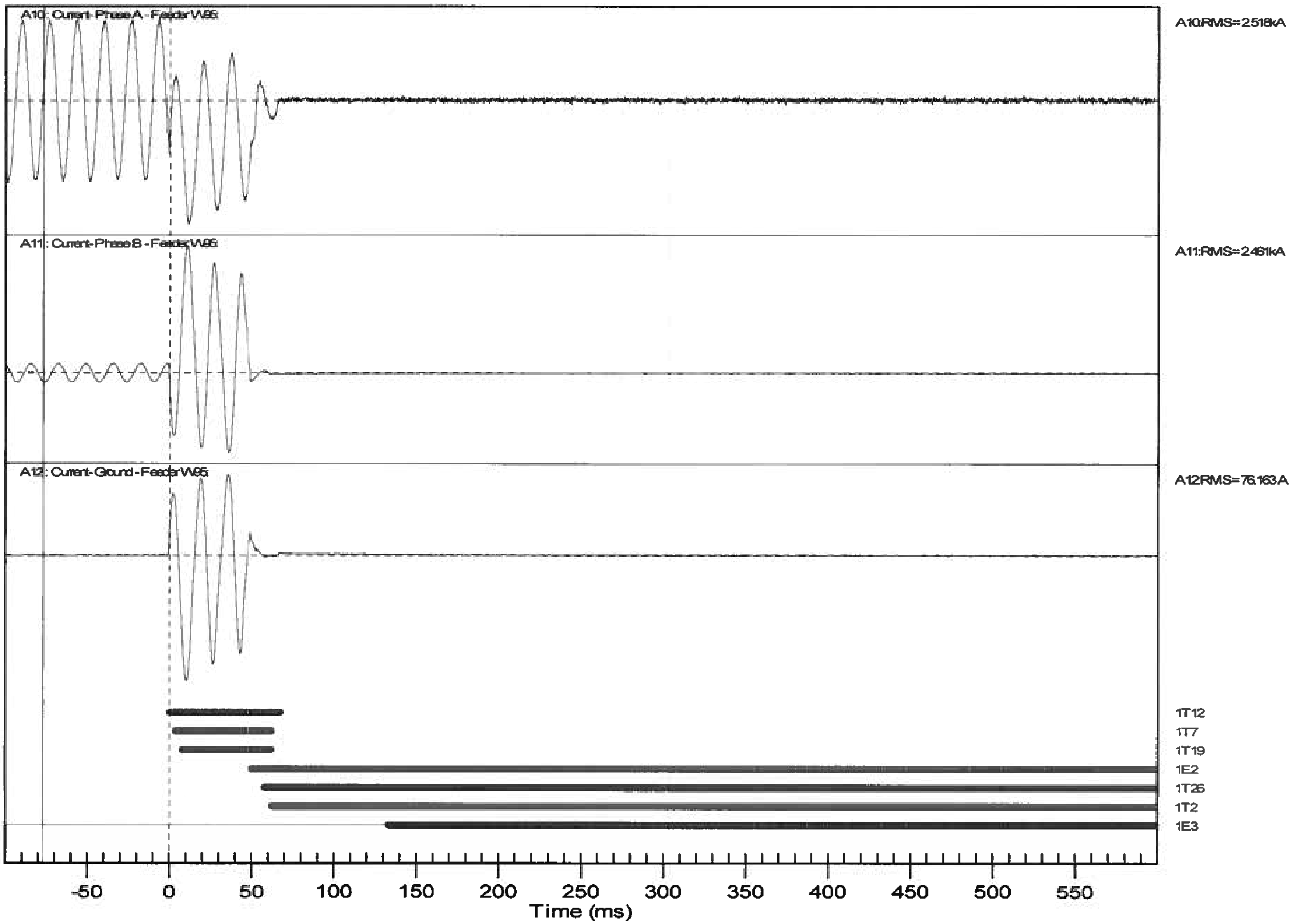
Fault Time : 11/07/2010-18:39:36.197710



Attachment 13, Sht. 3

R03F0392 : Buchanan 345kV (DFR)

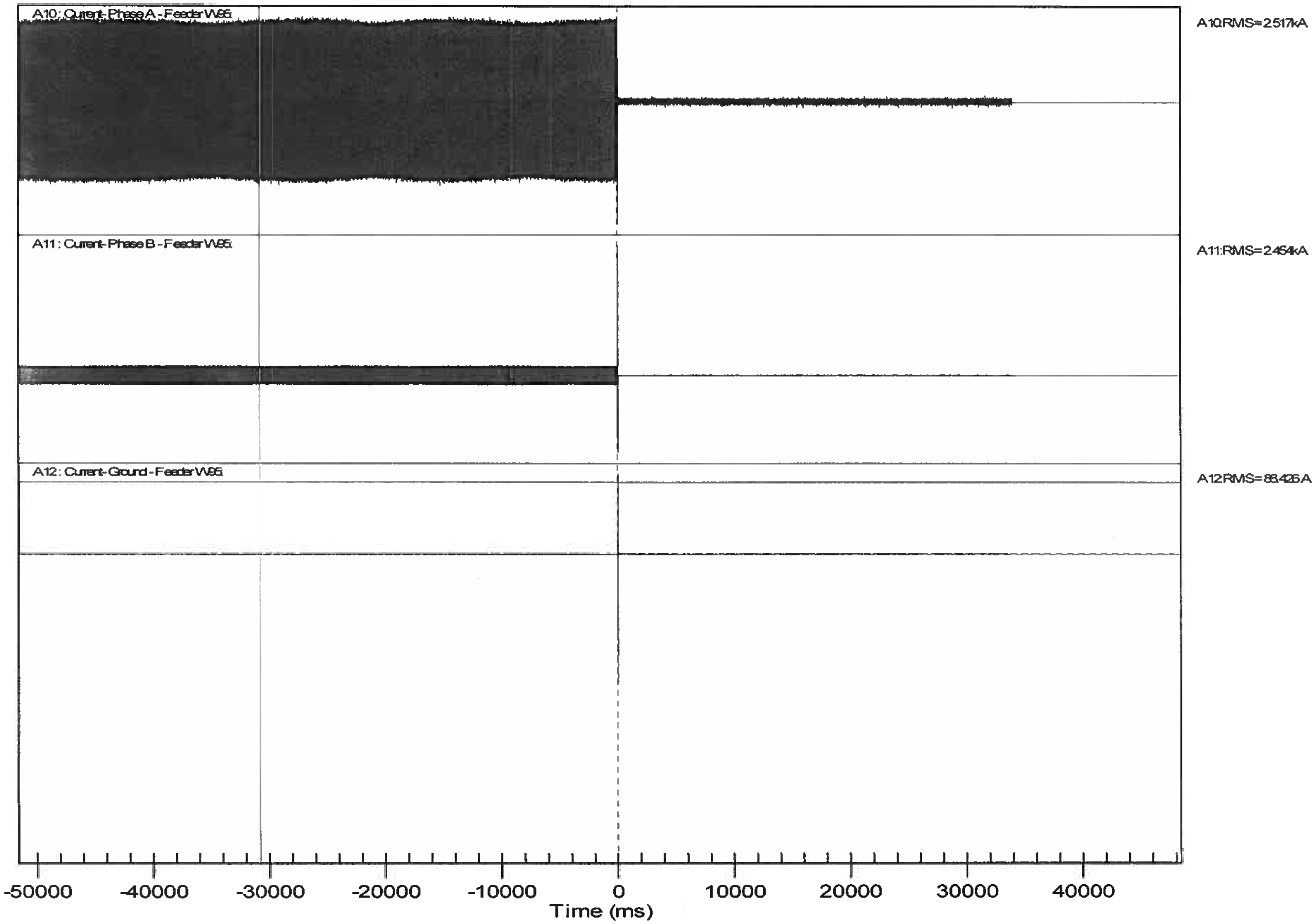
Fault Time : 11/07/2010-18:39:36.197710



Attachment 13, Sht. 4

R03F0391 : Buchanan 345kV (DFR)

Fault Time : 11/07/2010-18:39:36.197710



Attachment III

Lucius Pitkin, Inc. *Consulting Engineers*

Advanced Analysis
Fitness-For-Service
Failure & Materials Evaluation
Nondestructive Engineering

FINAL REPORT
TRANSFORMER BUSHING ROOT CAUSE ASSESSMENT
21 MAIN TRANSFORMER FAULT OF NOVEMBER 7, 2010

REPORT No. F10503-R-001
Revision 2

May 19, 2011

Prepared for:

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EXECUTIVE SUMMARY

Based on the Entergy Root Cause Evaluation Report [1][1], at 18:39 hours on November 7th, 2010, with the plant at approximately 100% power, a fault occurred on the Indian Point Energy Center (IPEC) 21 Main Transformer (21MT), which resulted in a Unit 2 automatic trip. A turbine trip/reactor trip via Main Generator Primary and Back-up Lockout Relays resulted, with subsequent 21 Main Transformer explosion.

A schematic of the 21MT with the "A", "B", and "C" phase bushings identified is shown in Fig. 1. The initiating event of the 21 Main Transformer failure was a fault originating from the "B" phase high voltage bushing to ground. A primary explosion and fireball ensued from this initiating event. The fault was triggered by an arcing event internal to the 21MT. A cut-away view of the transformer bushing internal components is provided in Fig. 2, and Fig. 3 has a close-up rendering of the internal coil/winding locations for the incident high voltage (HV) bushings. As a consequence of the electrical arc generated during the internal fault, a rapid increase of pressure inside the power transformer was experienced.

The abrupt dynamic pressure increase resulted in a breach of the 21 Main Transformer tank, as seen in Fig.4. Subsequent to the tank failure, oil from inside the 21MT tank containment was released to the surrounding ground, as shown in Fig. 5, and oxygen from the atmosphere was drawn into the tank via diffusion forces. As the atmospheric gas mixed inside the tank with hot combustible gases, spontaneous gas ignition occurred. A secondary explosion was witnessed due to the ignition of the combustible gases.

The unit trip occurred right after an audible deep 60 cycle humming noise, consistent with an overload. This observation was noticed by more than one person on-site at the time of the explosion, based on the Event Recollection Forms [1] for this incident. Additionally, the trip occurred within a minute of receiving a main generator high RF Alarm. Plant experience for the 21MT showed this alarm follows increases in lagging MVARs, however prior to the 21MT fault the alarm occurred without a corresponding change in MVARs.

[1] Numbers in [xx], refer to references in Section 6.0

At the point of the unit trip, the Digital Fault Recorder (DFR) data provided by Con Edison did not show any current or voltage anomalies. There were also no DC offsets or fault noise (smooth steady cycles), and none of the ground traces showed current.

Lucius Pitkin, Inc. (LPI) was requested by Entergy IPEC to provide engineering services in support of the root cause analysis (RCA) for the 21MT fault. External and internal visual examinations of the 21MT tank were performed by LPI personnel, and a direct cause for the failure of the 21MT was attributed to a fault in the "B" phase high voltage (HV) bushing. However, a root cause determination for the bushing failure required a tear-down inspection of the HV bushings. The transformer was supplied by TUSA, a Siemens-owned company, and the HV bushings were manufactured by Trench Limited.

The tear-down inspection of the HV bushing was performed at the Trench manufacturing facility in Ajax, Ontario, Canada on January 20th, 2011. The failed "B" phase HV bushing internal assembly, also known as the capacitor assembly, was removed from the housing and installed between roller supports for unwrapping of the layers. The lower section of the capacitor was badly damaged, both electrically and thermally. A radial electrical puncture was found through the layers at the upper edge of the lower capacitor section, based on measurements and side-by-side comparison to a scale assembly drawing. The paper layers were found well wetted throughout the length of the capacitor. This confirmed that the oil level in the bushing was correct. The capacitor layers were unwound and inspection was conducted at each layer. During disassembly, a faintly discolored line was noted in the paper, immediately adjacent to the aluminum foil on the outside edge. This observation was examined in more detail and electrical treeing was found.

The radial electrical puncture through the layers became progressively more narrow as the unwinding progressed nearer the core conductor. This morphology suggested that the puncture originated in the core and progressed radially and axially outward toward the ground plane provided by the grounded test layer. The puncture initiated in layer 20 or 21, approximately. An axial electrical fault appears to have progressed from the puncture initiation site. This puncture was located approximately 52 inches (132 cm) from the base of the capacitor construction. The paper layers underlying the puncture initiation site were unaffected and there was no evidence of electrical damage to the copper core conductor below this puncture location. During the teardown, Trench Limited stated that the assembly appeared consistent with their normal practices and that there were no quality defects observed. For the purposes of this report, a "quality defect" was interpreted to mean a conspicuous defect in which the bushing as it was manufactured deviated from the design or contained defects that could noticeably affect performance

The “C” phase HV bushing was similarly disassembled and inspected. The lower section of the capacitor construction was thermally damaged, resulting in charring and exfoliation of the paper layers. No electrical punctures were found. The paper layers were found with similar tree structures as were observed for the “B” phase bushing.

Based upon this inspection, it is LPI’s opinion that the root cause for the transformer failure was electrical treeing in the bushing paper insulation, which caused accelerated degradation of the oil-impregnated paper insulation. Treeing is a local breakdown of an organic material caused by a localized electrical stress concentration that exceeds the dielectric breakdown strength of the material. The electrical trees observed on the incident bushings at the Trench manufacturing facility were found initiating at the electrically stressed edge of the aluminum foil interface with the paper layers. Therefore, LPI finds that the root cause of the 21MT failure was a condition where the electric stress concentration at the edge of the metal foil connection with the paper insulating material exceeded the dielectric breakdown strength of the insulating material. This dielectric breakdown condition propagated through adjacent layers of the paper insulation until an avalanche condition resulted wherein full-scale breakdown progressed rapidly and without significant warning.

LPI
Est. 1885

DOCUMENT RECORD	
Document Type:	☐ **Calculation** ☒ **Report** ☐ **Procedure**
Document No:	F10503-R-001
Document Title:	Final Report – Transformer Bushing Root Cause Assessment, 21 Main Transformer Fault of November 7th, 2010
Client:	Entergy Operations, Inc.
Client Facility:	Indian Point Energy Center
Client PO No:	10297978
Quality Assurance:	**Nuclear Safety Related?** ☒ **No** ☐ **Yes**

Computer Software Used?:	☐ **No**[1] ☒ **Yes**[2]	1. Check NO when EXCEL, MathCAD and/or similar programs are used since algorithms are explicitly displayed. 2. Include Software Record for each computer program utilized (N.A. for this report)
Instrument Used?:	☐ **No** ☒ **Yes**[3]	3. Include Document Instrument Record (N.A. for this report)

Revision	**Approval Date**	**Preparer**	**Checker**	**Design Verification**	**Approver**[4]
0	2/21/11	*J.G.*	*B.H*	*N.A.*	*P.M.B*
1	4/21/11	*JG/BH*	*B.H*	*N.A.*	*P.M.B*
2	5/19/11	*JG/pmb* Joseph Groeger B. Hohmann		N.A.	P.M. Bruck

[4] The Approver of this document attests that all project examinations, inspections, tests and analysis (as applicable) have been conducted using approved LPI Procedures and are in conformance to the contract/purchase order.

Page	**5**	**of**	**66**	**Total Pages**	Include any Title Sheet and Attachments in page count

RECORD OF REVISION

Revision No.	Date	Description of Change	Reason
0	See Document Record	Interim Update	
1	See Document Record	Initial Final Report	
2	See Document Record	Final Report. Clarified statements within Executive Summary and Conclusion.	Final Report. Clarified certain statements made.

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ATTACHMENTS

TABLE OF FIGURES

1.0 INTRODUCTION

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A schematic of the 21MT with the “A”, “B”, and “C” phase bushings identified is shown in Fig. 1. The initiating event of the 21 Main Transformer failure was a fault originating from the “B” phase high voltage bushing to ground. A primary explosion and fireball ensued from this initiating event. The fault was triggered by an arcing event internal to the 21MT. A cut-away view of the transformer bushing internal components is provided in Fig. 2, and Fig. 3 has a close-up rendering of the internal coil/winding locations for the incident high voltage (HV) bushings. As a consequence of the electrical arc generated during the internal fault, a rapid increase of pressure inside the power transformer was experienced.

The abrupt dynamic pressure increase resulted in a breach of the 21 Main Transformer tank, as seen in Fig.4. Subsequent to the tank failure, oil from inside the 21MT tank containment was released to the surrounding ground,as shown in Fig. 5, and oxygen from the atmosphere was drawn into the tank via diffusion forces. As the atmospheric gas mixed inside the tank with hot combustible gases, spontaneous gas ignition occurred. A secondary explosion was witnessed due to the ignition of the combustible gases.

The unit trip occurred right after an audible deep 60 cycle humming noise, consistent with an overload. This observation was noticed by more than one person on-site at the time of the explosion, based on the Event Recollection Forms [1] for this event. Additionally, the trip occurred within a minute of receiving a main generator high RF Alarm. Plant experience for the 21MT showed this alarm historically follows increases in lagging MVARs, however prior to the 21MT fault the alarm occurred without a corresponding change in MVARs.

At the point of the unit trip, the Digital Fault Recorder (DFR) data provided by Consolidated Edison for the Buchanan substation, did not show any current or voltage anomalies. There were also no DC offsets or fault noise (smooth steady cycles), and none of the ground traces showed current.

1.1 Scope of Work and Objectives

LPI was requested by Entergy IPEC to assist in the root cause evaluation of the 21MT failure. In support of this request, the following work has been performed by LPI:

- Participation in meetings and engineering analysis with members of the IPEC Root Cause Evaluation team in the days immediately following the fault
- Detailed review of IPEC 21MT data and Operator Experience (OE) documents
- Literature review of HV power transformer failures and bushing component failures
- External inspection of 21MT structure including dimensional measurements and digital photographs of the event site
- Internal inspection of 21MT structure including close-up digital photographs of bushing components
- Calculation of the estimated dynamic pressure increase experienced by the 21MT tank during the fault
- Finite element simulations of the structural response under the estimated pressure pulse load
- Participation in the tear-down inspection of the “A”,”B”, and “C” phase high voltage (HV) bushing components from the 21 MT unit
- Testing and analysis of the 21MT HV bushing oil and impregnated paper insulation and non-used aluminum foil bushing material
- Report preparation

2.0 VISUAL INSPECTION

LPI personnel were on-site at the IPEC facility in Buchanan, NY following the fault to visually inspect the scene and assist the IPEC root cause analysis (RCA) team. The 21MT was one of a pair of parallel 20.3 kV/345kV step-up transformers serving the output of Unit 2. The 21MT had been replaced in 2006, resulting in a service life of less than five years prior to the fault event and explosion. The nominal design life for the transformer would be expected to be at least 40 years. The 21 Main Transformer had undergone routine maintenance testing prior to the fault on November 7, 2010. Some of these tests included dissolved gas analysis (DGA), corona scans, and electrical tests such as power factor (PF) testing. No adverse trending in these maintenance tests, which could have highlighted an unsafe operating condition, were observed. In addition, electrical testing was performed on the bushings during every outage, and no significant negative trends were indicated by these tests.

2.1 External Transformer Inspection

Fig. 6 was taken by IPEC personnel on November 7, 2010 after the 21MT failure occurred. As seen in the photograph, the force of the explosion deformed conduit that was running to the ventilation system. By the time LPI personnel arrived on the scene, demolition crews were already disassembling the 21 Main Transformer, as seen in Fig. 7. The “B” phase high voltage feeder bus section was broken away at the stand-off insulator above the radiators. A close-up photograph of the removed “B” phase HV feeder bus section is shown in Fig. 8.

As shown in Fig. 9, the extent of the failed transformer tank deformation is greatest beneath the “B” phase bushing base flange region. The maximum deflection (laterally) at the open seam was estimated as approximately 15 to 16 inches (38 to 41 cm).

2.2 Internal Transformer Inspection

A follow-up visual inspection of the internal components of the 21 Main Transformer was initially performed on November 10, 2011 to look for evidence of arcing, conductor separation, shield displacement, or other causes of the fault. The “B” phase bushing area and inside the corona shield enclosure were two particular regions of interest (ROI) based on the external visual inspection. A detailed configuration of the 21MT HV bushing is provided in Fig. 10. Significant arc striking was observed at the bottom terminal of the “B” phase bushing, as seen in Fig. 11. Of the “A”, “B”, and “C” phase HV bushings, the “B” phase experienced the most severe damage from the fault event. As shown in Fig. 12, most of the aluminum foil and insulating paper was torn and unraveled from the lower section of this bushing. Pieces of both the insulating material and epoxy housing from the “B” phase bushing were found scattered inside and outside of the transformer immediately following the failure, indicating the initiating event prior to failure occurred inside of the transformer tank.

In contrast to the severe damage experienced by the “B” phase, the “A” phase bushing experienced less visible damage. A photograph of the “A” phase HV bushing from the initial internal visual inspection is shown in Fig. 13. As illustrated in Fig. 13, the external epoxy cover of the “A” phase bushing was completely intact exposing no insulating paper. The shield was shifted downward due to minor damage to the shield bracing, however the shield surface was in good condition with no evidence of arcing.

The “C” phase bushing also sustained damage, however it was not as extensive as the damage experienced by the “B” phase. The difference in the extent of damage between the “B” and “C” phase HV bushings can be observed in Fig. 14, which was taken after the bushings had been removed from the transformer. The external epoxy cover on the “C” phase bushing had been ejected, however most of the insulating paper was found still intact.

Visual internal inspection showed that the transformer core, connections, and current transformers (CTs) appeared in good condition (Ref. 1). Based on the internal inspection, the direct cause of the transformer failure was attributed to a fault originating from the “B” phase HV bushing. In order to determine a root cause for the failure, the bushings were sent to the Trench manufacturing facility in Ajax, Ontario for tear-down inspection.

2.3 Site Visit to Trench for Bushing Tear-down Inspection

On January 20, 2011, Trench Limited agreed to host a tear-down of the failed “B” phase and non-failed “A” and “C” phase HV bushings from the 21 Main Transformer at its manufacturing facility in Ajax, Ontario, Canada. At the meeting were representatives from Trench, Siemens, Entergy, NEIL, and LPI.

A meeting was held in advance of the bushing disassembly to review the past Trench COTA bushing failures, as addressed in the 2010 Doble Conference publication, "*Investigation of Failures of 230 kV OIP Copper Conductor Bushings*" [2]. In this review, bushing failures were attributed to copper deposition-initiated electrical treeing in the paper layers of COTA bushings manufactured in France, with fixed copper center conductors. The root cause was determined to be unidentified components of the particular insulating oil used at that time (Shell Dialla D). The corrective action that resulted from this study was to change to an Esso insulating oil, Type N-35 Voltesso and to an aluminum alloy fixed center conductor. During discussion, it was the position of Trench that a power factor tip-up test would indicate the onset and progression of degradation caused by 'copper migration'.

Trench identified the field-failed bushings as follows:

- 1 from Alabama Power
- 3 from Georgia Power

Trench stated that these field-failed bushings were all manufactured in their facility in France, with fixed copper conductors and Shell Dialla D oil. More recently, a 500 kV Trench bushing failed at Florida Power and Light [3]. This was identified as being manufactured in the Trench UK facility. A failure analysis study was recently initiated and was expected to be completed in March 2011.

Trench stated that they have no history of any failures with the COTA type bushings manufactured in the Ajax facility, with the exception of those that are the subject of this investigation. They stated that Trench has manufactured more than 100,000 bushings, split between the COT (condenser oil transformer) and COTA (condenser oil transformer ANSI) types. They added that the internal constructions are virtually identical, however the external dimensions and flanges are different and the test tap configurations are different.

Trench was acquired by Siemens AG in 2005, however it operates as an independent manufacturer.

Trench stated that one of their design features is the application of NBR rubber O-ring seals, as compared to other manufacturers who use flat gaskets. Trench stated that they use 30% compression on their O-rings. This design is approximately 25 years old.

Trench stated that they normally supply the bottom shield for their bushings, however for the IPEC 21MT and 22MT transformers which were manufactured by TUSA, a Siemens-owned company, the shields were integral to the transformers.

Trench confirmed that the subject IPEC bushings were manufactured at the Ajax, Ontario facility in 2005 and that all were part of the same production run. These bushings were of the COTA style, with a fixed conductor design and a 23 inches (58.42 cm) CT pocket length. Trench added that they changed oils in approximately 2005 from the Voltesso N-35 to Voltesso N-36. The N-36 version contains an inhibitor (typically an antioxidant). Trench representatives were unsure which oil would have been used in the subject bushings.

The bushings received from IPEC were identified as follows:

S/N 05F9080-04	This B phase bushing failed in service
S/N 05F9080-01	This C phase bushing was damaged during the fault event and sustained thermal damage to the lower housing and the oil was lost
S/N 05F9080-03	This A phase bushing sustained limited damage during the fault event. The internal oil was lost following recovery. Trench stated that the seal was damaged and caused the oil loss.

A tour of the manufacturing plant was provided. Trench purchases the porcelain bushings, epoxy lower housings, flanges, and most of the metal components from sub-suppliers. The principal manufacturing operations conducted by Trench include the capacitor assembly, assembly of the capacitor into the corresponding housing, installation of seals, bake-out and vacuum extraction of moisture, vacuum backfill with insulating oil, testing, and final documentation.

The capacitor assembly process was shown during the visit. The aluminum foil sections are manually measured and hand-cut into rectangular sections as observed in Fig. 15. The outer corners are removed to reduce electric stress concentration. The foils have a bare face and a blue-tinted adhesive face. The paper is continuously fed from rolls into the assembly press that consists of two heated pinch rollers. The rolling operation is interrupted to insert aluminum foil sheets between the paper layers.The layer is then thermally bonded such that the adhesive layer of foil is hot-pressed into the paper and the process is continued until all of the layers have been incorporated. The outermost layers include a window through the paper for the capacitive test probe and an outer nickel foil layer to which a ground connection is soldered. The ground and test electrodes are installed later in the fabrication process and contact these internal connection points. The ground layer is continuously grounded with the bushing in service.

2.3.1 Bushing Disassembly and Examination

As part of the tear-down diasassembly process, the bushing core was removed from the housing, as shown in Fig. 16. The failed “B” phase HV bushing (S/N 05F9080-04) internal assembly, also known as the capacitor assembly, was removed from the housing and installed between roller supports for unwrapping of the layers. The lower section of the capacitor was badly damaged, both electrically and thermally as Fig. 17(a) shows. A radial electrical puncture was found through the layers at the upper edge of the lower capacitor section, based on measurements and side-by-side comparison to a scale assembly drawing. The puncture is shown in Fig. 17(b). The paper layers were found well wetted throughout the length of the capacitor. This confirmed that the oil level in the bushing was correct. The capacitor layers were unwound and inspection was conducted at each layer. During disassembly, a faintly discolored line was noted in the paper, immediately adjacent to the aluminum foil on the outside edge. This observation was examined in more detail and electrical treeing was found. It was the opinion of the Trench representatives that this was evidence of the ‘copper deposition’ problem identified as the root cause for the previous Trench (France) bushing failures.

The radial electrical puncture through the layers became progressively more narrow as the unwinding progressed nearer the core conductor. This morphology suggested that the puncture originated in the core and progressed radially and axially outward toward the ground plane provided by the grounded test layer. The puncture initiated in layer 20 or 21, approximately. Fig.18 shows the radial puncture initiation site. As shown in Fig.18, an axial electrical fault appears to have progressed from the puncture initiation site. This puncture was located approximately 52 inches (132 cm) from the base of the capacitor construction. The paper layers underlying the puncture initiation site were unaffected and there was no evidence of electrical damage to the copper core conductor below this puncture location. During the teardown, Trench Limited stated that the assembly appeared consistent with their normal practices and that there were no quality defects observed. For the purposes of this report, a “quality defect” was interpreted to mean a conspicuous defect in which the bushing as it was manufactured deviated from the design or contained defects that could noticeably affect performance

The “C” phase HV bushing was similarly disassembled and inspected. The lower section of the capacitor construction was thermally damaged, resulting in charring and exfoliation of the paper layers. No electrical punctures were found. The paper layers were found with similar tree structures as were observed for the “B” phase bushing. Trench representatives again suspected ‘copper deposition’ for the electrical treeing. Fig. 19 is a photograph of the electrical trees observed at the paper/aluminum foil interface of the “C” phase bushing. No quality defects were identified in the “C” phase HV bushing during the site visit.

The non-failed “A” phase bushing (05F9080-01) was reserved for follow-up electrical testing, as agreed during the meeting. The plan developed for this testing included a rebuilding of the bushing using its present core. The goal was to determine if electrical testing would be effective for detecting what Trench representatives believed to be the ‘copper deposition’ treeing observed in the companion “B” and “C” phase bushings. Subsequent efforts by Trench indicated that the power factor and capacitance were at original (nameplate) values at 2 kV, however with 4 kV applied, the capacitor core began to smoke. Testing was abandoned.

3.0 ANALYSIS METHODS AND APPLICATIONS

Several analytical methods were applied in the laboratory to samples removed from the “B” phase and “C” phase bushings, including both paper and aluminum foil sections. Oil was extracted from the paper samples by Soxhlett refluxing with a high purity organic solvent (hexane). The solvent was run through each analysis method as well to account for any impurities. Laboratory testing was limited in scope and intended to provide fundamental information to support a root cause analysis. The analytical methods and their application are described in the following sections of this report.

3.1 Ion-Coupled Plasma Chromatography (ICP)

This method has very high sensitivity to metals and was used primarily to determine if traces of copper were present in the oil extracted from paper samples in both bushings. A 3 parts-per-trillion detection limit is capable with ICP. Secondary applications of this method were to determine if any corrosive ions were present in the oil and if a stabilizer might be indicated. Testing found **no** evidence of copper in the treed paper insulation region. This was inconsistent with the “copper deposition” mechanism speculated by Trench representatives as the root cause of the electrical treeing phenomenon.

3.2 Gas Chromatography with Mass Spectrometer Detector (GC/MS)

This method is routinely used to identify organic compounds. This was applied to oil samples removed from paper from the “B’ and “C” phase bushings. Analysis was conducted to determine if any corrosive organic compounds were present in the oils, if any stabilizers were present, and if the oil contained any adverse contaminants that were not expected.

3.3 Fourier Transform Infrared Spectroscopy (FTIR)

This analysis method was applied to a non-used sample of the aluminum capacitor foil to identify the polymeric thermally-activated blue-colored adhesive layer on one face. Trench supplied the foil sample, and the foil sample was representative of the foil used in the subject bushings.

3.4 Energy Dispersive X-Ray Analysis (EDX)

This analytical method is primarily used for identification of inorganic compounds and metals in a sample, based on the energy of emitted X-rays. A sample of the non-used aluminum foil provided by Trench was analyzed to quantify the purity of the aluminum alloy and to confirm that the material used in the bushing fabrication was correctly selected for the application.

3.5 Optical Microscopy

This instrument was used to inspect the structure of the paper layers, the edges of the aluminum foils, and details of the paper condition at the edge of the foil layers.

3.6 Internal Pressure Fault Modelling & Tank Analysis

Calculations to develop likely internal pressures in the tank as a result of arcing of the bushing were prepared using a method based on the sudden generation of gas by an electrical arc. The range in dynamic pressure increase was calculated from the limits of gas formation and energy rates found in literature [10, 11, 12]. The approach utilized was meant to determine the volume of gas generated . An estimate of the temperature of the gas was made by relating the change in temperature to the change in energy using the constant specific heat of hydrogen. The sudden introduction of the gas to the tank oil produces the estimate of maximum and minimum oil pressure. Solving this relationship determines an estimate of the radius of the gas bubble, formed at the end of a specific time interval.

The above approach is provided for a likely range of pressures. To better narrow the likely pressures, a finite element analysis (FEA) model was developed on the transformer tank wall. The ANSYS [17] software code was utilized. The model was iterated with a pressure within the bounds of the minimum and maximum pressure estimated from the gas bubble formation, to derive a likely pressure the tank experienced, based on the measured deformation of the wall of the tank.

4.0 SUMMARY AND DISCUSSION OF ANALYTICAL RESULTS

4.1 Internal Pressure Fault Modelling & Stress Analysis

As a consequence of the electrical arc generated during the internal fault, a rapid increase of pressure inside the power transformer was experienced. The abrupt dynamic pressure increase resulted in a breach of the 21 Main Transformer tank, as seen in Fig.4. Oxygen from the atmosphere was drawn into the tank via diffusion forces. As the atmospheric gas mixed inside the tank with hot combustible gases, spontaneous gas ignition occurred. A secondary explosion was witnessed due to the ignition of the combustible gases. The instantaneous pressure increase from the electrical arc was calculated to have been in the range of approximately 233 to 943 psi based on energy rates found in the literature and thermodynamic limits of gas formation [10, 11, 12]. The full details of this calculation are provided in Appendix A. Additionally, a finite element analysis (FEA) model of the tank wall of the transformer was performed to validate this calculation and provide an upper bound estimate on the maximum pressure experienced by the transformer tank during the transient operating fault state. Results from the FEA model determined a maximum instantaneous pressure increase in the 700 to 800 psi range could have resulted in a 15 to 16 inch (38 to 41 cm) out-of-plane deflection for the transformer wall. Appendix B contains a detailed description of the FEA model parameters.

4.2 Oil Analysis

The oil in both the "B" phase and "C" phase bushings was found to be identical. Results from the GC/MS analysis for the "B" phase bushing is provided in Fig. 20, and Fig. 21 has the GC/MS for the "C" phase extracted oil. The oil is a hydrocarbon type mineral oil. The small sharp peaks evident in Fig. 20 and Fig. 21 are indicative of an antioxidant. The oil is free of significant corrosive ions (i.e. chlorates, sulfates, etc.), and contains a hindered phenol antioxidant added as a stabilizer. Mass spectroscopy of the antioxidant oil additive is shown in Fig. 22. A specific mass spectral match to a commercial antioxidant was not found for the oil sample used in Fig. 22, however MS analysis shows a good correlation between the additive and 2,6-di-terciary butyl-p-cresol. For the MS analysis of the "B" phase bushing oil, a good match with butylated hydroxytoluene (BHT) was obtained for the oil additive. BHT is a common commercially available antioxidant often used in oils due to its low cost and high solubility. This type of antioxidant protects against high temperature exposure. Additionally, this is not a metal-deactivating type of antioxidant that would inhibit the adverse effects of metal ions. The oil samples are free of any trace of copper or aluminum above the threshold sensitivity of 3 parts-per-trillion. The presence of an antioxidant (i.e., ‘inhibitor’) suggests that the oil is of the Voltesso N-36 type. A mixture of the N-35 and N-36 types cannot be excluded however. No undesirable organic contaminants were found in either sample.

4.3 Bushing Foil Analysis

The EDX spectrum for the non-used aluminum foil sample provided by Trench is shown in Fig. 23. The aluminum foil is pure aluminum on one face. This is probably aluminum alloy 1145, a typical capacitor foil. It is free of any significant copper. This alloy is approximately 99.5% aluminum with traces of other elements.

Fig. 24 contains the GC/MS results for the aluminum foil adhesive layer provided by Trench from a non-used piece of foil representative of the foil material that would have been present in the 21MT HV bushings. GC/MS analysis of the adhesive layer indicated the presence of fatty acids, a phthalate plasticizer, and traces of other compounds. The effect of these compounds on electrical treeing is not known. Based on the FTIR results provided in Fig. 25, the 'heat-activated' adhesive side of the foil consists of polyvinyl butyral,a vinyl polymer, and blue colorant. The vinyl polymer melts upon application of heat and some of the adhesive extrudes beyond the edge of the foil in some locations. There is no curing process and there are no unreacted organic compounds that might serve an adverse electrical role.The colorant is an organic dye. The EDX analysis of the blue adhesive foil layer is shown in Fig. 26, and is consistent with the results of the GC/MS analyses. The EDX analysis was conducted to determine if the blue adhesive layer was a copper-containing compound, which could help explain previously reported findings by Trench of copper in the electrically treed regions of prior failed bushings. However, no traces of copper were observed. Only carbon and oxygen were found.

4.4 Electrical Stress

Fig. 27 is a photograph taken with an optical microscope documenting evidence of electrical treeing in the paper insulation removed from the “B” phase bushing . Fig. 28 shows the results for the GC/MS analysis of a sample taken from an electrically treed paper region in the “B” phase bushing. Fig. 28 shows that there is no chemical breakdown of the paper, and no local oil breakdown. These findings are consistent with electrical treeing, where the breakdown occurs on a microscopic scale. However, these findings are inconsistent with bulk dielectric breakdown on the paper due to thermal degradation, moisture-induced chemical aging, or other bulk dielectric breakdown phenomenon. The location of where typical breakdown products, such as furans, would have been found had they been present is indicated in Fig. 28. Fig. 29 contains the EDX spectrum for the treed area along the foil edge of layer 19 in the “B” phase bushing. There was no elemental trace of copper found in this sample, only carbon and oxygen.

Significant electrical treeing was found along the edges of the aluminum foils, extending into the paper. This treeing is absent on the shielded edges of the aluminum foil where the electrical stress is low. An example of the treeing is shown in Fig. 30, for a paper sample from the non-failed “C” phase bushing.

Treeing is a local breakdown of an organic material caused by localized electric stress concentration that exceeds the dielectric breakdown strength of that material. Treeing is a time and electric stress-dependent process. Electrical trees form due to localized breakdown of an organic compound during which chemical bonds are broken and organic materials decompose into carbon and other decomposition products. Electrical trees are dark due to carbon formation. Since electrical trees form due to localized breakdown, their paths erode the dielectric strength of the remaining thickness of insulating material. Breakdown of the insulation thickness results when the electric stress concentration regions at the tips of propagating trees exceed the bulk dielectric breakdown strength of the insulation.

In the case of the subject 21MT Trench bushings, electrical trees were found in the paper layers initiating at the electrically stressed edges of the aluminum foils. The observance of electrical treeing is a direct indicator that the electric stress concentration is in excess of what the paper can withstand. The electrical treeing observed had advanced significantly in the less than five years of energized service on the 21MT HV bushings.

Treeing compromises the axial and radial breakdown strength of the paper layers since these are three-dimensional structures. As the insulation quality breaks down, the electric withstand strength decreases between adjacent paper layers. At some point, dielectric breakdown between the layers will occur. In a laminated capacitor structure, breakdown between the layers results in an avalanche condition wherein full-scale breakdown progresses rapidly and without significant warning.

Champion et al. [8] performed an accelerated laboratory test to study electrical treeing breakdown in epoxy resin impregnated paper (ERIP) condenser bushings. They found that electrical tree initiation and ultimately inter-foil breakdown occurred in four distinct groups, as shown in Fig. 31. Of the 29 inter-foil breakdowns examined in the research study, 17 were due to tree initiation at foil edges, and five were due to tree initiation at foil corners. Inter-foil failure of the remaining seven samples was attributed to the method by which the accelerated testing of the bushings was performed. Additional research [7, 9] also points to the significance of the manufacturing lay-up process for the insulating paper and aluminum foil layered assembly to the integrity of the finished bushing component.

4.5 Failure Assessment

The fault that occurred on the 21MT at IPEC on November 7, 2010 was a direct result of failure in the "B" phase HV bushing. It should be noted that a fault caused by bushing failure, similar to the one observed at IPEC, would be limited to the lower section of the bushing. This is because only the lower section of the bushing contains the aluminum foil layers for radial and axial electric stress grading. The capacitor structures are placed just above the flange, extending to the lower section beneath the epoxy housing. Additionally, the highest bulk electrical stresses (i.e. largest voltage gradient) exist in the flange area. Above this region, there is only paper and no ground plane, so the electrical stresses in this area are inconsequentially low. The only stress in this region would be capacitive loss to the surrounding air through the bushing. In the lower section, the outermost layer is ground via a ground connection that is a component of the test tap. For this reason, the only internal ground plane is in the area of the test tap that sits right above the flange. In a general prematurely aged bushing condition where the dielectric is breaking down, an electrical fault can only occur where a path forms to ground.

Treeing and breakdown in laminated capacitor structures is a recognized problem. In power systems, capacitors are widely used for power quality control at the transmission and distribution level. Failures of these capacitors are typically violent and occur without warning. Pressure relief devices generally are fitted to these capacitors to prevent rupture of the cases and subsequent oil release. Electric stress control is a key consideration when designing these devices to assure long service life.

Electric stress control in a capacitor is controlled by design (i.e. stress grading) and by limiting the electric stress concentration at the edge of the metal foils where they contact the insulating material. Certain capacitor manufacturers use precision-slit foils with outer edges that are folded over. This technique results in smooth, rounded edges where the foil layers abut the paper. Other methods used for some capacitor applications include etching as well as other proprietary processes. In all cases, the goal is to prevent an increase in the electric stress concentration caused by sharp edges or asperities.

Trench uses aluminum foils that are cut manually with a standard paper cutter. Based upon the manufacturing procedure observed during the January 20, 2011 teardown inspection, the edges were not folded over or treated in a manner which would have mitigated the potential for edge effects. Since the companion "C" phase HV bushing indicated a similar treeing problem when compared to the failed "B" phase bushing, the problem appears to be correlated with a stress concentration condition at the inter-foil edge location, rather than by an anomalous condition present in a single defective bushing.

5.0 ROOT CAUSE DETERMINATION

As a result of physical examination, chemical analysis, and inspection of the bushing components with a microscope, the subject bushings have degraded through initiation and propagation of electrical treeing. Trees initiated from the electrically stressed edge of the aluminum foil layers into the insulating paper layers. Treeing degraded the dielectric strength of the paper, resulting in a radial puncture and subsequent fault through the capacitor core of the failed bushing. Similar treeing degradation as seen in the failed "B" phase HV bushing was identified in the companion "C" phase HV bushing.

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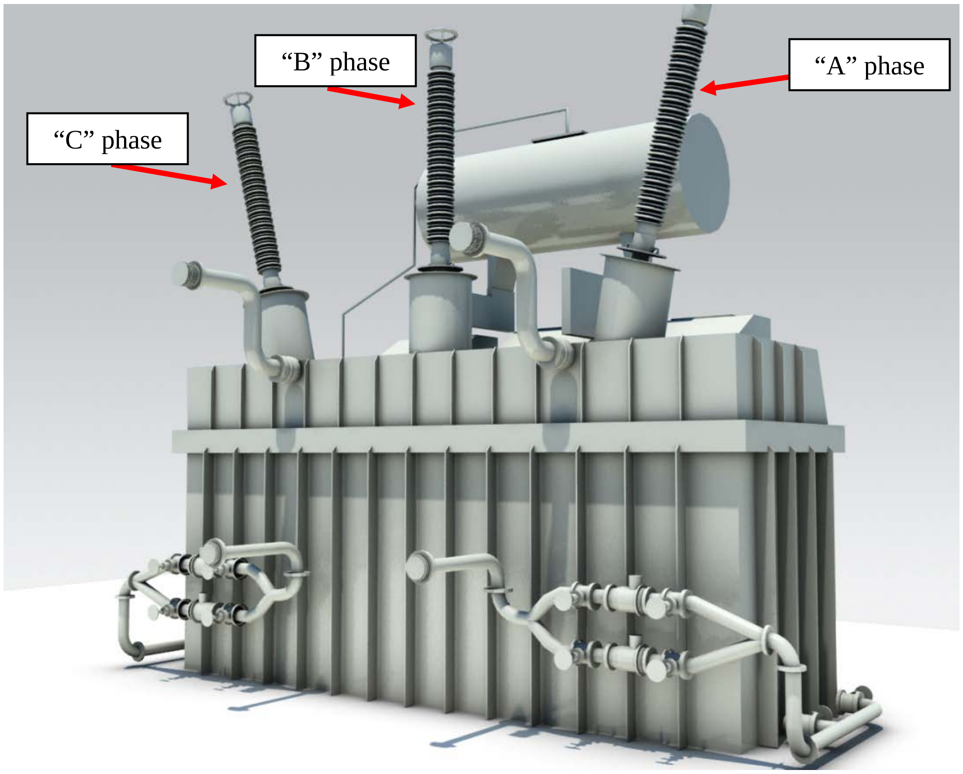


Fig. 1: Illustration of 21MT with designation for "A", B", and "C" phase bushings

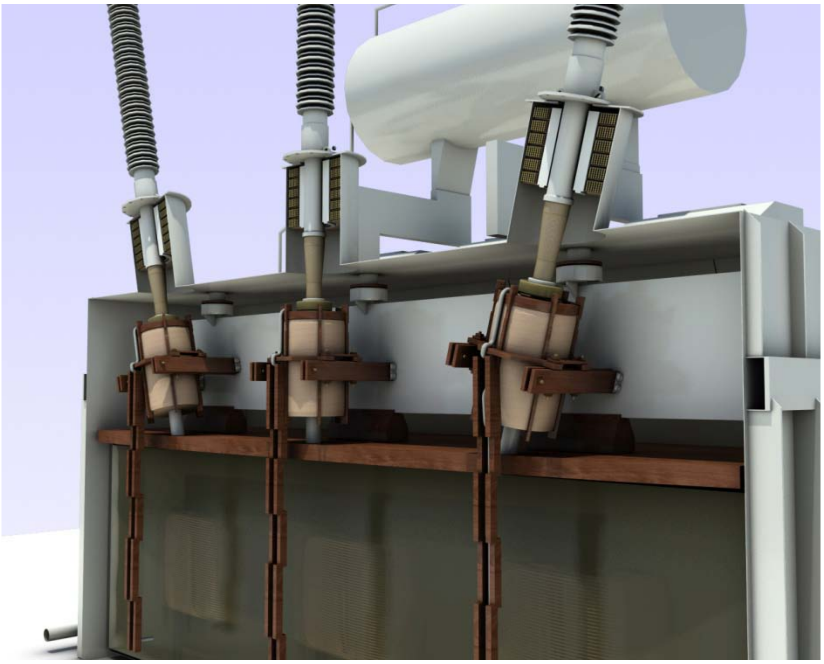


Fig. 2: Cut-away view of the internal components of the transformer bushings

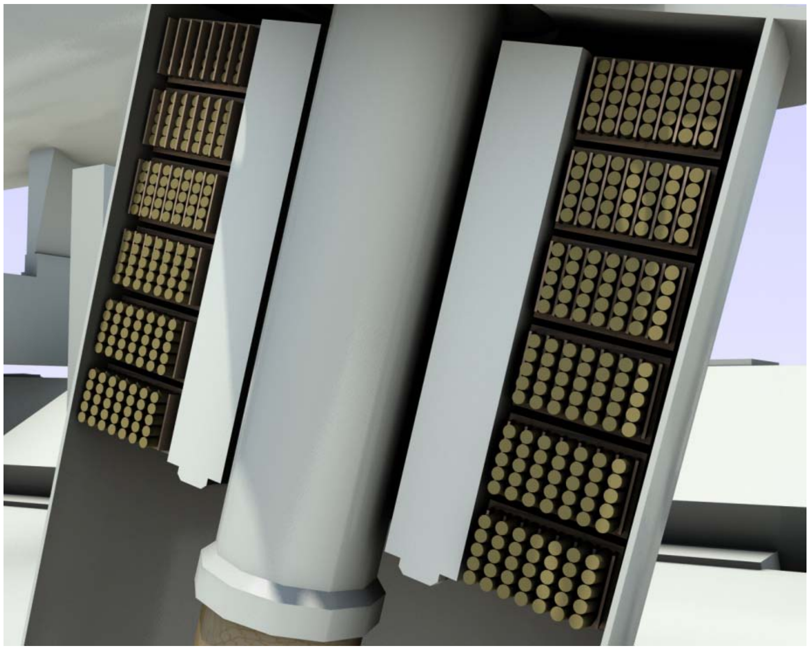


Fig. 3: Close-up rendering of the internal current transformer location on an HV bushing

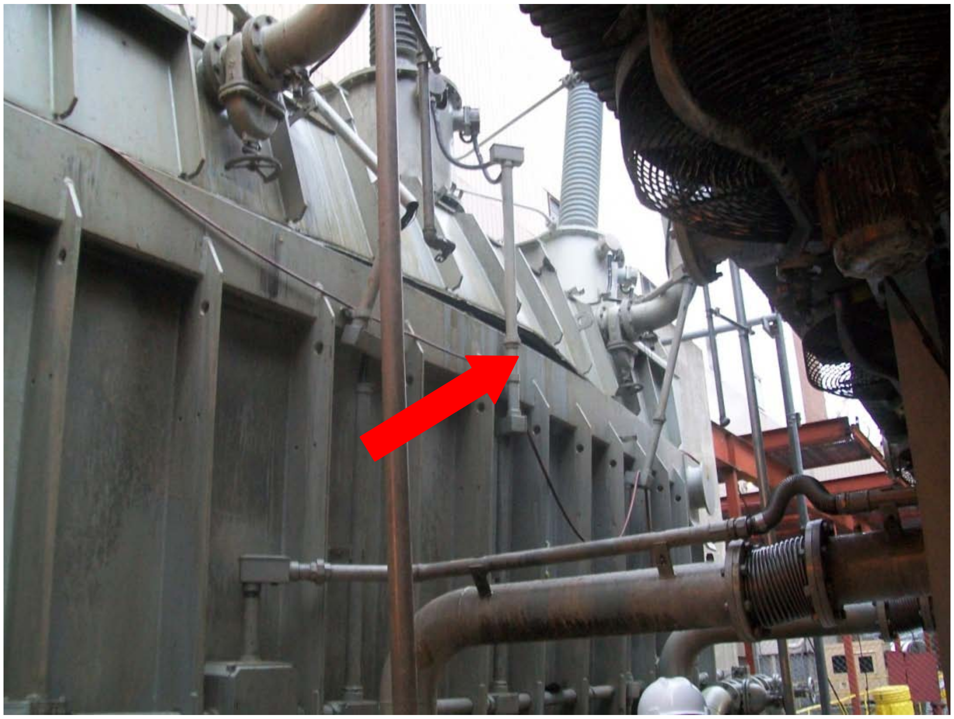


Fig. 4: Site conditions following the 21MT tank rupture

Fig. 5: Oil released following the 21MT tank rupture

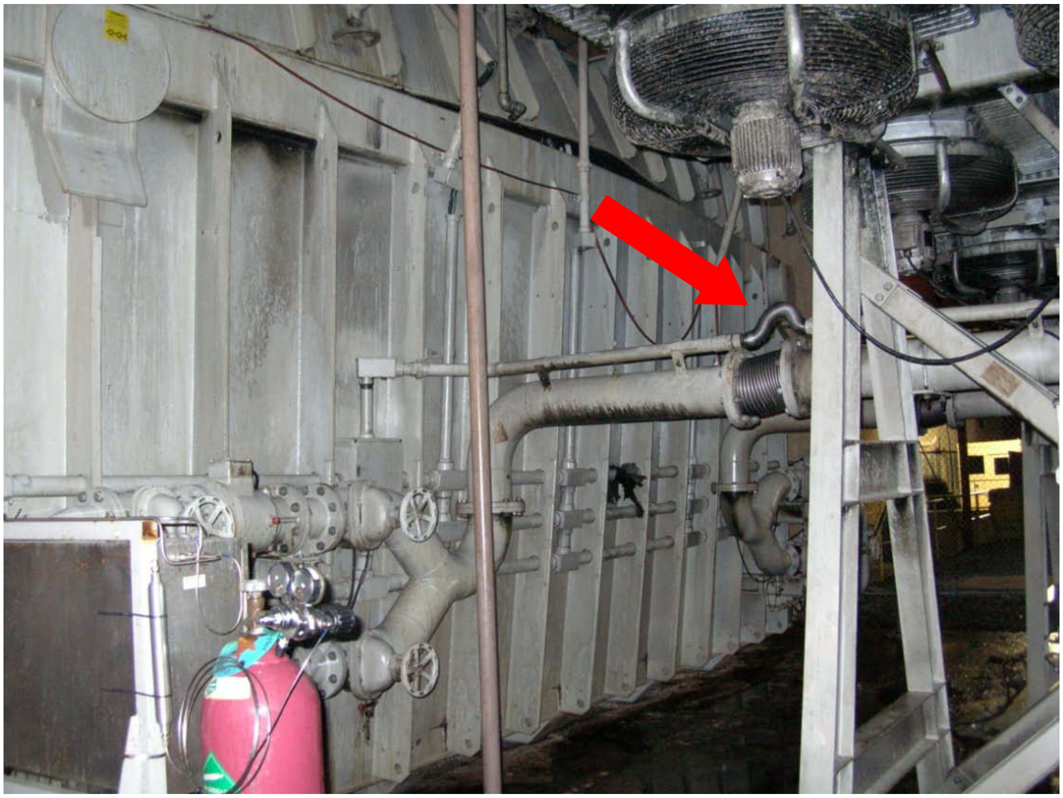


Fig. 6: Photo of external appearance of 21MT taken by IPEC personnel the night of the fault. Red arrow points to deformed conduit from force of explosion.

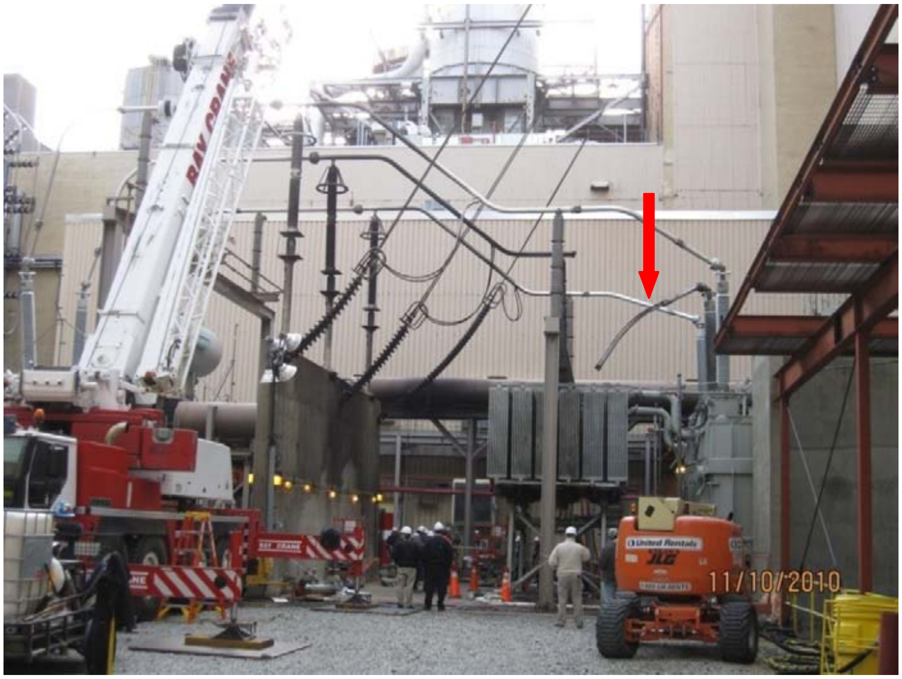


Fig. 7: Rigging crews on-site to disassemble 21MT. Red arrow points to fractured HV feeder bus section.

Fig. 8: Fracture surface of “B” phase HV feeder bus section showing localized melting

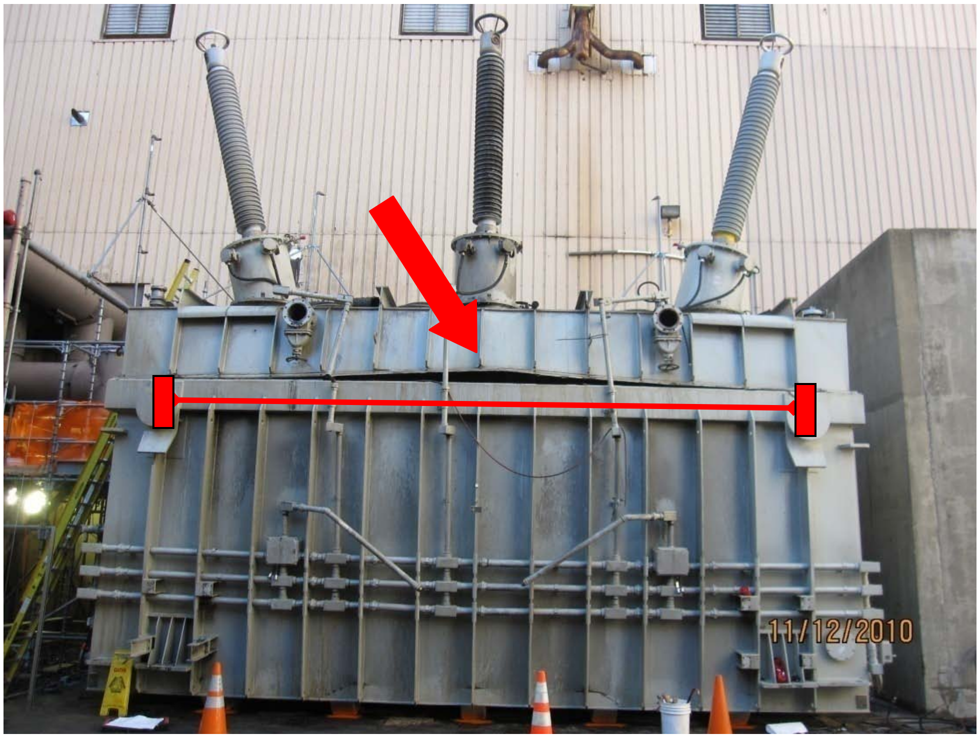


Fig. 9: View of 21MT tank structure after removal of radiators. The red line is approximately the extent of the burst weld seam.

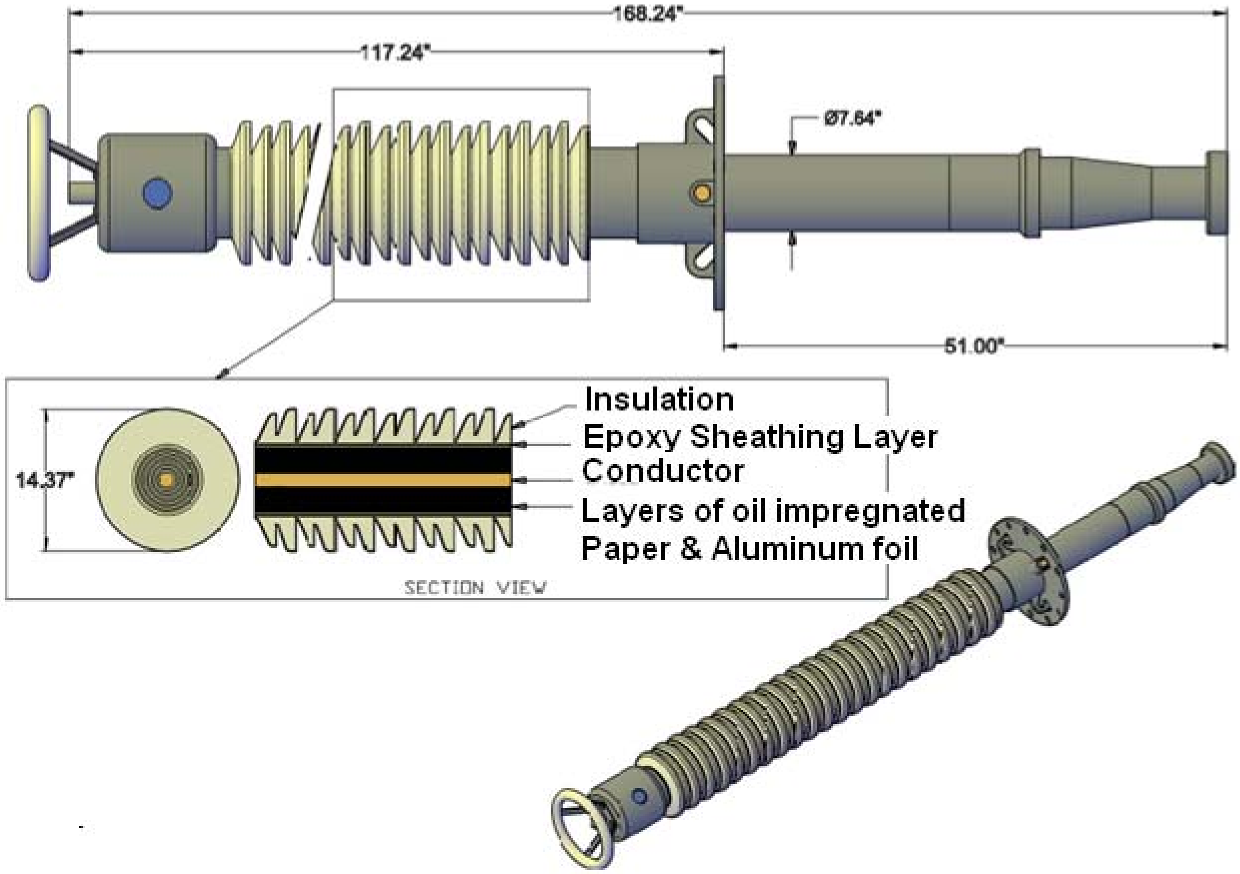


Fig. 10: Configuration of 21 Main Transformer HV Bushing

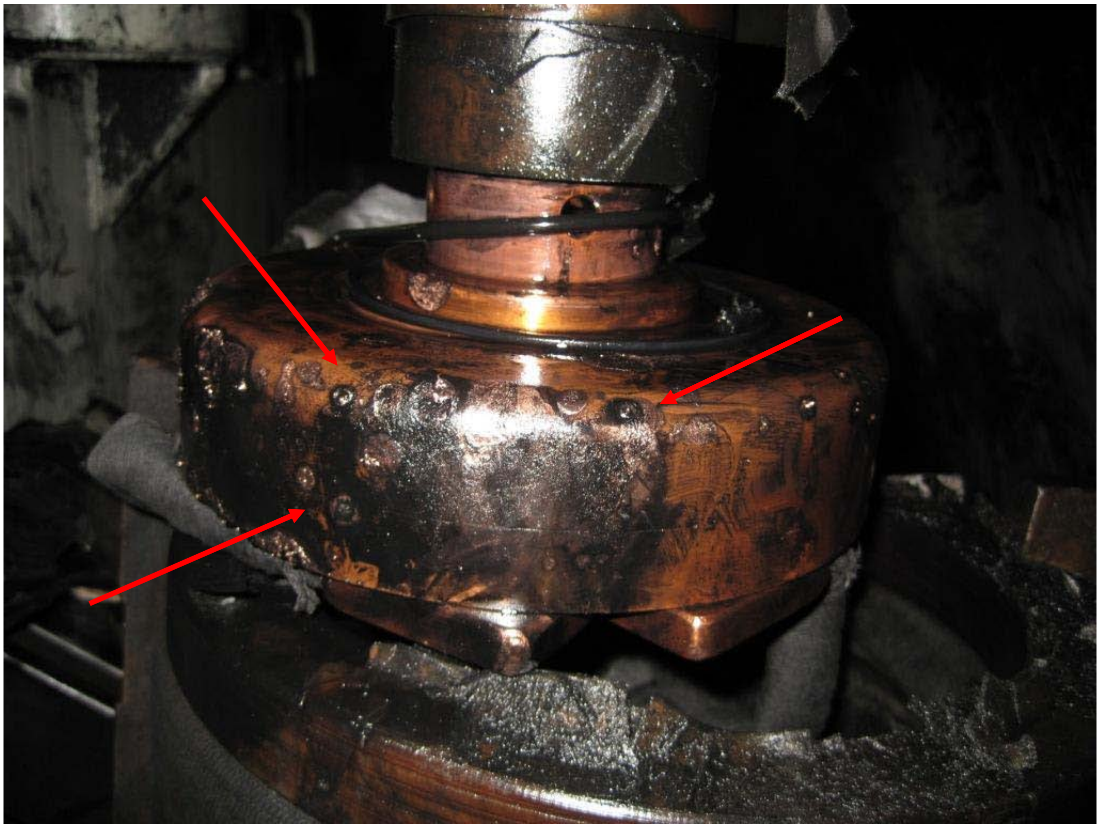


Fig. 11: Numerous arc strikes observed at the bottom terminal of the “B” phase bushing

Fig. 12: Failure of the “B” phase bushing insulating material

Fig. 13: Condition of the “A” phase HV bushing

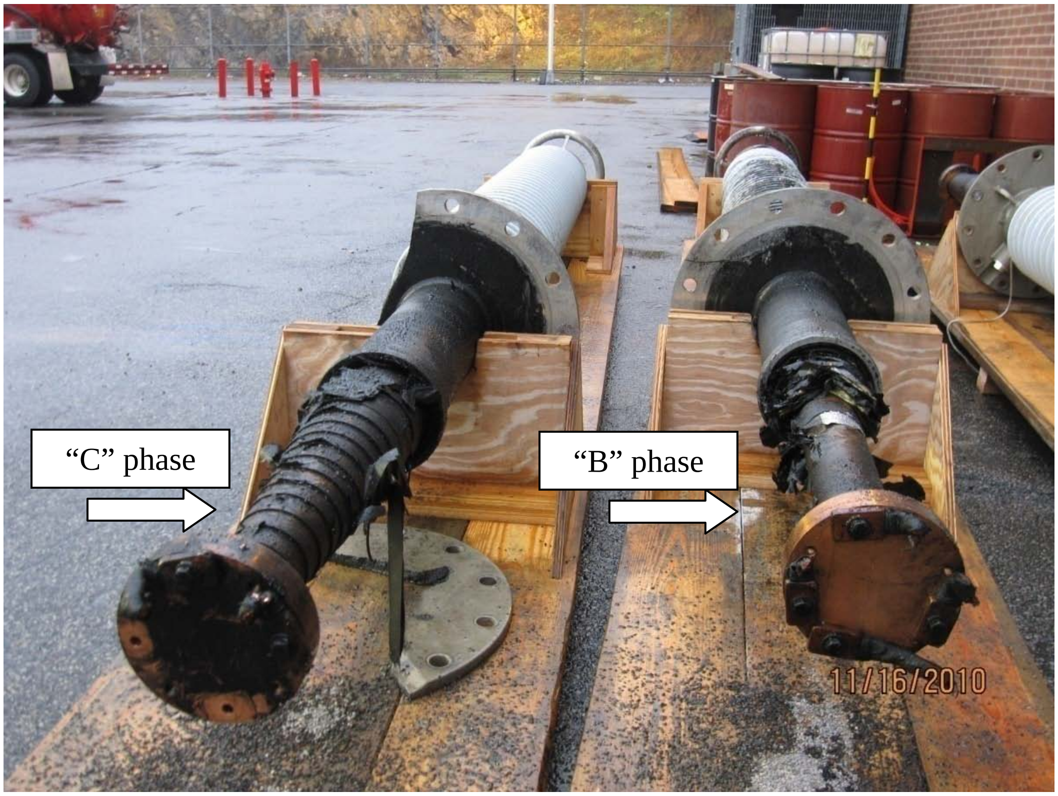


Fig. 14: Extent of damage to "B" phase and "C" phase HV bushings after removal from transformer

Fig. 15: Overview photo of bushing's capacitor structure as witnessed upon teardown

Fig. 16: Removal of core from bushing at Ajax Trench facility

(a) 
(b) 

Fig. 17:(a) Overview of “B” phase bushing at Ajax Trench manufacturing facility. (b) Outer surface of radial puncture in “B” phase bushing capacitor.

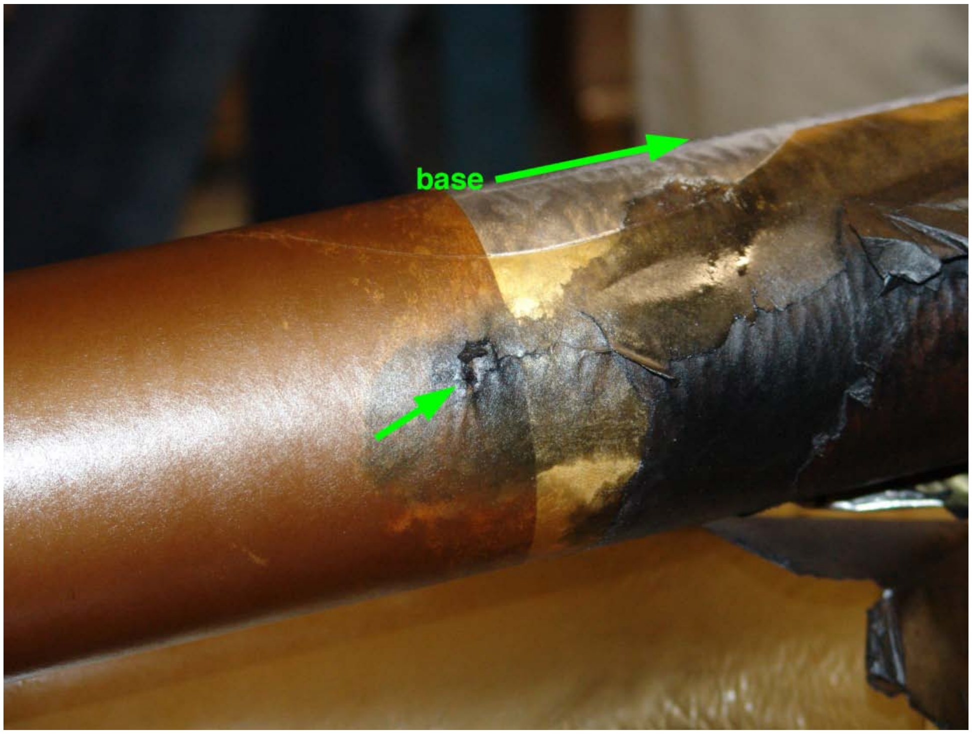


Fig. 18: Radial puncture initiation site in layer 20 or 21 of failed “B” phase bushing

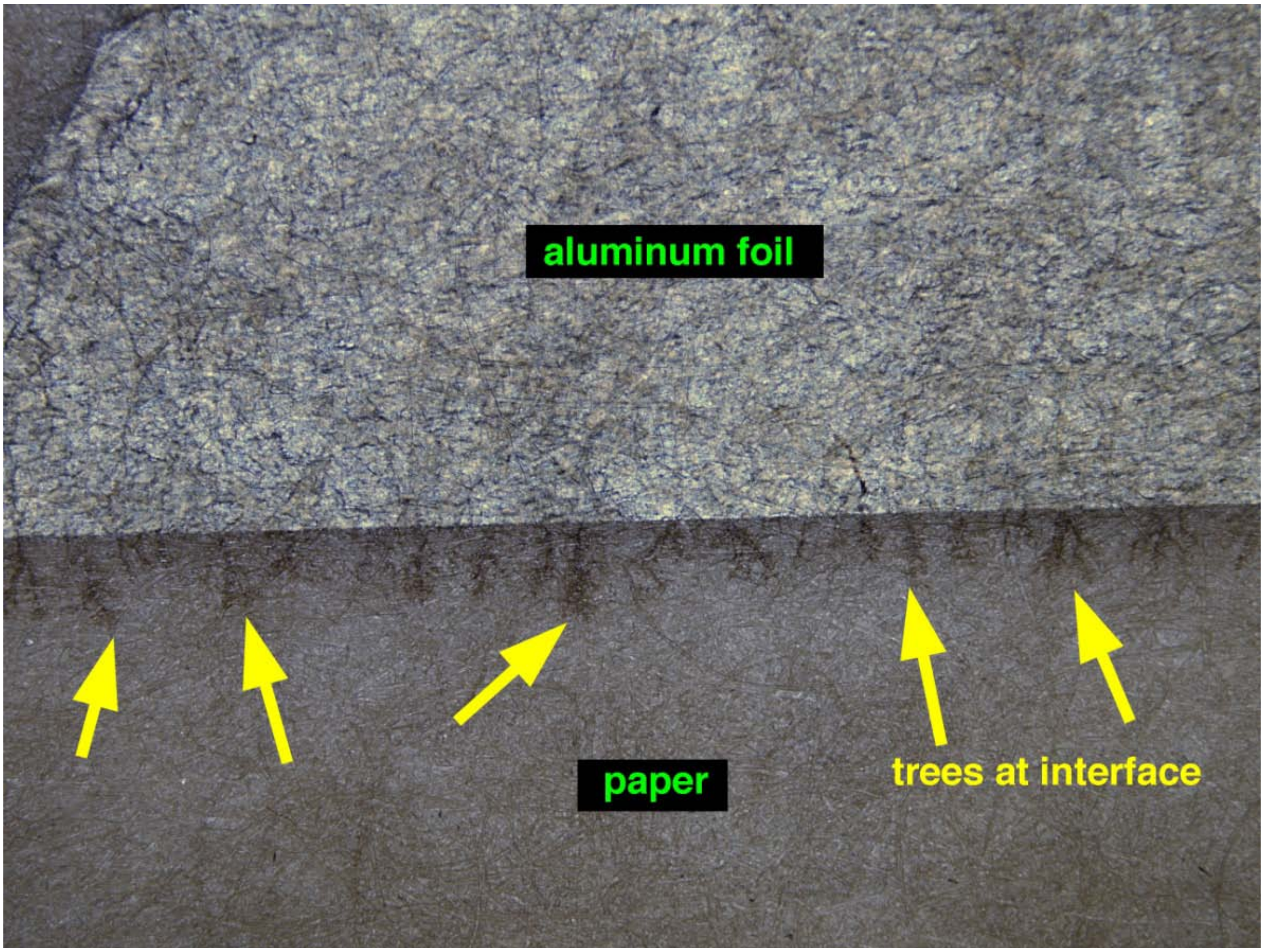


Fig. 19: Trees observed at paper/foil interface in "C"phase bushing

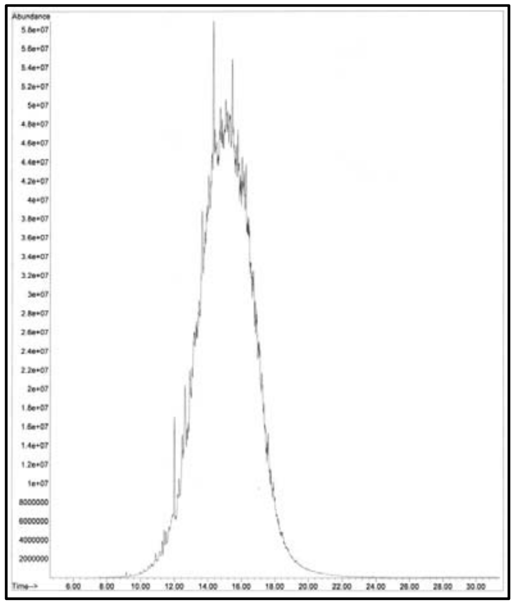


Fig. 20: GC/MS results from the "B" phase bushing oil extracted from the insulating paper in Layer 19

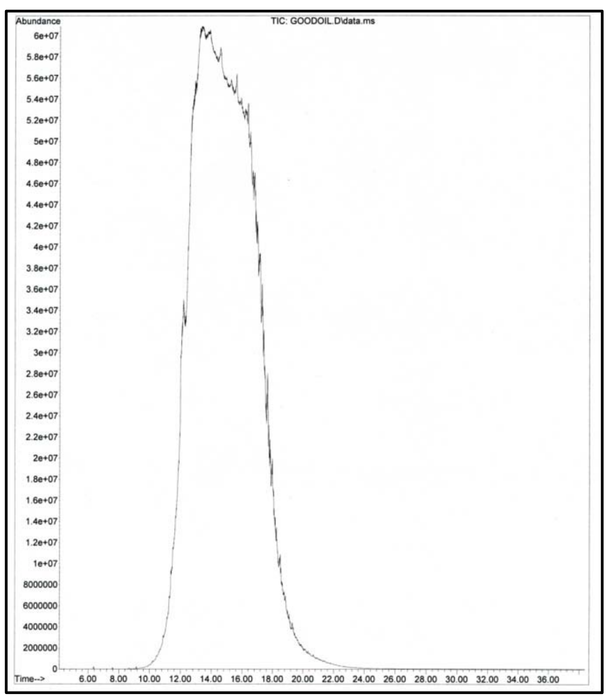


Fig. 21: GC/MS results from the extracted "C" phase bushing oil

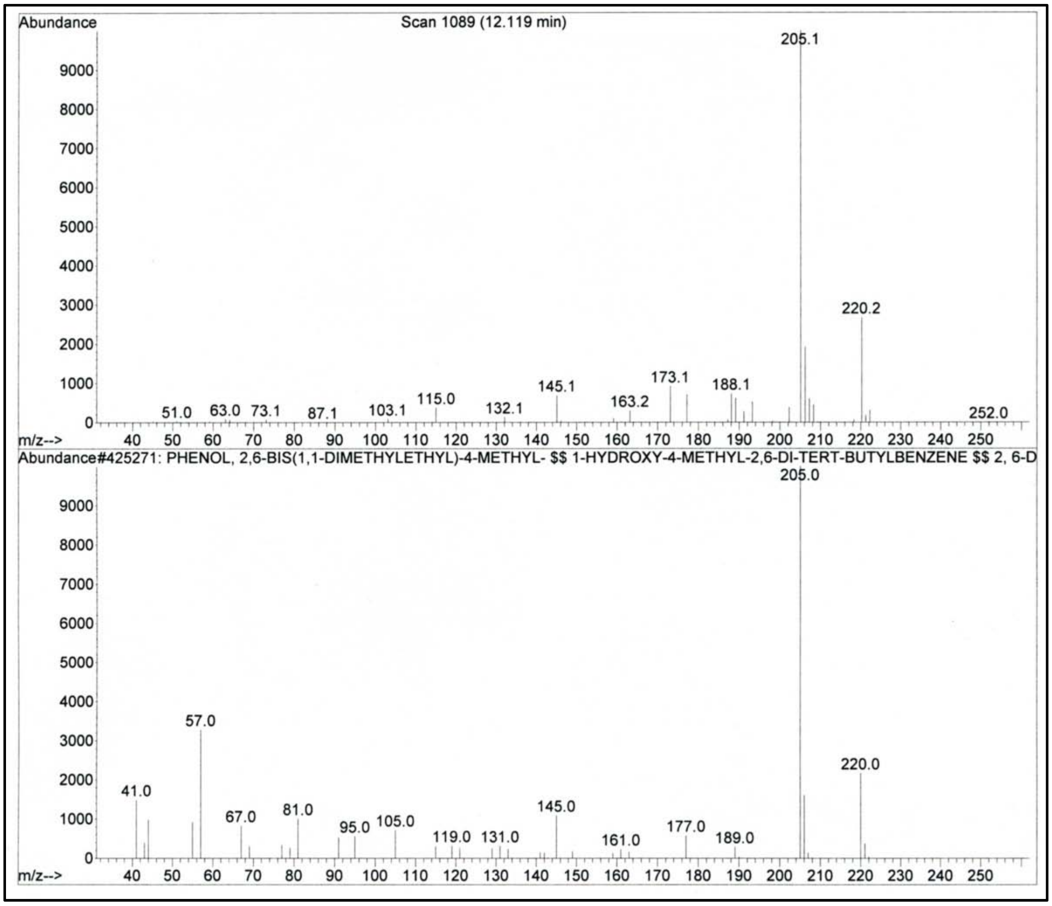


Fig. 22: MS analysis of additive found in the oil relative to the bottom reference mass spectrum of BHT

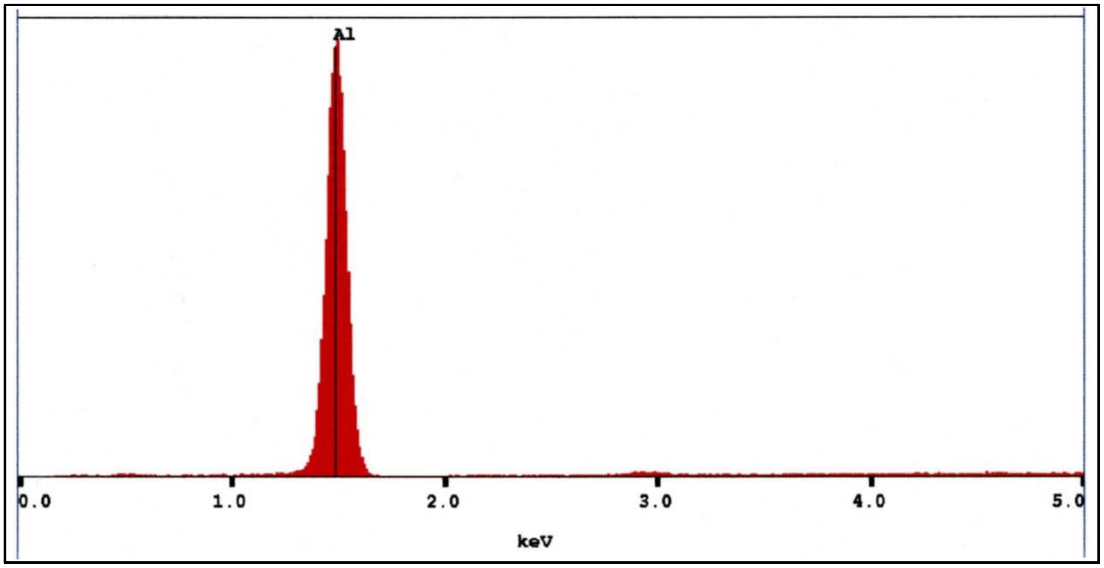


Fig. 23: EDX spectrum of representative aluminum foil sample used in the bushings at the Ajax Trench facility

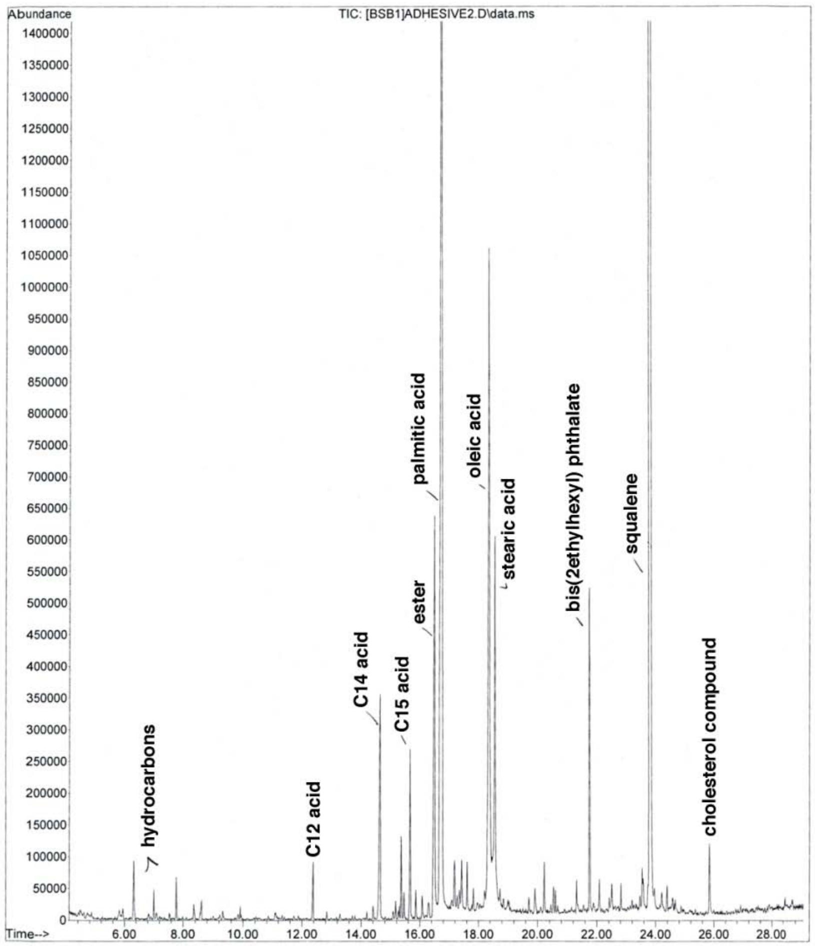


Fig. 24: Gas Chromatography (GC)/ Mass Spectroscopy (MS) results from representative foil adhesive layer provided at Ajax Trench facility

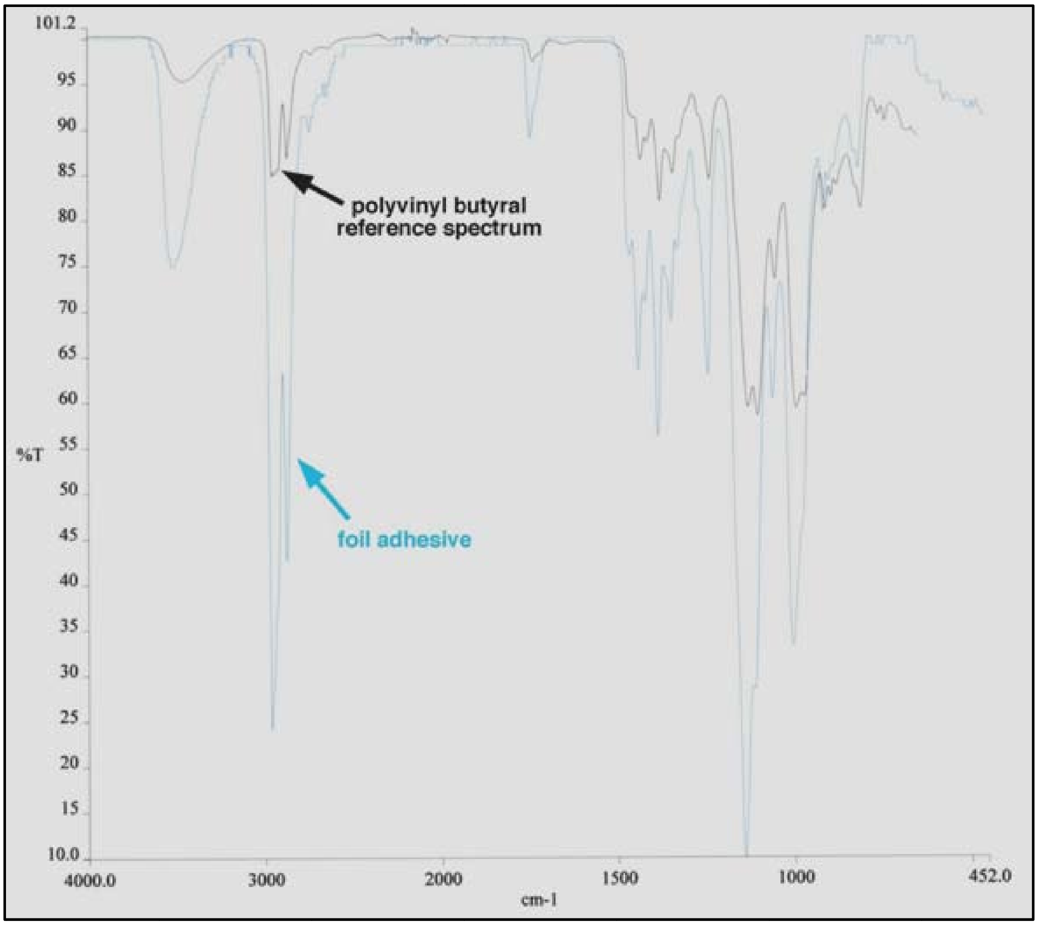


Fig. 25: FTIR results from adhesive layer of non-used aluminum foil provided at the Ajax Trench facility

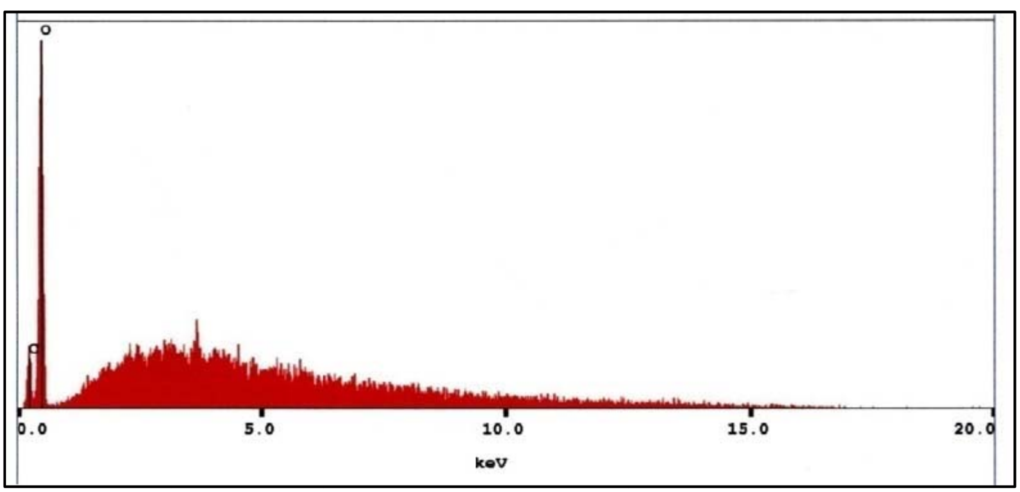


Fig. 26: EDX spectrum from blue adhesive layer on non-used aluminum foil

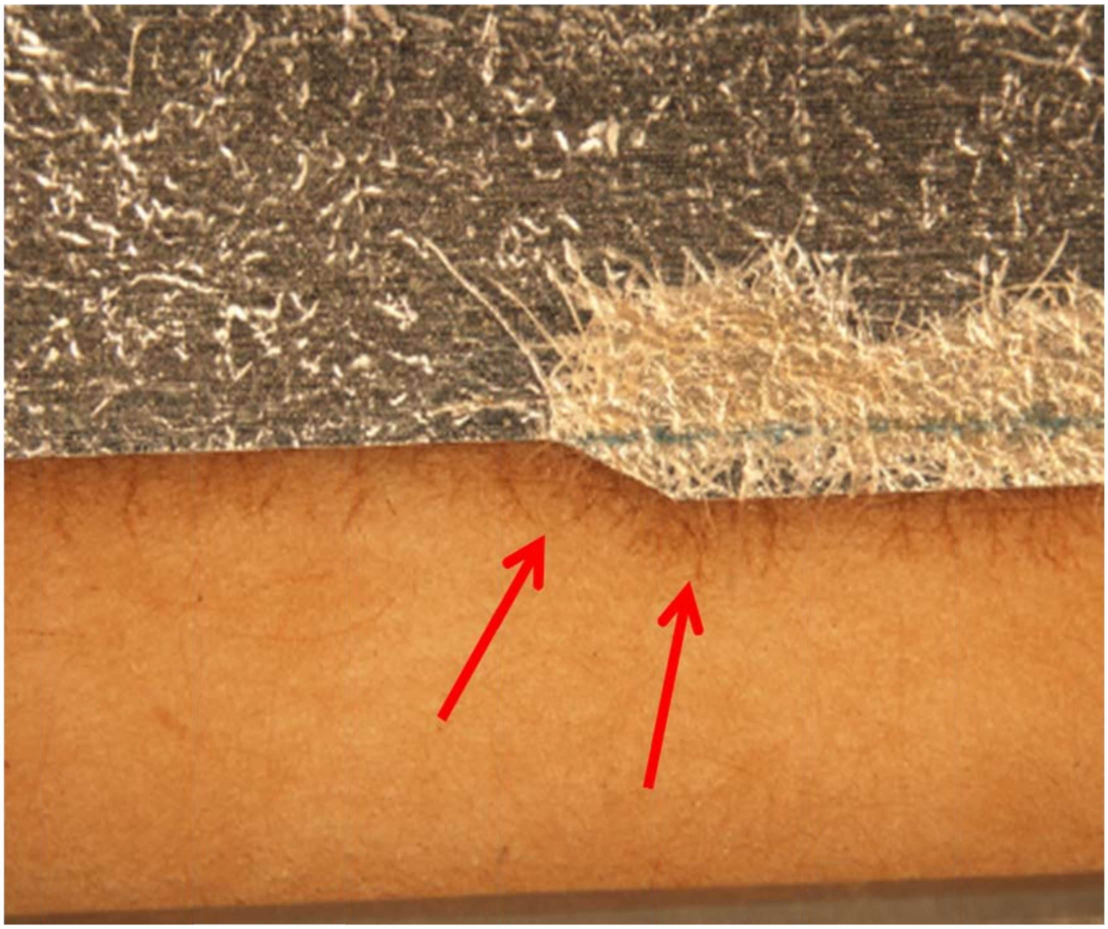


Fig. 27: Evidence of electrical treeing in paper insulation removed from “B” phase bushing

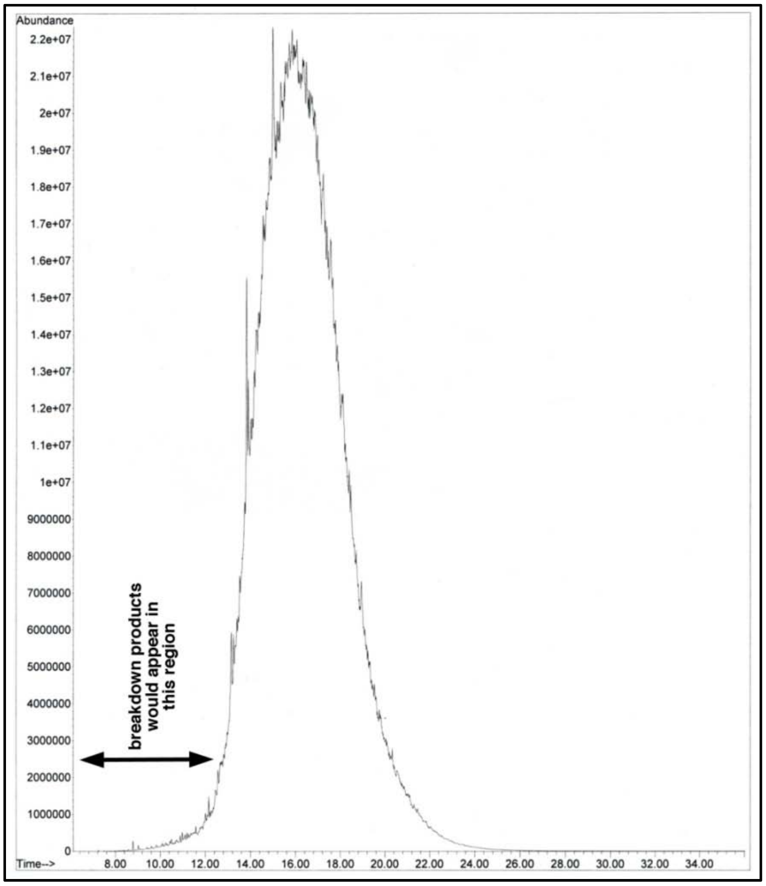


Fig. 28: GC/MS result from electrically treed area of paper removed from “B” phase bushing

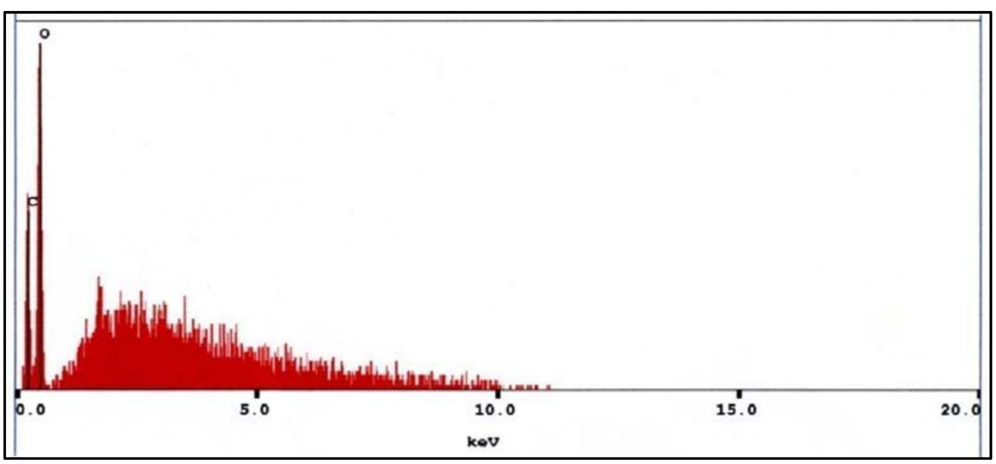


Fig. 29: EDX spectrum from Layer 19 of foil edge in “B” phase bushing

Fig. 30: Electrical treeing observed in “C” phase bushing only at electrically-stressed edge

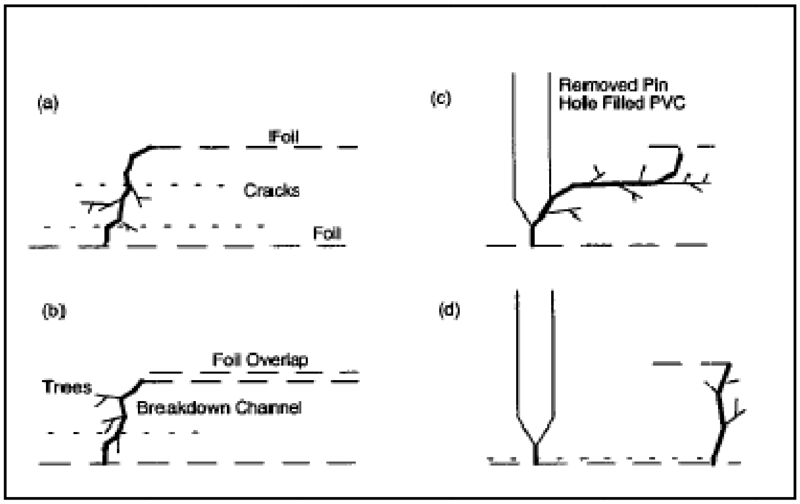


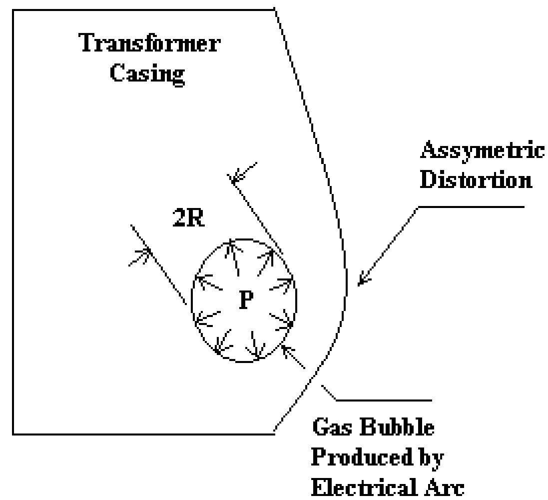
Fig. 31: Schematic showing different classes of inter-foil breakdown. (a) treeing from edge of foil to next adjacent foil. (b) treeing from foil corner in overlap region. (c) treeing from pin foil breakdown structure to adjacent outer foil. (d) treeing from edge of crack which had formed during a previous pin-foil breakdown. *Reprinted from [8]*

APPENDIX A: Dynamic Pressure Increase Calculation

Evaluation of Transformer Pressurization During Fault

Introduction:

This calculation estimates the dynamic pressure increase in the transformer casing due to the sudden generation of gas by an electrical arc. The pressure can be compared to the pressure predicted by the Structural Model that would cause the measured distortion of the transformer casing. The range in dynamic pressure increase is calculated from the limits of gas formation and energy rates found in the literature.



Assumptions:

1. The generated gas is primarily H2, but can have other gasses. Per [1] 68% of the gas generated is H2 (page 159). Dissolved gas analysis of transformer oils indicates that C2H4 (ethylene) is also generated. A 50% H2 and 50% C2H4 mix is assumed. This is considered conservative because a lower gas volume and pressure pulse is produced than for 100% H2.

2. The gases are governed by the ideal gas law.

3. The transformer oil is similar in properties to Exxon univolt 60.

Method:

1. Determine the volume of gas generated from the Electrical Energy and the gas generation values.

2. Find the mass of gas from the volume using the ideal gas equation and standard conditions.

3. Estimate the temperature of the gas by relating the change in temperature to the change in energy using the constant volume specific heat of Hydrogen.

4. Write the system of equations of physics which represent the phenomena of sudden introduction of gas to a fluid. Do this for the range of high and low energy to produce the maximum and minimum pressure. These equations are as follows.

   a. The Joukowski equation relating the sudden acceleration (change in velocity) of the fluid to the sudden pressure pulse.

   b. The first derivative of displacement (bubble radius) with respect to time equals the velocity of the gas-oil interface .

   c. The relationship of bubble radius to bubble volume.

   d. The ideal gas law which relates the pressure to the mass, volume and temperature.

5. Solve the system of equations in order to determine the pressure and radius of the gas bubble which is formed at the end of the time interval. Do this for the range of high and low energy to produce the maximum and minimum pressure.

Define Constants:

Specific Gravity of insulating oil reference 6. (below) $SG_{oil} := 0.88$

```
F.  PHYSICAL DATA

The following data are approximate or typical values and should not be used
for precise design purposes.

BOILING RANGE                              VAPOR PRESSURE
 IBP Approximately 238~C (460~F)            Less than 0.01 mm Hg @ 20~C
 by ASTM D 2887

SPECIFIC GRAVITY (15.6~C/15.6~C)           VAPOR DENSITY (AIR = 1)
 0.88                                       Greater than 5
```

Density of water. $\rho_{wtr} := 62.4 \cdot \frac{lb}{ft^3}$

Density of oil $\rho_{oil} := \rho_{wtr} \cdot SG_{oil}$ $\rho_{oil} = 54.91 \frac{lb}{ft^3}$

The Bulk Modulus of Oil, Ref. 7, Table A.3 $K_{oil} := 1.38 \cdot 10^9 \cdot \frac{newton}{m^2}$ $K_{oil} = 2.88 \times 10^7 \frac{lbf}{ft^2}$

The sonic velocity of Oil $C_{oil} := \sqrt{\frac{K_{oil}}{\rho_{oil}}}$ $C_{oil} = 4.11 \times 10^3 \frac{ft}{sec}$

The time duration of the arc. Ref. 4. $\Delta t := .055 \cdot sec$

Gas Constant for Hydrogen, Ethylene, mix [Crane]. $R_{H2} := 766.8 \cdot \frac{ft \cdot lbf}{lb \cdot R}$ $R_{eth} := 55.1 \cdot \frac{ft \cdot lbf}{lb \cdot R}$ $R_{gas} := .5 \cdot R_{H2} + .5 \cdot R_{eth}$

Constant volume specific heat for Hydrogen-Ethylene mix. $C_v := .5 \cdot 2.43 \cdot \frac{BTU}{lb \cdot R} + .5 \cdot 0.33 \cdot \frac{BTU}{lb \cdot R}$

The Temperature at Standard Conditions $T_{std} := (25 + 273) \cdot K$

The pressure at Standard Conditions $P_{std} := 14.7 \cdot psi$

$$\rho_{std} := \frac{P_{std}}{R_{gas} \cdot T_{std}}$$

$$\rho_{std} = 9.6 \times 10^{-3} \frac{lb}{ft^3}$$

Unit definition $kW := 1000 \cdot watt$

Evaluate Energy from Arc-Fault

Based on amperage time trace: $A_{rms} := 29500amp$

Information in the literature [2] indicates that an arc under oil "develops a voltage drop, usually between 50 and 150 volts." This means the voltage across the arc is clamped by the arc to between 50 and 150 volts, and the current that flows is limited only by the impedance of the source, system, and components

$V_{low} := 50volt$ $\qquad$ $V_{high} := 150volt$

$E_{low} := A_{rms} \cdot V_{low} \cdot \Delta t$ $\qquad$ $E_{high} := A_{rms} \cdot V_{high} \cdot \Delta t$

$E_{low} = 81.13\, kW \cdot sec$ $\qquad$ $E_{high} = 243.38\, kW \cdot sec$

Evaluate Expected Gas Volume

Reference [2] suggests that for an arc under oil in a transformer the rate of gas generation is between 3 and 10 cubic inches per "kilowatt second" of arc energy. This converts to 49 to 164 cubic centimeters per kilowatt-second. Reference [1] indicates that the "volume of gas evolved per kw-sec is approximately 55 cc per kw-sec of total arc energy for values above 500 A." Reference [1] further indicates that "the volume of gas liberated increases rapidly with applied pressure up to about 180 cc kw-sec at 20 atmospheres." Finally, reference [3] "assumes that 90 cubic centimeters (5.5 cubic inches) of gas is evolved in an arc under oil of 1 kilowatt-second." The authors of [2] and [3] did their work for Westinghouse Electric, and the author of [1] worked for General Electric, so there appears to be good independent agreement on this empirical range of values. The following calculations will use a range of 49 to 164 cubic centimeters per kilowatt-second, as this range encompasses the values presented by the other two references for arcs occurring under oil at atmospheric pressure

Per [1] $\qquad$ compare to [2]

$Gas_{create_0} := 3 \cdot \frac{in^3}{kW \cdot sec}$ $\qquad$ $Gas_{create_1} := 10 \cdot \frac{in^3}{kW \cdot sec}$ $\qquad$ $90 \cdot \frac{cm^3}{kW \cdot sec} = 5.49 \frac{in^3}{kW \cdot sec}$

minimum expected volume. $\qquad$ maximum volume.

$Vol_{min} := E_{low} \cdot Gas_{create_0}$ $\qquad$ $Vol_{max} := E_{high} \cdot Gas_{create_1}$

$Vol_{min} = 0.14\, ft^3$ $\qquad$ $Vol_{max} = 1.41\, ft^3$

$Vol_{min} = 3.99 \times 10^3\, cm^3$ $\qquad$ $Vol_{max} = 3.99 \times 10^4\, cm^3$

Find the Mass of Gas

Use the ideal gas equation and standard conditions.

Reference 1 page 159 states the 68% of the volume of the gas formed is H2. If it is assumed that all of the gas created is H2 the mass of the H2 is found from the ideal gas equation and the standard conditions.

The density of H2/C2H4 at standard conditions. $\rho_{std} := \dfrac{P_{std}}{R_{gas} \cdot T_{std}}$ $\rho_{std} = 9.6 \times 10^{-3} \dfrac{lb}{ft^3}$

Minimum mass

$$M_{gasmin} := \frac{P_{std} \cdot Vol_{min}}{R_{gas} \cdot T_{std}}$$

$$M_{gasmin} = 0.001\, lb$$

Maximum Mass

$$M_{gasmax} := \frac{P_{std} \cdot Vol_{max}}{R_{gas} \cdot T_{std}}$$

$$M_{gasmax} = 0.01\, lb$$

Estimate the temperature of the gas by relating the change in temperature to the change in energy using the constant volume specific heat of Hydrogen.

These temperatures are associated with high energy and therefore may be very large.

$$\Delta T_{max} := \frac{E_{high}}{M_{gasmin} \cdot C_v}$$

$$\Delta T_{max} = 1.24 \times 10^5\, R$$

$$T_{gasmax} := T_{std} + \Delta T_{max}$$

$$T_{gasmax} = 1.24 \times 10^5\, R$$

This very high temperature represents the instantaneous arc temperature and may be stretching the limits of the ideal gas equation.

$$\Delta T_{min} := \frac{E_{low}}{M_{gasmax} \cdot C_v}$$

$$\Delta T_{min} = 2.29 \times 10^3\, K$$

$$T_{gasmin} := T_{std} + \Delta T_{min}$$

$$T_{gasmin} = 4.66 \times 10^3\, R$$

Define the system of equations of the sudden gas expansion
These equations are as follows.

a. The Joukowski equation which relates the sudden acceleration (change in velocity) of the fluid to the sudden pressure pulse.

b. The first derivative of displacement (bubble radius) with respect to time equals the velocity of the interface of gas and oil.

c. The relationship of bubble radius to bubble volume.

d. The ideal gas law which relates the pressure to the mass, volume and temperature.

The equations will be solved simultaneously with the Mathcad solver. This procedure is described below. The simultaneous solver requires that the equations not contain units. Therefore the above constants will be repeated in values that have consistent units of lbf, lbm, ft, and secs.

This calculation estimates the pressure pulse at the end of the arc time interval by considering the compressibility of the gas and the inertia of the surrounding fluid.

MAXIMUM DYNAMIC PRESSURE PULSE

Remove units for solver

$\rho_{oil} := \rho_{oil} \cdot \frac{ft^3}{lb}$ $\quad T_{gasmax} := T_{gasmax} \cdot R^{-1}$ $\quad T_{gasmin} := T_{gasmin} \cdot R^{-1}$

$K_{oil} := K_{oil} \cdot \frac{ft^2}{lbf}$ $\quad M_{gasmax} := M_{gasmax} \cdot lb^{-1}$ $\quad M_{gasmin} := M_{gasmin} \cdot lb^{-1}$

$C_{oil} := C_{oil} \cdot \frac{sec}{ft}$ $\quad R_{gas} := R_{gas} \cdot \frac{R \cdot lb}{lbf \cdot ft}$

$\Delta t := \Delta t \cdot sec^{-1}$

Provide an initial guess of all the unknowns. There are 4 unknowns.

$\Delta P_{gas} := 14400$ $\quad Vol_{gas} := 10$ $\quad Vel_{oil} := 5$ $\quad \Delta R := .75$

Given

Equation #1 $\Delta P_{gas} = \dfrac{\rho_{oil} \cdot C_{oil} \cdot Vel_{oil}}{32.2}$

The Joukowski equation which relates the sudden acceleration (change in velocity) of the fluid to the sudden pressure pulse.

Equation #2 $Vel_{oil} = \dfrac{\Delta R}{\Delta t}$ $\Delta R > 0$

The first derivative of displacement (bubble radius) with respect to time equals the velocity of the interface of gas and oil.

Equation #3 $Vol_{gas} = \dfrac{4}{3} \cdot \pi \cdot \Delta R^3$

The relationship of bubble radius to bubble volume. This equation gives the volume of the gas bubble at the end of the time step Δt.

Equation #4 $\Delta P_{gas} = \dfrac{M_{gasmax} \cdot R_{gas} \cdot T_{gasmax}}{Vol_{gas}}$

The ideal gas law which relates the pressure to the mass, volume and temperature.

Use Find function for the Solution.

$$\begin{pmatrix} A \\ B \\ C \\ D \end{pmatrix} := \text{Find}\left(\Delta P_{gas}, Vol_{gas}, Vel_{oil}, \Delta R\right)$$

$A = 135.86 \times 10^3$ $B = 5.08$ $C = 19.39$ $D = 1.07$

$\Delta P_{gas} := A \cdot \dfrac{lbf}{ft^2}$ $Vol_{gas} := B \cdot ft^3$ $Vel_{oil} := C \cdot \dfrac{ft}{sec}$ $\Delta R := D \cdot ft$

This is the solution for the maximum pressure with units.

$\Delta P_{gas} = 943.49\ psi$ $Vol_{gas} = 5.08\ ft^3$ $Vel_{oil} = 19.39\ \dfrac{ft}{sec}$ $\Delta R = 1.07\ ft$

MINIMUM DYNAMIC PRESSURE PULSE

Re-define the initial guess of all the unknowns. There are 4 unknowns.

$\Delta P_{gas} := 14400$ $\quad Vol_{gas} := .01$ $\quad Vel_{oil} := 5$ $\quad \Delta R := .25$

Given

Equation #1 $\quad \Delta P_{gas} = \dfrac{\rho_{oil} \cdot C_{oil} \cdot Vel_{oil}}{32.2}$

The Joukowski equation which relates the sudden acceleration (change in velocity) of the fluid to the sudden pressure pulse.

Equation #2 $\quad Vel_{oil} = \dfrac{\Delta R}{\Delta t}$

The first derivative of displacement (bubble radius) with respect to time equals the velocity of the interface of gas and oil.

Equation #3 $\quad Vol_{gas} = \dfrac{4}{3} \cdot \pi \cdot \Delta R^3$

The relationship of bubble radius to bubble volume. This equation gives the volume of the gas bubble at the end of the time step Δt.

Equation #4 $\quad \Delta P_{gas} = \dfrac{M_{gasmin} \cdot R_{gas} \cdot T_{gasmin}}{Vol_{gas}}$

The ideal gas law which relates the pressure to the mass, volume and temperature.

Use Find function for the Solution.

$$\begin{pmatrix} A \\ B \\ C \\ D \end{pmatrix} := \text{Find}\left(\Delta P_{gas}, Vol_{gas}, Vel_{oil}, \Delta R\right)$$

$A = 3.36 \times 10^4$ $\quad B = 0.08$ $\quad C = 4.8$ $\quad D = 0.26$

$\Delta P_{gas} := A \cdot \dfrac{lbf}{ft^2}$ $\quad Vol_{gas} := B \cdot ft^3$ $\quad Vel_{oil} := C \cdot \dfrac{ft}{sec}$ $\quad \Delta R := D \cdot ft$

This is the solution for the minimum pressure with units.

$\Delta P_{gas} = 233.49\,psi$ $\quad Vel_{oil} = 4.8 \dfrac{ft}{sec}$ $\quad Vol_{gas} = 0.08\,ft^3$ $\quad \Delta R = 0.26\,ft$