References:

1. Frank M. Clark, "Insulating Materials for Design and Engineering Practice", John Wiley and Sons, Inc. New York N.Y. 1962.

2. R.L. Bean, N. Chackan Jr., H.R. Moore, E.G. Wentz, "Transformers for the Electric Power Industry" Westinghouse Electric Corporation, Power Transformer Division, McGraw Hill Book Co. New York, N.Y., 1959.

3. R. L. Bean, H. L. Cole, "A Sudden Gas Pressure Relay for Transformer Protection," AIEE Transactions, Volume 72, 1953, pp. 480-483

4. Recorded Electrical Conditions Report

5. Randall Noon, "Engineering Analysis of Fires and Explosions", CRC Press, Boca Raton, FL. 1995.

6. Univolt 60, Material Safety Data Sheet, Date issued: 02/22/95 Supersedes date: 09/15/93 Exxon Company USA,

7. F.M. White, "Fluid Mechanics" 3rd edition, McGraw-Hill, Inc. New York, N.Y. 1994.

8 J. T. Madill, "Typical Transformer Faults and Gas Detector Relay Protection," AIEE Transactions, Volume 66, 1947, pp. 1052-1060.

APPENDIX B: FEA Analyses

Finite element analyses (FEA) of the transformer tank wall was performed to investigate the structural impact of instantaneous pressure pulses on the 21 Main Transformer. The computer software program ANSYS v.11 [17] was used for the analyses. Several cases of internal pressure pulse loads of 700 psi and 800 psi were evaluated to obtain the dynamic response of the transformer wall. The analysis is conservative because the pressure is assumed to reach a peak value irrespective of the large deformation experienced by the wall. The maximum deflection was calculated to be 15 to 16 inches (38 to 41 cm), and the maximum estimated pressure was determined to be between 700 psi and 800 psi for this deflection.

As shown in Fig. B.1, the model uses element *Solid45* to generate an explicit and representative 3D model of the transformer wall, reinforcement plates, and welds. All welds were explicitly modelled as 0.25 in. fillet welds, as Fig. B.2 shows. In Fig. B.2, the upper stiffener and lower stiffener are welded, but the gap in between the welds open up like a “fish-mouth” under dynamic loading. For this reason, it was determined there was no need to add contact elements in this gap region.

A single material definition was used for the wall, reinforcement plates, and welds. Plastic material behavior was incorporated into the analyses by using bilinear kinematic hardening plastic properties. These were defined by yield stress and tangent modulus parameters.

The boundary conditions included constraint of the X-direction displacement (UX) nodes on both sides of the wall to represent continuity. As Fig. B.1 shows, all degrees of freedom (DOF) of nodes which were 2 in. from the top-side and bottom-side regions of the wall were fixed. This constraint was included because the top and bottom horizontal plates of the transformer wall were of sufficient thickness to supply a restraint on movement in those regions.

Fig. B.3 shows the applied loading condition. A dynamic internal pressure load was selected to be applied to the inner side of the wall. Deadweight loads were applied in the first load step before application of the transient loads. The pressure pulse included a ramp-up loading time of 0.001 seconds followed by a 0.025 second hold time. The decay time of the pressure pulse was selected to be 0.027 seconds, and was also simulated as a ramp-down rather than step-down function.

Damping of the structure was introduced via a stiffness matrix multiplier, and was selected at a ratio proportional to the stiffness. The stiffness matrix multiplier, β, was set equal to 8.52×10^{-5} . This value was based on a damping ratio of 1% at a frequency of 37Hz, which was the first natural mode of the linear structure.

Various pressure pulse simulations at peak dynamic pressure values of 700 psi and 800 psi were analyzed. As Fig. B.4 shows, the maximum out-of-plane deflection at a peak pressure of 700 psi was found to be around 15 inches (38 cm). The residual out-of-plane deflection after the pressure pulse is around 6 in., which was approximately the deflection observed in the 21MT while on-site for the external visual inspection. For the simulation run at a peak dynamic pressure of 800 psi, the maximum out-of-plane deflection was found to be slightly greater than 16 inches (41 cm). These values are within the range of dynamic pressures calculated in Appendix A.

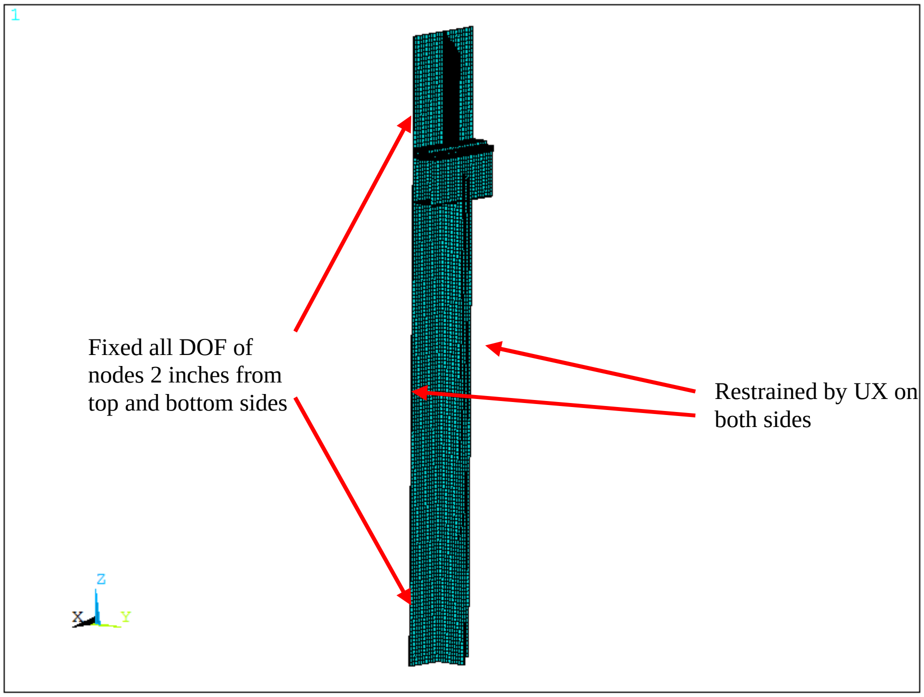

Fig. B.1: Sketch of the representative transformer model.

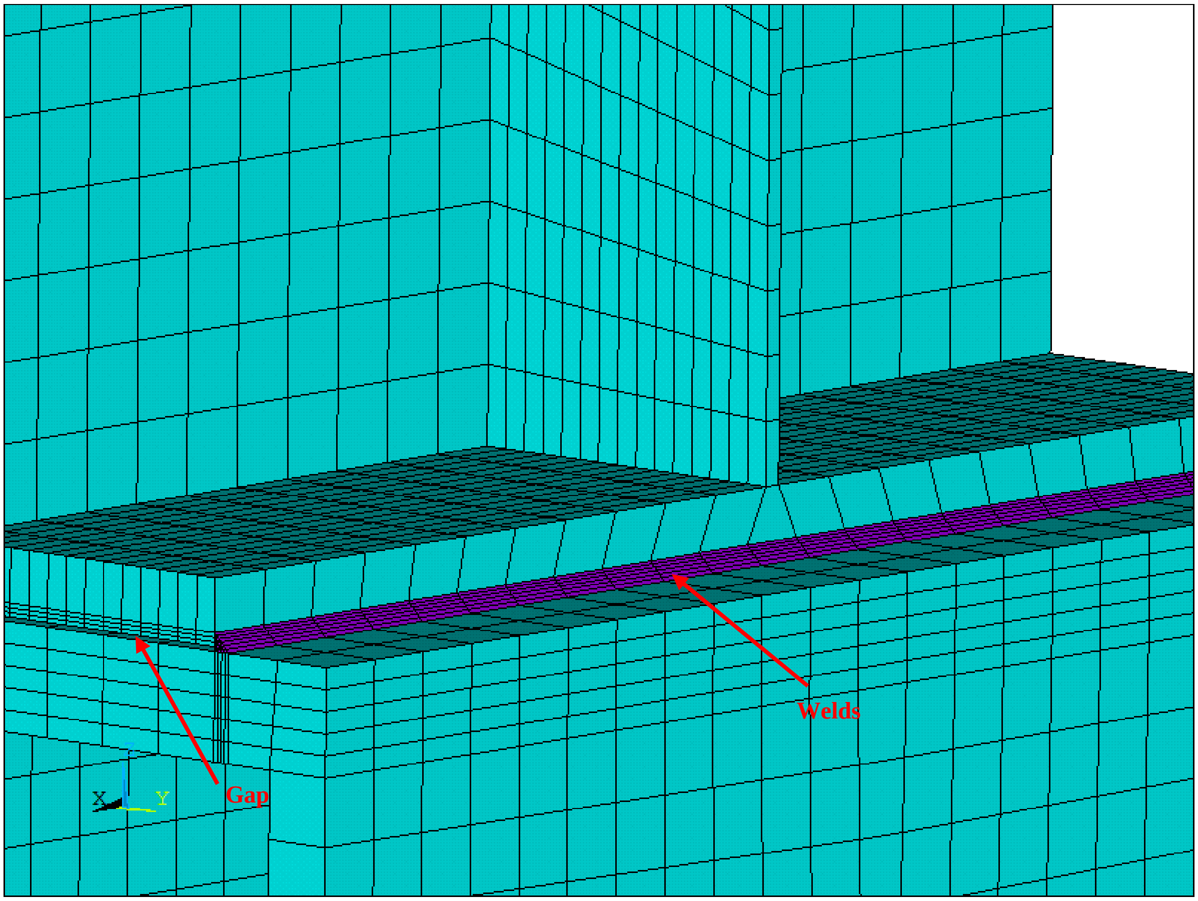

Fig. B.2: Close-up sketch of gap and weld region along transformer wall.

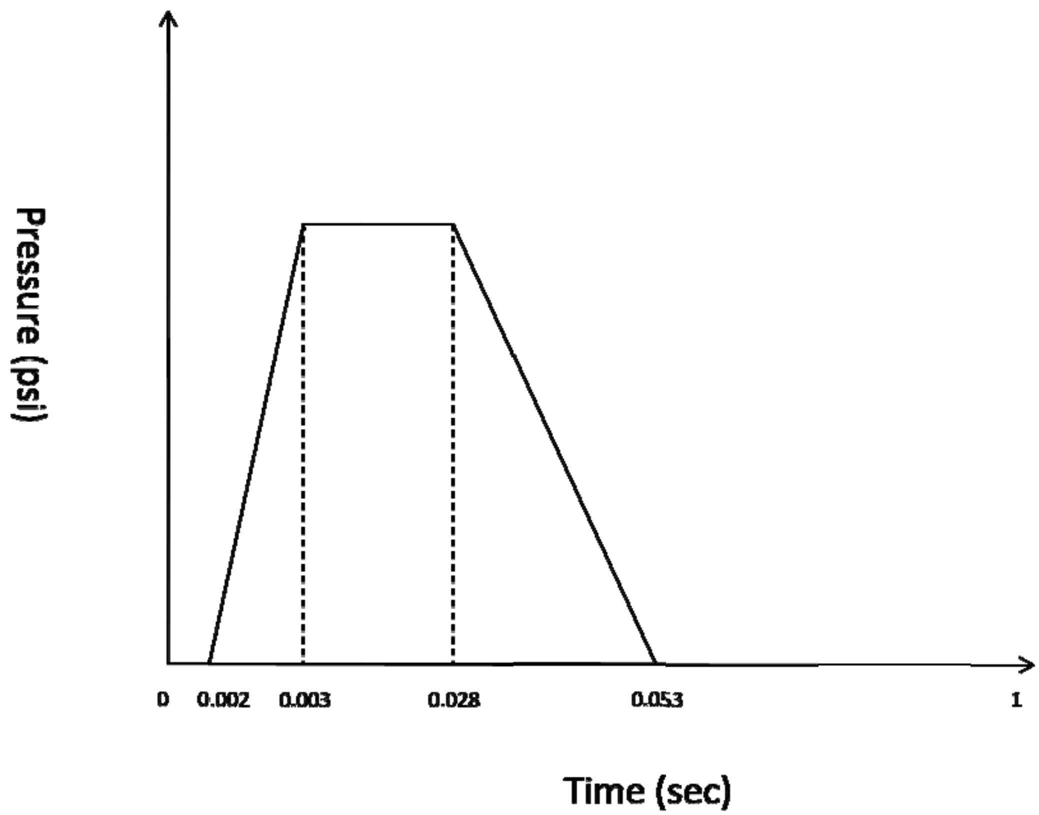

Fig. B.3: Graph of the loading conditions selected for the analyses.

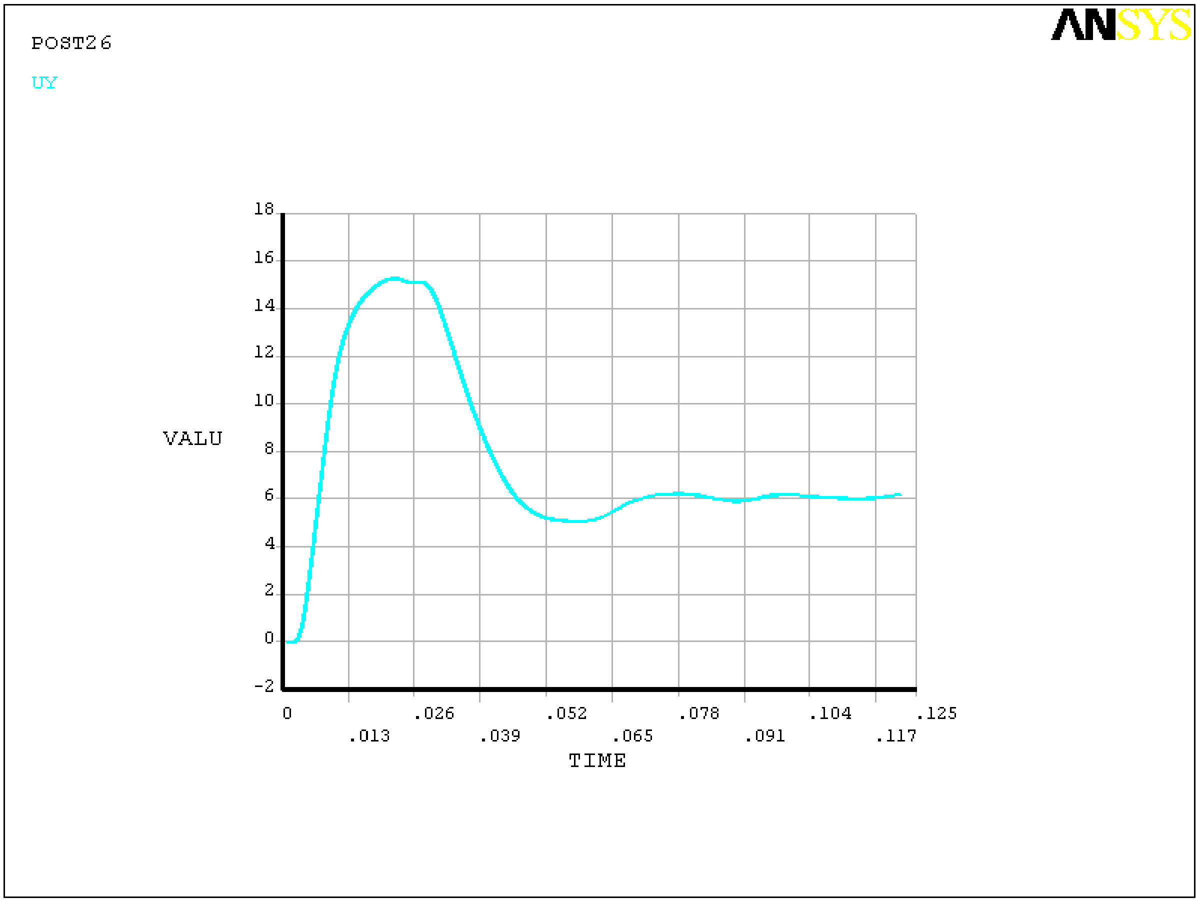

Fig. B.4: Maximum out-of-plane deflection and residual deflection for a 700 psi peak dynamic pressure.

Lucius Pitkin, Inc. *Consulting Engineers*

Advanced Analysis
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Nondestructive Engineering

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Attachment
IV

Unit 22 Main Transformer Test Results Review

Test	Acceptance Criteria		Baseline/ Nameplate	Last Test Data	This Test Data	Results Review
Transformer Power Factor	<0.5% is SAT, 0.5% to 1.0% Requires Engineering Review and Acceptance, >1.0% is UNSAT	CH	N/A	0.28	0.19	SAT - all values are <0.5%.
		CHL(UST)		0.35	0.26	
		CHL		0.35	0.26	
		CL		0.39	0.29	
		CHL(UST)		0.35	0.26	
		CHL		0.34	0.26	
Transformer Capacitance	<5% of Baseline SAT, 5% to 10% of Baseline Requires Engineering Review and Acceptance, >10% of Baseline is UNSAT	CH	6929	6965	6938	SAT - all values are <5% of Baseline values.
		CHL(UST)	14018	14052	14006	
		CHL	14021	14072	14013	
		CL	43751	44086	43948	
		CHL(UST)	14018	14048	14004	
		CHL	14039	14059	14016	
Bushing Power Factor	<0.5% is SAT, 0.5% to 1.0% Requires Engineering Review and Acceptance, >1.0% is UNSAT, 2X Nameplate is UNSAT	H1 (C1)	0.27	0.24	0.30	SAT - all values are <0.5%.
		H1 (C2)	N/A	0.22	0.27	
		H2 (C1)	0.27	0.25	0.30	
		H2 (C2)	N/A	0.23	0.26	
		H3 (C1)	0.27	0.25	0.31	
		H3 (C2)	N/A	0.23	0.26	
Bushing Capacitance	<5% of Nameplate SAT, 5% to 10% of Nameplate Requires Engineering Review and Acceptance, >10% of Nameplate is UNSAT	H1 (C1)	449	443	440	SAT - all values are <5% of Nameplate values. The capacitance values are decreasing however they are in spec.
		H1 (C2)	12314	12271	12228	
		H2 (C1)	450	446	445	
		H2 (C2)	12260	12271	12229	
		H3 (C1)	449	448	446	
		H3 (C2)	12314	12270	12223	

Unit 22 Main Transformer Test Results Review

Test	Acceptance Criteria		Baseline/ Nameplate	Last Test Data	This Test Data	Results Review
Bushing Hot Collar	<0.1W is SAT, 0.1W to 0.3W Requires Engineering Review and Acceptance, >0.3W UNSAT	X1	N/A	0.019	0.021	SAT - all values are <0.1W and similar to past results.
		X2		0.021	0.022	
		X3		0.018	0.020	
		X4		0.018	0.017	
		X5		0.018	0.021	
		X6		0.018	0.017	
Excitation Current	Currents (mA) measured should follow the pattern of two similar high readings (H1-H0 and H3-H0) and one lower reading (H2-H0).	H1-H0	N/A	353.60	373.95	SAT - the currents measured follow the expected pattern of two similar high readings (H1-H0 and H3-H0) and one lower reading (H2-H0).
		H2-H0		275.90	296.38	
		H3-H0		352.91	375.15	
Leakage Reactance	Change in impedance and reactance from previouss test is < 3% and within 2% of average.	A Imp	N/A	34.457	34.451	SAT - the change in impedance and reactance from previous test is < 3% and within 2% of average.
		A Reac		34.478	34.448	
		B Imp		34.619	34.603	
		B Reac		34.576	34.600	
		C Imp		34.779	34.634	
		C Reac		34.714	34.631	
Transformer Turns Ratio (TTR)	Within 5% of calculated ratio	H1/X1	9.5668	9.558	9.5632	SAT - measured ratio is within 5% of calculated.
		H2/X2	9.5668	9.555	9.5603	
		H3/X3	9.5668	9.561	9.5624	
Winding Resistance	Measured resistance shall not very by more than 5% from adjacent windings.	H1-H2	N/A	75.950	79.047	SAT - measured resistances are within 5% of each other. The difference in readings from past results could be attributed to instruments used, the quality of test equipment connections and/or temperature correction. The results from this test have been temperature corrected to 20C.
		H2-H3		75.860	79.277	
		H3-H1		76.140	79.288	
		X1-X0		931.0	860.4	
		X2-X0		911.0	866.5	
		X3-X0		929.0	856.0	

Unit 22 Main Transformer Test Results Review

Test	Acceptance Criteria		Baseline/ Nameplate	Last Test Data	This Test Data	Results Review
Winding Insulation Resistance (Megger)	≥ 1500 Megohms	H to G	N/A	4200	77900	SAT - all readings are greater than the acceptance criteria. The difference in readings from past results is due to different testing technique and equipment used.
	≥ 16 Megohms	L to G		4200	63400	
	≥ 1500 Megohms	H to L		4200	30100	
SFRA	There is no distinct acceptance criteria for this test. Comparison between phases and past test results is required. Requires Engineering review and acceptance.	N/A	Performed in 2008	N/A	N/A	SAT - Review of traces by System Engineering, Siemens and Doble indicate the test is SAT.
Dissolved Gas Analysis (DGA)	There is no distinct acceptance criteria for this test. The results are reviewed against past gassing trends, EN-EE-G-001 and IEEE C57.104	N/A	N/A	Performed 10/29/10	N/A	SAT - Review of the oil analysis results by System Engineering finds the results to be acceptable.

Unit 2 UAT Test Results Review

Test	Acceptance Criteria		Baseline	Last Test Data	This Test Data	Results Review
Transformer Power Factor	<0.5% is SAT, 0.5% to 1.0% Requires Engineering Review and Acceptance, >1.0% is UNSAT	CH	N/A	0.41	0.31	SAT - all values are <0.5% with the exception of CL. The CL is acceptable at 0.51% based on it being below 1.0%, historically being higher than the other power factors, it is not trending up and the value is similar to the other similar auxiliary transformers on site.
		CHL(UST)		0.48	0.34	
		CHL		0.52	0.35	
		CL		0.72	0.51	
		CHL(UST)		0.48	0.35	
		CHL		0.48	0.34	
Transformer Capacitance	<5% of Baseline SAT, 5% to 10% of Baseline Requires Engineering Review and Acceptance, >10% of Baseline is UNSAT	CH	13393	13376	13391	SAT - all values are <5% of Baseline values.
		CHL(UST)	20070	20065	20050	
		CHL	20079	20074	20095	
		CL	2455	2456	2426	
		CHL(UST)	20065	20062	20049	
		CHL	20067	20069	20052	
Bushing Hot Collar	<0.1W is SAT, 0.1W to 0.3W Requires Engineering Review and Acceptance, >0.3W UNSAT	H1	N/A	0.018	0.016	SAT - all values are <0.1W and similar to past results.
		H2		0.019	0.016	
		H3		0.024	0.019	
		X0		0.022	0.021	
		X1		0.018	0.027	
		X2		0.028	0.026	
		X3		0.026	0.018	
Excitation Current	Currents (mA) measured should follow the pattern of two similar high readings (H2-H3 and H3-H1) and one lower reading (H1-H2).	H1-H2	N/A	163.07	165.72	SAT - the currents measured follow the expected pattern of two similar high readings (H2-H3 and H3-H1) and one lower reading (H1-H2).
		H2-H3		324.9	332.63	
		H3-H1		345.28	329.4	

Unit 2 UAT Test Results Review

Test	Acceptance Criteria		Baseline	Last Test Data	This Test Data	Results Review
Transformer Turns Ratio (TTR)	Within 5% of calculated ratio	5R (H1/X1)	2.889	2.883	2.883	SAT - measured ratio is within 5% of calculated.
		5R (H2/X2)	2.889	2.883	2.883	
		5R (H3/X3)	2.889	2.883	2.883	
Winding Resistance	Measured resistance shall not very by more than 5% from adjacent windings.	H1-H2	N/A	61.750	56.838	SAT - measured resistances are within 5% of each other. The difference in readings from past results could be attributed to instruments used, the quality of test equipment connections and/or temperature correction. The results from this test have been temperature corrected to 20C.
		H2-H3		60.020	56.896	
		H3-H1		60.620	56.688	
		X1-X0		2.623	2.852	
		X2-X0		2.658	2.867	
		X3-X0		2.662	2.890	
Winding Insulation Resistance (Megger)	≥ 46 Megohms	H to G	N/A	4200	2400	SAT - all readings are greater than the acceptance criteria. The difference in readings from past results is due to different testing technique and equipment used.
	≥ 16 Megohms	L to G		4200	24200	
	≥ 46 Megohms	H to L		4200	2560	
SFRA	There is no distinct acceptance criteria for this test. Comparison between phases and past test results is required. Requires Engineering review and acceptance.	N/A	Performed in 2008	N/A	N/A	SAT - Review of traces by System Engineering and Siemens indicate the test is SAT.
Dissolved Gas Analysis (DGA)	There is no distinct acceptance criteria for this test. The results are reviewed against past gassing trends, EN-EE-G-001 and IEEE C57.104	N/A	N/A	Performed 10/29/10	N/A	SAT - Review of the oil analysis results by System Engineering finds the results to be acceptable.

Attachment
V

SIEMENS

March 16, 2011

Leonard Martin
Commodity Leader
Materials, Purchasing & Contracts
Entergy

Subject: Indian Point Trench Bushings Transformers Issues

Dear Leonard,

Please see attached our reports developed to date for the above mentioned transformers. The reports include the ST 02/11 Photographic Report and the ST 19/10 General Aspects After Event Report, including all attachments. We will issue the final Root Cause Analysis Report upon completion of the investigation. We would be pleased to discuss these reports with you or your team.

Sincerely,

Andrew Lawless
Vice President, Transformers Business Unit

Cc: Entergy Corporation
Dave Bauer, Arthur Bortz, John Curry, James Findley, Tom Orlando, John Schaefer, Kristi Quirk, T. M. Cook

Siemens Energy, Inc.
John Sprance, Kenneth Reuter, Vickie Adams, James McIver, Michael Wenger, Carl Lockhart

Siemens Energy, Inc.
P.O. Box 29503, Raleigh, NC 27626-0503
7000 Siemens Road, Wendell, NC 27591 Tel: (919) 365-2200

TRENCH

March 15, 2011

Siemens Energy, Inc.
E T TR AM
Mr. Kazi.

Entergy/IPEC Nuclear Station, Buchanan, NY

Dear Mr. Kazi,

The photographic report ST02/11 summarizes Trench's and Siemens' investigation on the failed bushing serial number 05F9080-04 originally installed in phase B of TR#21 at Indian Point Nuclear station.

It was concluded that further investigation is required in order to determine the root cause of the bushing failure

However the investigation also reveals:

1. This kind of failure has never been reported on a Trench bushing
2. It is not systemic and does not reveal any design flaws

Trench has an installed base of over 120,000 bushings; we re-emphasize that no advisory has ever been issued on our bushings.

Recommendations on TR#21
Although we believe that treeing activity will be limited on the bushing in service since November 2010, we recommend that Entergy continuously monitor the MPT 21 bushings until their removal.

Recommendations on TR#22
As the root cause analysis of the bushing failure is at a very early stage we recommend to take the bushings on TR#22 out of service to do further investigations in our facility. These bushings can be replaced with spare bushings which are available onsite.

Various onsite tests on the TR#22 bushings in November 2010 showed no evidence of degradation; we therefore confirm that the bushings are safe to operate until the next scheduled outage on May 09, 2011.

Sincerely,

Uli Bauch
General Manager
Trench Canada Bushings

Trench Limited
Bushings Division
432 Monarch Ave.
Ajax, Ontario
Canada, L1S 2G7, Tel: (905) 426 2665

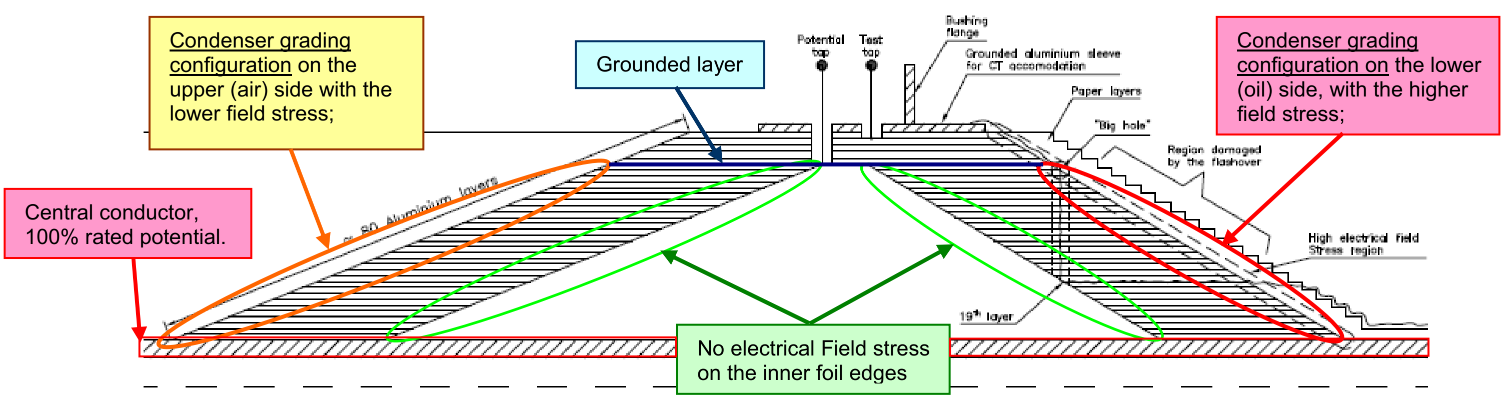
1. Bushing Data

Type:	COTA - Transformer OIP (Oil Impregnated Paper Bushing)
Type of installation	Oil-Air Bushing
Style	**1175–F020–23–AG3–02**
Insulation Class	**345 kV**
BIL	**1175 kV**
SIL Wet	**825 kV**
Rated Maximum Voltage Line to Ground	**220 kV**
1 Min Dry Voltage	**520 kV**
Rated cont. Current	**2000 A**
Serial Numbers Transformer #4.019.269 (Unit #21)	**05F9080 – 01 Terminal H1** **05F9080 – 04 Terminal H2** **05F9080 – 03 Terminal H3**
Year of Manufacturing	**2005**

2. Scope

This Photographical Report contains the significant photographs taken during the inspection of the bushings of terminal H2 and H3 of the transformer Unit #21, which bushing H2 exploded on November 07, 2010, causing the outage of the power plant.
The inspection was performed on January 18, 2011, at the Bushing factory of TRENCH in Toronto/Ajax – Canada.

For a better understanding of the pictures shown in the ***section 4***, in the sketch below the schematic structure of the investigated condenser bushing is shown. This sketch is also reproduced in the ***section 5***. Note that in TRENCH bushings, capacitive layers of the condenser body use split-foils for the upper and lower portions of the bushing.



Sketch 1. View of the longitudinal half section of the condenser core, showing the main elements and detail of the regions with capacitive grading.

Radial electrical stresses from the centre conductor to the outer grounded capacitive layers are kept uniform and linear throughout the active part by using capacitive voltage grading.

Since the dielectric strength of the air is low, the upper side grading of the bushing must be designed over a longer distance resulting in a low axial electric field stress compared to the oil-immersed lower end of the bushing where the axial electric fields are compressed over a smaller distance resulting in higher stresses.

3. Summarized Inspection Description

On January 18, 2011, the bushing inspection and tear down took place at the Trench factory in Toronto/Ajax – Canada.
After an introductory explanation about the TRENCH bushing facility and capabilities, a brief presentation was given by TRENCH regarding the failure of 3 of Trench France 230-kV bushings occurred in 2006. These bushings were of a different design than the IPEC bushings under consideration, and their failure was attributed to insulation breakdown due to copper migration caused by a corrosive reaction initiated by polar compounds in the Shell Diala D mineral oil used in those bushings.

3.1 Inspection of Bushing of **Terminal H2** (S. No. 05F9080 – 04)

The first bushing inspected was the one installed on the terminal H2 of the transformer Unit #21. The location of the failure was determined to have occurred on the oil immersed (lower-end) side of the bushing, causing an explosion and subsequent transformer tank rupture and fire (see ***Technical Report ST 19/10***).

For the inspection, first the condenser core was extracted from the outer shell (see ***Picture 3***). Then the condenser core was placed on rollers installed over a wooden box, which was intended to accommodate the unwound paper layers.

Upon unwinding of the outer paper layers, where the voltage tap foil and the ground foil are located (which are grounded during normal operation of the transformer), small brown traces were observed at the edge of the aluminum foils.

These treeing traces extended around 1 mm axially along the paper insulation and had a starting point at the upper edge of the aluminum foils installed at the upper portion of the condenser core. Since the lower part of the H2 bushing was mostly destroyed during the failure, the major part of the aluminum foils could be inspected only on the upper part (above the bushing flange region).

These brown traces were similar to the ones shown during the TRENCH presentation on the opening meeting.

It was also observed that the traces became gradually lighter as the examination progressed from the outer layers to the innermost ones.

The innermost 18 foil layers at the lower part of the bushing were not damaged during the failure (see *picture 32*), allowing the inspection of the bottom portion of the condenser core. Similar treeing traces were found at these locations.

It was noticed that the traces on the edges of the aluminum foils were observed only at the outer foil edges. This means:

- ✓ On the bottom edge of the foils of the bottom portion of the active part;
- ✓ And on the upper edge of the foils of the upper portion of the active part;

The location of the traces suggests that their formation is related to the presence of electrical fields. The inner edges of the aluminum foils are exposed to a negligible electrical field stress and no traces were observed in these regions (refer also to ***Sketch 1***).

The most likely failure path was identified as starting on or around the outer edge of the first layer following the layer of the potential tap, passing through the "big hole" and reaching the 100% potential at the central conductor near the bottom terminal. The failure path also expanded to the bushing flange at the zero potential side (refer to the ***sketch 6*** – ***section 5***).

3.2 Inspection of Bushing of **Terminal H3** (S. No. 05F9080 – 03)

Following the teardown sequence, the bushing of terminal H3 of the transformer Unit #21 was inspected next.

The epoxy cast insulator of the lower part of this bushing had shattered in pieces but there was no damage to the condenser core. As all the layers of the condenser core were intact, both upper and lower foil edges could be fully inspected.

Similar to the H2 terminal bushing, treeing traces were found on the first layer below the grounded layer of the voltage tap and on most the remaining foils.

The traces at the lower edge of the bottom foils were more pronounced than those found at the upper part of the H2 bushing. It was also observed at the layers of the bottom part of this bushing that the intensity of the traces decreased from the outer layers to the innermost ones.

On the upper edge of the foils of the upper portion of the condenser core also showed traces, these with similar intensity as those detected on the H2 bushing.

3.3 Inspection of Bushing of **Terminal H1** (S. No. 05F9080 – 01)

Based on the similar findings on the first two inspected bushings, it was decided not to unwind the third bushing, originally installed at the terminal H1. However, according to information provided by TRENCH, this bushing was also unwound at a later date and showed similar evidence of traces as the ones that were detected on the other two bushings already inspected.

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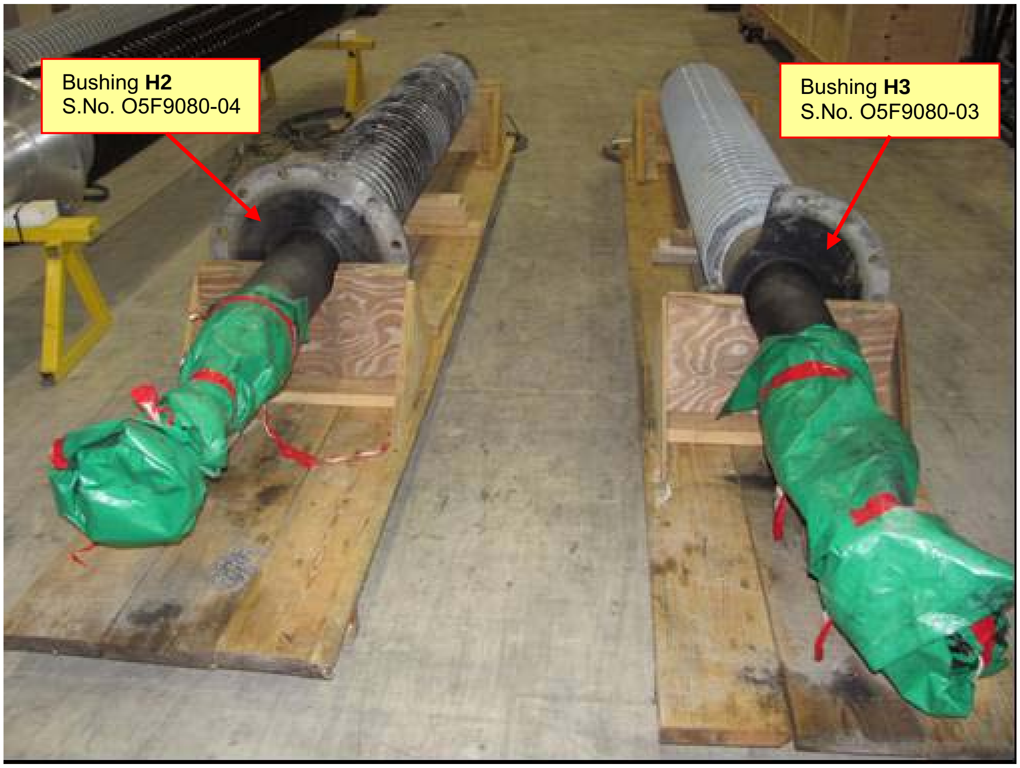
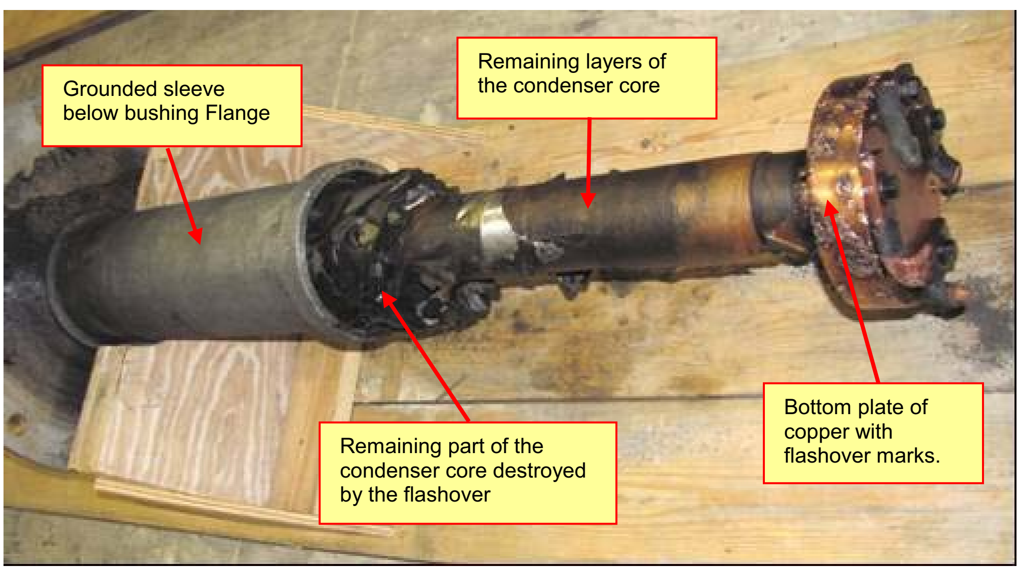
4. Selection of the significant Photos of the Inspection



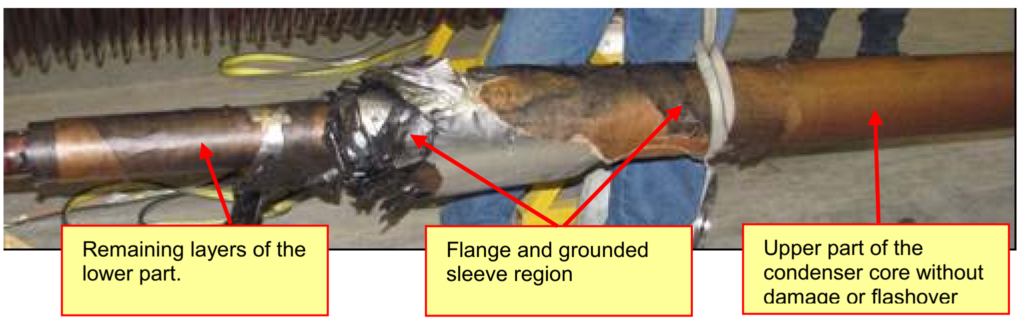
Picture 1: General view of the bushings as received from the Indian Point site;

4.1 Inspection Photos of Bushing **Terminal H2** (S. No. 05F9080 – 04)

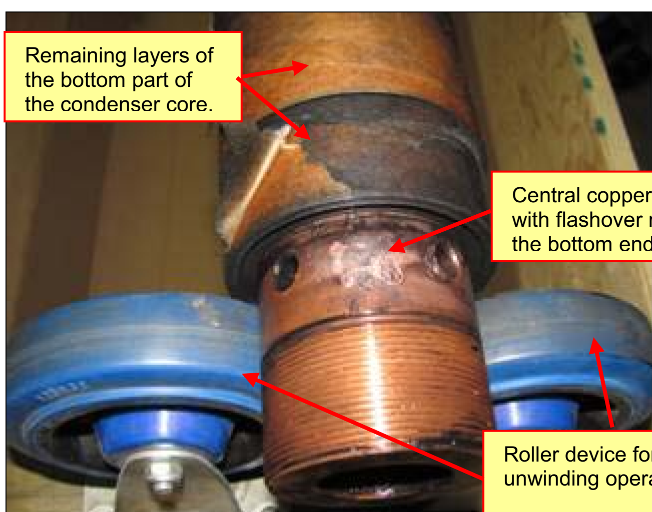


Picture 2: General view of the **H2** bushing showing the bottom part destroyed by the flashover;

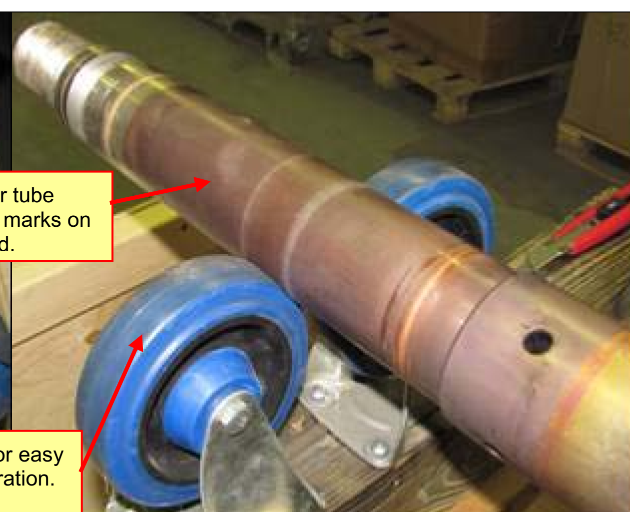
Picture 3: H2 bushing core being extracted from the porcelain body & flange.



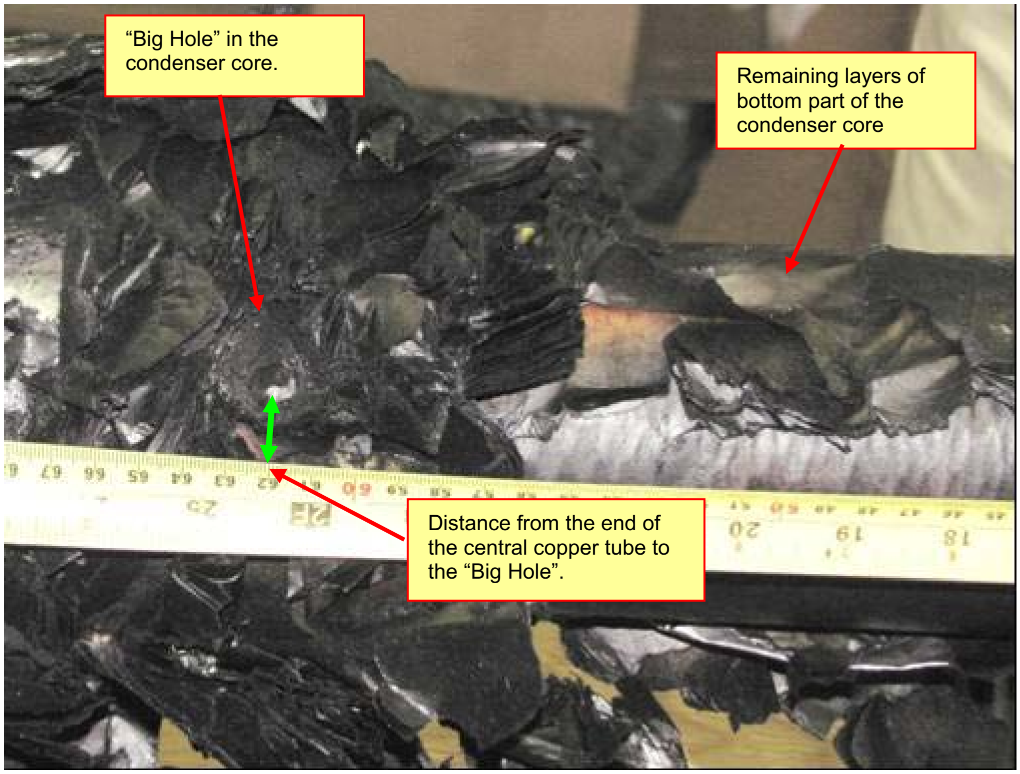
Picture 4: Bushing H2: Major parts of the condenser core after extraction.



Picture 5: Bushing H2 installed on the device for unwinding the condenser core.

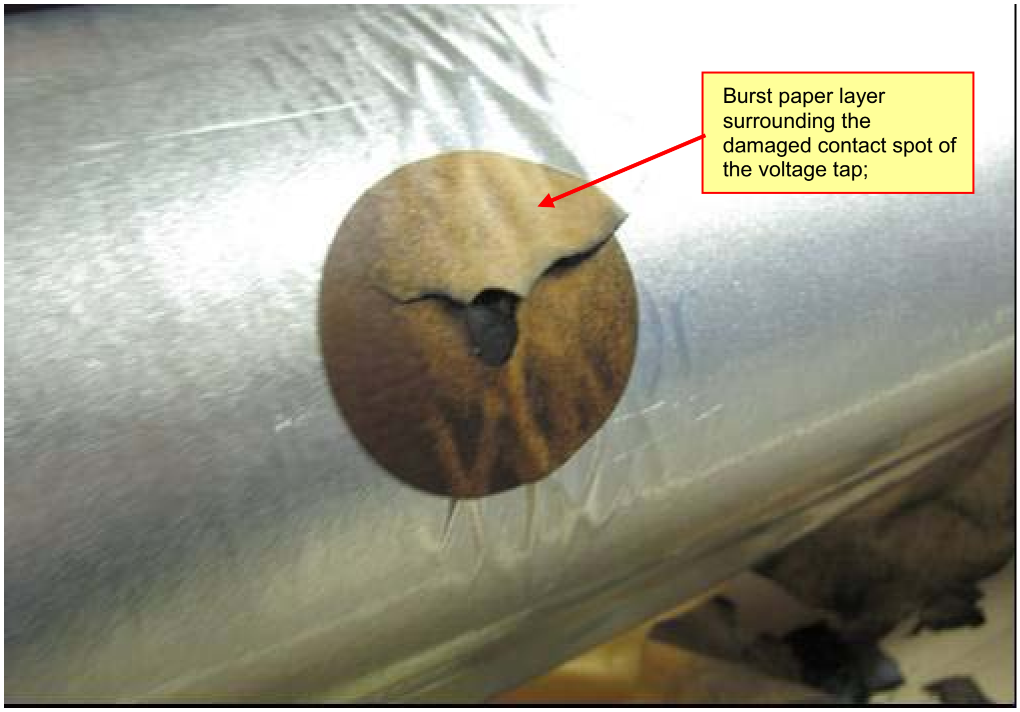


Picture 6: Bushing H2: central conductor tube, after complete unwinding of the layers of the condenser core

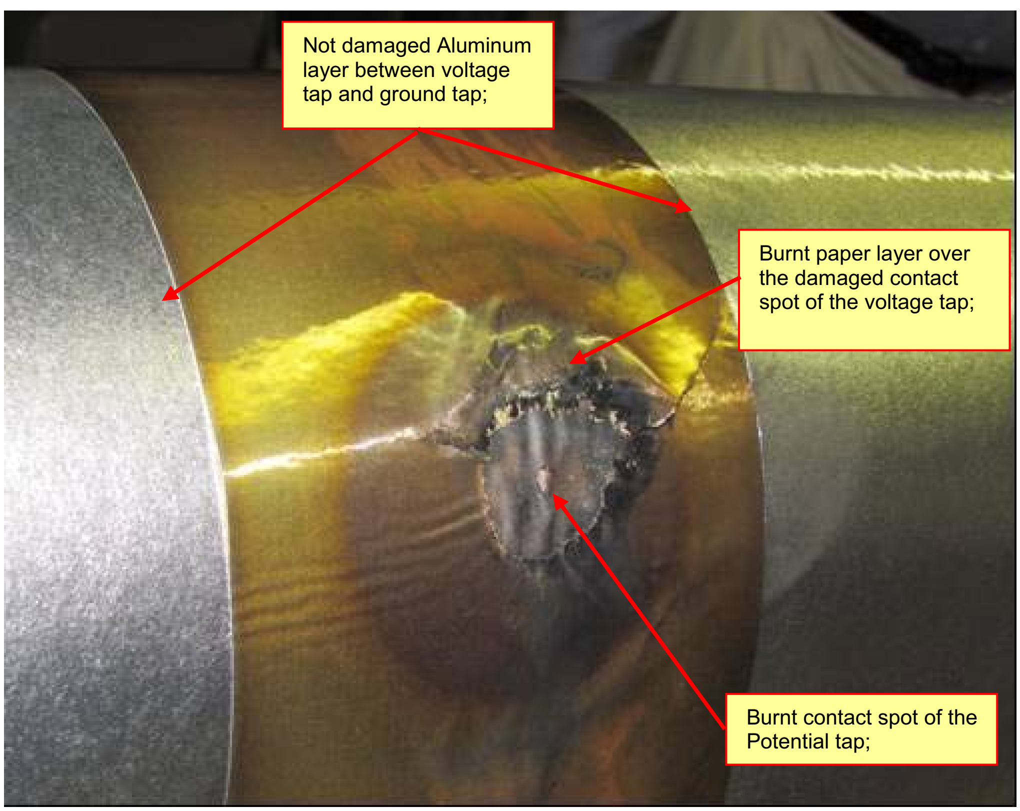


Picture 7: **H2** bushing: identification of the major flashover path at the destroyed layers;

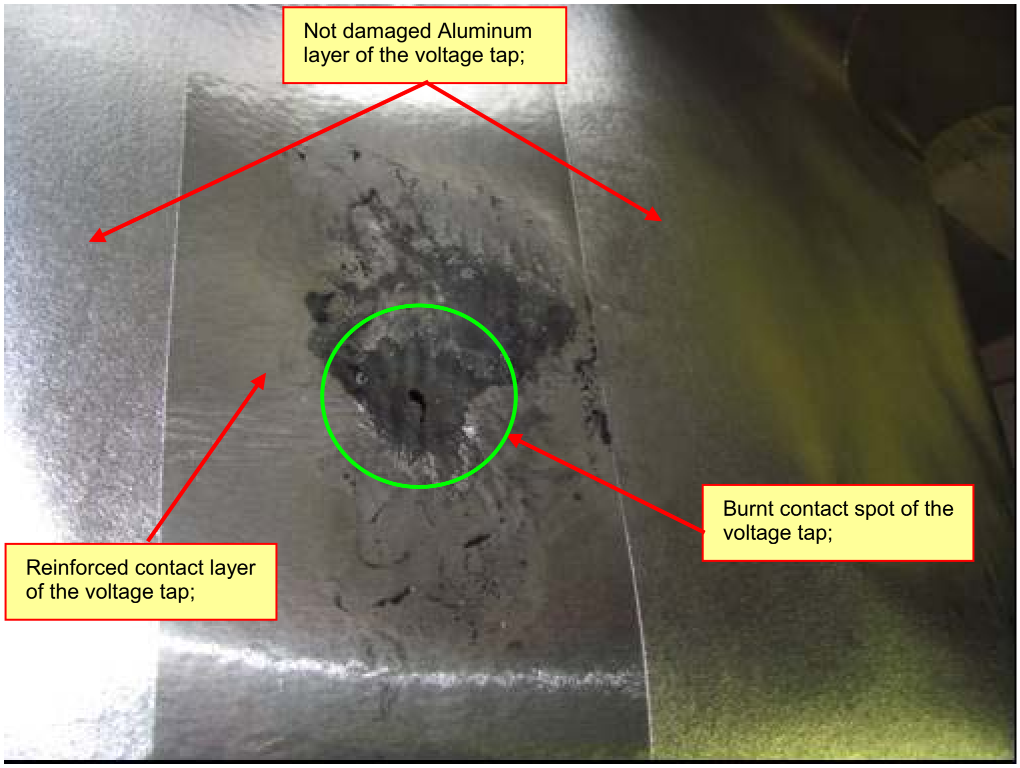
Picture 8: H2 bushing: distance from the end of the central conductor to the voltage tap.



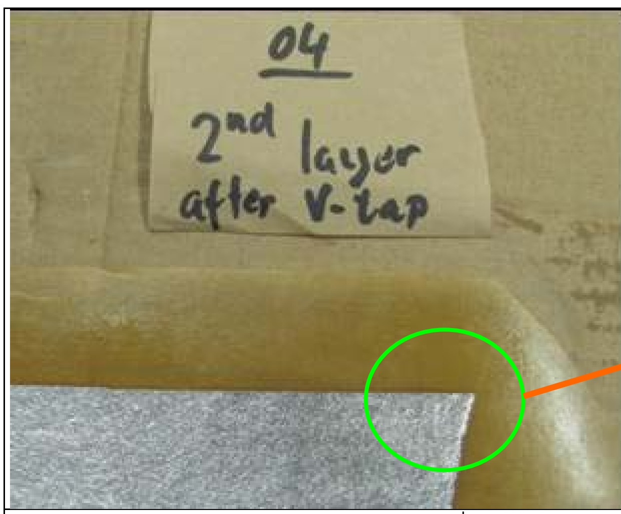
Picture 9: H2 bushing: Aluminum layer between the ground tap and the voltage tap.

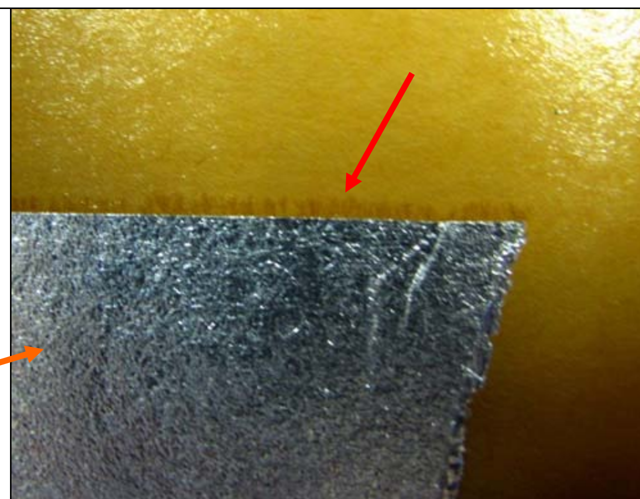


Picture 10: H2 bushing: Further Aluminum layer after Test tap and the burnt voltage tap.



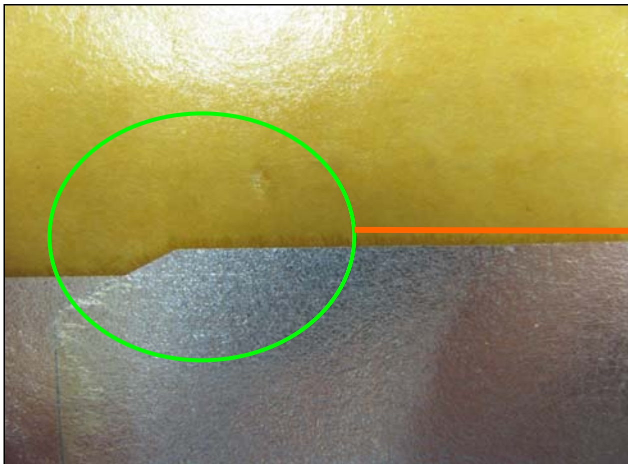
Picture 11: H2 bushing: burnt contact layer of the voltage tap.



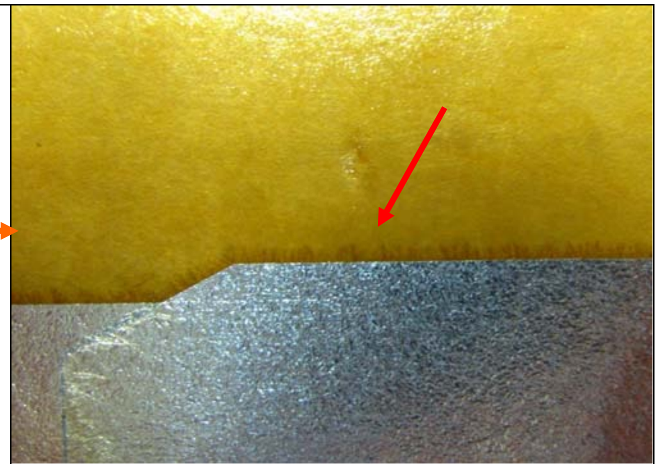


Picture 12: **H2 bushing**: Detail of the 2nd layer beneath (inwards) the voltage tap layer with "treeing" traces on the edge.
Green circle: enlarged area on the picture aside.

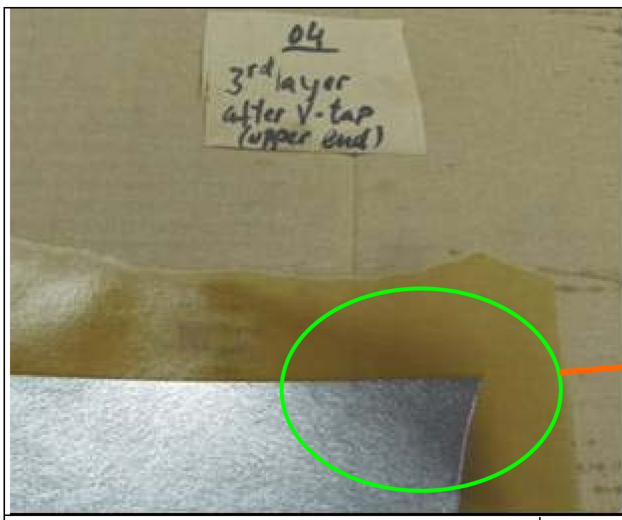
Picture 13: **Red arrow**: "Treeing" traces on the upper edge of the aluminum foil;



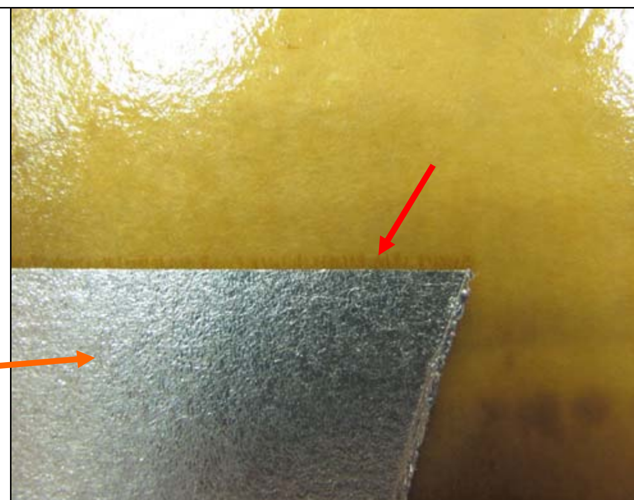
Picture 14: ***H2 bushing***: Further detail of the 2nd layer beneath (inwards) the voltage tap layer with "treeing" traces on the edge.
Green circle: enlarged area on the picture aside.



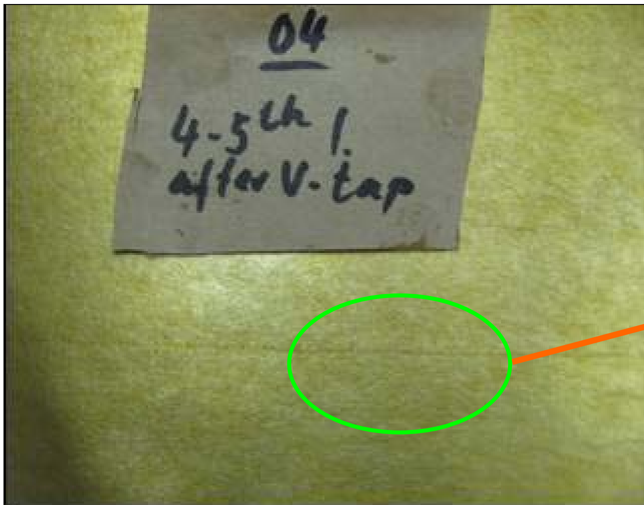
Picture 15: ***Red arrow***: "Treeing" traces on the upper edge of the aluminum foil;



Picture 16: ***H2 bushing***: Further detail of the 3rd layer after (inwards) the voltage tap layer with "treeing" traces on the edge.
Green circle: enlarged area on the picture aside.

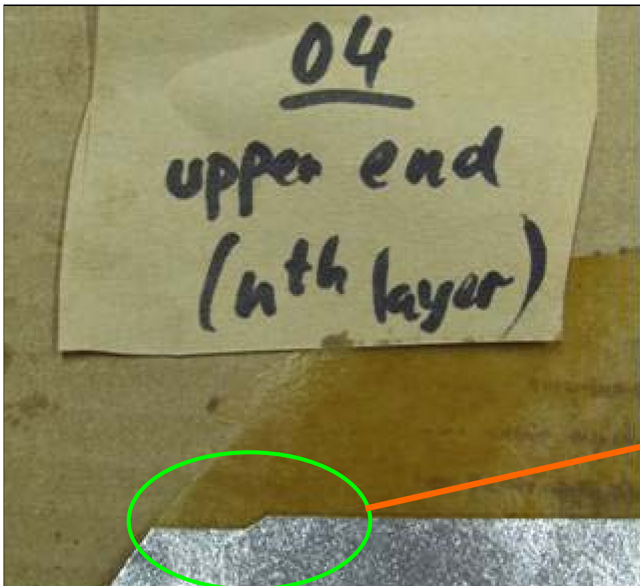


Picture 17: ***Red arrow***: "Treeing" traces on the upper edge of the aluminum foil;

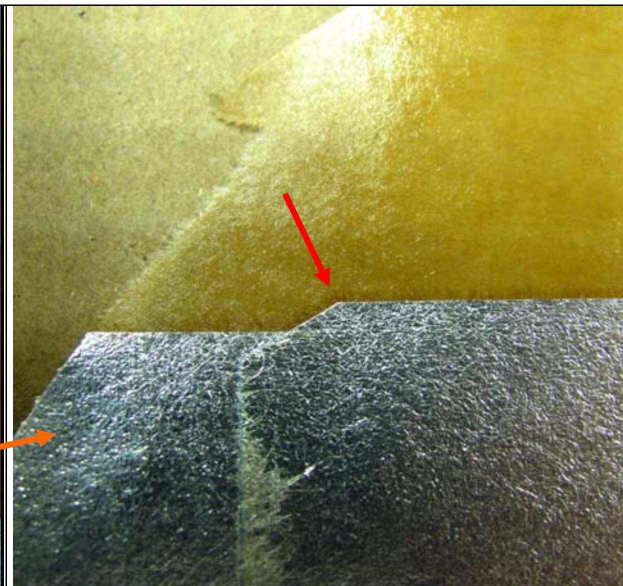


Picture 18: ***H2 bushing***: "Treeing" traces on the paper layer underneath the aluminum foil. This is the 4th layer beneath (inwards) the voltage tap layer.
Green circle: enlarged area on the picture aside.

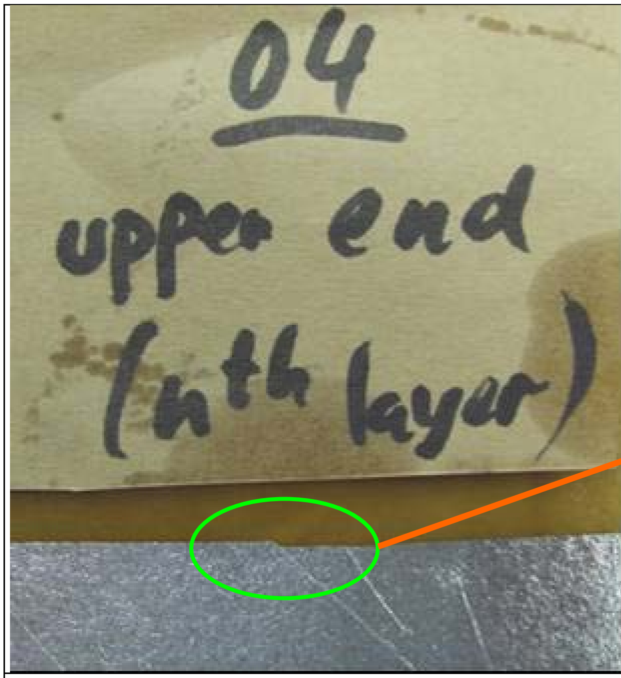
Picture 19: ***Red arrow***: "Treeing" traces on the paper underneath the upper edge of the aluminum foil;



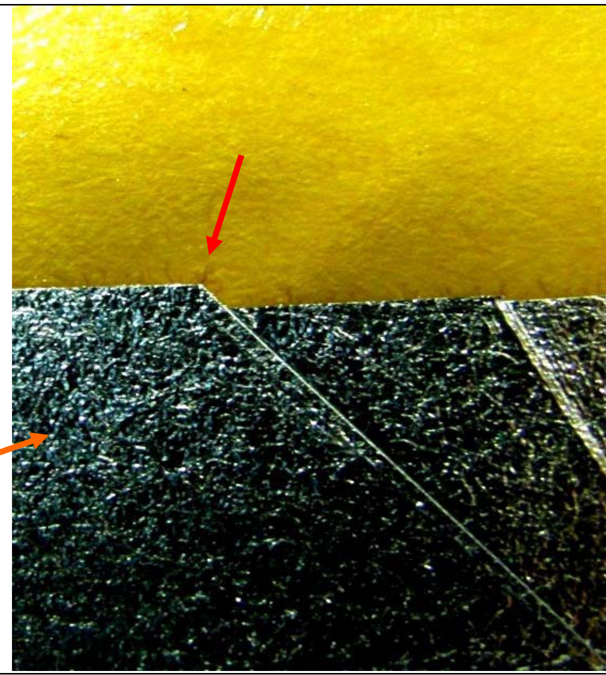
Picture 20: ***H2 bushing***: "Treeing" traces on the edge of one further aluminum foil layer of the middle portion of the condenser core;
Green circle: enlarged area on the picture aside.



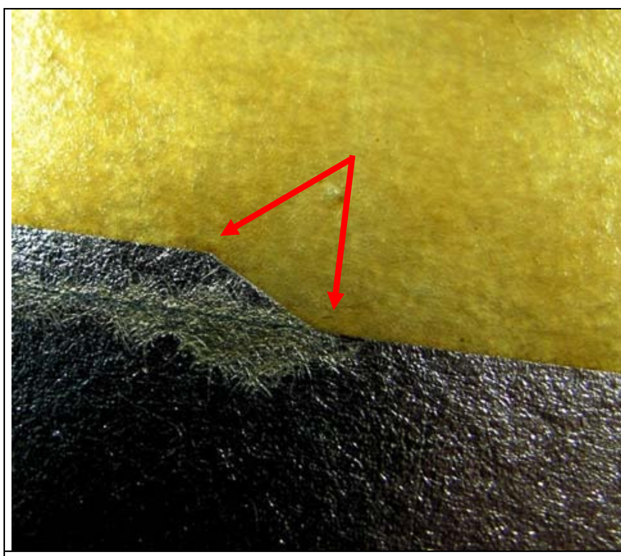
Picture 21: ***Red arrow***: "Treeing" traces on the upper edge of the aluminum foil; the intensity of the traces became lighter on the layers closer to the central conductor.



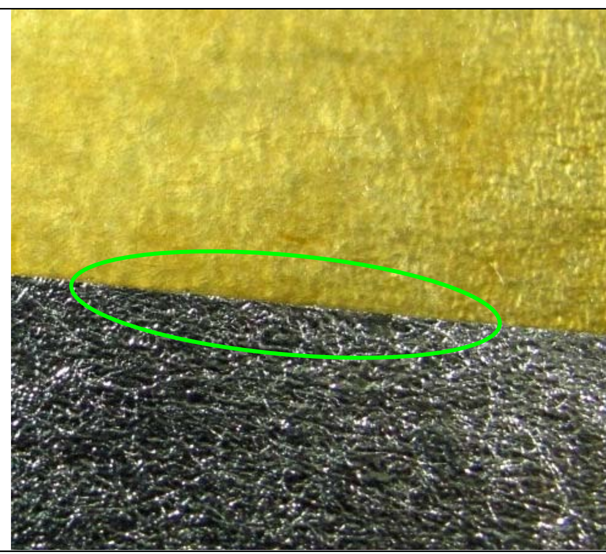
Picture 22: ***H2 bushing***: "Treeing" traces on the edge of one further aluminum foil, one layer beneath the middle portion of the condenser core;
Green circle: enlarged area on the picture aside.



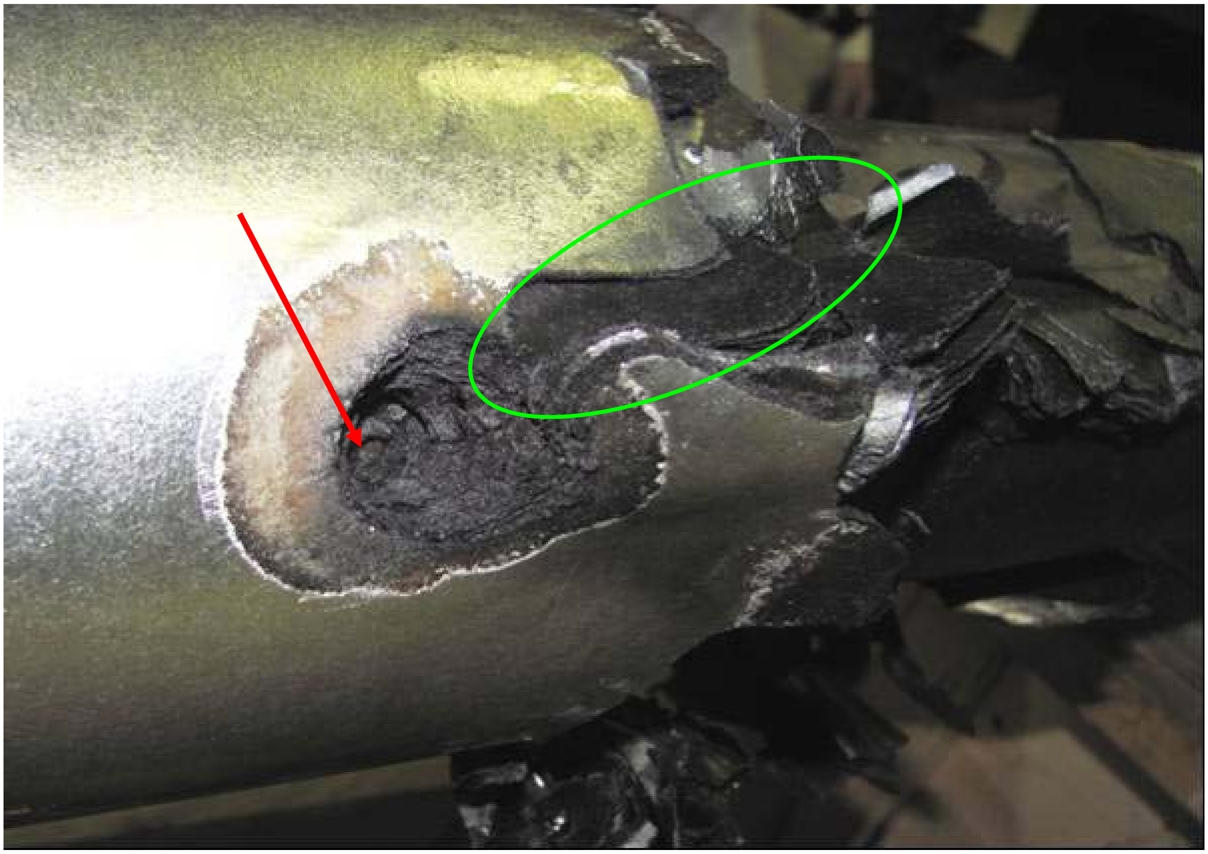
Picture 23: ***Red arrow***: "Treeing" traces on the upper edge of the aluminum foil; the intensity of the traces became gradually lighter on the layers closer to the central conductor.



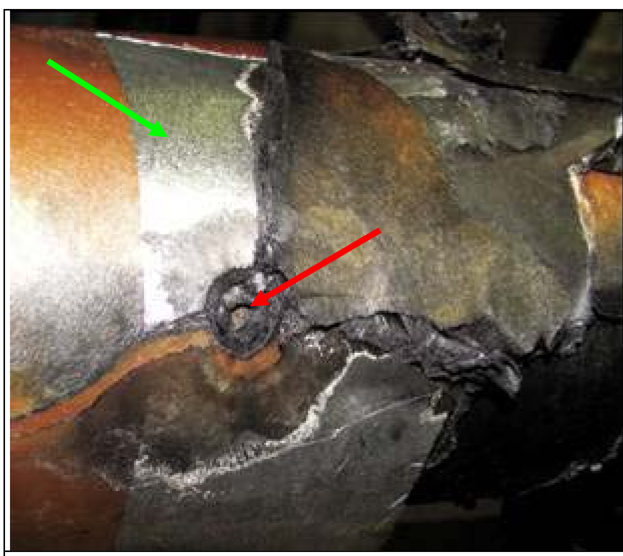
Picture 24: ***H2 bushing***: Very light "treeing" traces (***red arrows***) on the edge of one aluminum foil layer situated near to the central conductor of the condenser core;



Picture 25: ***Green circle***: Upper (internal) edge of a bottom aluminum layer; the region of edge of the aluminum foil is completely free from "treeing" traces. Similar situation was confirmed on the lower (internal) edge of the upper foil All internal edges showed similar characteristic, being free of "treeing" traces.

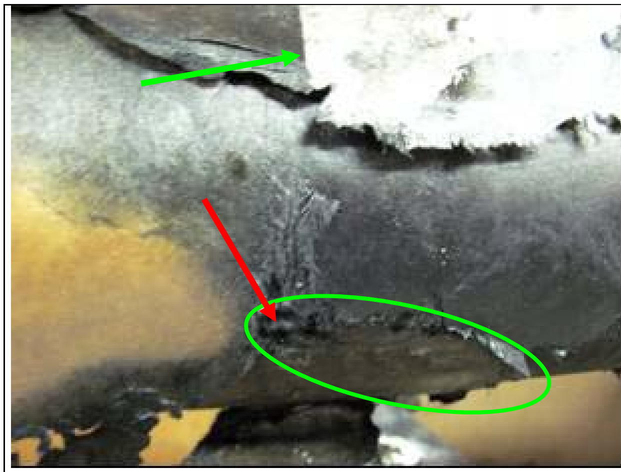


Picture 26: Detail view of the “big hole” extending down until the 19th layer (***red arrow***) (reckoning from the inner conductor outwards); ***Green circle***: Discharge path, beginning on the hole.

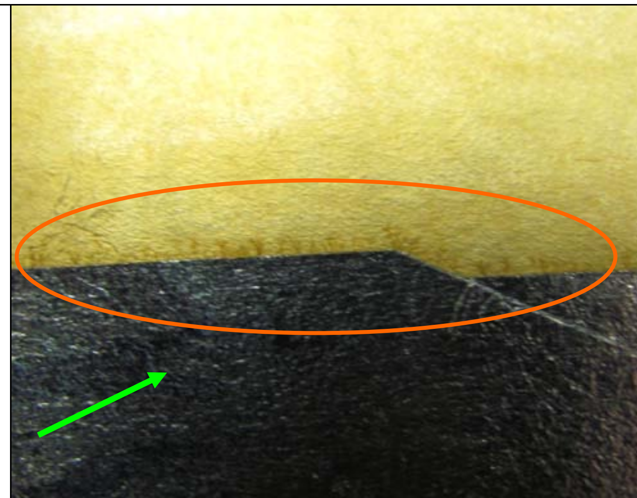


Picture 27: ***H2 bushing***:
Red arrow: Bottom of the “big hole”
Green arrow: 21th layer (2 layers above the 19th)

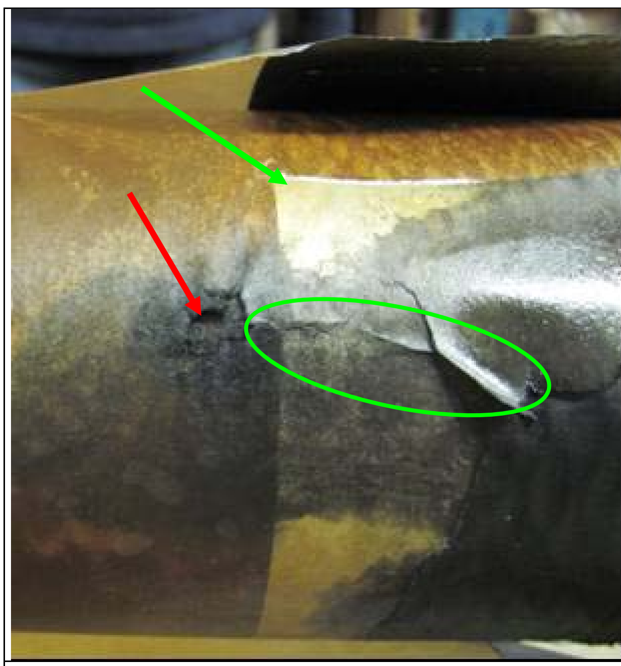
Picture 28: ***H2 bushing***:
Green circle: discharge path;
Red arrow: Bottom of the “big hole”
Green arrow: 20th layer (1 layer above the 19th)



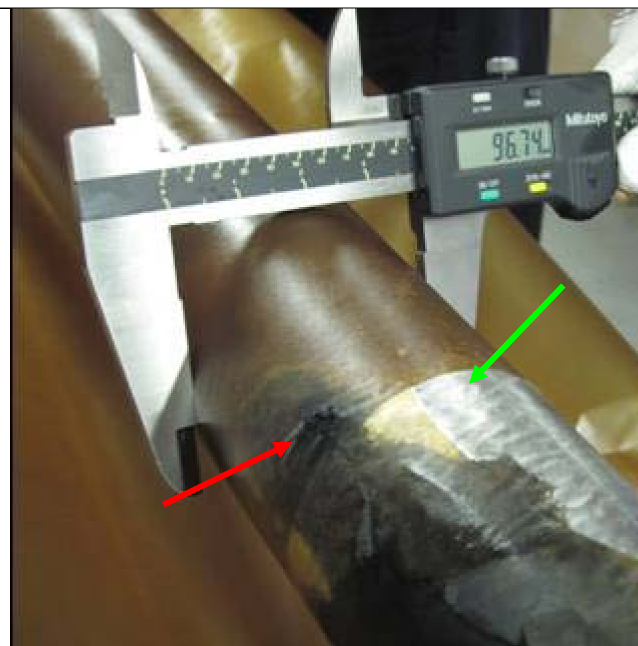
Picture 29: ***H2 bushing***:
Green circle: discharge path;
Red arrow: Bottom of the "big hole"
Green arrow: remaining part of the 19th layer touched by the discharge.



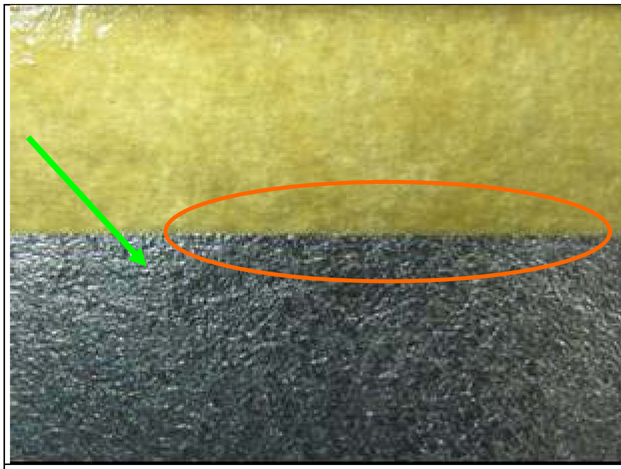
Picture 30: ***H2 bushing***:
Orange circle: traces on the bottom edge of the 18th layer;
Green arrow: 18th layer (1 layer beneath the 19th)



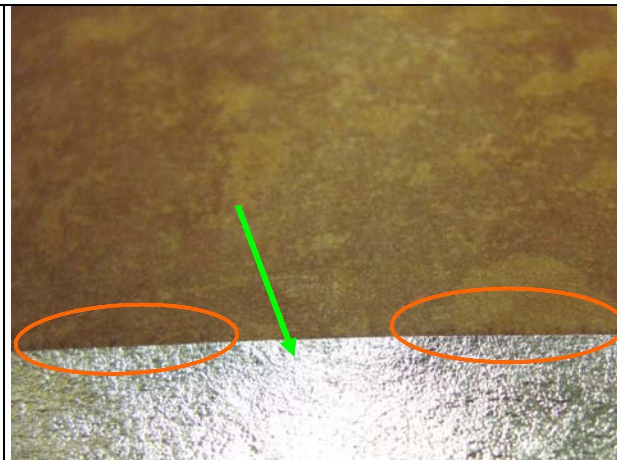
Picture 31: ***H2 bushing***:
Green arrow: 18th layer;
Red arrow: Bottom of the "big hole"
Green circle: discharge path also visible by mechanical & burnt marks on the 18th layer.



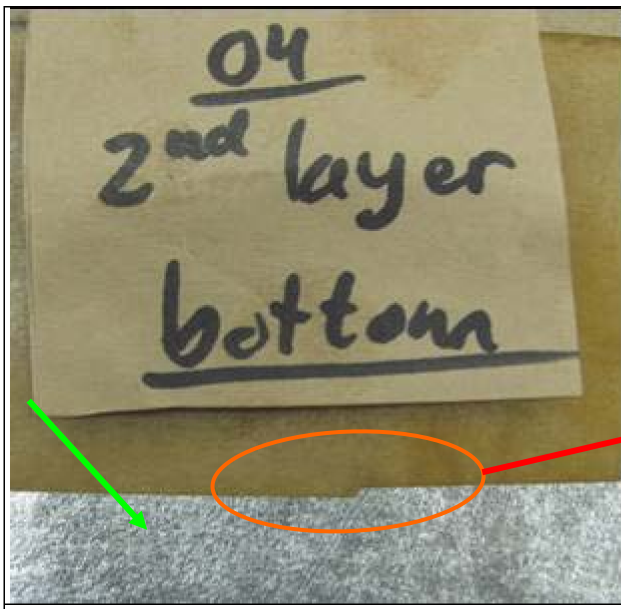
Picture 32: ***H2 bushing***:
Measuring the diameter of the 18th layer;
Red arrow: Bottom of the "big hole"
Green arrow: 18th layer;



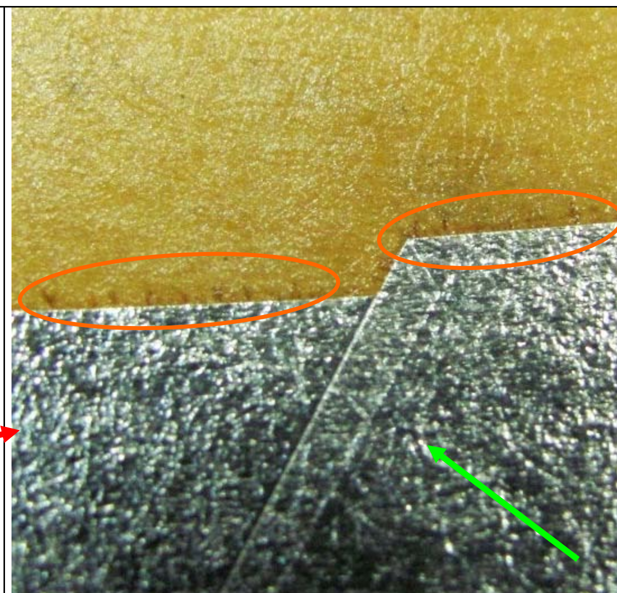
Picture 33: ***H2 bushing***:
Green arrow: 18th layer;
Orange circle: upper edge of the 18th layer's bottom part completely free from "treeing" traces.



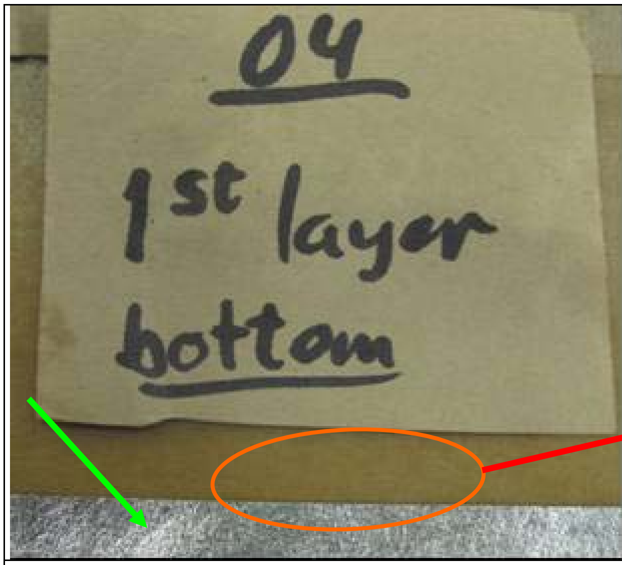
Picture 34: ***H2 bushing***:
Orange circle: lower part of the 17th layer with slight "treeing" traces on the bottom edge
Green arrow: 17th layer;

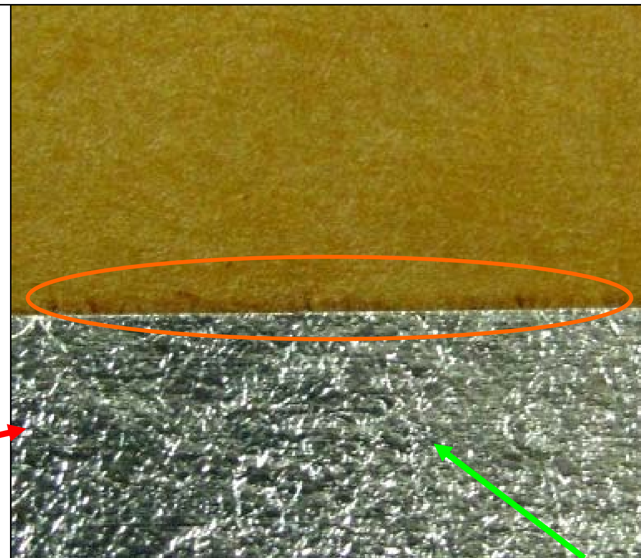


Picture 35: ***H2 bushing***:
Green arrow: 2nd layer above the inner conductor;
Orange circle: enlarged region shown on picture 36, with slight "treeing" traces made visible.



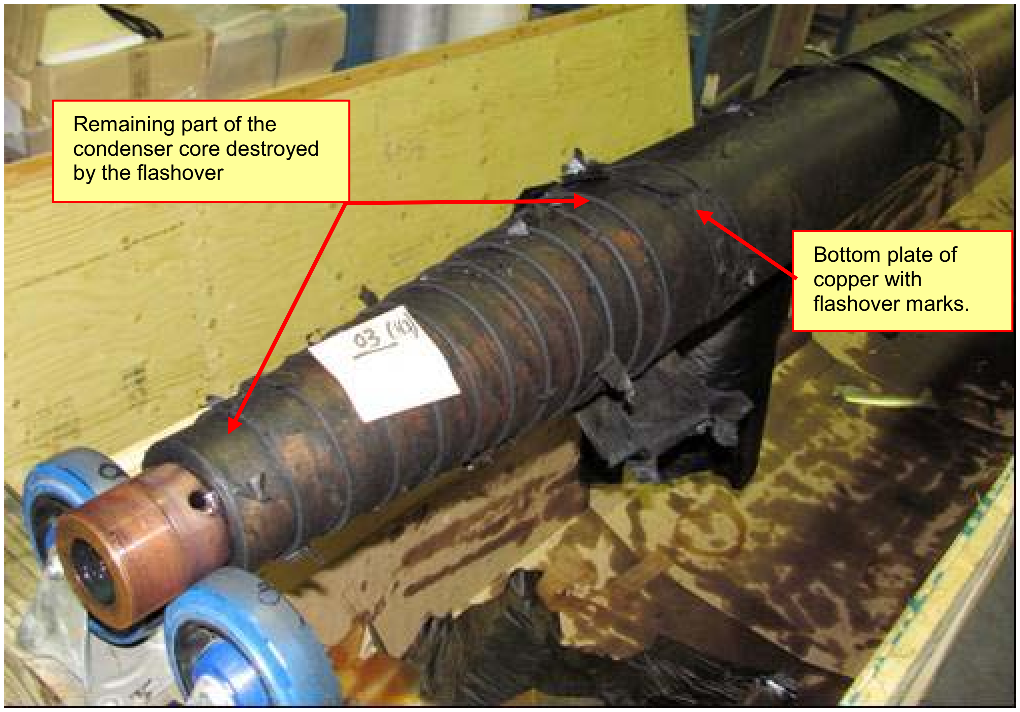
Picture 36: ***H2 bushing***:
Green arrow: 2nd layer;
Orange circle: lower part of the 2nd layer with slight "treeing" traces on the bottom edge.



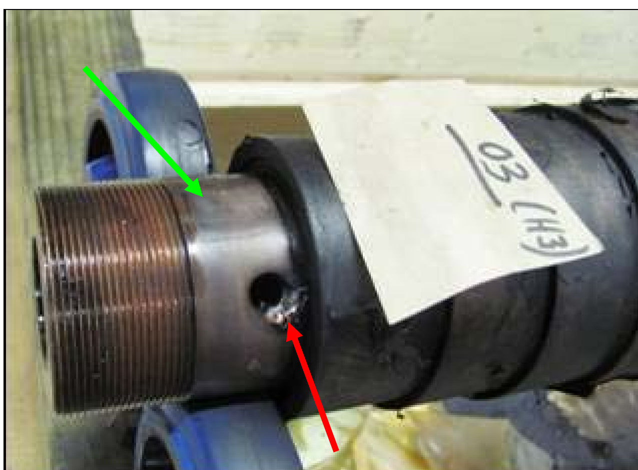
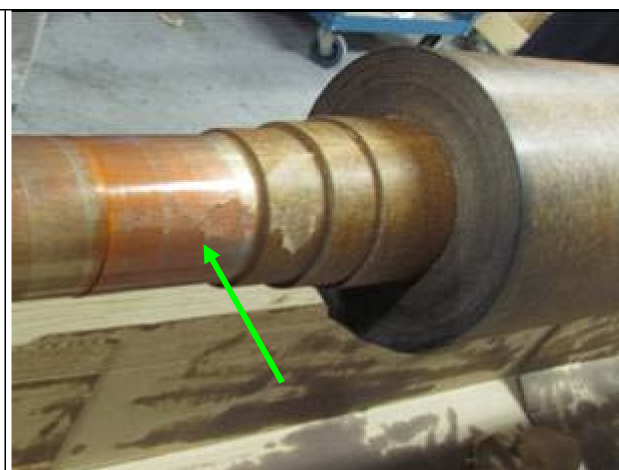


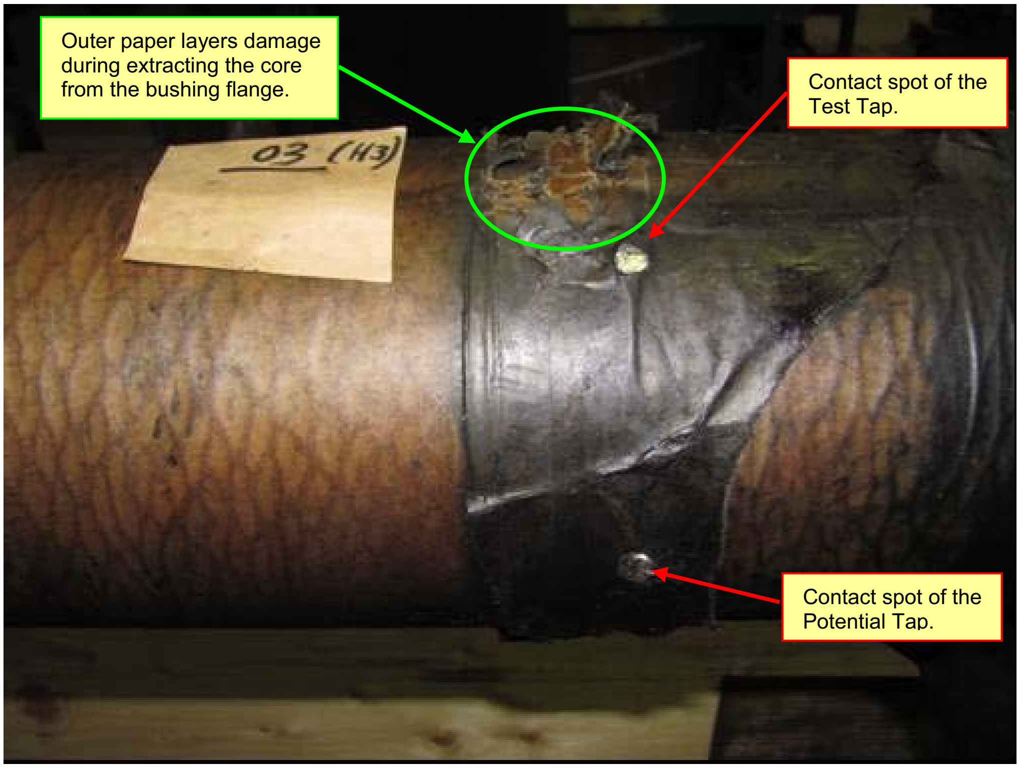
Picture 37: ***H2 bushing***: ***Green arrow***: 1st layer wound on the central copper conductor after the required paper thickness is applied; ***Orange circle***: enlarged region shown on picture 38, with slight "treeing" traces made visible.	***Picture 38:*** ***H2 bushing***: ***Green arrow***: 1st layer; ***Orange circle***: lower part of the 1st layer with slight "treeing" traces on the bottom edge.

3.4 Inspection of Bushing of **Terminal H3** (S. No. 05F9080 – 03)



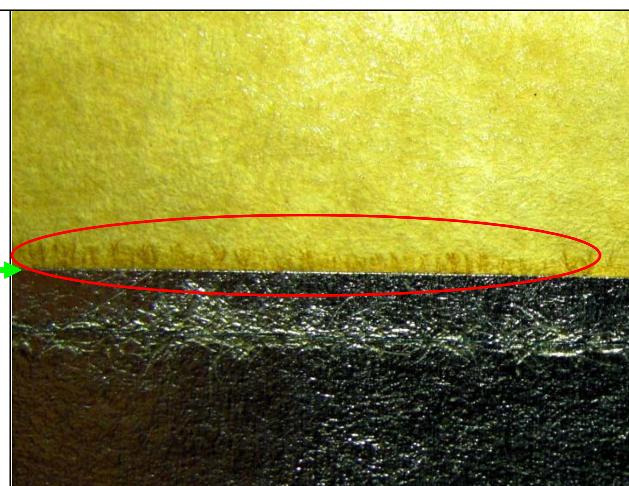
Picture 39: General view of the **H3** bushing showing the bottom part; all layers of the condenser core are complete, only few external paper turns are slightly burnt when the epoxy envelope of the oil side was broken and thrown away due to the mechanical impact caused by the flashover at the bushing H2 on the central phase.

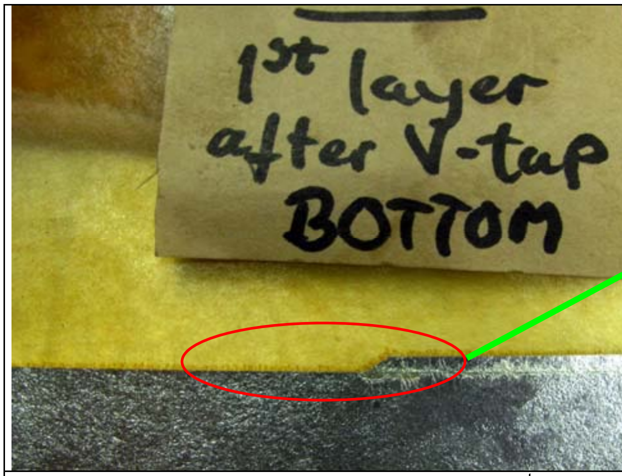
 	
Picture 40: ***H3 bushing***: ***Green arrow***: Central copper conductor; ***Red arrow***: Discharge mark on the central conductor, occurred after explosion of H2 bushing;	***Picture 41:*** ***H3 bushing***: ***Green arrow***: Central copper conductor of bushing H3, upper part.



Picture 42: Bushing **H3:** detail view of the flange region, showing the contact spots of the Test & Potential taps without damage.

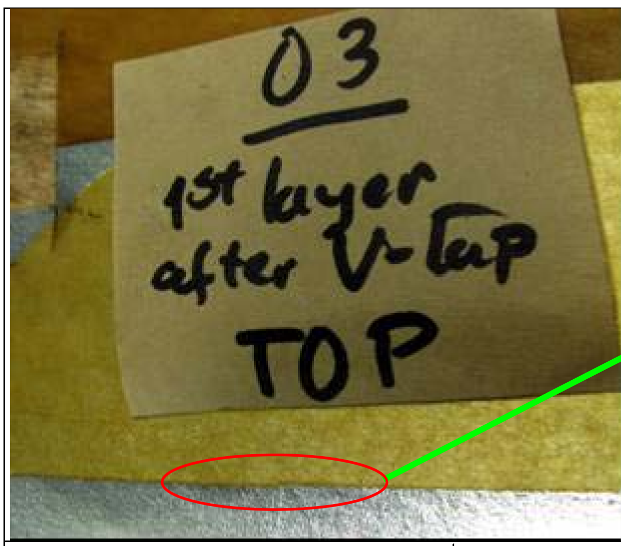
After taken away the grounded layers corresponding to the voltage and ground taps, the first layer below the voltage tap layer showed intense traces at its lower edge, as shown in the pictures below:

	
Picture 43: ***H3 bushing***: : 1st layer beneath the voltage tap layer; ***Red circle***: region enlarged (***Green arrow***) on photo #44, with clear "treeing" traces at the bottom edge of the 1st layer beneath the voltage tap.	***Picture 44:*** ***H3 bushing***: enlarged detail of the 1st layer; ***Red circle***: detail of "treeing" traces clearly shown at the lower edge of the layer.

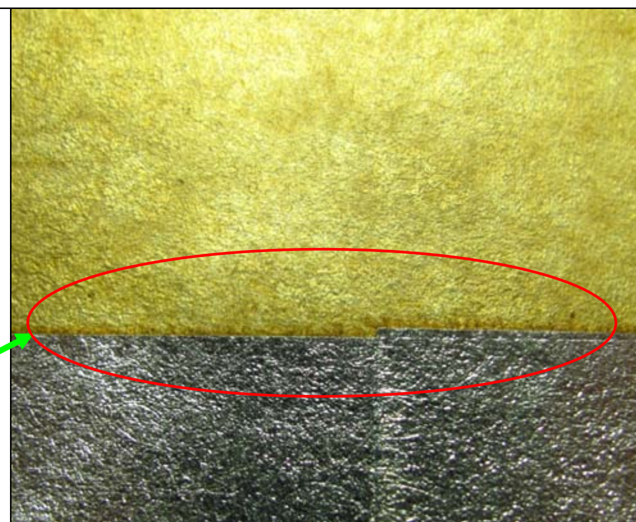


Picture 45: ***H3 bushing***: further detail of the 1st layer beneath the voltage tap layer:;
Red circle: region enlarged on the photo #46 (***Green arrow***) with clear "treeing" traces at the bottom edge of the 1st layer beneath the voltage tap.

Picture 46: ***H3 bushing***: detail view of the layer beneath the voltage tap:
Red circle: detail of "treeing" traces clearly shown at the lower edge of the layer.

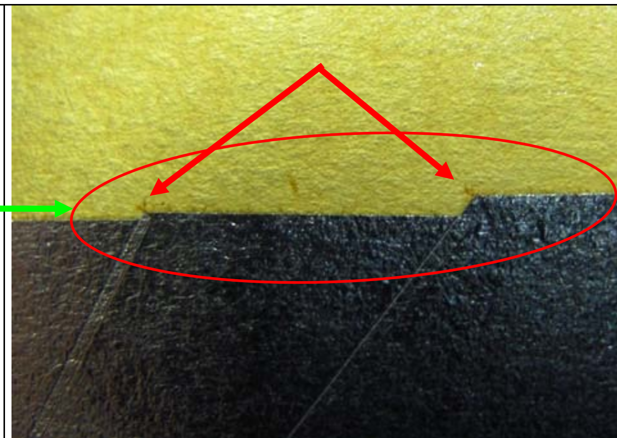


Picture 47: ***H3 bushing***: detail of the 1st layer beneath the voltage tap layer, upper edge of the upper foil:
Red circle: region enlarged on photo #48 (***Green arrow***)
These "treeing" traces are lighter than those at the bottom edge of the bottom layer beneath the voltage tap.

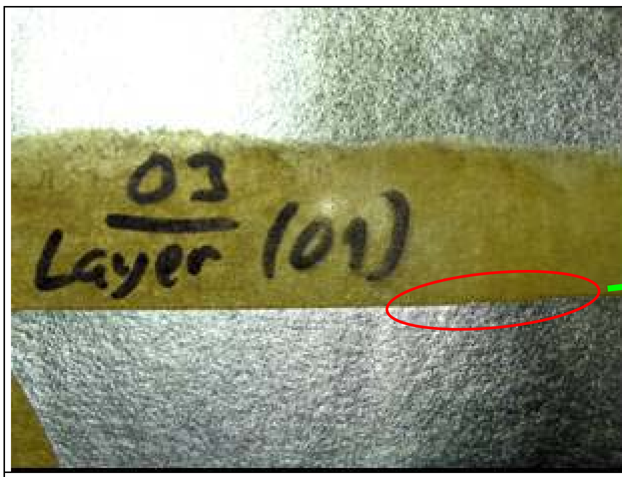


Picture 48: ***H3 bushing***: detail view of the upper edge of the upper foil of the layer beneath the voltage tap:
Red circle: detail clearly shows "treeing" traces at the upper edge of the upper foil. These are lighter than discharge traces on bottom edge of bottom foil.

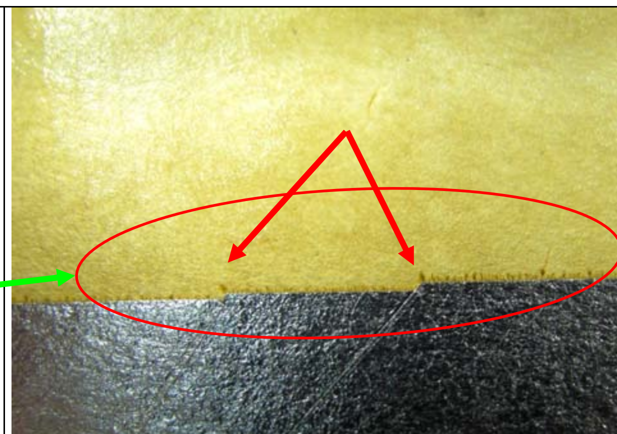
Picture 49: ***H3 bushing***: detail of an intermediate layer halfway between the voltage tap layer and the central conductor, bottom edge of the lower foil:
Red circle: region enlarged on photo #50 (***Green arrow***) lighter "treeing" traces observed than traces observed on the layer just beneath the voltage tap.



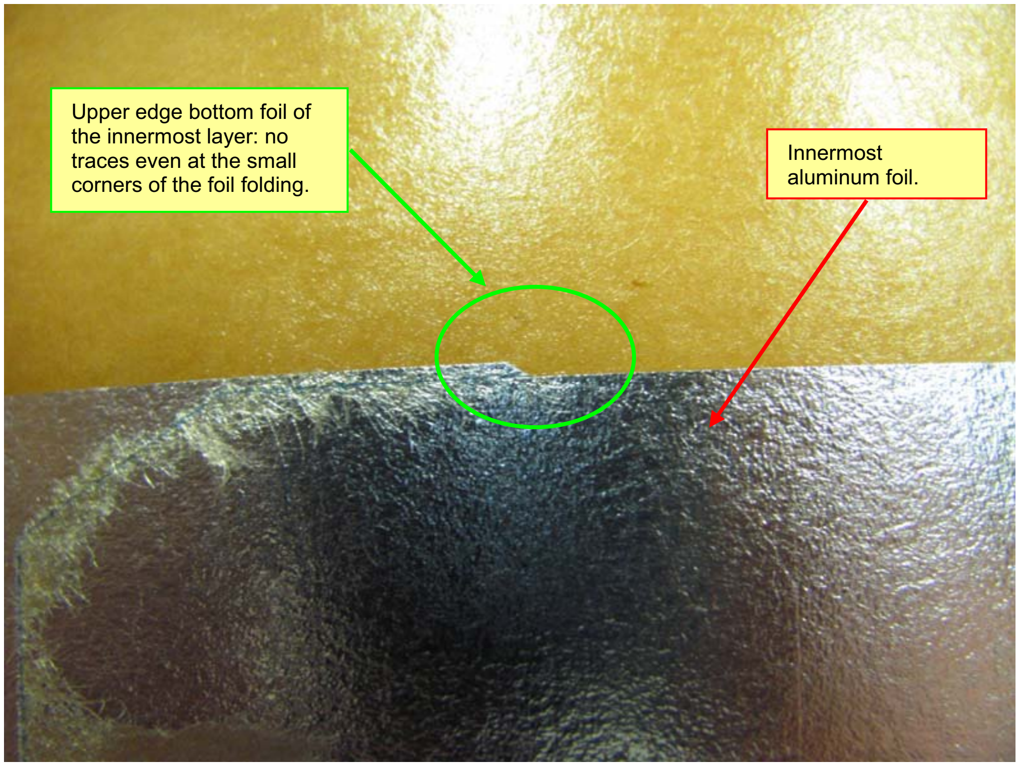
Picture 50: ***H3 bushing***: detail view of the bottom edge of the lower foil of the intermediate layer
Red circle: detail of the clear but slighter "treeing" traces, where it is visible that the traces are more intense at the corners created by small folding of the aluminum foils (***red arrows***).



Picture 51: ***H3 bushing***: detail of the innermost layer (1st layer over the central conductor), bottom edge of the lower foil:
Red circle: region enlarged on photo # 52 (***Green arrow***) with clearly visible "treeing" traces.



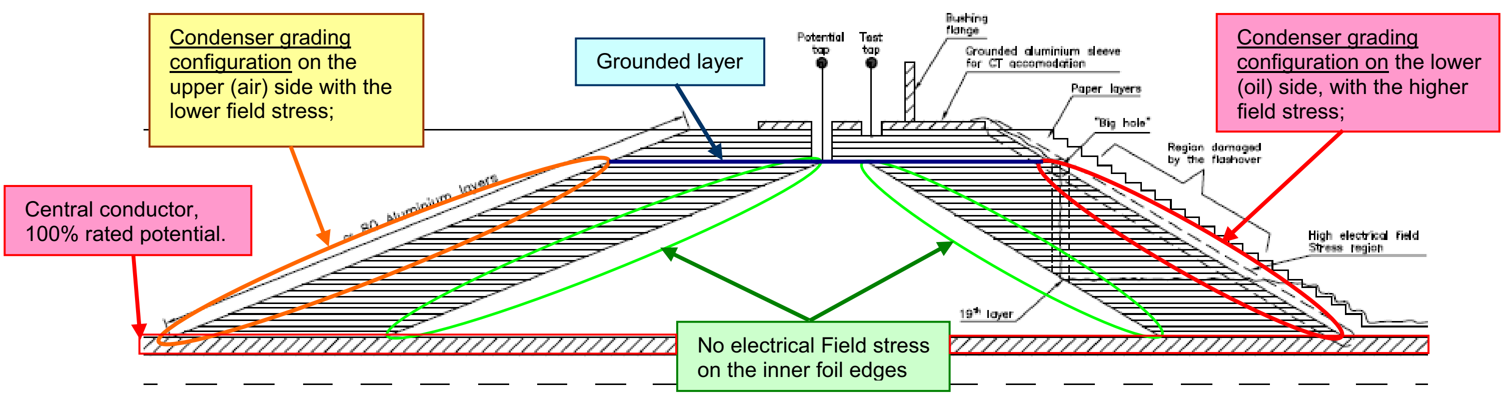
Picture 52: ***H3 bushing***: detail view of the bottom edge of the lower foil of the innermost layer:
Red circle: detail of the clear but slighter traces, where it is visible that the "treeing" traces are more intense at the corners created by small folding of the aluminum foils (***red arrows***).



Picture 53: Bushing **H3:** detail view of the innermost aluminum foil (1st layer over the central conductor),.
No ”treeing” traces are visible at the internal (upper edge) of the lower foil.

5. Most Probable Failure Path

A drawing with the schematic sketch of the structure of the condenser core of the investigated bushing is shown on the picture indicated on the ***Attachment 1***.

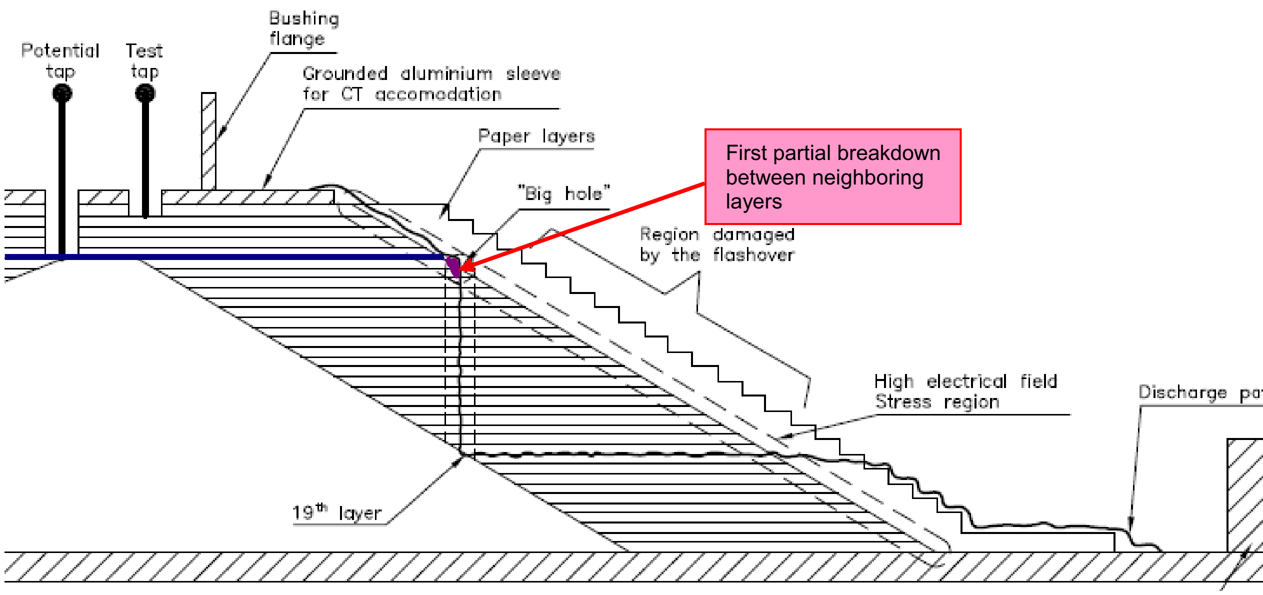


Sketch 2. View of the longitudinal half section of the condenser core, showing the main elements and detail of the regions with capacitive grading.

In the following items, the most probable failure path is explained:

5.1 The "treeing" on the lower edge of the layers on the bottom part (oil side of the bushing) of the condenser core is more intense than on the upper part (air side of the bushing).

Remark: The "treeing" activity within the insulation will not sustain initial partial discharges at a level sufficient to generate overall bushing failure.



Sketch 3. The highest electrical field stress at the edge of each layer is radially inward (e.g. in direction of the next inner layer) Therefore, the partial breakdown between two layers tends to grow inwards.

5.2 As the "treeing" continues to extend along the paper fibers, the insulation system is weakened resulting in a distorted electrical grading at the edge of the aluminum foils.

5.3 Sporadic system overvoltages imposed on the weakened insulation result on partial discharges (PD's) of substantial energy to create the first puncture between layers, establishing a carbonized (e.g. semi-conductive) path between layers.

5.4 Consequently at this point the PD's melt the aluminum foil underneath and begin to damage the paper layers underneath. As soon the overvoltage stops, the partial discharge also extinguishes.

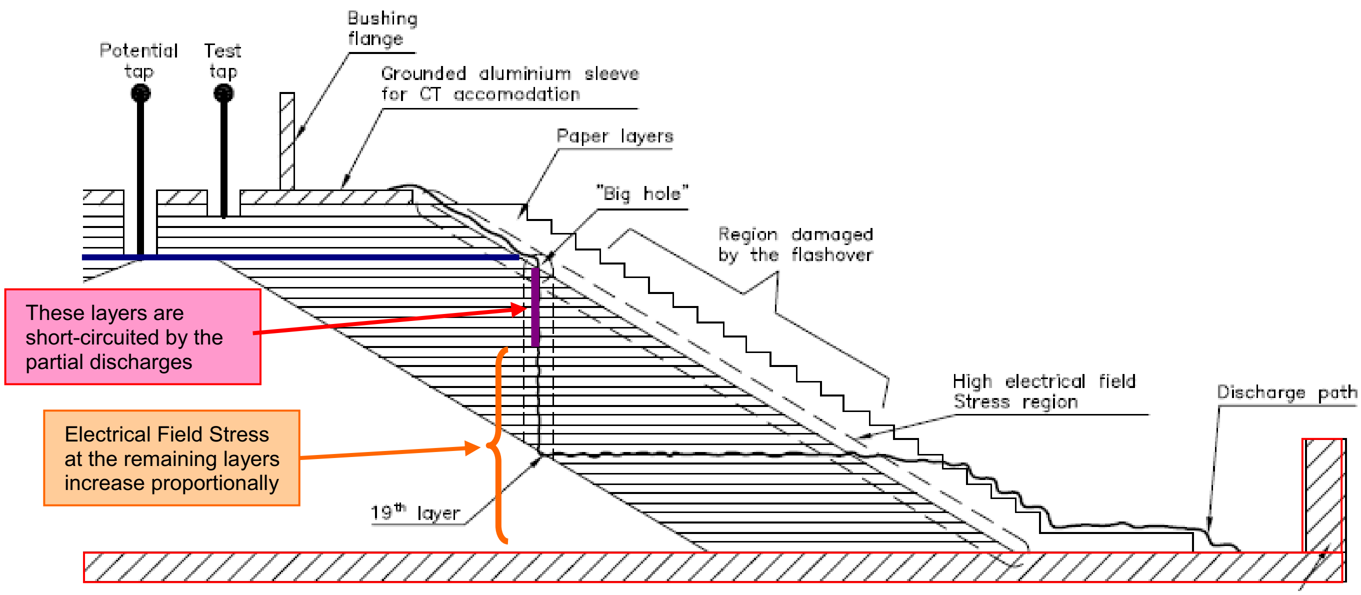
5.5 When further overvoltages will occur, the gassing in the oil and byproducts from the paper degradation produces the weakening of the insulation of the remaining paper layers underneath.

5.6 When the remaining paper layers cannot withstand the electrical field stress to the next aluminum layer, a further puncture will occur, enlarging the semi-conductive path in direction of the central conductor.

5.7 Consequently, each following normal overvoltage will cause the repetition of the phenomenon between the second and third layer, then between the third and forth layer and so layer-to-layer breakdown continues inwards.

Note: The stress between layers increases in the same proportion when the carbonized path progresses and successive layers are short circuited.

5.8 After a certain number of layers are short circuited by the mentioned carbonized path, PD's initiated by an overvoltage will no longer extinguish. This is because the voltage stress between layers is raised to the point where normal operating voltage maintains the PD activity.

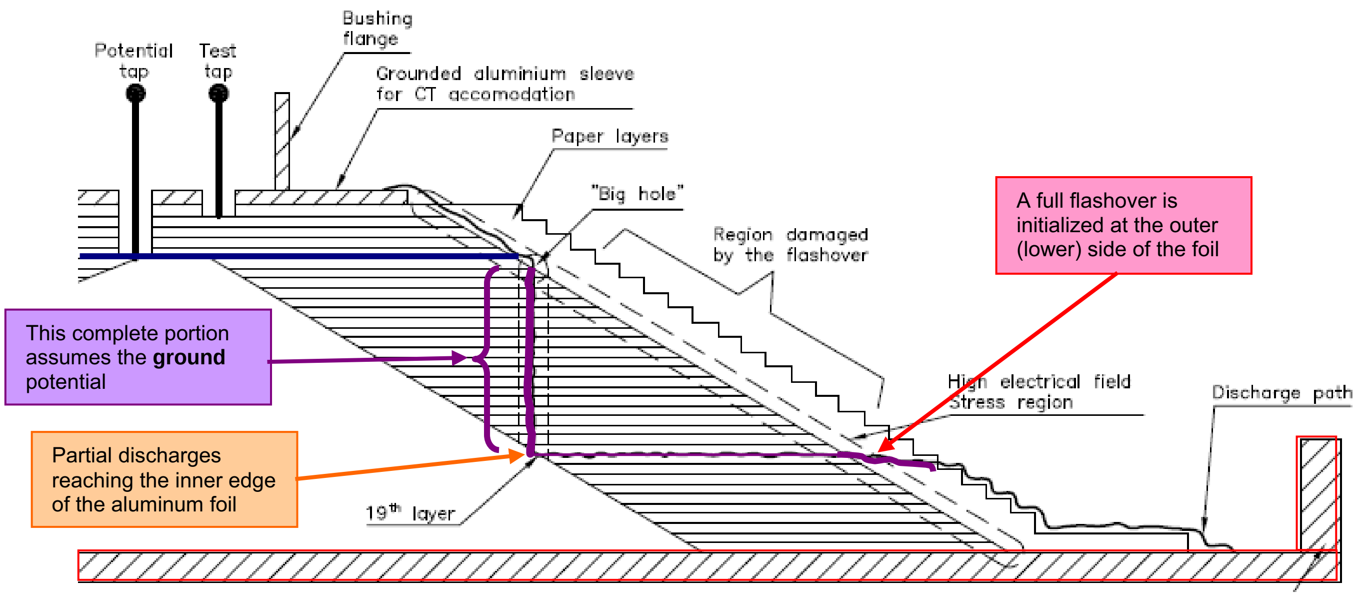


Sketch 4. Once established, the partial discharges do not extinguish and continuously grow inwards.

5.9 Now, having the PD activity no more extinguished, the progression of the phenomenon of short circuiting further layers goes faster and faster, also bringing the ground potential closer to the 100% potential of the central conductor.

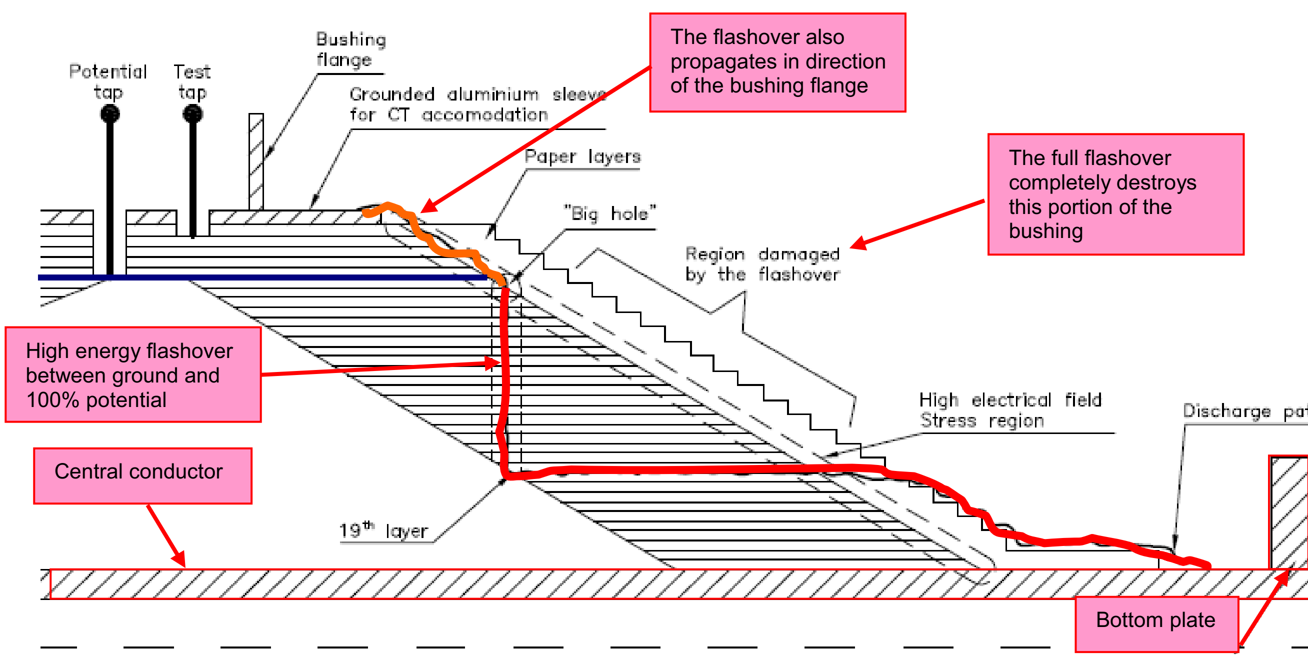
5.10 The progression of the partial discharge activity continues inwards and stops when the inner edge of the aluminum layers is touched. At this point a critical condition is reached at the outer (bottom) edge of the foil at the lower part of the bushing, where the field stress gets so high that a pre-breakdown in the oil is generated.

5.11 This pre-breakdown activity rapidly escalates to a discharge toward the central conductor, which is at the 100% potential.



Sketch 5. When the partial discharges reach the inner edge of one foil, there is no further radial breakdown between layers which can be established. But the electrical field stress at the lower edge on the outer side of this foil is now extremely high, initializing a full flashover to the central conductor.

5.12 Finally, the discharge expands until it reaches the grounded flange. This establishes a high energy flashover between the central conductor and the bushing flange. The pathway travels axially through the 19th layer, rupturing the external paper layers and causing the explosion of the oil side of the bushing. This final high energy discharge results in external electrical failure.



Sketch 6. The flashover reaches the central conductor and establishes the high energy discharge between 100% potential and ground. An explosive thermal oil expansion occurs, making the lower part (oil side) of the bushing to rupture.

6. Observations

During the tear down of the failed bushing of the middle phase of the Unit #22 transformer, "treeing" traces were detected on the upper edges of the foils above the flange region of the condenser core. Only the innermost layers of the lower part (oil side) could be inspected, as from the 19th layer outwards the condenser core was mostly destroyed by the high energy flashover.

The second bushing which was inspected, belonging to the "C" phase showed the same type of "treeing" traces at the upper part (air side) of the bushing. In addition, the lower portion of the condenser core showed the same treeing marks. It was noted that these were clearly more intense than those within the upper portion of "C" phase.

This is explainable as, by construction, the electrical field stress at the lower part of the condenser core (oil side of the bushing) is significantly higher than the field stress at the upper part of the condenser core (air side of the bushing).

In contrast, at the edge of the inner side of the foils (refer to ***Sketch 2***) no "treeing" marks were detected at all. This is consistent with the fact that there is no significant electrical stress occurring at the internal edges of the foils.

These observations suggest that the formation of the "treeing" traces is related to the presence of an electric field.

The proposed path for the failure as indicated in section 5 is consistent with the findings at the failed bushing. That is, the presented failure path matches with the findings observed in the field (refer to Technical Report ST 19/01dd. January 17, 2011) as well as those verified during the bushing tear-down, as reported herewith.

These facts suggest that most probably some abnormal condition related to the insulating system of the condenser core, involving the oil as well as the paper layers was a contributing factor to the bushing failure.

The investigation about the causes of the mentioned abnormality in the bushing insulating system is still ongoing and will be reported separately. This may give some insight about the ultimate root cause of this phenomenon.

As the root cause analysis is only at an early stage, it is not yet known what factor(s) have created the abnormality in the bushing that led to its electrical failure. Complete investigation may require specialized research such as additional (non-standardized) oil testing, search for contaminants in other bushings removed from service, etc.

Since this is first and only failure reported for this type of TRENCH bushings, it is not yet clear what tasks will be required to fully explain failure cause.

Overall failure investigation will take several months and will certainly require more data from in-service bushings than what is available from the spare bushing installed in the MT 32 as well as those bushings installed on bus MT 22.

7. Various Failure Hypotheses

Several possible causes of failure have been considered during this investigation. This section describes the various possibilities (and any resolution that has occurred as of the issuance date of this report – 11March 2011.)

A) External system event

As a result of a ruptured MPT 21 transformer tank, there was an oil fire and damage to the overhead buswork. An external system event was considered as a possible failure cause. This was due to arcing along broken buswork, reports of possible flashes in the adjacent switchyard and evidence of a post insulator flashover next to the failed transformer phase “B”.

As a result of this investigation, the flashover along the porcelain of the insulating post of the phase “B” 345 kV bus appears to be only a consequence of the fire ball which involved the post. In addition, the possibility was considered that bushing explosion could be initialized solely due to a transmission overvoltage event (i.e. external to the transformer.)

Unfortunately, transient records of system events prior to and during the transformer’s failure are incomplete and a definitive conclusion could not be reached (for example, it was not possible to consider lightning activity and possible transient overvoltages which occurred some days or weeks prior to the transformer failure.) However, the presence of insulation treeing within the MPT 21 bushings probably excludes the possibility of this initial hypothesis.

B) Transformer design and manufacturing

The possibility of a design or manufacturing defect was also considered as a possible failure scenario. This hypothesis was discussed extensively in the initial failure report #ST_19Jan2011 and excluded therein. Briefly summarized, this hypothesis was disproved by DGA data and during inspection of the failed transformer’s core and coils. The two factors were:

1) IPEC monitoring data clearly indicated that active part of the transformer (Core & Coils, together with its insulating system) was completely healthy until 2 ½ hours before flashover at the H2 bushing. This statement is based on DGA results of the on-line gas monitoring device installed on the tank, which periodically analyzed MPT21 transformer oil (every 4 hours).

2) Visual inspection revealed a lack of Core & Coil damage. All physical displacement and fire damage of leads, bushing supports and other ancillary parts within the tank was attributed to the oil surge during tank rupture and consequent fire damage. The physical evidence indicates that transformer #21 itself was not the initiating cause of failure.

C) Abnormality in insulation within bushing’s condenser core

Since the treeing traces were not present at the time of winding or processing of the bushing’s active part, it is reasonable to believe that such traces developed during the number of years that the bushing was in service.

Preliminary laboratory analysis of the paper samples indicates the presence of copper in such traces and did not find indication of charring or partial discharge activity in the area. The copper most likely comes from the centre conductor as there are no other sources of this material inside the bushing.

Considering the above findings, the hypothesis is presented that a reaction may have occurred inside the bushing. Because root cause analysis of the bushing is only at an early stage, it is not yet possible to identify various mechanisms which might have contributed to the insulation abnormality. Overall failure investigation may take several months, and is dependent on access to

the spare bushing installed on unit MT 32 as well as those bushings installed on unit MT 22. Complete understanding of the failure mechanism will certainly require more data from in-service bushings, in addition to that which is available from IPEC units.

D) Bushing Insulation Treeing, followed by PD enhancement from system OV

This hypothesis is being presented based upon observations obtained during the bushing teardown described in report sections above.

All three MPT 21 bushings were taken apart and inspected and all showed the same type of treeing on the edge of foils at the upper part (air side) and lower part (oil side) of the bushings. In areas of higher electrical stress, the treeing was clearly more intense. This suggests that the formation of the traces is related to the presence of an electric field.

It is important to note here that this hypothesis requires interaction between a pre-existing insulation abnormality and a normal, arrester-protected system overvoltage transient. The scenario is based upon the fact that treeing traces observed during bushing teardown do not appear to show signs of partial discharge activity. If such a situation is generally true throughout affected bushings, this would mean that initial treeing activity cannot support partial discharge at operating voltage. Therefore, insulation breakdown would also require an initiating overvoltage event. Therefore, in this hypothesis repeated cases of normal system overvoltage are required to initiate partial discharge at the observed insulation abnormalities.

Root cause analysis of the bushing insulation's abnormality is only at an early stage, and will be reported upon in subsequent report(s). It is not yet known what factor(s) have created the abnormality in the bushing that led to its electrical failure. Since this is first and only failure reported for this type of TRENCH bushings, it is not yet clear what tasks will be required to fully explain failure cause.

8. Monitoring and Replacement Recommendations

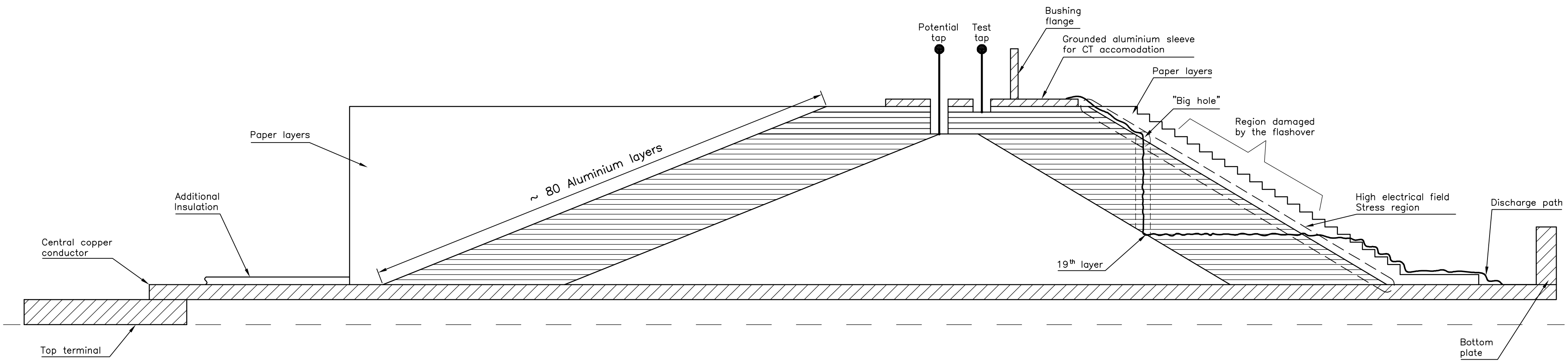
For monitoring and replacement recommendations please see the attached statement from TRENCH.

9. Attachment List

Attachment 1: Schematic structure of the investigated Condenser Bushings

ENTERGY – Indian Point

345kV Bushing



Data 03/02/2011	Liber. –	Modif. –	
Grupo –	–		
Elab. G. Prado Verif. Miethke	–	Denom. 345kV Bushing	Toler. –
Siemens Ltda Transformadores TUSA		Identif. ENTERGY–Indian Point	Escala – CAD
		PA – Des. –	Rev. – Fl. 1/1

1. Equipment Data

Ratings:	Three Phase Generator Step Up Transformer Power Rating: **372/449,6/562 (629) MVA** Cooling: **ONAN/ONAF/ODAF** Frequency: **60 Hz**	
	Rated Voltages:	**HV**: 345 +2x2,5% -2x2,5% kV (DETC) – YN **LV**: 20,3 kV – D
Customer:	**ENTERGY** ENTERGY NUCLEAR NORTHEAST - INDIAN POINT ENERGY NY/USA	
Serial Number	**#4.019.269 (Unit #21)**	

2. Scope

This report contains the major aspects of the inspections, investigations and tests performed after the event on November 07, 2010, when the H2 bushing (phase “B”) installed on the unit #21 exploded, rupturing the weld between cover and tank, making vaporized oil get spilled out as a fire ball.

3. History

Two units were manufactured in 2005; final electrical tests were performed on January 2006. Replacing old units from other manufacturer, these first two units were installed and commissioned at site in 2006:

Unit #21: Serial Number **4.019.269**;

Unit #22: Serial Number **4.019.272**;

An additional unit was manufactured in 2009 as a spare (Serial Number **8.324.845**), final acceptance tests of this unit performed in May 2009.

The dimensions, arrangement of the cooling system were designed to match within the existing space and be suitable to be connected to the existing LV bus duct.

Two units operate in parallel solidly connected both on the HV and LV side. On the LV side via bus duct which is connected to the single power generator; on the HV side by the common 345 kV bus protected by a single surge arrester per phase, from which point on a regular transmission line transports the energy to the neighbored Substation of CONED, crossing the street.

On November, 7th 2010 at 6:39 pm the unit #21 failed due to an internal flashover at the oil side of the H2 bushing.

This caused an explosion which ruptured the weld between the cover and the transformer tank in front of the H2 bushing. The oil was expelled like a fireball which touched the radiator bank, the firewall, as well as the HV surge arrestor and post insulator of the central phase (“B” phase).

The event triggered the intervention of the fire brigade, which successfully extinguished the fire in few minutes. During this operation a second explosion occurred, minutes after the first, when the transformer was completely off circuit (disconnected by the 345 kV circuit breaker and disconnect switches and the generator shut down at the LV side). This second explosion was interpreted as

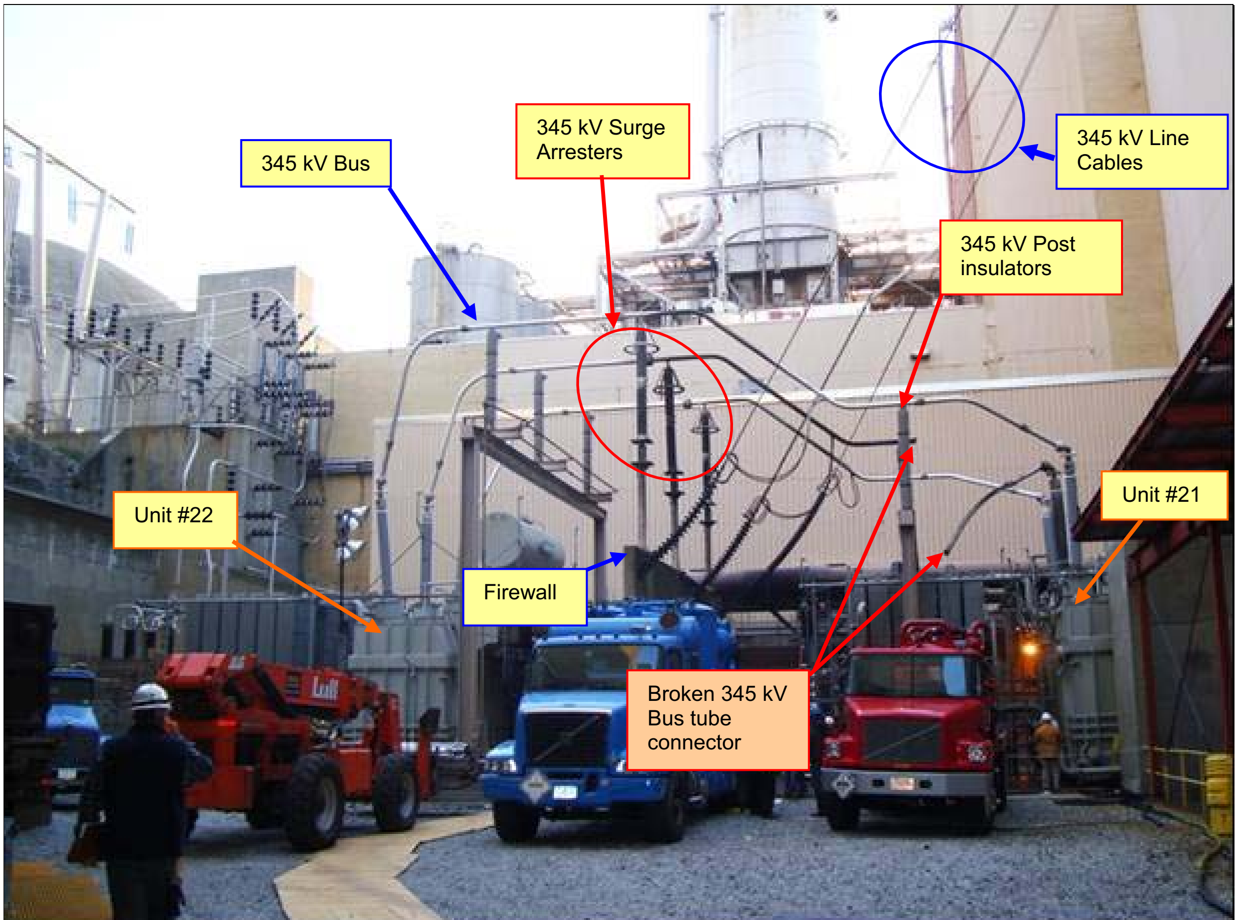
an ignition of the oil mist formed inside the tank, triggered by the remaining heat of the former explosion.

The oil was completely spilled out of the tank due to the rupture of the valves of the cooling system caused by the mechanical impact of the explosion.

The sister unit #22 was not touched by this event, as it is separated from the damaged unit by a firewall.

4. Analysis of the Sequence of Events

The ***Picture 1*** was taken on November 08, 2010, one day after the event and shows the main components of interest for the analysis of the event occurred with Unit #21.



Picture 1: General view of the transformer yard showing the main involved components.

The analysis of the sequence of events (see ***Attachment 1***) showed that the circuit breaker on the 345 kV opened very quickly after ~3 cycles, triggered by the Buchholz relay trip of Unit #21.
Both units #21 & #22 are solidly connected at the LV side to the main generator of nuclear power plant. According to information of ENTERGY, the excitation of the generator was cut down immediately upon receiving the trip signal from Unit #21.

Considering that the excitation of the main generator takes approximately one second to be reduced to less than 20% of the rated level, during this period of time the HV terminals of both units remained with high potential. This is valid even for the unit #21, as its windings were not damaged by the event as confirmed later.

Thus, the voltage on terminal H2 sustained the arc on the phase "B" bushing of unit #21, which vaporized the surrounding oil and expelled it like a fire ball through the ruptured weld of the tank cover.

The fire involved the radiator bank, the post insulator of the phase "B" installed on a beam over the radiator battery, also hitting the firewall on the top on which the 345 kV surge arresters are installed.

Flashover marks were identified on the post insulator of phase "B". Whether this flashover occurred some time before the event and triggered the failure of the H2 bushing of Unit #21 or this flashover was a result of the ionized air of the fireball could not be clarified until now. Eventually the dissection of the failed bushing may bring additional evidences about this question.

It has to be considered that the Units #21 & #22 are equipped with an on-line monitoring device (TRUE-GAS) which performs an on-line oil analysis for dissolved gases (DGA) every 4 hours. This on-line gas monitor showed perfectly stable values until ~2.5 hours before the event.
(see ***Attachment 2***).

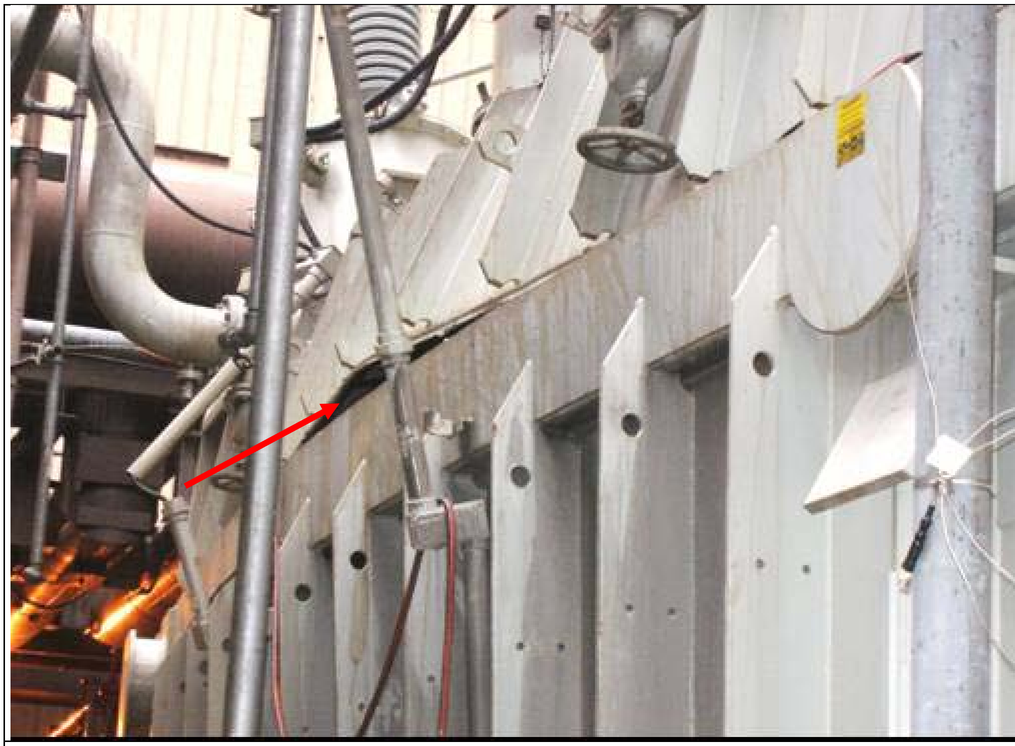
The records of the on-line monitoring device verify that no internal event inside the transformer was detectable until close to the failure occurrence.

On the other hand, it has to be considered that the bushing oil is completely separated from the transformer oil. The oil space inside the bushing is a sealed container, where oil volume expansion due to heat is absorbed by a gas space situated in the bushing head. Thus, the on-line gas monitor of the transformer oil cannot detect any gas evolution inside the bushing oil. This means, any pre-damage ongoing in the insulating system of the bushing cannot be detected through the monitoring of the transformer oil.

5. Inspection of the damaged Unit #21

5.1 Inspection on the External Parts

The flashover at the oil side of the H2 bushing caused an explosive pressure wave inside the tank which ruptured the weld between cover and tank in front of the middle phase (***Picture 2 & 8***).
Other consequential damages (caused by the tank wall at the HV side bowing out) were found at several points of the tank reinforcements (***Picture 5 & 6***).
The shock wave throughout the tank ruptured also the bottom main valves of the cooling system. This caused complete drainage of the oil, which continued to spill out until reaching the level of these valves (***Picture 3 & 4***).
Also the porcelain of the neutral bushing installed at the tank wall was broken by the shock wave (***Picture 7***).



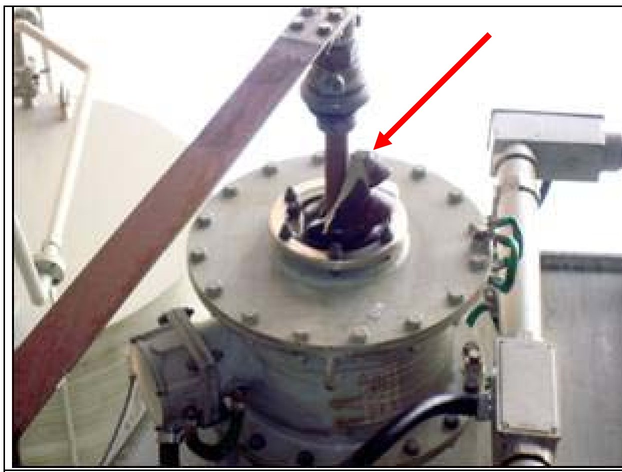
Picture 2: Damaged tank of the Unit #21 after the occurrence:
Red arrow: Ruptured tank & cover weld caused by the shock wave produced by the flashover on the oil side of H2 bushing.

Picture 3: ***Red arrow***: ruptured cooling system 12" valve

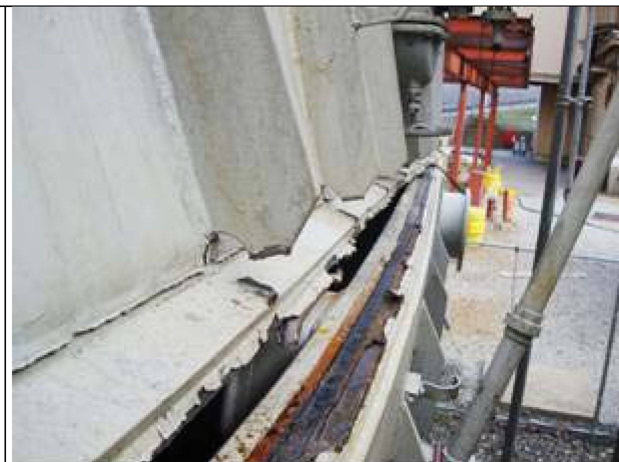
Picture 4: ***Red arrow***: ruptured cooling system 12" valve

Picture 5: **Red arrow**: mechanical stress marks on the corner of the tank frame;

Picture 6: **Red arrow**: mechanical stress marks on the bottom end of the vertical tank reinforcements;

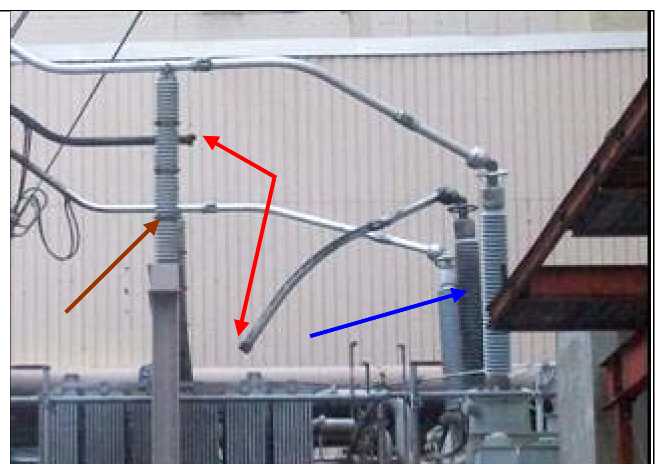


Picture 7: **Arrow**: Neutral bushing (H0) broken porcelain;

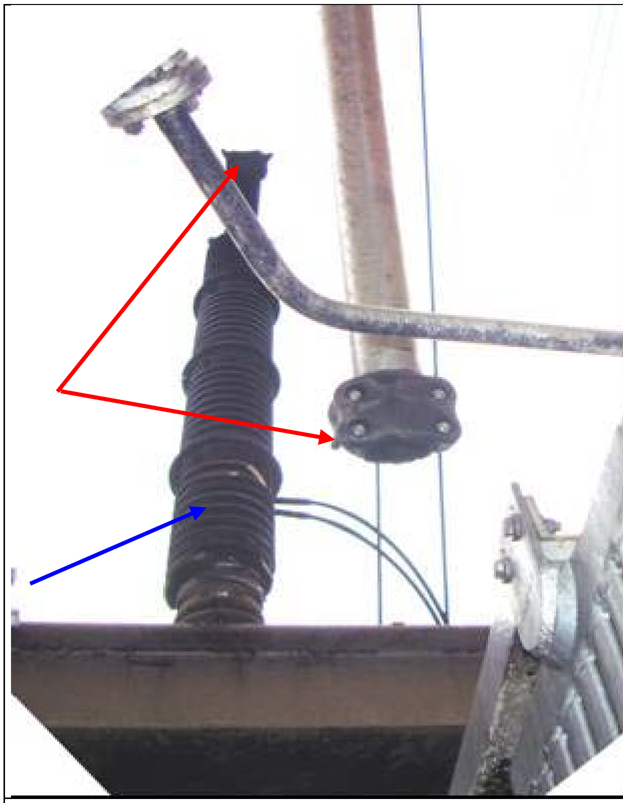


Picture 8: Detail of the ruptured tank & cover weld;

Picture 9: Radiators and fans were involved by the fire;

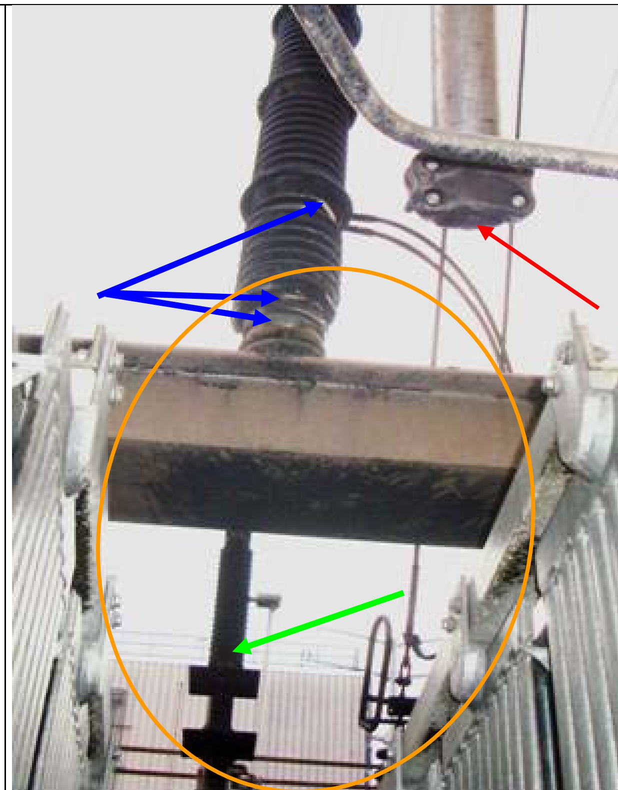


Picture 10: **Red arrows**: 345 kV bus disrupted due to the connector broke apart by the mechanical impact;
Blue arrow: H2 bushing (Phase "B");
Brown arrow: Insulating post for the 345 kV bus;

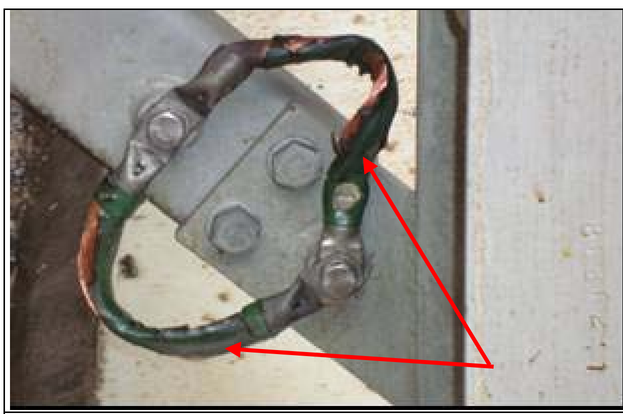


Picture 11:
Red arrows: Showing the parts of the connector which was broken due to the mechanical impact of the shock wave caused by the flashover on the H2 bushing;

Blue arrow: Insulating post for the 345 kV bus;



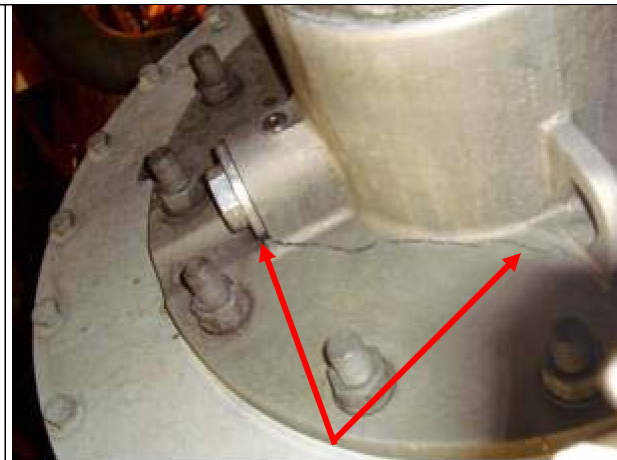
Picture 12: ***Red arrow***: Broken connector of 345 kV bus;
Blue arrows: Damaged porcelain of the insulating post for the 345 kV bus;
Orange circle: Space between the radiator banks in front of the phase "B" bushing, allowing the propagation of the expelled fire ball until the surge arrester installed on the top of the fire wall (***Green arrow***)



Picture 13: ***Red arrows***: The grounding lead insulation was melted by the fire, rather than by a short circuit current to ground: the plastic covering of the grounding strips is melted only at a single side;

Picture 14: ***Red arrows***: The plastic covering of the grounding leads melted away but the copper isn't discolored,. Therefore no heavy fault current to ground circulated during the event through these components.

Picture 15: ***Red arrow***: Damaged top connector of the H2 Bushing (Phase “**B**”)



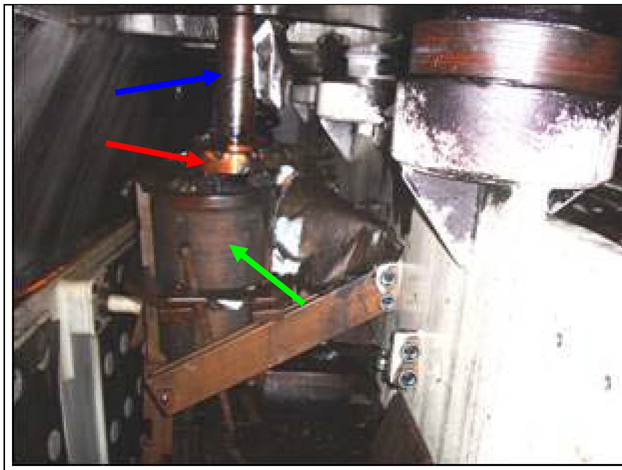
Picture 16: ***Red arrows***: Crack on the flange of the H3 Bushing (Phase “**C**”) caused by the shock wave.

5.2 Internal Inspection: HV Bushings and DETC

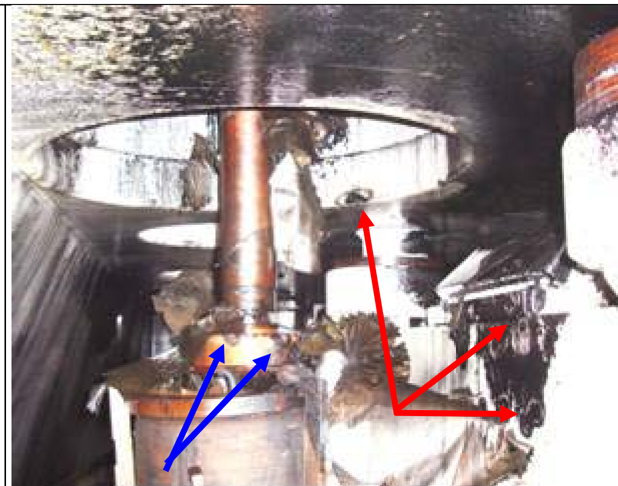
The internal inspection was performed by the Siemens Field Engineer after the atmosphere inside the transformer was thoroughly flushed with dry air. The transformer was released with healthy conditions of Oxygen content and adequate levels of other gases by a gas monitor.

It was confirmed that a flashover occurred inside the H2 bushing. This destroyed completely the bushing’s oil side portion (i.e.between the tank cover and the internal lead connection). Several flashover marks were found at its bottom plate made of copper and also on the nearby grounded parts of the phase “B” (turret and upper core frame) (see ***Pictures 17 & 18***).
The shielding electrode which was installed on the lower end of the bushing was forced downwards by the heavy pressure surge created inside the oil. This was due to the explosive expansion of the gases caused by the flashover inside the bushing and due to the oil being expelled through the tank rupture in vicinity of the H2 bushing (see ***Picture 17 & 18***).

This shielding electrode is installed at the lower end of the bushing to provide electrical shielding to the bottom plate and also to the flexible connection leads bolted to the bottom plate. A specific report was issued on this matter of the shield displacement (see ***Attachment 3 – Technical Report ST15/10***).



Picture 17: ***Red arrow***: Bottom plate of the **H2** Bushing; ***Blue arrow***: remaining insulation its condenser core; ***Green arrow***: Shielding electrode forced downwards;



Picture 18: ***Red arrows***: Flashover marks on the grounded parts around **H2** bushing (on frame and turret); ***Blue arrows***: Arcing marks on the bushing bottom plate;

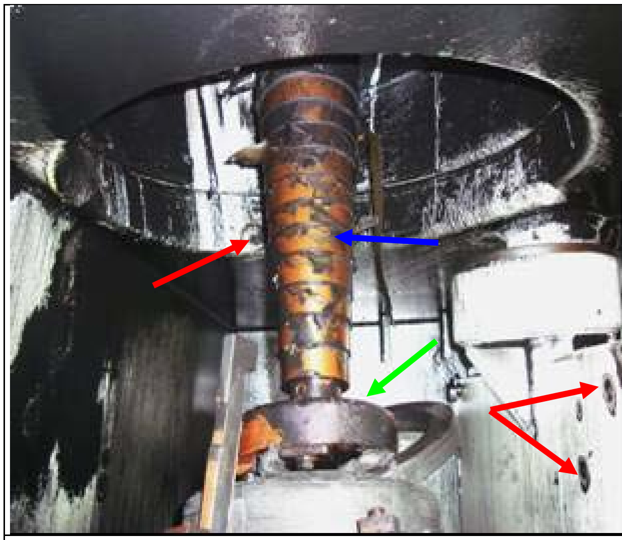
It was observed that also the bushings of the outer phases were heavily damaged. This physical damage appears to be due to ignition of oil, and the electrical discharges occurred after failure of the phase “B” bushing:

- The Phase “C” bushing had its lower insulating shell made of epoxy resin broken; several discharge marks were also visible on the bottom plate and surrounding grounded parts;
- The Phase “A” bushing had its epoxy shell heavily burned by the flashover at phase “B”; several foot points of discharges were also visible on the bottom plate.

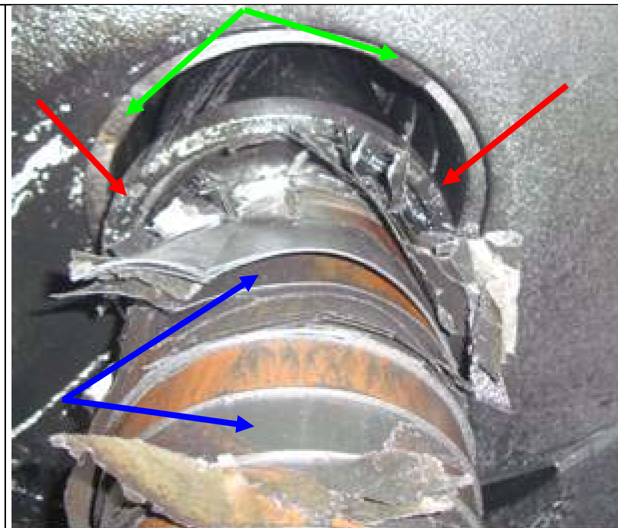
It has to be pointed out that those flashover foot points (arcing marks) on the phases “A” and “C” were caused at the instant when the explosion on phase “B” bushing occurred. This created a shock wave followed by ionized gases. When this gas bubble hit the outer phases, further electrical flashovers occurred.

As the windings of the Unit #21 were intact even after the H2 bushing failed, the HV bushings of all three phases still presented a high voltage potential. This is because the main generator had its excitation shut down, but the magnetic circuit maintained its output voltage for a period of approximately one second (~60 cycles).

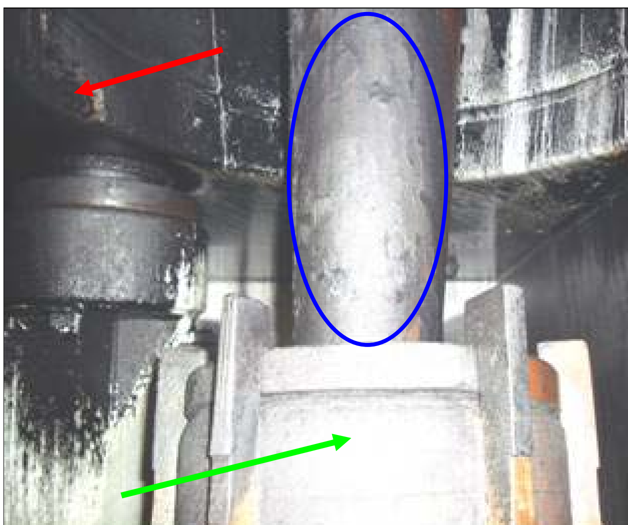
Thus, the sustained potential on all three HV bushings was sufficient to create the subsequent flashover events on all three phases.



Picture 19: **H3** (Phase "**C**") **H3** Bushing:
Red arrows: Flashover marks on grounded parts;
Blue arrow: Condenser core without its epoxy shell;
Green arrow: Shielding electrode dropped downwards;



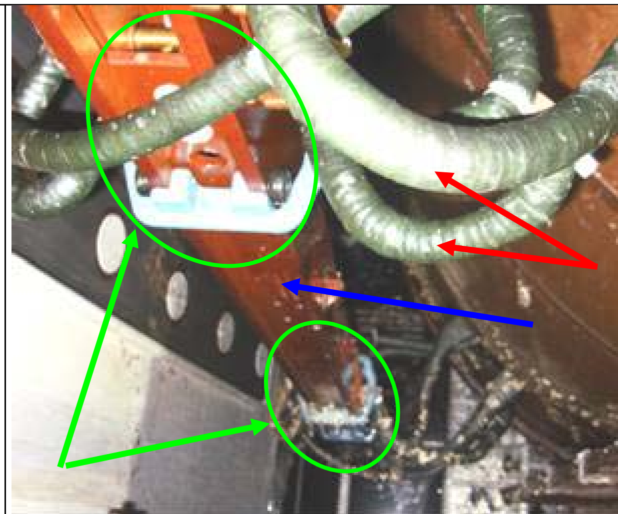
Picture 20: ***Red arrows***: Flashover marks on the grounded parts of the **H3** bushing;
Blue arrows: insulating layers of the condenser body;
Green arrows: Supporting spacers for the bushing CT's.



Picture 21: **H1** (Phase "**A**") **H1** Bushing:
Red arrow: Flashover marks on grounded parts (turret);
Blue circle: Epoxy shell at the oil side heavily burned;
Green arrow: Shielding electrode still in place;

Picture 22: **H1** (Phase "A") **H1** Bushing:
Red arrows: Flashover marks on the grounded parts of the **H1** bushing turret;
Blue arrow: Inner part of the phase "A" turret;

Picture 23: **DETC on HV winding**:
Red arrow: HV neutral point outlead connection without any damage, flashover or burning marks;
Blue arrow: Slider of the DETC didn't show any damage;
Green circle: The contact group of the DETC didn't show any damage or displacement;



Picture 24: **DETC on HV winding**:
Green circles: Both contact groups of the DETC didn't show any damage or displacement;
Blue arrow: Slider of the DETC didn't show any damage;
Red arrows: HV tap outleads for the DETC;

5.3 Internal Inspection: HV Windings

During the internal inspection only the upper part of the HV winding was accessible.

Even so, it could be verified that the HV windings of all three phases did not show any damage as a result of the bushing failure. This included absence of any flashover mark or any distortion caused by heavy short circuit currents.

This situation confirms adequacy of the transformer's design, according to the calculation of the short circuit currents. These circulating currents passed through the several parts of the involved circuit during the heavy flashover event on the phase "B" and also some consequential flashover occurrences at the phases "A" and "C".

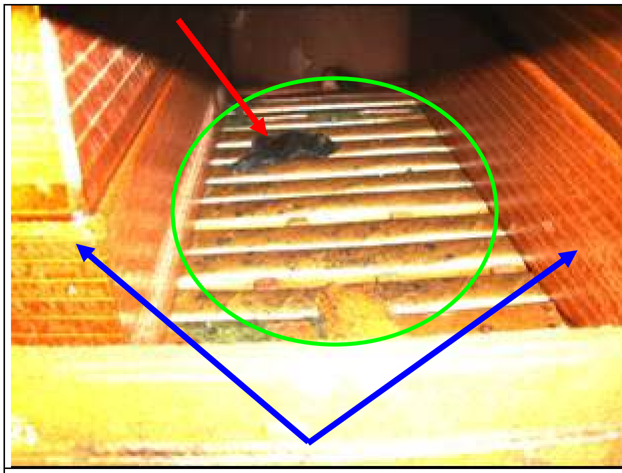
The short circuit calculation (see ***Attachment 4***) performed by the ENTERGY specialist showed, as expected, that the main short circuit contribution during the first ~4 cycles of the event came from the 345 kV network (~20kA). This flow was from the network through the damaged bushing to ground. In contrast, the contribution from the main generator flowing through the windings of both transformers (as they are solidly paralleled on the LV side) was only 10% of this value (~2 kA). It was restricted by the sub-transient impedance of the main generator, in series with the impedance of the transformers.

After the 345kV circuit breaker cleared the 345 kV network from the power plant, the high potential at the HV bushings of all three phases was sustained only by the remaining magnetization of the main generator, as already mentioned in the foregoing item.

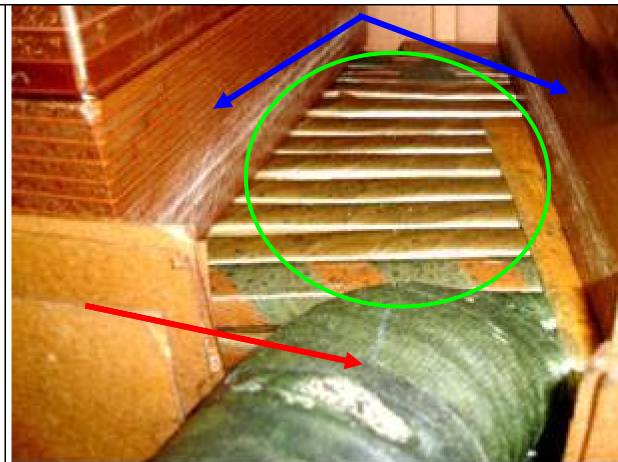
This situation caused several flashover events between the bushing bottom plate and the grounded parts, as the upper part of the tank was filled with ionized gas generated by the flashover, as explained under ***item 5.2***.

These secondary flashover events extinguished only when the voltage supplied by the generator dropped to less than 20% of its rated value, which most probably occurred approximately one second (~60 cycles) from the main event on the H2 bushing.

The pictures on the following page show the parts of the windings which could be accessed.

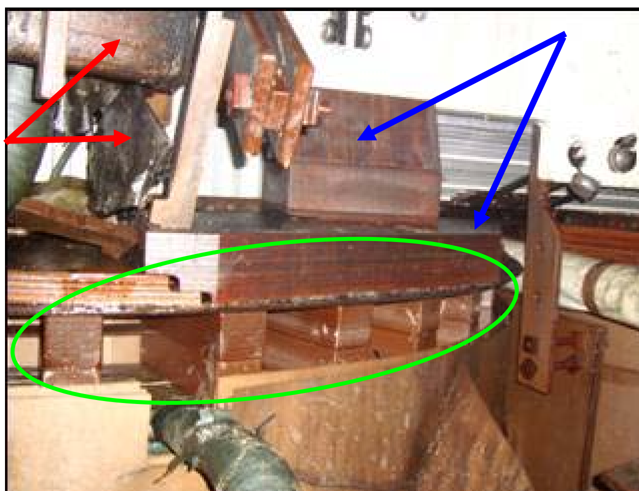


Picture 25: Top of the HV winding:
Red arrow: Debris of burned paper coming from the bushing flashover;
Blue arrow: Pressboard spacers on the top of the HV winding;
Green circle: Showing carbonized debris resulting from the flashover; no bending of the HV conductors was detected, demonstrating that no remarkable short circuit forces occurred during the flashover event;

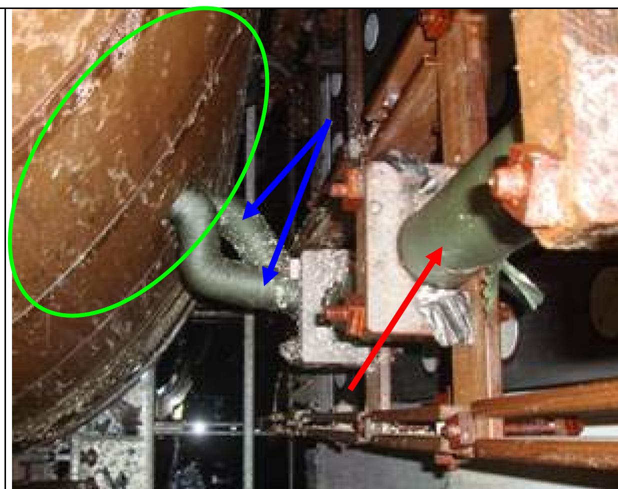


Picture 26: Top of the HV winding:
Green circles: ; No bending of the HV winding conductors was detected, demonstrating that no remarkable short circuit forces occurred during the flashover event;
Blue arrow: Pressboard spacers on the top of the HV winding;
Red arrow: HV winding outlead on the uppermost disk connecting to the neutral point (H0 Terminal);

Further pictures of the surroundings of the windings:



Picture 27: Top of the HV winding Phase “B”:
Red arrow: Shielding electrode of the H2 bushing as well as some paper debris of burned paper coming from the bushing flashover;
Blue arrows: Winding pressing elements showing no displacement or misalignment;
Green circle: Pressboard spacers right in place on the top of the HV winding, no displacement or misalignment was detected;



Picture 28: External part of the HV winding:
Green circle: Pressboard cylinder involving the HV winding; no damage was observed;
Blue arrows: Outleads from each half (upper and lower part) of the HV winding;
Red arrow: HV winding central outlead connecting to the HV phase terminal;

5.4 Further Inspections: HV Bushings, 345 kV Bus, Insulator Post of 345 kV Bus

After the dismantling from the damaged Unit #21, the HV bushings were inspected; the relevant pictures oft this inspection are included in the ***Attachment 5***.

Also the insulator post which supports the 345 kV bus of phase "B" was inspected. This is because clear flashover marks were detected both on the porcelain body as well as on the fixing elements of the top and of the bottom of the insulator. For this inspection the relevant pictures are included in the mentioned ***Attachment 6***.

The connector which joins both sections of the 345 kV bus of phase "B" was broken by the mechanical impact of the shock wave caused by the flashover at the H2 bushing. This separated the bus connector of phase "B".

The inspection of the broken connector clearly shows that the H2 bushing explosion caused mechanical shock which ruptured the connector. Even after the bushing explosion there was a significant voltage potential present causing several flashover events between the pieces of the connector as they separated.

All relevant pictures of this inspection are included in the mentioned ***Attachment 6***.

6. Preliminary Observations as of 19Jan 2011

The first output of the investigation and analysis of the evidences related to the failure event. This clearly indicated that the active part of the transformer (Core & Coils, together with its insulating system) was completely healthy until 2 ½ hours before the flashover at the H2 bushing. This statement is based on the DGA results of the on-line gas monitoring device installed on the tank analyzing periodically (every 4 hours) the transformer oil. In addition, the lack of Core & Coil damage indicates that transformer #21 itself was not the initiating cause.

At the time of this inspection of the destroyed transformer, it was not clear whether the explosion of the H2 bushing was caused by an external event or due to deterioration of the bushing's insulation. Subsequent teardown and inspection of the failed bushing showed failure cause to be related to a deterioration of the insulation system of the bushing's condenser core.

Further information regarding physical inspection and teardown of bushings from failed transformer unit #21 was obtained after generation of this report. This detail is contained in the report entitled "TRENCH Bushing Inspection_Photo Report #ST 2 11".

The flashover along the porcelain of the insulating post of the phase "B" 345 kV bus appears to be only a consequence of the fire ball which involved the post.

7. Attachment List

Attachment 1: Sequence of Events Recorder Report dd. Nov. 08, 2010;
Attachment 2: DGA records of the TRUE GAS on line monitoring device;
Attachment 3: Technical Report – HV Bushing Shielding Electrode;
Attachment 4: Fault Current Calculation;
Attachment 5: Photographical Report – HV Bushings;

Attachment 6: Photographical Report – 345 kV Bus;

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

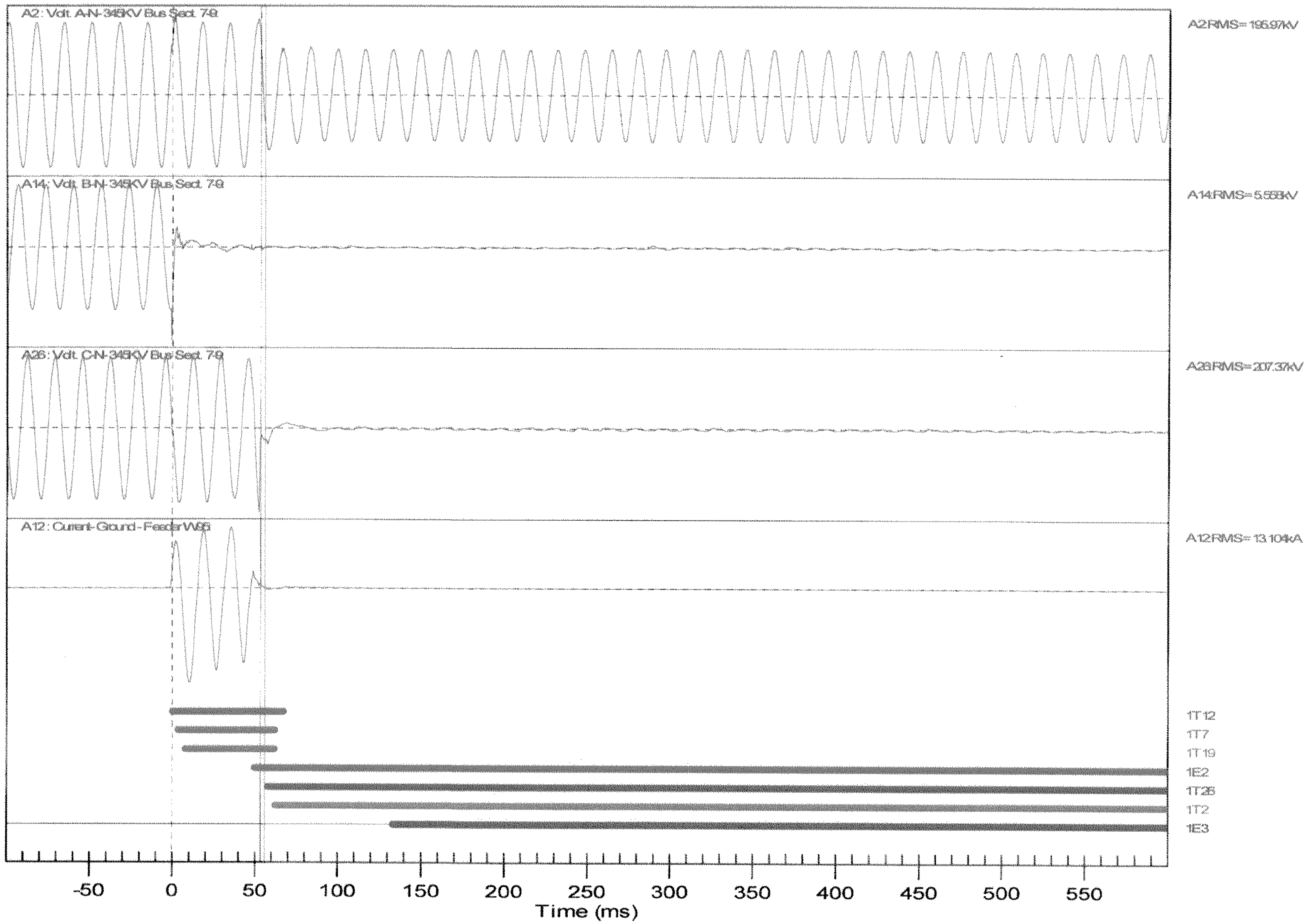
Station Name : Buchanan (SER) Control House #2
Remote ID : 16

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

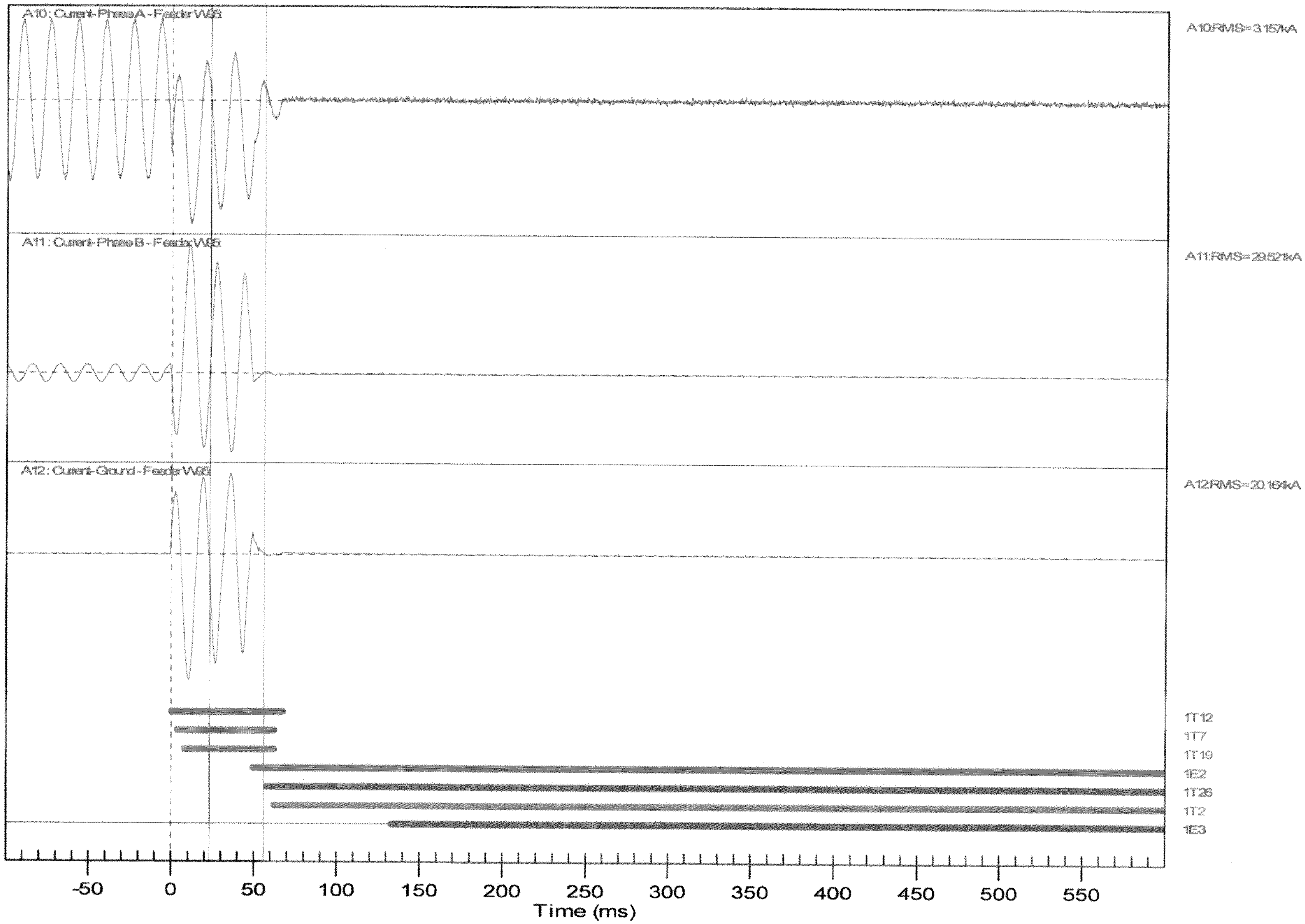
R03F0392 : Buchanan 345kV (DFR)

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



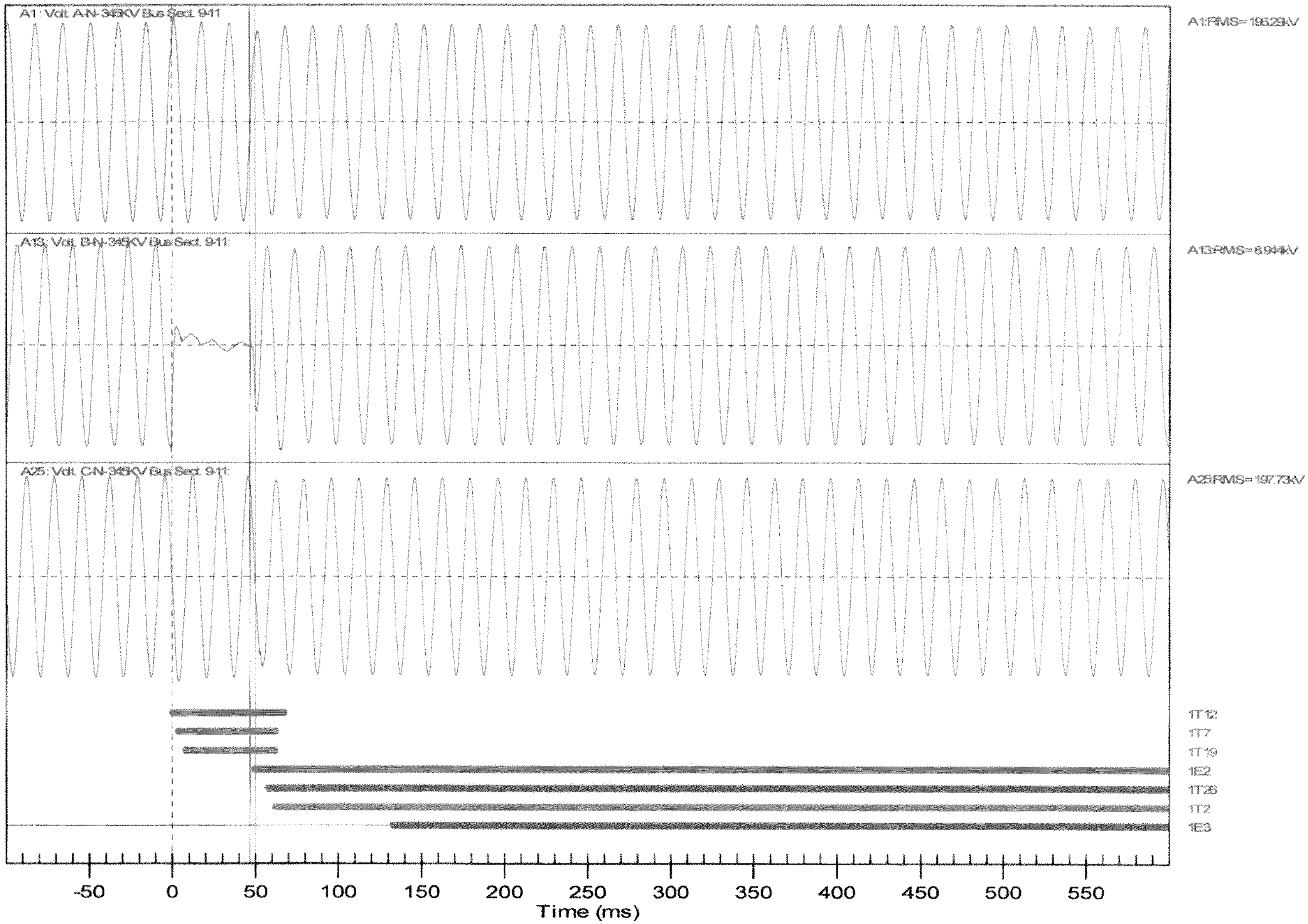
R03F0392 : Buchanan 345kV (DFR)

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



R03F0392 : Buchanan 345kV (DFR)

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



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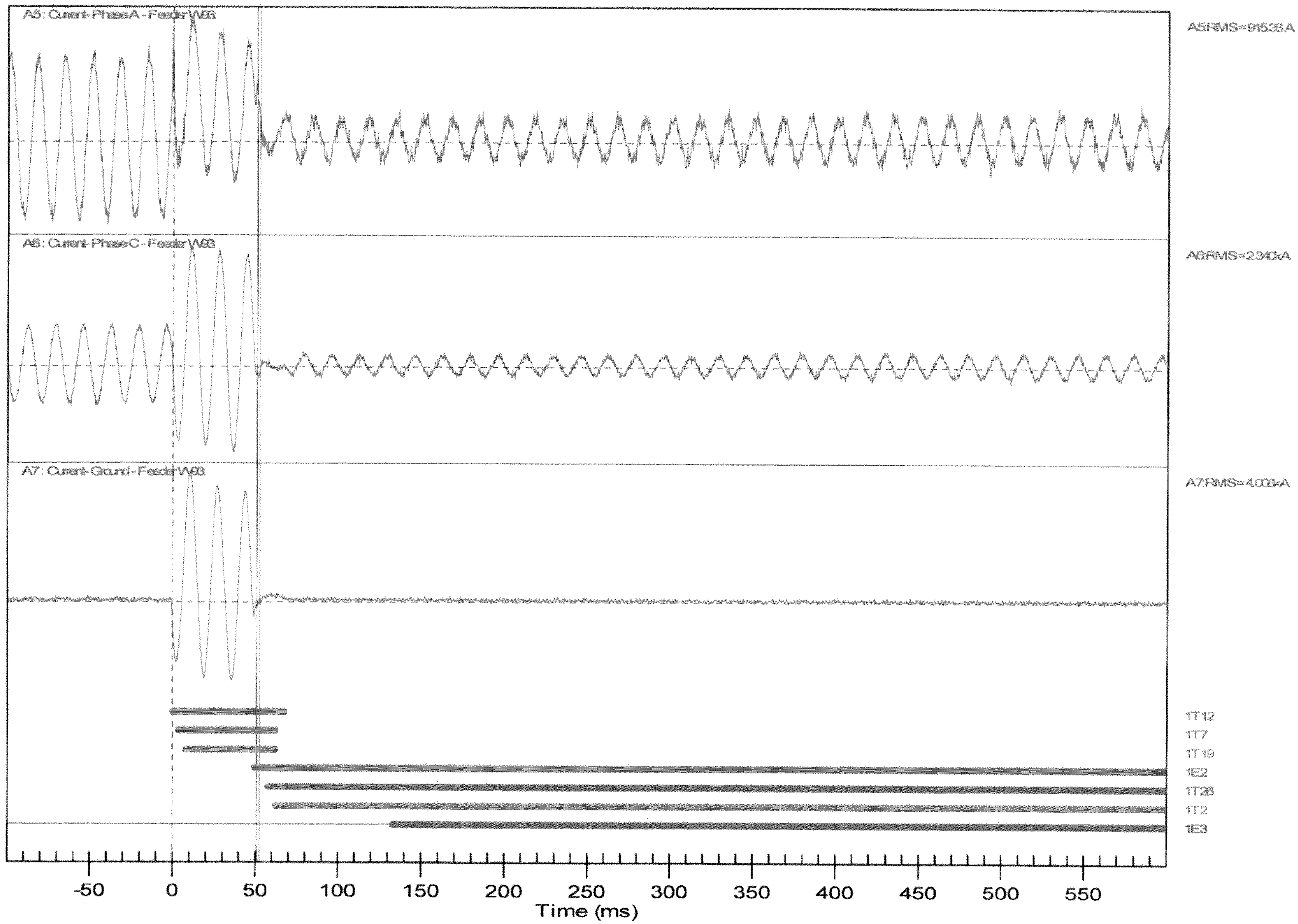

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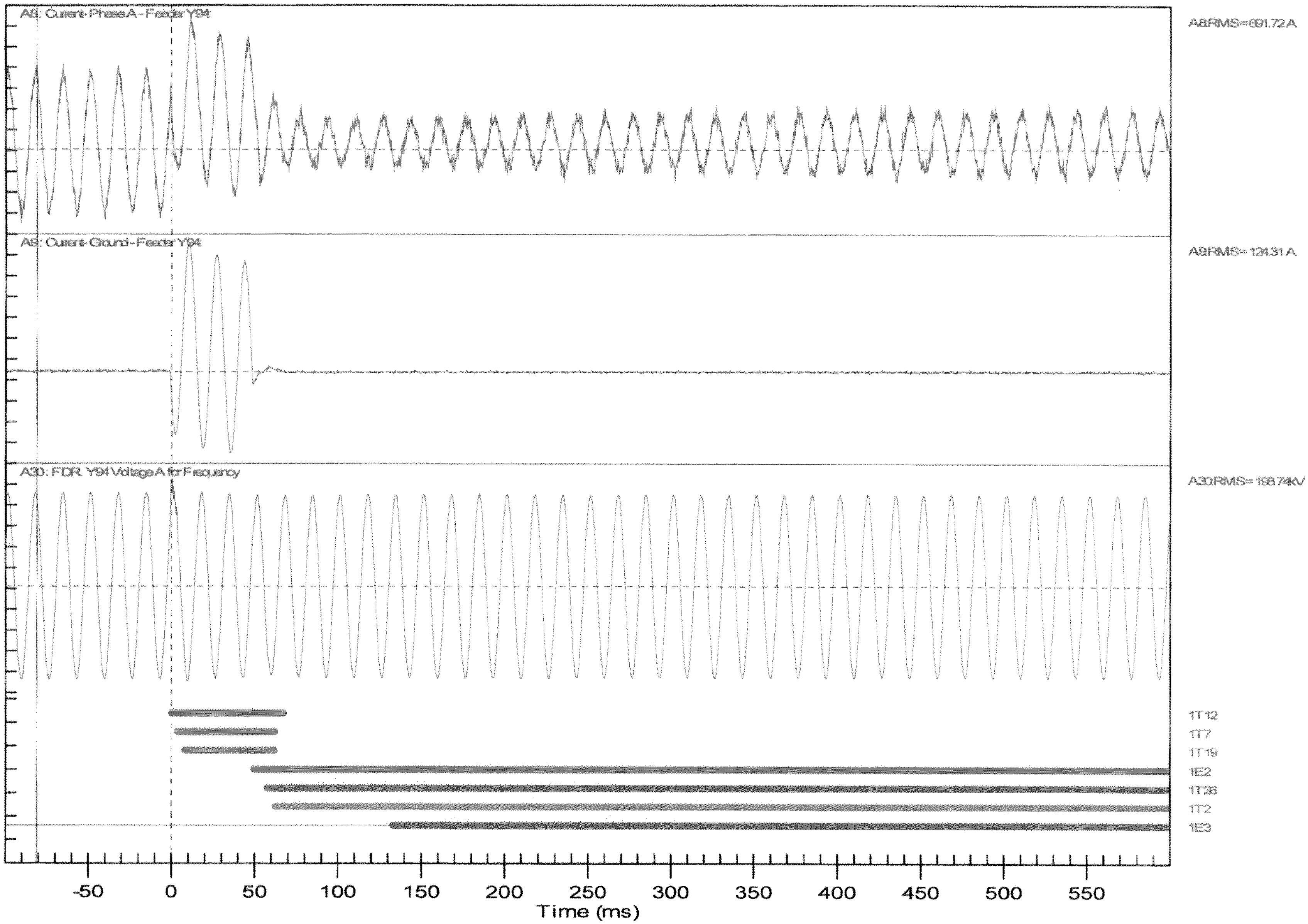
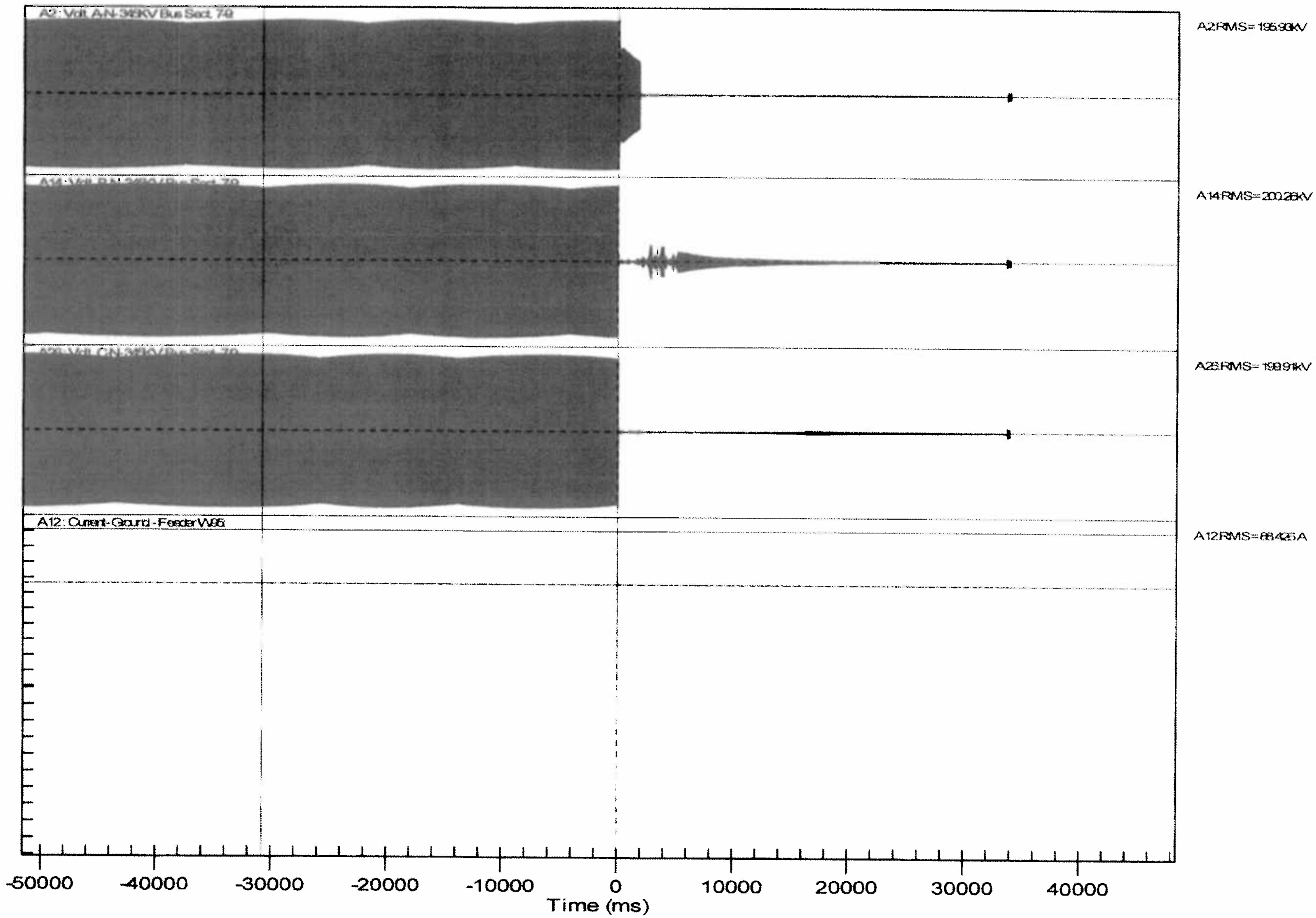


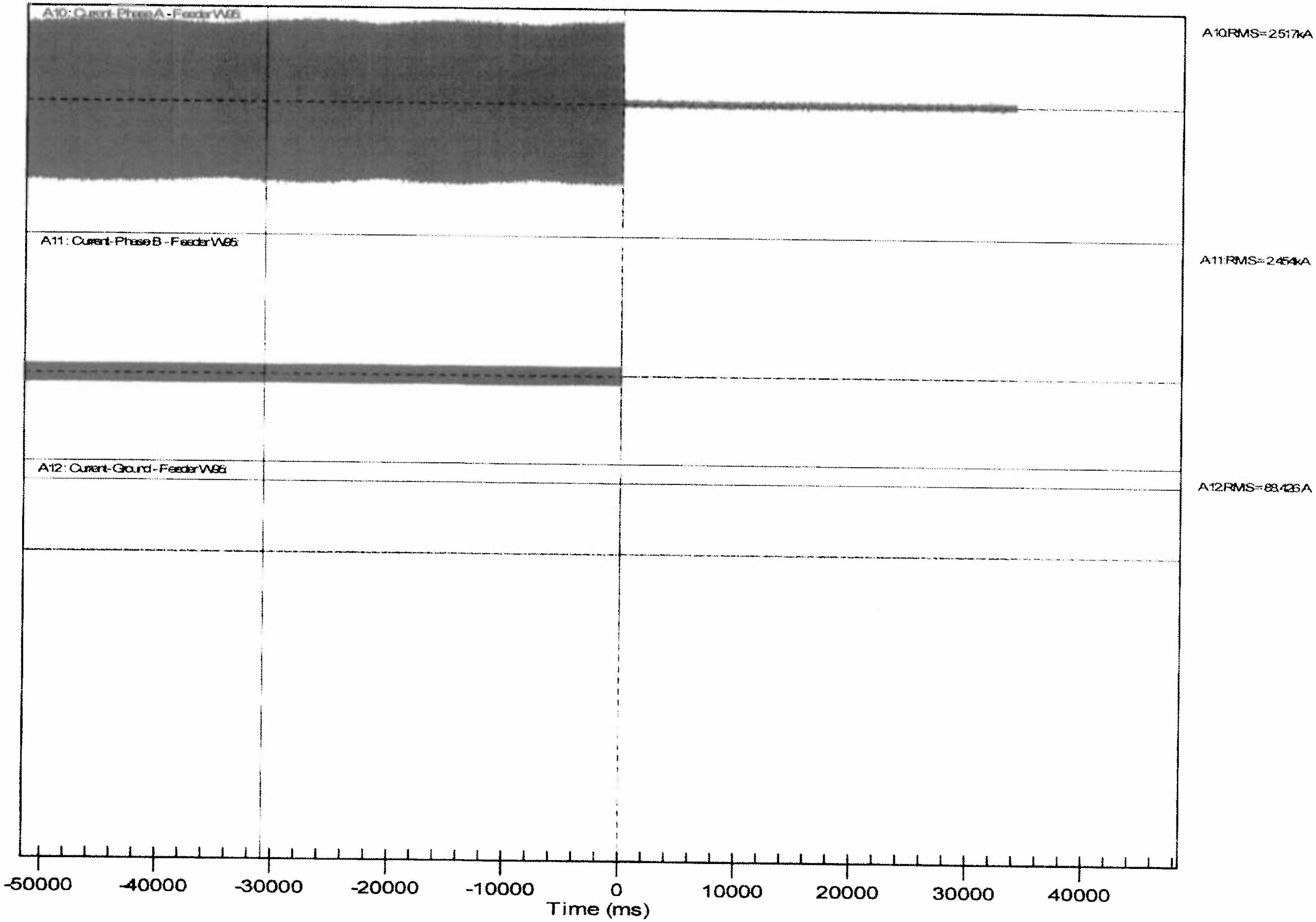
R03F0391 : Buchanan 345kV (DFR)

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



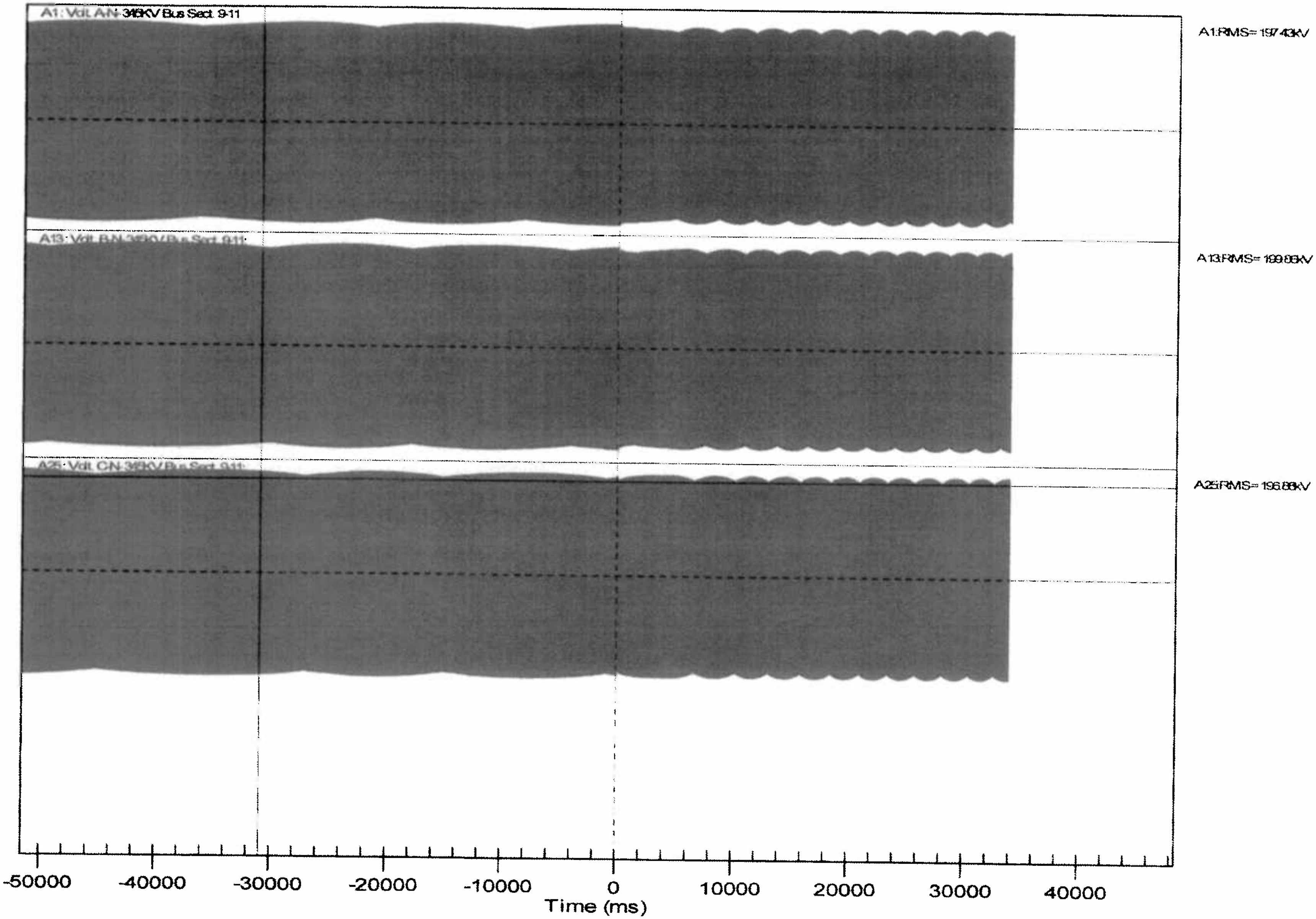
R03F0391 : Buchanan 345kV (DFR)

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



R03F0391 : Buchanan 345kV (DFR)

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



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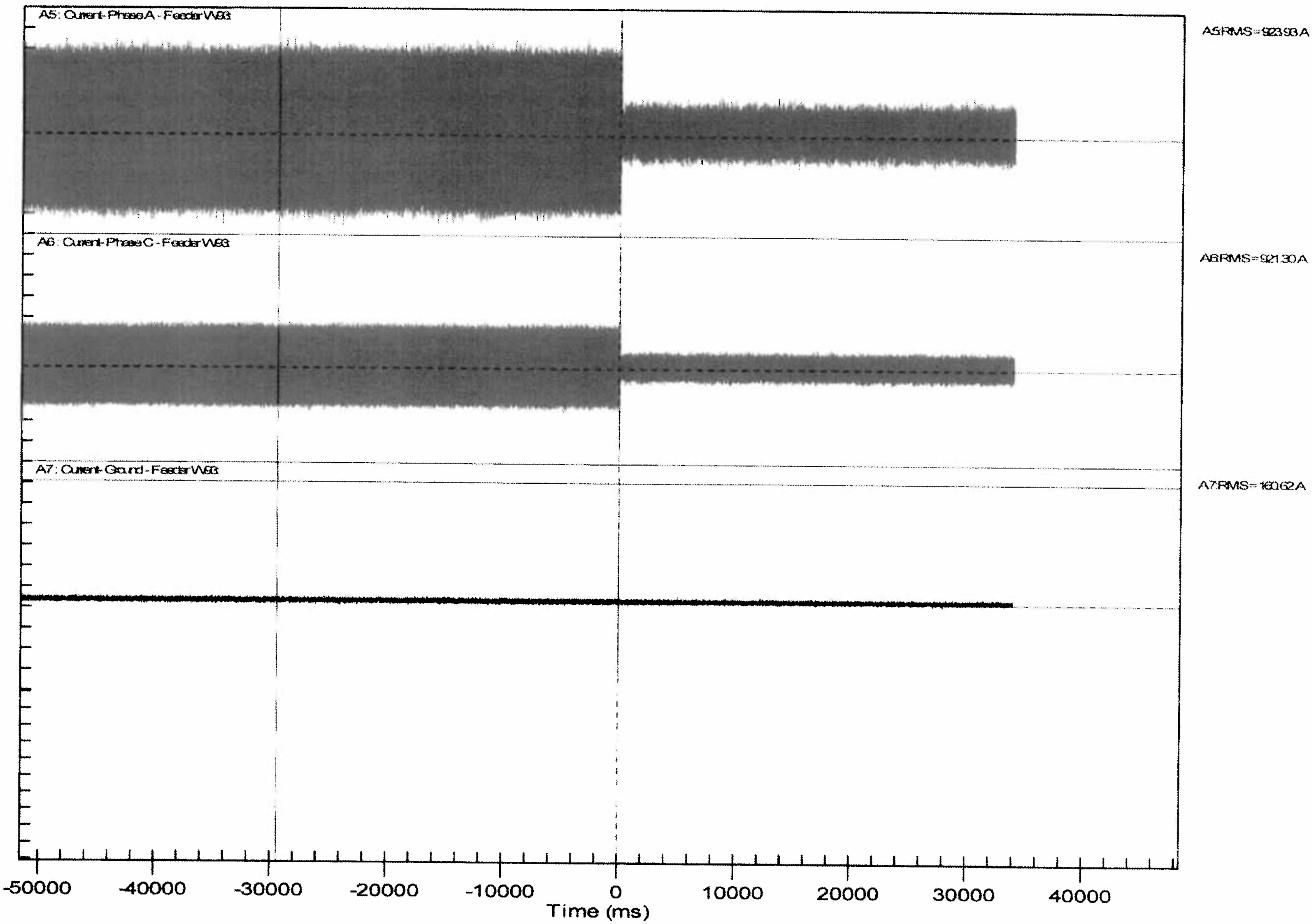
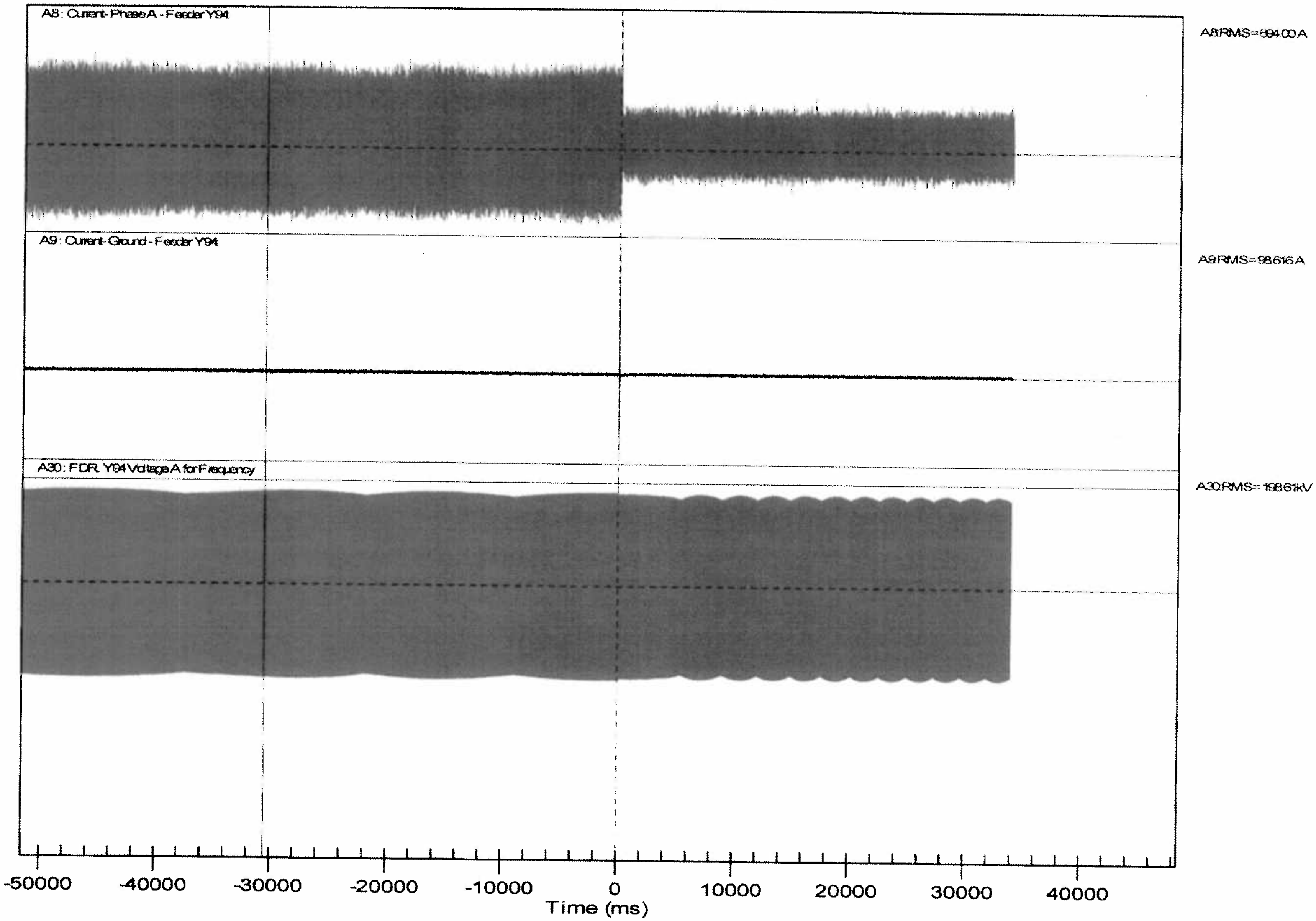
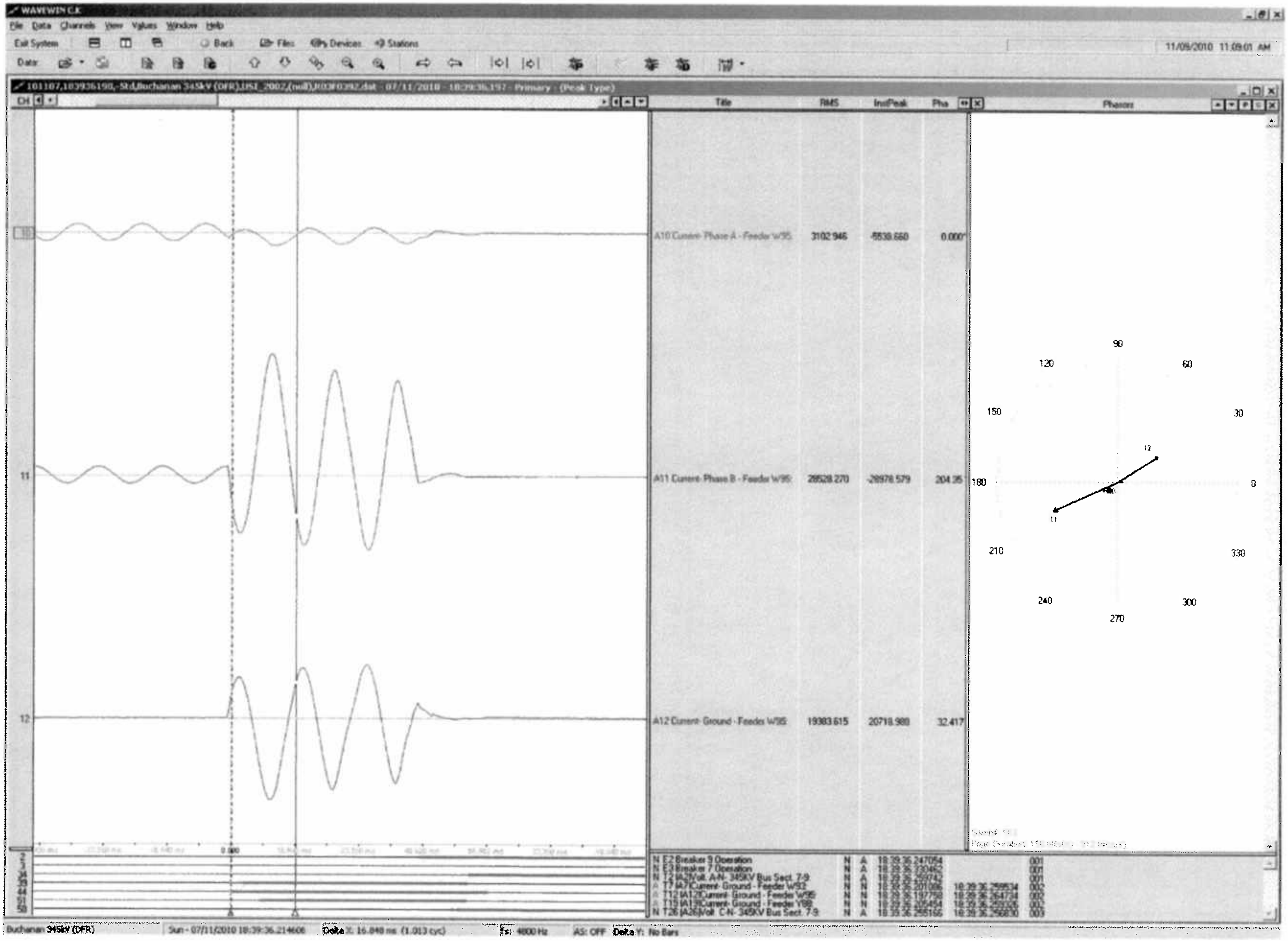


R03F0391 : Buchanan 345kV (DFR)

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




WAVEWIN C.K
File Data Channels View Values Window Help
Exit System
Back
Files
Devices
Stations
11/09/2010 11:09:01 AM
Title
RMS
InstPeak
Pha
Phasors
A10 Current- Phase A - Feeder W95
3102.946
-5538.660
0.000°
A11 Current- Phase B - Feeder W95
28528.270
-28978.579
204.35
A12 Current- Ground - Feeder W95
19383.615
20718.980
32.417
90
60
120
30
150
180
0
210
330
240
300
270
N E2 Breaker 9 Operation
N E3 Breaker 7 Operation
Buchanan 345kV (DFR)
Sun - 07/11/2010 18:39:36.214606
Delta X: 16.840 ms (1.013 cyc)
Fs: 4800 Hz
AS: OFF
Delta Y: No Bars

#21

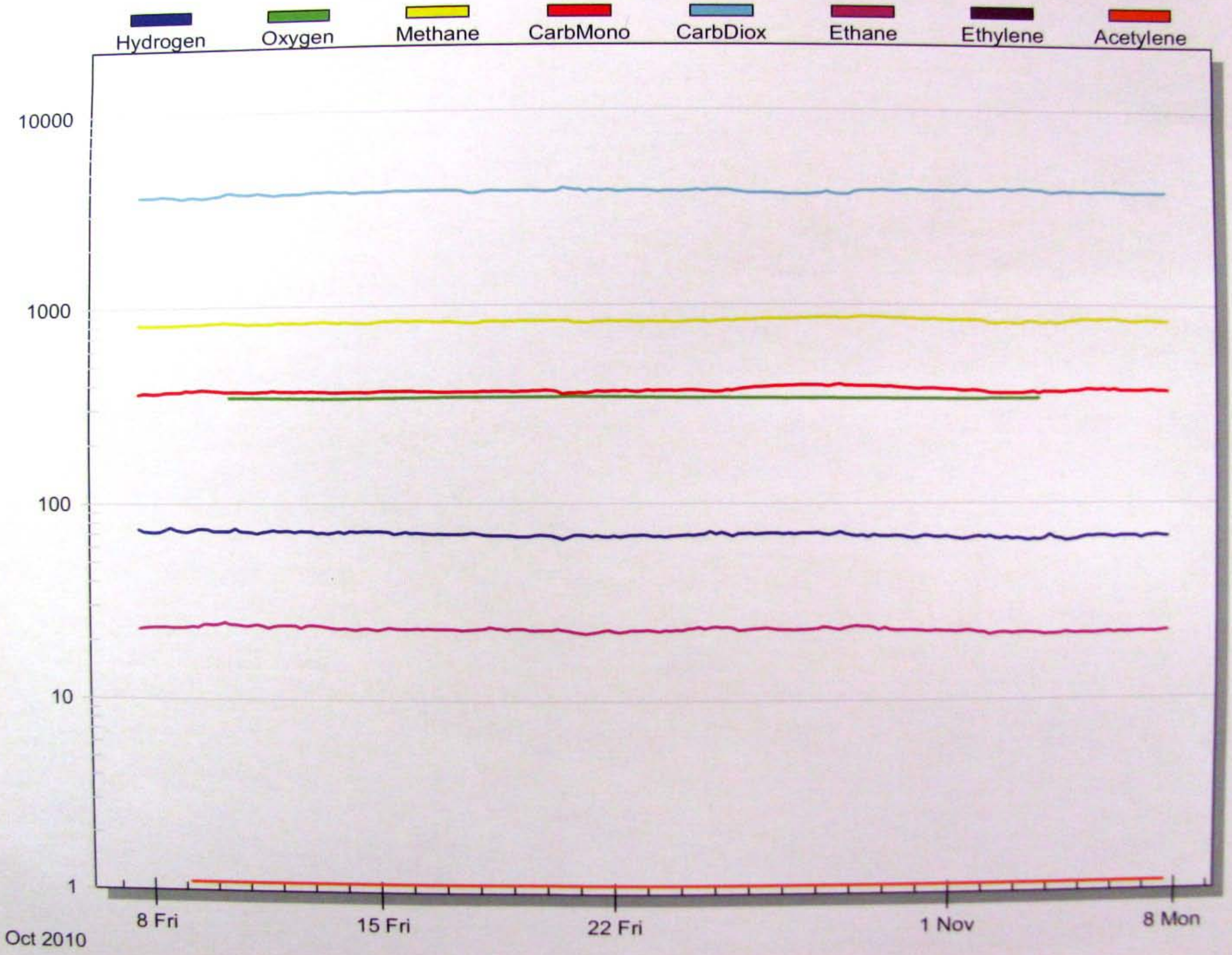
Serial Number: 4 019 269

Main Transformer 21 DGA Trending

TRUE GAS On-Line Monitoring Data

Report #	Sample Date	Top Oil Temp °C	Hydrogen (H2)	Oxygen (O2)	Nitrogen (N2)	Methane (CH4)	Carbon Monox. (CO)	Ethane (C2H6)	Carbon Dioxide (CO2)	Ethylene (C2H4)	Acetylene (C2H2)	Total Gas	COMB GAS	EST TCG %	C2H4/ C2H2	Comb Gas Rate
IEEE Limits			100			120	350	65		50	1		720			
100650	10/29/2010	68.8	123	264	12700	142	265	30	5940	12	0	19476	572	3.29	0.00	-1.00
100245	10/05/2010	58	133	1530	15500	150	281	24	6170	8.3	0	23796	596	2.81	0.00	0.82
99362	09/01/2010	70	110	275	13000	144	271	30	6370	13	0	20213	568	3.08	0.00	1.11
98871	08/04/2010	72	107	12600	56400	134	255	29	5940	12	0	75477	537	0.66	0.00	-0.39
98275	07/12/2010	67.2	108	226	11900	135	262	29	5900	12	0	18572	546	3.26	0.00	0.44
97805	06/15/2010	71	102	235	12000	133	259	28	5550	12	0	18319	534	3.15	0.00	0.44
97365	05/21/2010	62.6	105	2240	18500	132	246	28	5350	12	0	26613	523	1.98	0.00	-0.50
96521	04/15/2010	62	116	366	12200	135	249	29	4650	12	0	17757	541	3.24	0.00	1.63
96062	03/27/2010	10	103	336	11700	130	239	27	4300	11	0	16846	510	3.13	0.00	-0.03
95189	01/26/2010	66.5	107	316	11500	128	240	26	4430	11	0	16758	512	3.24	0.00	0.74
94661	12/30/2009	67	105	309	11500	119	233	24	4410	11	0	16711	492	3.15	0.00	0.15
94410	12/04/2009	56.8	106	360	11200	117	230	24	4600	11	0	16648	488	3.21	0.00	-0.76
93872	11/05/2009	51.8	103	407	11700	123	250	23	4820	11	0	17437	510	3.16	0.00	0.25
93595	10/24/2009	55	105	533	12000	120	249	23	5030	10	0	18070	507	3.08	0.00	1.11
93230	10/05/2009	70	102	12100	52500	115	237	22	4920	10	0	70006	486	0.66	0.00	-0.96
92668	09/08/2009	62.2	101	8060	38800	127	251	22	4930	11	0	52302	512	0.92	0.00	1.48
92130	08/14/2009	63.7	96	2510	19600	117	231	21	4690	9.7	0	27275	475	1.73	0.00	-2.69
91483	07/13/2009	68	157	50	13600	115	251	27	5930	11	0	20141	561	3.40	0.00	2.53
91332	06/26/2009	65	133	279	10100	113	230	32	4500	10	0	15397	518	3.96	0.00	-0.18
90595	05/29/2009	61	142	2260	19800	108	239	24	5470	10	0	28053	523	2.11	0.00	-1.44
89151	04/23/2009	56	155	430	10800	123	267	21	4430	9.3	0	16235	575	4.26	0.00	2.80
88534	03/24/2009	64	99	636	11700	113	247	23	4380	9.2	0	17207	491	3.05	0.00	1.29
88067	02/24/2009	60	85	924	12500	102	237	22	4480	8.8	0	18359	455	2.59	0.00	-3.03
87399	01/26/2009	60	112	537	9870	118	289	16	4170	8.4	0	15120	543	4.07	0.00	-1.11
86963	12/29/2008	66	137	2090	15600	124	286	19	4500	7.7	0	22764	574	2.80	0.00	-0.04
86622	12/01/2008	68	162	5940	32200	113	275	17	4250	8.2	0	42965	575	1.46	0.00	3.96
86028	11/04/2008	63	97	1030	13600	97	244	21	4970	9.1	0	20068	468	2.55	0.00	-3.04
85477	10/08/2008	65	146	358	9250	108	260	26	4540	10	0	14698	550	4.68	0.00	-1.22
84741	09/11/2008	63	159	406	10800	107	283	24	5020	10	0	16809	583	4.37	0.00	2.30
84114	08/12/2008	74	157	854	14100	90	239	20	5080	7.8	0	20548	514	3.12	0.00	-1.93
83513	07/16/2008	65	162	445	11100	97	283	15	4340	8.7	0	16451	566	4.30	0.00	0.41
82927	06/19/2008	61	145	8150	41400	101	287	15	4070	7.2	0	54175	555	1.08	0.00	3.27
82203	05/20/2008	63	114	619	11700	84	235	16	3910	8.0	0	16686	457	3.15	0.00	0.75
81879	04/30/2008	56	116	412	9770	79	225	15	3620	7.5	0	14244	442	3.70	0.00	0.00
81158	03/23/2008	37.5	116	6600	31600	78	225	16	3440	7.2	0	42082	442	1.11	0.00	-1.33
80500	02/25/2008	42	139	398	9330	77	260	14	2530	6.4	0	12754	496	4.53	0.00	-4.96
80118	01/31/2008	45	164	938	12300	92	323	15	3640	6.5	0	17478	600	4.09	0.00	6.33
79711	01/07/2008	48	111	494	10300	75	241	14	3510	6.9	0	14752	448	3.54	0.00	0.81
79477	12/12/2007	50	107	565	9990	71	229	13	3350	6.6	0	14332	427	3.48	0.00	-3.04
78926	11/14/2007		113	2490	17000	75	303	13	3830	7.7	0	23832	512	2.36	0.00	0.76
78408	10/16/2007	56	112	2180	14700	71	284	17	4340	6.4	0	21710	490	2.60	0.00	2.30
77813	09/19/2007	59	77	9100	41600	70	261	14	4070	6.5	0	55198	428	0.75	0.00	-0.32
77188	08/22/2007	62	83	840	11100	69	266	13	4010	6.0	0	16387	437	2.99	0.00	-1.23
76651	07/31/2007		96	2100	14800	61	289	12	3880	6.4	0	21244	464	2.44	0.00	0.46

21 MPT (IPEC) PPM in Oil



21 old

Together We Power The World

Report # 100650 **Sample # 2** **Entergy Nuclear Northeast - White Plains Office** **Received 11/03/2010** **Date November 09, 2010**

Serial Number: 4019269	Equipment Number: 21 MAIN	Container Id: LAB ASSIGNED # 4713	Phase:
Substation Name: Indian Point	Preservation System: Free Breathing	Miscellaneous Id:	Ambient Temp °C:
Design Type:	Transformer Name: 21 MAIN	Second Name:	Humidity:
Manufacturer:	Transformer Type: Transformer	Sample Point: Main Tank Bottom	Top Oil Temp °C: 68.8
MFR. Year:	Maximum kV: 362	Sequence #:	Peak Temp °C:
Cooling System: ONAN/ONAF	Maximum MVA: 629	Sample Date/By: 10/29/2010 9:20	Fluid Level:
Fluid Type: Mineral	XFMR Oil Capacity: 19787 Gallons	Appr Type: XFMR	Pressure PSI:
LTC MFR./Model:	LTC Type:	LTC Tank Type :	LTC Capacity: Filter LTC:

Dissolved Gas Analysis The dissolved gas analysis is run in accordance with ASTM D 3612 and IEC 60567. Values are reported in ppm vol/vol at STP and calibrated with gas-in-oil standards. Values before August 15, 2002 are reported at NTP and calibrated with gas standards.

Report #	Sample Date	Top Oil Temp °C	Hydrogen (H2)	Oxygen (O2)	Nitrogen (N2)	Methane (CH4)	Carbon Monox. (CO)	Ethane (C2H6)	Carbon Dioxide (CO2)	Ethylene (C2H4)	Acetylene (C2H2)	Total Gas	COMB GAS	EST TCG %	C2H4/ C2H2	Comb Gas Rate ppm/day
100650	**10/29/2010**	**68.8**	**123**	**264**	**12700**	**142**	**265**	**30**	**5940**	**12**	**0**	**19476**	**572**	**3.29**	**0.00**	**-1.00**
100245	10/05/2010	58	133	1530	15500	150	281	24	6170	8.3	0	23796	596	2.81	0.00	0.82
99362	09/01/2010	70	110	275	13000	144	271	30	6370	13	0	20213	568	3.08	0.00	1.11
98871	08/04/2010	72	107	12600	56400	134	255	29	5940	12	0	75477	537	0.66	0.00	-0.39
98275	07/12/2010	67.2	108	226	11900	135	262	29	5900	12	0	18572	546	3.26	0.00	0.44
97805	06/15/2010	71	102	235	12000	133	259	28	5550	12	0	18319	534	3.15	0.00	0.44
97365	05/21/2010	62.6	105	2240	18500	132	246	28	5350	12	0	26613	523	1.98	0.00	-0.50
96521	04/15/2010	62	116	366	12200	135	249	29	4650	12	0	17757	541	3.24	0.00	1.63
96062	03/27/2010	10	103	336	11700	130	239	27	4300	11	0	16846	510	3.13	0.00	-0.03
95189	01/26/2010	66.5	107	316	11500	128	240	26	4430	11	0	16758	512	3.24	0.00	

Overheating of oil and cellulose, condition is of no immediate concern. Resample in 3 months.

1. Equipment Data

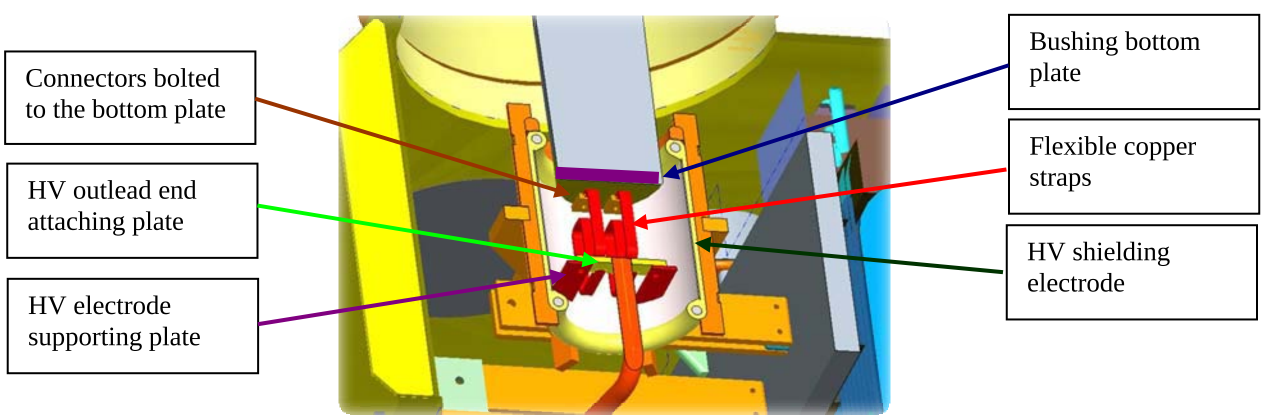
Ratings:	Three Phase Generator Set up Transformer Power Rating: **372/449,6/562 (629) MVA** Cooling: **ONAN/ONAF/ODAF** Frequency: **60 Hz**	
	Rated Voltages:	**HV**: 345 +2x2,5% -2x2,5% kV (DETC) – YN **LV**: 20,3 kV – D
Customer:	**ENTERGY** ENTERGY NUCLEAR NORTHEAST - INDIAN POINT ENERGY USA	
Serial Number	**#4019269**	

2. Function of the HV Bushing Shielding Electrodes

The shielding electrodes installed around the bottom end of the HV bushing has the function to prevent the connection between the HV outlead and the HV bushing bottom plate be exposed to a high electrical field stress.
Considering that the maximum current of the transformer is around 1100A, the connection of the HV outlead to the bushing bottom plate is done via four flexible copper straps. Thus, this bottom plate as well as the flexible strap and the correspondent bolts have sharp edges, which shall not be exposed to a high electrical field stress.

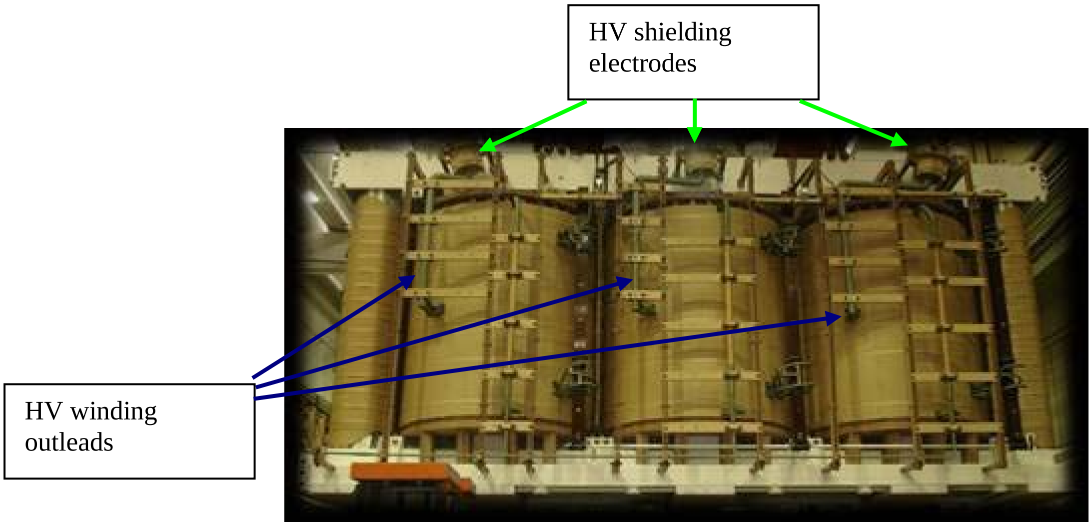
3. HV Electrode Assembly details

The shielding electrode is attached with four bolts to the end plate of the HV solid copper tube. The flexible copper straps which made the connection to the HV bushing bottom plate are brazed to this conductor end flange.
The other ends of the flexible straps are brazed to solid copper terminals, which is then bolted in the bushing bottom plate.
The copper connectors of the flexible straps are the only bolted contact between HV bushings and HV winding outleads.

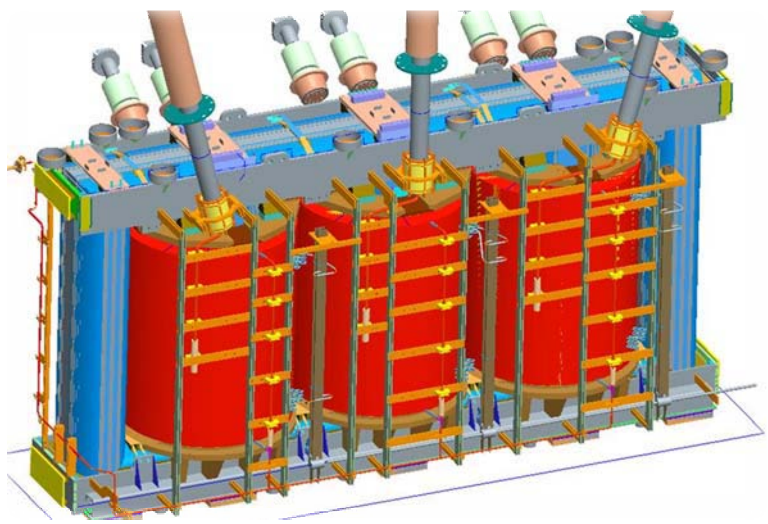


Picture 01 – ProE View Shielding Electrode

The HV winding outleads are made of copper tubes with a thick paper insulation supported in many points, as it is visible in the ***Pictures 02*** and ***03***. The supported HV winding outleads alone provide a self-supporting structure to the HV shielding electrodes



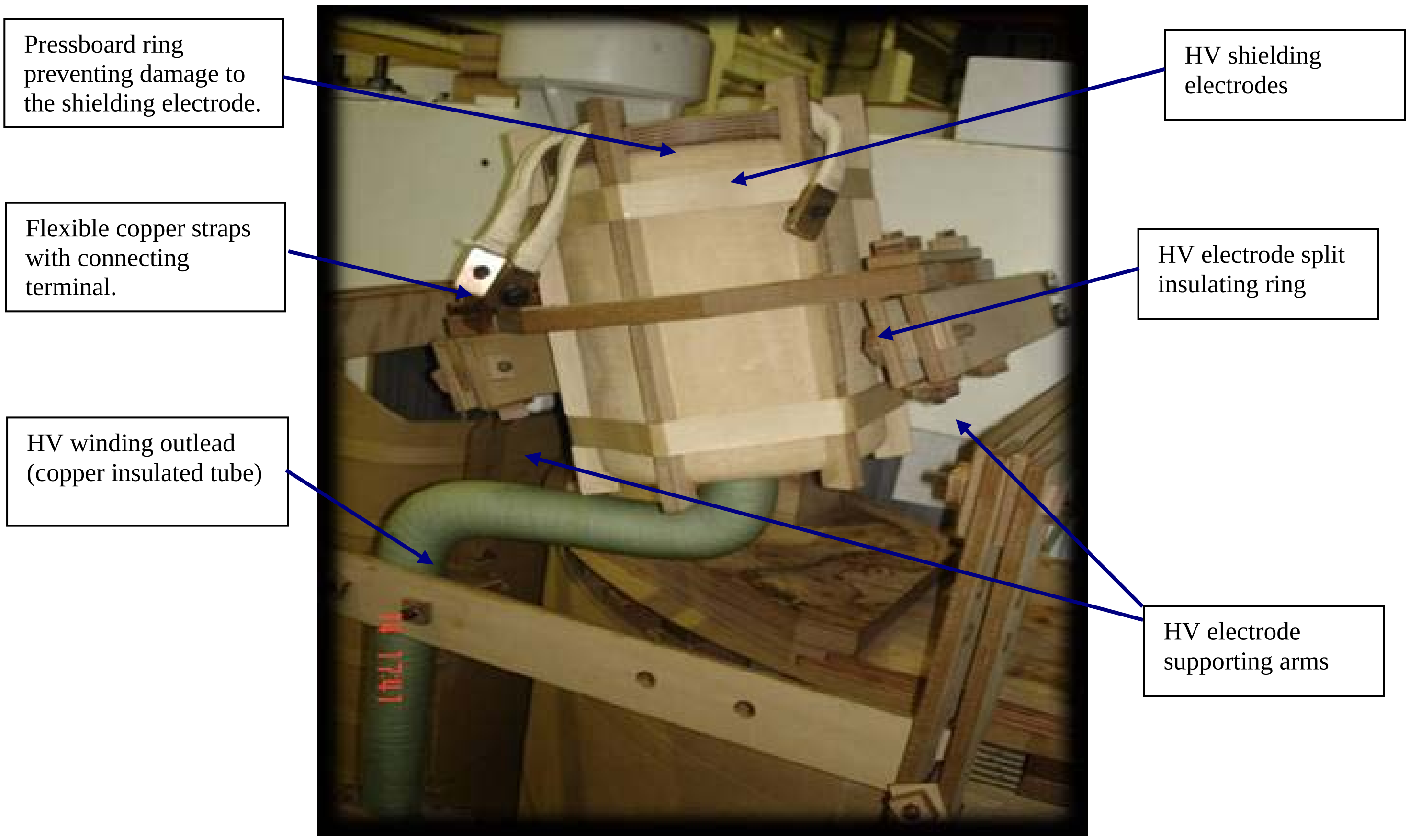
Picture 02 – General View – Core and Coils



Picture 03 – General ProE View of the active part

Additionally, the shielding electrode assembly is supported externally by a structure of WEIDMAMANN Transformer Pressboard, manufactured of pure compressed long fiber cellulose.

This structure is composed by a split ring around the electrode and two supporting arms, which provide the required clearance between the electrode (100% potential) and the grounded parts of the frame.
Each arm is bolted (using two bolts) to a steel plate welded to the upper frame.
See ***Picture 04*** below.



Picture 04 – Shielding Electrode

All this structure is designed to withstand to the maximum forces caused by an external short circuit.
The insulation on the upper part of the electrode is also protected by a solid pressboard ring, which prevents the bottom plate of the bushing to damage the electrode insulation when lowering the bushing into the transformer.

4. Assembly details

Installing the HV bushing into the turrets, it must be observed that the bottom plate cannot damage either the CT insulation or the insulation of the shielding electrode.
Approximately 10 inches before the flange makes contact with the turret, the internal connection of the flexible copper strap to the bottom plate shall be done.
This step is uppermost important to be enacted for the two outside phase bushings, which are installed at an angle to the vertical.
When lowering the bushings into the final position, is shall be observed that the flexible strap fits completely into the shielding electrode and that the bottom plate of the bushing reaches its specified penetration into the shielding electrode.

5. Critical Analysis of the possible Failure Mode of the Shielding Electrode

The two independent supporting systems of the shielding electrode prevent the electrode dropping down, making impossible the bushing bottom plate getting uncovered.
Even in a very unlikely event of a shielding electrode getting loose, this condition would cause some partial discharges be onset at the bushing bottom plate.
The generation of fault gases caused by the partial discharges would be promptly detected by the on-line gas monitoring device. (THRU-GAS)
The traces of this device showed a perfectly stable condition very close to the event (about 2:30 hours before the flashover event). Also the off-line DGA results taken two month before (September 01, 2010) the event showed stable results, without any concern about fault gases.
Thus the transformer itself was in a good shape until the occurrence of the internal flashover event.

6. Analysis of the internal Flashover Event

The flashover inside the bushing punctured its condenser body and hit the grounded metallic flange extension (see ***Picture 05***).
This flashover caused an explosive rupture of the insulation shell installed on the bottom part of the bushing. Consequentially, the very steep pressure wave generated by the explosion displaced the shielding electrode downward, breaking the supporting pressboard arms (see ***Picture 06***).

Picture 05 – Detail view of failed bushing H2:
Red Line: indicates the arcing trace puncturing the condenser body and hitting the grounded flange extension.

Picture 06 – View of Phase 2 after the flashover event, showing the Shielding Electrode and the supporting pressboard arms damaged by the explosion.

The ionized medium around the bottom part of the bushing caused many secondary discharges between the bushing bottom plate and the grounded parts (see ***Picture 07***)., as the voltage at the HV terminals was sustained for several cycles by the generator even after 345kV circuit breakers cleared the transformer from the transmission line.

Picture 07 – Detail view of failed bushing H2:
Red Arrows: indicates the arcing marks on the bottom plate.

7. Conclusion

The DGA results show that there was no disturbance at the internal part of the transformer previous to the flashover event.
It is concluded that the HV shielding electrodes of all three phases were sound until the occurrence of the internal flashover event.

It can be noted that the bushings and shielding electrodes installed on unit MT 22 are of duplicate design to that described above for MT 21. Also, on-line gas monitoring of MT 22 shows similar stable behavior as the DGA monitoring of MT 21. (See section 5 above for discussion of the significance of stable DGA observations with respect to proper orientation of shielding electrode.)

It is reasonable to conclude that shielding electrodes and bushing bottom plates were in correct position in both MT 21 and MT 22, prior to the internal flashover within MT 21. Therefore, Siemens has made the recommendation that the benefits of oil draining and internal inspection of MT 22 were minimal, and did not justify the possible negative impact such draining would create (that is, a lengthened outage duration.)

Bernd Rudolf Wilhelm Miethke TECHNICAL SUPPORT	Tamyres Luiz Machado TECHNOLOGY DIRECTOR

GE Power Systems
Generator

Generator Data For Stability Study

Purchaser: Consolidated Edison Co.

Station: Indian Point #2

Requisition No.: 305–70094

Rated Conditions:

kVA: 1,439,200

kV: 22

RPM: 1800

PF: 0.91

SCR: 0.58

H_2psig: 75

Full Load Field Amps: 6051 Response Ratio 0.5

Field Resistance: 0.0908 ohms @ 125° C, 0.0656 ohms @ 25° C

Field Amps: 9103 @ rated generator volts and amps, and zero pf overexcited

Sat. Curve: 483HA530

Vee Curve: 483HA531

Estimated Capability Curve: 483HA532

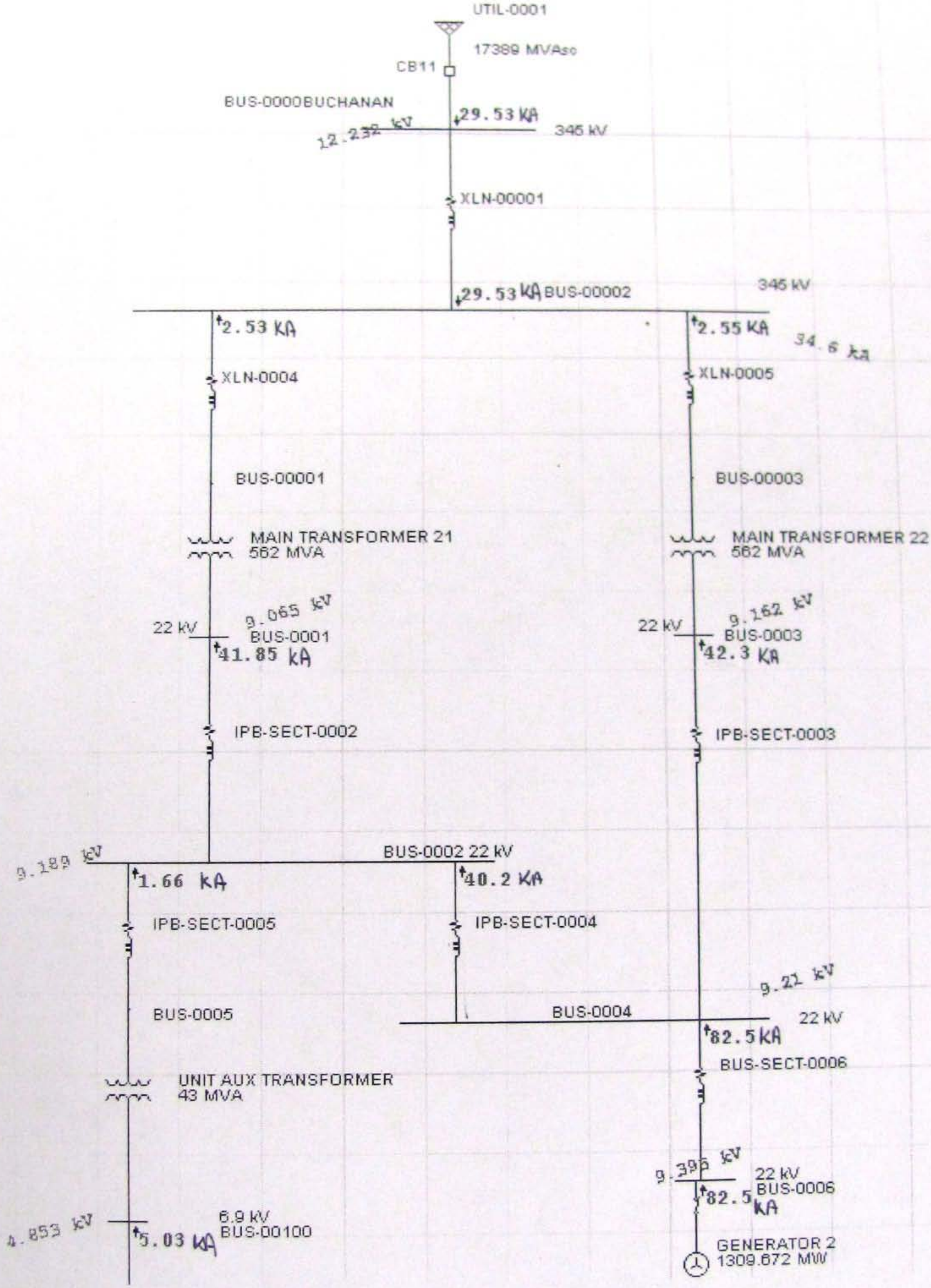
Type of Exciter: GENERREX

Generator WR^2: 1,563,392 Lb–ft^2

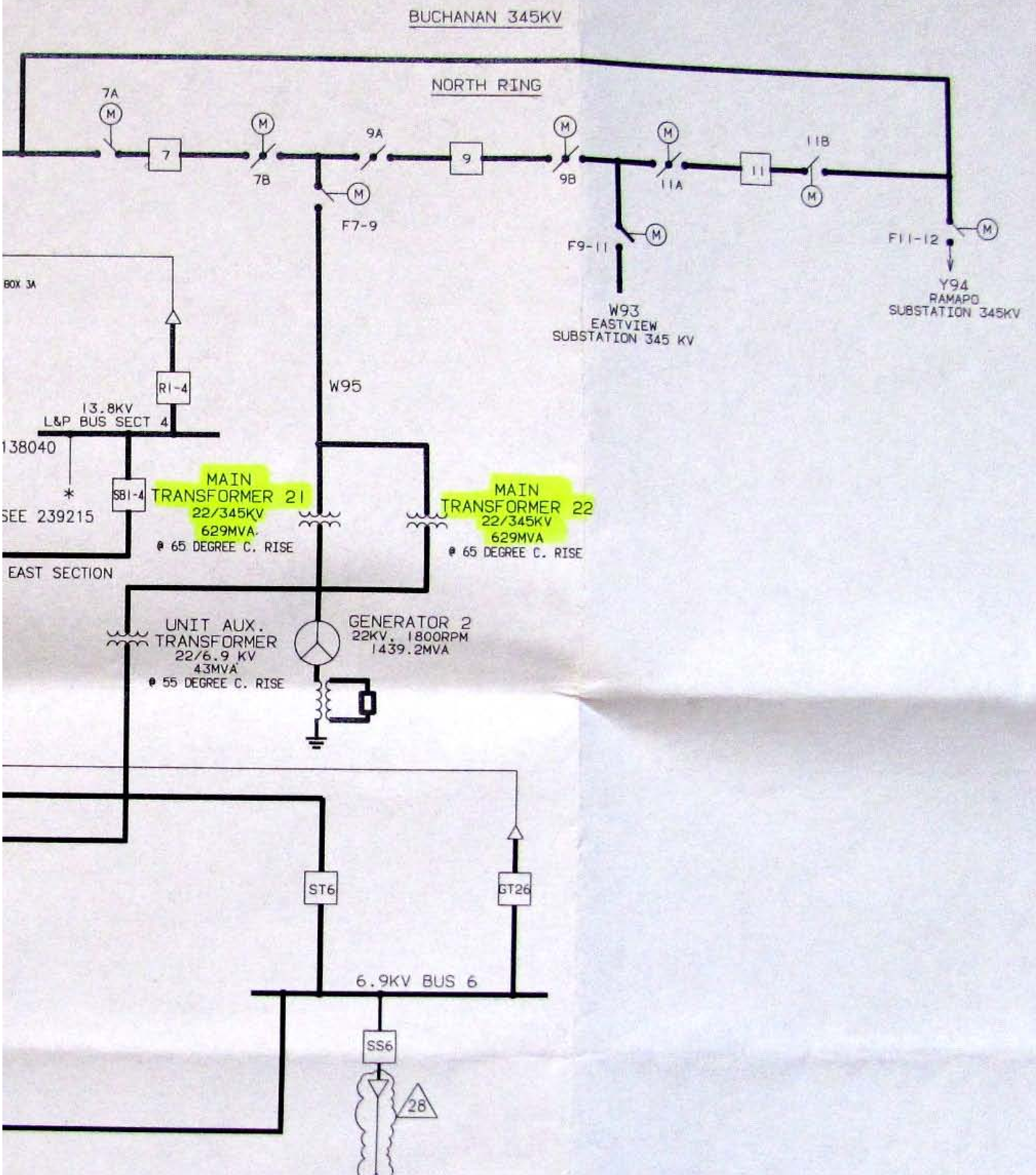
Generator Constants at Rated kVA: 1,439,200 kVA @ .91PF & 22000 Volts

X_d	1.90	X_q	1.79	T'_{do}	9.617
X'_{di}	0.420	X'_q	0.623	T''_{do}	0.036
X'_{dv}	0.370	X_o	0.215	$T_a2=T_a3$	0.359
X''_{di}	0.325	X_{Lm}	0.250	T'_{qo}	0.422
X''_{dv}	0.260	R_1	0.0039	T''_{qo}	0.061
X_{2v}	0.260	R_2	0.0269	T'_{d1}	3.43
Cap 3 Phase	1.6496 uf	Ra 25°C	0.000588 ohms	T'_{d3}	1.685
X_2	0.260	Rf 25°C	0.0656 ohms	T'_{d2}	2.807
		T_a1	0.290	T''_d	0.026

$$H = \frac{(0.231)(WR^2)(RPM^2)(10^{-6})}{\text{KVA base}} \quad \text{KW–Sec./KVA}$$



3-phase duty cycle fault current


BUCHANAN 345KV
NORTH RING
7A
7
7B
9A
9
9B
11A
11
11B
F7-9
F9-11
F11-12
W93
EASTVIEW
SUBSTATION 345 KV
Y94
RAMAPO
SUBSTATION 345KV
BOX 3A
R1-4
W95
13.8KV
L&P BUS SECT 4
138040
SEE 239215
SB1-4
MAIN
TRANSFORMER 21
22/345KV
629MVA
@ 65 DEGREE C. RISE
MAIN
TRANSFORMER 22
22/345KV
629MVA
@ 65 DEGREE C. RISE
EAST SECTION
UNIT AUX.
TRANSFORMER
22/6.9 KV
43MVA
@ 55 DEGREE C. RISE
GENERATOR 2
22KV. 1800RPM
1439.2MVA
ST6
GT26
6.9KV BUS 6
SS6
28

1. Scope

This Photographical Report contains the relevant pictures obtained during the external inspection of the HV Bushings manufactured by TRENCH / Canada, which were directly involved with the event occurred on November 7th 2010 with the Step up transformer 629 MVA installed on the ENTERGY Nuclear Plant at Indian Point –NY/USA.

Remark: the pictures of the inspection of the Insulating Post supporting the 345 kV buses which interconnects the HV terminal of both Units #21 & #22 as well as the pictures taken from the connector which joins the two sections of the 345 kV buses and which broke making the two section fell apart during the flashover event are contained in the ***Attachment 6***.

2. Pictures of the HV Bushing Inspection

Type of the HV bushings: **1175 – F020-23-AG3-02-AEP**, LI Level: 1175 kV, manufactured in 2005;

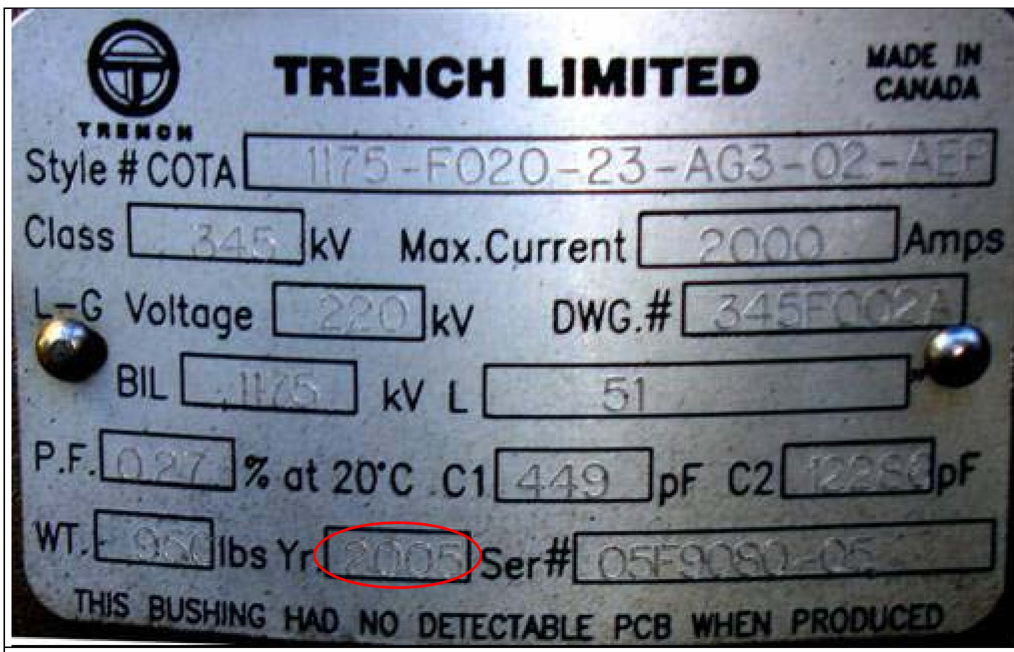
The Serial Numbers of the HV Bushings which were installed on the Unit #21 are:

05F9080-01 assembled in H1

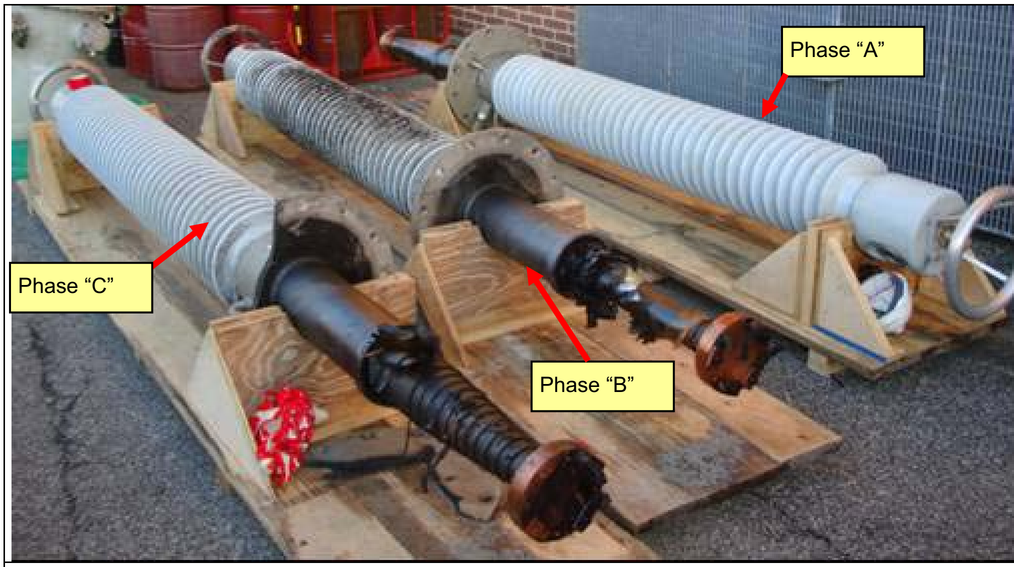
05F9080-04 assembled in H2

05F9080-03 assembled in H3

After the bushings were disassembled from the damaged transformer, they could be inspected in respect of the external damages occurred due the flashover at the bushing installed in phase "B".



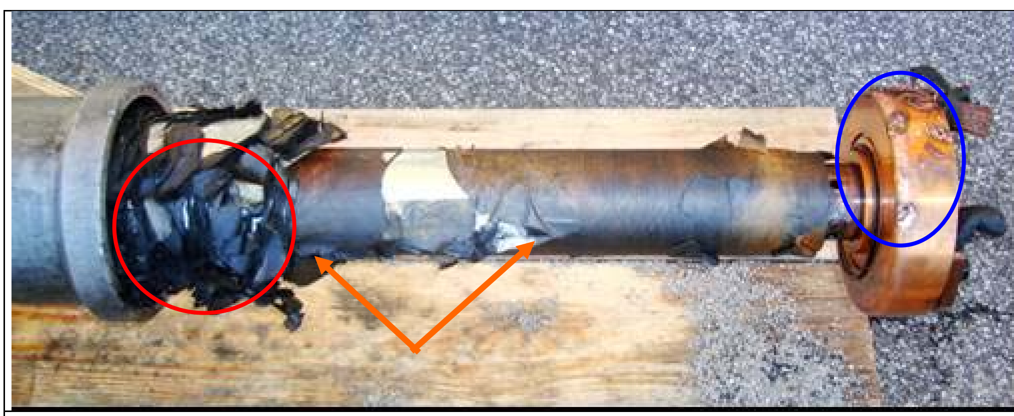
Picture 1: Nameplate of one of the bushings installed in the sister Unit #22:
Red circle: Year of manufacturing: **2005**.



Picture 2: General view of the bushings after disassembled from the Transformer Unit #21

2.1 Pictures of the H2 Bushing (Phase "B")

The bushing installed on H2 (Phase "B") experienced an internal flashover, which made the epoxy shell being ruptured, causing a explosive shock wave inside the oil, which ruptured the weld between cover and tank wall. The tank wall itself bowed outwards.
As the flashover was sustained for approximately one second (~60 cycles) by the remaining magnetic field of the main generator, the oil was expelled as a dust from the tank an immediately caught fire, involving the radiator banks, the insulating post sustaining the 345 kV bus phase "B" connected to the H2 bushing.



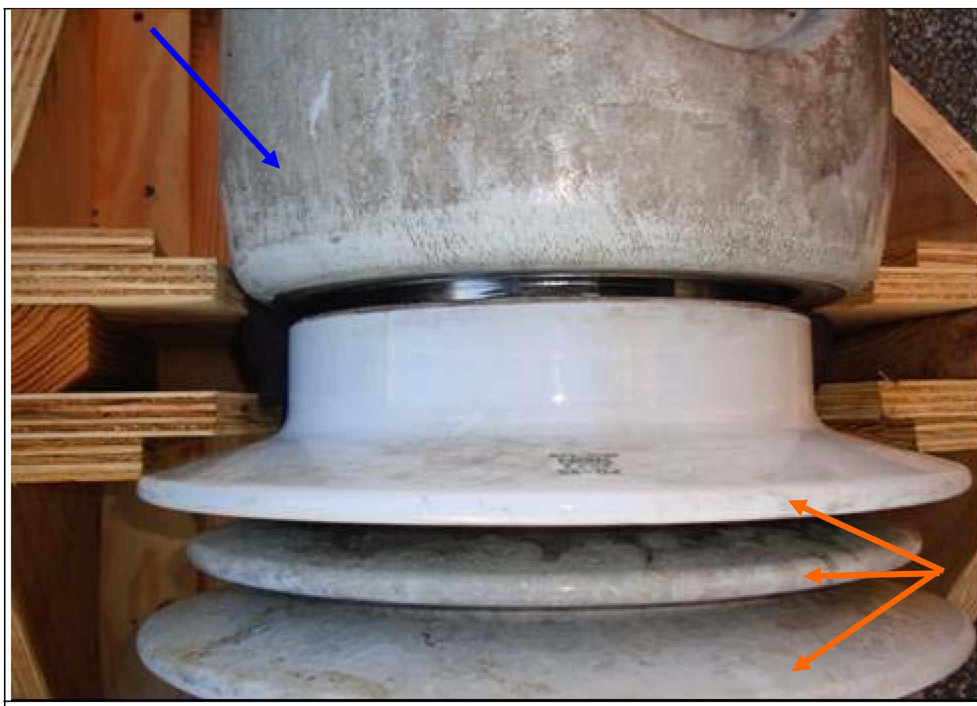
Picture 3: General view of the bushing H2:
Red circle: Area with the puncture to inner layers;
Orange arrows: Discharge trace on the remaining layers;
Blue circle: Flashover foot points on the bottom plate;

Inside the tank, the ionized atmosphere of the burning oil mist made several flashovers to be produced between the bottom plate of the bushing and the surrounding grounded parts.

Picture 4: General view of the bushing H2:
Red circle: Area with the puncture to inner layers;
Orange arrow: Remaining layers of the condenser body;
Blue circle: Flashover foot points on the bottom plate;

Picture 5: Detail view of failed bushing H2:
Red Line: indicates the arcing trace puncturing the condenser body and hitting the grounded flange extension.

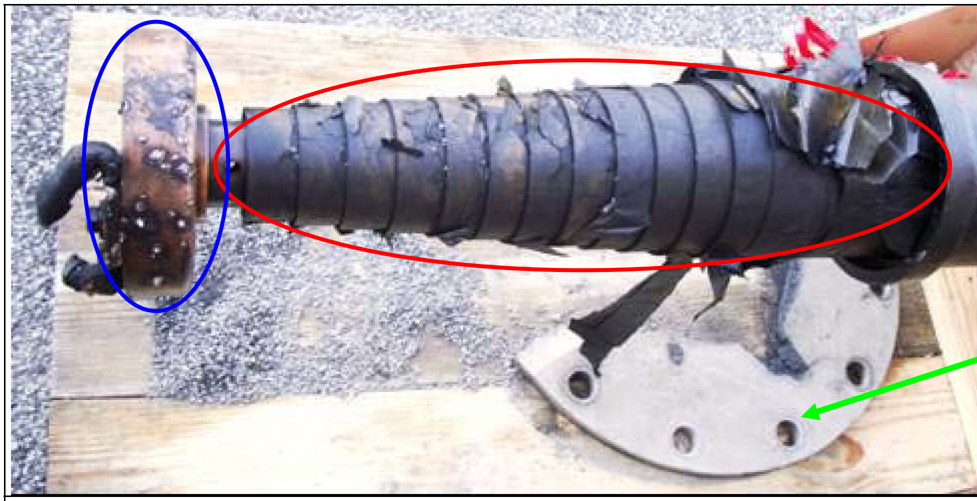
Picture 6: Further view of the bushing H2:
Red circle: Area of the layers destroyed by the flashover;
Orange arrows: Further flashover foot points on the bushing flange extension;
Blue arrow: Remaining layers of the condenser body;



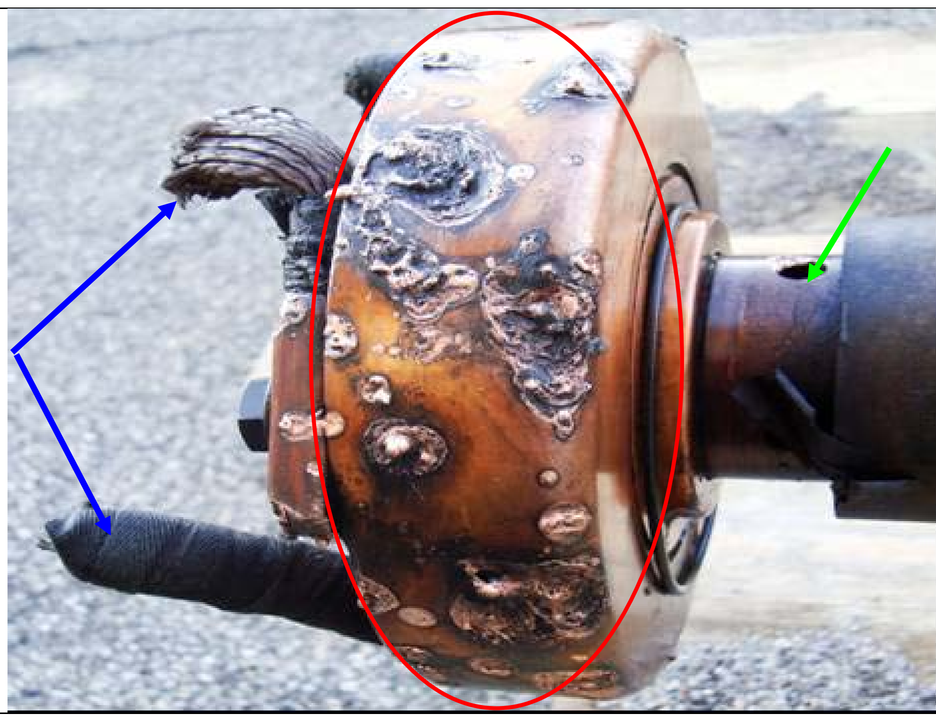
Picture 7: View of the H2 bushing head:
Red circle: The bushing head was distached from the porcelain as the lower epoxy shell was destroyed by the internal flashover;
Orange arrows: Porcelain sheds;
Blue arrow: Bushing head;

2.2 Pictures of the H3 Bushing (Phase "C")

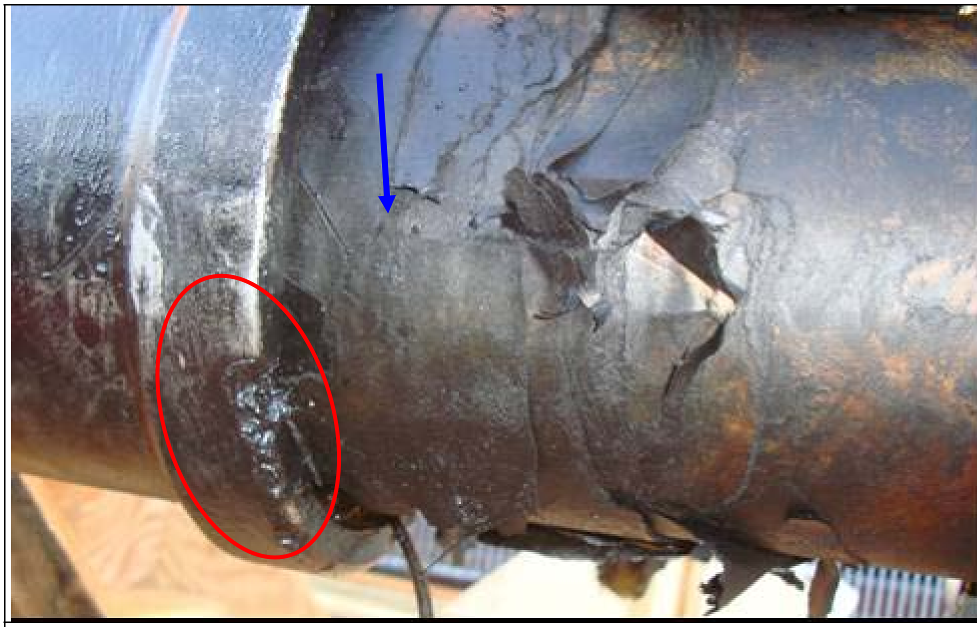
The bushing H3 (installed on Phase "C") had its lower epoxy shell mechanically destroyed by the shock wave caused by the explosion of the bushing H2.



Picture 8: View of the H3 bushing:
Red circle: Condenser body partially damaged, without the epoxy shell destroyed by the flashover on the H2 bushing;
Blue circle: Flashover foot points between bottom plate and surrounding grounded parts;
Green arrow: Part of the bushing flange that was broken by the mechanical impact of the pressure surge inside the tank;



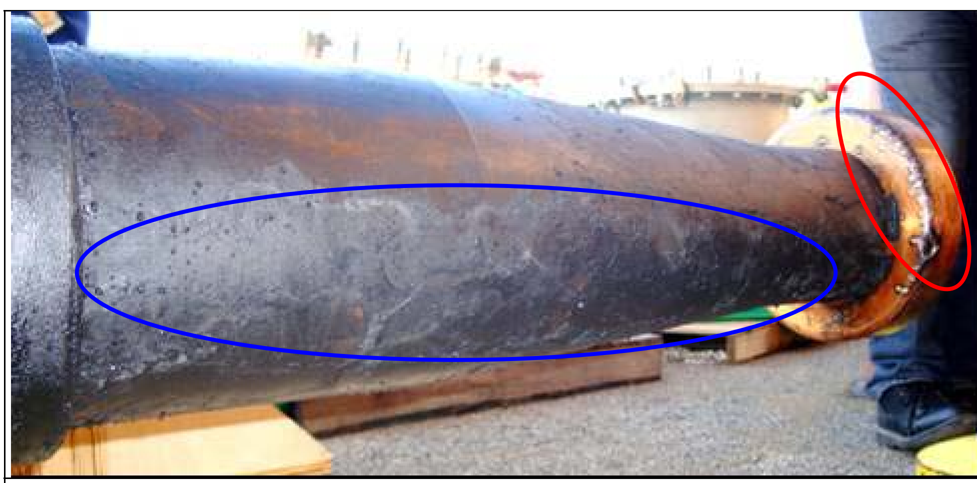
Picture 9: View of the H3 bushing bottom plate:
Red circle: Foot points caused by several flashover strikes occurred after the H2 event;
Blue arrows: Flexible connection leads cut away during the dismantling of the bushing;
Green arrow: Oil circulation hole on the central conductor;



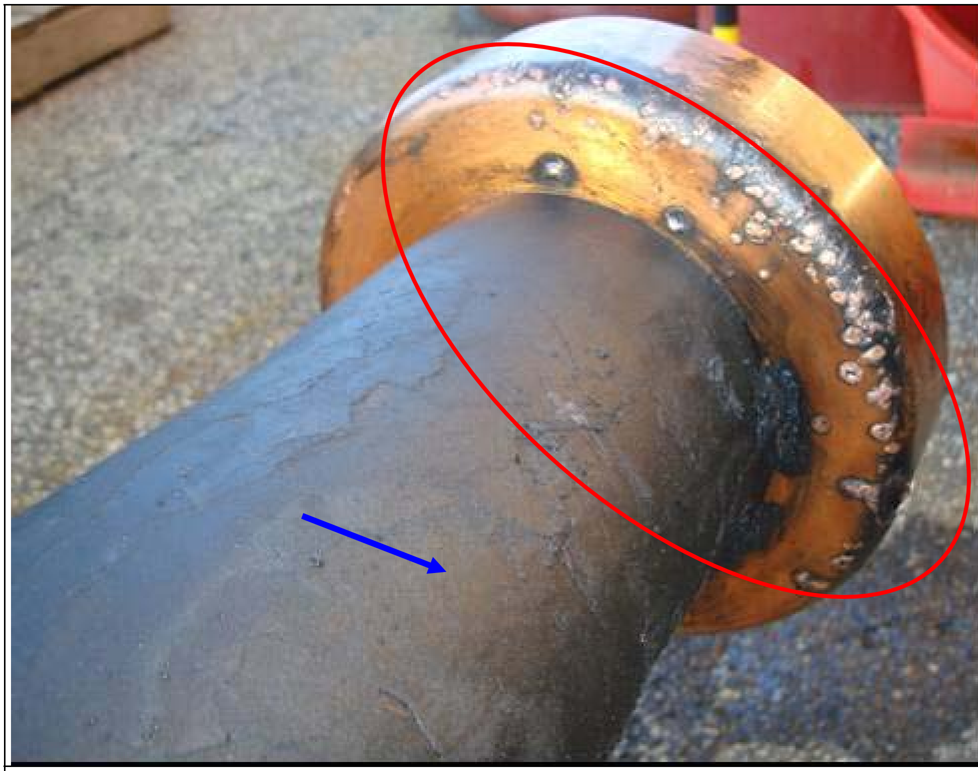
Picture 10: View of the H3 flange extension region:
Red circle: Foot points on the grounded flange extension caused by flashover events occurred on the condenser body ;
Blue arrow: Discharge traces on the condenser body;

2.3 Pictures of the H1 Bushing (Phase "A")

The H1 bushing had its epoxy shell heavily burned, but the shell maintained the bushing filled with oil, whereas the other two bushings lost all oil due to the destruction of the epoxy shell on the oil side.



Picture 11: View of the **H1** bushing oil side area:
Red circle: Foot points on the bushing bottom plate caused by flashover events to surrounding grounded parts after the H2 bushing explosion;
Blue circle: Heavy burning marks on the external surface of the epoxy shell;



Picture 12: Detail view of the **H1** bushing bottom plate:
Red circle: Foot points on the bottom plate caused by several flashover events occurred after the explosion of the H2 bushing;
Blue arrow: Heavily burned surface of the epoxy shell at the oil side.

3. Further Investigation

The bushings are packed in appropriate crates and stored at the external areas of the Indian Point site, ready to be dispatched for the final investigation by dissection of their condenser core.

These dissections bring some evidences that may clarify the questions about the origin of the explosion of the H2 bushing and thus give the necessary evidences for the root cause analysis.

Once the local and date for the investigation are defined, the bushings will be dispatched in sequence.

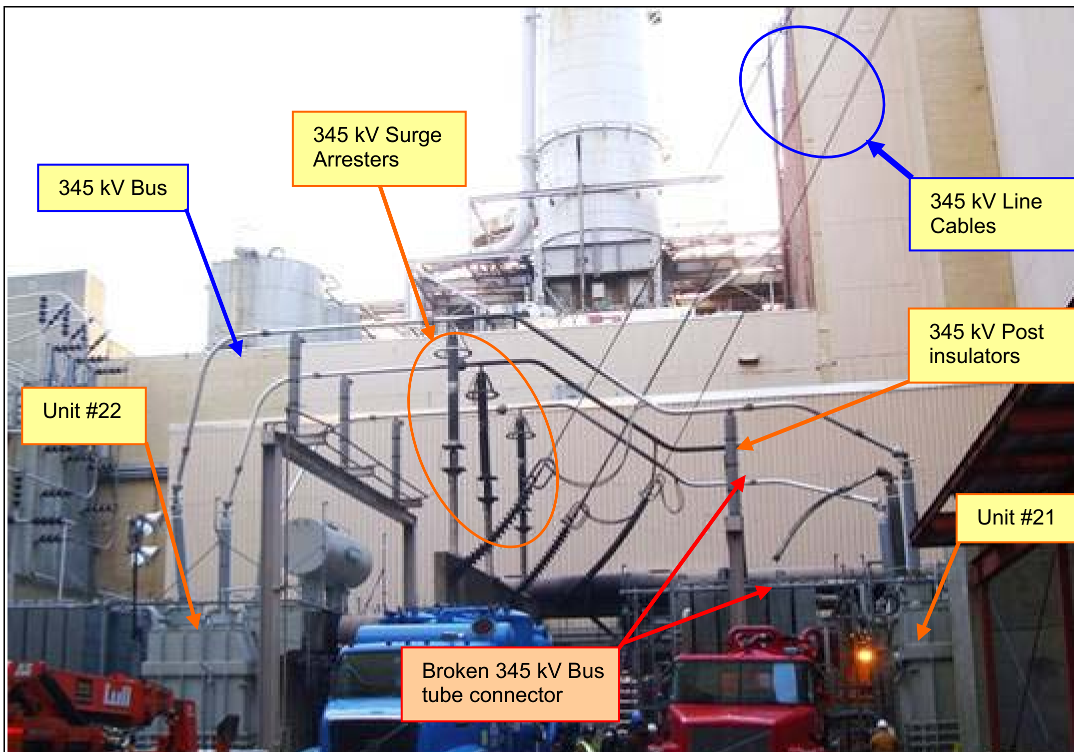
1. Scope

This Photographical Report contains the relevant pictures obtained during the inspection of the 345 kV buses and the post insulator which sustains these buses of the phase "B", which were directly involved with the event occurred on November 7th 2010 with the Generator Step Up (GSU) Transformer 629 MVA 345 kV installed on the ENTERGY Nuclear Plant at Indian Point –NY / USA.

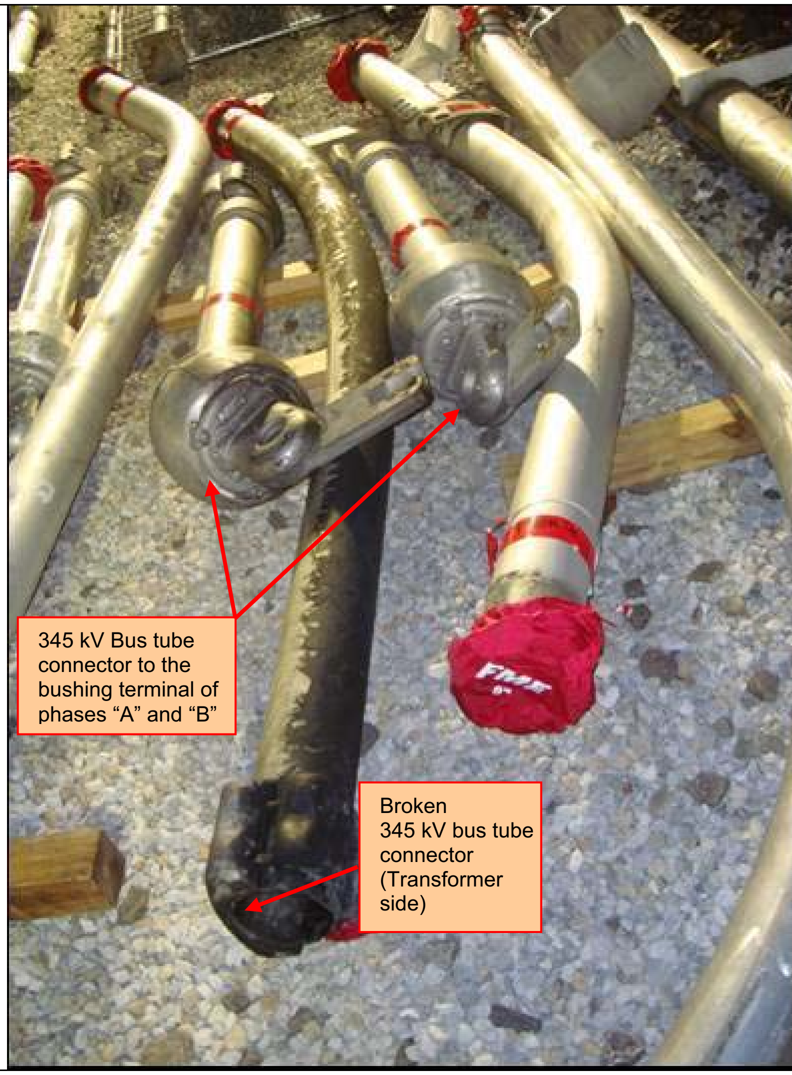
2. Inspection of the 345 kV Bus Connector

The connector of phase "B" which joints the two sections of the 345 kV bus on the right side of the surge arrester broke as a consequence of the mechanical shock caused by the flashover and explosion of the H2 bushing installed at Unit #21.

Consequently, the section connected to the H2 bushing fell apart as shown in ***Picture1*** below and the insulator post was broken at its base, as shown in the pictures of the following item.

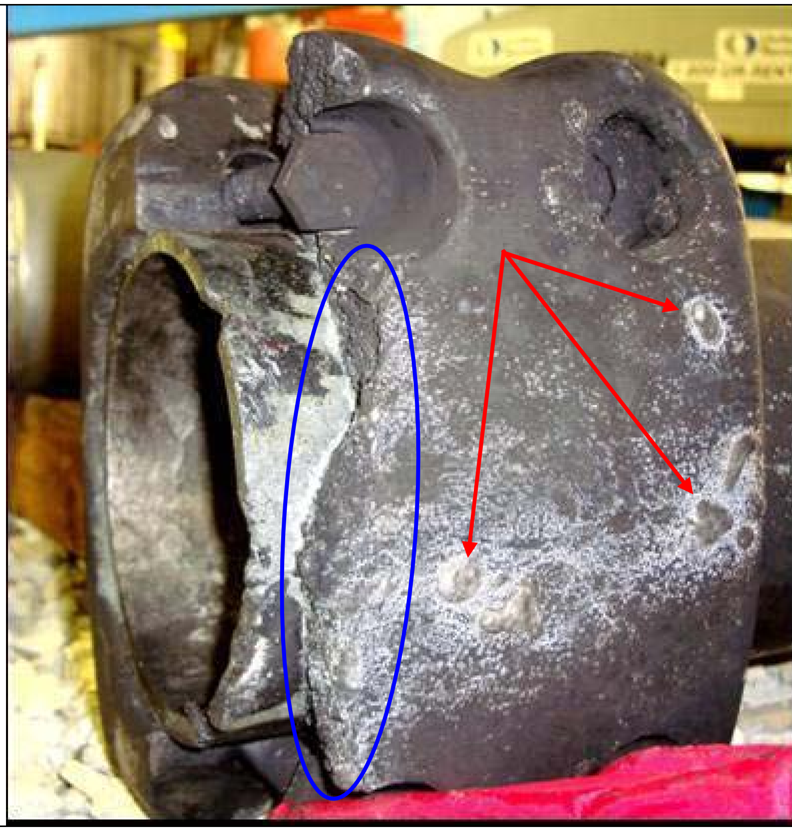


Picture 1: General view of the transformer yard showing the main involved components.

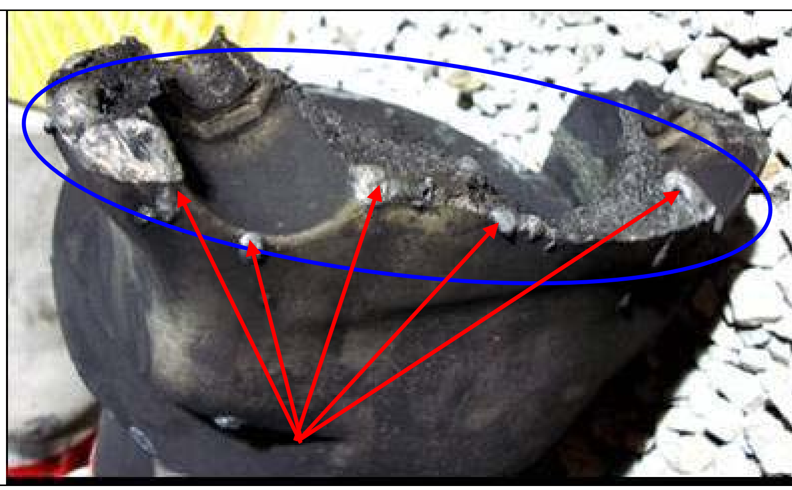


Picture 2: General view of the 345 kV buses after dismantling;

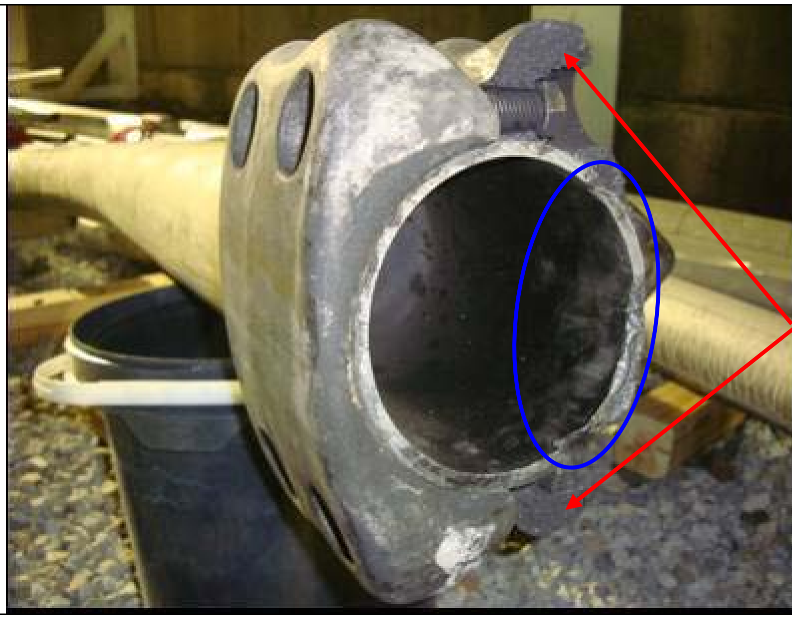
Picture 3: Detail view of the broken connector of phase "B",
(**Surge arrester side**);
Blue circle: Fractured surface with melting points caused by arcing;
Red arrows: Flashover marks;



Picture 4: Detail view of other half of the broken connector of phase “B” (**Transformer side**);
Blue circle: Fractured surface with melting points caused by arcing;
Red arrows: Melted aluminum deposited on the connector surface, which fell down when the flashover occurred on the braking connector;



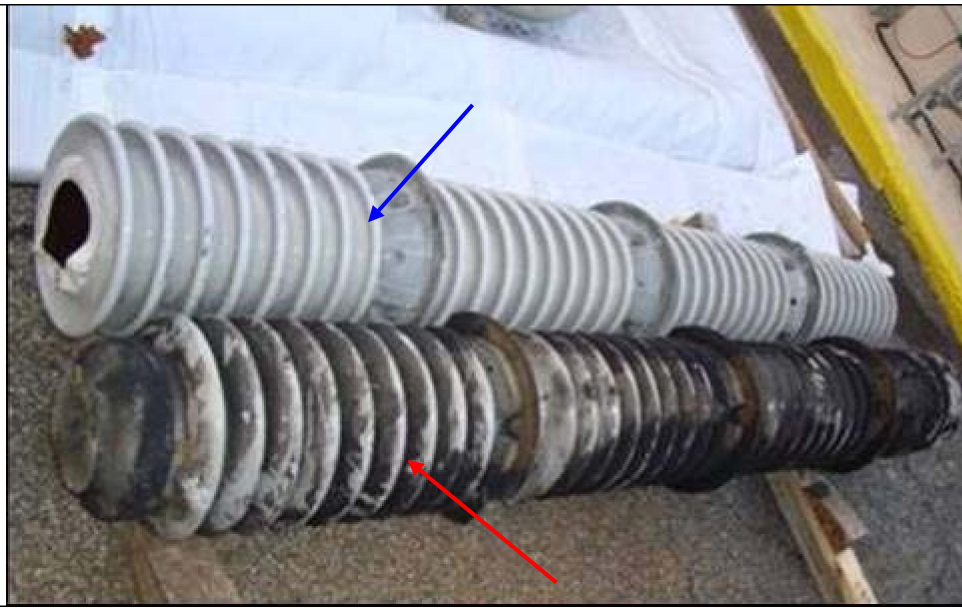
Picture 5: Detail view of one half of the broken connector of phase “B” (**Surge arrester side**);
Blue circle: Fractured surface with melting points caused by arcing;
Red arrows: Melted aluminum caused by the flashover occurred between the parts of the braking connector;



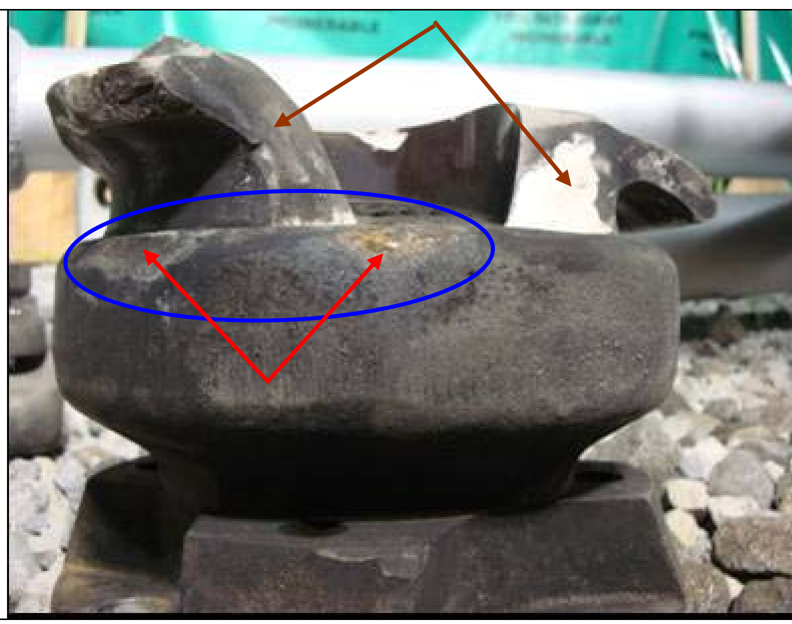
Picture 6: Detail view of one half of the broken connector of phase “B” **(Transformer side)**;
Blue circle: Tube end with melting & arcing marks;
Red arrows: Fractured surface of the connector;

Picture 7: Detail view of bus tube of phase “B” **(Transformer side)**;
Remark: the blackened surface of the tube was caused by the fireball which involved this part of the 345 kV bus after the explosion of the H2 bushing;
Red arrows: Melted aluminum deposited on the upper surface of the tube coming from the arcing occurred between the connector parts which broke in consequence of the mechanical shock wave;

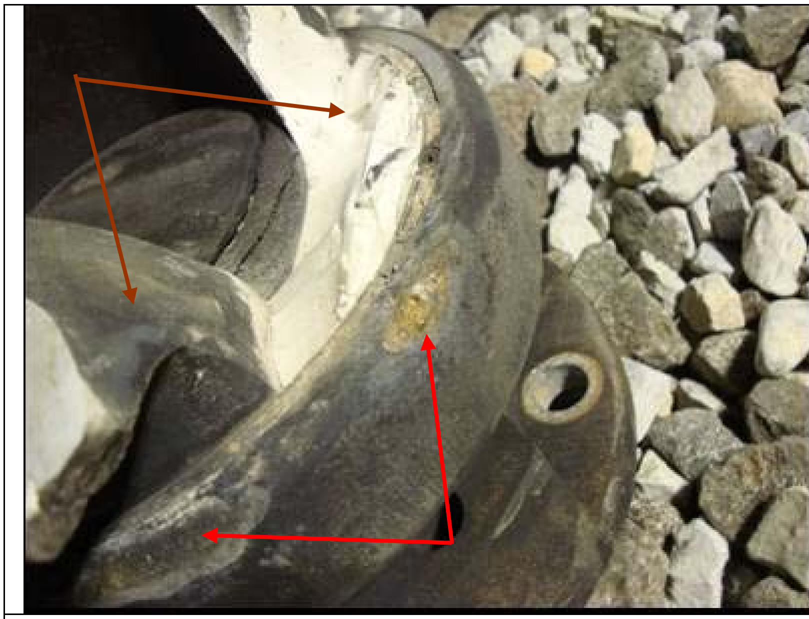
3. Investigation of the Phase "B" 345 kV Post Insulator



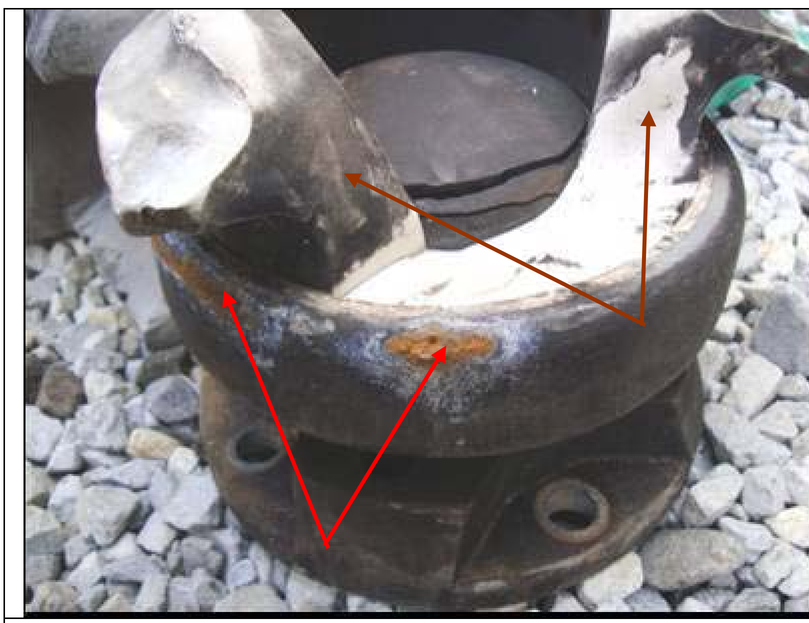
Picture 8: General view of the Post Insulators:
Red arrow: Phase "B" insulator, blackened by the dust of the fireball caused by the bushing explosion and which involved the components of phase "B";
Blue arrow: Phase "C" insulator, with a clean porcelain surface.



Picture 9: Detail view of the fixing base of the Post Insulator phase "B":
Red arrow: Foot points of the flashover which occurred on the post Insulator, before the occurrence of rain;
Blue circle: Flashover marks on the fixing base of the Insulator;
Brown arrows: Fracture surface of the broken porcelain.



Picture 10: Further detail view of the fixing base of the Post Insulator phase “B”,:
Red arrows: Foot points of the flashover which occurred on the post Insulator, **before they were wetted by rain**;
Brown arrows: Fracture surface of the broken porcelain.



Picture 11: Detail view of the fixing base of the Post Insulator phase “B”:
Red arrows: **Rusty foot points** of the flashover which occurred on the post Insulator, **after the occurrence of rain**;
Brown arrows: Fracture surface of the broken porcelain.

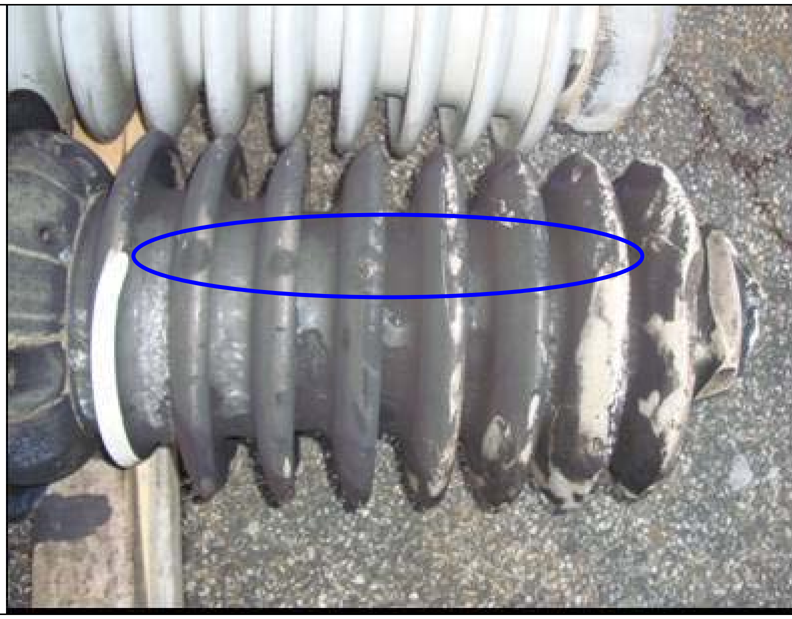
Picture 12: Detail view of the fixing base of the Post Insulator phase "B":
Blue circle: **Rusty foot points** of the flashover which occurred on the post Insulator, **after the occurrence of rain**;

Picture 13: Detail view of the top of the Post Insulator phase "B":
Red arrows: **Rusty foot point** of the top armature **after the occurrence of rain**;

Blue circle: Flashover traces on the porcelain surface of the uppermost shed.

Picture 14: Detail view of the intermediate sections of the Post Insulator phase "B":
Blue circle: Flashover traces on the upper metallic piece installed between porcelain sections;

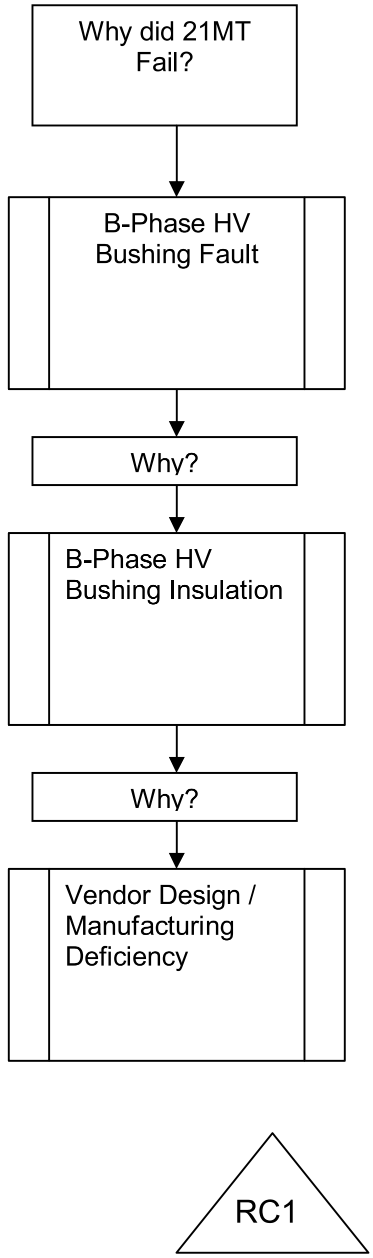
Picture 15: Detail view of the intermediate sections of the Post Insulator phase "B":
Blue circle: Flashover traces on the bottom metallic piece installed between porcelain sections;



Picture 16: Bottom piece of the Post Insulator phase “B”:
Blue circle: Flashover traces on the porcelain sheds;

Picture 17: Detail view of the bottom piece of the Post Insulator phase “B”:
Blue circle: Flashover traces on the porcelain sheds;

Attachment VI
Why Staircase Analysis



Attachment VII

Problem Statement (object/deviation format): 21 Main Transformer Failed

		IS (Facts Only)	IS NOT (Facts Only)		DISTINCTION (Facts Only)	CHANGE (Facts Only)
A	What	21 Main Transformer	22 Main Transformer	A	21 Main Transformer	NKC - transformers are sister units
B	What	Multiple arc strikes on B phase bushing conductor.	Main Arc Strikes on A or C	B	B Phase initiated event	
C	What			C		
D	Where	B' Phase failure as evident by protective relays. Overall Unit Differential Phase 'B' (87/GTB) and Main Transformer Differential Phases 'B' and 'C' (87/T21B and 87/T21C)	A' or 'C' Phases	D	B' Phase	NKC
E	Where	B' Phase failure as evident by location of tank rupture. Tank ruptured at top center below the location of the 'B' phase high voltage bushing	Tank rupture at any other location on the transformer.	E	B' Phase below location of HV Bushing	NKC
F	Where			F		
G	Where			G		
H	Where			H		
I	When	11/7/10 at 18:38 Automatic Reactor Trip	Prior to 11/7/10 (recent history)	I	Occurred within a minute of receiving a Generator High RF Alarm	This alarm has been coming in following increases in Lagging MVARs, this time the alarm occurred without a corresponding change in MVARs
J	When	Replaced in 2006- early in life cycle	Not at initial, middle or end of life.	J	Early in life cycle	NKC - monthly transformer oil sample results have been trending steady, no sudden changes in gassing rate.
K	When			K		
L	Extent	Catastrophic failure of B phase bushing resulting in tank rupture and neutral bushing failure	Non-Catastrophic Failure	L	Catastrophic failure	NKC
M	Extent	Two explosions occurred. One was upon the Unit trip and the second was ~ 10 minutes later. Other than sound no other observations were made of the second explosion.	One or multiple explosions.	M	A second explosion occurred after the Unit had been tripped for ~10 minutes	NKC - CCR verified Breakers 7 and 9 and disconnect F7-9 were Open at the time of the event. The Generator Field shorting breaker was verified Closed on 11/9/10.
N	Extent	Upon initial explosion oil was observed to be coming out of transformer and flaring up. Upon full actuation of deluge the fire went out.	Sustained Fire	N	Upon initial explosion the tank was observed to be ruptured and there was fire	NKC
O	Extent	Primary and Backup Pilot Wire Relays for Feeder W95 Tripped (87L1/345 and 87L2/345)	Generator Differential (87G or 87G2)	O	87L1/345 and 87L2/345, these relays are outside of the transformer zone of protection	NKC
P	Extent	B Phase bushing no condenser paper or resing insulation	C phase and A phase	P		
Q	Extent			Q		
R	Extent			R		

	POSSIBLE CAUSE (Technically explains deviation)	EXPLAINS ONLY IF (Assumptions)		DOES NOT EXPLAIN (Conflicting facts)
#1	"B" Phase bushing failed internally	Failure was catastrophic, there was no evidence of degradation in prior tests	#1	
#2	~~Failure of crib supports or corona shield~~	Evidence of arcing found in prior oil samples	#2	No Evidence of arcing found in routine oil samples
#3	~~Failure of bushing connectors~~	There was past evidence thermography hot spots	#3	No thermography hot spots or corona inspection issues.
#4	~~Loss of bushing oil~~	Loss of oil level in bushing	#4	
#5			#5	
#6			#6	
#7			#7	

TABLE 1 – SAFETY CULTURE COMPARISON

SAFETY CULTURE COMPONENT	DESCRIPTION	CR-IP2-2010-06801 – Unit 2 tripped due to a fault in 21 Main Transformer
1. Decision-Making	Licensee decisions demonstrate that nuclear safety is an overriding priority:	Considered, but not applicable to issue.
2. Resources	The licensee ensures that personnel, equipment, procedures, and other resources are available and adequate to assure nuclear safety.	Considered, but not applicable to issue.
3. Work Control	The licensee plans and coordinates work activities, consistent with nuclear safety:	Considered, but not applicable to issue.
4. Work Practices	Personnel work practices support human performance.	Considered, but not applicable to issue.
5. Corrective Action Program	The licensee ensures that issues potentially impacting nuclear safety are promptly identified, fully evaluated, and that actions are taken to address safety issues in a timely manner, commensurate with their significance.	Considered, but not applicable to issue.
6. Operating experience	The licensee uses operating experience (OE) information, including vendor recommendations and internally generated lessons learned, to support plant safety.	Considered, but not applicable to issue.
7. Self- and Independent Assessments	The licensee conducts self- and independent assessments of their activities and practices, as appropriate, to assess performance and identify areas for improvement.	Considered, but not applicable to issue.

SAFETY CULTURE COMPONENT	DESCRIPTION	CR-IP2-2010-06801 – Unit 2 tripped due to a fault in 21 Main Transformer
8. Environment For Raising Concerns	An environment exists in which employees feel free to raise concerns both to their management and/or the NRC without fear of retaliation and employees are encouraged to raise such concerns.	Considered, but not applicable to issue.
9. Preventing, Detecting, and Mitigating Perceptions of Retaliation	A policy for prohibiting harassment and retaliation for raising nuclear safety concerns exists and is consistently enforced.	Considered, but not applicable to issue.
10. Accountability	Management defines the line of authority and responsibility for nuclear safety.	Considered, but not applicable to issue.
11. Continuous learning environment	The licensee ensures that a learning environment exists.	Considered, but not applicable to issue.
12. Organizational change management	Management uses a systematic process for planning, coordinating, and evaluating the safety impacts of decisions related to major changes in organizational structures and functions, leadership, policies, programs, procedures, and resources. Management effectively communicates such changes to affected personnel.	Considered, but not applicable to issue.
13. Safety policies	Safety policies and related training establish and reinforce that nuclear safety is an overriding priority in that:	Considered, but not applicable to issue.

Notes

1	**RC1:** The most probable root cause deals with a vendor design/manufacturing deficiency associated with transformer bushings. There were no safety culture issues identified for this root cause.
2	There were no significant contributing causes identified for this event.
3	
4	

TABLE 2 – DETAILED SAFETY CULTURE COMPONENT REVIEW

		Description	CR-IP2-2010-06801 – Unit 2 tripped due to a fault in 21 Main Transformer
1. Decision-Making		**Licensee decisions demonstrate that nuclear safety is an overriding priority. Specifically (as applicable):**	
DM	H.1(a)	The licensee makes safety-significant or risk-significant decisions using a systematic process, especially when faced with uncertain or unexpected plant conditions, to ensure safety is maintained. This includes formally defining the authority and roles for decisions affecting nuclear safety, communicating these roles to applicable personnel, and implementing these roles and authorities as designed and obtaining interdisciplinary input and reviews on safety-significant or risk-significant decisions.	Considered, but not applicable to issue.
DM	H.1(b)	The licensee uses conservative assumptions in decision making and adopts a requirement to demonstrate that the proposed action is safe in order to proceed rather than a requirement to demonstrate that it is unsafe in order to disapprove the action. The licensee conducts effectiveness reviews of safety-significant decisions to verify the validity of the underlying assumptions, identify possible unintended consequences, and determine how to improve future decisions.	Considered, but not applicable to issue.
DM	H.1(c)	The licensee communicates decisions and the basis for decisions to personnel who have a need to know the information in order to perform work safely, in a timely manner.	Considered, but not applicable to issue.
2. Resources		**The licensee ensures that personnel, equipment, procedures, and other resources are available and adequate to assure nuclear safety. Specifically, those necessary for:**	
RES	H.2(a)	Maintaining long term plant safety by maintenance of design margins, minimization of long-standing equipment issues, minimizing preventative maintenance deferrals, and ensuring maintenance and engineering backlogs which are low enough to support safety.	Considered, but not applicable to issue.
RES	H.2(b)	Training of personnel and sufficient qualified personnel to maintain work hours within working hours guidelines.	Considered, but not applicable to issue.
RES	H.2(c)	Complete, accurate and up-to-date design documentation, procedures, and work packages, and correct labeling of components.	Considered, but not applicable to issue.
RES	H.2(d)	Adequate and available facilities and equipment, including physical improvements, simulator fidelity and emergency facilities and equipment.	Considered, but not applicable to issue.

		Description	CR-IP2-2010-06801 – Unit 2 tripped due to a fault in 21 Main Transformer
3. Work Control		**The licensee plans and coordinates work activities, consistent with nuclear safety. Specifically (as applicable):**	
WC	H.3(a)	The licensee appropriately plans work activities by incorporating • risk insights; • job site conditions, including environmental conditions which may impact human performance; plant structures, systems, and components; human-system interface; or radiological safety; and • the need for planned contingencies, compensatory actions, and abort criteria.	Considered, but not applicable to issue.
WC	H.3(b)	The licensee appropriately coordinates work activities by incorporating actions to address: | • the impact of changes to the work scope or activity on the plant and human performance. • the impact of the work on different job activities, and the need for work groups to maintain interfaces with offsite organizations, and communicate, coordinate, and cooperate with each other during activities in which interdepartmental coordination is necessary to assure plant and human performance. • The need to keep personnel apprised of work status, the operational impact of work activities, and plant conditions that may affect work activities. • The licensee plans work activities to support long-term equipment reliability by limiting temporary modifications, operator work-arounds, safety systems unavailability, and reliance on manual actions. Maintenance scheduling is more preventive than reactive.	Considered, but not applicable to issue.
4. Work Practices		**Personnel work practices support human performance. Specifically (as applicable):**	
WP	H.4(a)	The licensee communicates human error prevention techniques, such as holding pre-job briefings, self and peer checking, and proper documentation of activities. These techniques are used commensurate with the risk of the assigned task, such that work activities are performed safely. Personnel are fit for duty. In addition, personnel do not proceed in the face of uncertainty or unexpected circumstances.	Considered, but not applicable to issue.
WP	H.4(b)	The licensee defines and effectively communicates expectations regarding procedural compliance and personnel follow procedures	Considered, but not applicable to issue.
WP	H.4(c)	The licensee ensures supervisory and management oversight of work activities, including contractors, such that nuclear safety is supported.	Considered, but not applicable to issue.
5. Corrective Action Program		**The licensee ensures that issues potentially impacting nuclear safety are promptly identified, fully evaluated, and that actions are taken to address safety issues in a timely manner, commensurate with their significance. Specifically (as applicable):**	
CAP	P.1(a)	The licensee implements a corrective action program with a low threshold for identifying issues. The licensee identifies such issues completely, accurately, and in a timely manner commensurate with their safety significance.	Considered, but not applicable to issue.

		Description	CR-IP2-2010-06801 – Unit 2 tripped due to a fault in 21 Main Transformer
CAP	P.1(b)	The licensee periodically trends and assesses information from the CAP and other assessments in the aggregate to identify programmatic and common cause problems. The licensee communicates the results of the trending to applicable personnel.	Considered, but not applicable to issue.
CAP	P.1(c)	The licensee thoroughly evaluates problems such that the resolutions address causes and extent of conditions, as necessary. This includes properly classifying, prioritizing, and evaluating for operability and reportability conditions adverse to quality. This also includes, for significant problems, conducting effectiveness reviews of corrective actions to ensure that the problems are resolved.	Considered, but not applicable to issue.
CAP	P.1(d)	The licensee takes appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity.	Considered, but not applicable to issue.
CAP	P.1(e)	If an alternative process (i.e., a process for raising concerns that is an alternate to the licensee's corrective action program or line management) for raising safety concerns exists, then it results in appropriate and timely resolutions of identified problems.	Considered, but not applicable to issue.
6. Operating Experience		**The licensee uses operating experience (OE) information, including vendor recommendations and internally generated lessons learned, to support plant safety. Specifically (as applicable):**	
OE	P.2(a)	The licensee systematically collects, evaluates, and communicates to affected internal stakeholders in a timely manner relevant internal and external OE.	Considered, but not applicable to issue.
OE	P.2(b)	The licensee implements and institutionalizes OE through changes to station processes, procedures, equipment, and training programs.	Considered, but not applicable to issue.

		Description	CR-IP2-2010-06801 – Unit 2 tripped due to a fault in 21 Main Transformer
7. Self- and Independent Assessments		**The licensee conducts self- and independent assessments of their activities and practices, as appropriate, to assess performance and identify areas for improvement. Specifically (as applicable):**	
SA	P.3(a)	The licensee conducts self-assessments at an appropriate frequency; such assessments are of sufficient depth, are comprehensive, are appropriately objective, and are self-critical. The licensee periodically assesses the effectiveness of oversight groups and programs such as CAP, and policies.	Considered, but not applicable to issue.
SA	P.3(b)	The licensee tracks and trends safety indicators which provide an accurate representation of performance.	Considered, but not applicable to issue.
SA	P.3(c)	The licensee coordinates and communicates results from assessments to affected personnel, and takes corrective actions to address issues commensurate with their significance.	Considered, but not applicable to issue.
8. Environment For Raising Concerns		**An environment exists in which employees feel free to raise concerns both to their management and/or the NRC without fear of retaliation and employees are encouraged to raise such concerns. Specifically (as applicable):**	
ERC	S.1(a)	Behaviors and interactions encourage free flow of information related to raising nuclear safety issues, differing professional opinions, and identifying issues in the CAP and through self assessments. Such behaviors include supervisors responding to employee safety concerns in an open, honest, and non-defensive manner and providing complete, accurate, and forthright information to oversight, audit, and regulatory organizations. Past behaviors, actions, or interactions that may reasonably discourage the raising of such issues are actively mitigated. As a result, personnel freely and openly communicate in a clear manner conditions or behaviors, such as fitness for duty issues that may impact safety and personnel raise nuclear safety issues without fear of retaliation.	Considered, but not applicable to issue.
ERC	S.1(b)	If alternative processes (i.e., a process for raising concerns or resolving differing professional opinions that are alternates to the licensee's corrective action program or line management) for raising safety concerns or resolving differing professional opinions exists, then they are communicated, accessible, have an option to raise issues in confidence, and are independent, in the sense that the program does not report to line management (i.e., those who would in the normal course of activities be responsible for addressing the issue raised).	Considered, but not applicable to issue.

		Description	CR-IP2-2010-06801 – Unit 2 tripped due to a fault in 21 Main Transformer
9. Preventing, Detecting, and Mitigating Perceptions of Retaliation		**A policy for prohibiting harassment and retaliation for raising nuclear safety concerns exists and is consistently enforced in that:**	
PDR	S.2(a)	All personnel are effectively trained that harassment and retaliation for raising safety concerns is a violation of law and policy and will not be tolerated	Considered, but not applicable to issue.
PDR	S.2(b)	Claims of discrimination are investigated consistent with the content of the regulations regarding employee protection and any necessary corrective actions are taken in a timely manner, including actions to mitigate any potential chilling effect on others due to the personnel action under investigation.	Considered, but not applicable to issue.
PDR	S.2(c)	The potential chilling effects of disciplinary actions and other potentially adverse personnel actions (e.g., reductions, outsourcing, and reorganizations) are considered and compensatory actions are taken when appropriate.	Considered, but not applicable to issue.
10. Accountability		**Management defines the line of authority and responsibility for nuclear safety. Specifically (as applicable):**	
ACC	A.1(a)	(a) Accountability is maintained for important safety decisions in that the system of rewards and sanctions is aligned with nuclear safety policies and reinforces behaviors and outcomes which reflect safety as an overriding priority.	Considered, but not applicable to issue.
ACC	A.1(b)	(b) Management reinforces safety standards and displays behaviors that reflect safety as an overriding priority.	Considered, but not applicable to issue.
ACC	A.1(c)	(c) The workforce demonstrates a proper safety focus and reinforces safety principles among their peers.	Considered, but not applicable to issue.

		Description	CR-IP2-2010-06801 – Unit 2 tripped due to a fault in 21 Main Transformer
11. Continuous learning environment		**The licensee ensures that a learning environment exists. Specifically (as applicable):**	
CLE	C.2(a)	(a) The licensee provides adequate training and knowledge transfer to all personnel on site to ensure technical competency.	Considered, but not applicable to issue.
CLE	C.2(b)	(b) Personnel continuously strive to improve their knowledge, skills, and safety performance through activities such as benchmarking, being receptive to feedback, and setting performance goals. The licensee effectively communicates information learned from internal and external sources about industry and plant issues.	Considered, but not applicable to issue.
OCM	**12. Organizational change management**	**Management uses a systematic process for planning, coordinating, and evaluating the safety impacts of decisions related to major changes in organizational structures and functions, leadership, policies, programs, procedures, and resources. Management effectively communicates such changes to affected personnel.**	Considered, but not applicable to issue.
13. Safety policies		**Safety policies and related training establish and reinforce that nuclear safety is an overriding priority in that:**	
SP	SP.4(a)	(a) These policies require and reinforce that individuals have the right and responsibility to raise nuclear safety issues through available means, including avenues outside their organizational chain of command and to external agencies, and obtain feedback on the resolution of such issues.	Considered, but not applicable to issue.
SP	SP.4(b)	(b) Personnel are effectively trained on these policies.	Considered, but not applicable to issue.
SP	SP.4(c)	(c) Organizational decisions and actions at all levels of the organization are consistent with the policies. Production, cost and schedule goals are developed, communicated, and implemented in a manner that reinforces the importance of nuclear safety.	Considered, but not applicable to issue.
SP	SP.4(d)	(d) Senior managers and corporate personnel periodically communicate and reinforce nuclear safety such that personnel understand that safety is of the highest priority.	Considered, but not applicable to issue.

Attachment IX

Entergy

PROPRIETARY INFORMATION [Withhold from public disclosure] under 10 CFR 2.390

IPEC Security (Internal) Incident Report

Date: 11 / 7 / 2010

Employee Name: M. MASTROPIETRO **Badge #** 3395

Contact Number: 736 - 8067.

Supervisor Name: OBRIEN **Phone #** 271-7028

*Please provide **a description on the events** that transpired as you recall them. Try to answer (Who, What, Where, When, Why) and any other important information you can recall.*

As MoBle Unit 35 (outside Patrol) I had just finished a patrol and stopped at the main gate, A few minutes Later Both S/O Kowalsky (unit 25) and myself heard an explosion (18:30) I Then saw a Ball of Fire in the Glass Window Facing Broadway. I went outside to see more. There was no actual Fire, But a Wave of Thick Black Smoke moving From north to South. I Notified my findings to Base 1, that I had seen Smoke coming From The Water meter House. A few minutes Late I was dispatched to pickup SSS OBRIEN, who would Ride with me to investigate The area of The City Water meter House. (18:46). There was nothing unusual That we found in That Area. The smoke had dissipated By This Time. UNIT 85, LT MANUEL had arrived at our Location waiting For The Verplank Fire Department.

Employee Signature [signature]

February 24, 2004

Entergy

PROPRIETARY INFORMATION [Withhold from public disclosure] under 10 CFR 2.390

IPEC Security (Internal)
Incident Report

Date: 11 / 7 / 2010

Employee Name: M. SPARNELLI **Badge #** 933

Contact Number: 736-8067

Supervisor Name: OBrien **Phone #** ____________

*Please provide **a description on the events** that transpired as you recall them. Try to answer (Who, What, Where, When, Why) and any other important information you can recall.*

AS UNIT 28 while viewing camera
FACING the main gate I noticeD A
Bright FLASH very noticABLE AgAINST
The BLAcK SKY seconDS Later the
whole Area / WAS FilleD with smok.
AnD then 35 CAlleD in to the BASE
station that He HearD AN explosion

Employee Signature [signature]

February 24, 2004

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K. Mann

ATTACHMENT 9.2 — INDIVIDUAL RECOLLECTION FORM

Sheet 1 of 2

Answer the following questions to the best of your ability based solely on your own recollections. Use additional sheets and attach sketches as necessary.

1. What did you see, hear, feel, or smell that may relate to the incident? When and in what sequence? Sounded like the generator took a "hit", only the sound was much louder than usual. Vibrations are felt in the NPO shack when the generator takes a hit. There was much more energy in this hit compared to other previously experienced

2. What conditions existed just prior to the incident?
Preparing for start of watch meeting. Watch turnover had finished ~ 10 minutes before.

3. What caused you to be aware of the incident?
Announcement of fire in U2 Xformer yard accompanied by a fire alarm.

4. What happened during the incident?
Noted Main transformer 21 deluge was activated & spraying down transformer. Fire brigade & leader convened. Fire brigade leader developed plan of attack for situation and followed through with plan.

5. What happened after the incident?
Additional foam sprayed onto transformer as precaution. Firewatch established. Released to assist with shutdown of plant.

6. What were you doing before, during and after the incident (be specific)?
Before - preparing for start of watch meeting in NPO shack
During - fire brigade duties, fire watch.
After plant shutdown duties

7. What actions did you take before, during and after the incident (be specific)? Cite times as accurately as you can remember. If you do not know times, try to relate times of actions to details of the incident.

Before. eating food when sound of generator changed (bogged down). Other alarms came in but were unk at that instant.
During. Scramble to put fire brigade gear on & arrive at scene
After. Fire watch. Plant shut down duties

8. What actions did you observe others take that may be relevant to the incident?

~~Every one~~ Previous shift teams (U2, U3) arrived to fight fire when alarm sounded.

9. What procedures or documents do you consider relevant to the incident?

NONE. main transformer failed causing event.

10. What consequences of the incident did you observe? When?

Destroyed main transformer. Oil water mix comming up from floor drain in east side sublevel of 15' elevation turbine building. Time was after 21 M.T. fire was under control.

11. What other information do you have relative to the incident that is based on your own personal observations or recollections? Attempted to isolate oil to ruptured main transformer pipe. Valves did not operate properly preventing isolation.

12. What error traps/precursors do you believe contributed to the incident

Precursor - malfunction of 21 main transformer.

13. What HU Tools or defenses may have prevented the incident?

NONE.

14. What do you consider to be the Lesson Learned from this incident?

Good teamwork gets things done in a timely & efficient manner
Also - be ready for anything.

Ross Rohlt

ATTACHMENT 9.2 — **INDIVIDUAL RECOLLECTION FORM**

Sheet 1 of 2

Answer the following questions to the best of your ability based solely on your own recollections. Use additional sheets and attach sketches as necessary.

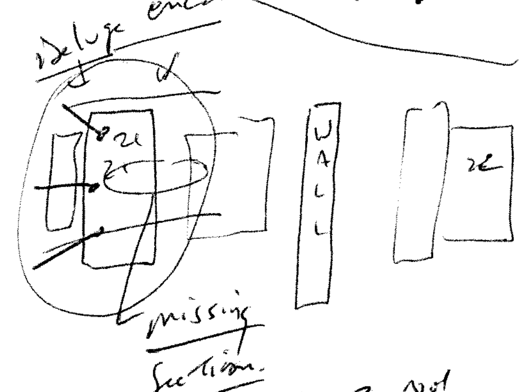
1. What did you see, hear, feel, or smell that may relate to the incident? When and in what sequence?

Walking out the north entrance thru 13KV yard; saw glow & heard Electric buzz followed by explosion & fireball that tripped Incoming Lines. Returned to CCR to inform them of "blowing a transformer" & Fireball → CCR sounded Fire alarm.

2. What conditions existed just prior to the incident?

3. What caused you to be aware of the incident?

> sound / buzz
> Light / glow
> fireball from Transformer yard



4. What happened during the incident?

2nd Time 2 Not

5. What happened after the incident?

went to roof to perform visual. Transformer 21 & 22 looked intact; could not see conservator due to Deluge fog. water fog. After second boom that shook CCR; went back to roof for visual. same as before. Transformer box looked intact; some bus bar missing a middle phase; bus blackened.

~~6. What were you doing before, during and after the incident (be specific)?~~

Reported Info to G. Keller.

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ATTACHMENT 9.2 — **INDIVIDUAL RECOLLECTION FORM**

Sheet 2 of 2

7. What actions did you take before, during and after the incident (be specific)? Cite times as accurately as you can remember. If you do not know times, try to relate times of actions to details of the incident.

reported 2 CCR; 2 trips to 88' roof for visual for G. Keller. Assisted As required IN CCR, relieved @ NLE red phone by Mike Bowman

8. What actions did you observe others take that may be relevant to the incident?

9. What procedures or documents do you consider relevant to the incident?

10. What consequences of the incident did you observe? When?

11. What other information do you have relative to the incident that is based on your own personal observations or recollections?

12. What error traps/precursors do you believe contributed to the incident

13. What HU Tools or defenses may have prevented the incident?

14. What do you consider to be the Lesson Learned from this incident?

2 high Pressure N_2 Trucks parked by MT's. If Involved; could have been "missles" in the yard.

TOM ALEXANDER

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ATTACHMENT 9.2 INDIVIDUAL RECOLLECTION FORM

Sheet 1 of 2

Answer the following questions to the best of your ability based solely on your own recollections. Use additional sheets and attach sketches as necessary.

1. What did you see, hear, feel, or smell that may relate to the incident? When and in what sequence? SLIGHT CONCUSSION, NUMEROUS ALARMS, SMOKE ODOR AT THE TIME OF, AND JUST AFTER THE INCIDENT.

2. What conditions existed just prior to the incident? 100% STEADY STATE OPERATION HI RF ALARM HAD JUST COME IN AGAIN, AND I WENT OVER TO THE U-1 SUPERVISORY PANEL TO SILENCE IT. AS I WAS WALKING BACK TO FINISH TURNOVER/BOARD WALK DOWN THE EVENT OCCURRED.

3. What caused you to be aware of the incident? SLIGHT CONCUSSION, NUMEROUS ALARMS, SMOKE ODOR AT THE TIME OF AND JUST AFTER INCIDENT, AND THE GENERATOR TRIPPED.

4. What happened during the incident? GENERATOR TRIPPED, ENTERED E-0, PERFORMED ACTIONS. FIRE BRIGADE DISPATCHED. TOOK ACTIONS TO STABILIZE THE PLANT.

5. What happened after the incident? - PLACED CCR VENTILATION TO MODE 3 RECIRC WHEN SMOKE ODOR DETECTED IN CCR.

6. What were you doing before, during and after the incident (be specific)?
   - BEFORE - BOP OPERATOR, PERFORMING SHIFT TURNOVER/BOARD WALK DOWN WITH ON-COMING NIGHT SHIFT.
   - DURING PERFORMING BOP ACTIONS IAW E PROCEDURES.
     - MAINTAINING SG LEVELS WITH AUX FEED. SECURING SECONDARY SYSTEMS AS NECESSARY (RF/GEN MON, LP STEAM DUMPS)

AFTER - TURNED OVER WATCH AND DUTIES TO ON-COMING NIGHT ...

7. What actions did you take before, during and after the incident (be specific)? Cite times as accurately as you can remember. If you do not know times, try to relate times of actions to details of the incident.
   - CONTROLLING AUX FEED TO MAINTAIN SG LEVELS
   - SECURING SECONDARY SYSTEMS (RF/GEN MONITOR, LP STEAM DUMPS.)

8. What actions did you observe others take that may be relevant to the incident?

9. What procedures or documents do you consider relevant to the incident?
   - E-0
   - FIRE PLAN
   - COP

10. What consequences of the incident did you observe? When?
    - PLANT TRIP
    - STATION AUX TAP CHANGER HANG UP - SA XFORMER WAS NOT BETWEEN TAPS.

11. What other information do you have relative to the incident that is based on your own personal observations or recollections?
    - SECOND EXPLOSION OCCURRED SOME TIME AFTER AND WAS MORE NOTICABLE DUE TO FEWER ALARMS GOING OFF IN THE CCR.

12. What error traps/precursors do you believe contributed to the incident

13. What HU Tools or defenses may have prevented the incident?

14. What do you consider to be the Lesson Learned from this incident?

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COSENTINO

ATTACHMENT 9.2 INDIVIDUAL RECOLLECTION FORM

Sheet 1 of 2

Answer the following questions to the best of your ability based solely on your own recollections. Use additional sheets and attach sketches as necessary.

1. What did you see, hear, feel, or smell that may relate to the incident? When and in what sequence? LOUD "THUMP" FROM TRANSFORMER YARD AT TIME OF TRIP

2. What conditions existed just prior to the incident?
GENERATOR RF ALARM WAS RECEIVED JUST PRIOR TO EVENT

3. What caused you to be aware of the incident?
SEE #1 ABOVE

4. What happened during the incident?
21 MAIN TRANSFORMER FAULT - UNIT TRIP

5. What happened after the incident?
NORMAL PLANT TRIP RESPONSE WITH EXCEPTION OF STATION AUX TRANSFORMER TAP CHANGER HANG UP. ALSO A SECONDARY EXPLOSION IN THE TRANSFORM

6. What were you doing before, during and after the incident (be specific)?
Before receiving RF ALARM - WATCH TURNOVER
AFTER TRIP - RESPONDING TO TRIP AND TRANSFORMER MALFUNCTION

7. What actions did you take before, during and after the incident (be specific)? Cite times as accurately as you can remember. If you do not know times, try to relate times of actions to details of the incident.

   RESPONSE TO RESULTS OF "INCIDENT"

8. What actions did you observe others take that may be relevant to the incident?

   NONE

9. What procedures or documents do you consider relevant to the incident?

   N/A

10. What consequences of the incident did you observe? When?

    OBVIOUS DAMAGE TO TRANSFORMER + SURROUNDING AREA

11. What other information do you have relative to the incident that is based on your own personal observations or recollections?

    NONE OF SIGNIFICANCE

12. What error traps/precursors do you believe contributed to the incident

    TOO EARLY TO TELL

13. What HU Tools or defenses may have prevented the incident?

    TOO EARLY TO TELL

14. What do you consider to be the Lesson Learned from this incident?

    TOO EARLY TO TELL

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Luke Hedges

ATTACHMENT 9.2 INDIVIDUAL RECOLLECTION FORM

Sheet 1 of 2

Answer the following questions to the best of your ability based solely on your own recollections. Use additional sheets and attach sketches as necessary.

1. What did you see, hear, feel, or smell that may relate to the incident? When and in what sequence? recieved AN RF ALARM, SECONDS LATER A GENERATOR TRIP occurred, moments later an OFFGOING RO RETURNED TO THE CCR AND REPORTED AN Explosion in The transformer yard, THERE WAS A SMOKEY ODOR IN THE CCR

2. What conditions existed just prior to the incident?
100% Power, normal conditions

3. What caused you to be aware of the incident?
FIRST OUT ALARM FOR THE TRIP

4. What happened during the incident?
Reactor TRIPPED, TAP CHANGER HANG UP ON STA AUX

5. What happened after the incident?
carried out E-0, ES-0.1 POP 3.2 AND POP 3.3

6. What were you doing before, during and after the incident (be specific)?
HAD recently taken The WATCH AND WAS REVIEWING PLANNED ACTIVITIES, DURING AND AFTER THE EVENT CARRIED OUT APPROPRIATE PLANT PROCEDURES

7. What actions did you take before, during and after the incident (be specific)? Cite times as accurately as you can remember. If you do not know times, try to relate times of actions to details of the incident. ~ 1845 carried out E-O

8. What actions did you observe others take that may be relevant to the incident?
APPROPRIATE IMMIDIATE ACTIONS

9. What procedures or documents do you consider relevant to the incident?
E-O, ES 0.1, POP 3.2

10. What consequences of the incident did you observe? When?
Reactor TRIP, IMMIDIATELY

11. What other information do you have relative to the incident that is based on your own personal observations or recollections? NONE

12. What error traps/precursors do you believe contributed to the incident
NONE

13. What HU Tools or defenses may have prevented the incident?
NONE

14. What do you consider to be the Lesson Learned from this incident?
ALWAYS BE READY

ATTACHMENT 9.2 **INDIVIDUAL RECOLLECTION FORM**

Sheet 1 of 2 Kevin McKenna 11/8/10 Fire Brigade leader

Answer the following questions to the best of your ability based solely on your own recollections. Use additional sheets and attach sketches as necessary.

1. What did you see, hear, feel, or smell that may relate to the incident? When and in what sequence? at approximately 1530 heard loud Bang, noticed lights out on North end of turbine Hall 53'. Went to CCR and was informed that there was an explosion in transformer yard

2. What conditions existed just prior to the incident?
100% power

3. What caused you to be aware of the incident?
loud bang / lights out on 53'.

4. What happened during the incident?
Reactor / turbine trip

5. What happened after the incident?
Fire brigade activated, Alert declared

6. What were you doing before, during and after the incident (be specific)?
Before: Discussing work for the day with FSS/STA,
During: Performing Duties as Fire brigade Leader
After: assisting watch team perform activities as directed by PCPs

ATTACHMENT 9.2 **INDIVIDUAL RECOLLECTION FORM**

Sheet 2 of 2

7. What actions did you take before, during and after the incident (be specific)? Cite times as accurately as you can remember. If you do not know times, try to relate times of actions to details of the incident.

   During: Directed the setup of Hose lines to apply Protein Foam to 21MT & Securing Water Deluge.

8. What actions did you observe others take that may be relevant to the incident?

   None

9. What procedures or documents do you consider relevant to the incident?

   Pre fire Plans

10. What consequences of the incident did you observe? When?

    None

11. What other information do you have relative to the incident that is based on your own personal observations or recollections?

    None

12. What error traps/precursors do you believe contributed to the incident

    None

13. What HU Tools or defenses may have prevented the incident?

    None

14. What do you consider to be the Lesson Learned from this incident?

    None

ATTACHMENT 9.2 **INDIVIDUAL RECOLLECTION FORM**

Sheet 1 of 2 MICHAEL RUH

Answer the following questions to the best of your ability based solely on your own recollections. Use additional sheets and attach sketches as necessary.

1. What did you see, hear, feel, or smell that may relate to the incident? When and in what sequence?

HI RF ALARM CLEARED AND CAME UP AGAIN, SECONDS LATER UNIT TRIPPED.

2. What conditions existed just prior to the incident?

"HI R.F. SIGNAL" ALARM WAS UP DUE TO EARLIER VAR ADJUSTMENT UNIT AT 100% POWER ALL CONDITIONS NORMAL.

3. What caused you to be aware of the incident?

UNIT TRIP. OFF GOING R.O. WHO STOOD NUCLEAR WATCH RETURNED + REPORTED THAT THERE WAS AN EXPLOSION IN XFMR YARD.

4. What happened during the incident?

ALL PRIMARY PLANT SYSTEMS RESPONDED AS REQUIRED NORMAL PRIMARY CONDITIONS

5. What happened after the incident?

BRIGADE RESPONSE, ALERT NOTIFICATION,

6. What were you doing before, during and after the incident (be specific)?

STANDING AT FLIGHT PANEL WHILE BOP ACKNOWLEDGED RF ALARM.

7. What actions did you take before, during and after the incident (be specific)? Cite times as accurately as you can remember. If you do not know times, try to relate times of actions to details of the incident.

IMPLEMENTED E-0 AT ~~E-0~~ 1834

8. What actions did you observe others take that may be relevant to the incident?

DON'T KNOW I WAS MONITORING PRIMARY PLANT

9. What procedures or documents do you consider relevant to the incident?

FIRE RESPONSE

10. What consequences of the incident did you observe? When?

NONE

11. What other information do you have relative to the incident that is based on your own personal observations or recollections?

NONE

12. What error traps/precursors do you believe contributed to the incident

NONE KNOWN

13. What HU Tools or defenses may have prevented the incident?

NONE

14. What do you consider to be the Lesson Learned from this incident?

N^2 TRAILERS POSSIBLY HINDERED FIRE BRIGADE RESPONSE

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ATTACHMENT 9.2 **INDIVIDUAL RECOLLECTION FORM**

Sheet 1 of 2

Answer the following questions to the best of your ability based solely on your own recollections. Use additional sheets and attach sketches as necessary.

1. What did you see, hear, feel, or smell that may relate to the incident? When and in what sequence? (1) Loud "Boom" → plant tripped
   (2) Funny smell
   (3) deluge visibly going off

2. What conditions existed just prior to the incident?
   Nothing out of the ordinary. No signs of the oncoming event.

3. What caused you to be aware of the incident?
   A Loud "Boom" Sound, then the Plant Tripped. The CCR Alert

4. What happened during the incident?
   The Plant tripped - Fire Brigade Gathered to the transformer yard to control situation

5. What happened after the incident? – I stood fire watch intermittently with other fire Brigade Members (taking turns).

6. What were you doing before, during and after the incident (be specific)?
   I had just arrived @ ~0625 → NPO office for the start of my shift. I had sat down when the loud "Boom" occurred. I immediately got up - put on PPE & exited NPO office. Then the CCR Alert came over the speaker + I dressed out in my fire Brigade PPE - proceeded to transformer yard & assisted in controlling situation (question 7)

7. What actions did you take before, during and after the incident (be specific)? Cite times as accurately as you can remember. If you do not know times, try to relate times of actions to details of the incident. ~0640 - Incident occured. I Dressed out FB PPE. Proceeded to transformer yard. Assisted w/ hoses, nozzles, foam w/ nozzle man. Unsure of exact times - Foam distribution was after deluge was secured.

8. What actions did you observe others take that may be relevant to the incident?
None

9. What procedures or documents do you consider relevant to the incident?
EOP's, FB Firebrigade training manuals

10. What consequences of the incident did you observe? When?
Following fire Brigade Actions, visual observations of 21 Main transformer damage, flooding on 5', 15'

11. What other information do you have relative to the incident that is based on your own personal observations or recollections?
None

12. What error traps/precursors do you believe contributed to the incident
- Possible Equipment failure

13. What HU Tools or defenses may have prevented the incident?
I don't know of any. I do not know why 21 main transformer failed

14. What do you consider to be the Lesson Learned from this incident?
- Never let your Guard down - Anything can happen At any time - without warning - Be sharp!

ATTACHMENT 9.2 **INDIVIDUAL RECOLLECTION FORM**

Sheet 1 of 2 P. CAMPBELL

Answer the following questions to the best of your ability based solely on your own recollections. Use additional sheets and attach sketches as necessary.

1. What did you see, hear, feel, or smell that may relate to the incident? When and in what sequence?
   - DURING BOARD WALK ~2 MINUTES BEFORE GEN RF ALARM
   - SEVERAL SECONDS OF 60HZ HUM AND PRESSURE WAVE
   - UNIT TRIP AND ALARMS UP

2. What conditions existed just prior to the incident?

   GEN RF ALARM - NO OTHER INDICATIONS

3. What caused you to be aware of the incident?

   THE SOUND OF A FAULTING TRANSFORMER

4. What happened during the incident?

   ENTERED E-0, GOT REPORT OF EXPLOSION/FIRE/SMOKE FROM OFFGOING RO, DISPATCHED FIRE BRIGADE, SECOND INTERNAL EXPLOSION OCCURRED

5. What happened after the incident?

   ES-0.1, RECOVERY, COOLDOWN

6. What were you doing before, during and after the incident (be specific)?

   BOARDWALK, IMMEDIATE ACTIONS, COMMUNICATIONS TO DISPATCH FIRE RESPONSE

ATTACHMENT 9.2 INDIVIDUAL RECOLLECTION FORM

Sheet 2 of 2

7. What actions did you take before, during and after the incident (be specific)? Cite times as accurately as you can remember. If you do not know times, try to relate times of actions to details of the incident.

see log

8. What actions did you observe others take that may be relevant to the incident?

N/A

9. What procedures or documents do you consider relevant to the incident?

E-0, ES 3.1, POP 3.2

10. What consequences of the incident did you observe? When?

- 480V room Hi temp, SAT tap changer hung up.

11. What other information do you have relative to the incident that is based on your own personal observations or recollections?

none

12. What error traps/precursors do you believe contributed to the incident

N/A

13. What HU Tools or defenses may have prevented the incident?

N/A

14. What do you consider to be the Lesson Learned from this incident?

N/A

Dewey

ATTACHMENT 9.2 INDIVIDUAL RECOLLECTION FORM

Sheet 1 of 2

Answer the following questions to the best of your ability based solely on your own recollections. Use additional sheets and attach sketches as necessary.

1. What did you see, hear, feel, or smell that may relate to the incident? When and in what sequence?

   I was in the one stop shop. I heard the Turbine trip and saw The U2 turbine lighting go out

2. What conditions existed just prior to the incident?

   100% power

3. What caused you to be aware of the incident?

   See #1 above

4. What happened during the incident?

   I came to the control room and assumed the ED Role.

5. What happened after the incident?

6. What were you doing before, during and after the incident (be specific)?

   Before - sitting in one stop shop
   during - ED going Through The Eplan
   After - Remained shift manager.

Entergy	NUCLEAR MANAGEMENT MANUAL	NON-QUALITY RELATED	EN-HU-103	REV. 3
		INFORMATIONAL USE		
Human Performance Error Reviews				

KELLER

ATTACHMENT 9.2 — INDIVIDUAL RECOLLECTION FORM

Sheet 1 of 2

Answer the following questions to the best of your ability based solely on your own recollections. Use additional sheets and attach sketches as necessary.

1. What did you see, hear, feel, or smell that may relate to the incident? When and in what sequence? IN ONE STOP SHOP. LOUD BOOM WITH BUILDING SHAKING.

2. What conditions existed just prior to the incident?

   100% – NO ISSUES

3. What caused you to be aware of the incident?

   BOOM

4. What happened during the incident?

   UNIT TRIP

5. What happened after the incident?

   UNIT STAYED TRIPPED WITH A FIRE 21 MT

6. What were you doing before, during and after the incident (be specific)?

   BEFORE – PRINTING TAGOUTS
   DURING – WATCHING LUKE + STATUS TREES
   AFTER – ADDRESSING NPS

7. What actions did you take before, during and after the incident (be specific)? Cite times as accurately as you can remember. If you do not know times, try to relate times of actions to details of the incident.

   CALLED 911 FOR OFSITE FIRE DEPT ≈ 1900 HRS

8. What actions did you observe others take that may be relevant to the incident?

   NORMAL EMERGENCY OPERATING PROCEDURES – JUST LIKE TRAINING.

9. What procedures or documents do you consider relevant to the incident?

   EOPS

10. What consequences of the incident did you observe? When?

    NONE

11. What other information do you have relative to the incident that is based on your own personal observations or recollections?

    NONE

12. What error traps/precursors do you believe contributed to the incident

    NONE

13. What HU Tools or defenses may have prevented the incident?

    UNKNOWN

14. What do you consider to be the Lesson Learned from this incident?

    NONE

Entergy

PROPRIETARY INFORMATION [Withhold from public disclosure] under 10 CFR 2.390

IPEC Security (Internal)
Incident Report

Date: 11 / 7 / 2010

Employee Name: M. Spagnuolo **Badge #** 933

Contact Number: 736 - 8067

Supervisor Name: OBrien **Phone #** ____________

Please provide ***a description on the events*** *that transpired as you recall them. Try to answer (Who, What, Where, When, Why) and any other important information you can recall.*

AS UNIT 28 while viewing camera
FACING the main gate I noticed A
Bright FLASH very noticable against
the Black sky seconds Later the
whole area was filled with smoke
And then 35 called in to the Base
station that he heard an explosion

Employee Signature [signature]

February 24, 2004

Equipment Failure Evaluation

CONDITION REPORT:	**IP2-2010-06801**

EQUIPMENT AFFECTED:

EQUIPMENT (COMPONENT) ID: 21MTRFR		**PROCESS SYSTEM CODE: 345K**	
UNIT	1 ☐ 2 ☒ 3 ☐ C ☐	**EDB PMO CODE: 3**	
TAG NAME	21 MAIN TRANSFORMER	**TAG SUFFIX NAME**	HCHM/NS
COMPONENT CODE	TRANSF		

1. Verification Of The Correctness Of Criticality Classification:	**YES**	**NO**
a. Is the Component Classification correct per EN-DC-153, Attachment 9.3, Section 1?	☒	☐
b. Is the Component Duty Cycle correct per EN-DC-153, Attachment 9.3, Section 2?	☒	☐
c. Is the Component Service Condition correct per EN-DC-153, Attachment 9.3, Section 3?	☒	☐

2. Adequacy Of System and Component Monitoring:	**YES**	**NO**	**N/A**
a. For condition monitoring performed under the System Monitoring Plan per EN-DC-159 or the Component Monitoring Plan per EN-DC-325, are the appropriate parameters being monitored at the optimum frequency to detect the degradation mechanisms/influences that resulted in this component failure? *As documented in the RCA, the mechanism that caused the failure (electrical treeing) is not detectable through condition monitoring. The electrical treeing was only evident upon bushing teardown.*	☐	☐	☒
b. If not performed, should it be?	☐	☐	☒
c. If performed, is the monitoring and threshold for action adequate?	☐	☐	☒
d. If performed, is there improvement needed in collecting or trending the data?	☐	☐	☒

3. Adequacy Of PM Program:	YES	NO	N/A
a. Does a PM task exist?	☒	☐	☐
b. Are the PM tasks adequate to defend against the degradation mechanisms/influences that resulted in this component functional failure? *As documented in the RCA, the mechanism that caused the failure (electrical treeing) is not detectable through preventive maintenance. The electrical treeing was only evident upon bushing teardown.*	☐	☐	☒
c. Is the PM task content adequate? Is the content consistent with the current PM Template?	☐	☐	☒
d. Is PM frequency adequate? Is the frequency consistent with the current PM Template?	☐	☐	☒
e. Is the current PM Template adequate? Is the content consistent with the current EPRI PM Template and/or industry guidance?	☒	☐	☐
f. If a PM Change or PM Deferral was previously performed, was it a causal factor in this component failure?	☐	☐	☒
g. Was applicable PM feedback adequately implemented?	☐	☐	☒

4. Adequacy Of Predictive Maintenance:	YES	NO	N/A
a. Is the Predictive Maintenance (PdM) tasks performed per the EN-DC-310 Predictive Maintenance Equipment List (PMEL) adequate to detect the degradation mechanisms/influences that resulted in this component functional failure? *As documented in the RCA, the mechanism that caused the failure (electrical treeing) is not detectable through predictive maintenance. The electrical treeing was only evident upon bushing teardown.*	☐	☐	☒
b. If not performed, should predictive maintenance tasks be initiated?	☐	☐	☒
c. If performed, is the monitoring and threshold for action adequate?	☐	☐	☒

5. Adequacy Of Work Practices:	**YES**	**NO**	**N/A**
a. Was the Work Order instruction scope, content and detail adequate?	☐	☐	☒
b. Were the maintenance practices appropriate and acceptable?	☐	☐	☒
c. Was the Post Maintenance Test (PMT) adequate? Was it performed?	☐	☐	☒

6. Adequacy Of Design And Operation:	**YES**	**NO**	**N/A**
a. Is the design of this component appropriate for the application? *As documented in the RCA, the root cause for this event is a Vendor Design/Manufacturing Deficiency.*	☐	☒	☐
b. Are the operating procedures and practices appropriate?	☒	☐	☐
c. Was the component operated within design?	☒	☐	☐
d. If a Design Change was performed:			☐
• Was the Design Change adequate? Is the component appropriate for its configuration/application?	☒	☐	☐
• Was Design Change implementation adequate?	☒	☐	☐

7. Adequacy Of Parts:	**YES**	**NO**	**N/A**
a. Were parts availability and quality adequate?	☐	☐	☒
b. Was Receipt, Inspection, and Storage adequate (ex. Environment, Shelf Life, Control of Scavenged Parts, Storage PM)?	☐	☐	☒
c. Were there Vendor quality or workmanship issues (manufacturing defects)? *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.*	☐	☒	☐
d. Was Procurement adequate (ex. Specification, Equivalence)?	☒	☐	☐

8. Adequacy Of Long Range Plan:	YES	NO	N/A
a. If the failure is attributed to an aging / obsolescence concern, is the EN-MS-S-013-Multi Long Range Plan or Life Cycle Management Plan adequate?	☐	☐	☒
b. Are Site Integrated Planning Database (SIPD) related items adequate?	☐	☐	☒
c. Are they appropriately prioritized, scheduled, and funded?	☐	☐	☒
d. If the SIPD item was deferred, was the deferral a causal factor in this component failure?	☐	☐	☒

Coding:

INPO PO&C Code(s):	**None**
INPO Failure Mode(s):	**FM38 – Short Circuit**
AP-913 Cause Code(s):	**601 – Vendor Quality or Workmanship Issues (Manufacturing Defect)**

Comments: