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ST. LAWRENCE 230 kV SUBSTATION

DISTURBANCE OF MARCH 6, 1996

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1. Introduction:

The St. Lawrence power project was built jointly by the New York Power Authority (NYPA) and Ontario Hydro (OH). The NYPA portion of the hydro electric facility, the St. Lawrence/FDR power project, can produce more than 900 MW of power and is connected to the New York electric grid through 230 kV and 115 kV substations. The plant, located in northern New York State, was built in the fifties and started operation in 1958. On March 6, 1996, a 230 kV line surge arrester failed causing a close-in C-g fault which was cleared successfully. A few cycles later, phase C of one of the 230 kV circuit breakers flashed-over to the tank causing a C-g bus fault, which was also cleared successfully. The incident grew out of proportion due to the undesired operation of a 230 kV breaker failure relaying system causing additional breaker tripping. The additional breaker tripping resulted in the operation of a special protection system which activated a 400 MW generation rejection and the net tripping of 31 circuit breakers during the disturbance. This paper will describe the substation protection and the events and phenomena which resulted in numerous tripping of breakers and isolation of generating units as well as corrective actions. In addition, digital fault records and sequence of event logs revealing unique system phenomena and verification of short circuit system simulation will be described.

2. Protection of the 230 kV System

2.1 Transmission Line L34P Protection Systems

The four mile 230 kV circuit L34P is protected by dual relaying systems, which were designed in the late seventies. As shown in Figure 1, the "A" and "B" line protection systems are supplied from phase angle regulator (PAR) line side current transformers (CT) at St. Lawrence Transformer Substation. The "A" system consists of an electromechanical pilot wire relay providing complete phase and ground protection applied over a privately owned hard-wire. The "B" system is a permissive over-reaching transfer trip (POTT) scheme using electromechanical mho distance relaying interfacing to a direct hard-wire communication link. PAR dual protection differential relaying zones are also shown in Figure 1. The PAR relaying systems as well as breaker failure relaying trip remote circuit breakers via direct transfer trip (DTT) system using hard-wire.

2.2 230 kV Circuit Breaker Failure Protection

The project was originally designed to optimize the cost of running cables between the switchyard and the relay room, which is located in the main building and separated by 1360 feet from the switchyard. For line relaying application, the paralleling of CT's was done at the entrance of the cable tunnel near the switchyard with a single four wire-conductor cable to the relay room. Following the 1965 blackout, a recommendation was made to add breaker failure (local backup) to the 230 kV bulk power system. To implement breaker failure relaying and to avoid running new cables due to the urgency of the implementation, instantaneous electromechanical fault detectors were added in the cable tunnel to be able to gain access to individual circuit breaker current. Figure 2 indicates the implementation of the breaker failure dc schematic. The initial design did not include circuit breaker (CB) immediate retrip function by CB failure initiation. In the mid seventies, two new bays 20 and 29 were added to the 230 kV switchyard to connect to OH's substation. The same philosophy was used for the design of the breaker failure for CB's 2002, 2008, 2902 and 2908. Although Northeast Power Coordinating Council (NPCC) criteria call for one relaying system for CB failure, dual identical systems (primary and secondary) were designed to continue to implement complete redundancy of all types of bulk power relaying systems.

2.3 230 kV Bus Protection

The 230 kV busses are protected by dual relaying systems. Each system is employing current-differential relaying concept with the use of high impedance overvoltage relays. Each system also energizes lockout relays to trip and lockout all bus associated circuit breakers.

2.4 Special Protection System (SPS) for Generation Rejection

The SPS associated with the St. Lawrence 230 kV system is a generation rejection scheme, which is designed to trip pre-selected generation not directly involved in clearing a fault from the power system, in response to certain contingencies or abnormal conditions. The generation rejection at St. Lawrence is activated to preserve system stability in Northeastern New York and Eastern Ontario. The SPS scheme is initiated by breaker failure relaying operations, any autotransformer fault, any bus fault or loss of any group of transmission lines. One of the line groups is the combined loss of both L33P and L34P lines. The loss of individual line is sensed by any of the following conditions:

a) A fault detected by the line relaying at the St. Lawrence/FDR terminal.

b) Breaker Type "b" auxiliary contacts sensing open breaker or associated local/remote maintenance switches in their local position.

c) A line-end-open (LEO) condition at Transformer Station terminal of the lines.

The initial trip of L34P due to the C-g fault and the subsequent trapping of L33P at St. Lawrence/FDR due to the tripping of both 230 kV busses initated the rejection of 400 MW hydro generation.

2.5 Conventional Breaker Failure DC Schematic for Bulk Power System Breakers at NYPA

Figure 3 shows a typical breaker failure dc schematic for HV or EHV live tank breaker. A retrip relay is added to minimize the extent of breaker failure actions specifically during testing. CB or CT column flashover (leakage protection) bypasses the CB failure timer. Also, a breaker failure initiation, which may coincide with the loss of SF6 gas, will also bypass the timer to quickly isolate the failed breaker. Pole disagreement action also initiates CB failure.

3. Sequence of Events

The bulk power system around the St. Lawrence 230 kV substation is shown in Figure 4. The substation steps of tripping and isolation during the disturbance are illustrated in figures 5, 7, 8 and 9. The sequence of events as constructed from the analysis of the St.Law 230 kV Digital Fault Recorder (DFR), sequence of events recorder (SER) and operation log is as follows:

Time	Event
a) 16:00:38.582	Phase C-to-ground fault occurred on the L34P circuit as shown in Figure 5. The fault was caused by the failure of the line surge arrester at the NYPA end of the circuit. Figure 6 shows the L34P voltages and currents for the C-g faults.
+ 25 msec	L34P primary relaying system (B) operated to energize CB's 2002 and 2008 primary trip buses and to initiate primary breaker failure relaying for CB's 2002 and 2008.
+ 33 msec	L34P secondary relaying system (A) operated to energize CB's 2002 and 2008 secondary trip buses.
+ 40 msec	Secondary breaker failure relaying for CB's 2002 and 2008 were initiated.
+ 58 msec (3.5 cycles)	CB 2008 tripped.
(From + 58 msec to <83 msec)	CB 2002 is attempting to interrupt and to clear the fault. Two attempts at zero crossings were unsuccessful.
+ 75 msec (4.5 cycles)	CB's AL34 and HL34 at St. Lawrence Transformer Station tripped to clear the OH end of the L34P line.
+ 83 msec (5 cycles)	CB 2002 tripped and cleared the c-g fault successfully.
+ 150 msec (9 cycles)	CB 2002 Phase C main interrupter failed resulting in the flash-over to the tank wall as shown in Figure 7.
+ 156 msec	Bus 1A Phase C secondary differential relay operated to energize its associated lockout relay.

+ 157 msec	CB 2002 primary breaker failure relaying system operated to energize its lockout relay to clear the backup breakers.
+ 158 msec	Bus 1A Phase C primary differential relay operated to energize its associated lockout relay.
+ 161 msec	CB 2008 primary breaker failure relaying system had an undesired operation which energized its lockout relay to clear the backup breakers.
+ 163 msec	CB 2002 secondary breaker failure relaying system operated to energize its lockout relay to clear the back-up breaker.
+ 166 msec (10 cycles)	Phase-C flashover inside breaker 2002 clears itself at current zero (fault lasted for about one cycle).
+ 171 msec	CB 2008 secondary breaker failure relaying system had an undesired operation which energized its lockout relay to clear the backup breakers.
+ 242 msec (14 cycles)	230 kV bus 1A is deenergized. 230 kV CB's 2002, 2102, 2202, 2402, 2502, 2602 and 2902 and 115 kV CB 1302 tripped. 230 kV bus 2A is deenergized. 230 kV CB's 2114, 2214, 2414, 2514, 2614 and 2908 and 115 kV CB 1314 tripped. No powerflow is going through either transformer bank #1 or 2.
+ 272 msec (16.3 cycles)	Generation shedding scheme is initiated by line end open conditions for the loss of L33P and L34P circuits and lockout relay was energized to trip the associated CB's.
+ 317 msec (19 cycles)	CB's 2208, 2224, 2508 and 2524 cleared by generation rejection scheme as shown in Figure 8. No power flow is going through transformer bank #3. At the same time, T4 is picking up more power flow.
b) 16:00 to 16:25	Investigation in Switchyard started and bay 2000 was isolated by opening breaker disconnect switches.
16:11	CB 2108 was opened undesirably by the operator as shown in Figure 9.

c) 16:30	Auto 2 and Bus 2A re-energized via CB 1314 and remaining bus breakers closed.
d) 16:52	ACBs 174, 184, 214, 224 tripped undesriably while resetting L33P/L34P LEO Generation Shedding Scheme.
e) 16:54	Bank 6 synchronized via CB 2514 bringing Units 23 and 24 on line.
f) 16:59	Bank 5 synchronized via CB 2214 bringing Units 19 and 20 on line.
g) 17:12 to 17:18	Remaining units 17, 18, 21, 22 synchronized to the system via their associated circuit breakers.
h) 17:58	Auto 1 and Bus 1A re-energized via CB 2502 and remaining bus Breakers closed.

4. Analysis of the Initial C-g Line Fault

The initial C-to-ground fault on the L34P circuit was caused by the failure of a conventional line surge arrester at the NYPA end of the L34P line. The fault was not solid-to-ground due to the presence of fault resistances of arrester discs and breaker arc. The gapped lightning arrester apparently sparked over under normal system condition, which may have been caused by an arrester gap deterioration. The arrester failed to reseal following the first current zero and conducted a fault current magnitude of over 24 kA for several cycles. Circuit breaker 2008 at Moses tripped in 3.5 cycles while CB 2002 attempted to interrupt twice at zero crossings, but was not successful. Finally, CB 2002 tripped and cleared the fault. CB'S AL34 and HL34 at OH's end of the line tripped in 4.5 cycles. The fault lasted for five (5) cycles and was cleared by the operation of the primary and secondary line relaying systems for the L34P circuit. As shown in figure 6, the fault current magnitude for the last cycle before interruption was possibly lowered by an additional resistance introduced during CB 2002 restrikes.

5. Analysis of the Second C-g Fault

The second C-g fault occurred after four (4) cycles from the successful interruption of the initial fault by tripping CB 2002. The fault occurred inside CB 2002 when the Phase C main interrupter failed resulting in the flash-over to the tank wall at the circuit breakers bus side as shown in Figure 7. The circuit breaker fault was inside the overlapping zone areas of line and bus protection systems. However, the line relaying system was operated earlier and tripped CB's 2002 and 2008, therefore, the fault had to be cleared by the operations of bus 1A primary and secondary relaying systems. In addition to bus differential relay operation and since the fault was inside CB 2002, it was also desirable to isolate the failed breaker. Consequently, the false operation of CB 2002 breaker failure relaying systems for the fault was desirable. However, the incident grew out of proportion due to the false (undesired) operation of CB 2008 breaker failure relaying. The generation shedding scheme was initiated by the resulting line end open condition for L33P and the loss of L34P circuit. A total of 400 MW was rejected by the operation of the special relaying system which energized lockout relays to trip the associated circuit breakers.

6. Analysis of Breaker Failure Relaying Performance during the Fault

The breaker failure relaying system was designed with solid state timers, which were mainly used for Z2 and Z3 step distance remote backup clearing applications. These were the only timers available at the time of the design. These timers have a dropout time of about three (3) cycles which is acceptable for a setting of 30-60 cycles for remote backup application. The poor performance of CB failure schemes during this disturbance is due to excessive delay in the dropout of the timer auxiliary initiating relay "TX" and the breaker failure fault detectors shown in Figure 2. In addition, the fault detectors are located in a non-controlled environment in the cable tunnel, subject to dust and humidity, which could degrade their performance. Figures 11, 12, 13 and 14 indicate the time charts for CB's 2002 and 2008 primary and secondary breaker failure relaying as derived from the SER system. CB 2002 secondary breaker failure indicated no dropout for the timer while the primary system has a "TX" dropout time of more than 50 msec and initiation dropout of 24 msec. CB 2008 secondary breaker failure indicated a "TX" dropout time of more than 38 msec and initiation dropout time of 50 msec. CB 2008 primary breaker failure indicated a "TX" dropout time of more than 34 msec and initiation dropout time of more than 44 msec. From the analysis above, it can be concluded that the timers never stopped after the initiation by the "TX" coils. The occurrence of the C-g fault inside CB 2002 after 9 cycles from 0 (4 cycles after successful interruption of initial fault), which falls into the span of breaker failure total clearing time of about 12 cycles, has presented a challenge to the performance of the breaker failure timing coordination.

7. Performance of CT's in the Presence of Asymmetrical Current

As shown in Figure 6 the secondary fault currents for the L34P circuit are not a faithful replica of the primary fault currents. The initial phase C-g fault has a large dc component with a slow decaying rate due to the large X/R ratio for the St. Law generating station. The dc component has far more influence in producing severe saturation than ac fault current. Sizing the CT to have an adequate knee-point voltage with suitable allowance for possible dc component and remanence can reduce effect of saturation. The accuracy class C800 for CT's associated with CB's 2002 and 2008 was downgraded to C200 for the 800:5 connected tap. The L34P electromechanical line relaying, CT cable leads, CT winding and CT lead resistances have a connected burden of about 2.2 Ohms. For a symmetrical fault current of 22 KA, the impressed voltage across the CT is about 302 V, which is slightly below the knee point for the 800:5 tap. The combination of high fault current, high burden, and a low connected CT ratio have stressed the CT to be near its non-linear region. In this incident, the initial asymmetrical fault current has caused CT partial saturation and left a remanence flux in the CT core. The only way of reducing remanence in CT cores that are presently in service is to demagnetize them by external means. In this incident the initial asymmetrical fault current had apparently caused a remanence in the CT core which was not removed. The occurrence of the second C-g fault inside CB 2002 a few cycles after the initial fault, had stressed the CT and caused severe saturation which contributed to the false operation of CB 2008 breaker failure relaying system.

8. Performance of the St. Lawrence 230 kV Circuit Breakers

Circuit breakers 2002 and 2008 have exhibited one earlier restrike in 1983 when clearing a ground fault near the OH substation of the L34P line. The fault was cleared in 4.5 cycles and was then followed by a breaker restrike in 0.5 cycle with final interruption at the next zero crossing. Other restrikes also occurred on similar 230 kV oil circuit breakers at the same substation while clearing ground faults. For the March 6, 1996 disturbance circuit breaker 2008 made a successful attempt to trip at 3.5 cycles. As shown in Figures 18 and 26 circuit breaker 2002 attempted to clear the fault at two zero crossings (at 4 and 4.5 cycles) without success. The failure of CB 2002 was not directly related to a restrike; however, it may have been precipitated by the early restrikes during the initial C-g fault. The higher short circuit current during the initial C-g fault preceding these restrikes, in comparison with earlier restrikes, could have contributed to the failure of breaker 2002. The first inspection of CB 2002 revealed no physical damage except for vented oil out of the breaker tank. Clearance was then taken and CB oil was drained to prepare for inspection. The internal inspection revealed that bus 1A interrupter assembly had failed to ground.

9. System Restoration

One of the challenges in restoring power systems following a major disturbance is the correct isolation of the failed equipment. As shown in Figure 10 , the final system configuration had MA-1 circuit isolated onto MWP-2 circuit and MA-2 circuit isolated onto MWP-1 circuit. Inspection of the affected systems supplemented by SER and DFR records, as well as relaying targets, have helped in the isolation of the failed equipment in this incident. It was the operation of the primary and secondary bus 1A differential relaying systems, in conjunction with the operation of L34P line relaying and CB's 2002 and 2008 breaker failure relaying systems, that lead to the initial isolation of CB's 2002 and 2008. This trouble-shooting process took approximately 25 minutes. Subsequent analysis of the disturbance resulted in the isolation of CB 2002 as the only failed equipment. Complete restoration of the system including the eight (8) hydro units was completed after 30 minutes from the isolation of the failed breaker. Analysis of the disturbance was completed two (2) weeks later. A clearance was issued for L34P line and the failed lightning arrester was replaced. Customers did not loose power during this disturbance. The event was simulated without generation rejection and the system was stable due to the relatively low power transfer south of the St. Lawrence plant. Monitoring of individual circuit breaker current by the DFR will be considered for future application to speedup system restoration for similar disturbances. For a breaker-and-a-half scheme only ground current for the middle breaker needs to be added to the DFR. This added current and the normally monitored line currents will provide individual current monitoring for the three breakers.

10. RMS Calculations and Verification of System Short-Circuit Model

Confirmation of power system model can be done by using fault type and fault location to run software packages to simulate faults and compare the study results with the recorded DFR RMS calculations. As shown in Figures 19 and 20 these calculations can be executed through the whole fault record by positioning two cursors "x" and "y" separated by a fixed one cycle length (16.66 msec). The calculation algorithm grabs the digital sampled data within the DFR memory (between the two cursors) and executes an accurate RMS value using one of the proven phasor calculation methods. The results are posted as a part of the records shown in the reference figures in primary RMS values. Since the second fault incident point is at voltage peak, the resulting symmetrical ground fault currents from all the sources can be used to validate the short circuit model by comparing the calculated RMS from the DFR record versus the RMS values obtained from short circuit study simulation. The arrester disk resistance and presence of breaker arc caused a reduction in fault currents. Therefore the C-g faults were not solid to ground making the comparison with conventional short circuit study results difficult to perform. The total symmetrical fault current for a solid phase-to-ground fault at St. Lawrence 230 kV bus was calculated as 31 kA using the short circuit simulation program. The measured asymmetrical fault current through the failed arrester was about 24 kA.

The RMS calculation can also be used to judge the performance of CT's during this disturbance. Figures 21 and 22 illustrate CT performance during the first and second C-g faults. The RMS calculations for L34P saturated neutral current and two unsaturated ground currents for the two faults are recorded for comparison.

TABLE 1

Fault	First C-g Fault Figure 21	Second C-g Fault Figure 22
L34P-In	19.86 kA	8.4 kA
XFMR 5&6 In	5.08 kA	4.45 kA
MMS2- In	1.39 kA	1.29 kA

Based on the results shown in Table 1 it is clear that CT performance for L34P circuit has deteriorated during the second fault due to severe saturation. The magnitude of the current for L34P has dropped to almost 1/3 while other non-saturated sources remained fairly close. The second fault had no dc offset as part of the fault current but the heavy fault current coupled with remanence left from the early asymmetrical fault has caused saturation and contributed to CB 2008 breaker failure relaying back-feeding to its current fault detectors and hence causing the misoperation.

11. Corrective Actions

The breaker failure back-feeding can be eliminated by the use of dedicated CT's for breaker failure protection function. This is impractical and certainly an uneconomical solution to the problem.

Another practical approach to remove the problem is to reduce the voltage imposed on the unenergized primary CT side by either reducing secondary CT current and/or reduce the connected CT burden. The reduction of the relay burden is accomplished by replacing electromechanical relaying with a low burden microprocessor based system. This replacement is normally justified due to the obsolescence of the electromechanical relaying and the advantages of new digital relaying. Normally, a reduction in testing requirements, diagnostic capability, and reduced cost of digital relaying justifies its implementation. The following actions are listed in order of simplicity and lower cost.

11.1 The power system is normally designed to withstand a normally cleared 3-phase fault and a stuck breaker for L-g faults. Therefore, only one circuit breaker is assumed to fail for any given L-g faults. Transient performance of CT in the presence of dc offset (without demagnetization) has contributed to the breaker failure back-feeding phenomena. Connecting the two busses with dual two-breaker bays compromised the original breaker-and-a-half design of the St. Lawrence 230 kV switchyard. This connection should have no impact for the normal design criteria. However, a breaker fault in any of the bays (2000 and 2900) coupled with a breaker failure back-feeding phenomenon results in the loss of both 230 kV buses and hence generation rejection for the tripping of the 230 kV ties L33P and L34P. The first obvious simple corrective action was to permanently open any of the diagonal breakers for the two bays. Since circuit breaker 2002 was isolated for replacement (due to its failure), CB 2908 was operated normally open. Their primary and secondary breaker failure lockout relays were also placed out-of-service. These isolations were required to eliminate the possibility of re-occurrence of breaker failure relaying back-feeding problems.

11.2 Based on the analysis of the secondary and primary breaker failure relaying systems, the coordination margin can be enhanced by increasing the timer setting. Figure 16 shows the breaker failure coordination chart with an increase in the timer setting from 7.5 cycles to 10 cycles. System planning has studied the impact on system power transfer limit as a result of the increase in breaker failure clearing time from (12-13 cycles) to (14 ½ - 16) cycles. Planning studies did not agree with the timer setting increase and this option was not followed.

11.3 Since the breaker failure timer setting cannot be increased, the existing breaker failure timers for the four breakers were replaced with new timers that have high speed dropout time of about 12 msec. Figure 17 shows the schematic with the new timer connection to the existing CB 2008 breaker failure circuit. Existing CB failure fault detector targets cannot be pulled with this modification. To compensate for this deficiency, new SER points are added and the holding coils (HC) for the phase and ground units are shorted. This replacement was done to only solve the excessive dropout time of the "TX" coil for the existing solid state timers.

11.4 To reduce voltage impressed on a CT during back-feeding, the CT ratio used for the protection of the 230 kV lines were reviewed for a possible increase in their ratio values. Recommendation to increase the existing CT ratio for one of the relaying systems from 800/5 to 1200/5 was provided. In addition, the existing obsolete pilot wire current differential and electromechanical distance relays will be replaced with a static or microprocessor-based relays. This replacement will accomplish a reduction in relay burden and a more sensitive relay, which will accommodate the increase in the CT ratio to 1200/5. Thus yielding a more accurate CT with lower impressed CT excitation voltage for a similar event.

11.5 The complete solution to the problem was to provide replacement of the electromechanical and solid state breaker failure components with an integrated microprocessor based package. This plan will require adding new cables from the junction boxes in the tunnel to the relay room. The existing two identical primary and secondary relaying systems will be replaced by two microprocessor-based systems supplied by different manufacturers (to avoid common mode failure).

12. System Phenomena of Interest

12.1 Breaker Failure Back-Feeding

As indicated in the DFR record shown in Figure 6, the initial phase C-g fault was cleared from the St. Lawrence end of the line in five (5) cycles. No primary current was flowing through CB 2008 when CB 2002 C phase failed to ground. Therefore, breaker failure relay operation for CB 2008 was due to back-feeding to its breaker failure current detector resulting in secondary current flow that exceeded the relay ground element pickup of 2 A. Figure 15 shows a source of difficulty for breaker failure relaying in ring-bus and breaker-and-a-half systems. Both CB's 2002 and 2008 have opened successfully and cleared the initial fault. However, when CB 2002 faulted to ground, all fault current I_A was flowing from the breaker's bus side CT to the line relaying. The flow of current I_L through burden Z_R will apply voltage V_R across CB 2008 current transformer. The voltage V_R apparently had approached the ANSI relaying accuracy class voltage for the current transformer connected tap of 800:5. In addition, the initial fault current contained a large dc offset as shown in Figure 6, and the secondary line current revealed that saturation occurred on either CT associated with CB's 2008 or 2002 or both. As a result, a remanent magnetic flux could have been left. This residual flux which degrades the quality of the CT could have contributed in the excessive current flow I_B through the fault detectors. This will force the CT associated with CB 2008 to draw excessive magnetizing current flow I_B; enough to pickup the fault detectors and cause the breaker failure relaying scheme to operate.

12.2 Fault Current Containing DC Offset Component

Faults occurring at incident angles other than at voltage peak will contain a dc components in the resulting fault currents. The dc components are generated in the fault loop because an instantaneous change of current can not occur in an inductance. Figure 6 shows the faulted Phase C current with a dc offset.

12.3 CT Saturation

The presence of dc offset in fault currents coupled with a large current magnitude can result in CT saturation. Figures 23 and 24 show CT saturations due to the initial asymmetrical fault currents for L34P line, the neutral of transformer bank #5, and polarizing circuit for auto transformers 1&2. Figure 23 also reveals that L34P CT had about one cycle time to reach the saturation flux density. Figure 24 reveals that the time to saturate for transformer #5 neutral CT is less than two cycles. CT saturation time is normally a function of fault current, core flux density, CT parameters, CT connected burden, and dc time constant.

12.4 Arc-Over at Voltage Peak

The live part of CB 2002 main interrupter, which is connected to 230 kV bus 1A when the breaker opened, failed resulting in the flashover to the tank wall. The resulting C-g fault incident point, as shown in Figure 25 is at voltage peak, which is typical for an arc-over of a live part of a breaker interrupter falling in the circuit breaker tank. The resulting Phase C fault current is symmetrical with no dc offset component.

12.5 Transient Response of Capacitive Voltage Transformer (CVT)

Figure 26 indicates voltage output from the CVT connected to the MA-1 230 kV circuit at St. Lawrence. Voltage oscillations for the first fault are different than the second fault. These faults occurred at different incident points on the voltage wave.

12.6 Zero Sequence Mutual Coupling Induced Voltage

Line L34P was tripped and locked out to clear the initial C-g fault, which was caused by Phase C lightning arrester failure. During the second C-g CB 2002 fault, ground current ($3I_o$) was flowing on feeder L33P as shown in Figure 27. L33P and L34P 230 kV circuits are mutually coupled due to the sharing of the same right-of-way. Therefore, ground current ($3I_o$) flow in L33P circuit during the second C-g fault induces a zero-sequence voltage in the parallel L34P line. Capacitive voltage transformers (CVT's) at St. Lawrence 230 kV switchyard for Phases A and C (B phase is not monitored) with the L34P circuit opened, revealed equal and in-phase voltage components. Figure 28 shows the induced zero sequence voltages on phases A and C between the ninth and the tenth cycle.

13. Conclusion

The occurrence of asymmetrical faults followed by a second fault presents a challenge to CT accuracy performance due to the presence of dc offset. This affects CT transient performance without demagnetization of the CT prior to the second fault. Multiple faults occurring within the span of CB failure clearing time also presents a challenge to the scheme timing margin. Secondary CT current back-feeding through breaker failure relaying for an opened breaker in a ring bus or breaker-and-a-half arrangement can cause additional breaker tripping and wider system disturbances. Analysis of power system disturbances can provide basic and useful information for the protection systems. Periodic review of the existing electromechanical relaying system should be conducted to check relay obsolescence or deterioration of their performance. Justification for electromechanical relaying replacement should be based on either the lack of spare parts, or its degraded performance or reduced maintenance cost associated with the application of microprocessor relaying. The availability of sequence of event recording (SER) systems at substation level is essential. It should be capable of a fine timing resolution of one msec to provide a quick means to analyze disturbances. Digital fault recorders (DFR) can supplement the SER records and speed up the process of developing the needed sequence of events . The availability of RMS calculations as a DFR analytical tool provide accurate and quick means to validate power system short circuit modeling.

Acknowledgment

The author wishes to thank Mr. Ben Shperling for his valuable contribution for the analysis of the 230 kV circuit breaker failure.

References

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Biography

MOHAMED A. IBRAHIM was born in Talka, Egypt on February 13, 1943. He received the B.S. degree in Electrical Engineering from Egypt in 1964 and the M.S. in Electrical Engineering from Newark College of Engineering, Newark, New Jersey in 1973. He attended and completed the Advanced Power System Engineering Course at General Electric, Schenectady, 1973-1974. He completed 33 credits of post graduate work at New Jersey Institute of Technology. He is a registered Professional Engineer in New York State.

From 1964 to 1969, he worked as a teaching assistance at Cairo Higher Institute of Technology, Egypt. From 1970 to 1980, he worked with the American electric Power Service Corporation in New York where he was a Senior Engineer. In October 1980, he joined the New York Power Authority. He is presently the Director of the System Protection and Control Engineering Section. He participated as a visiting lecturer at the Auburn University, the Rensselaer Polytechnic Institute and Washington State University. He is a member of the adjunct teaching staff at Polytechnic University in New York teaching graduate protective relaying courses. He is the author and the co-author of eighteen (18) technical papers in the computer relaying and protection areas.

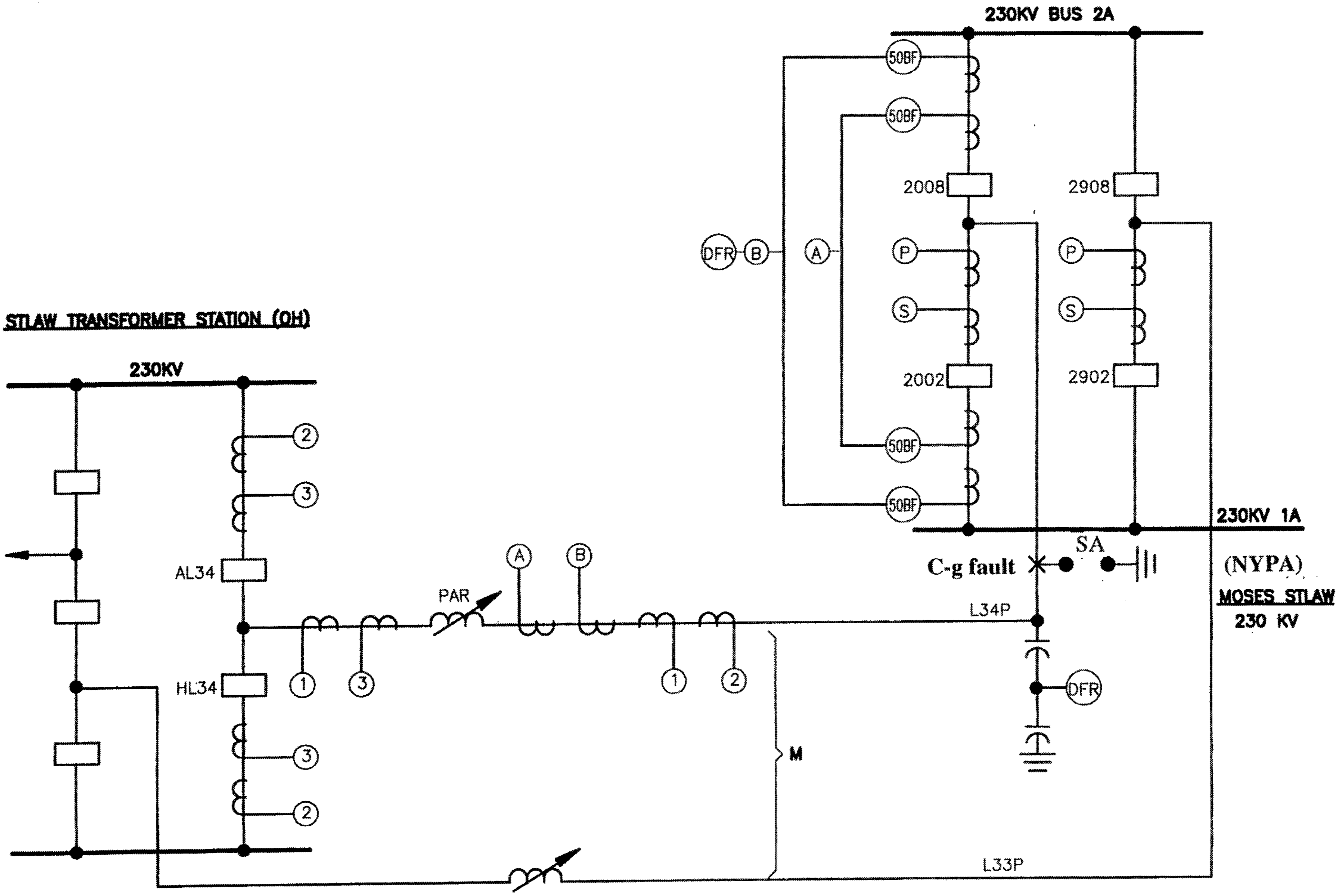


FIGURE 1

ONE LINE AC FOR THE PROTECTION OF THE L34P CIRCUIT

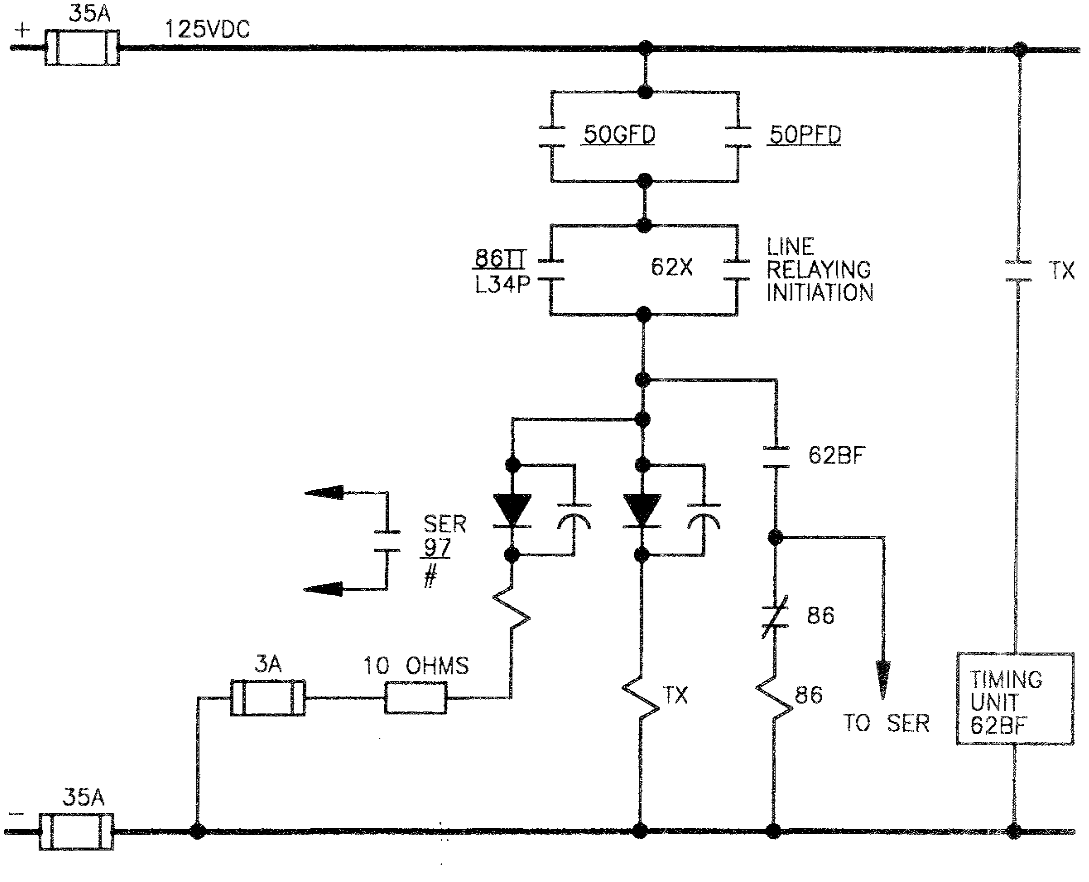


FIGURE 2
BREAKER FAILURE DC SCHEMATIC
FOR 230KV CB'S 2002 AND 2008

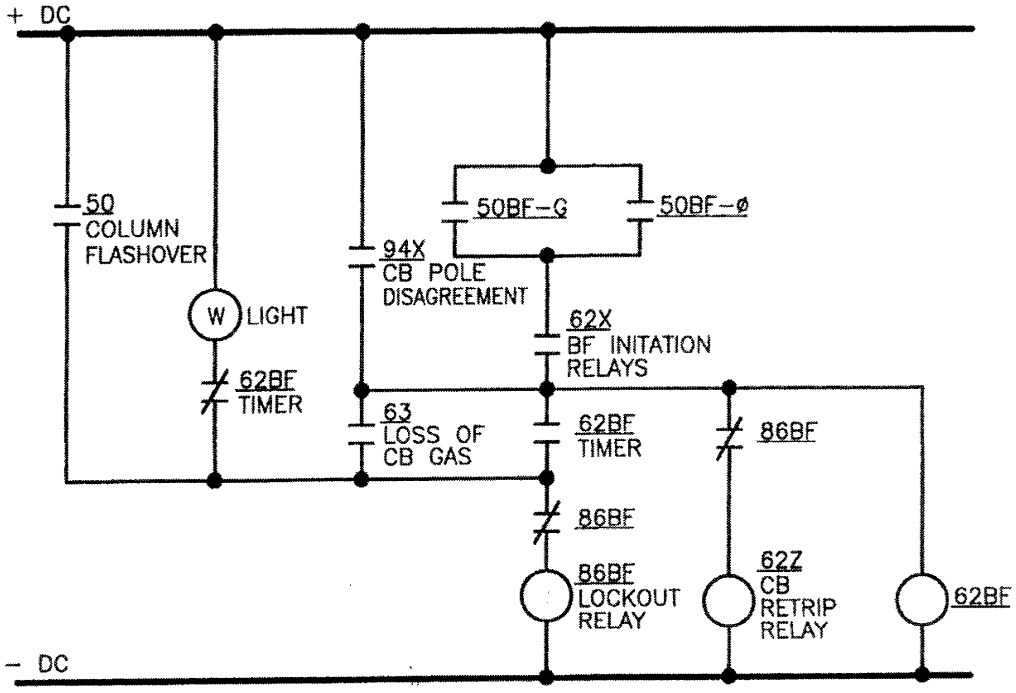


FIGURE 3
TYPICAL DC SCHEMATIC FOR BREAKER FAILURE PROTECTION

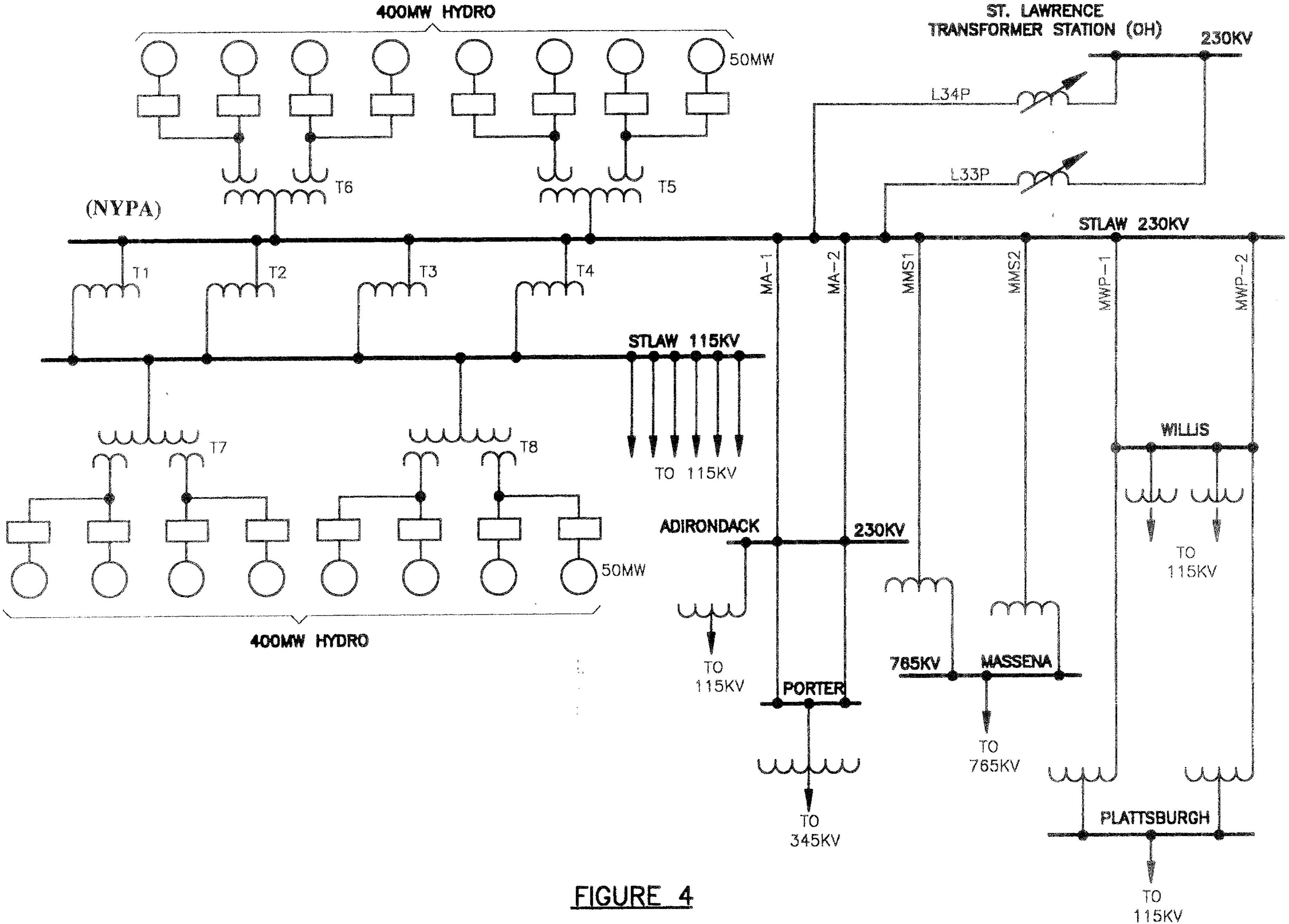


FIGURE 4

CONNECTED POWER SYSTEM PRIOR TO THE DISTURBANCE

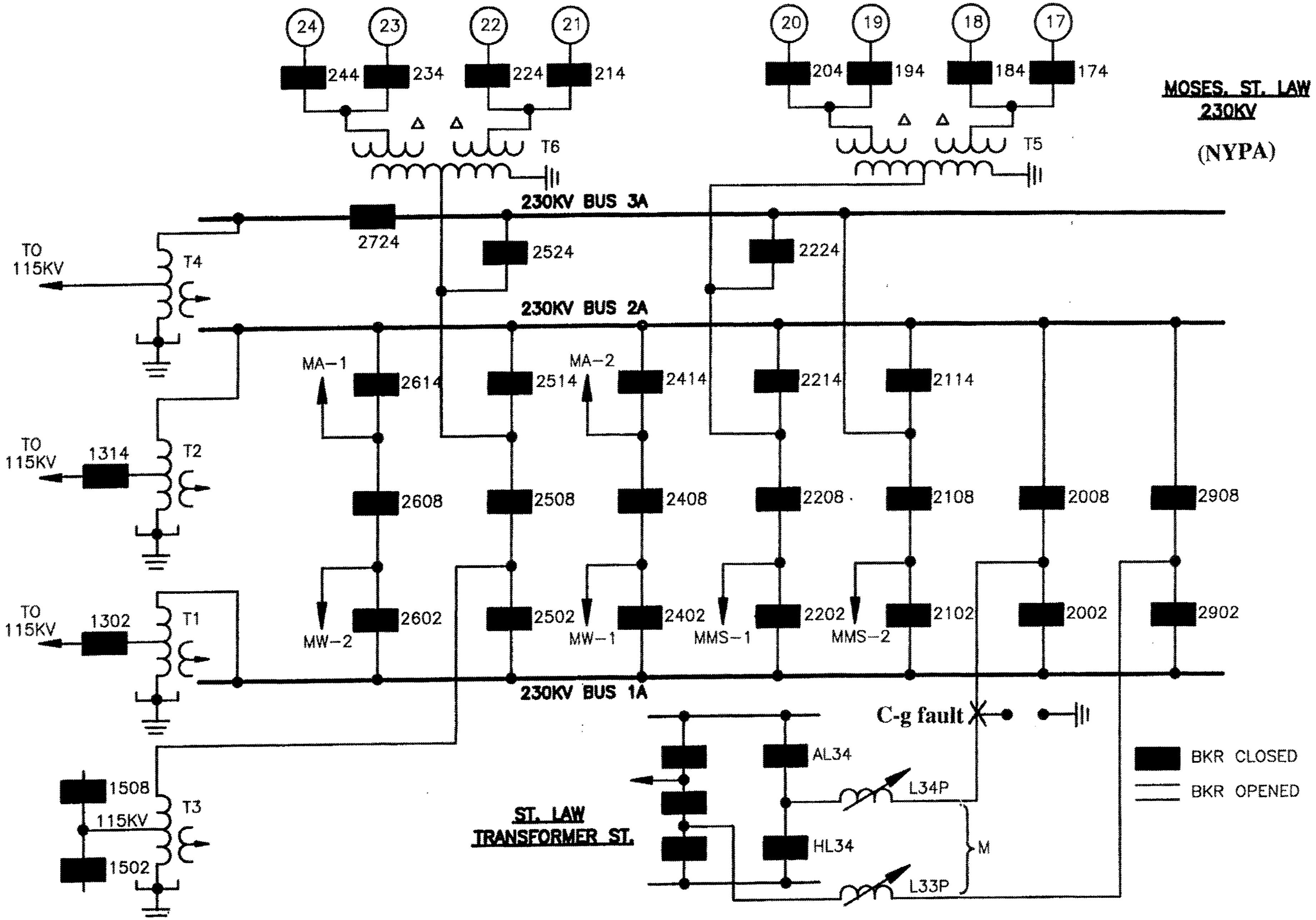


FIGURE 5
SUBSTATION CONFIGURATION AT T=0

NEW YORK POWER AUTHORITY ENGINEERING DIVISION (WPO)---Digital Transient Recorder LASER QUICK-PLOT Program Version 2.
STATION NAME: Moses 230KV EVENT NO. 1075 DATE: 03/06/96 TRIGGER TIME: 16:00:38.583
No. of Recorded Channels=66 Total Event Length=51.20 cycles Pre-trigger Length=12.77 cycles Sampling Rate=6,000 samples/second
Plot Creation Date: 03/11/96 Time: 14:16:47 Plot 1 of 1 Every point plotted
Maximum Dynamic Scaling with Channel Grouping, Selected Channels Plotted, Selected Timeframe Plotted
Description: Fault Record expanded

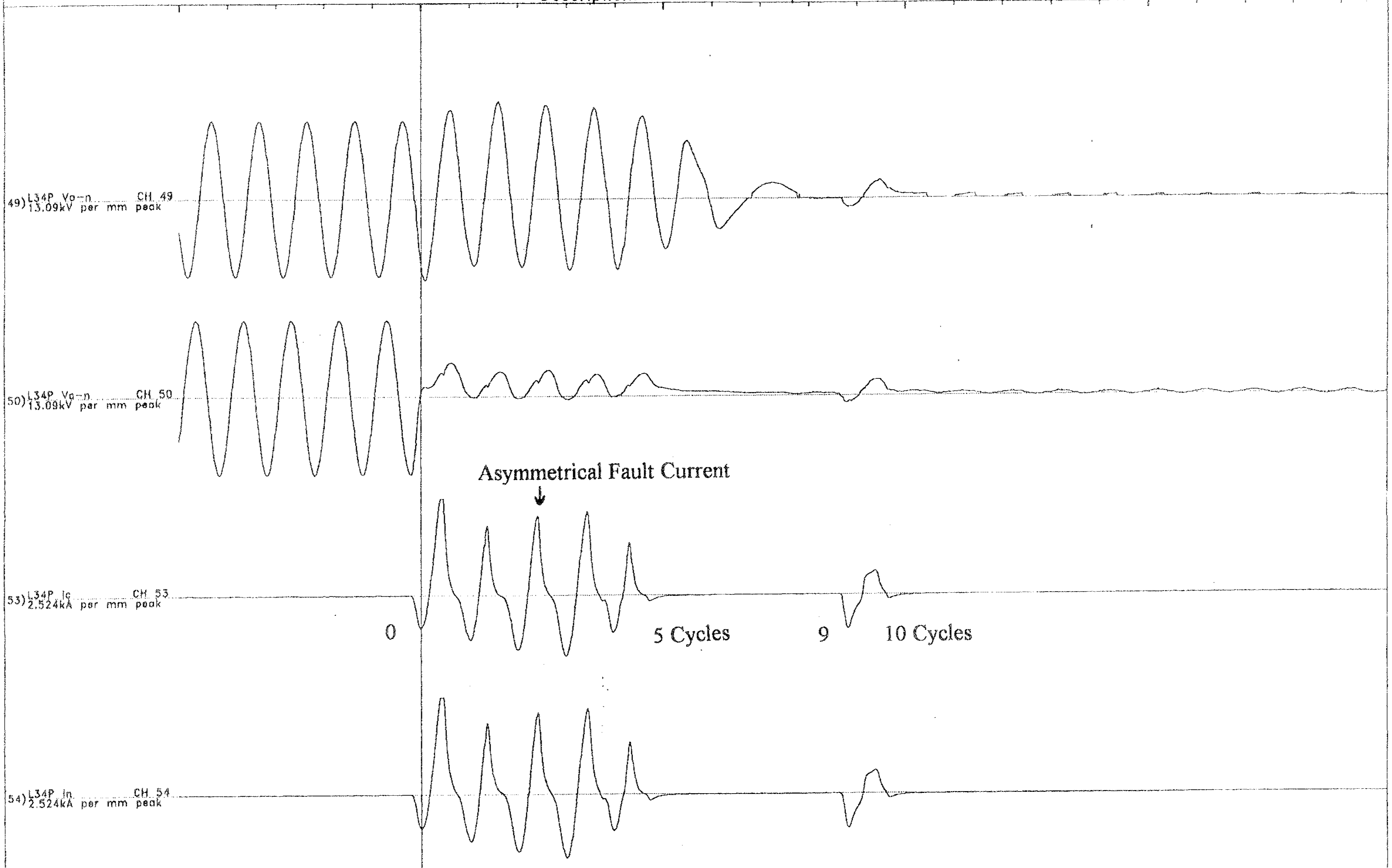


Figure 6

L34P voltages and currents during L-g Faults

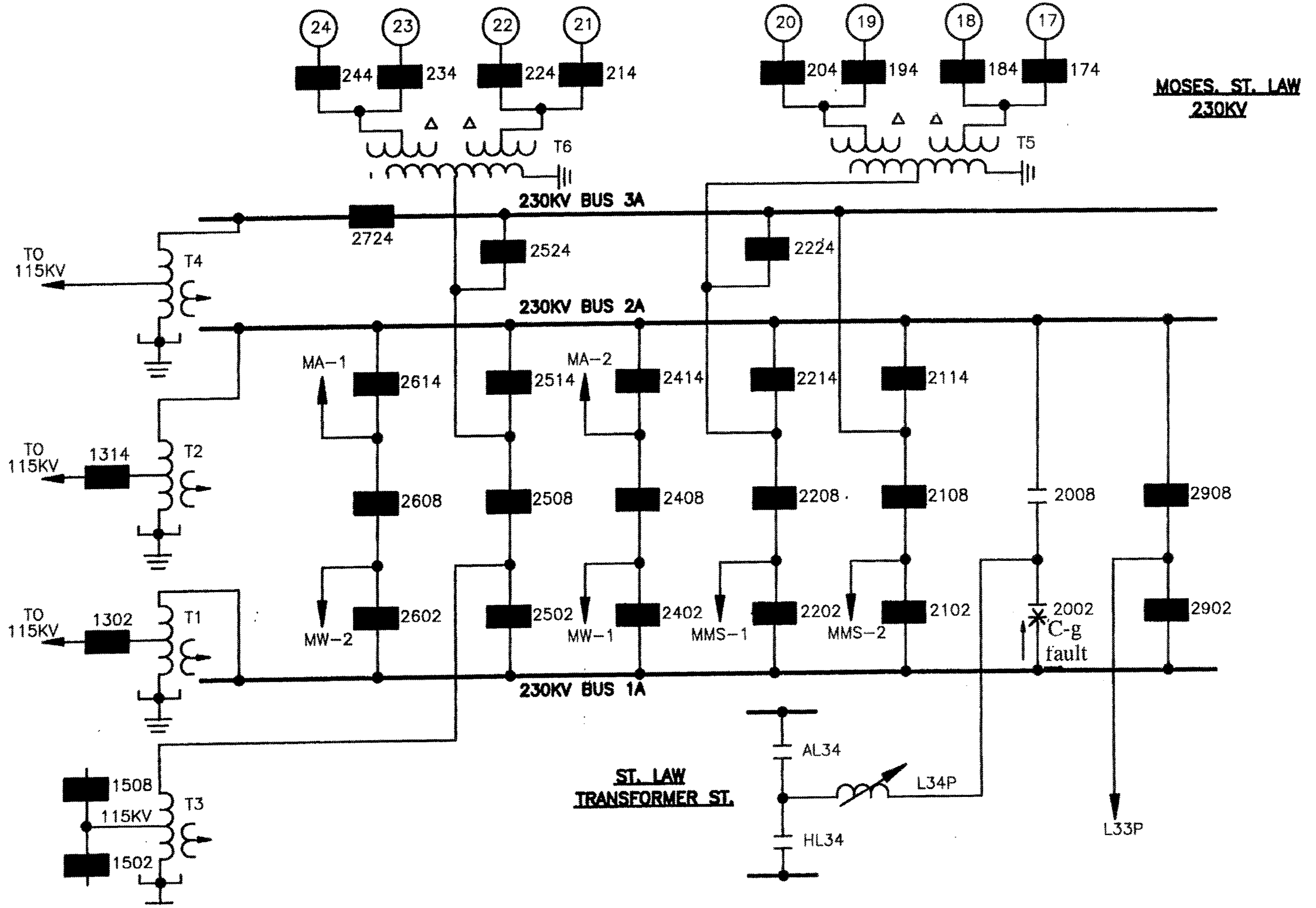


FIGURE 7
SUBSTATION CONFIGURATION AT T=150 MSEC. (9 CYCLES)

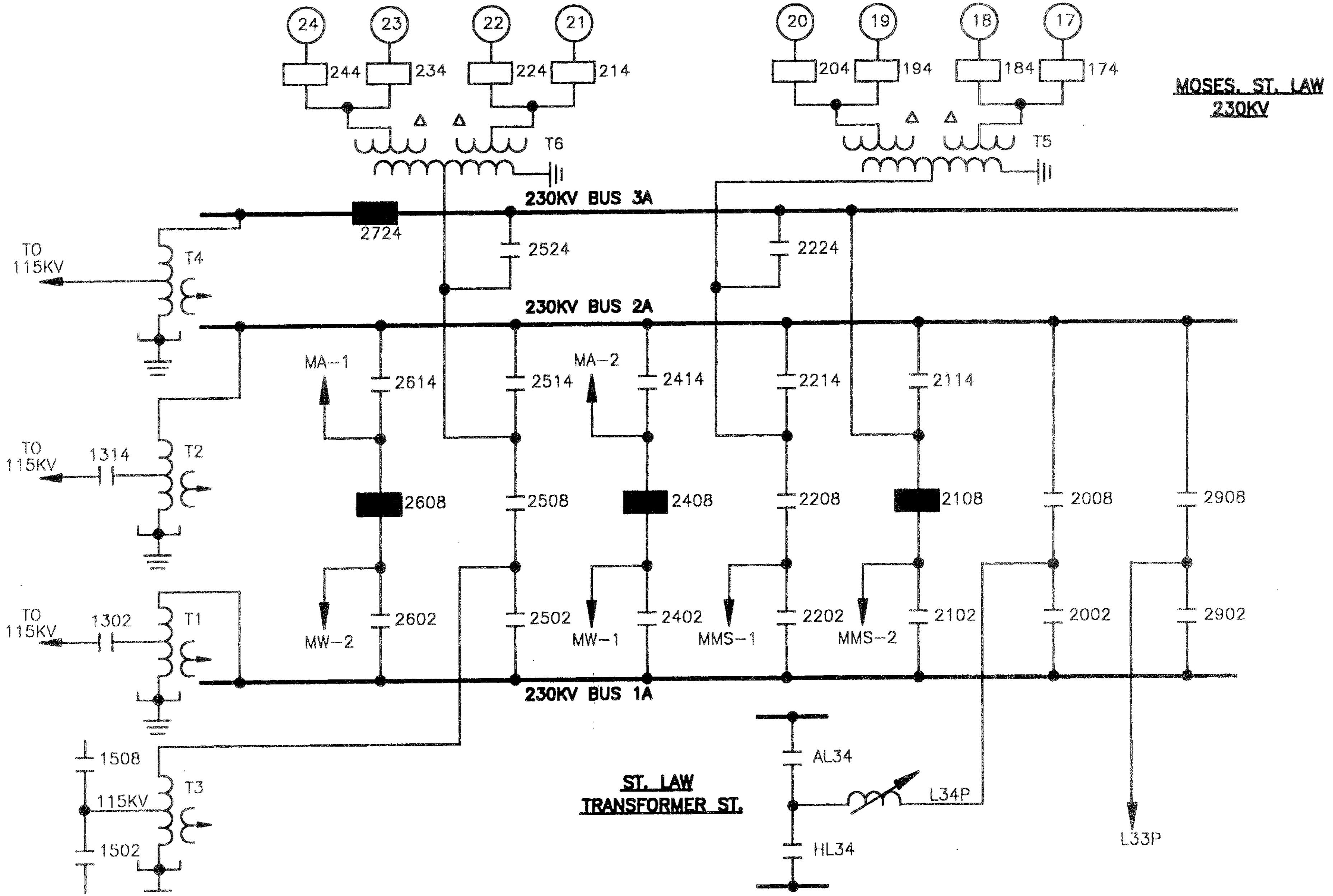


FIGURE 8

SUBSTATION CONFIGURATION AT T=317 MSEC. (19 CYCLES)

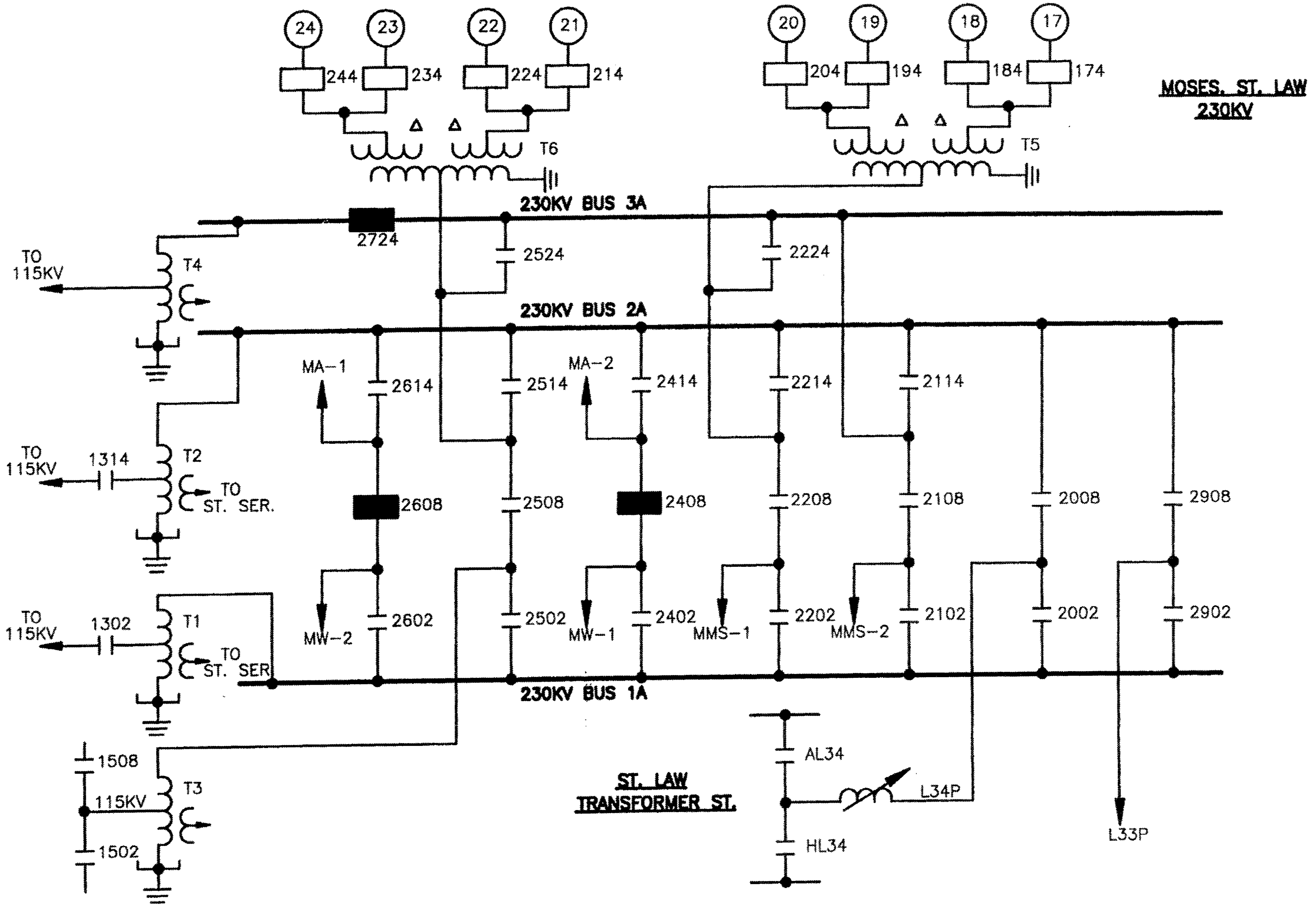


FIGURE 9

SUBSTATION CONFIGURATION AT T=11 MINUTES

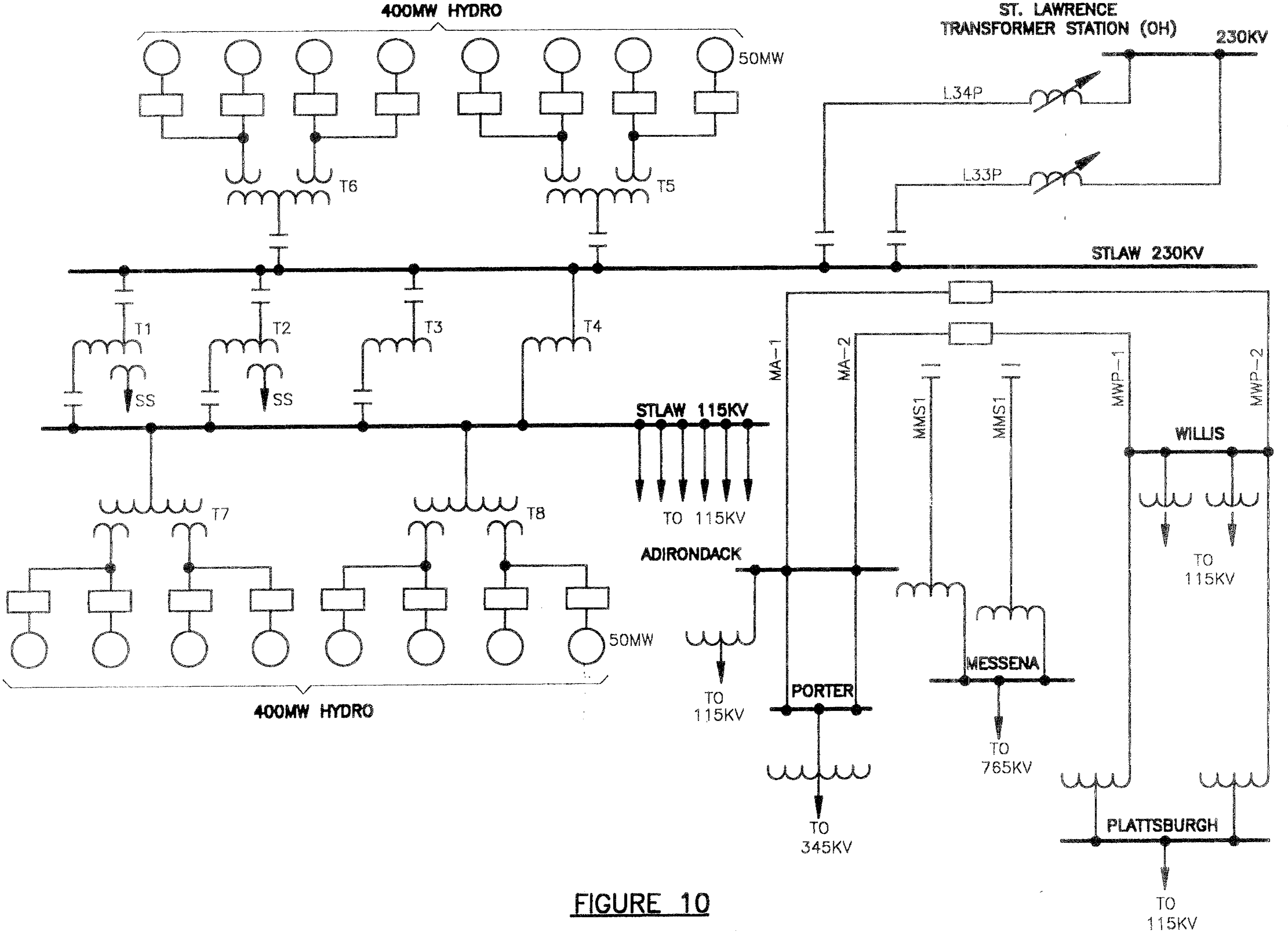
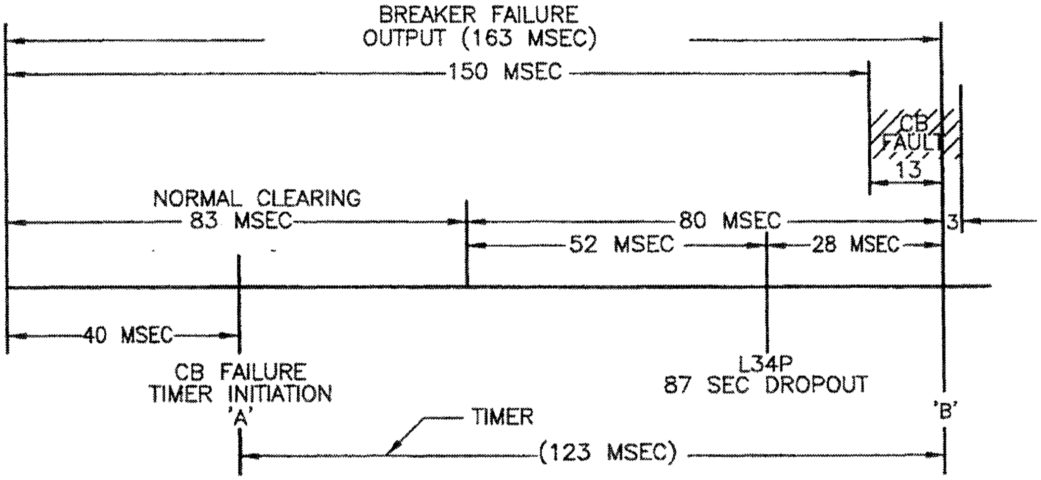


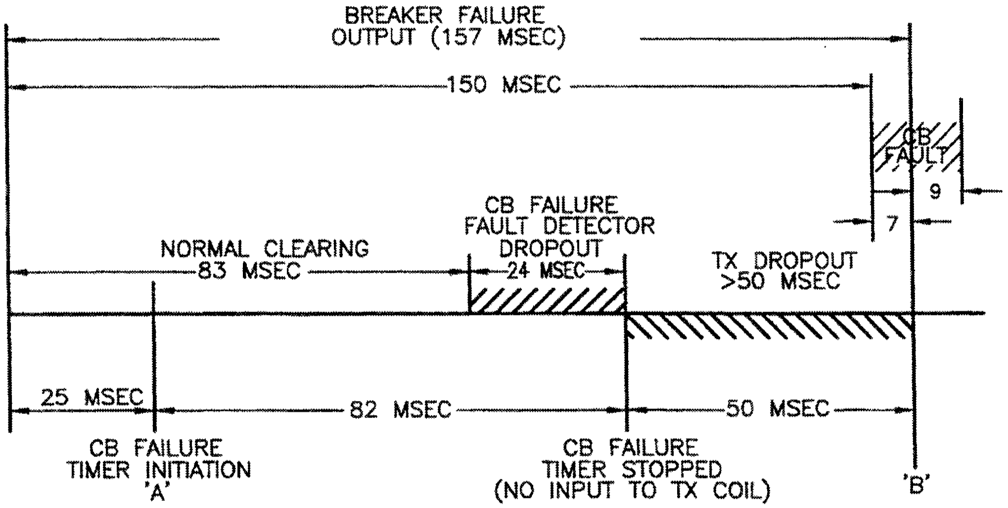
FIGURE 10

POWER SYSTEM CONFIGURATION AFTER THE DISTURBANCE



* TX NEVER DROPPED OUT
* TIMER NEVER STOPPED
* FAULT DETECTOR NEVER DROPPED OUT

FIGURE 11
CB 2002 SECONDARY BREAKER FAILURE RELAYING TIMING CHART



* TX NEVER DROPPED OUT

FIGURE 12
CB 2002 PRIMARY BREAKER FAILURE RELAYING TIMING CHART

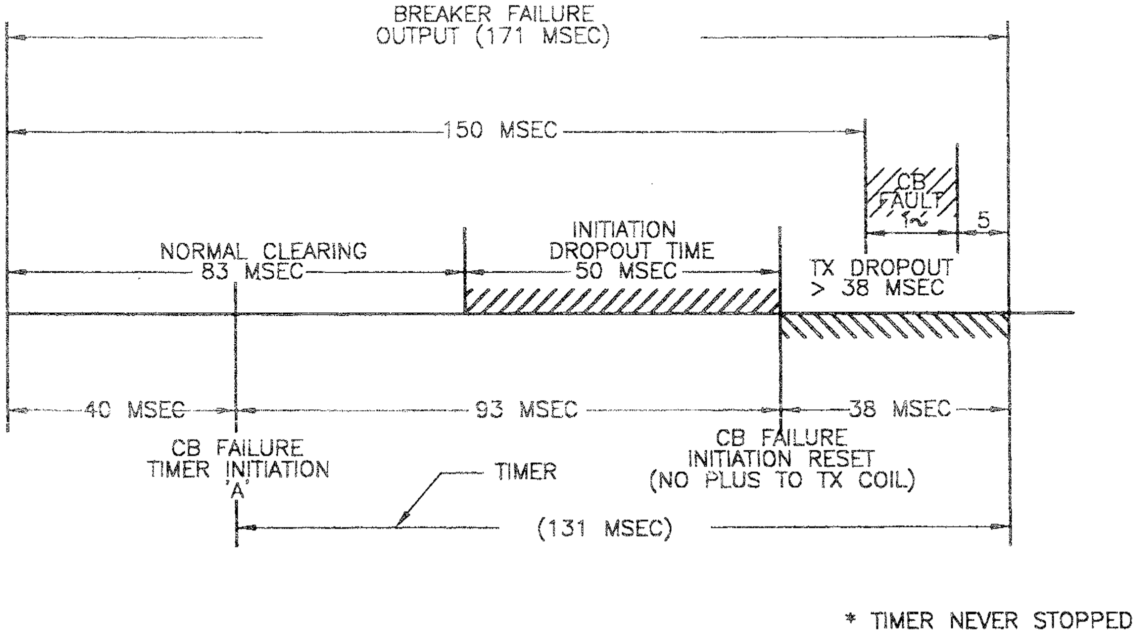


FIGURE 13
CB 2008 SECONDARY BREAKER FAILURE RELAYING TIMING CHART

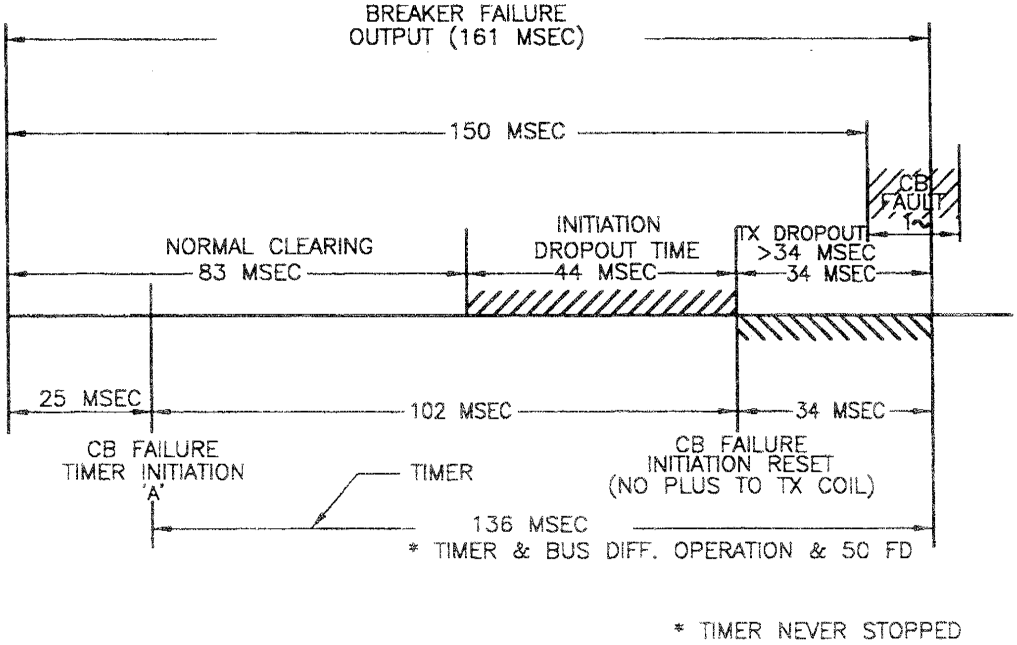


FIGURE 14
CB 2008 PRIMARY BREAKER FAILURE RELAYING TIMING CHART

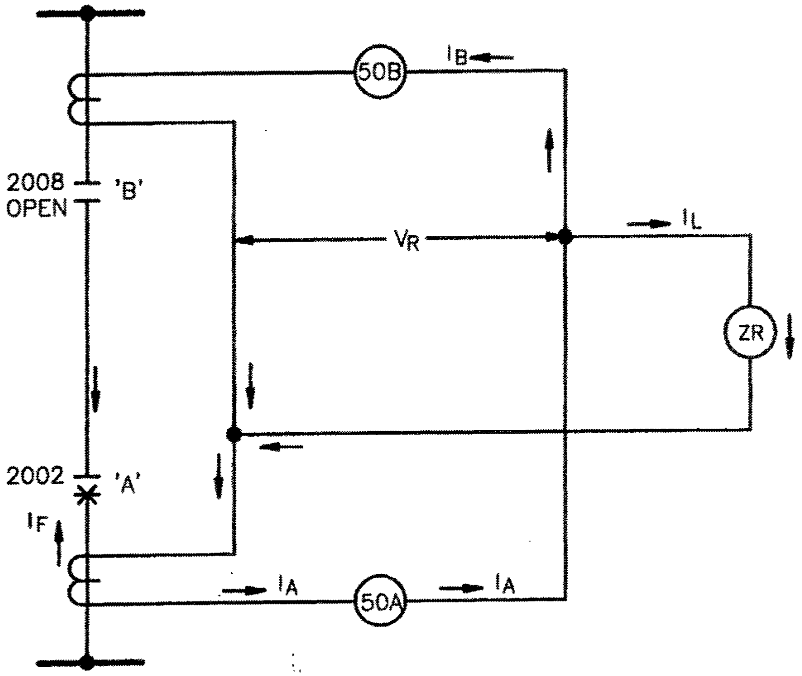
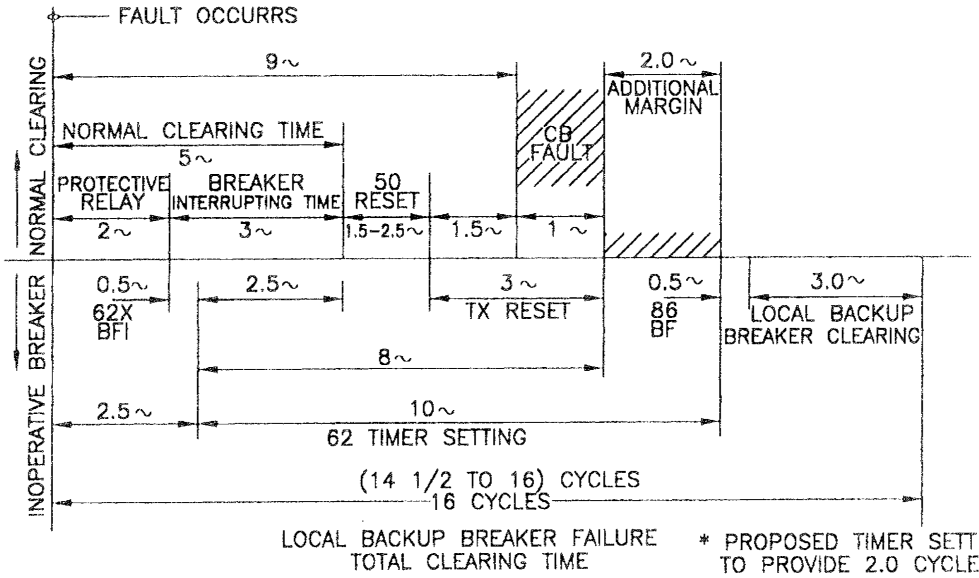


FIGURE 15

BACK–FEED TO BREAKER "2008"
FAILURE CURRENT DETECTOR



* PROPOSED TIMER SETTING OF 10 CYCLES
TO PROVIDE 2.0 CYCLES OF ADDITIONAL MARGIN
TO A SIMILAR EVENT

FIGURE 16

TIME CHART OF BREAKER FAILURE SCHEME

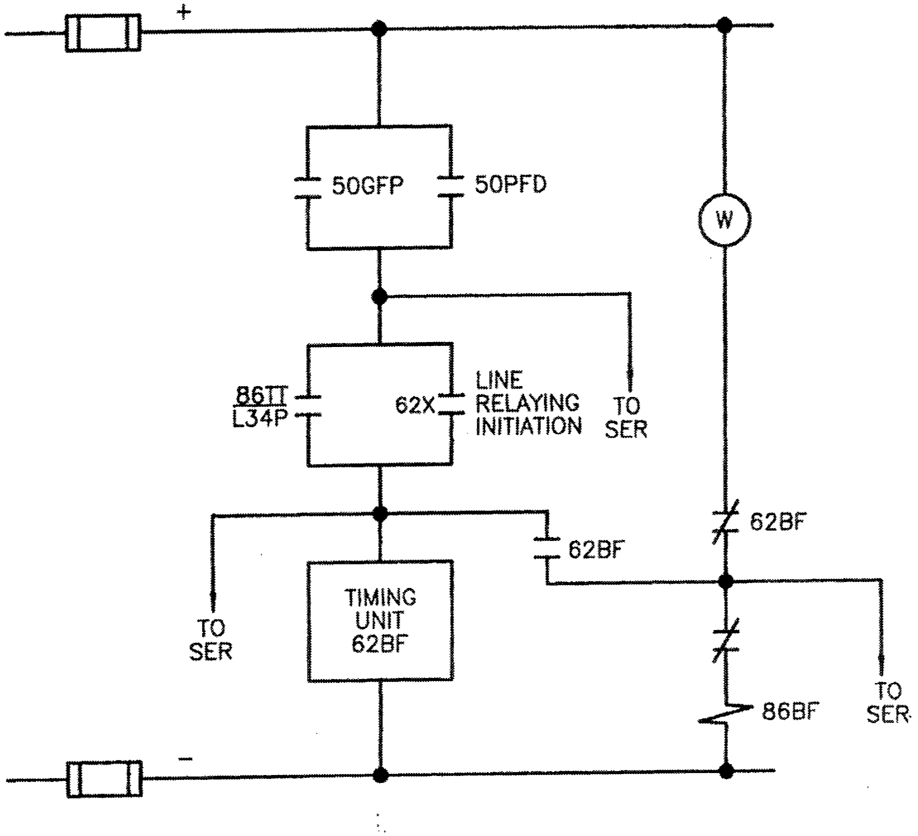


FIGURE 17

BREAKER FAILURE DC SCHEMATIC

SHOWING REPLACEMENT OF THE TIMING UNIT

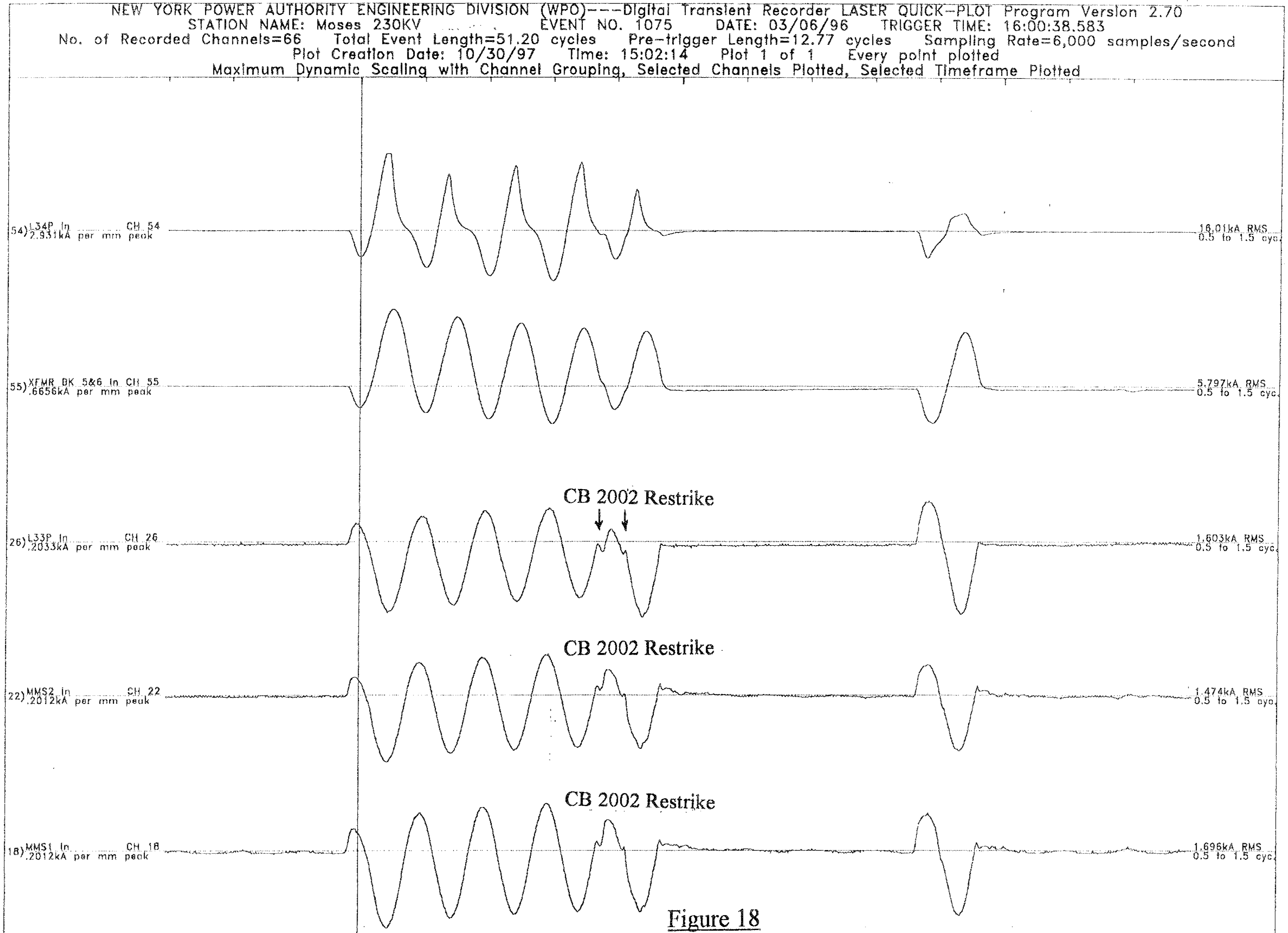
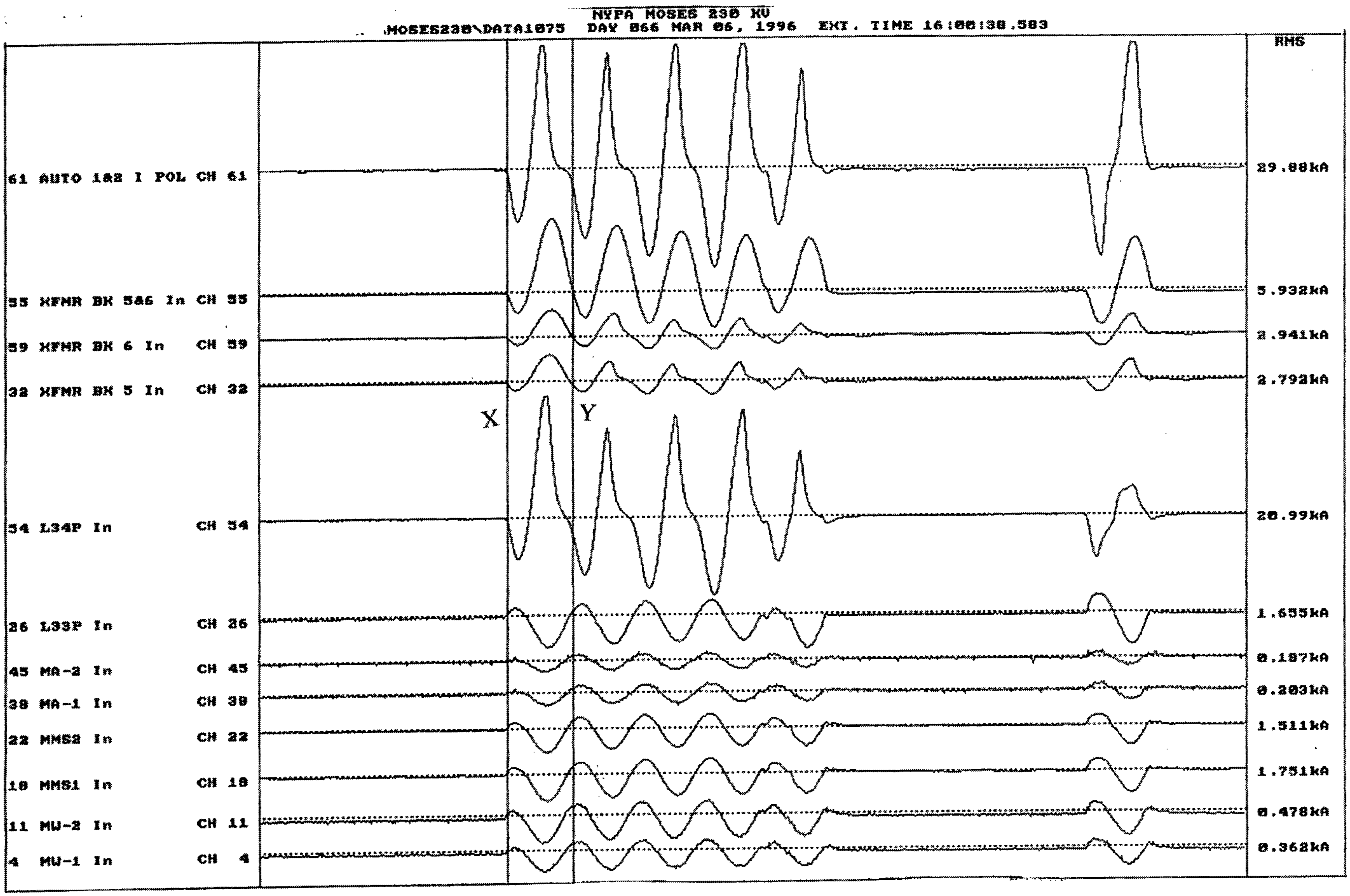


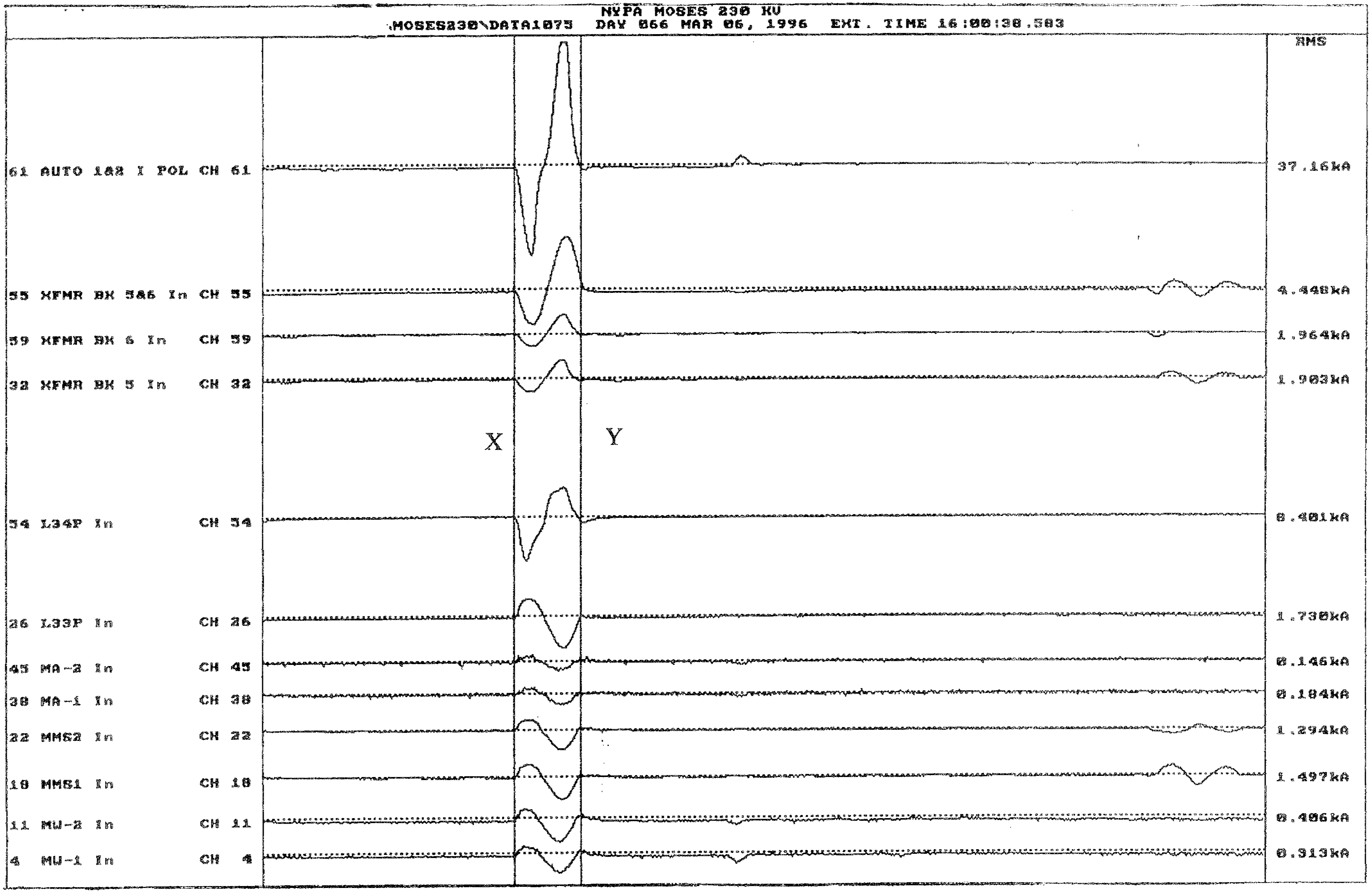
Figure 18

Ground Current Contributions to the Fault indicating possible



One Cycle Window

Figure 19
RMS Values for Ground Current Contributions to the Initial C-g Fault



One Cycle Window

Figure 20

RMS Values for Ground Current Contributions to the Second C-g Fault

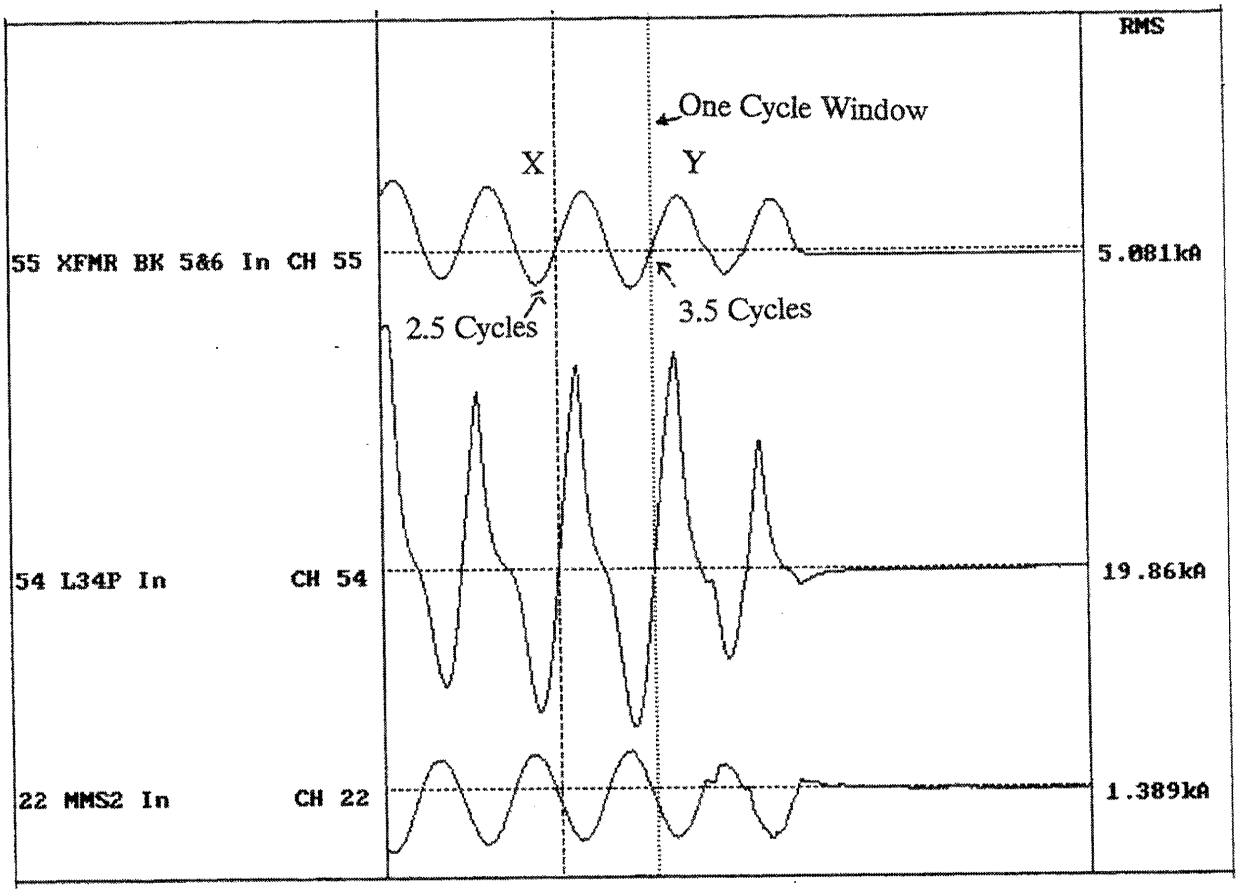


Figure 21
RMS for Selected Ground Currents for Initial C-g Fault(2.5-3.5 Cycles)

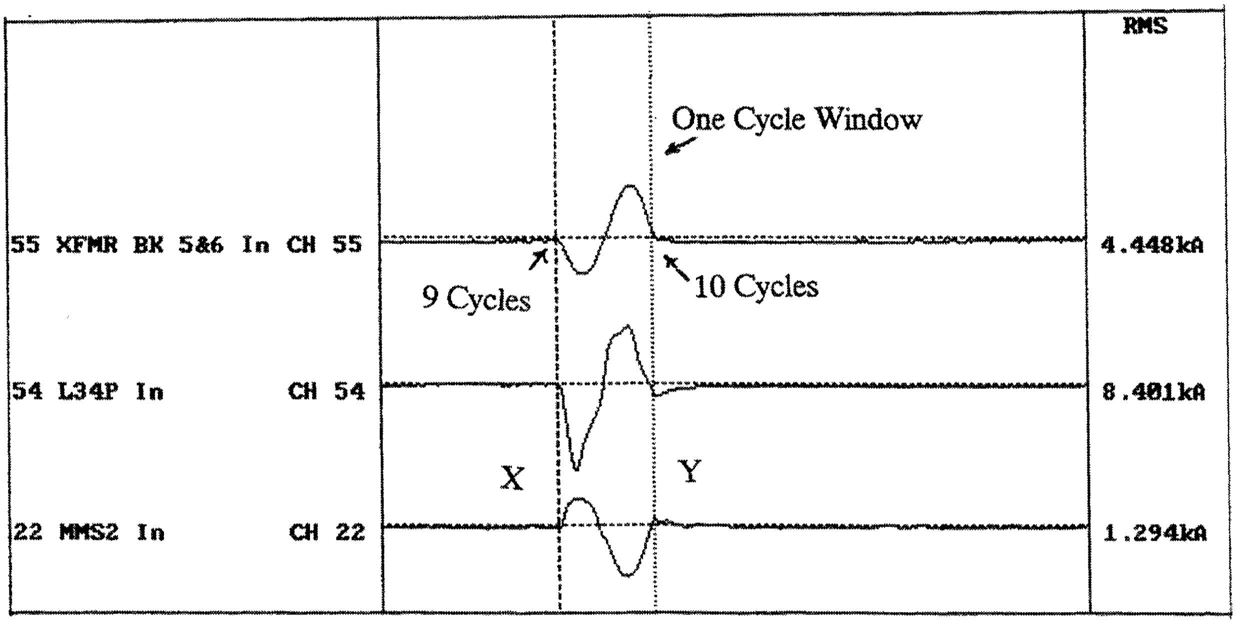


Figure 22
RMS for Selected Ground Currents for Second C-g Fault(9-10 Cycles)

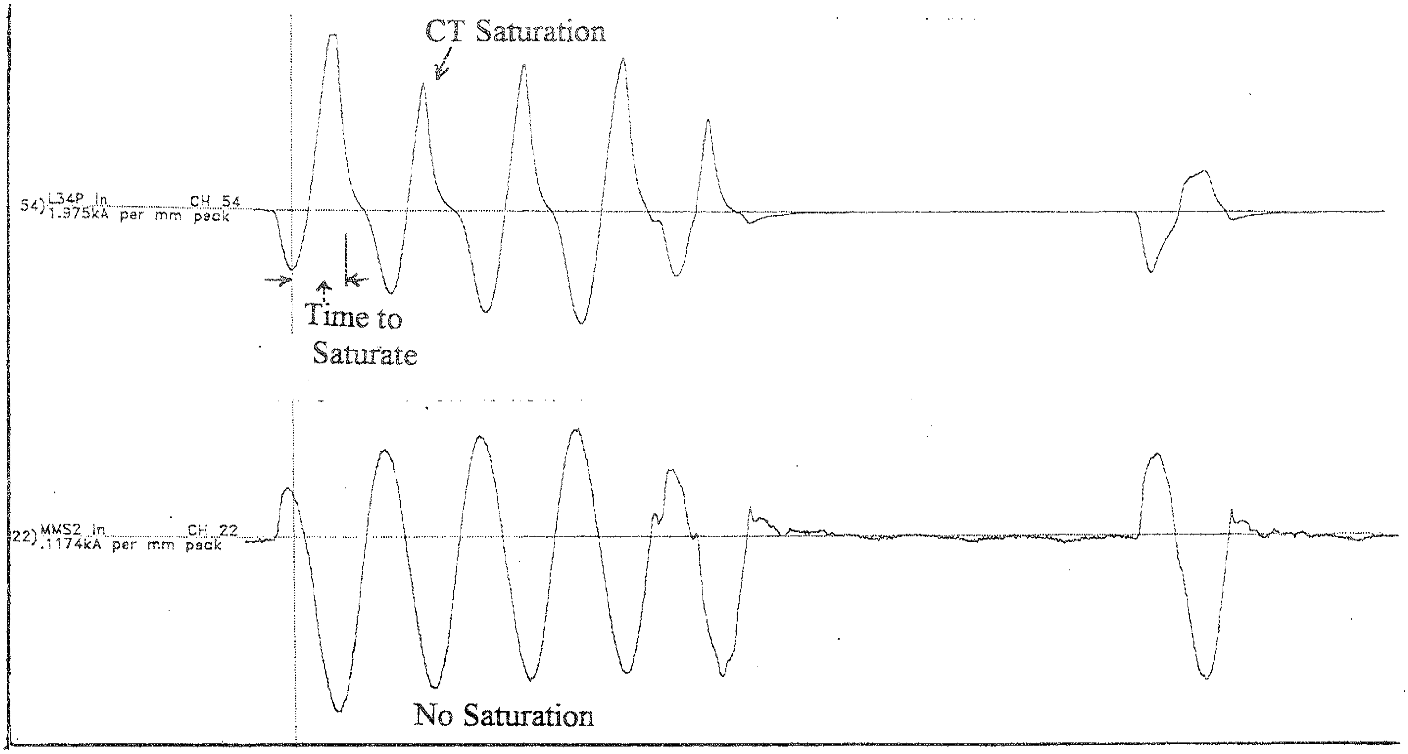


Figure 23
CT Saturation for L34P Line Current

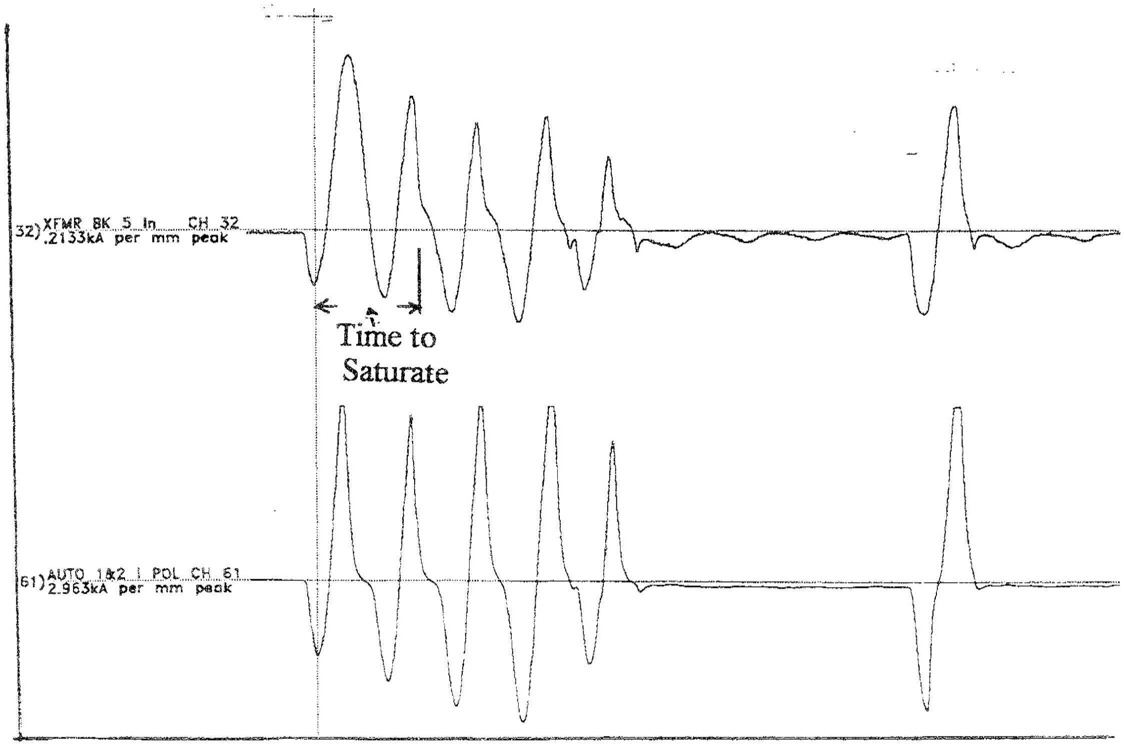


Figure 24
CT Saturation for XFMR BK 5 neutral &AUTO 1&2 Pol. Currents

NEW YORK POWER AUTHORITY ENGINEERING DIVISION (WPO)---Digital Transient Recorder LASER QUICK-PLOT Program Version 2.70
STATION NAME: Moses 230KV FAXTRAX EVENT NO. 1075 DATE: 03/06/96 TRIGGER TIME: 16:00:38.583
No. of Recorded Channels=66 Total Event Length=51.20 cycles Pre-trigger Length=12.77 cycles Sampling Rate=6,000 samples/second
Plot Creation Date: 10/30/97 Time: 15:04:26 Plot 1 of 1 Every point plotted
Maximum Dynamic Scaling with Channel Grouping, Selected Channels Plotted, Selected Timeframe Plotted

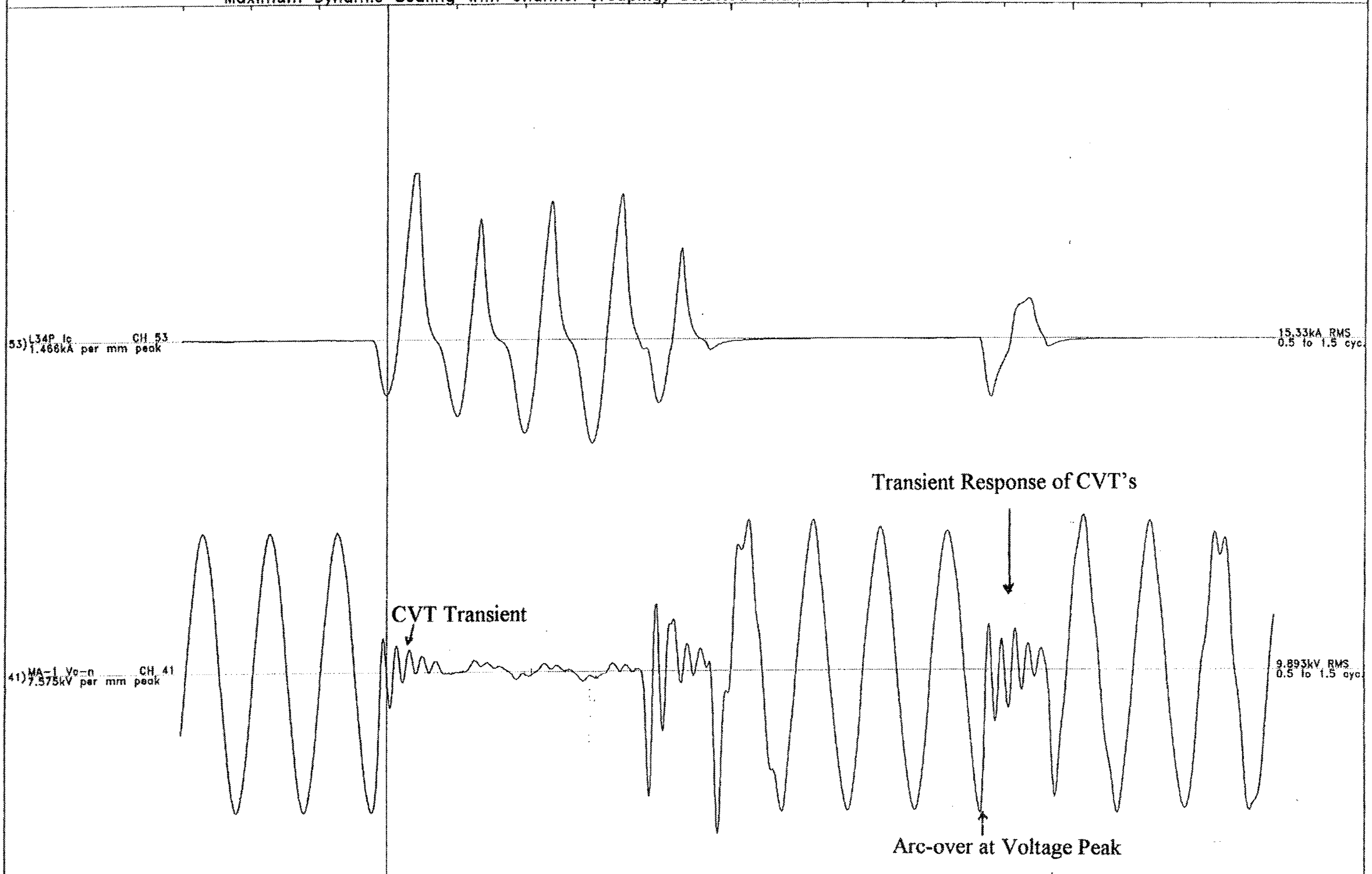
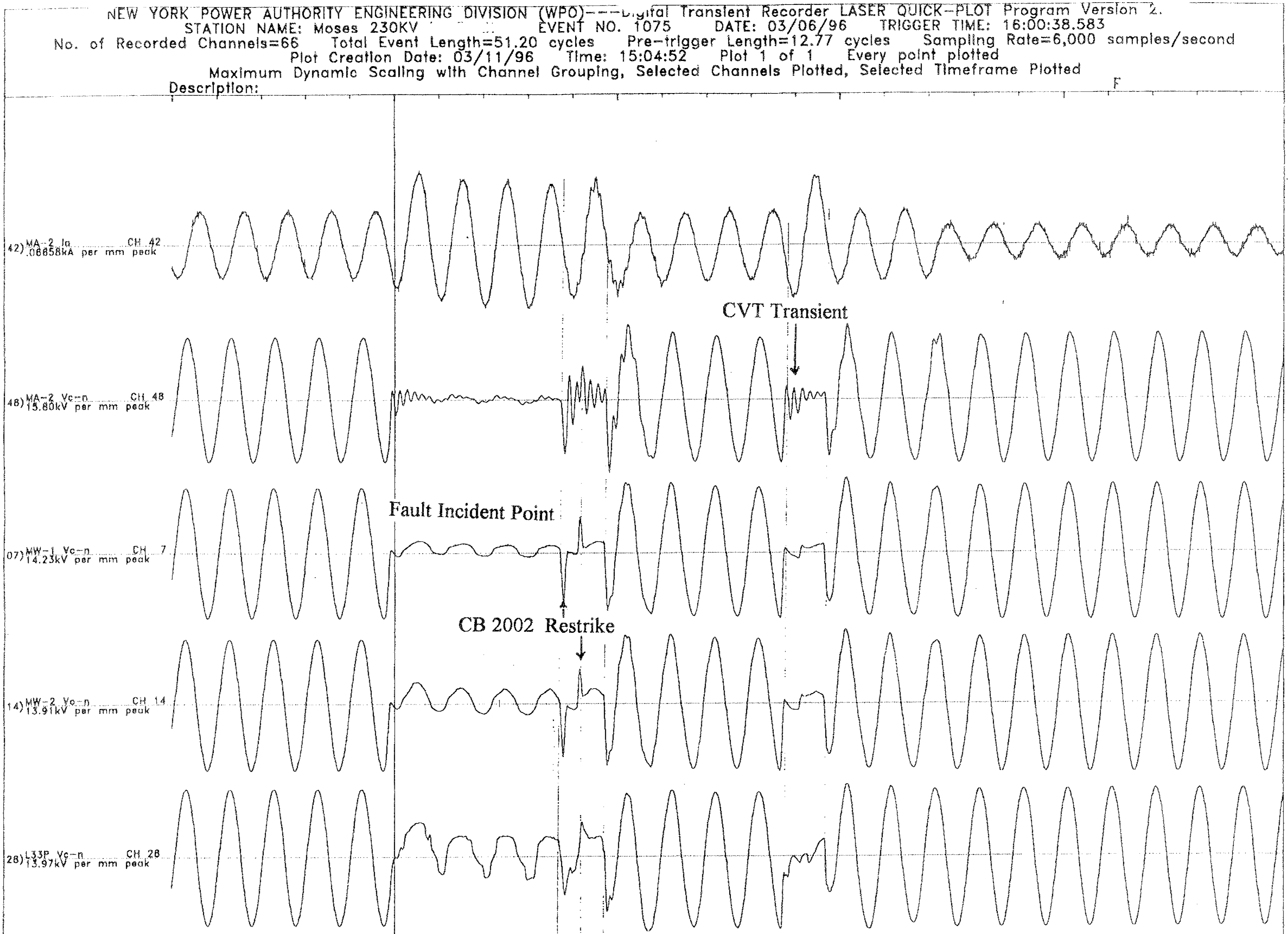


Figure 25
Second C-g Fault incident Angle &CVT Transient

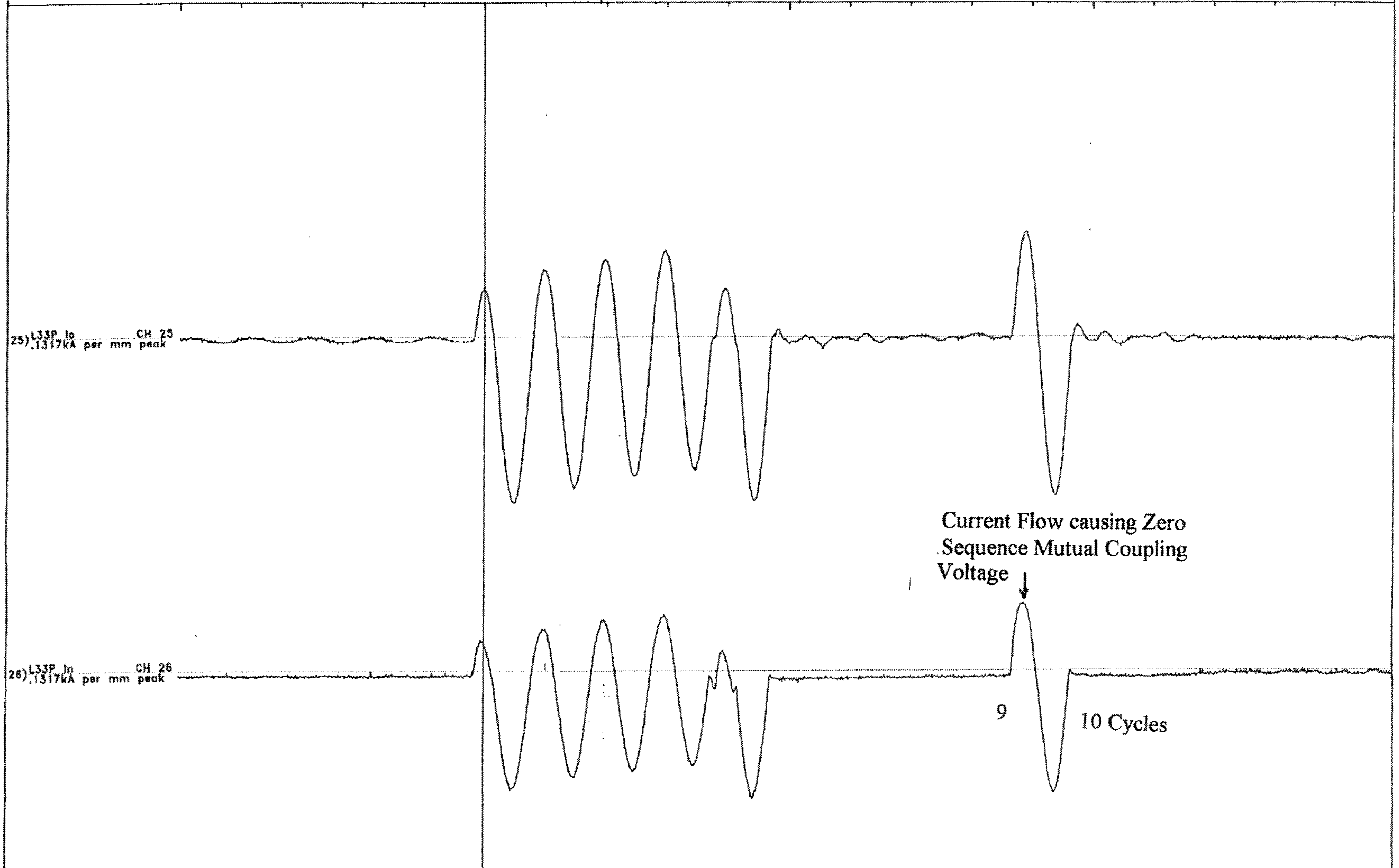


NEW YORK POWER AUTHORITY ENGINEERING DIVISION (WPO)---Digital Transient Recorder LASER QUICK-PLOT Program Version 2.
STATION NAME: Moses 230KV EVENT NO. 1075 DATE: 03/06/96 TRIGGER TIME: 16:00:38.583
No. of Recorded Channels=66 Total Event Length=51.20 cycles Pre-trigger Length=12.77 cycles Sampling Rate=6,000 samples/second
Plot Creation Date: 03/11/96 Time: 15:04:52 Plot 1 of 1 Every point plotted
Maximum Dynamic Scaling with Channel Grouping, Selected Channels Plotted, Selected Timeframe Plotted
Description:

Figure 26

Faulted Phase Voltages for 230 KV Lines

NEW YORK POWER AUTHORITY ENGINEERING DIVISION (WPO)---Digital Transient Recorder LASER QUICK-PLOT Program Version 2.50
STATION NAME: Moses 230KV EVENT NO. 1075 DATE: 03/06/96 TRIGGER TIME: 16:00:38.583
No. of Recorded Channels=66 Total Event Length=51.20 cycles Pre-trigger Length=12.77 cycles Sampling Rate=6,000 samples/second
Plot Creation Date: 03/11/96 Time: 16:07:35 Plot 1 of 1 Every point plotted
Maximum Dynamic Scaling with Channel Grouping, Selected Channels Plotted, Selected Timeframe Plotted
Description: Fault Record expanded



Current Flow causing Zero Sequence Mutual Coupling Voltage

Figure 27
L33P Phase and Neutral Current Contributions to the Ground Faults

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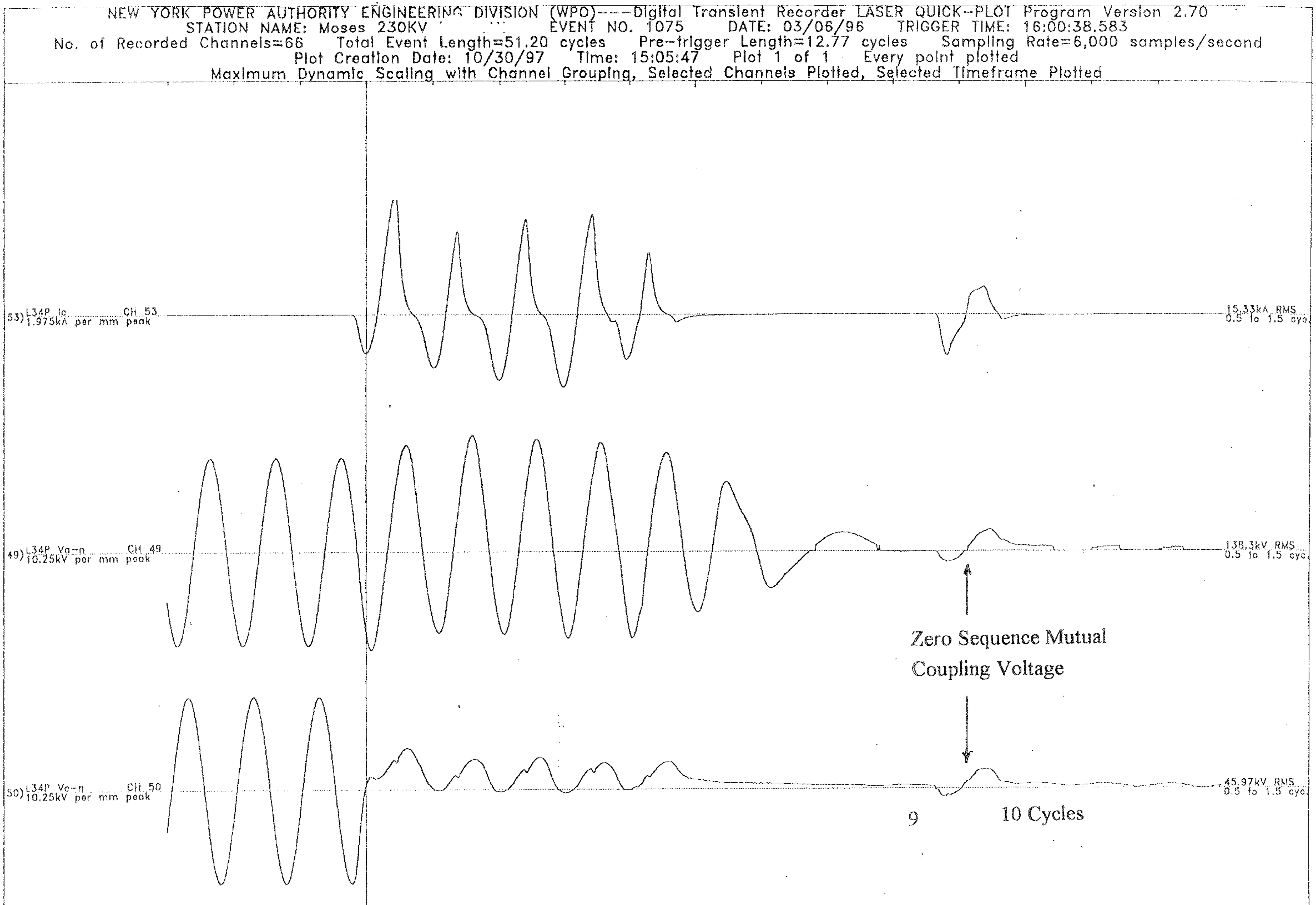

NEW YORK POWER AUTHORITY ENGINEERING DIVISION (WPO)---Digital Transient Recorder LASER QUICK-PLOT Program Version 2.70
STATION NAME: Moses 230KV EVENT NO. 1075 DATE: 03/06/96 TRIGGER TIME: 16:00:38.583
No. of Recorded Channels=66 Total Event Length=51.20 cycles Pre-trigger Length=12.77 cycles Sampling Rate=6,000 samples/second
Plot Creation Date: 10/30/97 Time: 15:05:47 Plot 1 of 1 Every point plotted
Maximum Dynamic Scaling with Channel Grouping, Selected Channels Plotted, Selected Timeframe Plotted

Figure 28

Zero Sequence Mutual Coupling Induced Voltages on the opened L34P Line