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SUBJECT: Forwards response to NRC 980406 RAI re emergency power sys.

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W. R. McCollum, Jr.
Vice President

June 18, 1998

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
Response to Request for Additional Information on the Oconee Emergency Power System

In a letter dated October 31, 1996, Duke Power committed to review the possibility of performing a one-time integrated emergency power and engineered safeguards functional test during the outage of all three Oconee units that was in progress at the time. In a follow-up letter dated November 21, 1996, Duke committed to the performance of a one-time integrated emergency power and ES functional test during the three unit Oconee outage.

The one-time integrated emergency power and ES functional test was performed on January 2-5, 1997. The one-time integrated emergency power and ES functional test demonstrated that the Oconee emergency power system was capable of performing its intended safety functions. In a letter dated January 30, 1997, Duke provided the schedule for the submittal of the test report and CYME computer simulation for the one-time integrated emergency power and ES functional test. A copy of the test report was submitted to the NRC by a letter which was dated April 30, 1997. In a letter dated December 18, 1997, Duke supplied a copy of the CYME computer simulation results of the one-time integrated emergency power and ES functional test.

During the NRC review of the test report and the CYME computer simulation results, additional information was requested by the NRC in a letter dated April 6, 1998. In Attachment 1, a response to the NRC's request for additional information is provided. This submittal does not contain any new commitments.

A001

Please address any questions to Michael Bailey at (864) 885-4390.

Very truly yours,

W. R. McCollum, Jr.
Site Vice President
Oconee Nuclear Station

Attachments

cc: L. A. Reyes, Regional Administrator
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NRR

ATTACHMENT 1

REQUEST FOR ADDITIONAL INFORMATION
OCONEE EMERGENCY ELECTRICAL POWER
DISTRIBUTION SYSTEM

A. Questions Relating to Emergency Power and Engineered Safeguards Functional Test Report dated April 30, 1997

1. Volume I, Section 1 of the Oconee Emergency Power and Engineered Safeguards Functional Test Report contains a very good overview of the Oconee emergency power system. It indicates that the Emergency Power Switching Logic will monitor the voltage available to the Normal Source and, if an undervoltage condition exists, will attempt to transfer to the Start-up Source if voltage is available there. It states that for events such as a unit trip, this transfer provides power to station loads.

Question:

a. Are there intentional delays incorporated into this transfer?

Response:

If an Oconee unit is operating, a rapid transfer from the Normal Source to the Start-up Source will follow a reactor, turbine, or generator trip see the response to Question A.1.b for details. If the Normal Source should lose voltage while an Oconee unit is on backcharge, the normal breakers would open, but a close signal would not be provided to the start-up breakers. The Main Feeder Bus Monitor Panel would initiate a signal to the Load Shed circuitry 20 seconds after loss of voltage on the main feeder bus. A Load Shed signal would be initiated 1 second later providing a close signal to the start-up breakers.

Question:

b. What signals other than undervoltage on the Normal Source will cause a transfer from the Normal Source to the Start-Up Source?

Response:

Turbine Trip (Relay 62GXA) - initiated by closing of the turbine stop valves.

Generator Lockout (Relay 86GB) - initiated by generator trouble (Faults, Loss of Excitation), main or auxiliary

transformer trouble, generator or 4160 VAC auxiliary supply breaker failure, or reactor trip.

Backup Generator Shutdown Lockout (Relay 86HY) - initiated 0.75 seconds after a turbine trip or immediately by turbine over speed. This lockout is also initiated by the generator over-frequency trip relay 81H with no intentional time delay.

Question:

c. Are these transfers fast transfers (no intentional time delay) or do they incorporate intentional time delays?

Response:

The transfers as a result of turbine trip and generator lockout are fast transfers. The transfers following a reactor trip are fast transfers (i.e. no intentional time delays) provided the Normal and Start-up Sources are synchronized.

Question:

d. What are the delays and for what purpose?

Response:

There are no intentional time delays in the transfers, which are listed in the response to Question A.1.b, if the Normal and Start-up Sources are synchronized. There is a delay of 1.3 seconds in the closing of the startup breaker to assure a dead bus transfer in case the Normal and Start-up Sources are not synchronized.

Question:

e. For the unit trip event, what signals other than undervoltage cause a transfer from the Normal Source to the Start-up Source?

Response:

Either the turbine trip or the generator lockout will cause an immediate transfer to the Start-up Source on an Oconee unit trip.

Question:

f. Are there delays in the transfer?

Response:

The transfers as a result of turbine trip and generator lockout are fast transfers. The transfers following a reactor trip are fast transfers (i.e. no intentional time delays) provided the Normal and Start-up Sources are synchronized.

Question:

g. On a unit trip, is there a delay between the reactor/turbine trip and the main generator trip (opening of generator switchyard circuit breakers)?

Response:

There are no intentional delays between the reactor trip and generator trip. The reactor trip will initiate a generator lockout which will trip the generator and open the generator switchyard circuit breakers.

Question:

h. What signal (or signals) trips the main generator?

Response:

The generator lockout and backup generator lockout will trip the generator (see the response to Question A.1.b for details).

Question:

i. Is the transfer from the Normal Source to the Start-Up Source tied in any way to the tripping of the main generator? If it is not tied to the trip of the main generator and will only transfer on undervoltage, what effect does the decreasing frequency from the coastdown of the generator have on the connected loads prior to transfer on undervoltage?

Response:

As discussed in the response to Question A.1.b, tripping of the generator will initiate a transfer from the Normal Source to the Start-up Source.

2. Table 4-5 in Volume I of the test report is a summary of the Keowee response during Test 3 (Keowee loading while accelerating). It indicates that there was only 0.3 second from the time the Keowee voltage regulator switched to automatic and the Oconee loads were energized by Keowee. Because there is no interlock that precludes loading the Oconee loads before the voltage regulator is brought online, it appears that the Oconee loads were dangerously close to being energized by Keowee before its voltage regulator was available.

Question:

a. Please explain how satisfactory loading of Keowee can be assured given such a slim margin.

Response:

In order to assist with the answer to this question, a brief discussion of the circuitry which transfers the voltage regulator to automatic is provided. The SV relay picks up a latching relay (90X1C) to initiate the transfer to automatic sequence. Once the SV relay picks up to initiate the transfer, the completion of the transfer is voltage insensitive and depends only on the timing out of the 90X1A/TD relay which has a time delay of 2.5 seconds. Thus, the transfer to automatic will be completed regardless of whether the Keowee unit is loaded prior to the pickup of the 90XB control relay which performs the switching sequence. This fact, in combination with the conclusion that the Keowee units are capable of supplying power to Oconee loads with the voltage regulator in manual as discussed below, makes the emergency power system loading and voltage regulator transfer to automatic timing not significant.

It should be noted that during the January 1997 Emergency Power Test 3 the voltage regulator transferred to automatic 0.3 seconds prior to Keowee being loaded. Therefore, the SV relay picked up approximately 2.8 seconds (2.5 seconds + 0.3 seconds) prior to Keowee being loaded.

Another aspect of the timing of the voltage regulator going to automatic is the effect of the field flash breaker cycling on the V/Hz ratio. The cycling of the field flash breaker will cause the generator output voltage to build slower than when the breaker remains closed for the duration of flashing the field. This will result in a lower V/Hz ratio for the Keowee start and a later pickup of the SV relays. With the field flash breaker cycling precluded, the V/Hz ratio should be higher and the V relays should pickup sooner during the startup sequence. Data taken during the Oconee Unit 1 EPSL Functional test in January 1998 and data submitted in Attachment 5 of the Duke letter dated January 31, 1996 confirms the conclusion that the V/Hz ratio is higher when the field flash breaker does not cycle for the duration of the field flash.

Finally, an evaluation of the impact of the Keowee unit loading with the voltage regulator in manual was performed previously. When in manual, no-load generator voltage is determined by the calibration of the Base Adjuster preset, which is currently calibrated to provide 14.1kV. An evaluation was performed to determine if the Keowee unit could perform its safety function with the assumed failure of the voltage regulator to function in automatic. As part of the evaluation, an analysis was performed using the CYME computer model. The analysis assumed that the Keowee field voltage remained constant at its no load rated voltage. In the analysis, the no load rated voltage was assumed to be a Base Adjuster preset of 13.5kV. Since the Base Adjuster preset is now calibrated to 14.1kV, this assumption is considered conservative. In addition, the exciter output (or field) voltage will actually increase to 104 percent of no load exciter output with a decrease in terminal voltage to 80 percent (Reference KC-2023 Attachment 10), and the CYME analysis mentioned below indicates the generator voltage remains above 80 percent for the entire transient. The CYME analysis is documented in OSC-5952 as Case 3L. This analysis concluded that the Keowee unit was still a viable source of power to the ONS emergency loads, even with the failure of the voltage regulator to transfer to automatic.

Question:

b. Has this vulnerability been modeled in the Keowee Probabilistic Risk Assessment (PRA)? If so, please indicate the unreliability attributed to this feature.

Response:

The Keowee PRA did not assume that the voltage regulator was required for proper Keowee unit operation following a LOOP. The Keowee PRA assumed that the base adjust setting on the voltage regulator provided an acceptable voltage level for operation of the loads at Oconee. The voltage regulator switch to the automatic mode is not required for system success. A failure to switch to automatic is not a failure of the Keowee unit to supply Oconee and is, therefore, not included as a failure mode in the Keowee PRA.

Question:

c. Describe the operation and setpoints of the 53 relays that control energization of the Keowee voltage regulator and the SV relay that controls the Keowee field flash breaker.

Response:

The 53 and SV (53-31T) relays monitor the generator output voltage through the potential transformer on the generator bus. The relays function to trip the field flash breaker (53-31T) and initiate the transfer of the voltage regulator to automatic control (53) on relay pick-up.

The SV Relays have a V/Hz pick-up characteristic. The 53-31T relay is set at 100 volts. The field flashing breaker will trip when this relay picks up.

The 53 relay is set at 70 volts and picks up the latching relay 90X1C which places the voltage regulator in the test position (this functions to energize the automatic voltage regulator circuits). In addition, relay 90X1C starts time delay relay 90X1A/TD which provides time for the regulator circuits to stabilize following energization. The time delay relay times out in 2.5 seconds to place the automatic regulator in control of generator voltage.

3. Section 4.3.1 of the report identifies an anomaly that occurred during Test 3 with the Keowee output volts/hertz (V/Hz) ratio. The V/Hz ratio was not being maintained at a nominal 1.05 pu, but rather increased from 0.76 pu to 1.016 pu over the course of the load start transient.

Question:

a. Although the Oconee loads were successfully loaded during the test, explain how successful loading of the Keowee loads can be assured given such a low (76 percent) initial V/Hz ratio.

Response:

Test 3 was a black start test of the Keowee unit. During Test 3, the V/Hz ratio was lower than expected due to the cycling of the field flash breaker. As indicated by the Keowee voltage and V/Hz curves which were submitted in Attachment 5 of the Duke letter dated January 31, 1996, data that was collected on the Keowee unit during an emergency start indicates, that with a correctly functioning field flash breaker and a Keowee unit "black-start", the V/Hz ratio will be 1 pu when the unit is loaded at 12.5 seconds when generator voltage reaches 60 percent. During Test 3, the V/Hz ratio when the Keowee unit loaded was approximately 0.8 pu with the cycling field flash breaker.

The field flash breaker cycling reduced the available excitation energy that was provided to the field during the acceleration period which caused the Keowee generator voltage to build more slowly. The affect of the field flash breaker cycling can be seen in figure 4.3.1-2 of the Emergency Power Test Report that was submitted on April 30, 1997. In the figure, a decrease in the slope in Keowee generator voltage was obvious as the Keowee unit accelerated during the periods when the field flash breaker was open. The Keowee generator voltage increased at a slower rate with the field flash breaker cycling open and shut, due to the power feeding back to the field through the exciter bridges. During startup, the exciter bridges are controlled to fire as early as possible in order to allow the voltage to build up as quickly as possible. The fact that the Keowee generator voltage continued to increase with the field flash breaker cycling open is indicative that the Keowee unit had reached a self sustaining level of voltage by that time.

A comparison of V/Hz ratios on 208VAC motor control center (MCC) 3XS1 for Tests 3 (Standby Start) and Test 4 (Load Rejection Start) is included in Attachment 10. During the

standby start (Test 3), the MCC V/Hz ratio was approximately 0.7 pu when the MCC loads started. During the load rejection start (Test 4), the MCC V/Hz ratio was approximately 0.65 pu when the MCC loads started. Thus, from a MCC V/Hz ratio perspective, the load rejection start was more conservative than the standby start test, even with the field flash breaker cycling problem. Since the load rejection start is more conservative from a V/Hz ratio perspective at the motor control center and can be modeled in the CYME analysis, there is considerable assurance that the loads will start as designed during the standby start scenario.

The fact that the Oconee emergency loads successfully started with the lower V/Hz ratio provides significant evidence that the loads will start with some margin with a properly functioning Keowee unit.

4. In the June 20, 1997, event that resulted in the failure of a Keowee unit to come up to voltage it was determined that the field flash breaker was cycling due to the setting of the 53-31T relay. That same setting was apparently in place on the Keowee unit being tested during the January 1997 tests. It is likely, therefore, that cycling of the field flash breaker was occurring during those tests that were performed with the Keowee unit started from standby.

Question:

a. Discuss the effect of the breaker cycling on the test results, including the effect on the V/HZ ratio and regulator timing issue described in question 2 above.

Response:

As discussed in the response to Question A.3.a above, the cycling of the field flash breaker will cause the generator output voltage to build slower than when the breaker remains closed for the duration of flashing the field. This will result in a lower V/Hz ratio for the Keowee start and a later pickup of the SV relays. With the field flash breaker cycling precluded, the V/Hz ratio should be higher and the SV relays should pickup sooner during the startup sequence. Data taken during the Oconee Unit 1 EPSL Functional test in January 1998 and data submitted in Attachment 5 of the Duke letter dated January 31, 1996 confirms the conclusion that the V/Hz ratio is higher when the field flash breaker remains closed.

The SV relay picks up a latching relay (90X1C) to initiate the transfer to Auto sequence. Once the SV relay picks up to

initiate the transfer, the completion of the transfer is voltage insensitive and depends only on the timing out of the 90X1A/TD relay which has a time delay of 2.5 seconds. Once initiated, the transfer to automatic will be completed regardless of whether the Keowee unit is loaded prior to the pickup of the 90XB control relay which performs the switching sequence. This fact, in combination with the conclusion that the Keowee units are capable of supplying power to Oconee loads with the voltage regulator in manual as discussed in the response to Question A.2.a above, makes the emergency power system loading and voltage regulator transfer to automatic timing not significant.

It should be noted that during the January 1997 Emergency Power Test 3 the voltage regulator transferred to automatic 0.3 seconds prior to Keowee being loaded. Therefore, the SV relay picked up approximately 2.8 seconds (2.5 seconds + 0.3 seconds) prior to Keowee being loaded.

Question:

b. Describe what effect, if any, the resetting of the 53-31T relay to its original setpoint will have on the V/Hz ratio and regulator timing issue.

Response:

Resetting the 53-31T relay to the original setpoint of 100 volts was done to prevent cycling of the field flashing breaker. The elimination of the field flash breaker cycling results in faster voltage build up and more time between when the voltage regulator goes in automatic and the Keowee unit is loaded. In addition, the V/Hz ratio will be higher. Review of subsequent Keowee emergency starts has proven that the field flash breaker cycling was successfully precluded. Additional information on the voltage regulator timing issue is in the response to Question A.4.a.

Question:

c. To our knowledge, the SV relay that controls Keowee voltage regulator energization will still cycle during a standby start of Keowee. Does Duke have any new thoughts following the June 20, 1997, event regarding any detrimental effects this might have on Keowee emergency operation? Do these relays cycle during normal starts of the Keowee units? Please discuss.

Response:

With the higher SV relay setpoint, the field flash breaker performs as designed (i.e. does not cycle) for an emergency start with the currently installed SV relay which is prone to cycling at reduced frequencies. Thus, the cycling SV relay currently has no detrimental effects on the operability of the Keowee units. In addition, the January 1997 emergency power test showed that the Keowee units functioned adequately with the cycling field flash breaker. Although the current design is acceptable, a modification is planned to replace the SV relay with a relay that is not susceptible to the reduced frequency cycling.

During normal starts, the Keowee unit speed is near rated when the field is flashed. Thus, the currently installed SV relays do not experience the cycling phenomena on normal starts.

5. Figure 4.3.1-5 shows quite a large frequency overshoot when Keowee is emergency started from standby in Test 3. In this test, the loaded Keowee unit accelerates to 67.5 Hz before it turns downward.

Question:

a. Are there any potential detrimental effects to the Keowee or Oconee loads that Keowee is powering when it accelerates to these frequency levels following an emergency start?

Response:

Induction motors, large and small, are designed to operate at speeds above their nominal rating for short duration without damage. The duration for the frequency overshoot is approximately 8 seconds. Oconee's motors have the mechanical capacity to experience this transient without damage. In addition, the Oconee and Keowee loads which are not induction

motors can withstand the frequency overshoot without any detrimental effects.

Question:

b. We note that the maximum frequency loading permissive on an emergency start from generation to the grid is 110 percent, which is lower than the level seen in Test 3. If the load were less during this test (e.g., no failure resulting in starting a large unscheduled load), would the larger frequency excursion have a detrimental effect on the loads?

Response:

Based on the size and inertia of the Keowee units when starting and accelerating on an engineered safeguards actuation, the application of Oconee loads on the Keowee units has a negligible effect on the speed startup profile. Previously recorded engineered safeguards test data of the Keowee units starting with no load, partial loads, and LOCA plus single failure loads indicate that the Keowee response is the same with a non noticeable effect due to loading. The effect of the overshoot is addressed in the response to Question A.5.a.

Question:

c. For the non-loss-of-coolant accident (LOCA) scenario where a single Oconee unit is picked up by a standby Keowee overhead unit following actuation of the external grid trouble protection system, would the large frequency excursion have a detrimental effect on the Oconee or Keowee loads?

Response:

No. See the response to Question A.5.a above for additional information.

6. In all the tests that involve stroking of Engineered Safeguards (ES) valves, a motor contactor transient is observed on the contactors associated with some of the valves. The transient occurs following contactor pickup when the voltage across the contactor recovers to a value sufficient to pull the contactor in. Section 4 of the report indicates that, although the transient has negligible impact on the valves' performance, it explains the current increases and decreases seen during the applicable motor-operated valve's (MOV's) inrush period. Although very short, these

current decreases are quite substantial; in many cases going to, or very near to, zero amperes. This indicates that although the contactor is not fully dropping out, the contacts may be parting sufficiently to cause some contact arcing during these periods of high current inrush.

Question:

a. Please discuss what effects this potential arcing could have on contact life and MOV reliability during an emergency event.

Response:

The electrical current transients recorded for the ES valves are within the inrush capability of the contactor contacts. In addition, the electrical current transients are of such a short duration that heat build-up and impact on contact life is negligible. The ES valves reliably operated through multiple (four) LOCA/LOOP scenarios during the Integrated Emergency Power and Engineered Safeguards Test. In addition, these contactors are periodically inspected as part of a preventative maintenance program which is designed to correct and/or prevent problems.

7. Section 5.2.4 of the report states that MOV 3LP-17, which is a gate valve, briefly stalled while starting following contactor pickup during Tests 4, 5, and 6. The stall times were 1.0, 1.0, and 0.4 seconds, respectively, for the three tests. The report indicates that the valve recovered in each case and completed its stroke to its proper ES position; and following inrush, valve stroke was normal and normal hammer-blow and unwedging was observed. We note that in all the LOCA tests where the MOVs are actuated, this particular valve's motor contactor picks up at a voltage value that is quite often one of the largest values seen on the group of valves that are monitored. On that basis, not considering any other variables, it would be expected that this valve would be the least likely to stall.

Question:

a. What variables make this particular valve so prone to stall?

Response:

When the initial analysis was done on the Engineering Safeguards (ES) actuated MOVs, only one phase of the three

monitored phases was analyzed for inclusion in the report since all valve stroke events could be identified regardless of which phase was analyzed. A more detailed review of the data for all three monitored phases indicates that the primary reason 3LP-17 appeared to stall was that the 'c' phase starter contact chattered while the 'a' and 'b' phase contacts maintained a stable energized state. Therefore, the 'a' and 'b' phases (one of which was included in the report) indicated stall conditions until the 'c' phase contact maintained a stable energized state. Once all three phases were energized, 3LP-17 stroked as expected. In retrospect, 3LP-17 did not actually stall as originally thought. Attachment 6 contains the plots of the current data for 3LP-17 which indicate the chattering of the 'c' phase contact.

Question:

b. Was this expected prior to the test?

Response:

Yes. The MOV calculations impose a high temperature effect due to self heating based on an assumed 5 second stall time for all Engineering Safeguards (ES) actuated MOVs. This high temperature effect results in a loss of torque output provided by the actuator. Therefore, it was expected that the ES MOVs would stall.

Question:

c. Prior to the test, was this valve considered to be the most limiting of the group of valves monitored?

Response:

In choosing valves to monitor to make up the test population, a cross section of ES MOVs were chosen in order to sample a variety of valve types (gate, globe, butterfly, ball, etc.), capture various system conditions, and ensure both Limitorque and Rotork actuators were included. Therefore, it was extremely difficult to compare the MOVs as a group to determine which would have most likely been the worst case or bounding valve. If a bounding MOV could have been chosen or if a smaller set of MOVs could have been tested to represent the population, the number of valves tested would have been smaller. 3LP-17 was not considered to be the most limiting of the group of valves monitored.

Question:

d. Please provide plots of the valve motor's thermal capability and overload protection, overlaid on the starting inrush current figures shown for this valve during the tests.

Response:

Copies of the requested plots are contained in Attachments 2 through 6.

8. During the tests a good deal of data was taken on a select group of MOVs.

Question:

a. What insights were gained relative to MOV operability as a result of the observed data?

Response:

The most significant insight gained during this testing was that the MOVs did not stall for 5 seconds as assumed. The MOV calculations impose a high temperature effect due to self heating based on the assumed 5 second stall time. This high temperature effect results in a loss of torque output provided by the actuator. Therefore, Duke's MOV analyses are very conservative for this aspect of the analyses. It should be noted that no significant valve anomalies were identified.

Question:

b. Were any of the insights used in the Oconee Generic Letter (GL) 89-10 MOV program?

Response:

The GL 89-10 MOV calculations still impose a high temperature effect due to self heating based on the assumed 5 second stall time. The MOV calculations were not changed based on insights provided by this testing. Therefore, the torque output provided by the actuator during undervoltage conditions given in the MOV calculations is conservative. The actual torque output provided by the actuator during an undervoltage condition would be greater since the MOVs do not stall or stall for much less than the assumed 5 seconds.

Question:

c. The motor control center voltage at contactor pickup, as well as the time for voltage to reach 100 percent, was identified in the test report for each monitored MOV. Was this data used to help establish the voltage profile across the MOVs for the analyses done under the GL 89-10 program? If it was used in the program, how was it used? If it was not used in the program, how well does it correlate to the voltage profile assumptions that were used?

Response:

These tests were performed with the Keowee Hydro units or Lee units as the source of power which is better than a "degraded" off site source. The MOV calculations use worst case undervoltage from a "degraded" off site source and assume this worst case undervoltage remains constant for the duration of the stroke. This approach bounds worst case conditions and resembles actual conditions for valves that have to open, especially gate valves that are closed statically then unwedged against design basis conditions. This approach is very conservative for valves that have to close where the voltage would have recovered by the time the valve encountered any significant system forces.

B. Questions Relating to the CYME Modeling of Emergency Power and Engineered Safeguards Function Tests 2, 5, and 6 dated December 18, 1997

1. The CYME modeling report identifies anomalies and differences between the operation of the reactor building cooling fan (RBCF) motors during the tests and what is modeled in the CYME analysis. It indicates that in Test 2 (loss of offsite power (LOOP) test) the model starts the RBCF on low speed from initially zero speed whereas in the actual test, the RBCF was initially running on high speed, started in low speed and later automatically shifted to high speed. For Tests 5 and 6 (LOCA/LOOP tests) the report indicates that RBCFs 3A and 3C were operated and modeled as described for Test 2, but RBCF 3B was started from standby (although rotating backwards) on low speed for both the test and the model.

Question:

a. Describe how and why the RBCF motors will start during actual LOOP and LOCA/LOOP scenarios. Also describe why they operated differently during the tests.

Response:

The Reactor Building Cooling Units (RBCUs) are two speed motors with speeds designated as LOW and HIGH. The control switches for the RBCUs is a four position maintained switch. The position designations are HIGH, LOW, AUTO, and OFF. The normal operating position for the switch is in the HIGH position. Since the control switch remains in the HIGH speed position following a LOOP event, the RBCU will go through a normal start which is to start in LOW speed and after the appropriate time automatically transfer to HIGH speed. This is what occurred in Test 2 and is the manner in which the circuit is designed. The CYME model is not capable of modeling a two speed motor and a discussion of the fact that this is not modeled is detailed in the response to Question B.3.a.

During an ES actuation, the RBCUs are designed to automatically start and run in LOW speed regardless of the position of the control switch. The control circuit is designed to bypass the control switch and the LOW speed overloads to enable the RBCUs every possible chance to run in LOW speed. During Test 5 and 6 (LOCA/LOOP tests), the reaction of the RBCUs were exactly what would be expected. The two operating RBCUs (3A and 3C) were taken to LOW speed

by the ES circuit and the RBCU that was not running (3B) was automatically started and ran in the LOW speed.

2. In Figure 2-24 of the report, the staff notes that, if the OD-3 trip of the RBCF motor is drawn in as it is in Figure 3-24, the motor starting current is very close to tripping this device. The report attributes the excessively large and long starting current to the reverse rotation of the motor due to damper back leakage, which is scheduled for a modification to better seal the damper.

Question:

a. If the RBCF motor will be rotating backwards prior to an event before the modification is complete, discuss operability of the RBCF in this condition given the very slim margin to motor tripping.

Response:

It is important to note that on Figure 2-24, the RBCF motor starts at approximately t = 950 cycles, whereas on Figure 3-24 the RBCF motor starts at approximately t = 810 cycles. The overcurrent device must be plotted based on the time the motor start is initiated. The OD-3 trip device is plotted on the attached copy of Figure 2-24 which is contained in Attachment 7. There is not any substantial difference between the margins shown on Figures 2-24 and 3-24. The fan which was monitored and hence plotted in Figure 3-24, RBCF 3B, is the one expected to have the longest starting time. RBCF 3B is fed from a 300KVA transformer, whereas RBCF 3A and 3C are fed from 1000KVA transformers. Thus, the source impedance for RBCF 3B is higher. The trip device in the circuit to RBCF 3B is the 225A TJJ breaker which when plotted shows significant margin. The OD-3 device is only in the circuits that supply the other two RBCFs (3A and 3C) whose feeder was not directly monitored but are expected to start faster. The starting current for these two fans (along with other loadcenter current) can be seen in Figures 3-32 and 3-34 for Test 6 and Figures 2-34 and 2-36 for Test 5.

3. The report states that the switching of the RBCF motors from low to high speed during the tests was not modeled by CYME because the model assumed the motors were starting in high speed from a zero speed condition. The report indicates that modeling of the safety system battery chargers at their current limit value, instead of the actual exponentially decaying current, adds a load equivalent to the RBCFs transferring to high speed. We note, however, that the battery current does not fully compensate for the RBCFs

transferring to high speed. In Figures 1-1 and 1-8 for example, the current due to the RBCFs between 1980 cycles and 2340 cycles is substantially greater in the test results than in the model results.

Question:

a. Comment on the effect this nonconservatism will have on using the CYME program to analyze future plant modifications or scenarios.

Response:

The "equivalent load" statement was made with reference to steady state conditions and should have included a clarifying statement that the inrush current period was not a concern. The transfer to high speed on the RBCF motors occurs 10 or more seconds after all other loads have started and reach steady state. Thus, the transfer to high speed does not impact the successful starting of the LOCA/LOOP loads. A review of Figures 1-28, 1-30, 1-32 and 1-35 demonstrates that the voltage on the 600 volt buses remains well within acceptable values (approximately 580V) when the RBCFs transfer to high speed. Thus, it is concluded that not modeling the transfer to high speed would not impact conclusions reached using the CYME program to analyze future plant modifications or scenarios.

4. With regard to the frequency response of the Keowee units, the report shows (Figures 1-5 and 2-5) that for Tests 2 and 5 the CYME model is nonconservative in estimating the maximum and minimum speed transients the machine experiences following load rejection from the grid. The report states that for both these tests the Oconee loads are placed onto the model at the time the loading actually occurred during the test. The frequency at loading during Test 2 is 59.6 Hz versus 60.9 Hz in the model. The frequency at loading during Test 5 is 64.7 Hz versus 62 Hz in the model. The report states that for Test 2, the frequency in the model at loading is slightly higher resulting in a slightly lower V/Hz ratio than in the test, which yields conservative model results. We note that for Test 5, just the opposite is the case. The frequency in the model is lower resulting in a higher V/Hz ratio than in the test, which yields nonconservative model results.

Question:

a. Comment on the use of nonconservative CYME model results for Test 5.

Response:

The loading in the model was placed onto Keowee at the same time instead of at the same frequency that loading occurred in the test to allow easier comparison of results. In Duke's existing and future Keowee analyses which model the load rejection scenarios, loading is and will be initiated at 110 percent frequency decreasing. Thus, the frequency at loading would be consistent with the test results. Even though the modeling performed comparing CYME and the test was slightly nonconservative at initial loading, the model bus voltages, MFB inrush and loading and motor start times (RBCF requires an adjustment due to initial reverse rotation) were conservative relative to the test results. Thus, the model results demonstrate the ability of the CYME model to conservatively predict the capability of the auxiliary power system loads to start and run from Keowee.

Question:

b. Comment on the nonconservative Keowee frequency response in the CYME model.

Response:

The purpose of modeling the Keowee unit and the Oconee auxiliary system loads is to verify the capability of the loads to start from Keowee. The comparison between the test results and the model demonstrates the capability to conservatively model the load response even with the frequency differences observed. With regard to response at the loads, the initial loading at a lower frequency is nonconservative but the undershoot as modeled is conservative. Existing and future modeling of load rejection scenarios are and will be modeled based on load initiation at 110% frequency decreasing. Thus, the loads are and will be modeled with a conservative V/Hz ratio.

Question:

c. For what purposes will the CYME transient response model of Keowee be used? Will it be used to analyze the effects on equipment that remain connected to Keowee over the full course of the transient (regulator controls, governor controls, protective devices, etc.) or just following connection of Oconee loads?

Response:

The CYME transient response model will be used to verify the capability to start and run Oconee loads from Keowee. Maximum overshoot and time to obtain 110 percent frequency decreasing following worse case load rejection is verified by periodic surveillance tests. Circuitry at Keowee precludes loads from loading on Keowee until frequency is at 110 percent decreasing following a load rejection. The 110 percent frequency setting in the circuitry is the same frequency that is included in Duke's analyses.

Question:

d. Will a test be performed to validate the CYME Keowee frequency response model for a Keowee full load, two-unit load rejection, or has one already been done? If one has been done, please provide the comparison of the test to the model.

Response:

The governor response has been validated using a single unit full load rejection test and reactor coolant pump test. A copy of the comparison of the test to the model is contained in Attachment 9. On a one unit or two unit full load rejection, the relay scheme presently in place at Oconee prevents loading until voltage and frequency have decreased below 110 percent. Test 2 shows that for a single load rejection, loading actually occurs near 60 hertz on the overhead path and Test 5 shows that loading actually occurs around 64.7 hertz on the underground path. With a two unit load rejection, the relaying will function in the same manner as a single load rejection. On a two unit load rejection, the overspeed will be slightly higher than a single unit load rejection, which will result in loading slightly later in time. For both cases, when the relay scheme permits loading, the frequency will be essentially the same and decaying at essentially the same rate. Thus, there will not be any significant difference in the Oconee auxiliary system load response for a single or two unit load rejection.

5. With regard to the frequency response question, as previously noted, the report indicates that the Oconee loads are placed onto the model at the time the loading actually occurred during the test.

Question:

a. How will it be determined for future evaluations at what point the loads should be placed onto the Keowee unit relative to its frequency response curve, when no tests may be available for the modeled configuration on which to baseline the model?

Response:

The timing corresponding with the tests was used in the models to allow a direct time comparison between the model results and the test. For example if there was a time difference in LOOP unit loading, the time difference was modeled. However, for existing and future modeling, the LOOP units are and will be simultaneously loaded in the model. On a load rejection, relaying prevents loading until the frequency is 110% decreasing which provides a common point for start of loading for any scenario. Thus, in present modeling and any future load rejection scenarios, loading will be based on the relaying permissive (i.e. 110% frequency decreasing), not a given time.

Question:

b. How can an accurate or conservative modeling be assured if the CYME frequency response model is nonconservative relative to the actual case?

Response:

See response to Question B.5.a above. Initiation of loading at 110 percent frequency decreasing will result in loading at a frequency that is equivalent to or higher than would be seen in the actual case. Note also that the start time for the motors in the CYME models for the load rejection cases were typically conservative.

6. The discussion in the report for Figure 3-5 indicates that the CYME program cannot begin its analysis at a frequency different from 60 Hz.

Question:

a. When the frequency of the power source shifts from 60 Hz, such as following a load rejection or load application, does the CYME program calculate the connected system impedances and motor characteristics using the new non-60 Hz frequencies seen over the course of the transient? For example, in Figures 1-5 and 2-5, is CYME calculating the connected Oconee electrical system impedances and motor starting currents using the Keowee output frequencies shown in those figures?

Response:

The CYME program calculates the connected system impedances and motor characteristics using the non-60 hz frequencies seen over the course of the transient.

7. The conclusion of the report states that although Test 3 (reduced voltage and frequency starting scenarios) is not included in this report, a comparison of the test data and CYME model predictions show the model to predict conservative results, except for the RBCF B motor.

Question:

a. If the CYME program cannot begin its analysis at a frequency different from 60 Hz, how was the program used to make this prediction?

Response:

Although the CYME program cannot directly be used to perform analyses with the Keowee unit starting from standby, it is used to predict the response of the Oconee loads indirectly. An analysis/comparison was performed for Test 3 assuming a small load rejection which gave an overspeed response similar to that seen during Test 3. Loading was applied in the model at load rejection. Since in the model loads will be starting entirely during the overspeed, the model will be conservative relative to the actual start from standby (i.e., rotating equipment load torque varies approximately as the square of the frequency and motor torque capability varies

approximately inversely with the square of the frequency). Figures H-1 through H-6 in Attachment 8 are a comparison of the model response and the Test 3 response. Similar comparisons of motor acceleration times indicate conservative motor start times (except for the RBCF which requires an adjustment for reverse rotation as previously identified in the report).

Question:

b. If the program cannot begin its analysis at a frequency different from 60 Hz how will it be used to predict the results for other Keowee start from standby scenarios, such as the LOOP with loading on the overhead path and Keowee initially in standby?

Response:

The Keowee unit will be modeled assuming a load rejection which gives an overspeed response similar to that seen in Test 3 as discussed above. Loading will be applied at load rejection. This is conservative since loads will be starting entirely during the overspeed transient as discussed in the response to Question B.7.a above.

Question:

c. If the CYME model will be used to analyze standby start scenarios how will it be validated for those scenarios?

Response:

Test 3 was modeled as described in the response to Question B.7.a above. This comparison provides sufficient validation that the response of the loads will be conservative. An adjustment in the start time of the RBCF will be required as previously identified.

8. Figure 1-1 in the report shows a substantially larger inrush for the Keowee main step-up transformers and Oconee startup transformers than what was predicted in the CYME model (3293 amperes versus 1900 amperes, respectively). The report attributes this difference primarily to the fact that the test data includes dc offset current and harmonic currents, whereas the model data includes only 60 Hz currents. It indicates that this is not a problem because the protective relaying for the transformers are designed to account for the dc offset and harmonic currents. Because the voltage depression associated with this inrush is conservative in the CYME model compared to the test results (12.1 kV versus 12.5

kV, respectively), this explanation appears reasonable provided the CYME results will not be used for any analytical work associated directly with the Keowee main step-up and Oconee startup transformers' inrush currents.

Question:

a. Describe for what purposes this CYME transformer inrush modeling may be used.

Response:

The transformer inrush is included to account for the impact that the 60 hertz rms current inrush has on the Keowee generator terminal voltage and the impact that this inrush has on voltage at loads at Oconee.

9. Figures 2-1 and 3-1 in the report show approximately a 0.7 second and 1.0 second delay, respectively, between the first LOOP unit loading and the second LOOP unit loading. The report states that these delays are modeled.

Question:

a. Are these delays modeled only for this validation effort to show the correlation between the model and the test? A conservative assumption would assume that the units load simultaneously.

Response:

The delays were modeled only to allow direct time correlation between the modeling and the test. The conservative assumption, simultaneously loading of the LOOP units, is used in existing analyses and will be used for future plant modeling.

C. Previous Request For Additional Information Question

In the response to staff questions dated February 25, 1998, it is stated that there are presently no periodic tests, which include the black start of the Keowee units. It is indicated that the ability of the Keowee units to start and run with no ac power available has been demonstrated by several one-time tests and that the capability of the Keowee batteries to provide sufficient energy to start Keowee and flash its field is verified annually by a battery service test. The staff notes that the battery service test does not check the subtle interactions between the battery and the field flash circuits. The voltage to the generator field, the field flash circuits, and other dc circuits is lower during a black start than it is during a start with ac power available. The lower dc voltage can result in an extended Keowee voltage buildup time following a standby start. The lower dc voltage can also result in different operating characteristics or inoperability of dc powered components, particularly when a component has degraded. The battery service test will not detect these potential problems or the resulting interactions. The staff therefore believes that periodic tests of the Keowee black start and black run capabilities should both be performed. We note that diesel generator plants periodically demonstrate the black start capability as part of the refueling outage load sequencing test specified in the Improved Standard Technical Specifications.

Question:

a. Please address the points raised in this question relative to the lack of a black start test.

Response:

A Keowee black start was conducted in January 1998 to collect data to be used in the calculations for the Keowee DC system. The results of these calculations will determine the acceptable parameters of the annual battery service test. If the battery performs within the acceptable parameter during the annual battery service test, it has sufficient capacity to flash the generator field during a black start. Therefore, there is no need to perform a periodic Keowee black start.

D. Probabilistic Risk Assessment Questions

1. The Keowee PRA states that the process for collecting Keowee data includes a 10-year period from January 1, 1984, to December 31, 1993.

Questions:

a. Since December 31, 1993, have additional Keowee component failures been found that would have made the system unavailable for an emergency start (excluding the Keowee failure to start on June 20, 1997)?

b. Were these failures identified through system generation starts, operability starts, or emergency starts?

c. If the failure was identified through emergency starts, would the failure have been manifested during a system generation start?

Response:

Three component failures have been identified that made a Keowee unit unavailable for emergency start.

On 2/3/94, Keowee Unit 1 failed to start when the field flashing breaker failed to close. This failure was attributed to wear of the breaker latching mechanism. This failure occurred during a start for system generation, a non-emergency condition.

On 12/9/96, a relay failure caused the dc breaker that supplied the control power to trip. This breaker transfer resulted in a loss of power for Keowee Unit 1 governor control. The failure was identified through an alarm that resulted from the loss of dc. In this case, there was no failure to start; however, the failure made the unit unavailable for both normal and emergency starts. This event was a failure of the dc breaker and not a failure of the unit to start on demand.

On 6/20/97, during the 100 kV power supply test, Keowee Unit 2 failed to start when the field flashing breaker failed to close. This failure was attributed to the breaker failing to latch. This failure occurred during an emergency start test, but could have occurred during a start for system generation.

2. Regarding Air Circuit Breaker (ACB) operation, the staff noted several ACB failures in the Augmented Inspection Team (AIT) report dated July 31, 1997 (AIT report 50-269/97-11, 50-270/97-11, 50-287/97-11). The staff's review of the Keowee PRA also found that dominant contributors to the failure of a Keowee unit to provide power to CT3 or CT4 include failures of ACBs 5 - 8. The staff also notes that high reliability of ACBs 3 and 4 is important during dual-unit grid generation.

Question:

a. Given that these components are tracked under the Maintenance Rule, what is the performance criteria for ACBs 1 through 8?

Response:

ACB 1 and 2	6 percent unavailability and 2 Maintenance Preventable Functional Failures (MPFF)
ACB 3 and 4	2 percent unavailability and 1 MPFF
ACB 5 thru 8	4 percent unavailability and 2 MPFF.

Question:

b. Based on previous discussions, the staff understands that ACBs 1 through 4 are tracked under the Keowee Super System, and ACBs 5 through 8 are tracked by themselves as a separate group. Considering ACB group 1 through 4 and ACB group 5 through 8, how are the performance criteria established for components in these groups since they have different testing/demand frequencies?

Response:

The performance criteria for ACBs 1 through 8 are established based on risk significance within the guidelines for the Maintenance Rule at Oconee. For ACBs 5 through 8, the risk is medium and the reliability criterion is 2 failures with 4 percent unavailability. For ACBs 3 and 4, the risk is high and the reliability criterion is 1 failure with 2 percent unavailability. For ACBs 1 and 2, the risk is low and the reliability criterion is 2 failures with 6 percent unavailability.

Question:

c. What are the demand/test frequencies for each ACB (ACBs 1 through 8)?

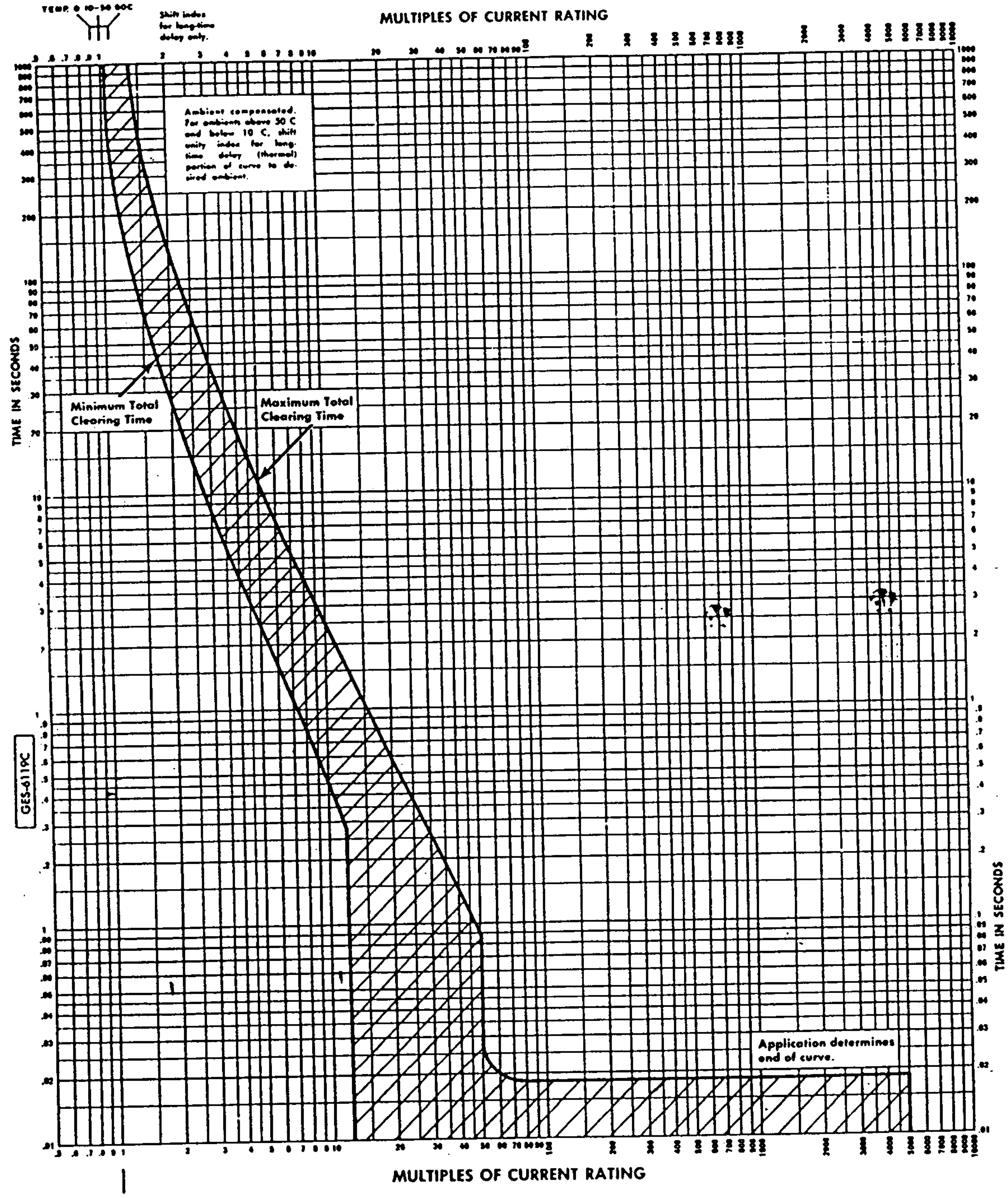
Response:

ACB 1 and 2 are demanded/tested on a weekly frequency. ACB 3 and 4 are demanded/tested on a monthly frequency. ACB 5 through 8 are demanded/tested on an annual frequency.

ATTACHMENT 2

Graphs for 3LP-17 Breaker and Overload Heaters

TED6 & THED6 15–50



GENERAL ELECTRIC	MOLDED-CASE CIRCUIT BREAKER **E 150 LINE**	GES-6119C
Current Ratings 15, 20, 25, 30, 35, 40, 45 and 50 amperes **Voltage Ratings** 2- and 3 pole—600 volts a-c **Frequency Rating** 60 Hertz	**Types TED and THED, 15–50 Amperes** **Ambient Compensated** **Long-time Delay and Instantaneous Time-current Curves** (Curves show ambient-compensated circuit breaker in open air, 10 to 50 C ambient, wired with conductors of corresponding rating, no prior load. For all other ambients, use rating shift index at top of sheet.)	**Adjustments** Long-time delay thermal trip: not adjustable. Instantaneous magnetic trip: not adjustable.

GENERAL ELECTRIC CO., DISTRIBUTION EQUIPMENT DIVISION, PLAINVILLE, CONN. 06062

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CLARK

BULLETIN
7323

DESCRIPTIVE INFORMATION

THERMAL OVERLOAD RELAYS

HEATER APPLICATION DATA

The information presented on this Bulletin is heater application data for Bulletin 7323 thermal overload relays only. A general description of these relays is given on composite Bulletin 7322, 7322-S, 7323.

Standard open type motors are usually rated 40° C. rise. Splash-proof and similar motors are usually rated 50° C. rise. Totally enclosed motors are usually rated 55° C. rise.

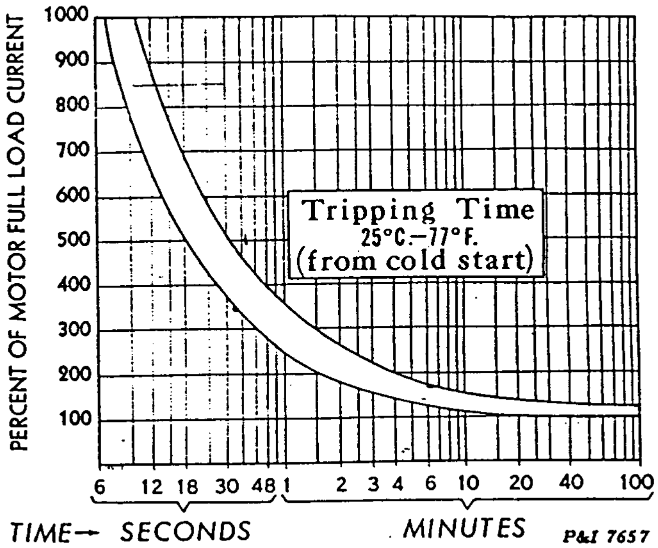
Heaters for multi-speed, single phase, and all special motors must be applied on the basis of motor full-load current and temperature rise only. Heaters for standard motors will be applied in accordance with Table No. 2 if motor data cannot be obtained.

The full load current of two phase motors is 0.87 times the three phase values.

Bulletin 7323 overload relays are used in all A.C. starters, sizes 00, 0, 1 and 2 only. Heater elements for use in these starters must be applied in accordance with the tables on page 3 of this bulletin. Heater elements for starter sizes 3, 4, 5, and 6 may be selected from Bulletin 7322-7322-S.

For Bulletin 7323 overload relays mounted as separate devices, either individually or as part of multi-motor control panels, open or enclosed, heater elements may be applied from tables 1, 2 and 3 on pages 1 and 2 of this bulletin.

If the relays are in any instance mounted as a unit with a starting contactor, that is, adjacent to the operating coil, it will then be necessary to select heaters from tables 4, 5 and 6 on page 3 of this bulletin. For open type panels with



relays mounted adjacent to contactor operating coils, select heaters the same as "Open Starters". For enclosed panels containing two or more contactors or other devices, select heaters the same as "Enclosed Starters", Bulletin 6030.

If full load current is not known, heaters may be selected from tables 2 and 3 on page 2. The information required is motor type, temperature rise, speed or number of poles, horse power, voltage, phase and frequency.

After starter is installed, heaters should be checked with motor name plate rating.

All of the heater tables are based on 40° C. rise motors with motor and control at the same ambient temperature.

MOTORS RATED 40° C. RISE

Motor and control at same ambient temperature: Select heaters directly from tables.

Motor at 40° C. ambient and control at 25° C. ambient: Use one size smaller heater than indicated by tables.

Motor at 25° C. ambient and control at 40° C. ambient: Use one size larger heater than indicated by tables.

MOTORS RATED 50° C. OR 55° C. RISE

Motor and control at same ambient temperature: Use one size smaller heater than indicated by tables.

Motor at 40° C. ambient and control at 25° C. ambient: Use two sizes smaller heaters than indicated by tables.

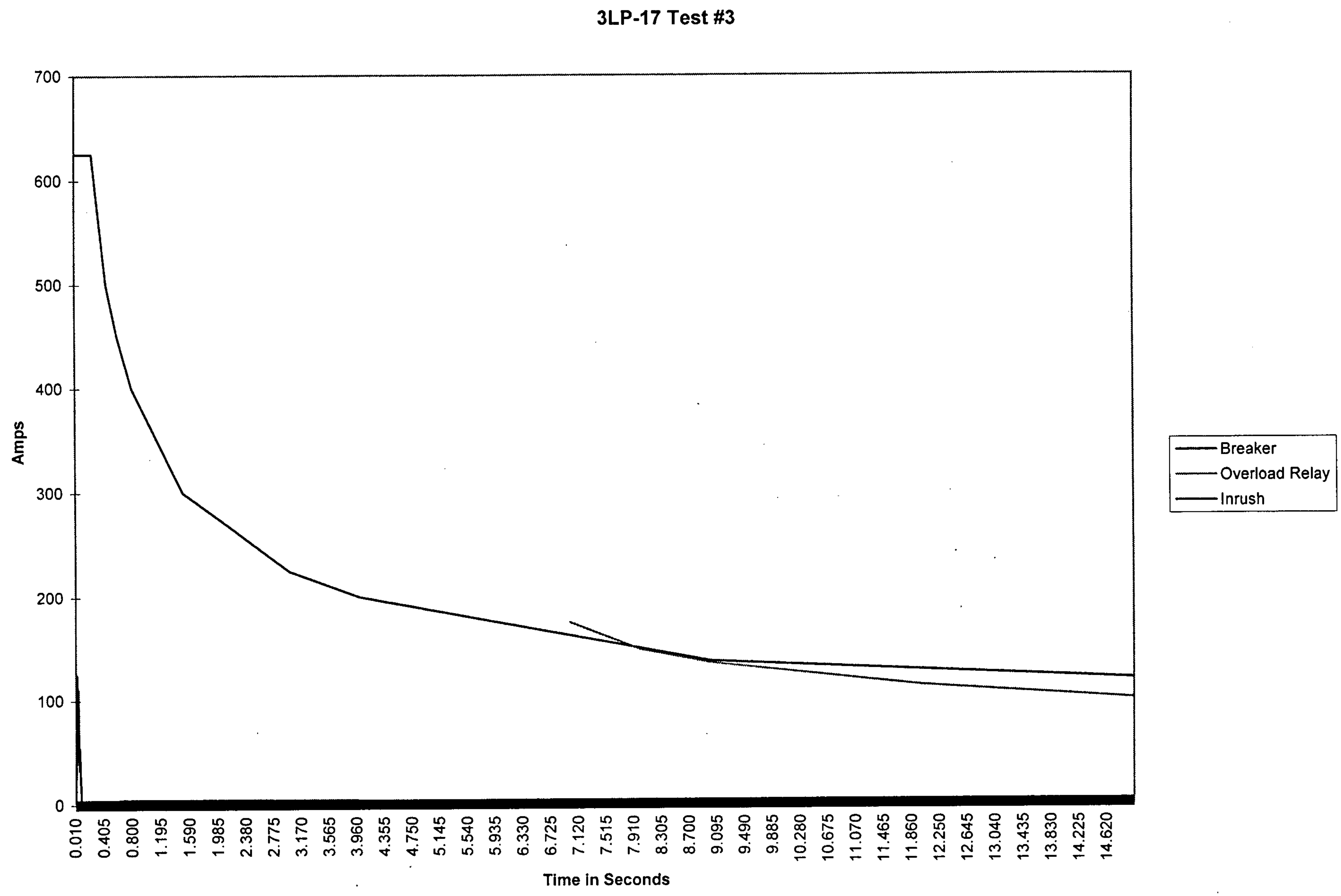
Motor at 25° C. ambient and control at 40° C. ambient: Select heaters directly from tables.

HEATER APPLICATION IN ACCORDANCE WITH MOTOR FULL LOAD CURRENT
FOR SEPARATELY MOUNTED RELAYS ONLY.

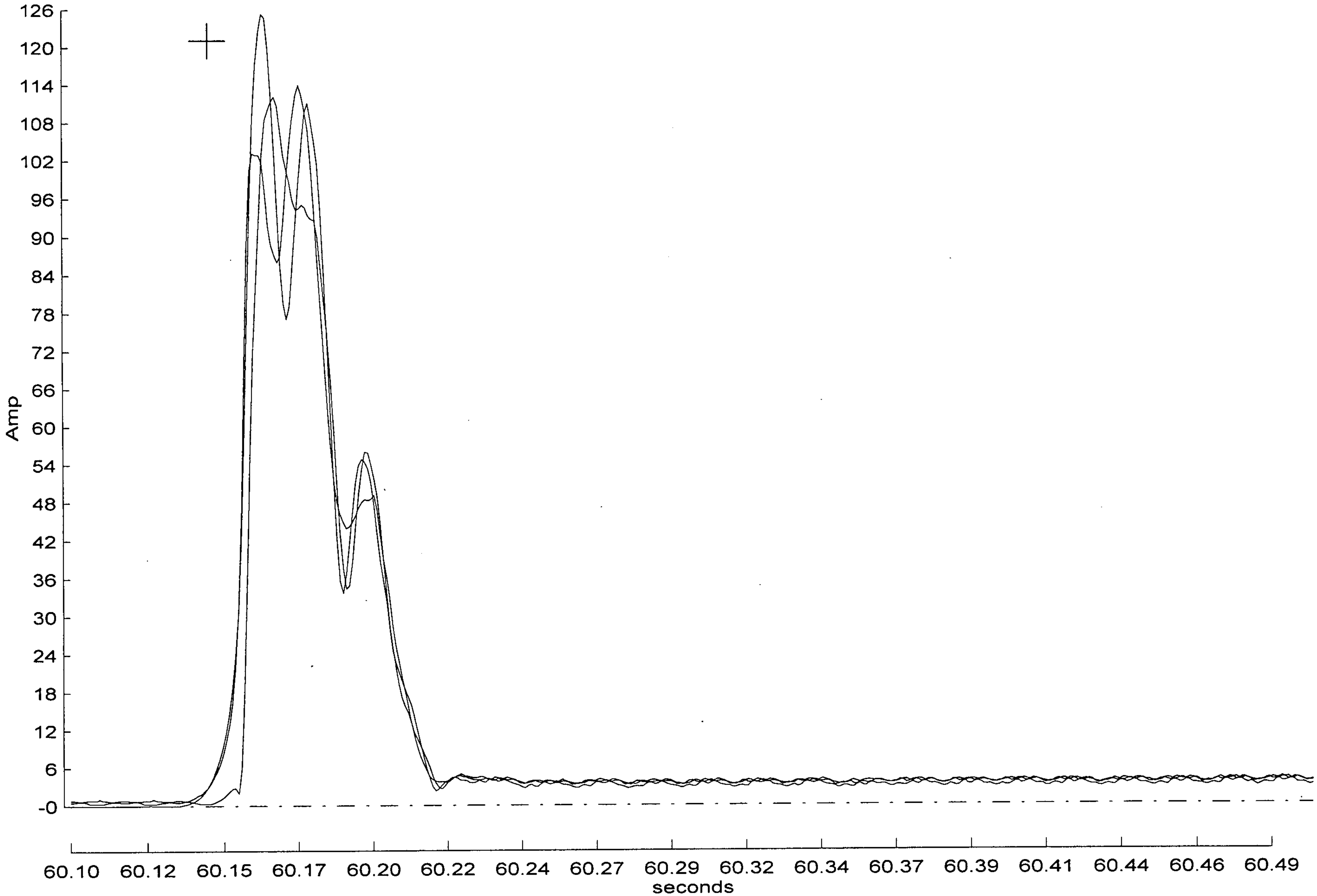
Motor Amperes		Heater Catalog Number	Motor Amperes		Heater Catalog Number
Minimum	Maximum		Minimum	Maximum	
.55	.60	S 0.6	5.98	6.60	S 6.5
.61	.65	S 0.66	6.61	7.18	S 7.2
.70	.76	S 0.76	7.19	7.92	S 7.8
.77	.84	S 0.84	7.93	8.73	S 8.6
.85	.95	S 0.93	8.74	9.65	S 9.5
.96	1.05	S 1.05	9.66	10.59	S 10.5
1.06	1.15	S 1.15	10.60	11.49	S 11.5
1.16	1.27	S 1.26	11.50	12.89	S 12.5
1.28	1.41	S 1.4	12.90	14.20	S 14.0
1.42	1.55	S 1.55	14.21	15.59	S 15.5
1.56	1.74	S 1.7	15.6	17.49	S 17.0
1.75	1.92	S 1.9	17.5	19.29	S 19.0
1.93	2.10	S 2.1	19.3	21.19	S 21.0
2.11	2.29	S 2.3	21.2	23.44	S 23.0
2.30	2.56	S 2.5	23.45	25.59	S 25.5
2.57	2.75	S 2.8	25.60	27.59	S 27.5
2.76	3.03	S 3.0	27.6	30.39	S 30.0
3.04	3.39	S 3.3	30.40	33.49	S 33.0
3.40	3.67	S 3.7	33.50	36.89	S 37.5
3.68	4.04	S 4.0	36.90	40.99	S 40.0
4.05	4.41	S 4.4	41.00	45.99	S 45.0
4.42	4.87	S 4.8	46.00	50.00	S 50.0
4.88	5.40	S 5.3			
5.41	5.97	S 5.9			

ATTACHMENT 3

Graphs of 3LP-17 Current During Test 3


3LP-17 Test #3
Amps
700
600
500
400
300
200
100
0
0.010
0.405
0.800
1.195
1.590
1.985
2.380
2.775
3.170
3.565
3.960
4.355
4.750
5.145
5.540
5.935
6.330
6.725
7.120
7.515
7.910
8.305
8.700
9.095
9.490
9.885
10.280
10.675
11.070
11.465
11.860
12.250
12.645
13.040
13.435
13.830
14.225
14.620
Time in Seconds
Breaker
Overload Relay
Inrush

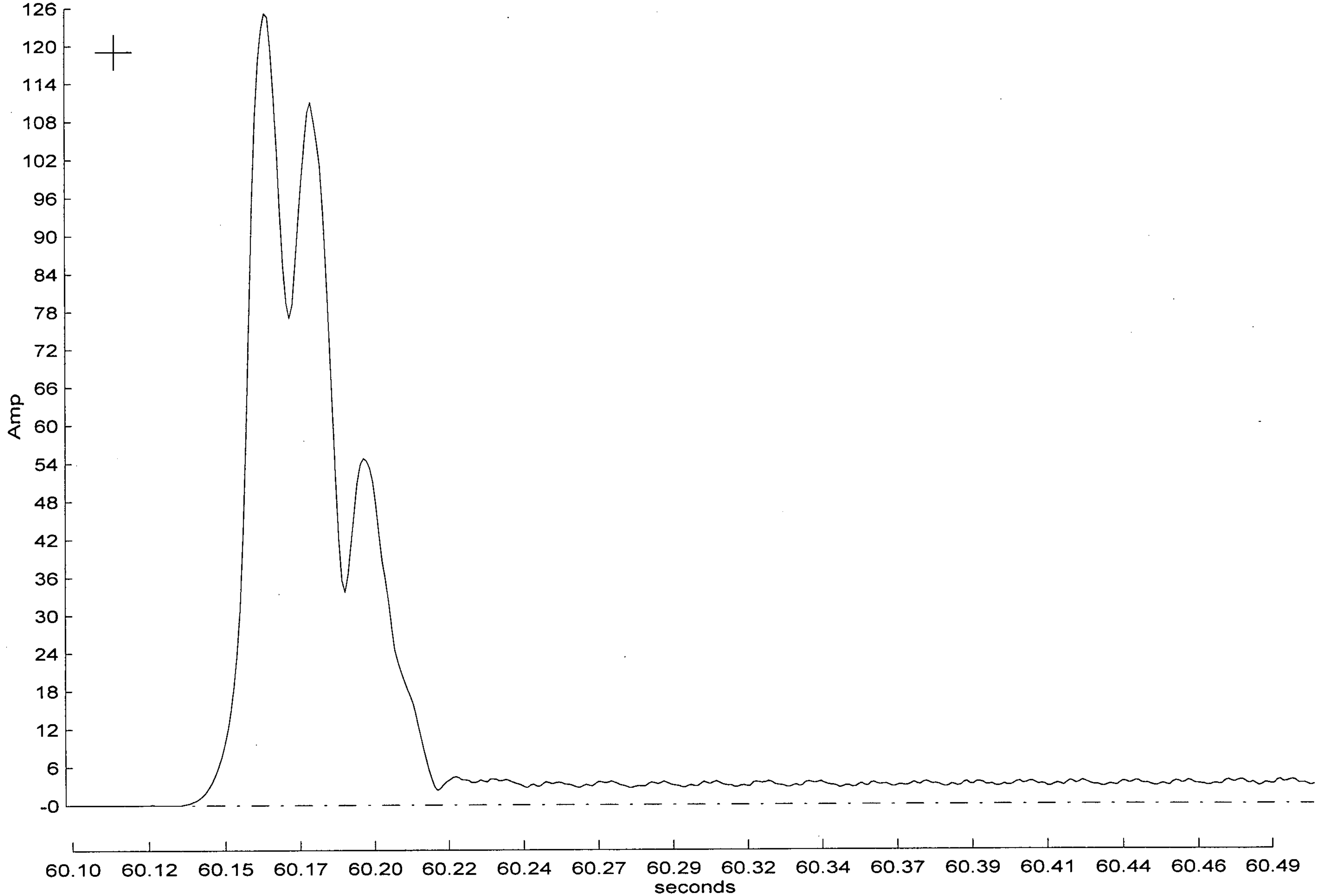
<1> M Test: Oconee 3 3LP017 1-4-97 10:21a 128.5 3 ES



Cursor coordinates = 60.1seconds, 121Amp
Ia-rms Ib-rms Ic-rms

3LP-17
ES Test #3
3 phases of current

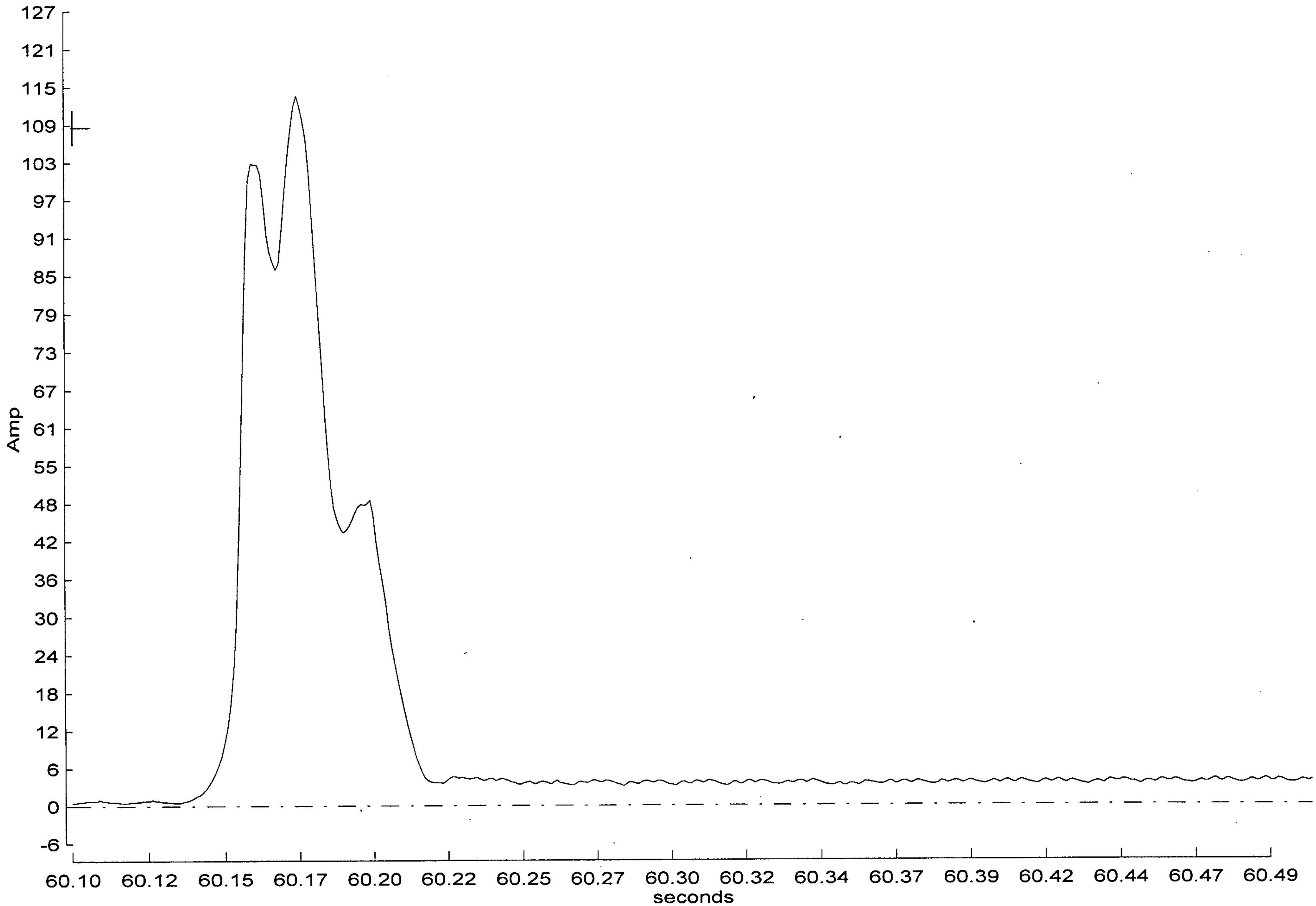
<1> M Test: Oconee 3 3LP017 1-4-97 10:21a 128.5 3 ES



Cursor coordinates = 60.1seconds, 119Amp
Ia-rms

3LP-17
ES Test #3
a phase of current

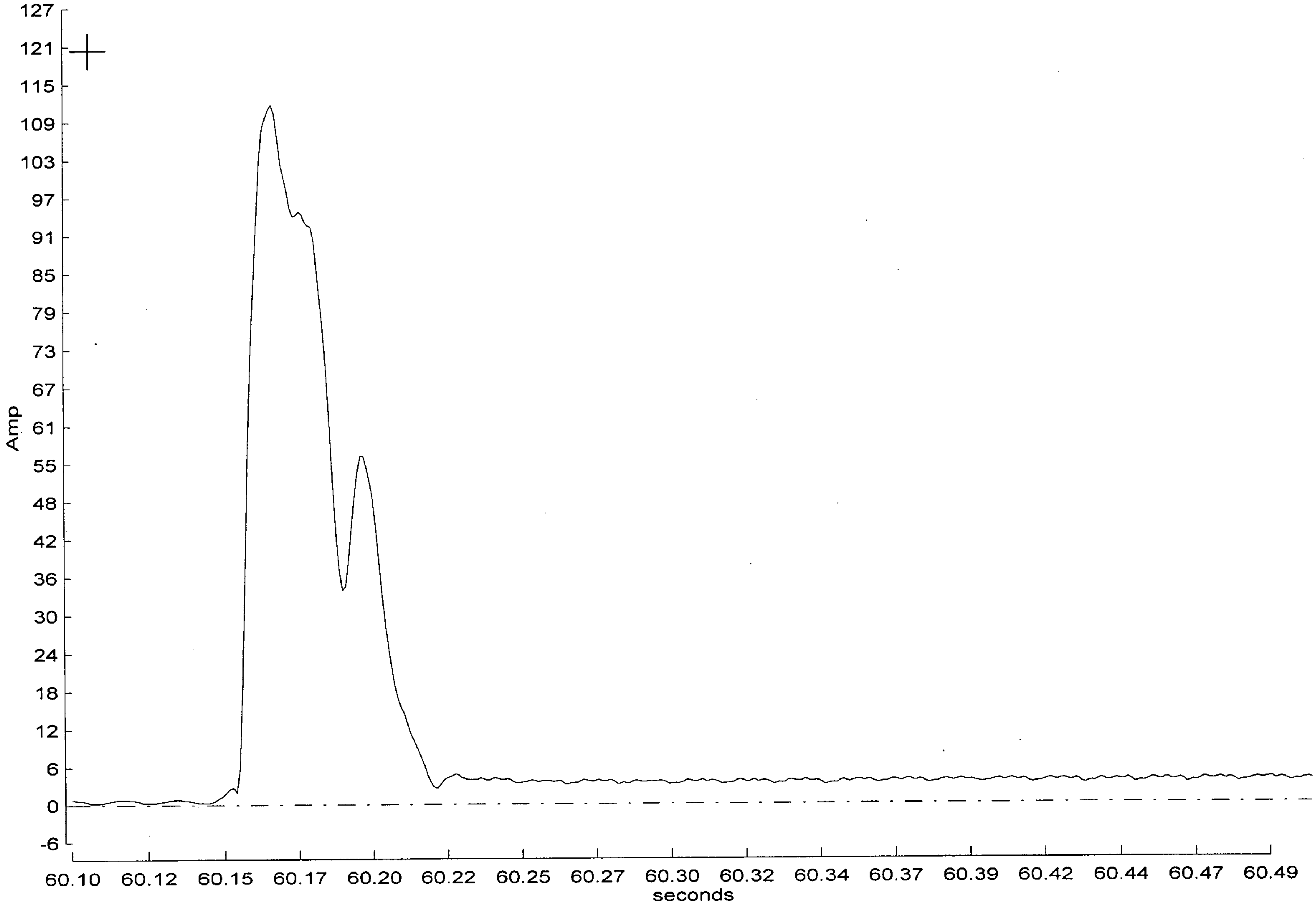
<1> M Test: Oconee 3 3LP017 1-4-97 10:21a 128.5 3 ES



Cursor coordinates = 60.1seconds, 109Amp
lb-rms

3LP-17
ES Test #3
b phase of current

<1 M Test: Oconee 3 3LP017 1-4-97 10:21a 128.5 3 ES



Cursor coordinates = 60.1seconds, 121Amp

Ic-rms

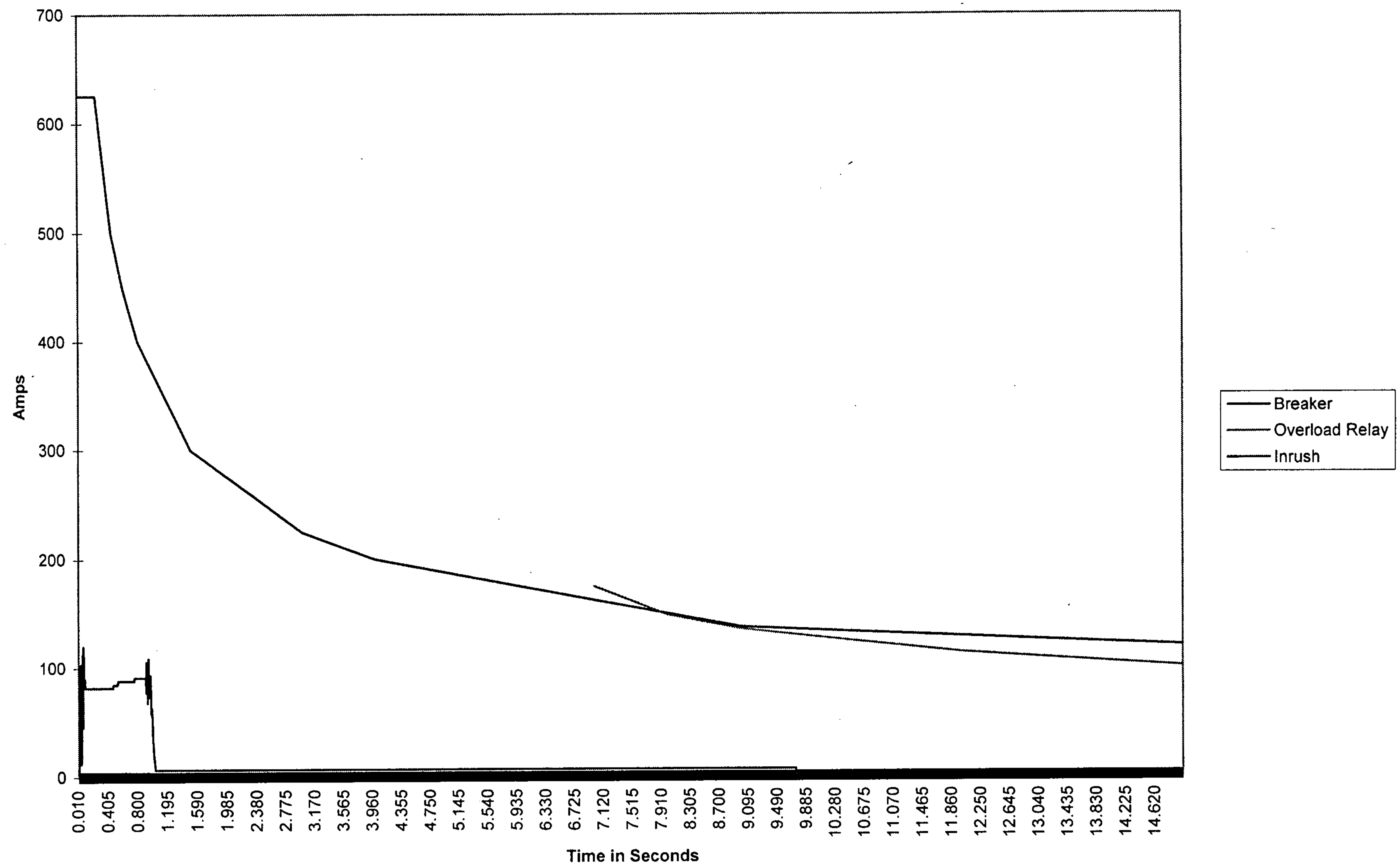
3LP-17
ES Test #3
c phase of current

ATTACHMENT 4

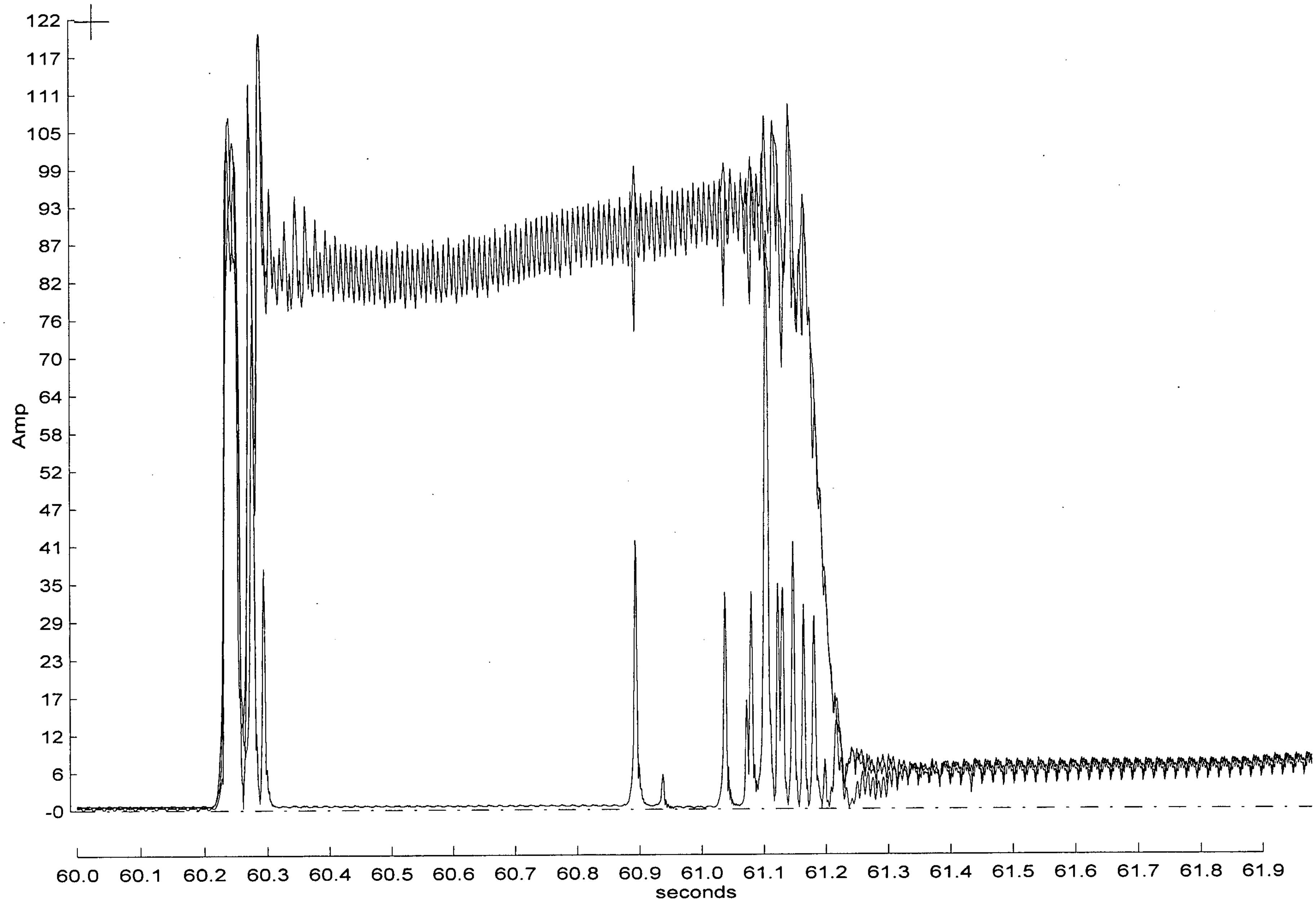
Graphs of 3LP-17 Current During Test 4

Test 4 in 0.005 increments Chart 10

3LP-17 Test #4



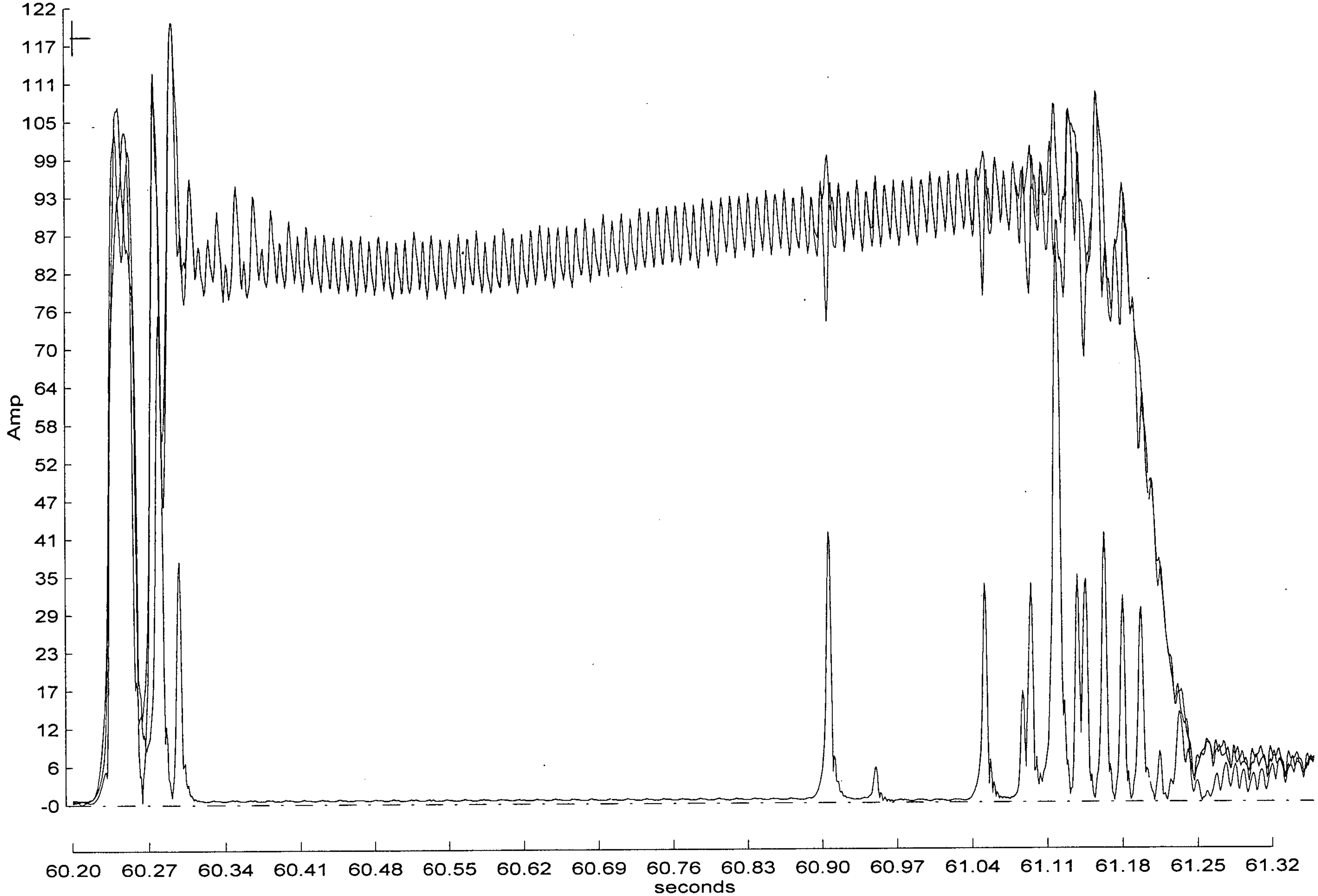
<1> [illegible] Test: Oconee 3 3LP017 1-4-97 4:36p 130.5 4 ES



Cursor coordinates = 60seconds, 122Amp
Ia-rms Ib-rms Ic-rms

3LP-17
ES Test #4
3 phases of current

<1> [illegible] Test: Oconee 3 3LP017 1-4-97 4:36p 130.5 4 ES

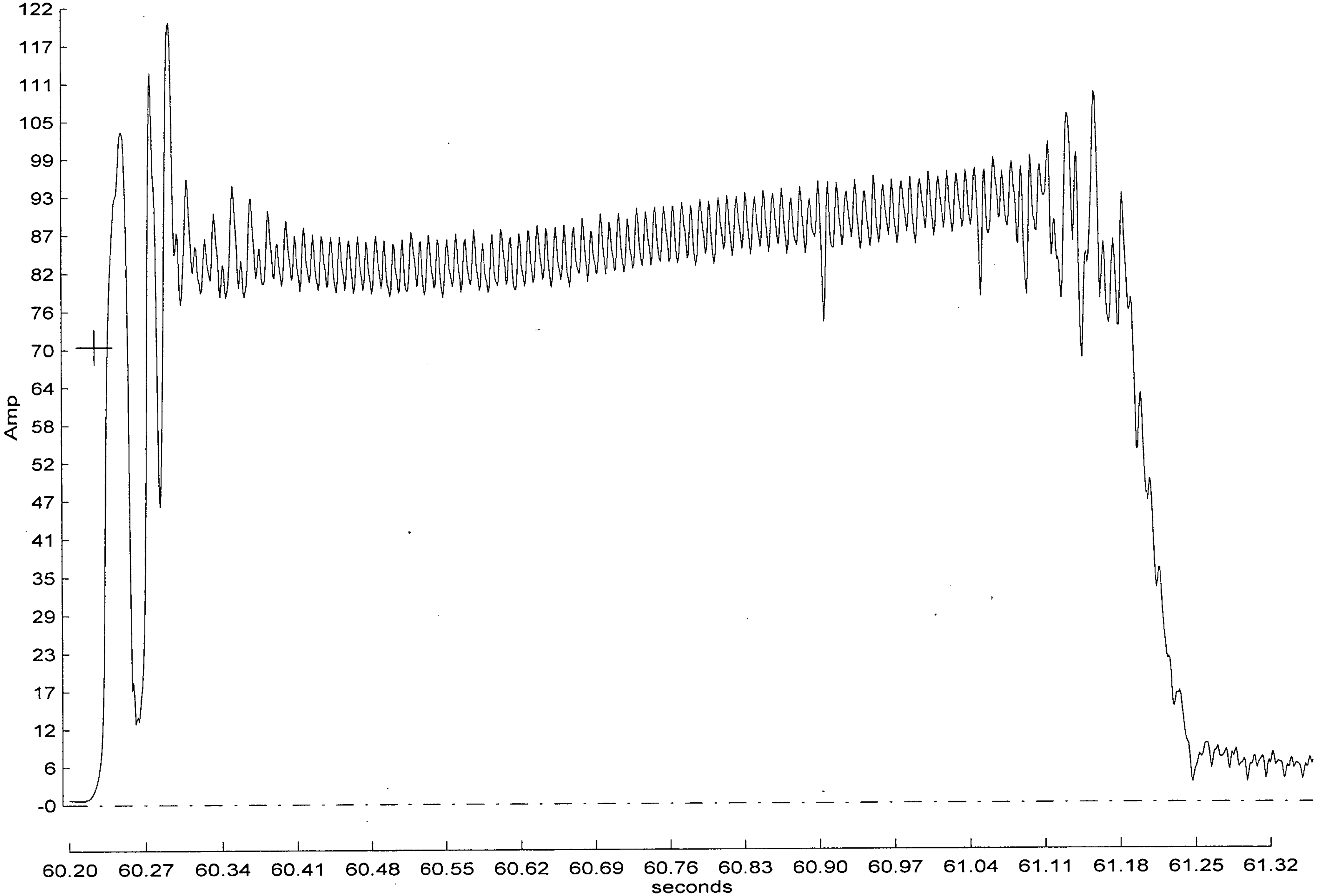


Cursor coordinates = 60.2seconds, 118Amp

Ia-rms Ib-rms Ic-rms

3LP-17
ES Test #4
3 phases of current

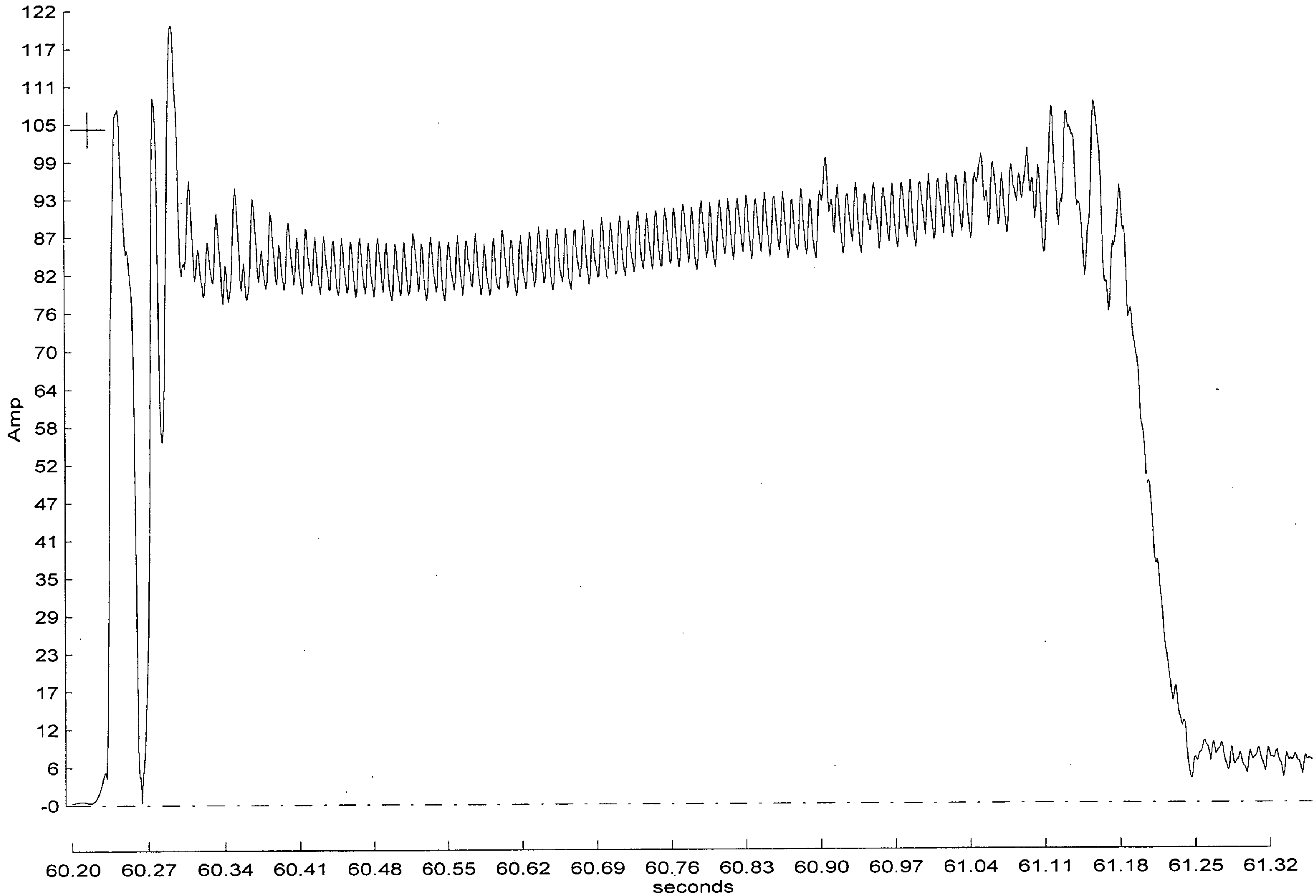
<1> [illegible] Test: Oconee 3 3LP017 1-4-97 4:36p 130.5 4 ES



Cursor coordinates = 60.2seconds, 70.4Amp
Ia-rms

3LP-17
ES Test #4
a phase of current

<1> M Test: Oconee 3 3LP017 1-4-97 4:36p 130.5 4 ES

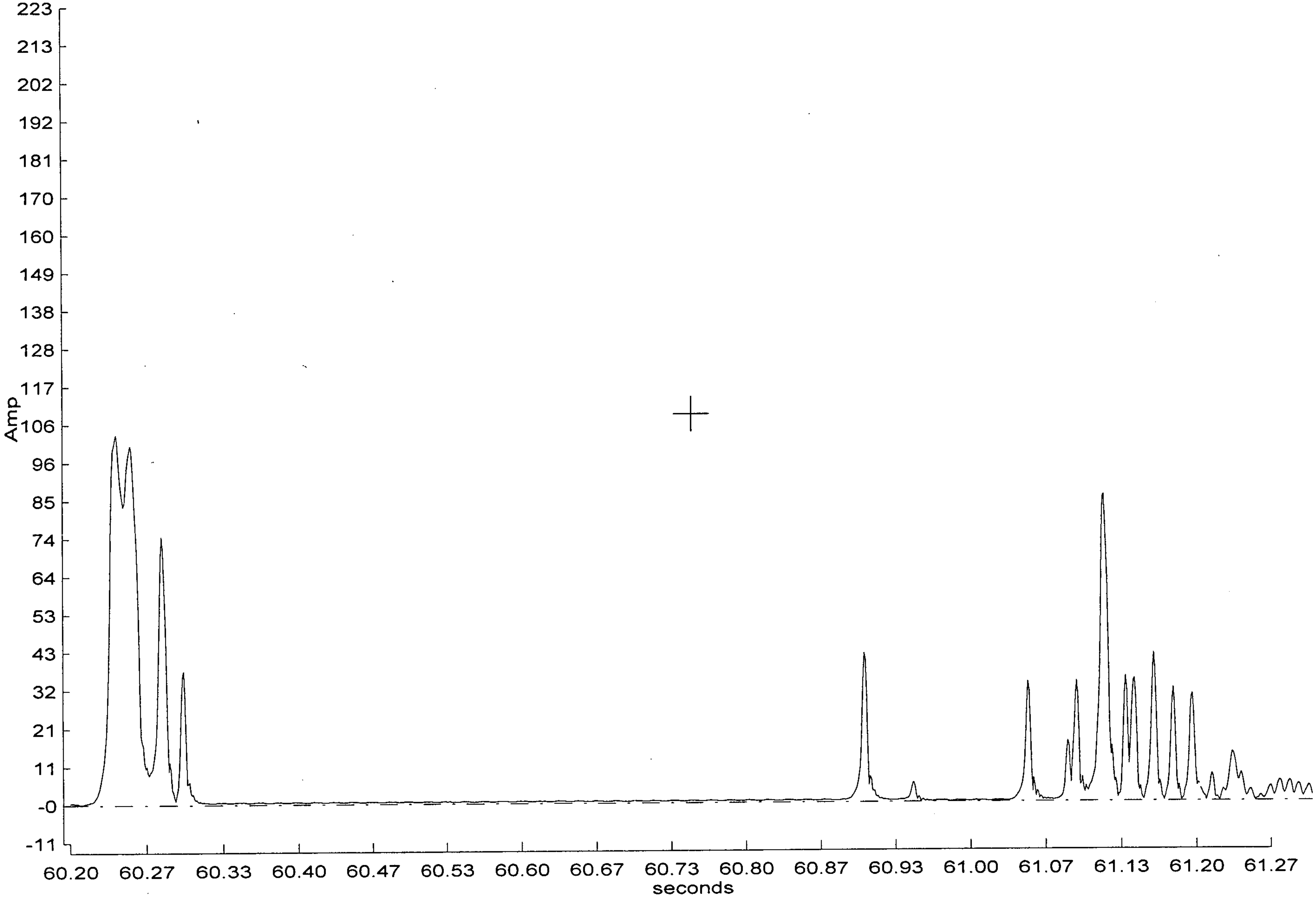


Cursor coordinates = 60.2seconds, 104Amp

lb-rms

3LP-17
ES Test #4
b phase of current

<1> [illegible]M Test: Oconee 3 3LP017 1-4-97 4:36p 130.5 4   ES



Cursor coordinates = 60.8seconds, 109Amp
lc-rms

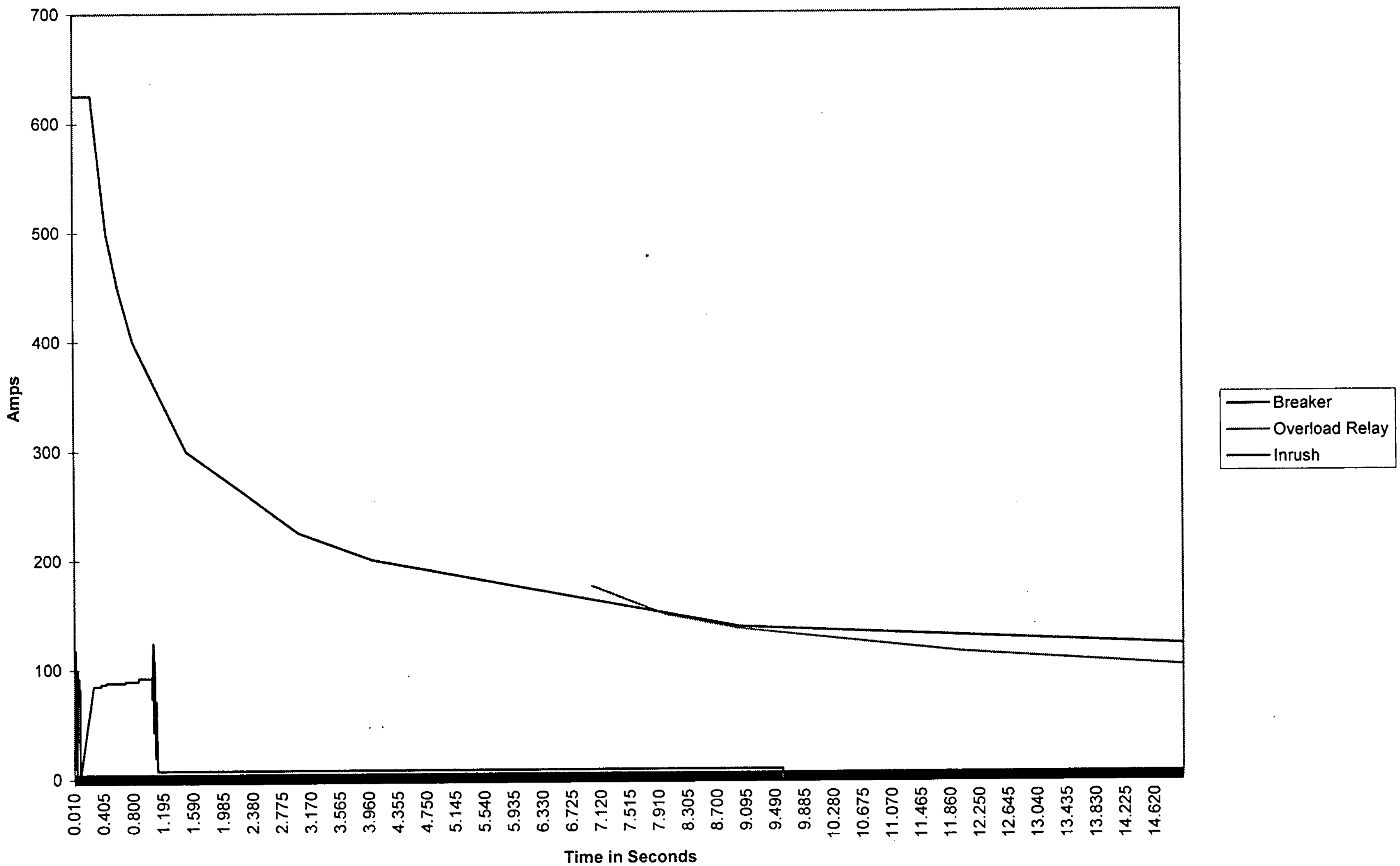
3LP-17
ES Test #4
c phase of current

ATTACHMENT 5

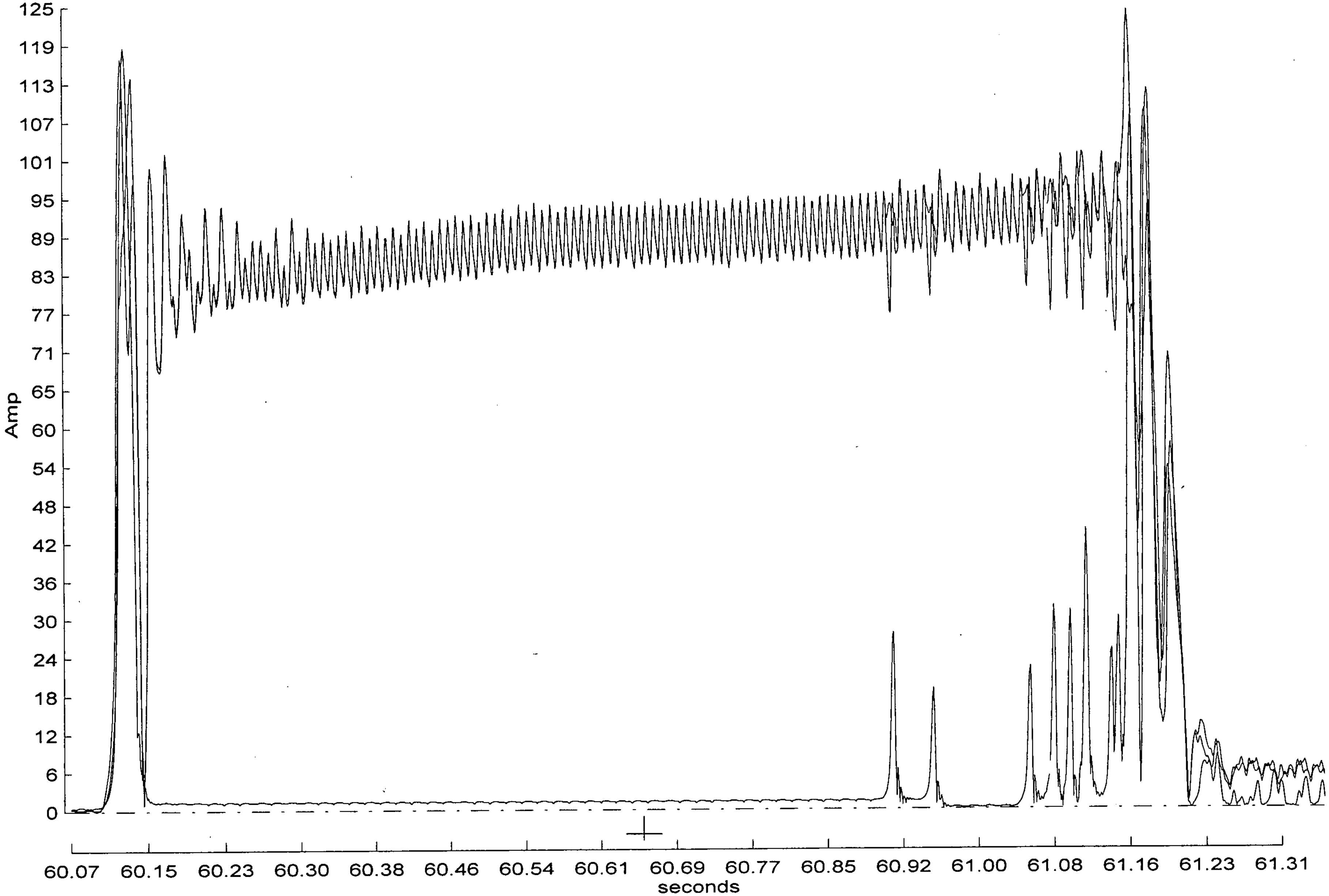
Graphs of 3LP-17 Current During Test 5

Test 5 in 0.005 increments Chart 10

3LP-17 Test #5



<1> M Test: Oconee 3 3LP017 1-4-97 10:41p 130.3 5 ES

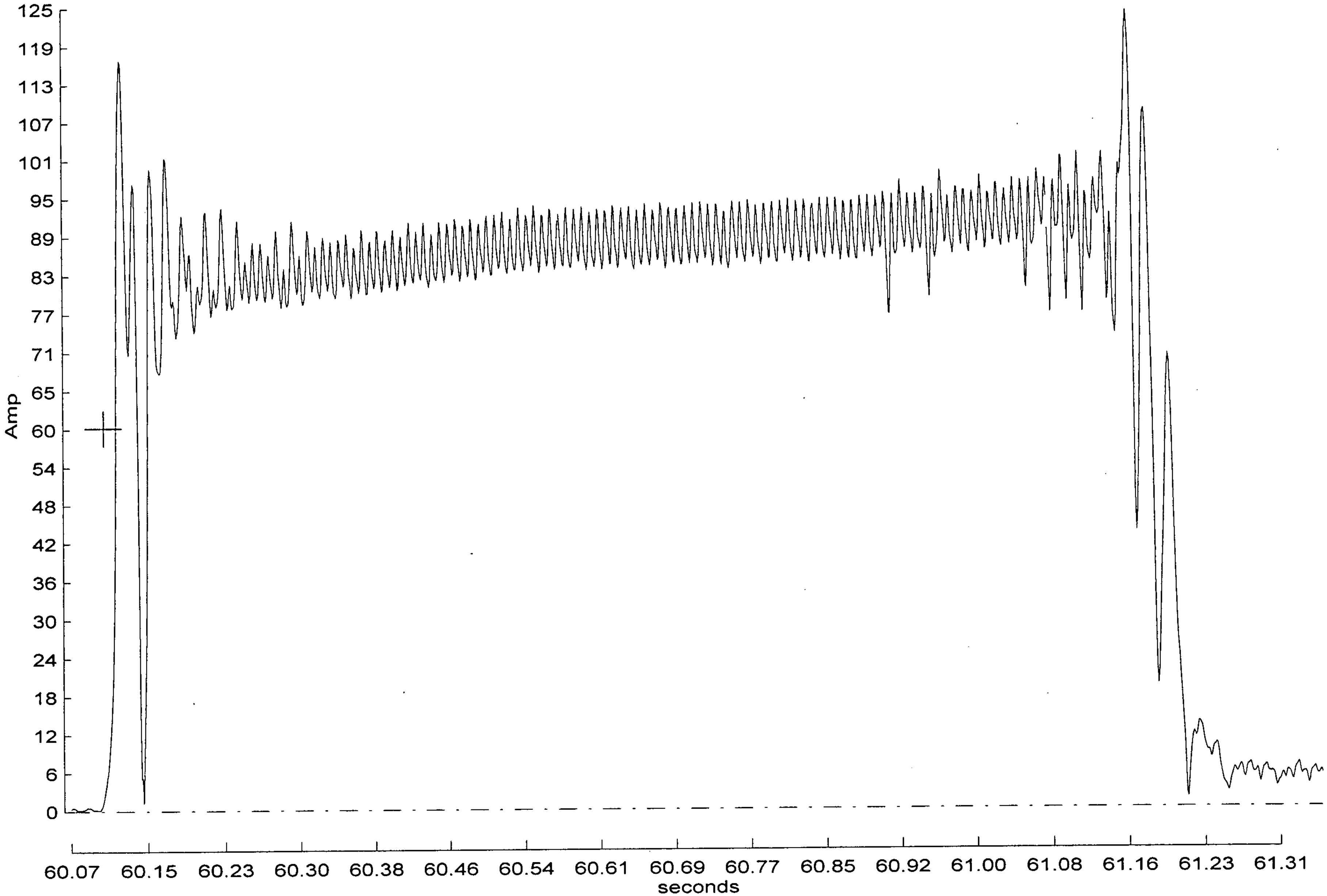


Cursor coordinates = 60.7seconds, -3.82Amp

Ia-rms Ib-rms Ic-rms

3LP-17
ES Test #5
3 phases of current

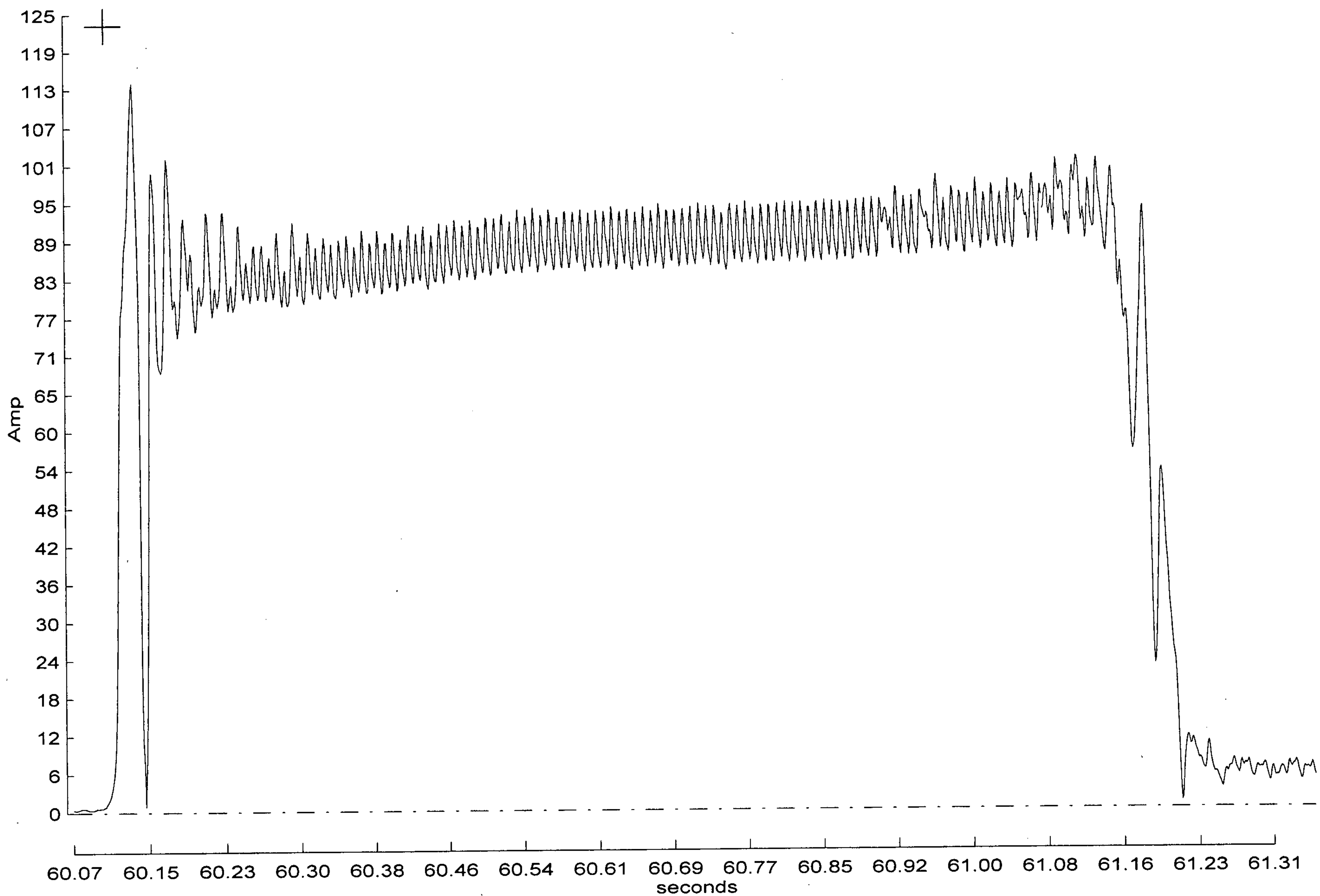
<1> M Test: Oconee 3 3LP017 1-4-97 10:41p 130.3 5 ES



Cursor coordinates = 60.1seconds, 59.7Amp
Ia-rms

3LP-17
ES Test #5
a phase of current

<1> M Test: Oconee 3 3LP017 1-4-97 10:41p 130.3 5 ES

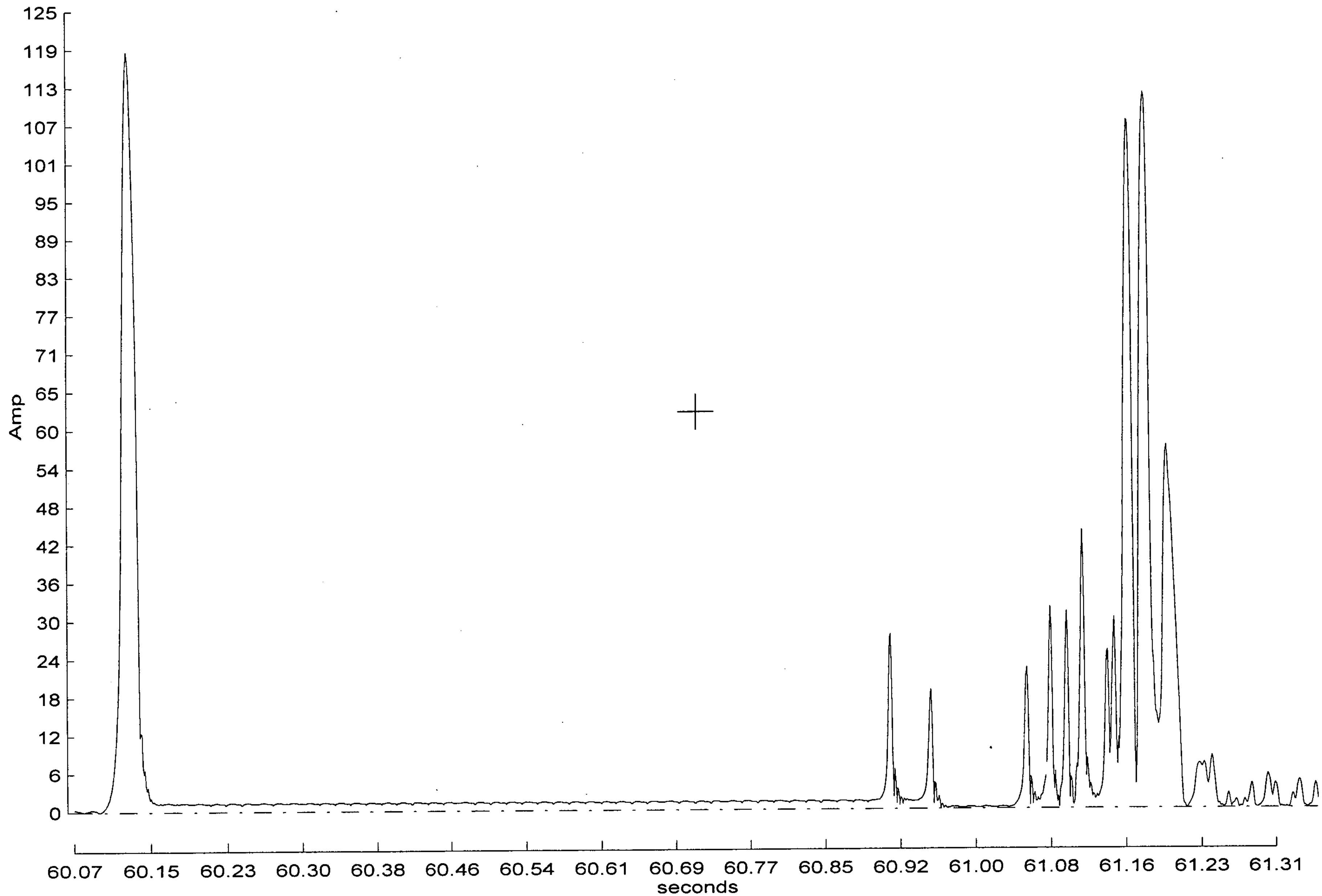


Cursor coordinates = 60.1seconds, 123Amp

lb-rms

3LP-17
ES Test #5
b phase of current

<1> M Test: Oconee 3 3LP017 1-4-97 10:41p 130.3 5 ES



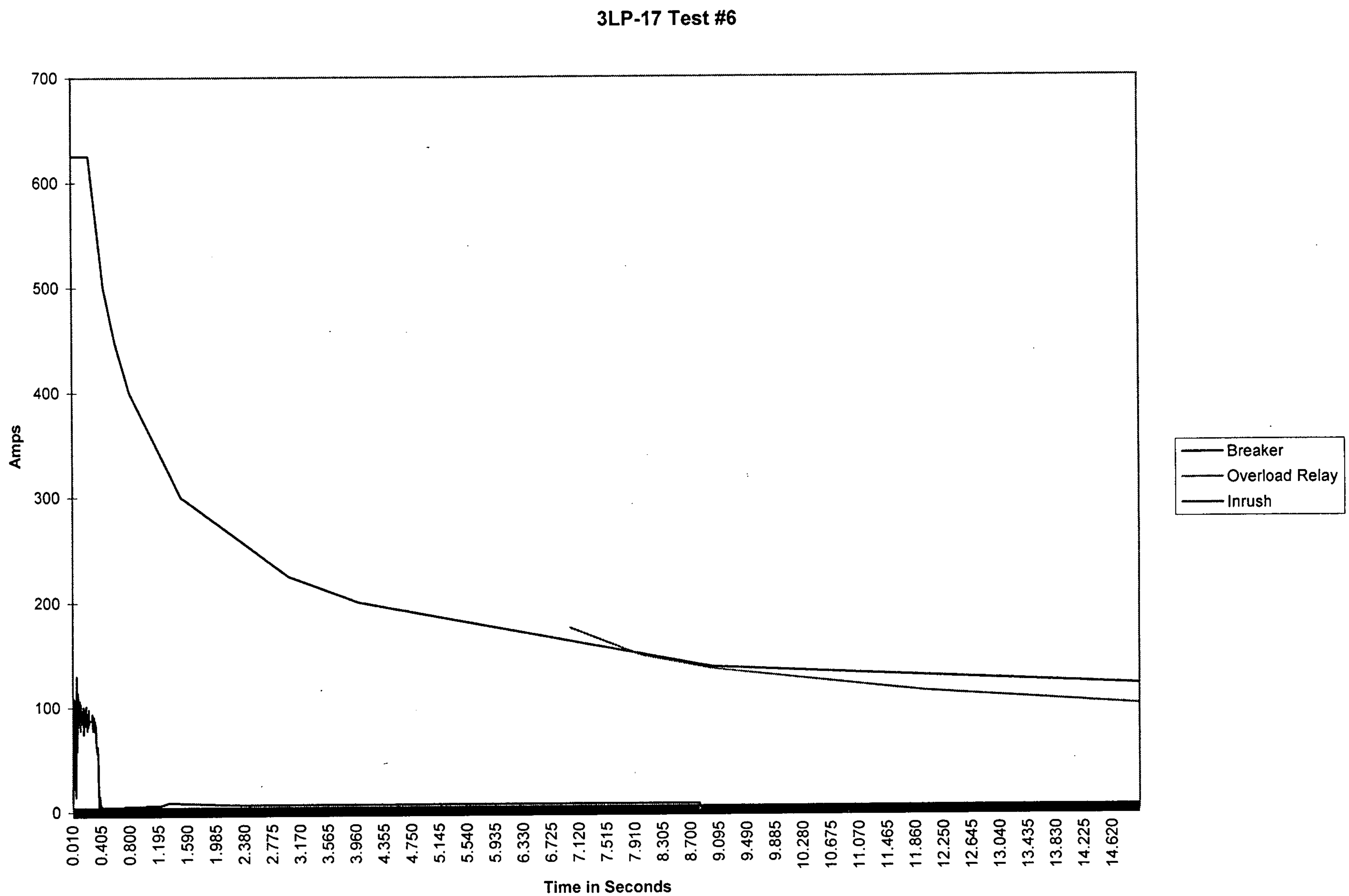
Cursor coordinates = 60.7seconds, 62.1Amp

Ic-rms

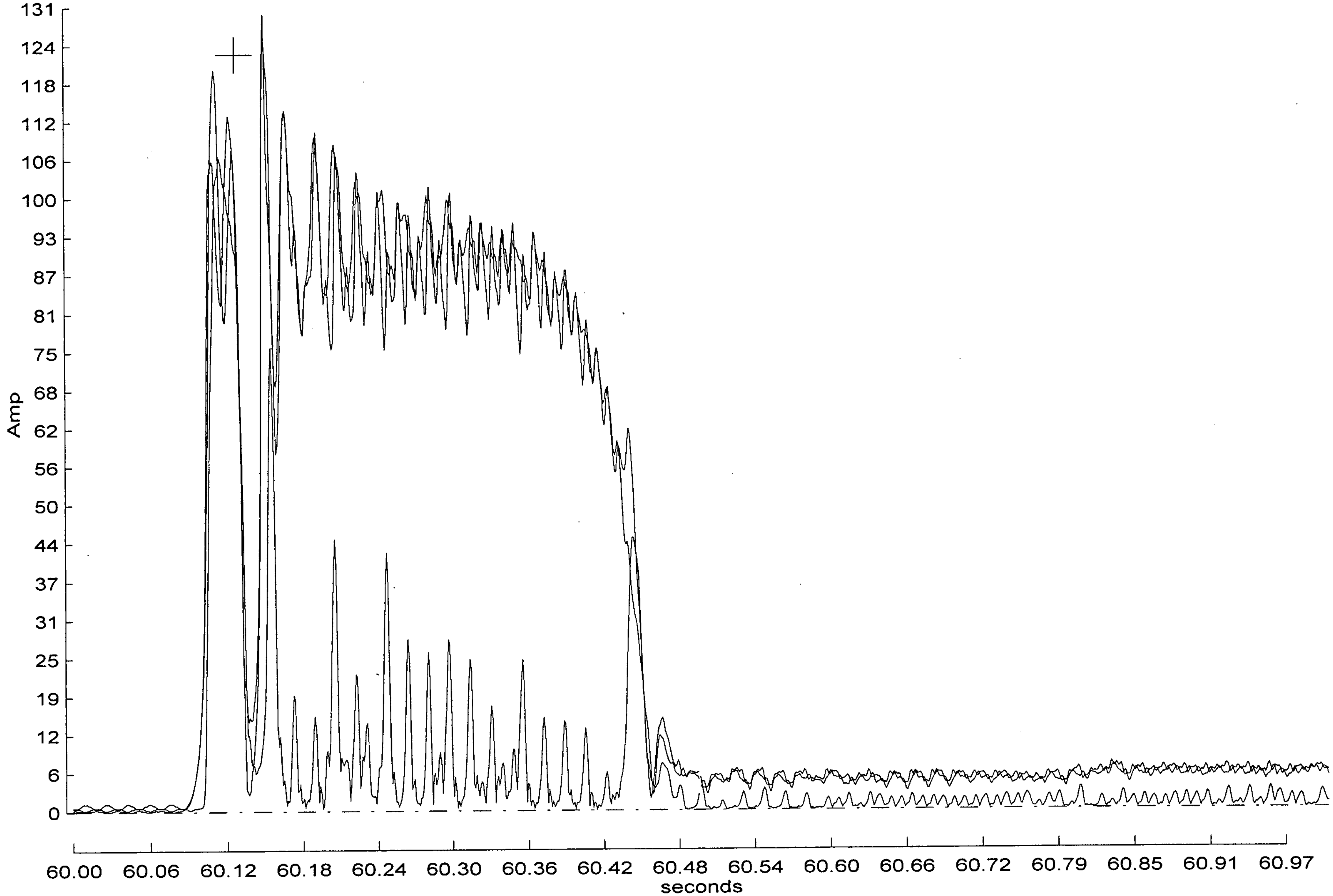
3LP-17
ES Test #5
c phase of current

ATTACHMENT 6

Graphs of 3LP-17 Current During Test 6


3LP-17 Test #6
Amps
700
600
500
400
300
200
100
0
0.010
0.405
0.800
1.195
1.590
1.985
2.380
2.775
3.170
3.565
3.960
4.355
4.750
5.145
5.540
5.935
6.330
6.725
7.120
7.515
7.910
8.305
8.700
9.095
9.490
9.885
10.280
10.675
11.070
11.465
11.860
12.250
12.645
13.040
13.435
13.830
14.225
14.620
Time in Seconds
Breaker
Overload Relay
Inrush

<1> M Test: Oconee 3 3LP017 1-4-97 4:01a 129.3 6 ES

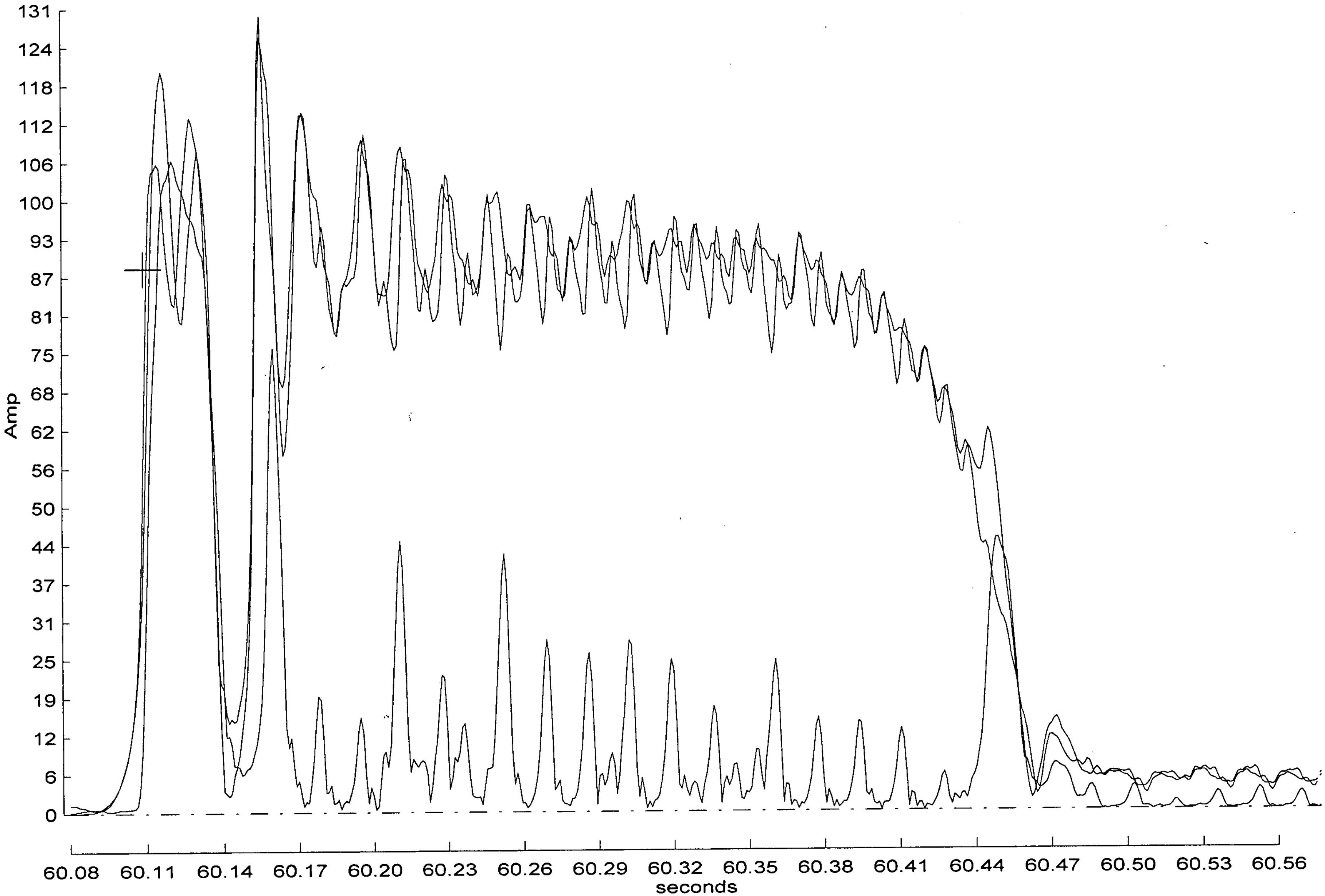


Cursor coordinates = 60.1seconds, 123Amp

Ia-rms Ib-rms Ic-rms

3LP-17
ES Test #6
3 phases of current

<1>[redacted]M Test: Oconee 3 3LP017 1-4-97 4:01a 129.3 6 ES

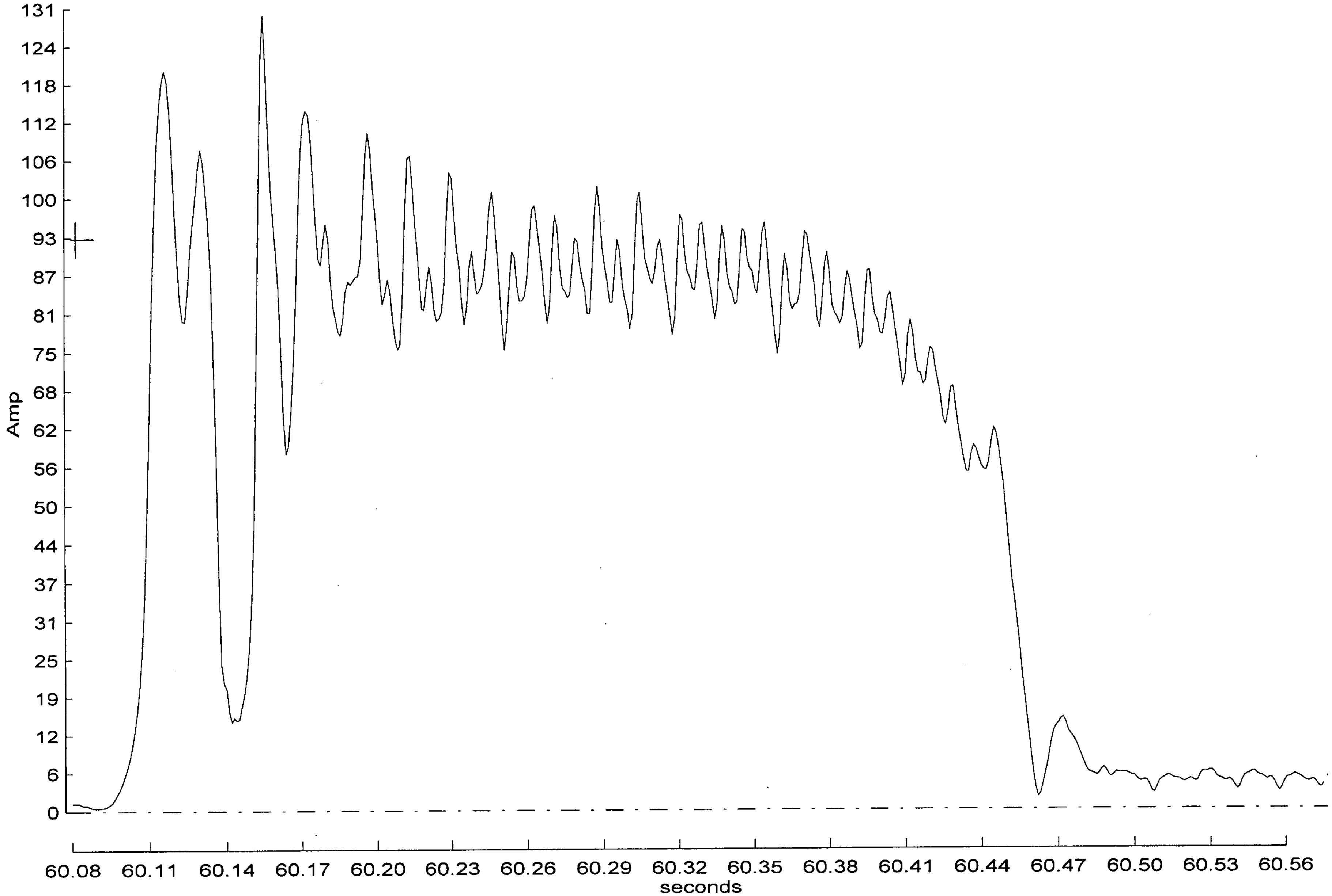


Cursor coordinates = 60.1seconds, 88.5Amp

Ia-rms Ib-rms Ic-rms

3LP-17
ES Test #6
3 phases of current

<1> M Test: Oconee 3 3LP017 1-4-97 4:01a 129.3 6 ES

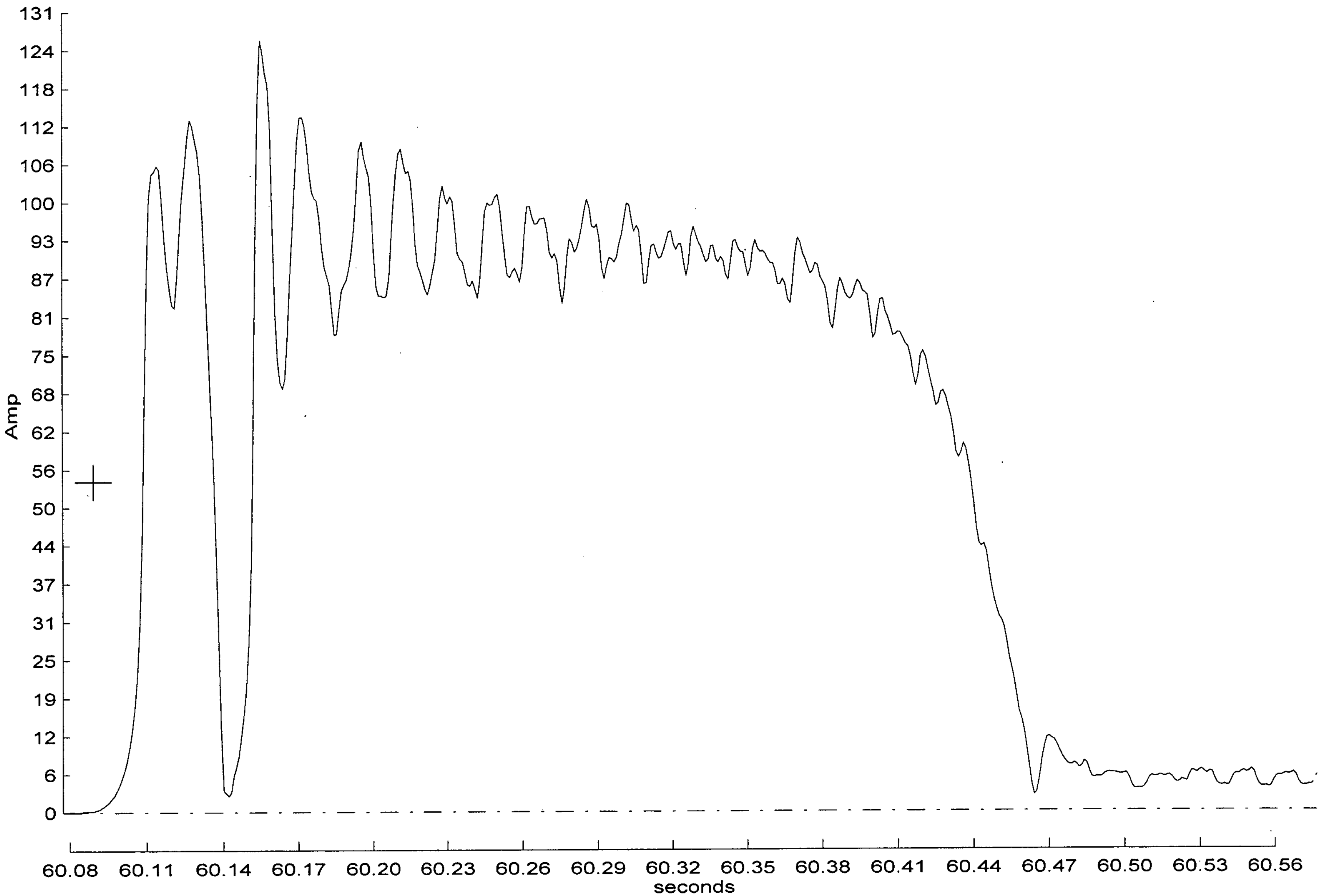


Cursor coordinates = 60.1seconds, 93.1Amp

Ia-rms

3LP-17
ES Test #6
a phase of current

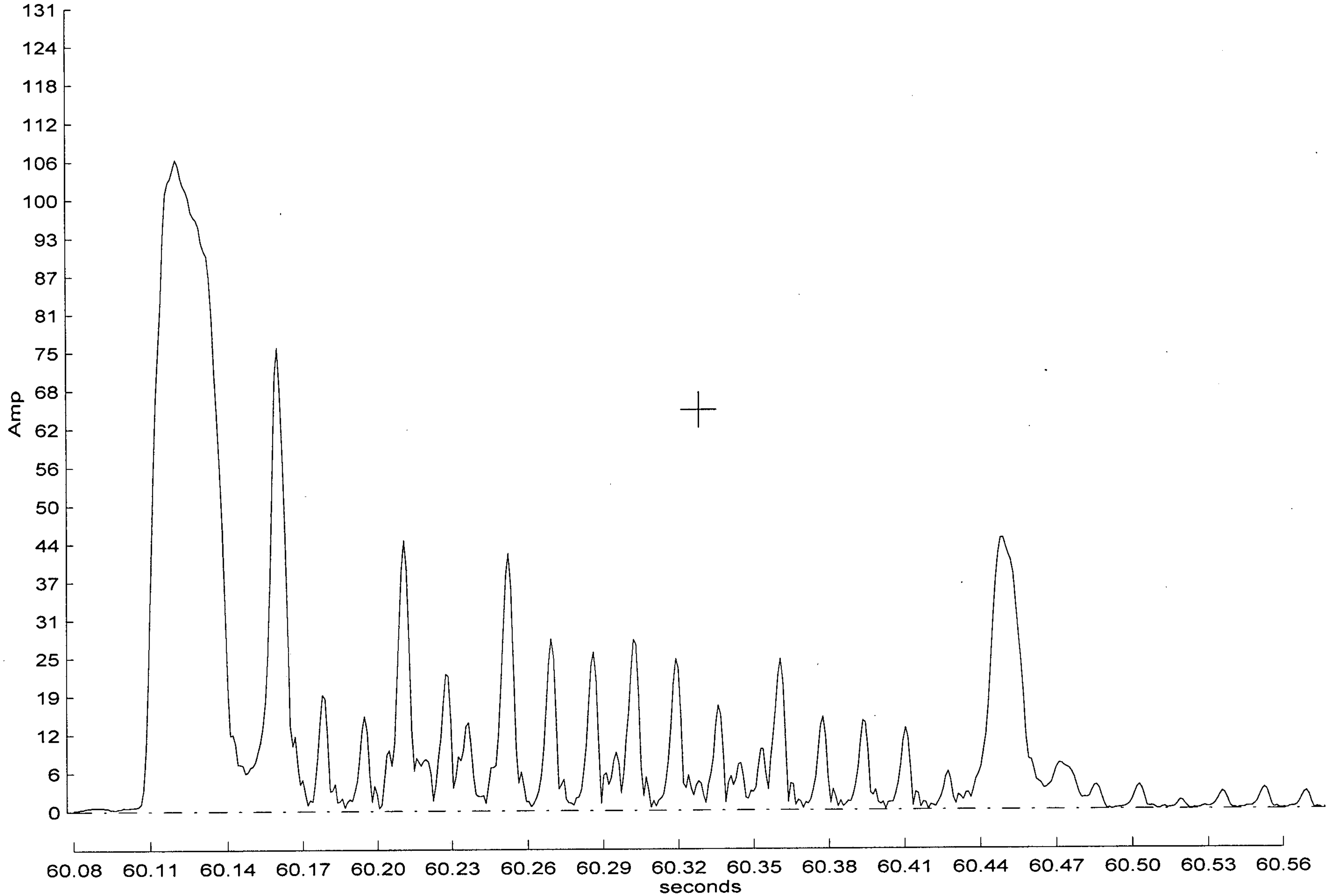
<1>[illegible]M Test: Oconee 3 3LP017 1-4-97 4:01a 129.3 6 ES



Cursor coordinates = 60.1seconds, 54Amp
lb-rms

3LP-17
ES Test #6
b phase of current

<1> M Test: Oconee 3 3LP017 1-4-97 4:01a 129.3 6 ES



Cursor coordinates = 60.3seconds, 65.2Amp

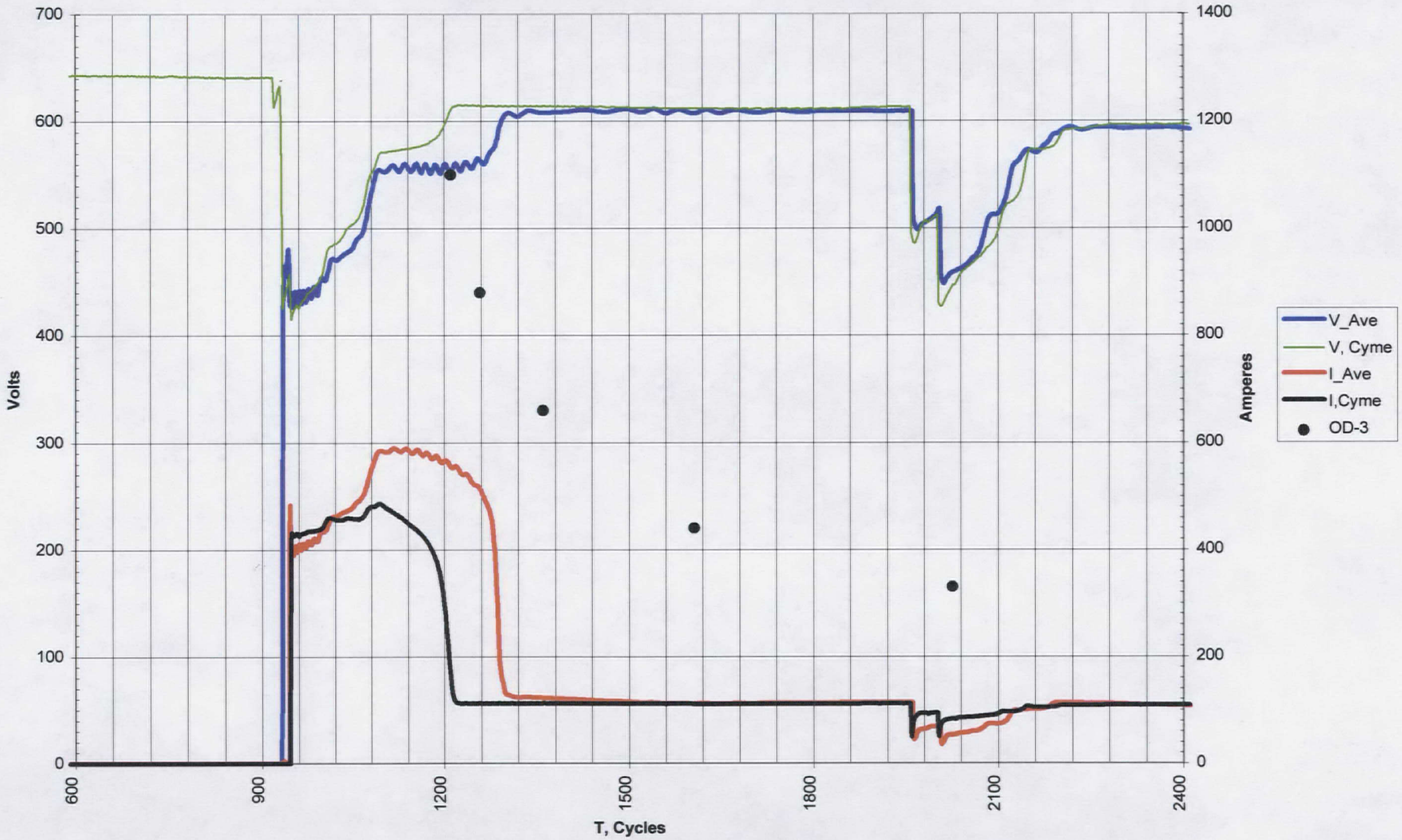
Ic-rms

3LP-17
ES Test #6
c phase of current

ATTACHMENT 7

Figure 2-24 - RBCF 3B Voltage and
Current During Test 5

Figure 2- 24: Test5, RBCF 3B Voltage and Current



ATTACHMENT 8

Keowee Data From Test 3

Figure H-1: Test3, Keowee Voltage and Current

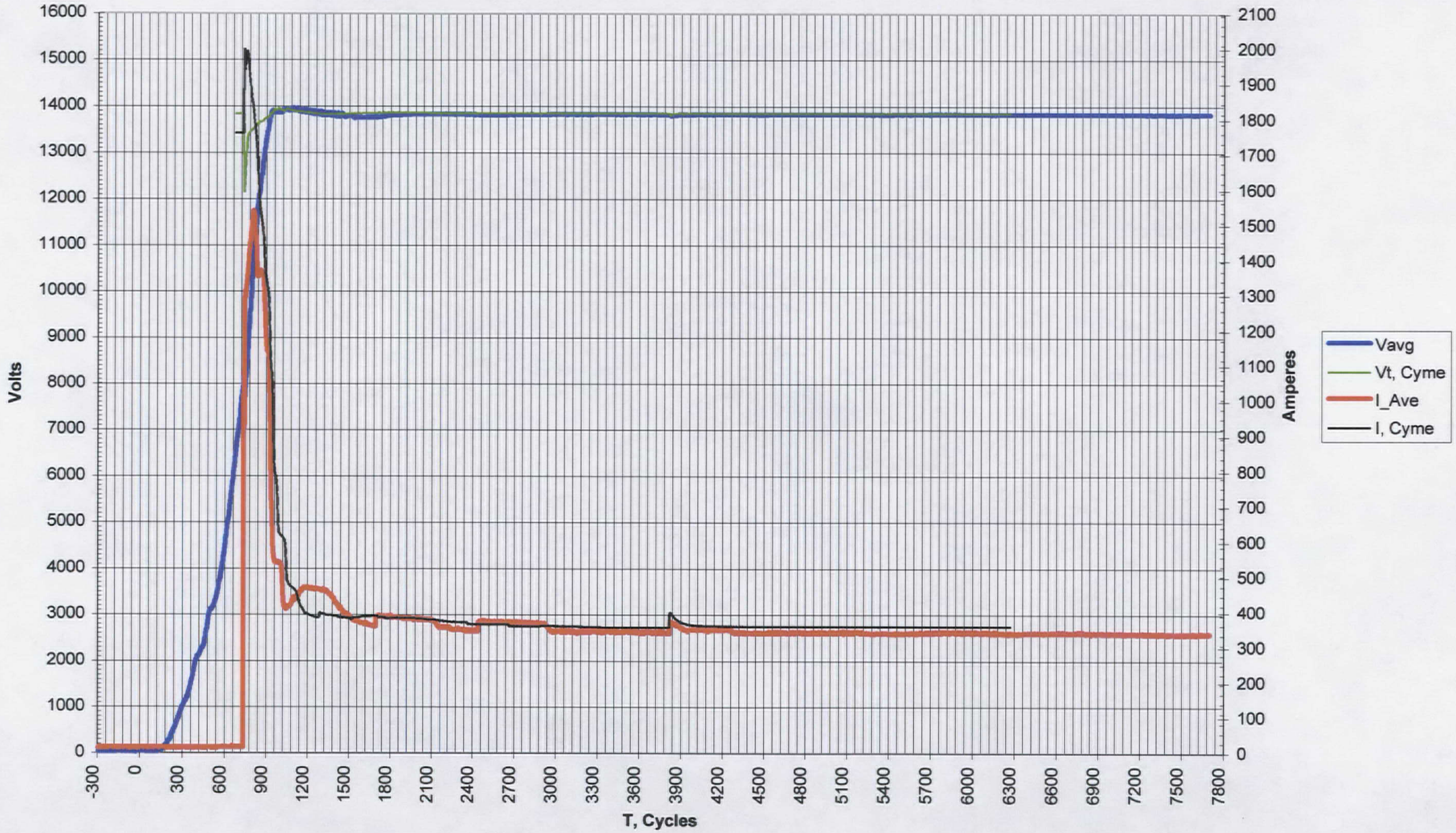


Figure H-2: Test3, Keowee Voltage

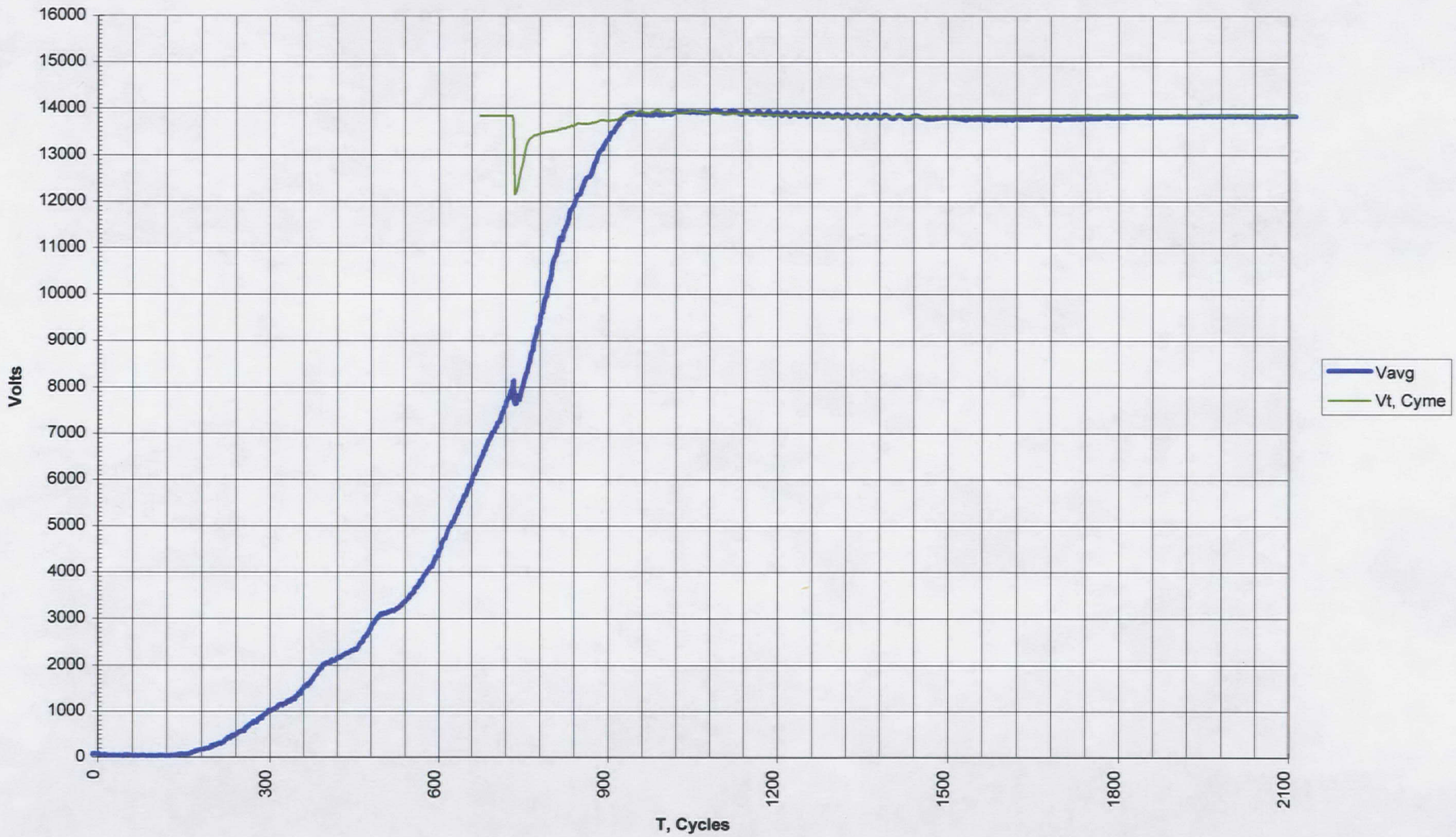


Figure H-3, Test3, Keowee KVA

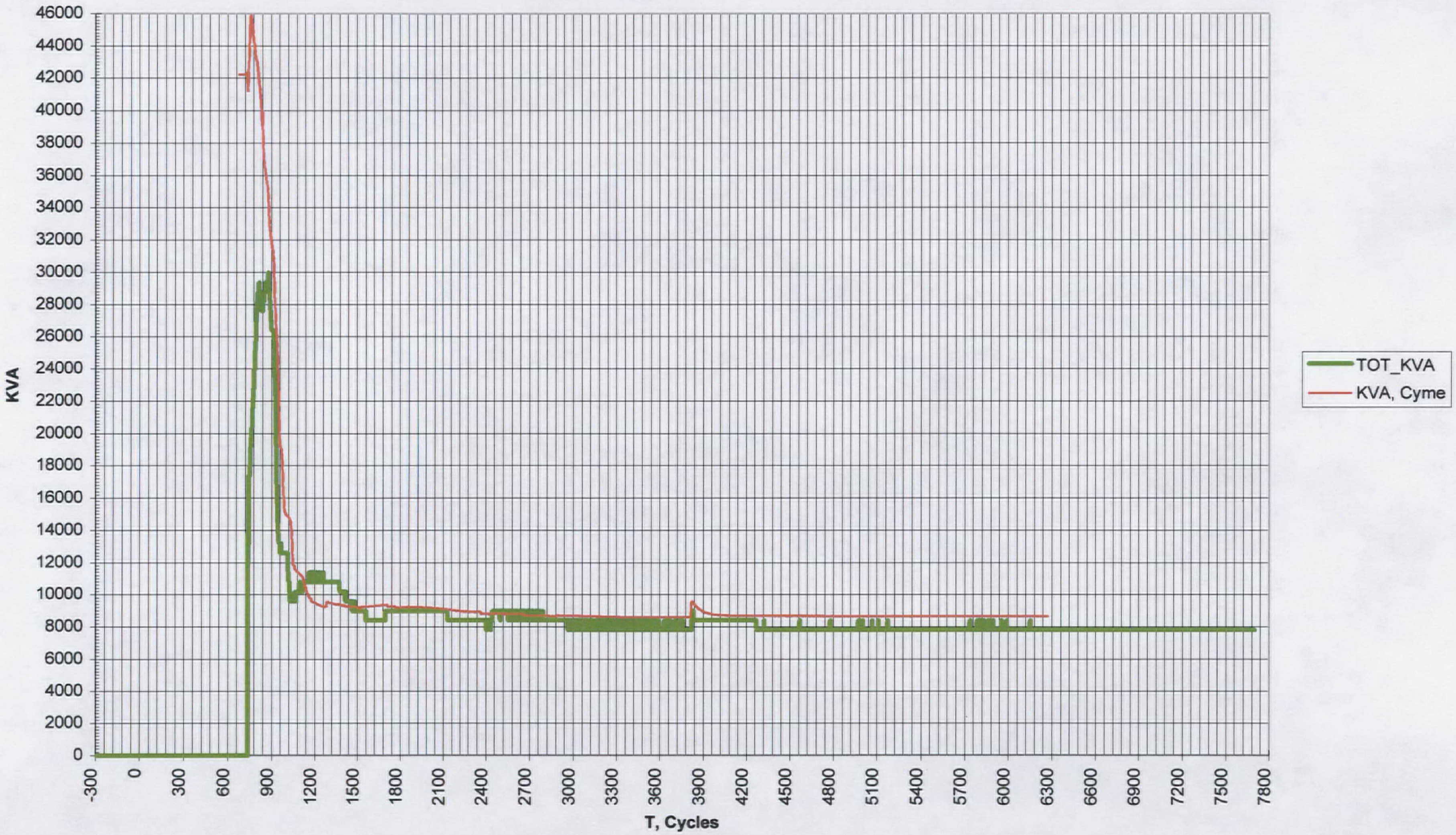


Figure H-4: Test3, Keowee KW

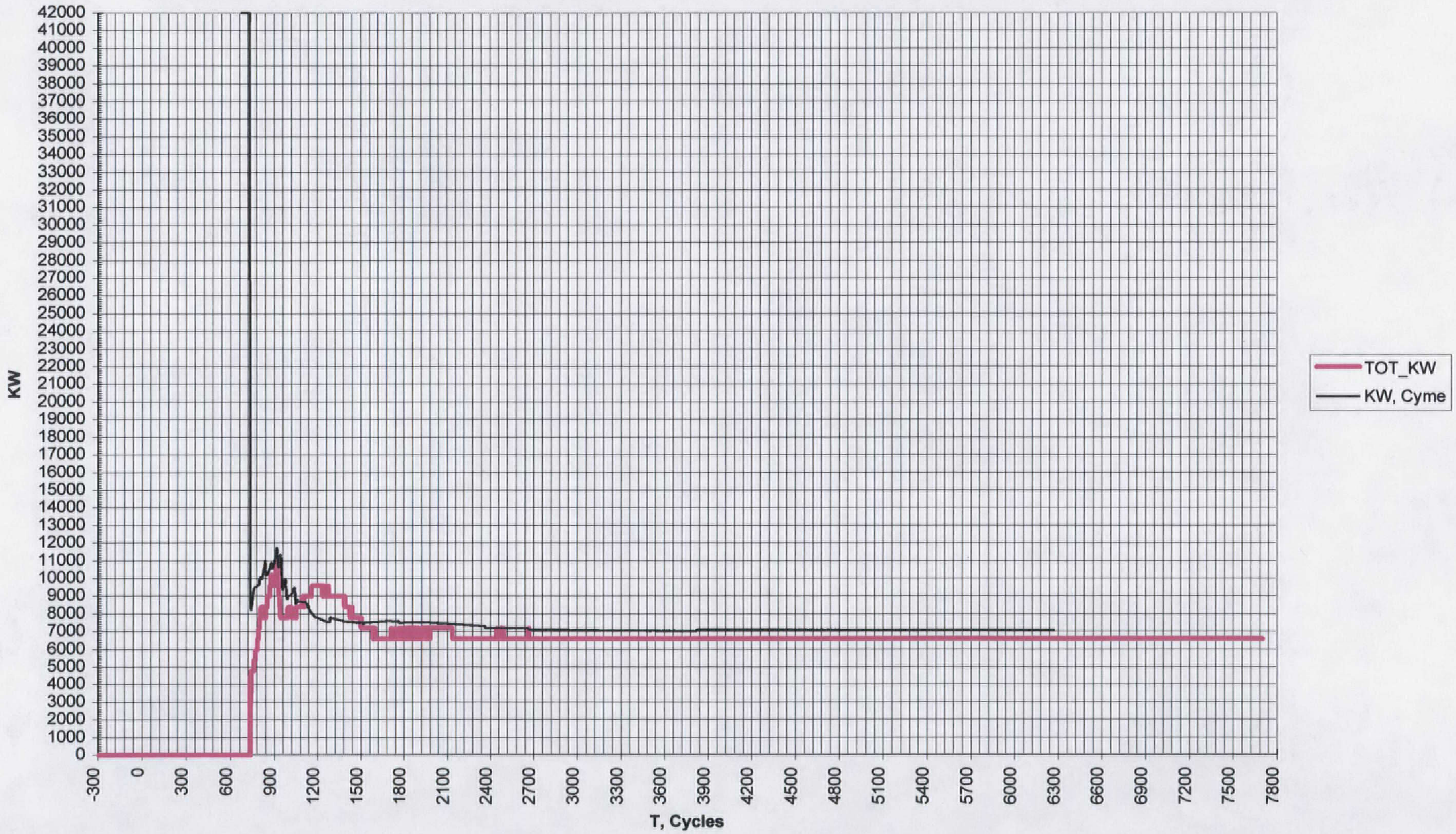


Figure H-5: Test3, Keowee Frequency and Current

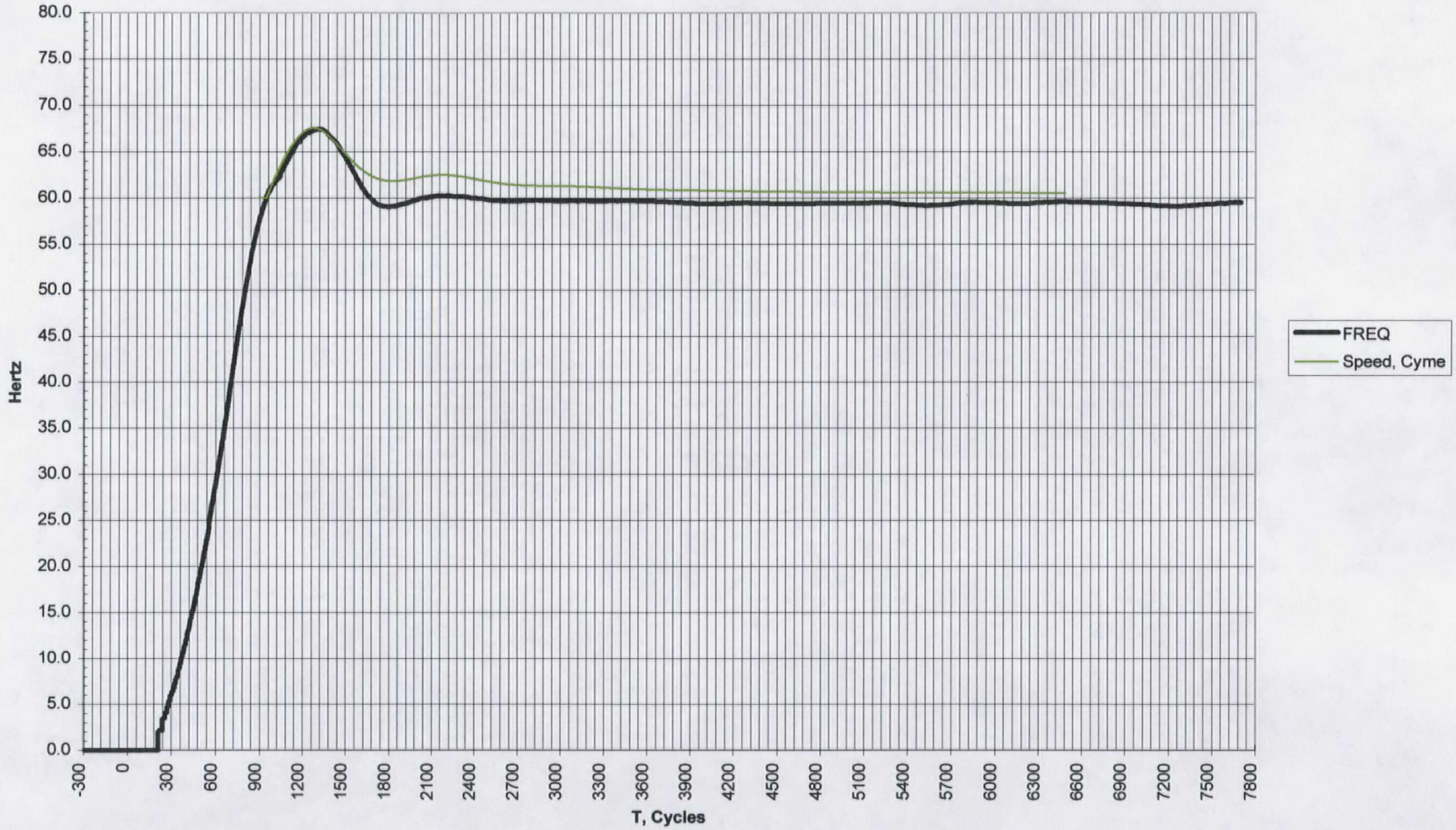
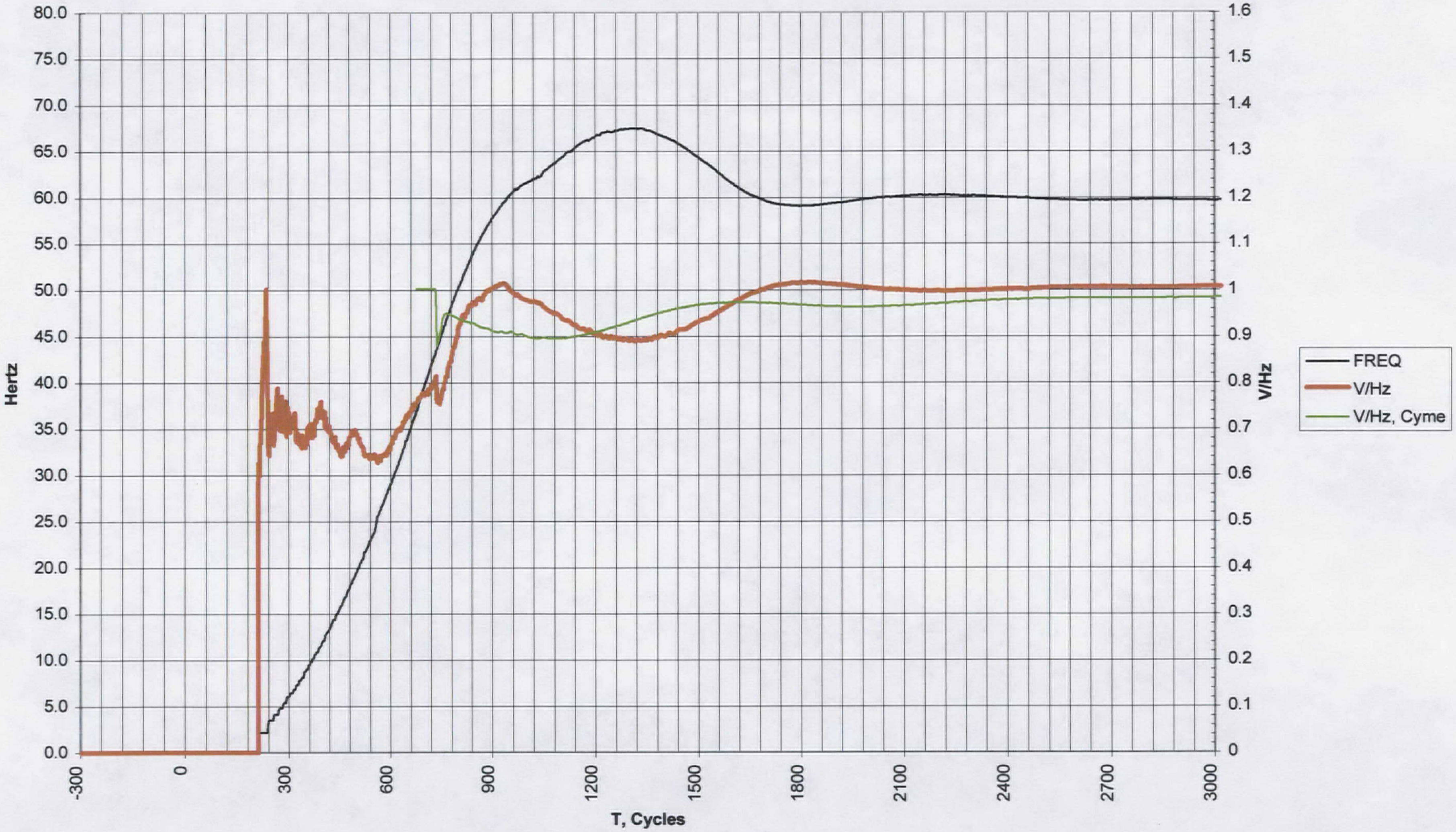
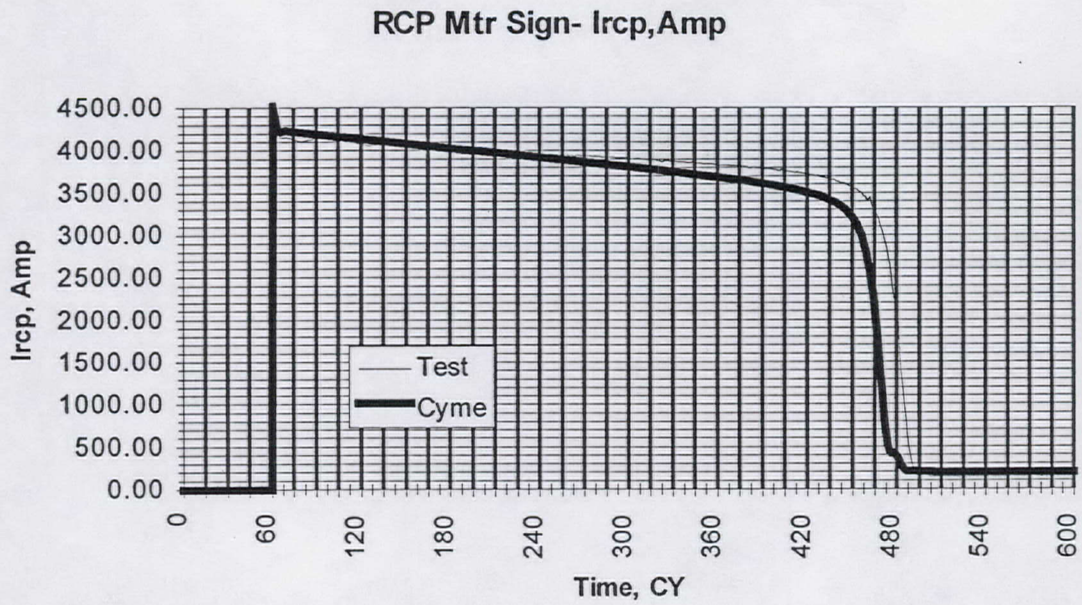


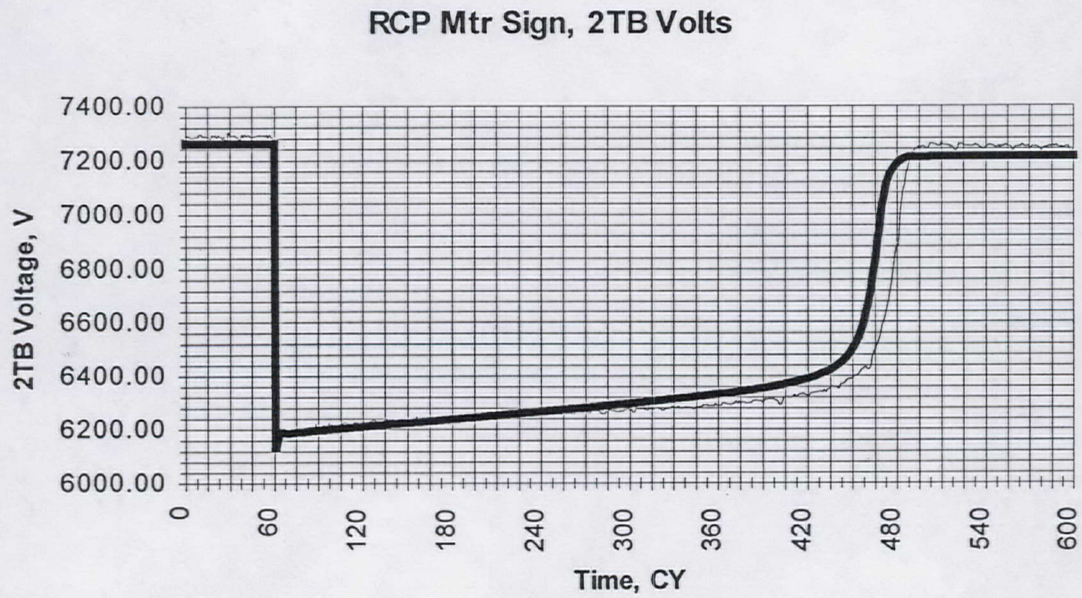
Figure H-6: Test3, Keowee Frequency and V/Hz

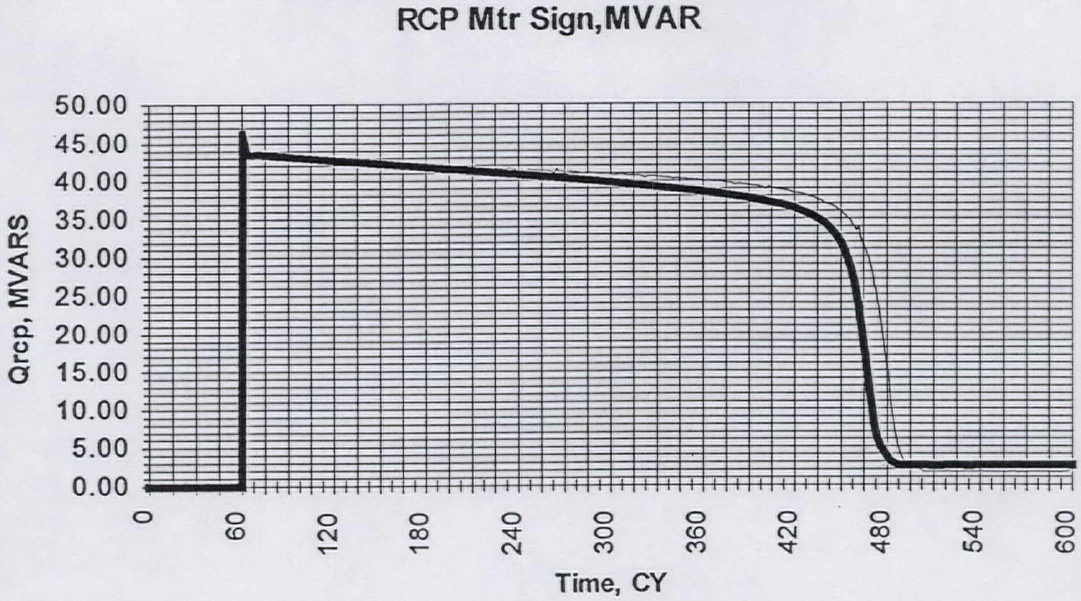


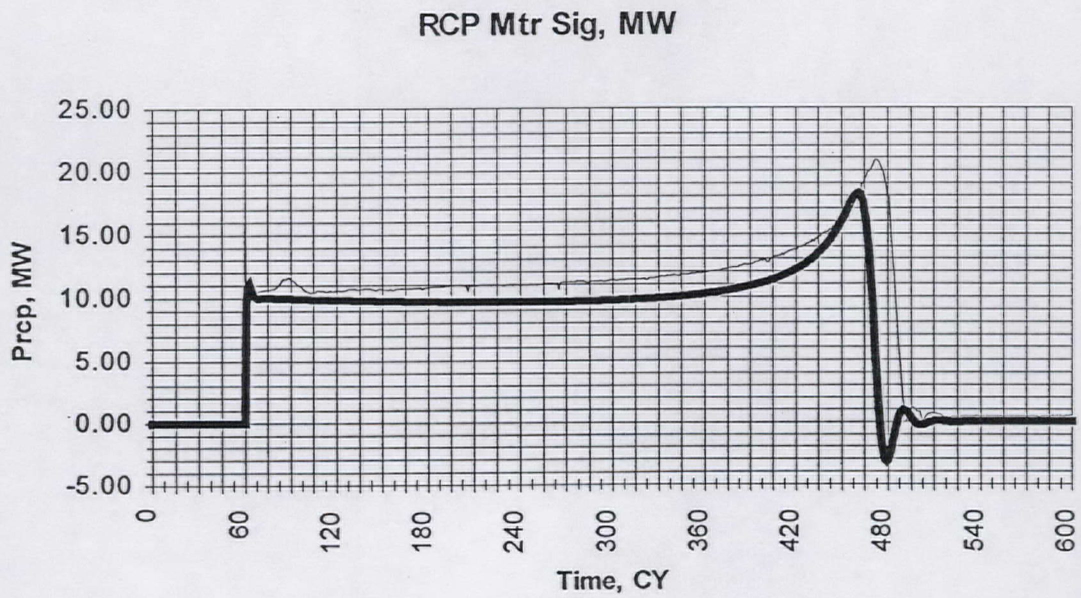
ATTACHMENT 9

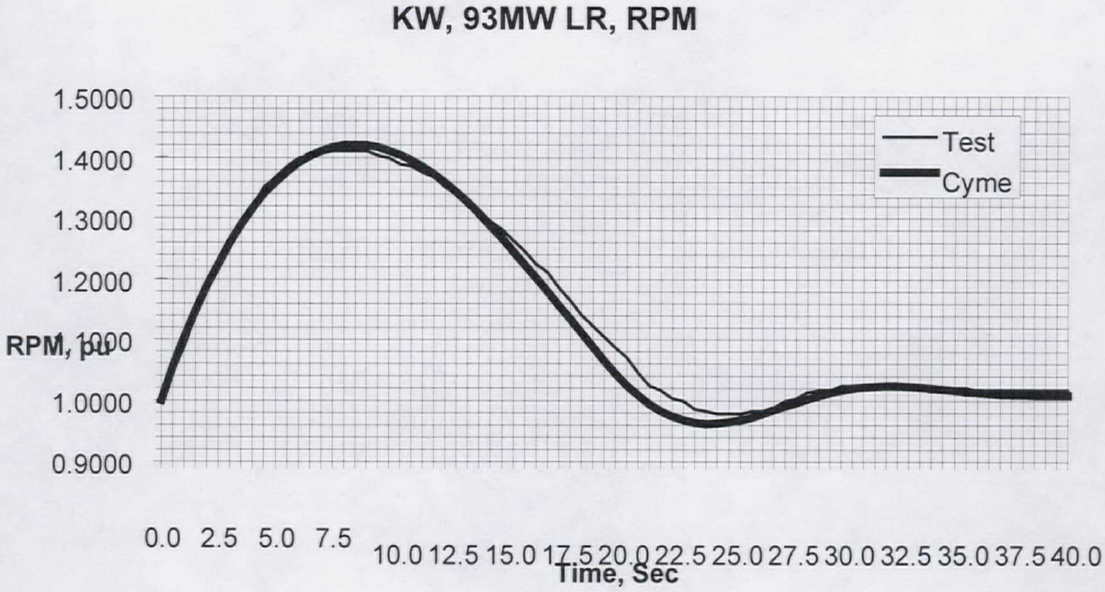
Validation of CYME Model to Test Results

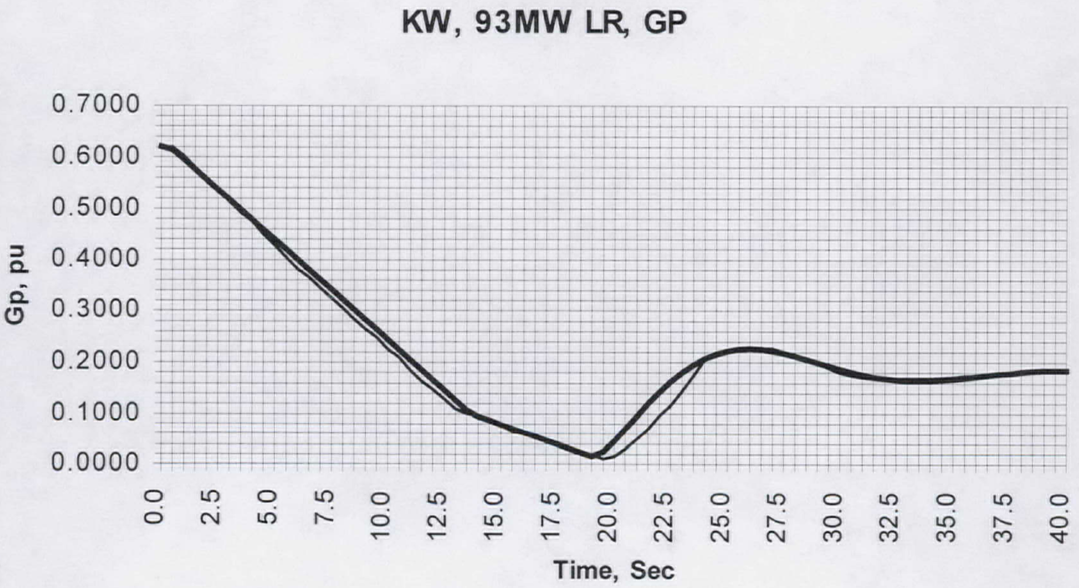

RCP Mtr Sign- Ircp,Amp
Ircp, Amp
4500.00
4000.00
3500.00
3000.00
2500.00
2000.00
1500.00
1000.00
500.00
0.00
Test
Cyme
0
60
120
180
240
300
360
420
480
540
600
Time, CY


RCP Mtr Sign, 2TB Volts
2TB Voltage, V
7400.00
7200.00
7000.00
6800.00
6600.00
6400.00
6200.00
6000.00
0
60
120
180
240
300
360
420
480
540
600
Time, CY


RCP Mtr Sign,MVAR
Qrcp, MVARS
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
0
60
120
180
240
300
360
420
480
540
600
Time, CY


RCP Mtr Sig, MW
Prcp, MW
25.00
20.00
15.00
10.00
5.00
0.00
-5.00
0
60
120
180
240
300
360
420
480
540
600
Time, CY


KW, 93MW LR, RPM
1.5000
1.4000
1.3000
1.2000
1.1000
1.0000
0.9000
RPM, pu
Test
Cyme
0.0 2.5 5.0 7.5 10.0 12.5 15.0 17.5 20.0 22.5 25.0 27.5 30.0 32.5 35.0 37.5 40.0
Time, Sec


KW, 93MW LR, GP
0.7000
0.6000
0.5000
0.4000
0.3000
0.2000
0.1000
0.0000
Gp, pu
0.0 2.5 5.0 7.5 10.0 12.5 15.0 17.5 20.0 22.5 25.0 27.5 30.0 32.5 35.0 37.5 40.0
Time, Sec

ATTACHMENT 10

V/Hz Ratio Plots for Motor Control Center 3XS1

Test3, Keowee V/Hz and 208V MCC 3XS1 V/Hz and Current (Standby Start)

Test4,Keowee V/Hz & 208V 3XS1 V/Hz and Current (Load Reject)