SPP Southwest Power Pool

Impact Study for Generation Interconnection Request GEN-2005-007

SPP Tariff Studies

#GEN-2005-007

January, 2006

Summary

I2R Technologies performed the following Study at the request of the Southwest Power Pool (SPP) for Generation Interconnection request GEN-2005-007. The request for interconnection was placed with SPP in accordance SPP's Open Access Transmission Tariff, which covers new generation interconnections on SPP's transmission system.

Pursuant to the tariff, I2R Technologies was asked to perform a detailed Impact Study of the generation interconnection request to satisfy the Impact Study Agreement executed by the requesting customer and SPP.

Per the Impact Study, oscillations were not damped out in all scenarios. The Customer will be required to specify and purchase a power system stabilizer (PSS) for the generator given the oscillations were not clearly damping out during the simulations.

It should be noted here as well as in the report that based on all prior queued projects going forward, loss of synchronism occurs while trying to export energy outside of the Xcel/Southwestern Public Service transmission system. For the simulation of Scenario 7 in the summer model and Scenarios 3, 4, and 7 of the winter model, it was demonstrated that additional tie lines from SPS to the rest of SPP will need to be analyzed. This will be accomplished through a Transmission Service study requested by the Customer through the Southwest Power Pool Open Access Transmission Tariff (OATT).

System Impact Study for Generation Interconnection Request For GEN-2005-007

Prepared by I2R Technologies

December 2005

System Impact Study GEN-2005-007

Table of Contents

System Impact Study GEN-2005-007

I. EXECUTIVE SUMMARY

The Customer has requested a generator interconnection study through the Southwest Power Pool (SPP) Tariff for a 230 kV interconnection for a 260 MW capacity addition to the existing Blackhawk generating facility located in the Xcel Southwestern Public Service (SPS) control area. This capacity addition will be interconnected into the 230 kV bus at the Hutchinson Substation. It will consist of a 260 MW, 290 MVA synchronous generator powered by a steam turbine. The projected in-service date for this capacity addition is June 1, 2009.

Data supplied by the Interconnection Customer was used to build load flow and dynamics models using Siemens PTI's PSS/E™ software package.

SPP provided both summer and winter load flow basecases based on the 2004 MMWG series of load flow models. The title of the summer basecase is "2004 SERIES, NERC/MMWG BASE CASE LIBRARY 2009 SUMMER, FINAL; FOR DYN". The title of the winter basecase is "2004 SERIES, NERC/MMWG BASE CASE LIBRARY 2006 WINTER, FINAL; FOR DYN". SPP also defined a comprehensive set of fault scenarios (21) to be evaluated in the dynamic analysis.

The following conclusions are reached from the load flow and dynamic analysis performed in this study:

- The system remained stable for twenty of the twenty-one scenarios simulated using the summer model.
- The system remained stable for eighteen of the twenty-one scenarios simulated using the winter model.
- The generating units in the SPS control area lost synchronism with the outside world during the simulation of Scenario 7 using the summer and winter model and Scenarios 3 and 4 using the winter model. This

condition occurs due to the study models containing all previously queued projects located in the northern Texas panhandle. All previously queued projects are considered to be in service and exporting power equally throughout the SPP footprint. This results in an SPS export scenario of over 1400 MW in the summer and winter cases. This condition illustrates the point that additional tie lines from SPS to the rest of SPP are necessary for all planned generation to be able to export from the SPS control area.

- The above condition was found to occur for Scenario 7 using the summer model in the absence of the Customer generation and for other sensitivities listed in Section VII. This shows the condition exists in the base case and will likely exist for SPS export scenarios of over 900MW.
- Oscillations were not damping out in all scenarios. The long-term oscillations were more pronounced in the winter model. Implementation of a power system stabilizer for the Customer generation is recommended to provide additional damping of the long-term oscillations.

Nothing in this study should be construed as a guarantee of transmission service. If the customer wishes to sell power from the facility, a separate request for transmission service shall be requested on Southwest Power Pool's OASIS by the Customer.

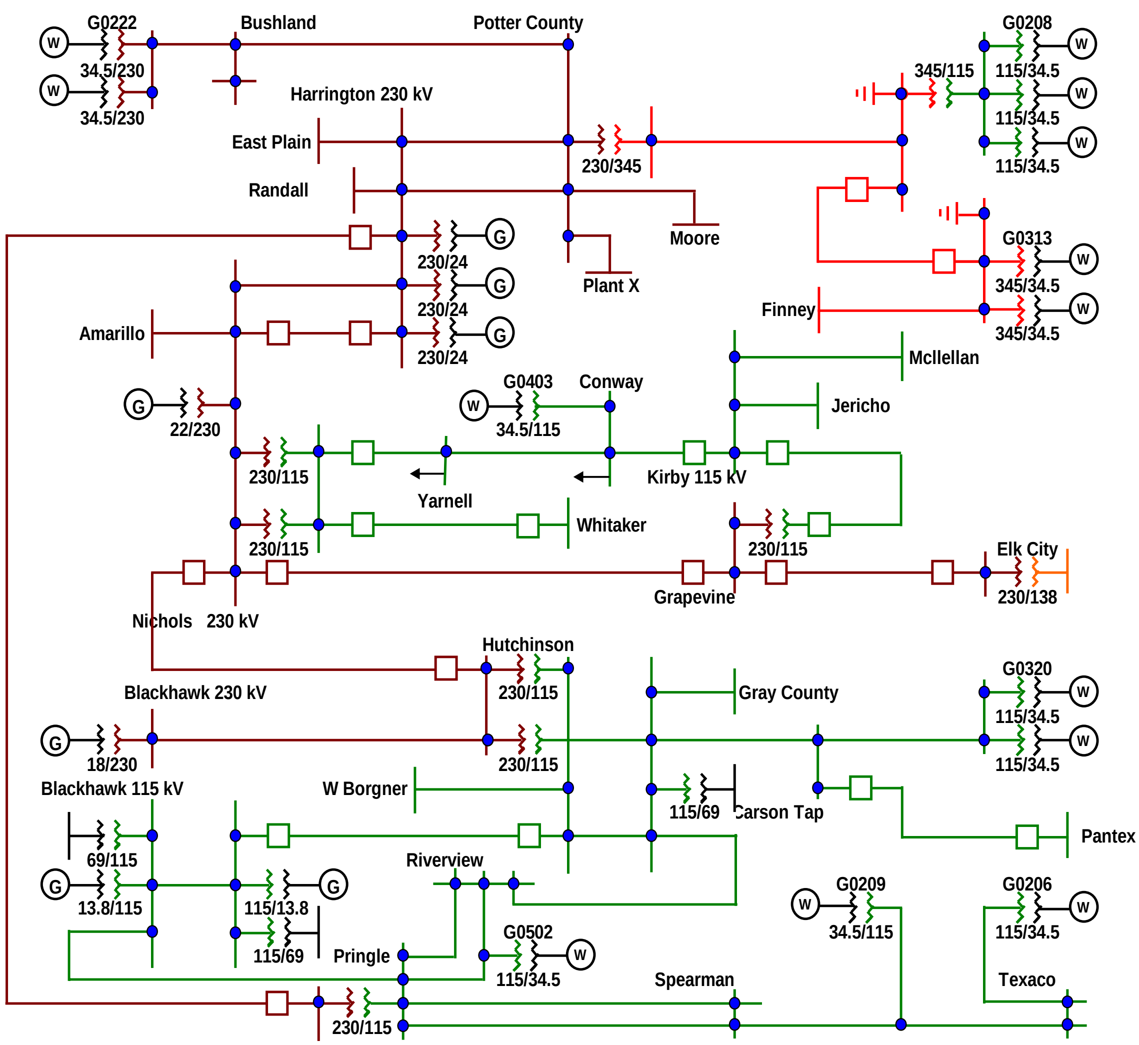
INTRODUCTION

The Customer has requested a generator interconnection study through the Southwest Power Pool Tariff for a 230 kV interconnection for a 260 MW capacity addition to the existing Blackhawk generating facility located in the SPS control area. This capacity addition will be interconnected into the 230 kV bus at the Hutchinson Substation. It will consist of a 260 MW, 290 MVA synchronous generator powered by a steam turbine. The projected in-service date for this capacity addition is June 1, 2009.

II. Configuration

The proposed capacity addition will be interconnected via a new 230 kV substation and line from the generating facility to the Hutchinson 230 kV substation. The one-line for the interconnection and nearby transmission system is shown below in Figure 1.

FIGURE 1



III. LOAD FLOW MODELING

SPP provided both summer and winter loadflow basecases based on the 2004 MMWG series of loadflow models. The title of the summer basecase is "2004 SERIES, NERC/MMWG BASE CASE LIBRARY 2009 SUMMER, FINAL; FOR DYN". The title of the winter basecase is "2004 SERIES, NERC/MMWG BASE CASE LIBRARY 2006 WINTER, FINAL; FOR DYN". These models provided the starting point for building a load flow model to evaluate the proposed capacity addition. Siemens PTI's PSS/E™ load flow program was used for this analysis

Line parameters for the new 230 kV line from the generating facility to the Hutchinson 230 kV Substation were provided as follows:

- R = 0.00326 per unit
- X = 0.02206 per unit
- B = 0.04147 per unit
- Normal/Emergency Rating = 452/497 MVA

An 18/230 kV step-up transformer will connect the new generator to the 230 kV bus. The following data was provided for this transformer:

- Capacity Self-cooled = 180 MVA
- Maximum Nameplate = 300 MVA
- Positive Impedance = 10%

Several previous queued projects were added to the base case. The system interconnection was modeled as defined by SPP. Generators were added to the load flow model using the appropriate IPLAN program provided by SPP or downloaded from the PTI web site. The following projects were added to the base case:

- GEN-2002-006 – 150 MW wind farm utilizing 100 GE 1.5 MW turbines located near the Texas County 115 kV bus

- GEN-2002-008 – 240 MW wind farm utilizing 133 Vestas 1.8 MW turbines located on the Potter-Finney 345 kV line
- GEN-2002-009 – 80 MW wind farm utilizing 44 Vestas 1.8 MW turbines located on the Texas County-Spearman 115 kV line
- GEN-2002-022 – 240 MW wind farm utilizing 104 Siemens 2.3 MW turbines off of the Bushland 230 kV bus
- GEN-2003-013 – 198 MW wind farm utilizing 132 GE 1.5 MW turbines located on the Potter-Finney 345 kV line
- GEN-2003-020 – 160 MW wind farm utilizing 106 GE 1.5 MW turbines located off of the Carson bus
- GEN-2004-003 – 240 MW wind farm utilizing 160 GE 1.5 MW turbines located off of the Conway bus
- GEN-2005-002 – 80 MW wind farm utilizing 40 Gamesa 2.0 MW turbines located on the Riverview-Pringle 115 kV line.

All of the previous queued projects along with the proposed capacity addition were dispatched using the SPP dispatch. Using the standard dispatch model for SPP Generation Interconnection requests, all of the previously queued projects were dispatched equally into the entire SPP footprint. Table 1 shows the summer dispatch of the previously queued and Customer generation to each SPP control area. Incremental imports were calculated for each SPP control area based on the generation dispatched in the summer base model. This resulted in an export from SPS of over 1400 MW. For each wind turbine, the default power factor control of unity and direct dispatch was chosen.

TABLE 1

Summer Dispatch

Area	Generation	% of Total	Import
SWPA	1,989.0	5.24%	86.3
AEPW	9,330.0	24.57%	405.0
GRDA	1,189.0	3.13%	51.6
OKGE	6,255.0	16.48%	271.5
WFEC	1,133.0	2.98%	49.2
SPS	5,508.0	14.51%	239.1
MIDW	26.0	0.07%	1.1
WERE	6,296.0	16.58%	273.3
KACP	4,321.0	11.38%	187.6
EMDE	1,150.0	3.03%	49.9
SPRM	769.0	2.03%	33.4
Total	**37,966.0**	**100%**	**1,648.0**

Table 2 shows the winter dispatch of the previously queued and Customer generation to each SPP control area. Incremental imports were calculated for each SPP control area based on the generation dispatched in the winter base model.

TABLE 2

Winter Dispatch

Area	Generation	% of Total	Import
SWPA	1,699.4	6.65%	109.6
AEPW	6,154.4	24.08%	396.8
GRDA	1,000.6	3.91%	64.5
OKGE	4,053.4	15.86%	261.4
WFEC	839.1	3.28%	54.1
SPS	3,983.3	15.59%	256.8
MIDW	23.9	0.09%	1.5
WERE	4,076.9	15.95%	262.9
KACP	2,532.2	9.91%	163.3
EMDE	801.2	3.13%	51.7
SPRM	393.9	1.54%	25.4
Total	**25,558.3**	**100%**	**1,648.0**

IV. Dynamic Modeling

Customer supplied data was used to build the round rotor generator model (GENROU), the IEEE type AC2A excitation system model (ESAC2A) and the IEEE stabilizing model (IEEEST). The stabilizing model was disabled for the dynamic simulations. PTI default data was used for the steam turbine-governor model (TGOV1).

Dynamic data for the prior queued projects were developed using the appropriate IPLAN program provided by SPP or downloaded from the PTI web site. Standard ride-through capability was selected for over/under voltage/frequency relays.

V. FAULT SCENARIOS

The SPP defined the following 21 fault scenarios.

1. A three-phase fault on the Nichols to Grapevine 230 kV line was evaluated. The fault was applied at the midpoint of the line for 5 cycles. Opening the 230 kV line between the Nichols Substation and the Grapevine Substation temporarily cleared the fault. After 20 cycles the 230 kV line was reclosed and the fault was reapplied at the midpoint of the line for 5 cycles. Reopening the 230 kV line between the Nichols Substation and the Grapevine Substation permanently cleared the fault.

2. A single-phase fault on the Nichols to Grapevine 230 kV line was evaluated. The fault was applied at the midpoint of the line for 5 cycles. Opening the 230 kV line between the Nichols Substation and the Grapevine Substation temporarily cleared the fault. After 20 cycles the 230 kV line was reclosed and the fault was reapplied at the midpoint of the line for 5 cycles. Reopening the 230 kV line between the Nichols Substation and the Grapevine Substation permanently cleared the fault.

3. A three-phase fault on the Grapevine to Elk City 230 kV line was evaluated. The fault was applied at Elk City for 5 cycles. Opening the 230 kV line between the Grapevine Substation and the Elk City Substation temporarily cleared the fault. After 20 cycles the 230 kV line was reclosed and the fault was reapplied at Elk City for 5 cycles. Reopening the 230 kV line between the Grapevine Substation and the Elk City Substation permanently cleared the fault.

4. A single-phase fault on the Grapevine to Elk City 230 kV line was evaluated. The fault was applied at Elk City for 5 cycles. Opening the 230 kV line between the Grapevine Substation and the Elk City Substation temporarily

cleared the fault. After 20 cycles the 230 kV line was reclosed and the fault was reapplied at Elk City for 5 cycles. Reopening the 230 kV line between the Grapevine Substation and the Elk City Substation permanently cleared the fault.

5. A three-phase fault on the Nichols to Yarnell to Conway to Kirby 115 kV line was evaluated. The fault was applied at Kirby for 5 cycles. Opening the 115 kV line between the Nichols Substation and the Kirby Substation temporarily cleared the fault. After 20 cycles the 115 kV line was reclosed and the fault was reapplied at Kirby for 5 cycles. Reopening the 115 kV line between the Nichols Substation and the Kirby Substation permanently cleared the fault.

6. A single-phase fault on the Nichols to Yarnell to Conway to Kirby 115 kV line was evaluated. The fault was applied at Kirby for 5 cycles. Opening the 115 kV line between the Nichols Substation and the Kirby Substation temporarily cleared the fault. After 20 cycles the 115 kV line was reclosed and the fault was reapplied at Kirby for 5 cycles. Reopening the 115 kV line between the Nichols Substation and the Kirby Substation permanently cleared the fault.

7. A three-phase fault on the Gen-2002-008 to Gen-2003-013 345 kV line was evaluated. The fault was applied at the midpoint of the line for 3 cycles. Opening the 345 kV line between Gen-2002-008 and Gen-2003-013 temporarily cleared the fault. After 30 cycles the 345 kV line was reclosed and the fault was reapplied at the midpoint of the line for 3 cycles. Reopening the 345 kV line between Gen-2002-008 and Gen-2003-013 permanently cleared the fault.

8. A three-phase fault on the Kirby to Grapevine 115 kV line was evaluated. The fault was applied at Grapevine for 5 cycles. Opening the 115 kV line between the Kirby Substation and Grapevine Substation temporarily cleared the fault. After 20 cycles the 115 kV line was reclosed and the fault was

reapplied at Grapevine for 5 cycles. Reopening the 115 kV line between the Kirby Substation and Grapevine Substation permanently cleared the fault.

9. A single-phase fault on the Kirby to Grapevine 115 kV line was evaluated. The fault was applied at Grapevine for 5 cycles. Opening the 115 kV line between the Kirby Substation and Grapevine Substation temporarily cleared the fault. After 20 cycles the 115 kV line was reclosed and the fault was reapplied at Grapevine for 5 cycles. Reopening the 115 kV line between the Kirby Substation and Grapevine Substation permanently cleared the fault.

10. A three-phase fault on the Nichols to Hutchison County Interchange 230 kV line was evaluated. The fault was applied at Hutchinson County Interchange for 5 cycles. Opening the 230 kV line between the Nichols Substation and Hutchison County Interchange Substation temporarily cleared the fault. After 20 cycles the 230 kV line was reclosed and the fault was reapplied at Hutchinson County Interchange for 5 cycles. Reopening the 230 kV line between the Nichols Substation and Hutchinson County Interchange Substation permanently cleared the fault.

11. A single-phase fault on the Nichols to Hutchison County Interchange 230 kV line was evaluated. The fault was applied at Hutchinson County Interchange for 5 cycles. Opening the 230 kV line between the Nichols Substation and Hutchison County Interchange Substation temporarily cleared the fault. After 20 cycles the 230 kV line was reclosed and the fault was reapplied at Hutchinson County Interchange for 5 cycles. Reopening the 230 kV line between the Nichols Substation and Hutchinson County Interchange Substation permanently cleared the fault.

12. A three-phase fault on the Nichols to Whitaker 115 kV line was evaluated. The fault was applied at Whitaker for 5 cycles. Opening the 115 kV line between the Nichols Substation and Whitaker Substation temporarily cleared the fault. After 20 cycles the 115 kV line was reclosed and the fault was

reapplied at Whitaker for 5 cycles. Reopening the 115 kV line between the Nichols Substation and Whitaker County Interchange Substation permanently cleared the fault.

13. A single-phase fault on the Nichols to Whitaker 115 kV line was evaluated. The fault was applied at Whitaker for 5 cycles. Opening the 115 kV line between the Nichols Substation and Whitaker Substation temporarily cleared the fault. After 20 cycles the 115 kV line was reclosed and the fault was reapplied at Whitaker for 5 cycles. Reopening the 115 kV line between the Nichols Substation and Whitaker County Interchange Substation permanently cleared the fault.

14. A three-phase fault on the Pringle to Harrington 230 kV line was evaluated. The fault was applied at Pringle for 5 cycles. Opening the 230 kV line between the Pringle Substation and Harrington Substation temporarily cleared the fault. After 20 cycles the 230 kV line was reclosed and the fault was reapplied at Pringle for 5 cycles. Reopening the 230 kV line between the Pringle Substation and Harrington Substation permanently cleared the fault.

15. A single-phase fault on the Pringle to Harrington 230 kV line was evaluated. The fault was applied at Pringle for 5 cycles. Opening the 230 kV line between the Pringle Substation and Harrington Substation temporarily cleared the fault. After 20 cycles the 230 kV line was reclosed and the fault was reapplied at Pringle for 5 cycles. Reopening the 230 kV line between the Pringle Substation and Harrington Substation permanently cleared the fault.

16. A three-phase fault on the Nichols to Harrington 230 kV line was evaluated. The fault was applied at Nichols for 5 cycles. Opening the 230 kV line between the Nichols Substation and Harrington Substation temporarily cleared the fault. After 20 cycles the 230 kV line was reclosed and the fault was reapplied at Nichols for 5 cycles. Reopening the 230 kV line between the Nichols Substation and Harrington Substation permanently cleared the fault.

17. A single-phase fault on the Nichols to Harrington 230 kV line was evaluated. The fault was applied at Nichols for 5 cycles. Opening the 230 kV line between the Nichols Substation and Harrington Substation temporarily cleared the fault. After 20 cycles the 230 kV line was reclosed and the fault was reapplied at Nichols for 5 cycles. Reopening the 230 kV line between the Nichols Substation and Harrington Substation permanently cleared the fault.

18. A three-phase fault on the Hutchinson to Blackhawk 115 kV line was evaluated. The fault was applied at Blackhawk for 5 cycles. Opening the 115 kV line between the Hutchinson Substation and Blackhawk Substation temporarily cleared the fault. After 20 cycles the 115 kV line was reclosed and the fault was reapplied at Blackhawk for 5 cycles. Reopening the 115 kV line between the Hutchinson Substation and Blackhawk Substation permanently cleared the fault.

19. A single-phase fault on the Hutchinson to Blackhawk 115 kV line was evaluated. The fault was applied at Blackhawk for 5 cycles. Opening the 115 kV line between the Hutchinson Substation and Blackhawk Substation temporarily cleared the fault. After 20 cycles the 115 kV line was reclosed and the fault was reapplied at Blackhawk for 5 cycles. Reopening the 115 kV line between the Hutchinson Substation and Blackhawk Substation permanently cleared the fault.

20. A three-phase fault on the Carson to Pantex 115 kV line was evaluated. The fault was applied at Carson for 5 cycles. Opening the 115 kV line between the Carson Substation and Pantex Substation temporarily cleared the fault. After 20 cycles the 115 kV line was reclosed and the fault was reapplied at Carson for 5 cycles. Reopening the 115 kV line between the Carson Substation and Pantex Substation permanently cleared the fault.

21. A single-phase fault on the Carson to Pantex 115 kV line was evaluated. The fault was applied at Carson for 5 cycles. Opening the 115 kV line between the Carson Substation and Pantex Substation temporarily cleared the fault. After 20 cycles the 115 kV line was reclosed and the fault was reapplied at Carson for 5 cycles. Reopening the 115 kV line between the Carson Substation and Pantex Substation permanently cleared the fault.

VI. RESULTS

The dynamic simulations were performed for each of the 21 fault scenarios describe above using the summer model. The Customer generation remained stable and in synchronism with the system for all single-phase fault scenarios (2, 4, 6, 9, 11, 13, 15, 17, 19, 21) simulated. Exhibit 1 provides the angles swings for the Customer generation and other nearby units for Scenario 17. Exhibit 2 illustrates the speed deviations for the same scenario. It can be observed that the transient swings settled out and the Customer generation remained stable.

The Customer generation remained stable and in synchronism with the system for all three-phase fault scenarios (1, 3 5, 8, 10, 12, 14, 16, 18, 20) simulated except for Scenario 7. Exhibit 3 shows the angles swings for the Customer generation and other nearby units for Scenario 16. Exhibit 4 contains the speed deviations for the same scenario. It can be observed that the transient swings settled out and the Customer generation remained stable.

Exhibit 5 illustrates the angles swings for the Customer generation and other nearby units for Scenario 7. It can be seen from Exhibit 5 that units in the SPS control area lost synchronism with the outside world. Angles for the SPS generation units moved together during this excursion. Exhibit 6 shows the speed deviations for the same scenario. It can be observed that the speed deviations were damping out indicating that the units did not continue to accelerate after losing synchronism with the outside world. Scenario 7 involves disconnecting the 345kV tie line from the Texas Panhandle to Kansas. The results illustrate that Customer plant will be able to interconnect and may be able to serve load within the SPS area; however, if the Customer wishes to export power from the facility outside of SPS in combination with the previous queued projects also exporting power, new system reinforcements (tie lines from SPS to the rest of SPP) will need to be constructed. These reinforcements will be determined when the

Customer applies for transmission service using the procedures of the SPP Open Access Transmission Tariff (OATT).

There were at least two scenarios where the dynamic oscillations of the Customer generation were not clearly damping out at the end of simulation period. This occurred during the simulation of Scenarios 12 and 18 which involved the application of three-phase faults. Speed deviations for Scenario 12 are provided in Exhibit 7. A power system stabilizer was not modeled for this Customer generation since the parameters must be tuned for each individual installation. Power system stabilizers provide damping for long-term oscillations which were observed in these simulations.

The dynamic simulations were performed for each of the 21 fault scenarios describe above using the winter model. The Customer generation remained stable and in synchronism with the system for all single-phase fault scenarios (2, 6, 9, 11, 13, 15, 17, 19, 21) simulated except Scenario 4. Exhibit 8 provides the angles swings for the Customer generation and other nearby units for Scenario 19. Exhibit 9 illustrates the speed deviations for the same scenario. It can be observed that the transient swings settled out and the Customer generation remained stable.

Exhibit 10 illustrates the angles swings for the Customer generation and other nearby units for Scenario 4. It can be observed from Exhibit 10 that units in the SPS control area lost synchronism with the outside world. Angles for the SPS generation units moved together during this excursion. Exhibit 11 shows the speed deviations for the same scenario. Even though speed deviations did not display an exponential damping, the final value at the end of simulation period was near zero.

The Customer generation remained stable and in synchronism with the system for all three-phase fault scenarios (1, 5, 8, 10, 12, 14, 16, 18, 20) simulated except for Scenarios 3 and 7. Exhibit 12 presents the angles swings for the

Customer generation and other nearby units for Scenario 18. Speed deviations can be seen for the same scenario in Exhibit 13. In these exhibits, the transient swings settled out and the Customer generation remained stable.

Exhibit 14 contains the angles swings for the Customer generation and other nearby units for Scenario 3. It can be seen from Exhibit 14 that units in the SPS control area lost synchronism with the outside world. Angles for the SPS generation units moved together during this excursion. Exhibit 15 provides the speed deviations for the same scenario. Even though speed deviations did not display an exponential damping, the final value at the end of simulation period was near zero. It should be noted that all generation was off-line at Nichols in the winter model.

Scenario 7 involves the disconnection of the tie line between the Texas Panhandle and Kansas. Scenarios 3 and 4 involve the disconnection of the 230kV tie line between SPS and AEP/PSO. The discussion presented in the summer model section about the need for new system reinforcements applies to the winter model as well.

There were several scenarios where the dynamic oscillations of the Customer generation were not clearly damping out at the end of simulation period. This occurred for Scenarios 1, 2, 10, 12, 14 and 18. All these scenarios except scenario 2 involved the application of a three-phase fault. Speed deviations for Scenario 14 are illustrated in Exhibit 16. A power system stabilizer should be given serious consideration for this Customer generation installation. The longer term oscillations were more severe in the winter case as compare the summer model. This can be attributed to considerable lower loads represented in the winter model.

VII. SENSITIVITIES

Scenario 7 was simulated with Customer generation off-line using the summer model. When the fault was applied, the generating units in the SPS appeared to lose synchronism with the outside world. The angle swings for this scenario are displayed in Exhibit 17. The unstable the condition appears to exist prior to the addition of the Customer generation under the scenario that previously queued generation projects are exporting power outside of SPS.

Initially Scenario 7 was simulated as three-phase fault. A sensitivity was performed with this fault simulated as a single-phase fault. The results are presented in Exhibit 18. Once again generating units in the SPS appeared to lose synchronism with the outside world.

In the original Scenario 7, a reclosing operation occurred after 30 cycles. The scenario was simulated without the reclosing operation. Exhibit 19 contains the angle swings for this modified scenario. As in the previous version of Scenario 7, generating units in the SPS appeared to lose synchronism with the outside world.

VIII. CONCLUSIONS

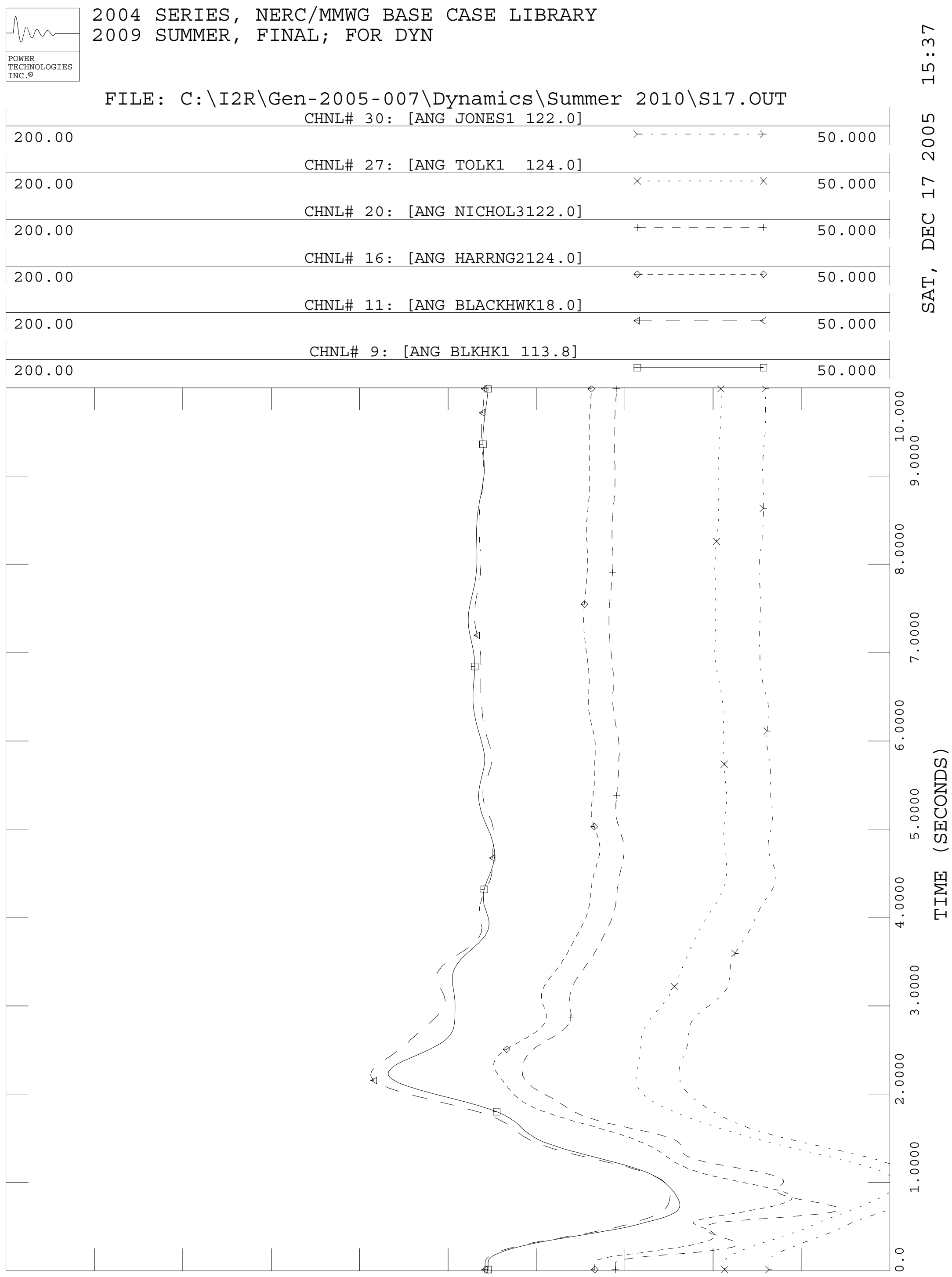
The following conclusions are reached from the load flow and dynamic analysis performed in this study:

- The system remained stable for twenty of the twenty-one scenarios simulated using the summer model.
- The system remained stable for eighteen of the twenty-one scenarios simulated using the winter model.
- The generating units in the SPS control area lost synchronism with the outside world during the simulation of Scenario 7 using the summer and winter model and Scenarios 3 and 4 using the winter model. These Scenarios involve disconnecting the limited tie lines from SPS to the rest of SPP and illustrate the lack of export capability in the SPS system.
- The above condition was found to occur for Scenario 7 using the summer model in the absence of the Customer generation. It also occurred for a single-phase fault or if there were no reclosing operations.
- Oscillations were not damping out in all scenarios. The long-term oscillations were more pronounced in the winter model. Implementation of a power system stabilizer for the Customer generations is recommended to provide additional damping of the long-term oscillations.

If any previously queued projects that were included in this study are not constructed, then this System Impact Study may have to be revised to determine the impacts of this Interconnection Customer's project on SPS transmission facilities. Since this is also a preliminary System Impact Study, not all previously queued projects were assumed to be in service in this System Impact Study. If any of those projects are constructed, then this System Impact Study may have to be revised to determine the impacts of this Interconnection Customer's project on SPS transmission facilities. In accordance with FERC and SPP procedures, the study cost for restudy shall be borne by the Interconnection Customer.

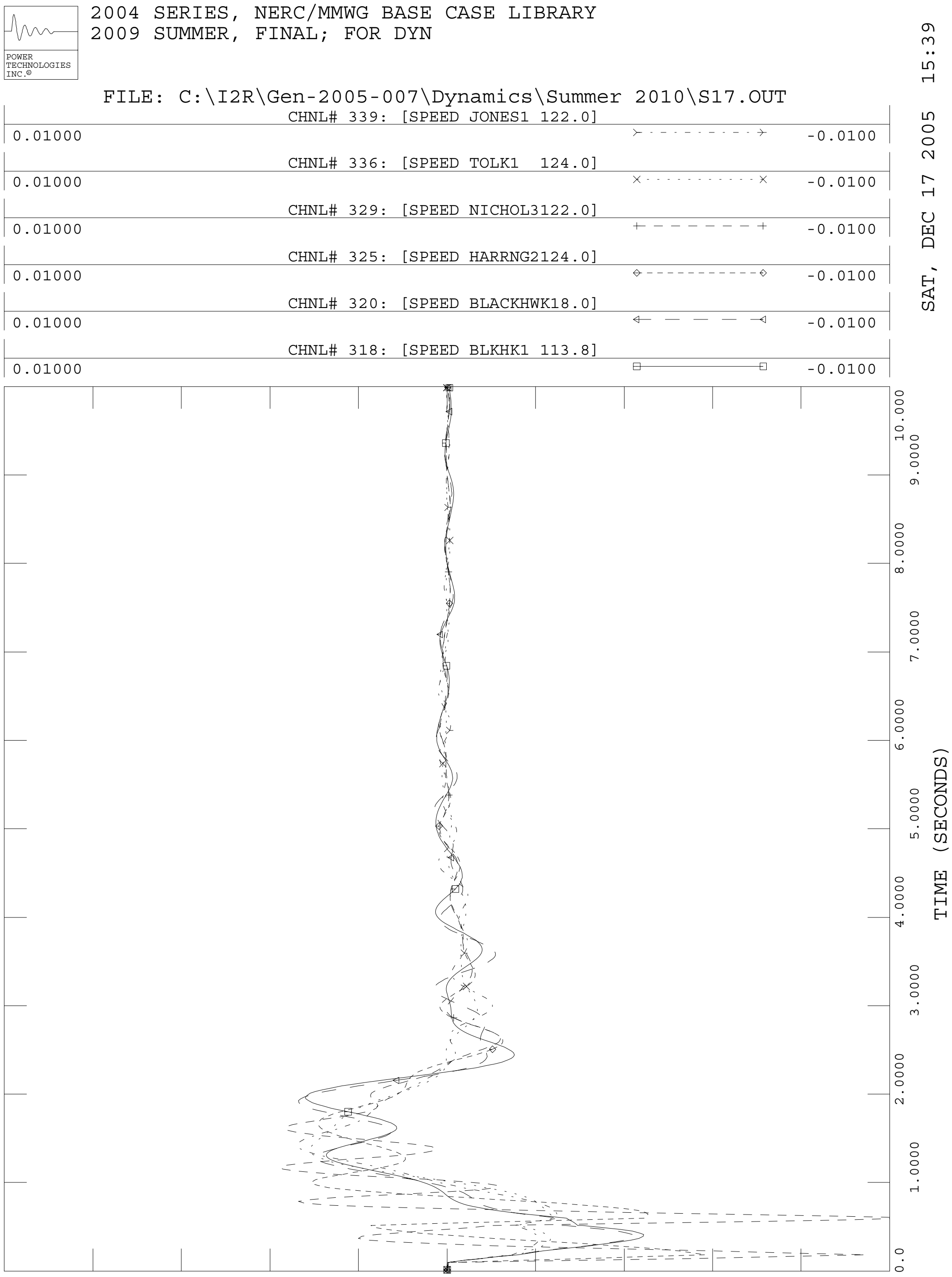
Nothing in this study should be construed as a guarantee of transmission service. If the customer wishes to sell power from the facility, a separate request for transmission service shall be requested on Southwest Power Pool's OASIS by the Customer.

EXHIBIT 1



POWER TECHNOLOGIES INC.©
2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2009 SUMMER, FINAL; FOR DYN
SAT, DEC 17 2005 15:37
FILE: C:\I2R\Gen-2005-007\Dynamics\Summer 2010\S17.OUT
CHNL# 30: [ANG JONES1 122.0]
200.00
50.000
CHNL# 27: [ANG TOLK1 124.0]
200.00
50.000
CHNL# 20: [ANG NICHOL3122.0]
200.00
50.000
CHNL# 16: [ANG HARRNG2124.0]
200.00
50.000
CHNL# 11: [ANG BLACKHWK18.0]
200.00
50.000
CHNL# 9: [ANG BLKHK1 113.8]
200.00
50.000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 2



2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2009 SUMMER, FINAL; FOR DYN
POWER TECHNOLOGIES INC.©
FILE: C:\I2R\Gen-2005-007\Dynamics\Summer 2010\S17.OUT
CHNL# 339: [SPEED JONES1 122.0]
0.01000 -0.0100
CHNL# 336: [SPEED TOLK1 124.0]
0.01000 -0.0100
CHNL# 329: [SPEED NICHOL3122.0]
0.01000 -0.0100
CHNL# 325: [SPEED HARRNG2124.0]
0.01000 -0.0100
CHNL# 320: [SPEED BLACKHWK18.0]
0.01000 -0.0100
CHNL# 318: [SPEED BLKHK1 113.8]
0.01000 -0.0100
SAT, DEC 17 2005 15:39
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 3

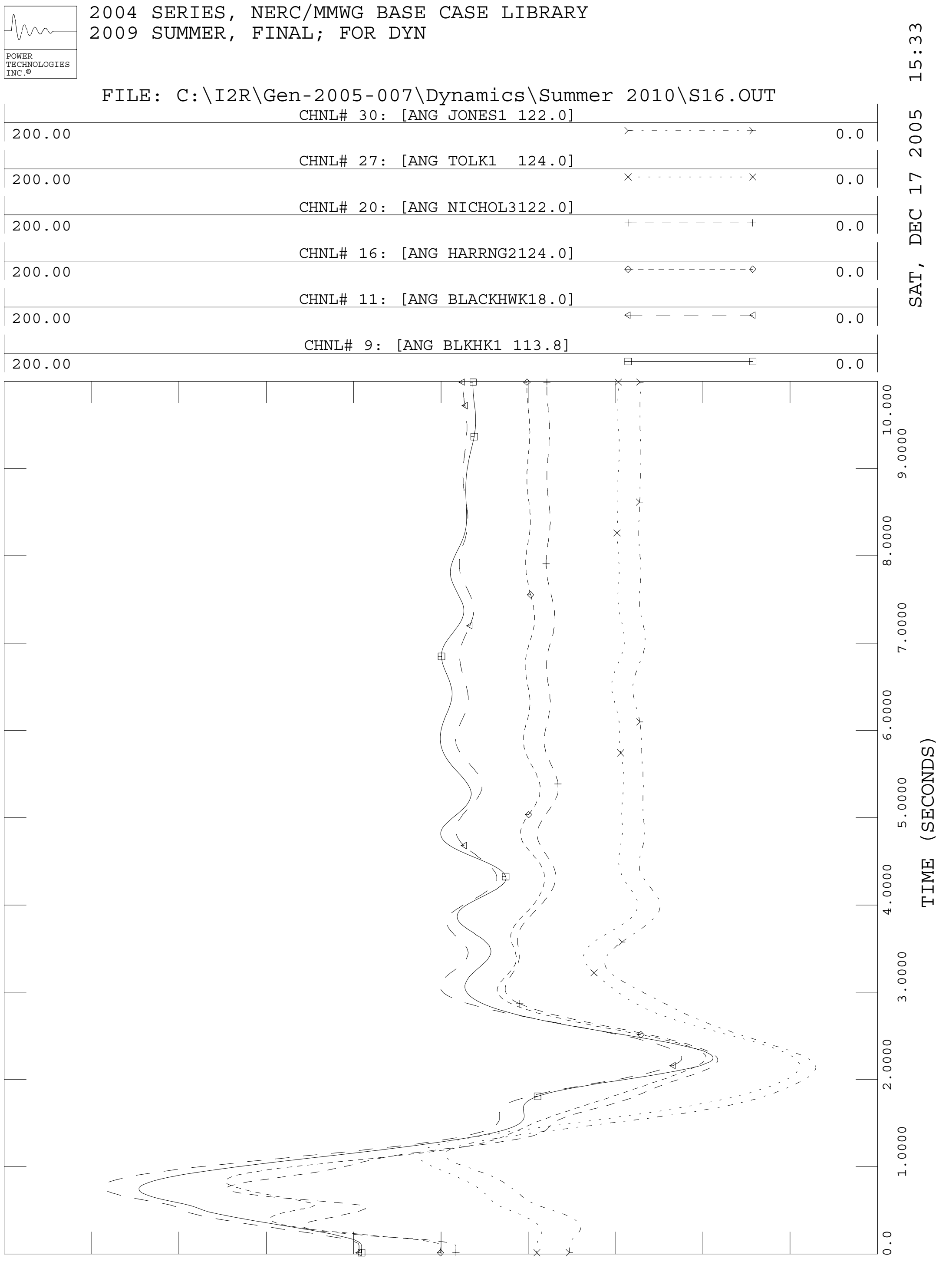

POWER TECHNOLOGIES INC.©
2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2009 SUMMER, FINAL; FOR DYN
SAT, DEC 17 2005 15:33
FILE: C:\I2R\Gen-2005-007\Dynamics\Summer 2010\S16.OUT
CHNL# 30: [ANG JONES1 122.0]
200.00
0.0
CHNL# 27: [ANG TOLK1 124.0]
200.00
0.0
CHNL# 20: [ANG NICHOL3122.0]
200.00
0.0
CHNL# 16: [ANG HARRNG2124.0]
200.00
0.0
CHNL# 11: [ANG BLACKHWK18.0]
200.00
0.0
CHNL# 9: [ANG BLKHK1 113.8]
200.00
0.0
10.000
9.0000
8.0000
7.0000
6.0000
5.0000
4.0000
3.0000
2.0000
1.0000
0.0
TIME (SECONDS)

EXHIBIT 4

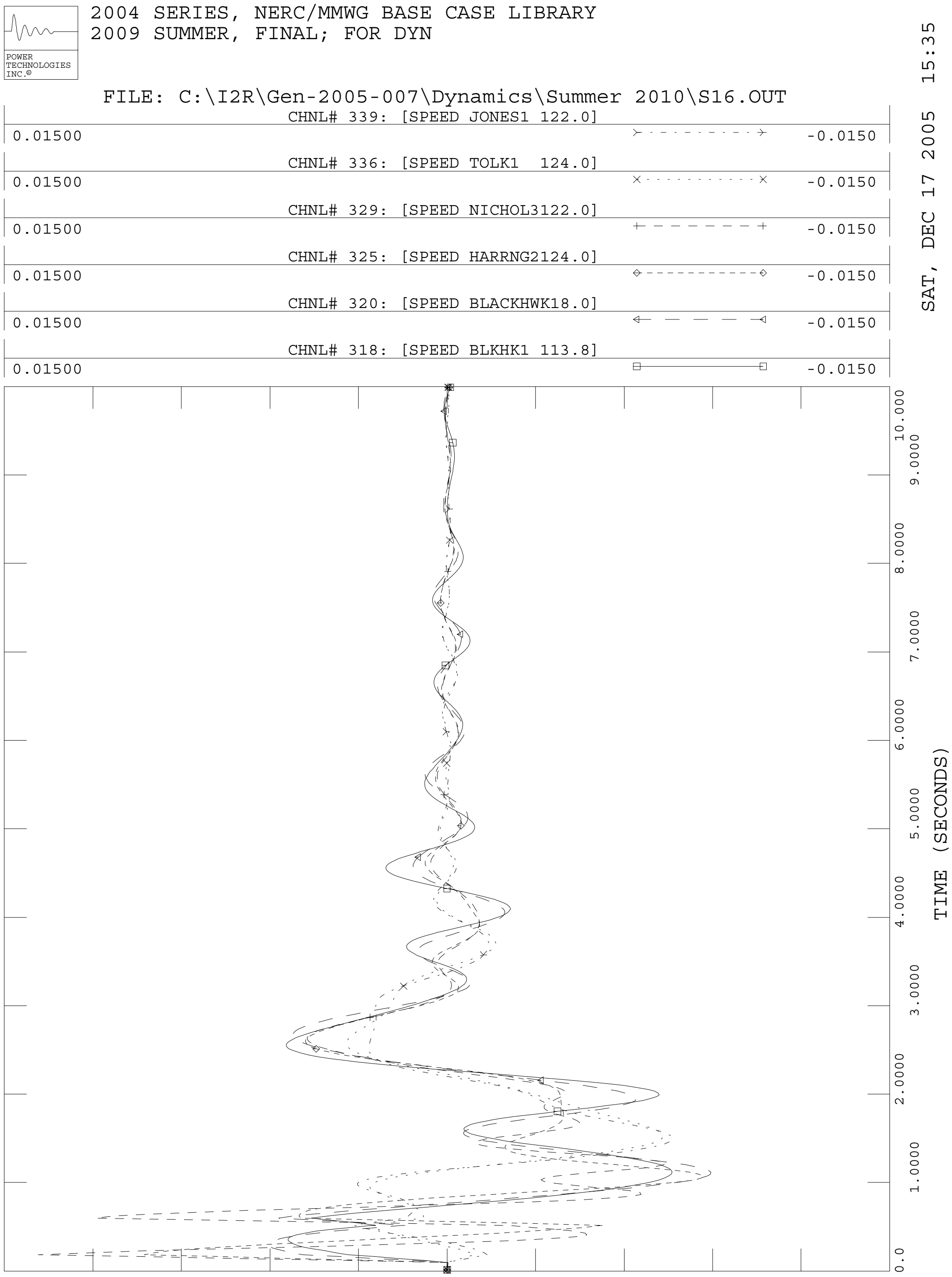
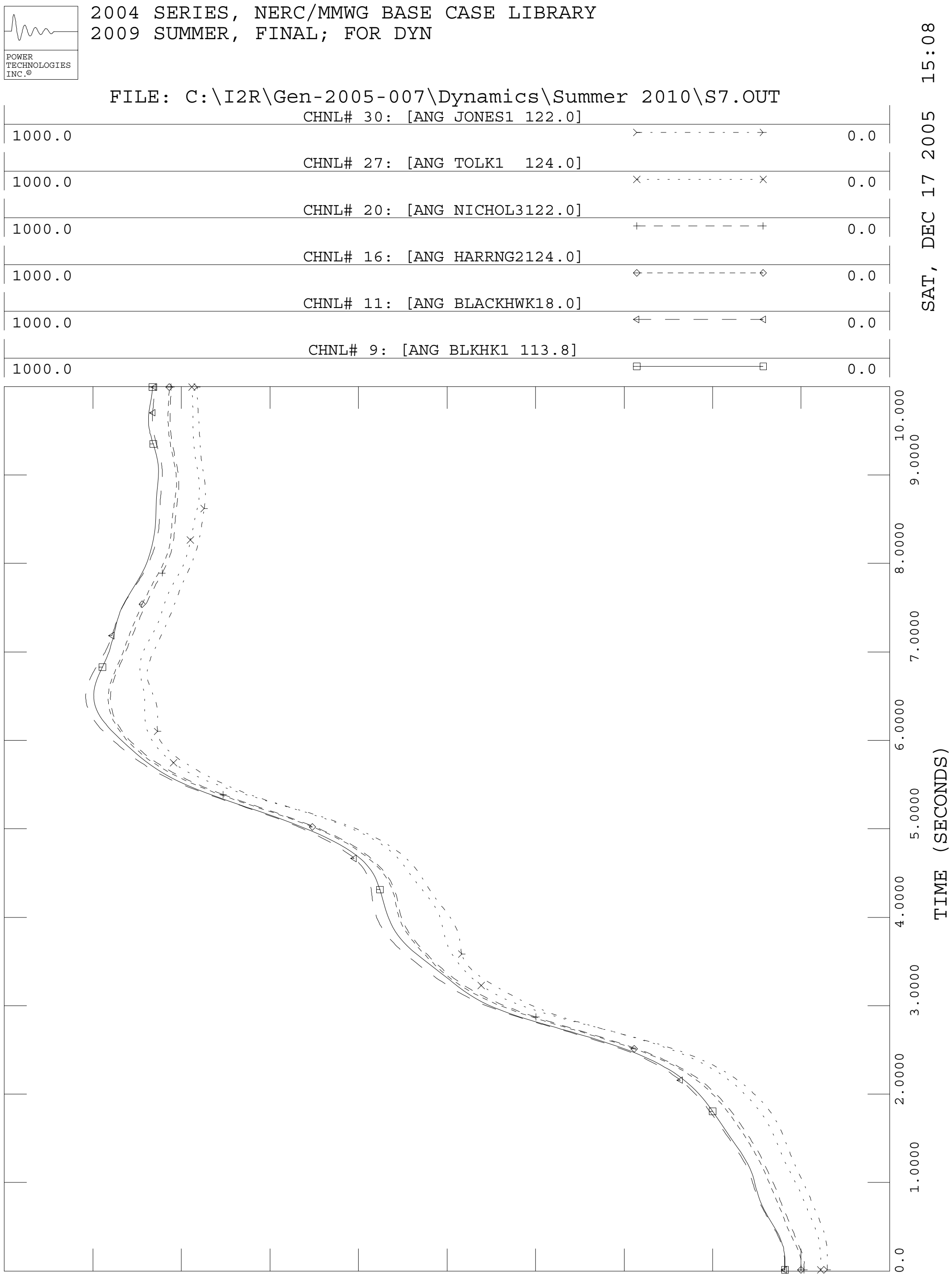
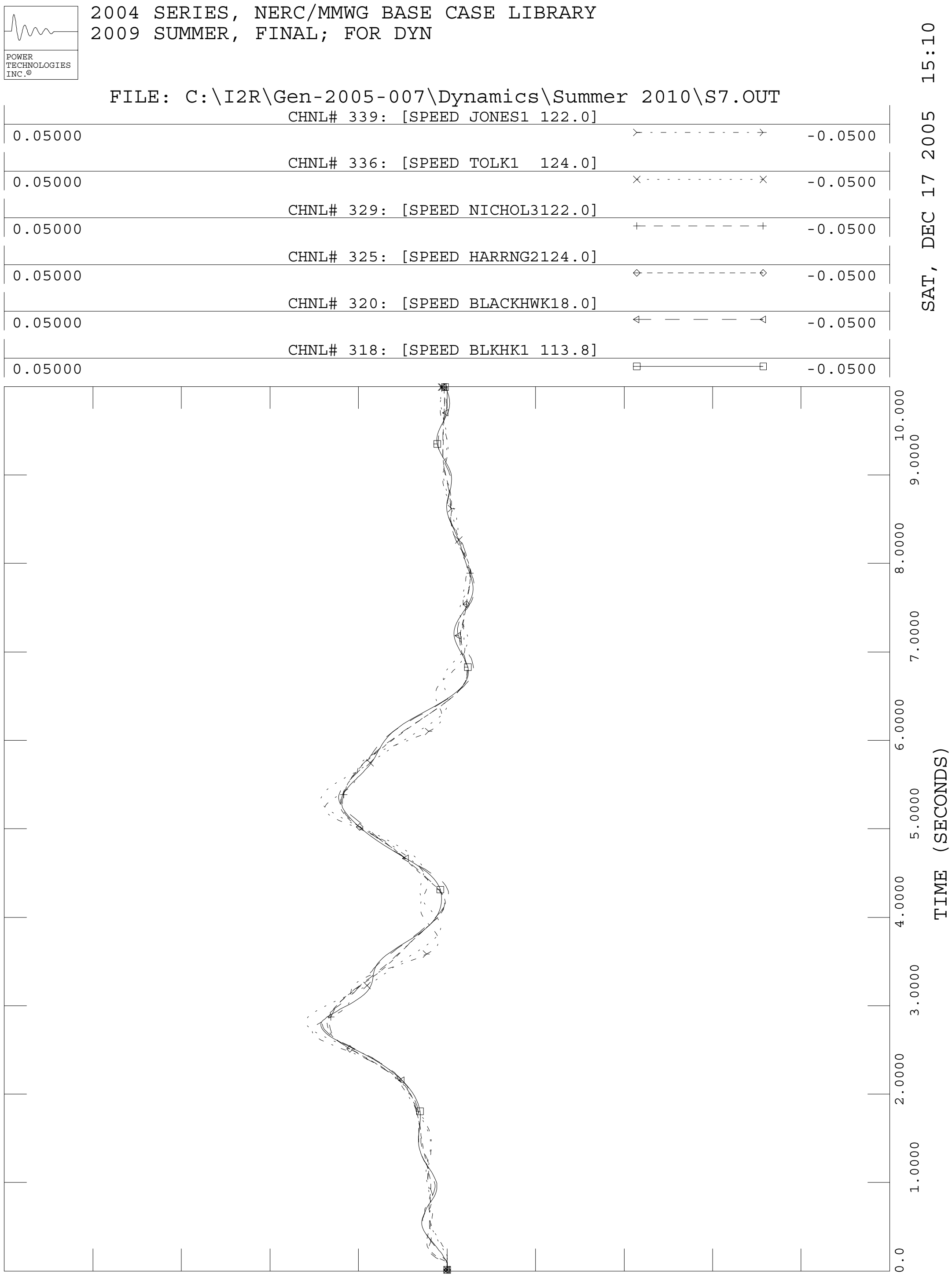

POWER TECHNOLOGIES INC.©
2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2009 SUMMER, FINAL; FOR DYN
SAT, DEC 17 2005 15:35
FILE: C:\I2R\Gen-2005-007\Dynamics\Summer 2010\S16.OUT
CHNL# 339: [SPEED JONES1 122.0]
0.01500 -0.0150
CHNL# 336: [SPEED TOLK1 124.0]
0.01500 -0.0150
CHNL# 329: [SPEED NICHOL3122.0]
0.01500 -0.0150
CHNL# 325: [SPEED HARRNG2124.0]
0.01500 -0.0150
CHNL# 320: [SPEED BLACKHWK18.0]
0.01500 -0.0150
CHNL# 318: [SPEED BLKHK1 113.8]
0.01500 -0.0150
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 5



2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2009 SUMMER, FINAL; FOR DYN
POWER TECHNOLOGIES INC.©
FILE: C:\I2R\Gen-2005-007\Dynamics\Summer 2010\S7.OUT
CHNL# 30: [ANG JONES1 122.0]
1000.0
0.0
CHNL# 27: [ANG TOLK1 124.0]
1000.0
0.0
CHNL# 20: [ANG NICHOL3122.0]
1000.0
0.0
CHNL# 16: [ANG HARRNG2124.0]
1000.0
0.0
CHNL# 11: [ANG BLACKHWK18.0]
1000.0
0.0
CHNL# 9: [ANG BLKHK1 113.8]
1000.0
0.0
SAT, DEC 17 2005 15:08
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 6



2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2009 SUMMER, FINAL; FOR DYN
POWER TECHNOLOGIES INC.©
FILE: C:\I2R\Gen-2005-007\Dynamics\Summer 2010\S7.OUT
CHNL# 339: [SPEED JONES1 122.0]
0.05000
-0.0500
CHNL# 336: [SPEED TOLK1 124.0]
0.05000
-0.0500
CHNL# 329: [SPEED NICHOL3122.0]
0.05000
-0.0500
CHNL# 325: [SPEED HARRNG2124.0]
0.05000
-0.0500
CHNL# 320: [SPEED BLACKHWK18.0]
0.05000
-0.0500
CHNL# 318: [SPEED BLKHK1 113.8]
0.05000
-0.0500
SAT, DEC 17 2005 15:10
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 7

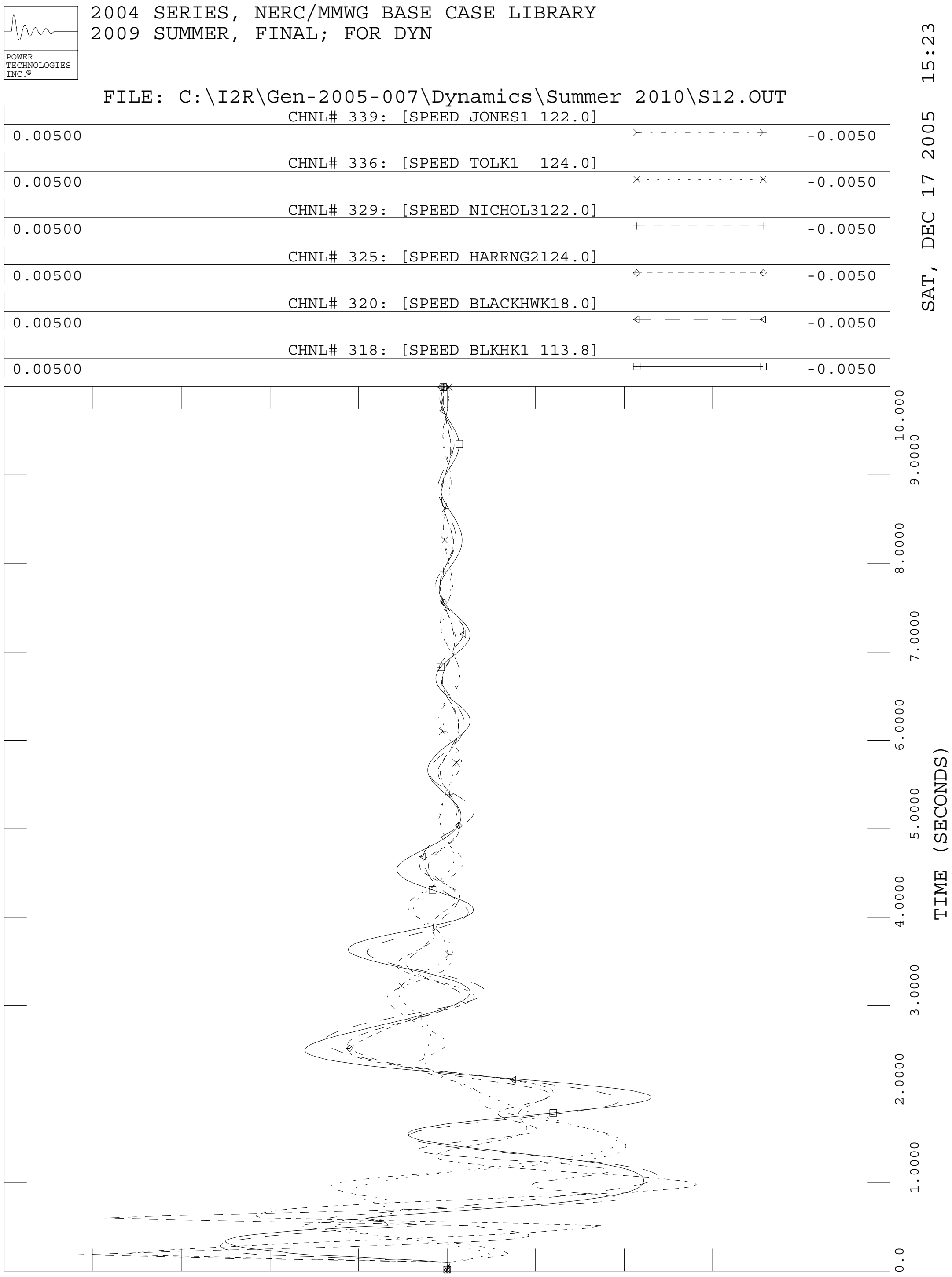

POWER TECHNOLOGIES INC.©
2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2009 SUMMER, FINAL; FOR DYN
SAT, DEC 17 2005 15:23
FILE: C:\I2R\Gen-2005-007\Dynamics\Summer 2010\S12.OUT
CHNL# 339: [SPEED JONES1 122.0]
0.00500 -0.0050
CHNL# 336: [SPEED TOLK1 124.0]
0.00500 -0.0050
CHNL# 329: [SPEED NICHOL3122.0]
0.00500 -0.0050
CHNL# 325: [SPEED HARRNG2124.0]
0.00500 -0.0050
CHNL# 320: [SPEED BLACKHWK18.0]
0.00500 -0.0050
CHNL# 318: [SPEED BLKHK1 113.8]
0.00500 -0.0050
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 8

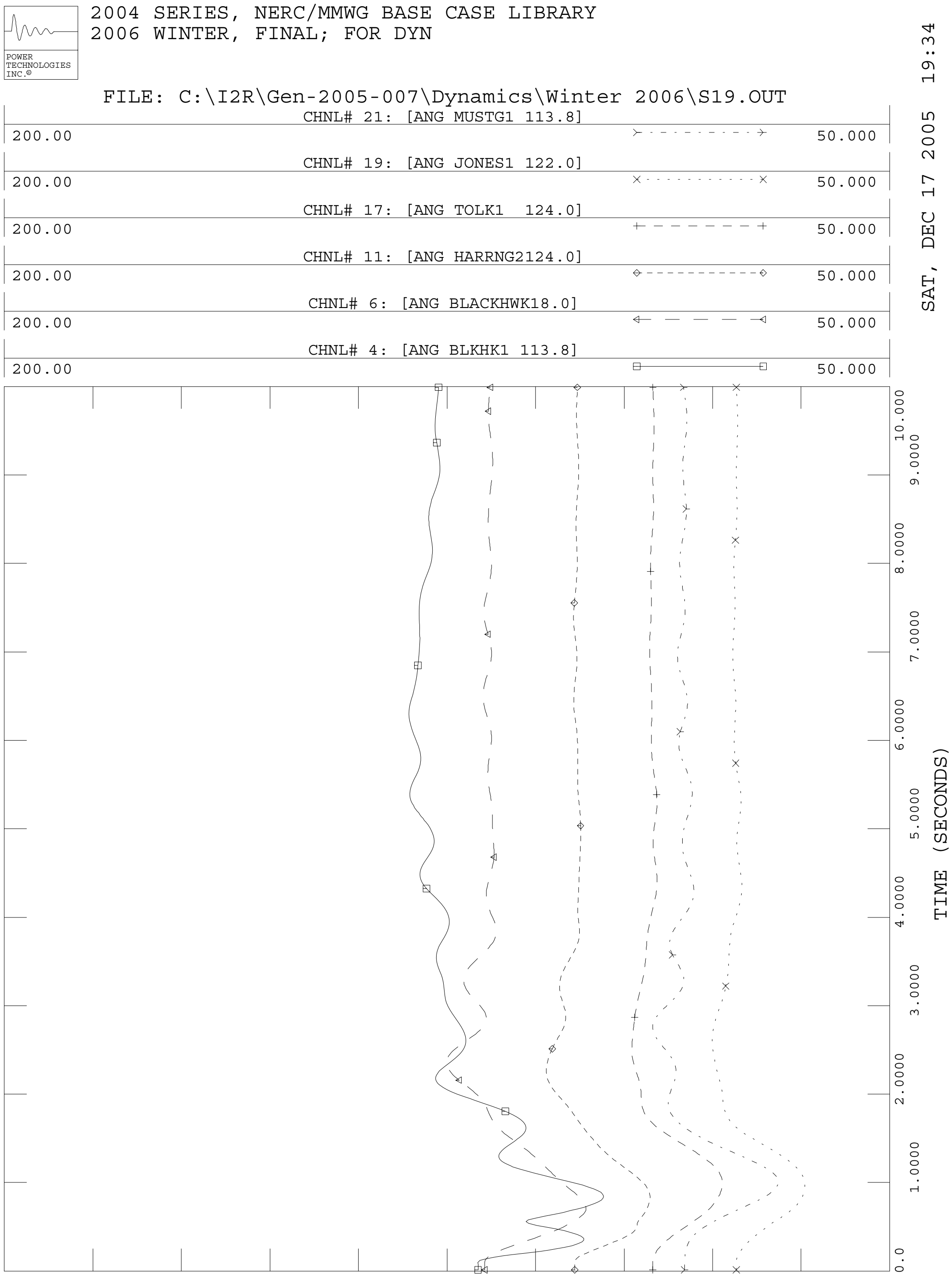

2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2006 WINTER, FINAL; FOR DYN
POWER TECHNOLOGIES INC.©
FILE: C:\I2R\Gen-2005-007\Dynamics\Winter 2006\S19.OUT
CHNL# 21: [ANG MUSTG1 113.8]
200.00
50.000
CHNL# 19: [ANG JONES1 122.0]
200.00
50.000
CHNL# 17: [ANG TOLK1 124.0]
200.00
50.000
CHNL# 11: [ANG HARRNG2124.0]
200.00
50.000
CHNL# 6: [ANG BLACKHWK18.0]
200.00
50.000
CHNL# 4: [ANG BLKHK1 113.8]
200.00
50.000
SAT, DEC 17 2005 19:34
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 9

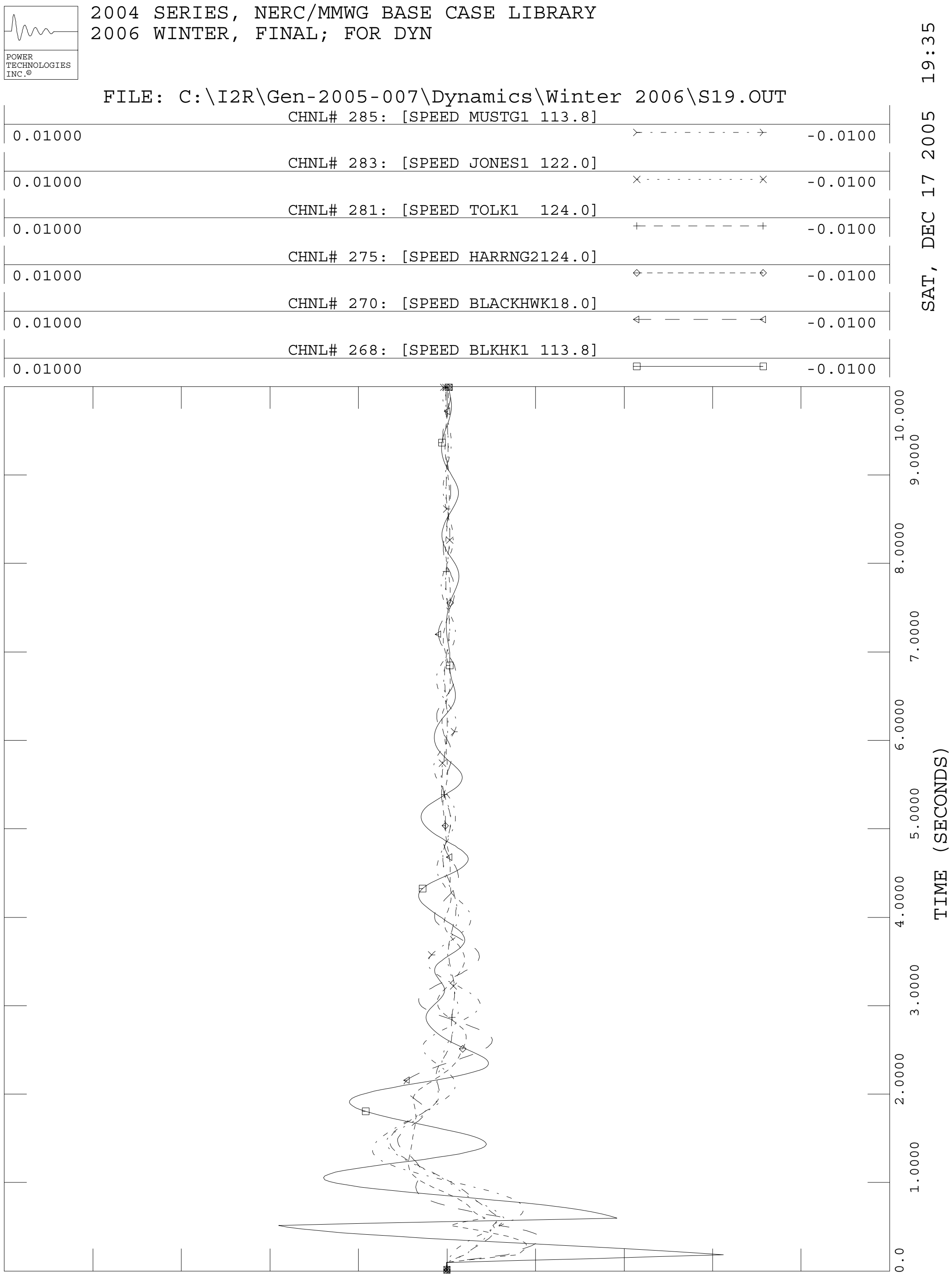

2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2006 WINTER, FINAL; FOR DYN
POWER TECHNOLOGIES INC.©
FILE: C:\I2R\Gen-2005-007\Dynamics\Winter 2006\S19.OUT
CHNL# 285: [SPEED MUSTG1 113.8]
0.01000
-0.0100
CHNL# 283: [SPEED JONES1 122.0]
0.01000
-0.0100
CHNL# 281: [SPEED TOLK1 124.0]
0.01000
-0.0100
CHNL# 275: [SPEED HARRNG2124.0]
0.01000
-0.0100
CHNL# 270: [SPEED BLACKHWK18.0]
0.01000
-0.0100
CHNL# 268: [SPEED BLKHK1 113.8]
0.01000
-0.0100
SAT, DEC 17 2005 19:35
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 10

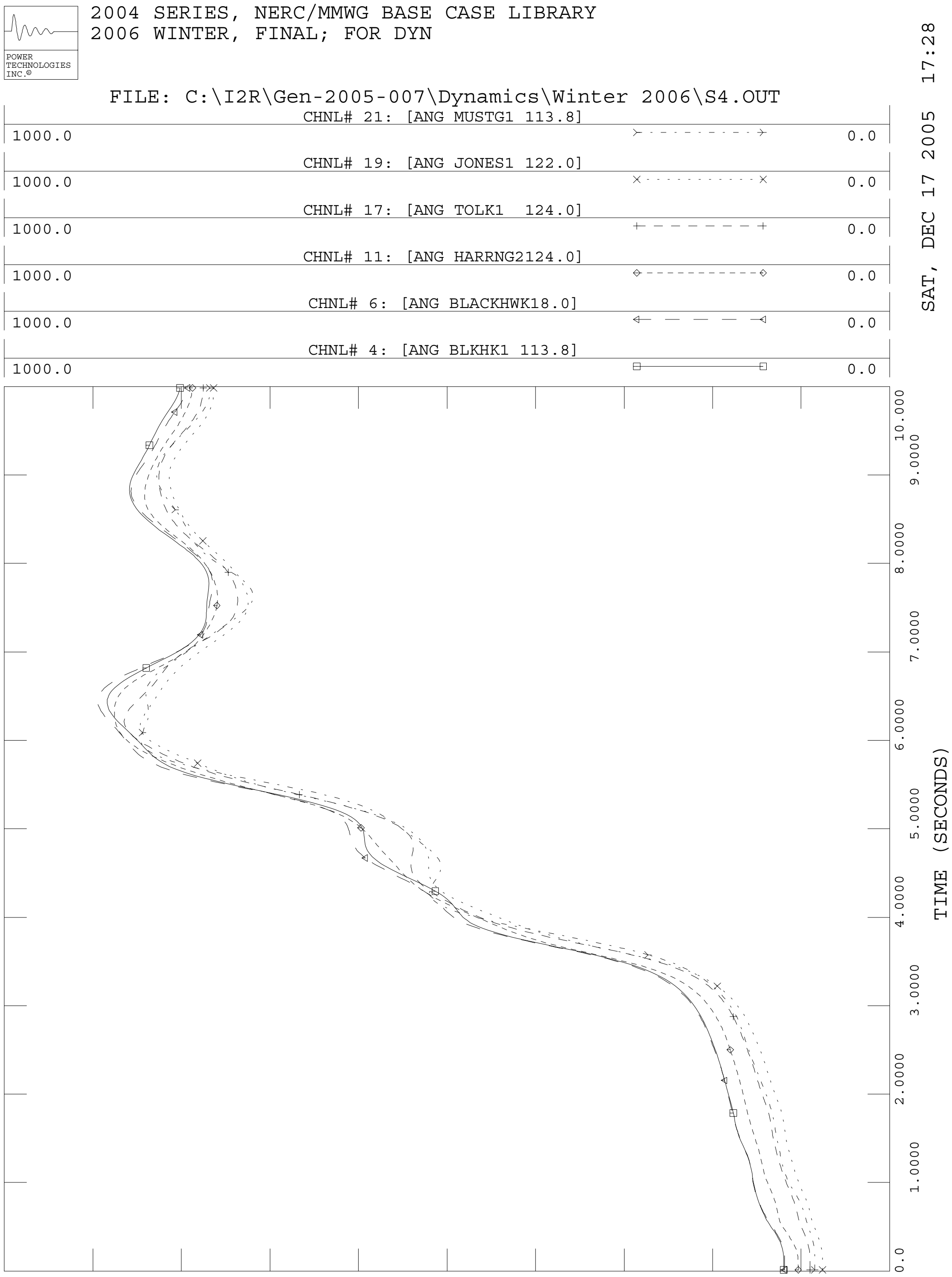
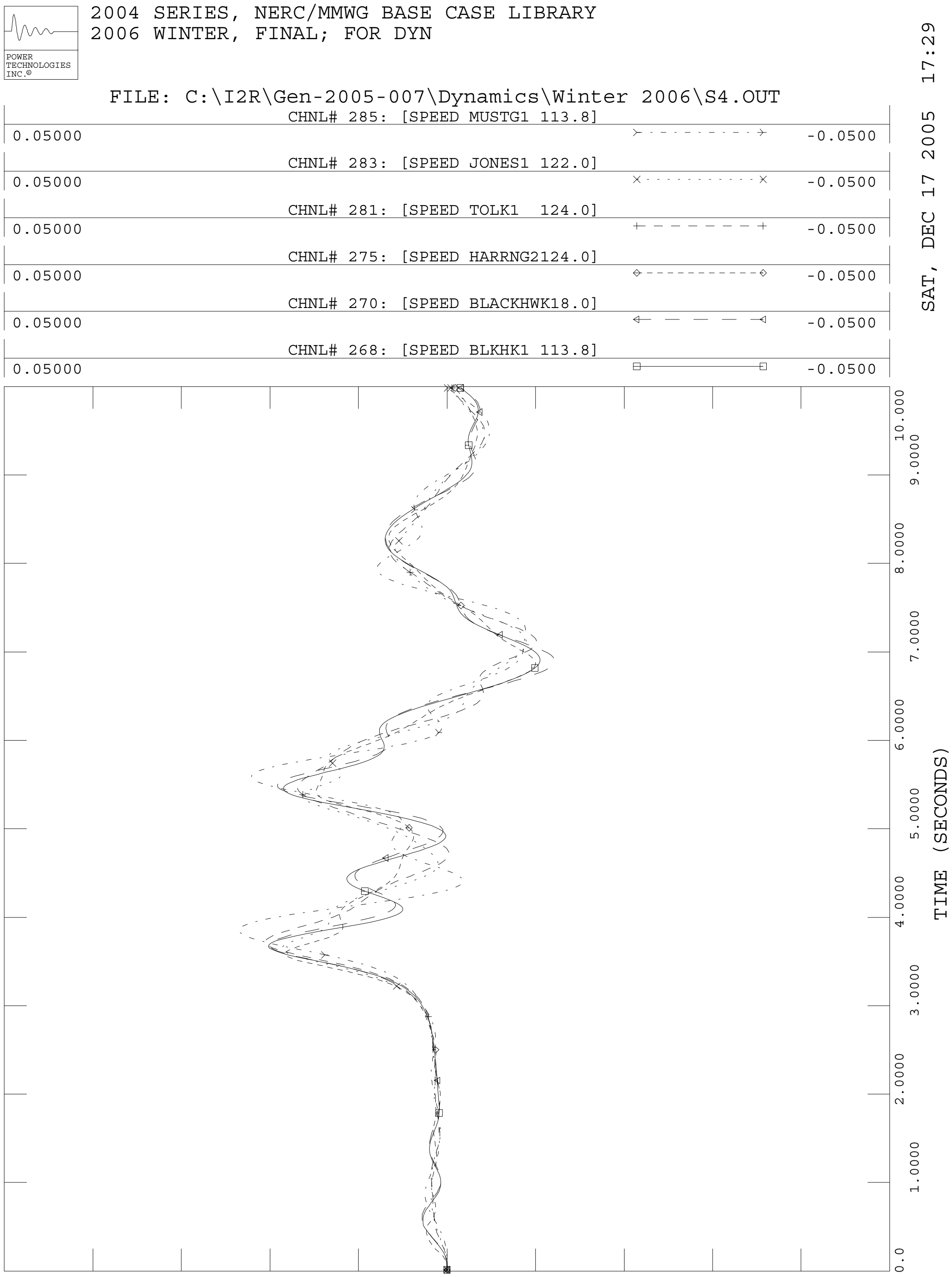
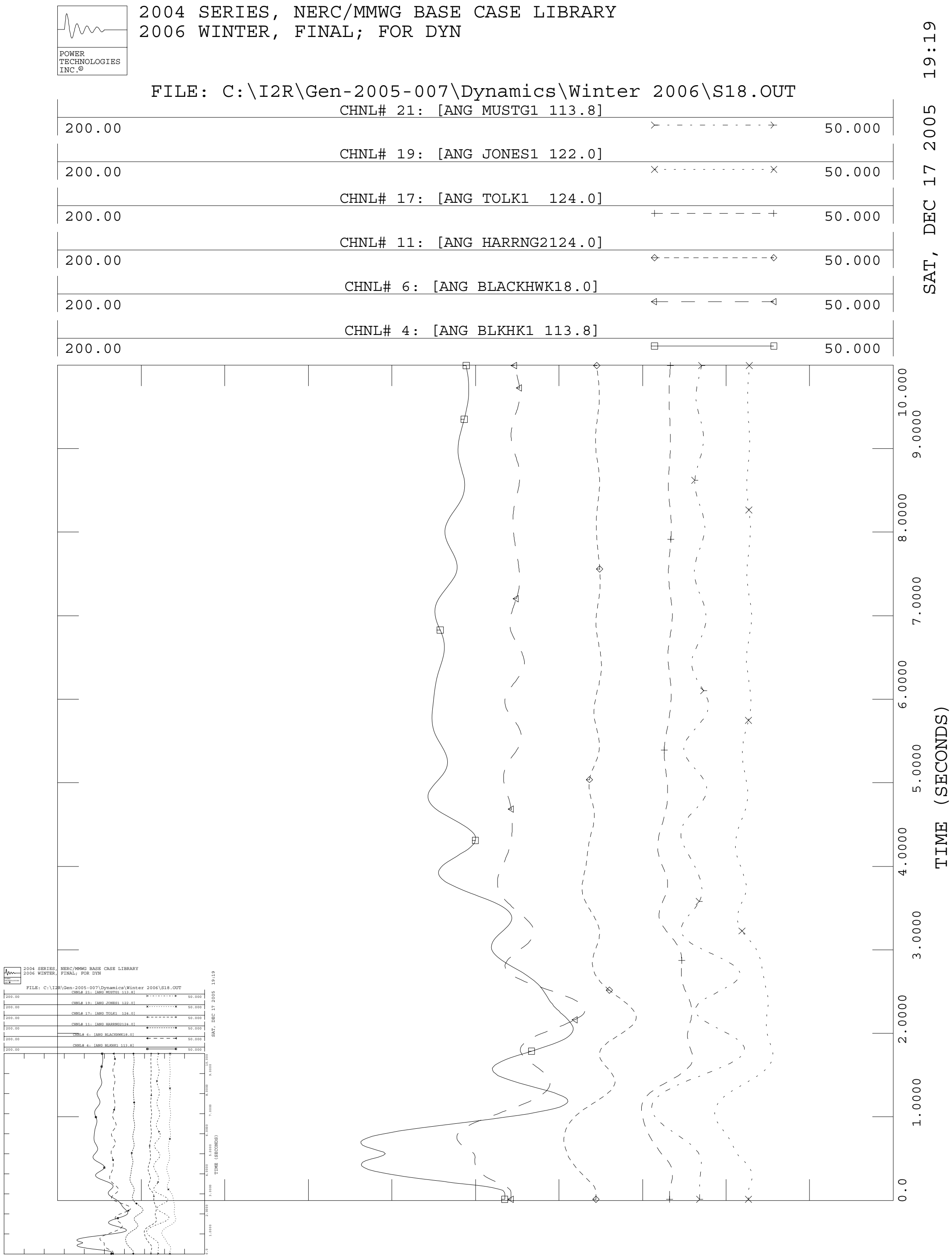

2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2006 WINTER, FINAL; FOR DYN
POWER TECHNOLOGIES INC.©
FILE: C:\I2R\Gen-2005-007\Dynamics\Winter 2006\S4.OUT
CHNL# 21: [ANG MUSTG1 113.8]
1000.0
0.0
CHNL# 19: [ANG JONES1 122.0]
1000.0
0.0
CHNL# 17: [ANG TOLK1 124.0]
1000.0
0.0
CHNL# 11: [ANG HARRNG2124.0]
1000.0
0.0
CHNL# 6: [ANG BLACKHWK18.0]
1000.0
0.0
CHNL# 4: [ANG BLKHK1 113.8]
1000.0
0.0
SAT, DEC 17 2005 17:28
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 11



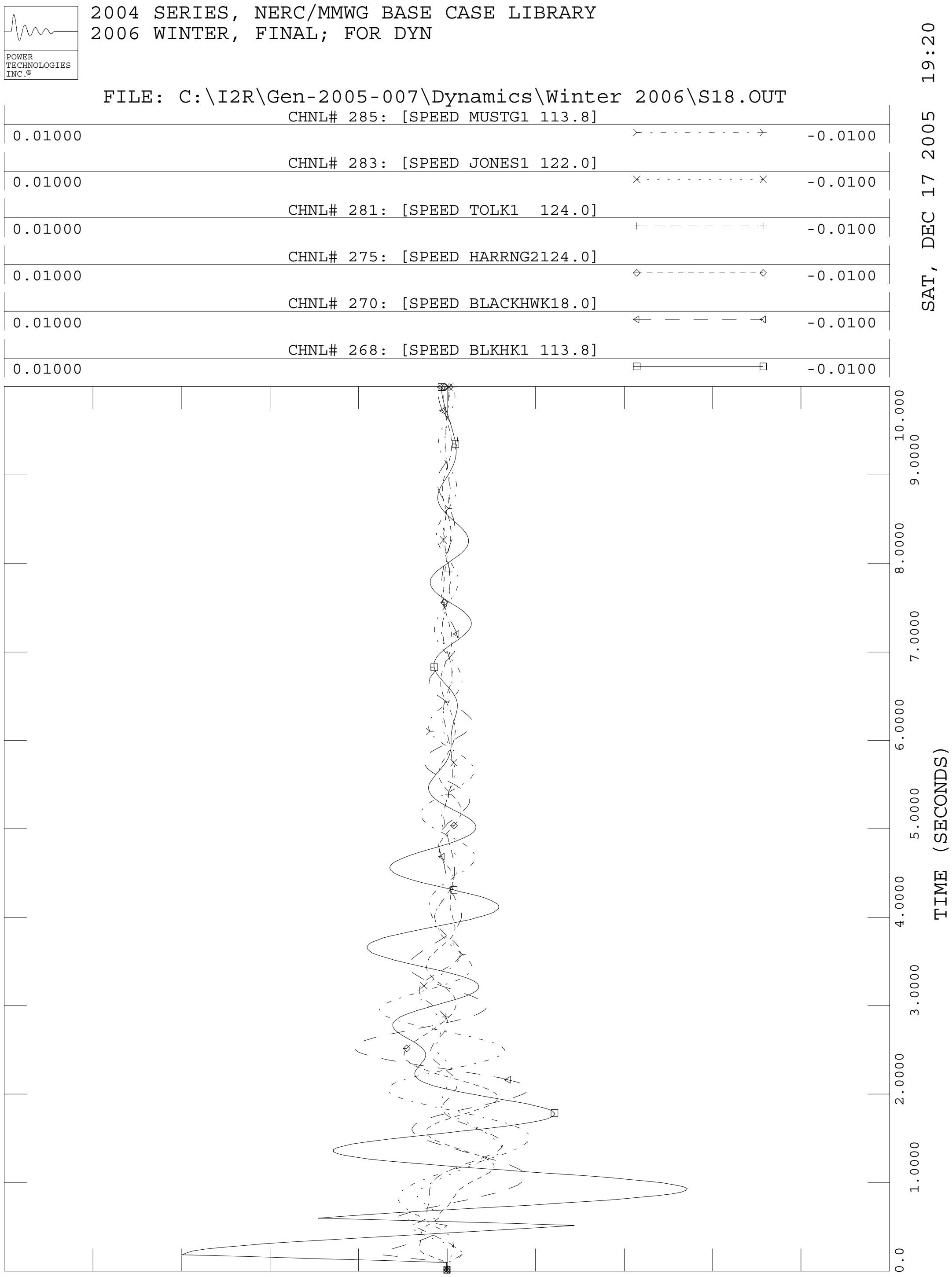
2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2006 WINTER, FINAL; FOR DYN
POWER TECHNOLOGIES INC.©
FILE: C:\I2R\Gen-2005-007\Dynamics\Winter 2006\S4.OUT
CHNL# 285: [SPEED MUSTG1 113.8]
0.05000
-0.0500
CHNL# 283: [SPEED JONES1 122.0]
0.05000
-0.0500
CHNL# 281: [SPEED TOLK1 124.0]
0.05000
-0.0500
CHNL# 275: [SPEED HARRNG2124.0]
0.05000
-0.0500
CHNL# 270: [SPEED BLACKHWK18.0]
0.05000
-0.0500
CHNL# 268: [SPEED BLKHK1 113.8]
0.05000
-0.0500
SAT, DEC 17 2005 17:29
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 12



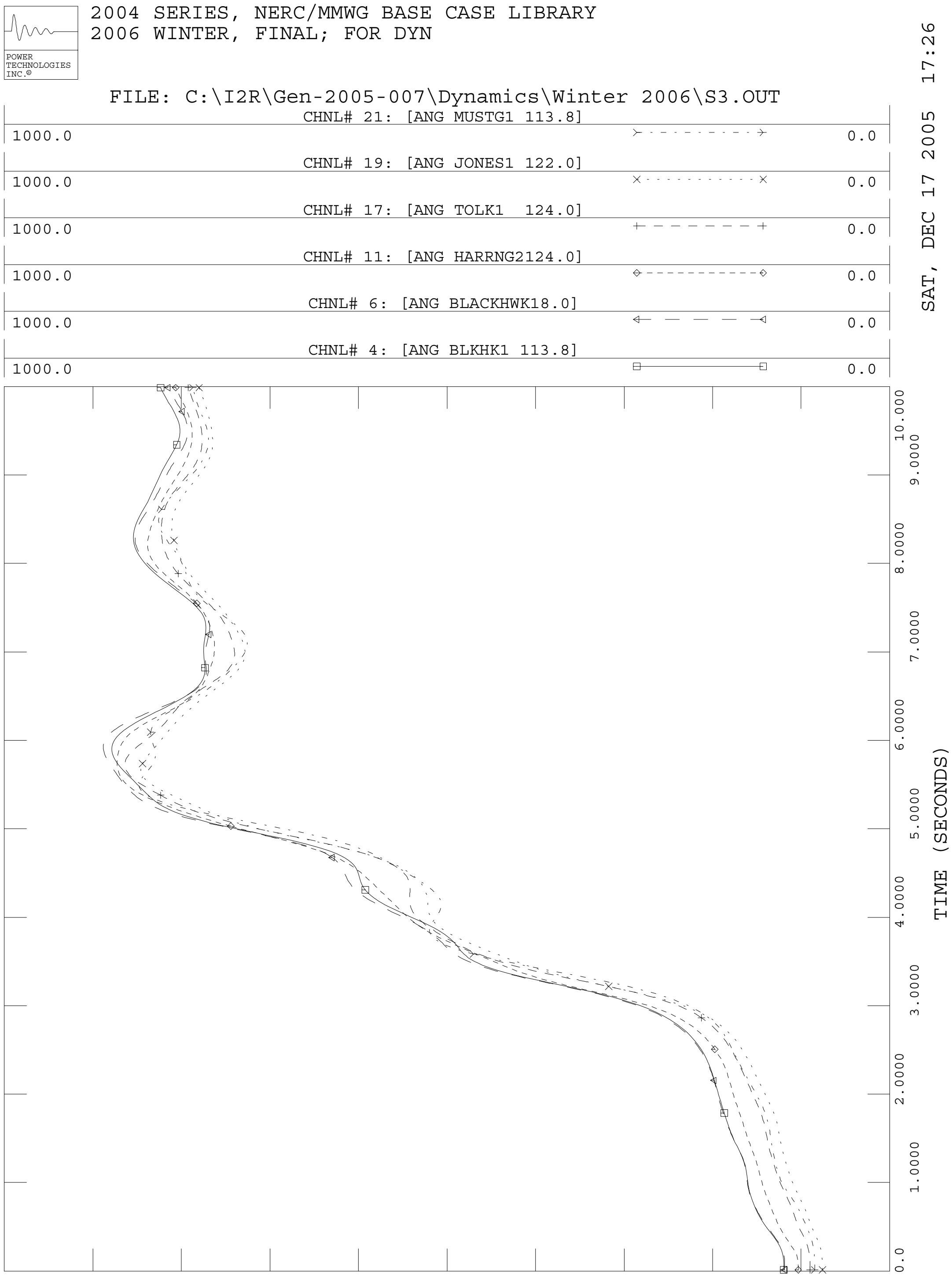
2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2006 WINTER, FINAL; FOR DYN
POWER TECHNOLOGIES INC.©
FILE: C:\I2R\Gen-2005-007\Dynamics\Winter 2006\S18.OUT
CHNL# 21: [ANG MUSTG1 113.8]
200.00
50.000
CHNL# 19: [ANG JONES1 122.0]
200.00
50.000
CHNL# 17: [ANG TOLK1 124.0]
200.00
50.000
CHNL# 11: [ANG HARRNG2124.0]
200.00
50.000
CHNL# 6: [ANG BLACKHWK18.0]
200.00
50.000
CHNL# 4: [ANG BLKHK1 113.8]
200.00
50.000
SAT, DEC 17 2005 19:19
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 13



POWER TECHNOLOGIES INC.©
2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2006 WINTER, FINAL; FOR DYN
FILE: C:\I2R\Gen-2005-007\Dynamics\Winter 2006\S18.OUT
CHNL# 285: [SPEED MUSTG1 113.8]
0.01000 -0.0100
CHNL# 283: [SPEED JONES1 122.0]
0.01000 -0.0100
CHNL# 281: [SPEED TOLK1 124.0]
0.01000 -0.0100
CHNL# 275: [SPEED HARRNG2124.0]
0.01000 -0.0100
CHNL# 270: [SPEED BLACKHWK18.0]
0.01000 -0.0100
CHNL# 268: [SPEED BLKHK1 113.8]
0.01000 -0.0100
SAT, DEC 17 2005 19:20
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 14



POWER TECHNOLOGIES INC.©
2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2006 WINTER, FINAL; FOR DYN
SAT, DEC 17 2005 17:26
FILE: C:\I2R\Gen-2005-007\Dynamics\Winter 2006\S3.OUT
CHNL# 21: [ANG MUSTG1 113.8]
1000.0
0.0
CHNL# 19: [ANG JONES1 122.0]
1000.0
0.0
CHNL# 17: [ANG TOLK1 124.0]
1000.0
0.0
CHNL# 11: [ANG HARRNG2124.0]
1000.0
0.0
CHNL# 6: [ANG BLACKHWK18.0]
1000.0
0.0
CHNL# 4: [ANG BLKHK1 113.8]
1000.0
0.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 15

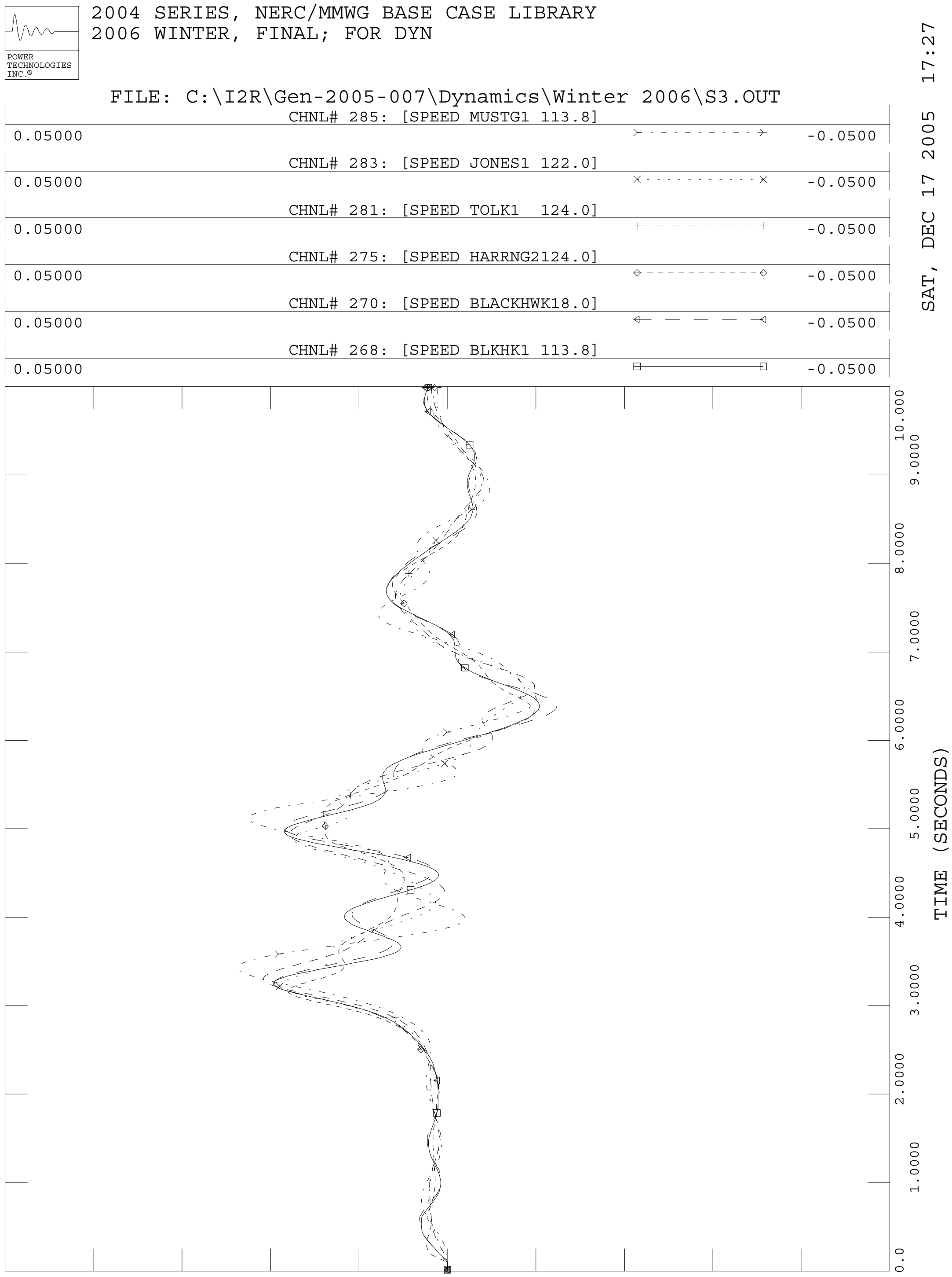

2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2006 WINTER, FINAL; FOR DYN
POWER TECHNOLOGIES INC.©
SAT, DEC 17 2005 17:27
FILE: C:\I2R\Gen-2005-007\Dynamics\Winter 2006\S3.OUT
CHNL# 285: [SPEED MUSTG1 113.8]
0.05000 -0.0500
CHNL# 283: [SPEED JONES1 122.0]
0.05000 -0.0500
CHNL# 281: [SPEED TOLK1 124.0]
0.05000 -0.0500
CHNL# 275: [SPEED HARRNG2124.0]
0.05000 -0.0500
CHNL# 270: [SPEED BLACKHWK18.0]
0.05000 -0.0500
CHNL# 268: [SPEED BLKHK1 113.8]
0.05000 -0.0500
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 16

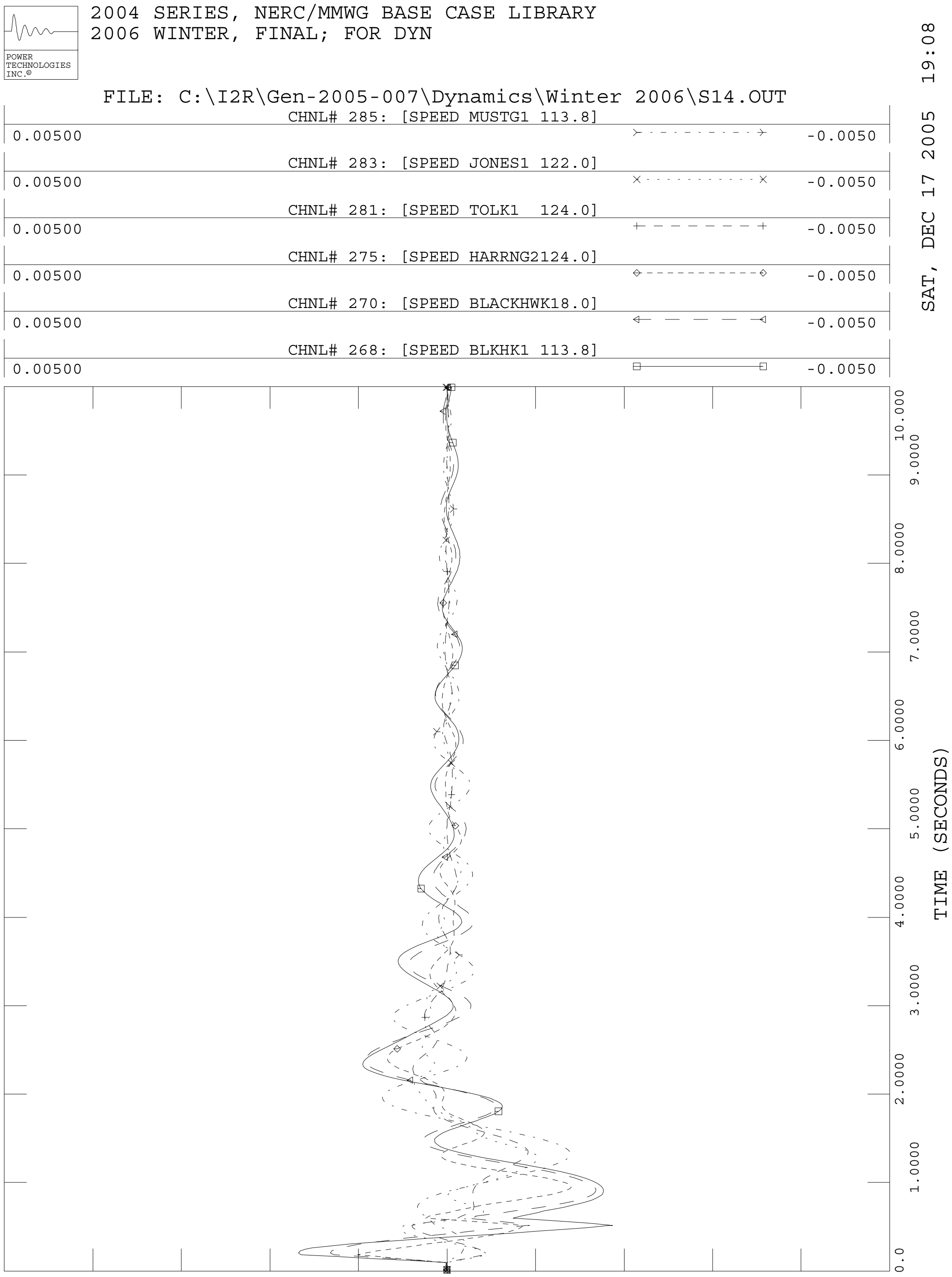
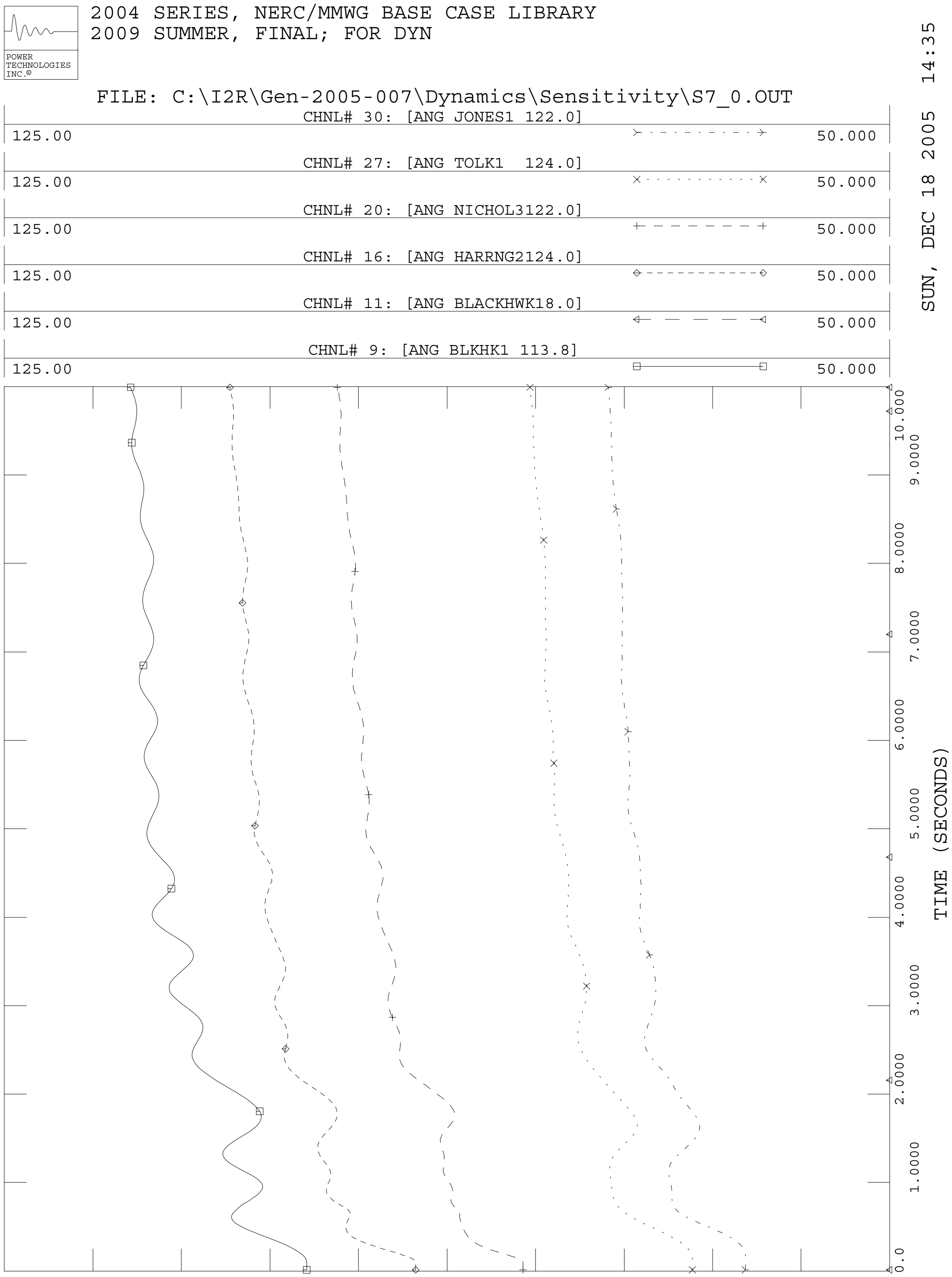

2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2006 WINTER, FINAL; FOR DYN
POWER TECHNOLOGIES INC.©
FILE: C:\I2R\Gen-2005-007\Dynamics\Winter 2006\S14.OUT
CHNL# 285: [SPEED MUSTG1 113.8]
0.00500
-0.0050
CHNL# 283: [SPEED JONES1 122.0]
0.00500
-0.0050
CHNL# 281: [SPEED TOLK1 124.0]
0.00500
-0.0050
CHNL# 275: [SPEED HARRNG2124.0]
0.00500
-0.0050
CHNL# 270: [SPEED BLACKHWK18.0]
0.00500
-0.0050
CHNL# 268: [SPEED BLKHK1 113.8]
0.00500
-0.0050
SAT, DEC 17 2005 19:08
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 17



2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2009 SUMMER, FINAL; FOR DYN
POWER TECHNOLOGIES INC.©
FILE: C:\I2R\Gen-2005-007\Dynamics\Sensitivity\S7_0.OUT
CHNL# 30: [ANG JONES1 122.0]
125.00 50.000
CHNL# 27: [ANG TOLK1 124.0]
125.00 50.000
CHNL# 20: [ANG NICHOL3122.0]
125.00 50.000
CHNL# 16: [ANG HARRNG2124.0]
125.00 50.000
CHNL# 11: [ANG BLACKHWK18.0]
125.00 50.000
CHNL# 9: [ANG BLKHK1 113.8]
125.00 50.000
SUN, DEC 18 2005 14:35
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

EXHIBIT 18

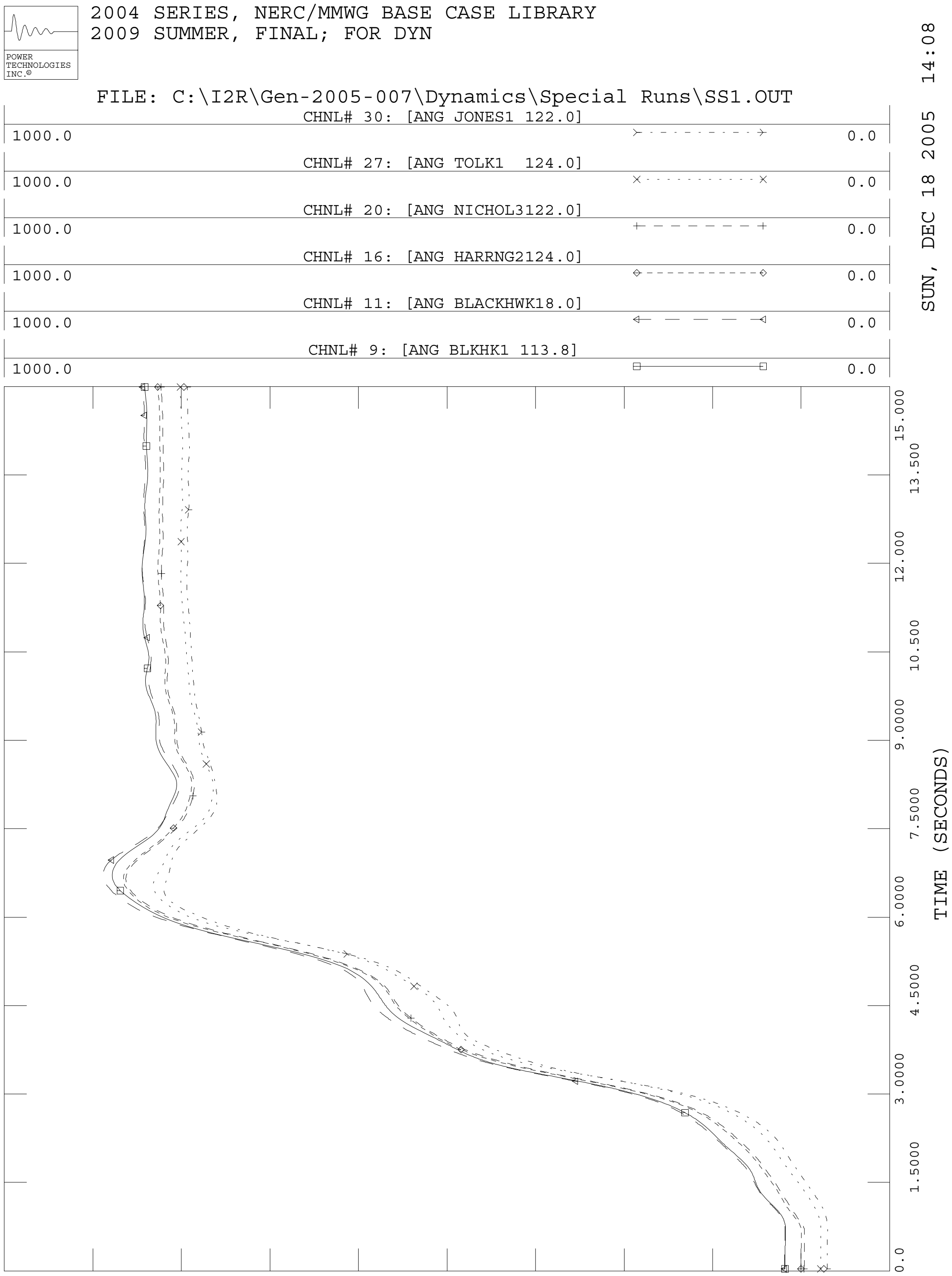
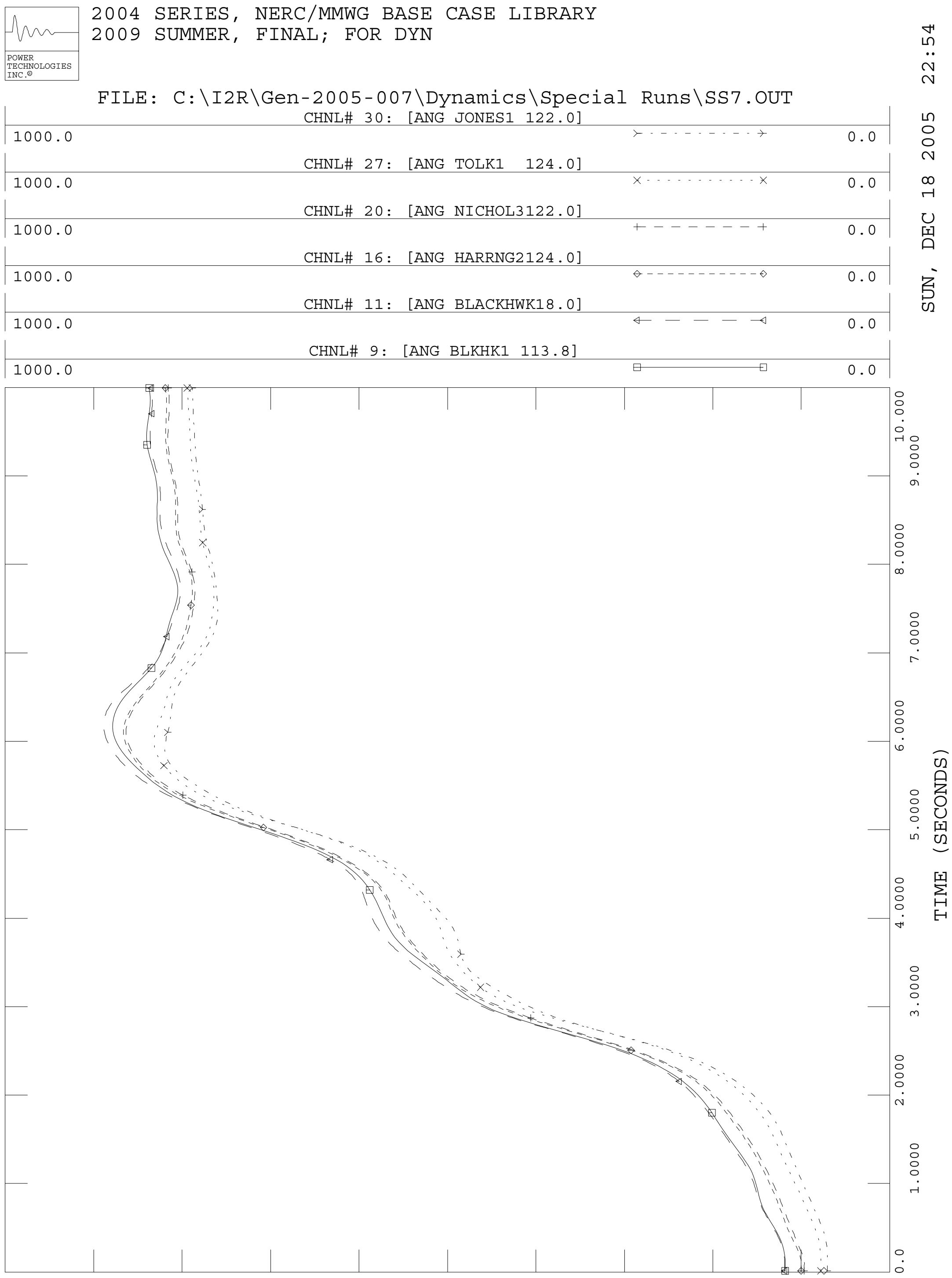

POWER TECHNOLOGIES INC.©
2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2009 SUMMER, FINAL; FOR DYN
FILE: C:\I2R\Gen-2005-007\Dynamics\Special Runs\SS1.OUT
CHNL# 30: [ANG JONES1 122.0]
1000.0
0.0
CHNL# 27: [ANG TOLK1 124.0]
1000.0
0.0
CHNL# 20: [ANG NICHOL3122.0]
1000.0
0.0
CHNL# 16: [ANG HARRNG2124.0]
1000.0
0.0
CHNL# 11: [ANG BLACKHWK18.0]
1000.0
0.0
CHNL# 9: [ANG BLKHK1 113.8]
1000.0
0.0
SUN, DEC 18 2005 14:08
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)

EXHIBIT 19


POWER TECHNOLOGIES INC.©
2004 SERIES, NERC/MMWG BASE CASE LIBRARY
2009 SUMMER, FINAL; FOR DYN
FILE: C:\I2R\Gen-2005-007\Dynamics\Special Runs\SS7.OUT
CHNL# 30: [ANG JONES1 122.0]
1000.0
0.0
CHNL# 27: [ANG TOLK1 124.0]
1000.0
0.0
CHNL# 20: [ANG NICHOL3122.0]
1000.0
0.0
CHNL# 16: [ANG HARRNG2124.0]
1000.0
0.0
CHNL# 11: [ANG BLACKHWK18.0]
1000.0
0.0
CHNL# 9: [ANG BLKHK1 113.8]
1000.0
0.0
SUN, DEC 18 2005 22:54
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)