CITIZENSHIP
DUKE POWER
SERVICE

Oconee Nuclear Station
McGuire Nuclear Station
Catawba Nuclear Station

THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY

DPC-NE-3000-A
Revision 1

December 1997

Nuclear Engineering Division
Nuclear Generation Department
Duke Power Company

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

December 27, 1995

Mr. M. S. Tuckman
Senior Vice President
Nuclear Generation
Duke Power Company
P. O. Box 1006
Charlotte, NC 28201-1006

SUBJECT: SAFETY EVALUATION FOR REVISION 1 TO TOPICAL REPORT DPC-NE-3000-P, "THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY" MCGUIRE NUCLEAR STATION, UNITS 1 AND 2; CATAWBA NUCLEAR STATION, UNITS 1 AND 2; AND OCONEE NUCLEAR STATION UNITS 1, 2, AND 3 (TAC NOS. M90143, M90144, AND M90145)

Dear Mr. Tuckman:

Your letter of August 9, 1994, submitted a revision to Duke Power Company (DPC) Topical Report DPC-NE-3000-P, "Thermal-Hydraulic Transient Analysis Methodology," dated June 1994, for review. The report describes changes to the DPC thermal-hydraulic transient analysis methodology that are due to: (1) the steam generator replacement for Catawba Unit 1 and McGuire Units 1 and 2, (2) changes to the methodology previously documented in DPC-NE-3000-P, and (3) corrections of typographical errors. Supplemental information was submitted in a letter dated September 12, 1995. This report, for reasons discussed in the enclosed Safety Evaluation, will be referred to hereafter, as Revision 1 to the original DPC-NE-3000-P report, which was issued in its approved form (DPC-NE-3000-PA) by DPC's letter of August 8, 1995.

Since Catawba Unit 2 continues to operate with the currently installed pre-heater steam generators, the previously reviewed and approved steam generator model will continue to be utilized. The DPC-NE-3000-PA report has been augmented in this revision to describe the models to be used for the Catawba Unit 1 and the McGuire Units 1 and 2 new feedring steam generators (FSG).

The staff finds DPC-NE-3000P, Revision 1, to be acceptable for referencing in Catawba, McGuire and Oconee licensing applications to the extent specified, and under the limitations stated, in DPC-NE-3000-P, Revision 1, and the associated NRC Safety Evaluation. The enclosed safety evaluation defines the basis for accepting this Topical Report. The staff was assisted in its review by the International Technical Services (ITS), Inc. The ITS Technical Evaluation Report (TER ITS/NRC/95-4) is also enclosed.

The staff does not intend to repeat its review of the matters described in the Topical Report and found acceptable when the report is referenced in a license application, except to ensure that the material presented is applicable to the specific plant involved. Staff acceptance applies only to the matters described in the Topical Report.

In accordance with procedures established in NUREG-0390, DPC must publish accepted proprietary and non-proprietary versions of this report. The accepted versions shall incorporate this letter and the enclosed Safety Evaluation between the title page and the abstract. The accepted versions shall include an -A (designating accepted) following the report identification symbol.

Should NRC criteria or regulations change so that staff conclusions regarding the acceptability of the report are invalidated, you will be expected to revise and resubmit your documentation, or to submit justification for continued effective applicability of the Topical Report without revision of the documentation.

This completes NRC actions for TAC Nos. M90143, M90144 and M90145.

Sincerely,

Robert E Martin

Robert E. Martin, Senior Project Manager
Project Directorate II-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket Nos. 50-269, 50-270, 50-287
50-369, 50-370, 50-413
and 50-414

Enclosures: 1. Safety Evaluation
2. Technical Evaluation Report ITS/NRC/95-4

cc w/encls: See next page

Duke Power Company

Catawba Nuclear Station
McGuire Nuclear Station
Oconee Nuclear Station

cc:
Mr. Z. L. Taylor
Regulatory Compliance Manager
Duke Power Company
4800 Concord Road
York, South Carolina 29745

Mr. Paul R. Newton
Duke Power Company, PB05E
422 South Church Street
Charlotte, North Carolina 28242

J. Michael McGarry, III, Esquire
Winston and Strawn
1400 L Street, NW.
Washington, DC 20005

North Carolina Municipal Power
Agency Number 1
1427 Meadowwood Boulevard
P. O. Box 29513
Raleigh, North Carolina 27626

Mr. Peter R. Harden, IV
Account Sales Manager
Westinghouse Electric Corporation
Power Systems Field Sales
P. O. Box 7288
Charlotte, North Carolina 28241

County Manager of York County
York County Courthouse
York, South Carolina 29745

Richard P. Wilson, Esquire
Assistant Attorney General
S.C. Attorney General's Office
P. O. Box 11549
Columbia, South Carolina 29211

Piedmont Municipal Power Agency
121 Village Drive
Greer, South Carolina 29651

North Carolina Electric Membership
Corporation
P. O. Box 27306
Raleigh, North Carolina 27611

Saluda River Electric Cooperative,
Inc.
P. O. Box 929
Laurens, South Carolina 29360

Senior Resident Inspector
4830 Concord Road
York, South Carolina 29745

Regional Administrator, Region II
U.S. Nuclear Regulatory Commission
101 Marietta Street, NW Suite 2900
Atlanta, Georgia 30323

Max Batavia, Chief
Bureau of Radiological Health
South Carolina Department of Health
and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of Justice
P. O. Box 629
Raleigh, North Carolina 27602

Mr. G. A. Copp
Licensing - EC050
Duke Power Company
526 South Church Street
Charlotte, North Carolina 28242-0001

Duke Power Company

Catawba Nuclear Station
McGuire Nuclear Station
Oconee Nuclear Station

cc:
Dr. John M. Barry
Mecklenburg County
Department of Environmental
Protection
700 N Tryon Street
Charlotte, North Carolina 29202

County Manager of Mecklenburg County
720 East Fourth Street
Charlotte, North Carolina 28202

Mr. J. E. Snyder
Regulatory Compliance Manager
Duke Power Company
McGuire Nuclear Site
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Senior Resident Inspector
c/o U.S. Nuclear Regulatory
Commission
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Mr. Dayne H. Brown, Director
Department of Environmental
Health and Natural Resources
Division of Radiation Protection
P. O. Box 27687
Raleigh, North Carolina 27611

County Supervisor of Oconee County
Walhalla, South Carolina 27621

Mr. J. W. Hampton
Vice President, Oconee Site
Duke Power Company
P. O. Box 1439
Seneca, South Carolina 29679

Mr. Ed Burchfield
Compliance
Duke Power Company
Oconee Nuclear Site
P. O. Box 1439
Seneca, South Carolina 29679

Mr. Robert B. Borsum
Babcock & Wilcox
Nuclear Power Division
Suite 525
1700 Rockville Pike
Rockville, Maryland 20852

Manager, LIS
NUS Corporation
2650 McCormick Drive, 3rd Floor
Clearwater, Florida 34619-1035

Senior Resident Inspector
U.S. Nuclear Regulatory Commission
Route 2, Box 610
Seneca, South Carolina 29678

Mr. W. R. McCollum
Site Vice President
Catawba Nuclear Station
Duke Power Company
4800 Concord Road
York, South Carolina 29745

Mr. T. C. McMeekin
Vice President, McGuire Site
Duke Power Company
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Elaine Wathen, Lead REP Planner
Division of Emergency Management
116 West Jones Street
Raleigh, North Carolina 27603-1335

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF THE NUCLEAR REACTOR REGULATION

TOPICAL REPORT DPC-NE-3000-P, REVISION 1

"THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY"

DUKE POWER COMPANY, ET AL.

MCGUIRE NUCLEAR STATION, UNITS 1 AND 2

CATAWBA NUCLEAR STATION, UNITS 1 AND 2

OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3

DOCKET NOS. 50-369, 50-370, 50-413, 50-414

50-269, 50-270, AND 50-287

1.0 INTRODUCTION AND BACKGROUND

By letter dated August 9, 1994, Duke Power Company (DPC or licensee) submitted a revision to the DPC Topical Report DPC-NE-3000-P, "Thermal-Hydraulic Transient Analysis Methodology," dated June 1994 (Reference 1) for NRC staff review and approval. The report describes changes to the DPC thermal-hydraulic transient analysis methodology that are due to: (1) the steam generator replacement for Catawba Unit 1 and McGuire Units 1 and 2, (2) changes to the methodology previously documented in DPC-NE-3000-P, and (3) corrections of typographical errors. Supplemental information was submitted in a letter dated September 12, 1995.

The subject report was submitted on August 9, 1994, and was identified by DPC as Revision 3 to the original DPC-NE-3000 report that was submitted by letter from H. B. Tucker to the NRC on September 29, 1987. The original report, following approvals for the Catawba, McGuire, and Oconee stations, was issued by DPC in its approved form by letter from M. S. Tuckman, DPC, to the NRC dated August 8, 1995, wherein it was identified as DPC-NE-3000-PA with no revision number. Accordingly, since the revisions in the August 9, 1994, report are beyond the scope of the original report, DPC's letter of September 12, 1995, renames the August 9, 1994, report as Revision 1 to DPC-NE-3000-P. Therefore, the August 9, 1994, report will be referred to, hereafter, as Revision 1 to the original DPC-NE-3000-P report.

In Revision 1 of the Topical Report DPC-NE-3000, DPC documents revisions to the currently approved thermal-hydraulic transient analysis methodology for Oconee, McGuire and Catawba stations (Reference 2). The revisions reflect changes due to the proposed replacement of the steam generators for McGuire

Units 1 and 2 and Catawba Unit 1 and methodology changes. Corrections of typographical errors are also included. Additional information was provided in Reference 3.

The currently approved methodology (Reference 2) for non-LOCA transient safety analysis is based upon the use of the RETRAN-02 and the VIPRE-01 computer codes for the McGuire, Catawba and Oconee stations. In Revision 1, only the RETRAN portion of the methodology was revised. The stated objective of the subject revision of the Topical Report is for DPC to demonstrate acceptability of changes in the analysis methodology for the Oconee, McGuire and Catawba plants.

This review is focused upon determining acceptability of the revised RETRAN plant models and their impact on previously approved analysis.

2.0 SUMMARY OF REPORT REVISIONS

The licensee incorporated, in Revision 1 of DPC-NE-3000, new sections describing Babcock and Wilcox's (B&W's) feedring steam generator (FSG), which is expected to replace the existing Westinghouse preheater steam generators (PSG) at the McGuire Units 1 and 2 and Catawba Unit 1 nuclear stations. Necessary modifications to associated components such as steamline and feedwater lines were also made.

There are minor modifications to the RETRAN methodology including the treatment of phase separation in some volumes and pressurizer modeling. Setpoint changes were incorporated into the description of the respective components and control systems. A description of the General Transport model to simulate boron transport (its use was approved in connection with the steamline break analysis in DPC-NE-3001 (Reference 4) was also added to the report for completeness. In addition, DPC corrected numerous typographical errors and made some editorial changes, which are of minimal technical significance.

3.0 EVALUATION

Revisions incorporated into the submittal can be categorized into three classes: (1) modeling upgrades and incorporation of a new steam generator model; (2) setpoint changes due to revised Technical Specifications; (3) non-technical correction to the text. Revisions to the approved RETRAN transient analysis methodology and their acceptability are discussed. Minor changes of a non-technical nature are not discussed, since these changes have no technical impact and are acceptable.

3.1 Revisions to RETRAN Models

These model revisions resulted from consolidation of modifications made due to (i) proposed steam generator replacements, (ii) better understanding gained through sensitivity studies performed since the original review, and (iii) plant Technical Specification changes.

3.1.1 Editorial Changes

The RETRAN General Transport model is used to simulate boron transport in the steamline break analysis. The model description is added to the Topical Report for completeness. The use of this model for steamline break was reviewed and approved in DPC-NE-3001.

3.1.2 Setpoint Changes

There are many setpoint changes used in the RETRAN control systems documented in this revision due to revised Technical Specifications. DPC will use setpoints which have been approved by the NRC.

3.1.3 Revised RETRAN Plant Models

Modeling upgrades were made in the (1) pressurizer model, (2) two-phase modeling, and (3) feedring steam generator (FSG) model. The addition of the FSG model and changes necessitated in associated components were also presented in this revision.

3.2 Description and Qualification of Revised Models

Pressurizer Model

The pressurizer vessel model was modified to include heat conductors using the local conditions heat transfer model. The pressurizer level is computed in the RETRAN control system whose modeling simulates the actual plant function.

Phase Separation

The bubble-rise model was used to simulate the two-phase separation in components where two-phase liquid is expected. The bubble rise velocity and gradient are specified. This option is specified instead of the homogeneous equilibrium model in the primary system volumes stated in the revision. As long as the primary system remains subcooled, the option is not activated. However, in the event that subcooling is lost, with the exception of the pressurizer, DPC should submit justification to the staff that use of this option is appropriate and will result in conservative predictions.

Steam Generator Replacement

The description of the B&W FSG is provided. Due to the design differences, the FSG nodalization is slightly different from the pre-heater SG nodalization. Although there is no transient data to qualify the adequacy of the nodalization, DPC provided a comparison of RETRAN-computed SG mass and level with the vendor-computed data and obtained good agreement. Similarly, DPC provided a comparison of RETRAN-computed RCS hot and cold leg temperatures given a specified RCS flow and steamline pressure with the vendor predictions. The comparison indicated that the heat transfer of the FSG was predicted well with the RETRAN model. Based upon these comparisons, it was concluded that the feedring SG nodalization and model are acceptable.

4.0 CONCLUSION AND LIMITATIONS

The DPC Topical Report DPC-NE-3000, Revision 1, and the DPC responses to NRC requests for additional information were reviewed.

The licensee's revised RETRAN models for the McGuire, Catawba and Oconee stations are acceptable for applications to non-LOCA transient and safety analysis.

Acceptability of the use of the proposed revisions in non-LOCA transients safety analysis remains subject to the limitations set forth in the SERs on DPC-NE-3001 and DPC-NE-3002 (References 4 and 5). Furthermore, acceptability does not remove limitations and restrictions set forth in the SER on the original DPC-NE-3000 for those issues not impacted by the subject revision.

Principal Contributor: L. Lois

Date: December 27, 1995

REFERENCES

1. Letter from H. B. Tucker (DPC) to NRC, Attachment "DPC-NE-3000 Revision 3" August 9, 1994.

2. DPC-NE-3000, "Thermal-Hydraulic Transient Analysis Methodology" original version July 1987, the approved version (DPC-NE-3000PA dated August 1994) submitted by letter from M. S. Tuckman, DPC, to NRC, dated August 8, 1995.

3. Letter from M. S. Tuckman (DPC) to NRC, "Request for Additional Information Relative to DPC-NE-3000P, Revision 1; Responses to Questions" September 12, 1995.

4. DPC-NE-3001P, "Duke Power Company Multidimensional Reactor Transients and Safety Analysis Physics Parameters Methodology," January 1990.

5. DPC-NE-3002, "FSAR Chapter 15 System Transient Analysis Methodology" Revision 1, November 1994.

ITS/NRC/95-4

TECHNICAL EVALUATION:
THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY
DPC-NE-3000 REVISION 3
FOR
DUKE POWER COMPANY

P.B. Abramson
H. Komoriya

Prepared for
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555
Under NRC Contract No. NRC-03-90-027
FIN No. L1318

International Technical Services, Inc.
420 Lexington Avenue
New York, NY 10170

Enclosure 2

TECHNICAL EVALUATION
OF THE THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY
TOPICAL REPORT DPC-NE-3000 REVISION 3
FOR THE
DUKE POWER COMPANY
OCONEE, MCGUIRE AND CATAWBA NUCLEAR STATIONS

1.0 INTRODUCTION

In Revision 3 of the topical report entitled "Thermal-Hydraulic Transient Analysis Methodology," DPC-NE-3000, dated July 1994 (Ref. 1), Duke Power COmpany (DPC) documents revisions to the currently approved thermal-hydraulic transient analysis methodology for Oconee, McGuire and Catawba stations (Ref. 2). The revisions reflect changes due to the proposed replacement of steam generators for the McGuire and Catawba Unit 1 stations and methodology changes. Corrections of typographical errors are also included. Additional information was provided in Reference 3.

The currently approved methodology (Ref. 2) for non-LOCA transient safety analysis is based upon the use of the RETRAN-02 and VIPRE-01 computer codes for McGuire, Catawba and Oconee stations. In Revision 3, only the RETRAN portion of the methodology was revised. The stated objective of the subject revision of the topical report is for DPC to demonstrate acceptability of changes in the analysis methodology for Oconee, McGuire and Catawba plants.

This review is focused upon determining acceptability of the revised RETRAN plant models and their impact on previously approved analysis.

2.0 SUMMARY

DPC incorporated, in Revision 3 of DPC-NE-3000, new sections describing B&W's feedring steam generator (FSG), which is expected to replace the existing Westinghouse preheater steam generators (PSG) at the McGuire and Catawba Unit 1 nuclear stations. Necessary modifications to associated components such as steam line and feedwater lines were also made.

There are minor modifications to the RETRAN methodology including the treatment of phase separation in some volumes and pressurizer modeling. Setpoints changes were incorporated into the description of the respective components and control systems. A description of the General Transport model to simulate boron transport (its use was approved in connection with the steam line break analysis in DPC-NE-3001 (Ref. 4)) was also added to the report for completeness. In addition, DPC corrected numerous typographical errors and made some editorial changes which are of no technical significance.

3.0 EVALUATION

Revisions incorporated into the submittal can be categorized into three classes: (1) modeling upgrades and incorporation of a new steam generator model; (2) setpoint changes due to revised Technical Specifications; (3) non-technical correction to the text. Revisions to the approved RETRAN transient analysis methodology and their acceptability are discussed. Minor changes of a non-technical nature are not discussed, since these changes have no technical impact and are acceptable.

3.1 Revisions to RETRAN Models

These model revisions resulted from consolidation of modifications made due to (i) proposed steam generator replacements, (ii) better understanding gained through sensitivity studies performed since the original review, and (iii) plant technical specification changes.

3.1.1 Editorial Changes

The RETRAN General Transport model is used to simulate boron transport in the steam line break analysis. The model description is added to the topical report for completeness. The use of this model for steam line break was reviewed and approved in DPC-NE-3001.

3.1.2 Setpoint Changes

There are many setpoint changes used in the RETRAN control systems documented in this revision due to revised Technical Specifications. DPC will use NRC approved setpoints.

3.1.3 Revised RETRAN Plant Models

Modeling upgrades were made in the (1) pressurizer model, (2) two-phase modeling, and (3) Feedring SG model. The addition of the Feedring SG model and changes necessitated in associated components were also presented in this revision.

3.2 Description and Qualification of Revised Models

Pressurizer Model

The pressurizer vessel model was modified to include heat conductors using the local conditions heat transfer model. The pressurizer level is computed in the RETRAN control system whose modeling simulates the actual plant function.

Phase Separation

The bubble-rise model was used to simulate the two-phase separation in components where two-phase liquid is expected. The bubble rise velocity and gradient are specified. This option is specified instead of the HEM option

in the primary system volumes stated in the Revision. As long as the primary system remains subcooled, the option is not activated. However, in the event that subcooling is lost, with the exception of the pressurizer, DPC should justify that its use is appropriate and results in conservative predictions.

Steam Generator Replacement

The description of the B&W Feedring Steam Generator (FSG) is provided. Due to the design differences, the FSG nodalization is slightly different from the pre-heater SG nodalization. Although there is no transient data to qualify the adequacy of the nodalization, DPC provided comparison of RETRAN computed SG mass and level with the vendor computed data and obtained good agreement. Similarly, DPC provided comparison of RETRAN computed RCS hot and cold leg temperatures given a specified RCS flow and steam line pressure with the vendor predictions. Comparison indicated that the heat transfer of the FSG was predicted well with the RETRAN model. Based upon these comparisons, it was concluded that the feedring SG nodalization and model is acceptable.

4.0 CONCLUSIONS

DPC topical report DPC-NE-3000 Revision 3 and the DPC responses to NRC questions were reviewed.

DPC's revised RETRAN models for the McGuire/Catawba and Oconee nuclear power plants are acceptable in application to non-LOCA transient and safety analysis.

Acceptability of the use of the proposed revisions in non-LOCA transient safety licensing analysis remains subject to the limitations set forth in the SERs on DPC-NE-3001 and 3002 (Ref. 5). Furthermore, acceptability does not remove limitations and restriction set forth in the SER on the original DPC-NE-3000 for those issues not impacted by the subject revision.

5.0 REFERENCES

1. Letter from H.B. Tucker (DPC) to USNRC, Attachment "DPC-NE-3000 Revision 3," August 9, 1994.

2. "Thermal-Hydraulic Transient Analysis Methodology," DPC-NE-3000, July 1987.

3. Letter from M.S. Tuckman (DPC) to USNRC, "Request for Additional Information Relative to DPC-NE-3000P, Revision 1; Responses to Questions," September 12, 1995.

4. "Duke Power Company Multidimensional Reactor Transients and Safety Analysis Physics Parameters Methodology," DPC-NE-3001-P, January 1990.

5. "FSAR Chapter 15 System Transient Analysis Methodology," DPC-NE-3002, Revision 1, November 1994.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

August 8, 1994

Docket Nos. 50-269, 50-270
and 50-287

Mr. M. S. Tuckman
Senior Vice President
Nuclear Generation
Duke Power Company
P. O. Box 1006
Charlotte, North Carolina 28201-1006

Dear Mr. Tuckman:

SUBJECT: SAFETY EVALUATION REGARDING THE THERMAL HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY DPC-NE-3000 FOR OCONEE NUCLEAR STATION UNITS 1, 2, AND 3 (TAC NOS. M87112, M87113, AND M87114)

By letter dated July 1987, Duke Power Company (DPC), submitted DPC-NE-3000, a topical report documenting DPC's use of the RETRAN computer code for McGuire/Catawba and Oconee. It was determined that DPC's use of the code was acceptable with respect to McGuire/Catawba; however, its use for Oconee licensing type analyses was restricted, primarily due to the difficulty in modeling the performance of the once-through steam generators. DPC submitted supplemental information, dated October 16, 1991, and October 5, 1993, to qualify the RETRAN model for use with Oconee analyses.

The NRC staff and its contractor, International Technical Services, Incorporated (ITS), have completed their review of the topical report and the supplemental submittals. The staff concludes that the DPC modifications of the steam generator model are acceptable. The staff's Safety Evaluation is included as Enclosure 1 and the ITS Technical Evaluation Report is included as Enclosure 2. This completes NRC actions for TAC Nos. M87112, M87113, and M87114. If you have questions regarding this matter, contact me at (301) 504-1495.

Sincerely,

L. A. Wiens, Project Manager
Project Directorate II-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. NRC Safety Evaluation
2. ITS Technical Evaluation Report

cc w/enclosures:
See next page

cc:
A. V. Carr, Esquire
Duke Power Company
422 South Church Street
Charlotte, North Carolina 28242-0001

J. Michael McGarry, III, Esquire
Winston and Strawn
1400 L Street, NW.
Washington, DC 20005

Mr. Robert B. Borsum
Babcock & Wilcox
Nuclear Power Division
Suite 525
1700 Rockville Pike
Rockville, Maryland 20852

Manager, LIS
NUS Corporation
2650 McCormick Drive, 3rd Floor
Clearwater, Florida 34619-1035

Senior Resident Inspector
U. S. Nuclear Regulatory Commission
Route 2, Box 610
Seneca, South Carolina 29678

Regional Administrator, Region II
U. S. Nuclear Regulatory Commission
101 Marietta Street, NW. Suite 2900
Atlanta, Georgia 30323

Max Batavia, Chief
Bureau of Radiological Health
South Carolina Department of Health
and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201

County Supervisor of Oconee County
Walhalla, South Carolina 29621

Mr. Steve Benesole
Compliance
Duke Power Company
Oconee Nuclear Site
P. O. Box 1439
Seneca, South Carolina 29679

Mr. Marvin Sinkule, Chief
Project Branch #3
U. S. Nuclear Regulatory Commission
101 Marietta Street, NW. Suite 2900
Atlanta, Georgia 30323

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of
Justice
P. O. Box 629
Raleigh, North Carolina 27602

Mr. G. A. Copp
Licensing - EC050
Duke Power Company
526 South Church Street
Charlotte, North Carolina 28242-0001

Dayne H. Brown, Director
Division of Radiation Protection
North Carolina Department of
Environment, Health and
Natural Resources
P. O. Box 27687
Raleigh, North Carolina 27611-7687

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATING TO TOPICAL REPORT DPC-NE-3000

THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY

FOR DUKE POWER COMPANY

OCONEE NUCLEAR STATION, UNIT NOS. 1, 2, AND 3

DOCKET NO. 50-269, 50-270, AND 50-287

1.0 INTRODUCTION

By letter dated July 1987, Duke Power Company (DPC), the licensee for Oconee Nuclear Station, Units 1, 2, and 3, submitted DPC-NE-3000, a topical report documenting DPC's use of the RETRAN computer code for McGuire/Catawba and Oconee. It was determined that DPC's use of the code was acceptable with respect to McGuire/Catawba; however, its use for Oconee licensing type analysis was restricted. DPC submitted supplemental information, dated October 16, 1991, and October 5, 1993, to qualify its RETRAN Oconee model.

International Technical Services (ITS), Incorporated, reviewed the topical and supplemental submittals, and provided a final Technical Evaluation Report (TER) to the staff. The primary aspects of the review focused on the ability of the RETRAN Oconee model to predict the primary and secondary side performance of the once-through steam generator (OTSG).

2.0 STAFF EVALUATION

Duke Power Company (DPC) developed two RETRAN models to analyze plant response for transient analysis. The two models were (1) the single loop model for cases when both loops have the same transient response, and (2) the two loop model for cases when the loops respond differently to transients. The difficulty in modeling the OTSG is due to the phenomena that occur during operation. The upper portion of the OTSG is super heated and the tubes are partially uncovered. This results in the primary-to-secondary heat transfer rate being a function of a two-phase mixture height in the steam generator (S/G). RETRAN is not capable of directly modeling the two-phase mixture; and the model of the secondary side of the S/G greatly affects the predicted plant response to transients. Therefore, it was necessary for the licensee to make compensations in the S/G model. The major compensations were the location of nodes in modeling the steam generator and timing of the emergency feedwater actuation signal.

Once the modeling changes were incorporated, the licensee verified the adequacy of the modified S/G model. The licensee demonstrated the adequacy of the base plant model by comparing the RETRAN analyses to the available plant data. Duke Power demonstrated that the differences in results using different nodalizations were small, and therefore concluded that the S/G nodalization in the base model is valid.

In using the model for the Final Safety Analysis Report type analysis, certain events cause specific plant responses. To compensate for the RETRAN model consistently overpredicting the primary-to-secondary heat transfer following a reactor trip, the licensee incorporated appropriate delays in the determination of the emergency feedwater actuation time.

The method of predicting the S/G mixture level in the RETRAN base code is non-conservative for once-through steam generators. Initially, DPC was not going to rely on the original RETRAN steam generator low level trip for actuation of the emergency feedwater system. However, DPC was able to modify the RETRAN control system to adequately simulate S/G level instrumentation. The ITS verified that the method used by DPC resulted in a conservative prediction of the S/G level for the time period of interest.

3.0 CONCLUSION

The ITS reviewed DPC-NE-3000 and the supplemental documents and provided separate TERs for the McGuire/Catawba plants and the Oconee plant. It was necessary to modify the RETRAN steam generator modeling to more accurately depict the response of Oconee's once-through steam generators. Duke Power provided a detailed justification and qualification of the RETRAN modifications including an explanation of the system impact due to inaccuracies in the modeling of primary-to-secondary heat transfer.

The steamline break modeling, although not part of this review, was briefly described as a modification of the Oconee base model nodalization. The descriptive method of steamline break analysis was found acceptable, but DPC stated that the specific details of the analysis will be submitted to the staff in a separate topical report.

The contractor has found the DPC approach to RETRAN modeling of the Oconee plant with compensating modeling techniques and transient assumptions to be acceptable. The approach is reasonable subject to the condition that the models are applied only to the Oconee plant. The staff concurs with the findings presented in the TER in that DPC has adequately modified the RETRAN computer code to simulate the response of the OTSG.

Prinicipal Contributor: S. Brewer

Date: August 8, 1994

SUPPLEMENTAL TECHNICAL EVALUATION: THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY DPC-NE-3000 FOR DUKE POWER COMPANY OCONEE NUCLEAR STATIONS

1.0 INTRODUCTION

DPC-NE-3000, dated July 1987 (Ref. 1), documented results of a series of studies performed by Duke Power Company (DPC) to support the development of thermal-hydraulic transient analysis methodology. The transient analysis methodology documented in the topical report was based on the use of the RETRAN-02 (Ref. 2) and VIPRE-01 (Ref. 3) computer codes, subject to conditions for its Oconee plants (which are B&W plants) and its McGuire and Catawba plants (which are Westinghouse plants) (Ref. 4)

The NRC review of DPC-NE-3000 resulted in acceptance of the methodology for McGuire and Catawba analysis applications. However, its licensing application to Oconee analysis was restricted until further qualification of the RETRAN Oconee models and their uses (Ref. 4). The VIPRE portion of the submittal for both types of plant analysis was found to be adequate.

The purpose of this review, which is based upon a review of the additional information (Refs. 1, 5, 6 & 7) provided by the licensee since the previous review, is to determine adequacy of the RETRAN Oconee plant model for use in licensing type calculations focusing upon the ability of the RETRAN Oconee model to predict the primary and secondary side performance of the once-through steam generator (OTSG).

Details of plant nodalization and transient benchmark calculations were presented in the original topical report and their review findings documented in Reference 4 and are unaffected by this supplement. In this report, only those changes which impact the previous review findings are presented. Review of actual licensing applications and associated conservative assumptions is beyond the scope of this review. Similarly, although a philosophical approach to the Oconee steam line break was provided, details of such transient analysis was stated by DPC to be beyond the scope of the topical report, and therefore detailed review of steam line break was not performed. DPC stated that a future topical report will detail this transient and others.

2.0 REPORT SUMMARY

The topical report was supplemented by submission of additional information

provided by DPC to specifically address conditions regarding use of RETRAN for Oconee application cited in the earlier SER on DPC-NE-3000.

Supplemental materials focused upon further qualification of the RETRAN Oconee steam generator model. Details of the steam generator model including nodalization sensitivity studies were provided. In addition, an explanation and analysis of sources of overprediction of primary-to-secondary heat transfer was provided.

A philosophical approach to Oconee steam line break analysis was also provided.

3.0 EVALUATION

Adequacy of DPC's application of the RETRAN computer code for thermal-hydraulic calculations of the transient behavior of its Oconee plants with focus upon DPC's Oconee steam generator modeling is discussed below.

3.1 Oconee Plant Model

DPC developed two Oconee RETRAN models: (1) a one-loop plant model to be used where there is little asymmetry between loop responses; and (2) a two-loop plant model to be used when asymmetric conditions are expected in the analysis. Detailed descriptions of the plant nodalizations and models selected for use in the analysis are presented in Chapter 2 of the topical report.

In the one-loop model, DPC models both steam generators and the accompanying hot and cold legs by one hot leg, one once-through steam generator (OTSG) and one cold leg. The core and steam generator nodalizations are the same as those in the two-loop plant model.

The base two-loop Oconee plant model consists of two separate loops each containing one hot leg, an OTSG and two cold legs. The OTSG is nodalized with equal height shell and tube side volumes except at the bottom of the steam generator. DPC stated that the specific degree of detail selected (i.e. the number of nodes) for the OTSG is necessary to model the void distribution in the OTSG.

The modeling of OTSGs is very difficult because in normal operation the steam in the upper portion of the SG is super heated and the SG tubes are partially uncovered (in marked contrast to U-tube type plants). Therefore the primary-to-secondary heat transfer rate is a function of the two-phase mixture height on the secondary side and the predicted transient behavior is strongly dependent upon the two-phase modeling on the secondary side of the steam generator. The mixture interface location and its transient behavior are very difficult to model with RETRAN, facts which DPC has acknowledged (Ref. 8).

DPC indicated, in Reference 5, certain potential nodalization and model changes for FSAR analyses to obtain conservative results. Each of these changes should add conservatism. However, it is recommended that DPC should

demonstrate that such implementation produces conservative results.

3.1.1 Oconee RETRAN Steam Generator Model Qualification

In DPC-NE-3000, DPC chose to demonstrate the adequacy of the base plant model for Oconee plants through comparison of RETRAN analyses to available plant data, providing reasonably thorough analyses of the transients analyzed. In the supplemental submittals, justifications of DPC's Oconee SG nodalization were documented. DPC performed SG nodalization sensitivity studies and demonstrated that the differences between the two nodalizations considered were small indicating that the SG nodalization in the base model is converged.

However, in the earlier benchmark analyses it was found that the Oconee RETRAN model consistently overpredicted primary-to-secondary heat transfer following reactor trip. In order to manage this inherent modeling difficulty with RETRAN, DPC classified the FSAR transients into four categories (Ref. 7) according to expected impact of overprediction of post-trip heat transfer.

Category 1 contains transients 15.2 through 15.7 and 15.12 for which this phenomenon has little impact. For the transients in Category 2 (15.13 and 10.4.7.1.7 (Feedwater Line Break)), overprediction of post-trip heat transfer will result in a conservatively higher initial rate of overcooling. Computation of the source term in the steam generator tube rupture event (Category 3) over a 2-hour time period is not significantly affected by the overprediction of the initial post-trip heat transfer since the secondary inventory boil-off during the 2-hour time period will remain essentially the same.

Category 4 consists of loss of main feedwater (LOMFW), LOMFW with loss of offsite AC power, LOMFW with loss of onsite and offsite AC power and loss of electric power accidents. For these transients, there is a potential for the post-trip heat transfer to have an impact on the acceptance criteria (MDNBR and peak system pressure) being met. In order to prevent a premature injection of emergency feedwater due to faster boil-off in the LOMFW event caused by overprediction of primary-to-secondary heat transfer, an additional delay in the EFW start time is used. For the loss of electric power events in which the RCP's are tripped off, in order to maintain the required SG liquid level for natural circulation in the RCS, the EFW is assumed to open immediately to increase SG levels after adequate delay times.

DPC stated that the use of compensatory conservative assumptions will assure that the overprediction of primary-to-secondary heat transfer following a reactor trip will result in overall conservative predictions. DPC further stated that the specific sizes of delay and other corresponding conservative assumptions will be addressed in a future topical report. This approach is reasonable.

3.1.2 Steam Generator Mixture Level Prediction

In the previous review, DPC stated that the steam generator level trip would not be relied upon for actuation of the emergency feedwater system (EFW).

However, during this review, DPC revised the earlier position by stating its intent to use this setpoint. Thus closer examination of the manner in which the SG level is computed was conducted.

EFW actuates on MFW pump trip or on low SG level. DPC used a RETRAN control system to simulate SG level instrument function by calculating a differential pressure between the location of the two taps used by the instrument.

Benchmark analysis presented in DPC-NE-3000 showed that at the time period of interest, the predicted SG level compared well against the plant data. Prior to reaching that low level, the prediction tended to show a lower level than the data indicated, but this underprediction had minimal impact on the transient scenario as long as the minimum SG level was maintained.

3.1.3 Steam Line Break Modeling

In order to conservatively model the licensing type analysis of the steam line break event, DPC modified the base model Oconee RETRAN nodalization. These modifications include a split core and reactor vessel incorporating cross flow junctions. Although limited descriptive details of how the steam line break analysis would be performed by DPC were provided in Reference 7 and found to be reasonable, no quantitative information related to qualification of the methodology was provided. DPC stated that the specific details regarding the analysis are beyond the scope of DPC-NE-3000 and will be submitted to the NRC in a separate topical report.

4.0 CONCLUSIONS

DPC topical reports DPC-NE-3000 and its supporting documents, including the DPC responses to NRC questions, were reviewed. These responses addressed conditions cited in the earlier SER issued on DPC-NE-3000. Of four conditions cited, modeling deficiency with respect to the steam generator was the most serious. DPC provided detailed justification and qualification of its Oconee steam generator models using RETRAN. Thorough explanation of sources of predicted bias in the primary-to-secondary heat transfer was provided and found to be reasonable.

It is DPC's intent to overcome RETRAN modeling problems with compensating modeling techniques and transient assumptions. Review of actual licensing applications and associated conservative assumptions was beyond the scope of this review, since such details are to be presented in a future topical report. Similarly, because DPC stated that the specific details regarding the analysis are beyond the scope of DPC-NE-3000 and will be submitted to the NRC in a separate topical report, detailed review of an Oconee split core model for the steam line break analysis was not performed as part of this review and should be performed as part of the review of a subsequent topical report.

This approach is reasonable subject to the following conditions:

1. Acceptability of use of the DPC RETRAN transient analysis methodology is applicable only to Oconee plants.

2. When these models are used in licensing calculations, DPC should demonstrate that the models are adequately modified, where appropriate, to incorporate sufficient conservatisms so that the resulting analysis is conservative. Furthermore, DPC should demonstrate that the compensatory assumptions and delay times which it introduces to offset the over-prediction of post-trip heat transfer produce adequately conservative results.

4.0 REFERENCES

1. "Thermal-Hydraulic Transient Analysis Methodology," DPC-NE-3000, July 1987.

2. Letter, C.O. Thomas (NRC) to T.W. Schnatz (UGRA), September 4, 1984, (Transmittal of RETRAN-02 Safety Evaluation Report).

3. "Acceptance for Referencing of Licensing Topical Report VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM Vols. 1-4," May 1, 1986.

4. Safety Evaluation on Topical Report DPC-NE-3000 "Thermal-Hydraulic Transient Analysis Methodology," November 15, 1991.

5. Letter from H.B. Tucker (DPC) to USNRC, "Handouts Presented in the October 7 & 8, 1991 Meeting with NRC Staff and Contract Reviewers, October 16, 1991.

6. Letter from H.B. Tucker (DPC) to USNRC, "Thermal-Hydraulic Transient Analysis Methodology," March 11, 1992.

7. Letter from M. S. Tuckman (DPC) to USNRC, "Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000" October 5, 1993.

8. Letter from H.B. Tucker (DPC) to USNRC, "Duke Power Response to NRC Questions Regarding Steam Generator Heat Transfer Modeling with the RETRAN Code," August 9, 1989.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

November 15, 1991

Docket Nos. 50-369, 50-370
50-413 and 50-414
50-269, 50-270, and 50-287

Mr. H. B. Tucker, Senior Vice President
Nuclear Generation
Duke Power Company
P. O. Box 1007
Charlotte, North Carolina 28201-1007

Dear Mr. Tucker:

SUBJECT: SAFETY EVALUATION ON TOPICAL REPORT DPC-NE-3000, "THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY (TAC NOS. 73765/73766/73767/73768)

The NRC staff with the support of its contractor has reviewed Duke Power Company Topical Report DPC-NE-3000, "Thermal-Hydraulic Transient Analysis Methodology," transmitted on September 29, 1987, as revised by letter dated May 11, 1989. Additional information supporting the review was provided by DPC letters dated June 15, June 19, August 9, and September 13, 1989, February 20, 1990, August 29, October 16, and November 5, 1991. The staff has found the topical report to be acceptable for referencing in the symmetric non-LOCA system and core thermal-hydraulic transient analyses for the McGuire and Catawba Nuclear Station subject to the conditions delineated in section 3.0 of the attached Safety Evaluation. At this time, DPC-NE-3000 is not acceptable for referencing in analyses involving the Oconee Nuclear Station. The staff is continuing its review of DPC-NE-3000 for Oconee.

This concludes our review activities in response to your submittals regarding Topical Report DPC-NE-3000 for the McGuire and Catawba Nuclear Stations.

Sincerely,

Robert Martin
for ~~Timothy~~ A. Reed, Project Manager
Project Directorate II-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Safety Evaluation
2. Technical Evaluation Report ITS/NRC/91-2,
   Parts 1 and 2

cc: See next page

Duke Power Company

McGuire Nuclear Station
Catawba Nuclear Station
Oconee Nuclear Station

cc:
Mr. R. C. Futrell
Regulatory Compliance Manager
Duke Power Company
Catawba Nuclear Site
Clover, South Carolina 29710

North Carolina Electric Membership
Corp.
P.O. Box 27306
Raleigh, North Carolina 27611

Saluda River Electric Cooperative,
Inc.
P.O. Box 929
Laurens, South Carolina 29360

North Carolina MPA-1
Suite 600
P.O. Box 29513
Raleigh, North Carolina 27626-513

Mr. Heyward G. Shealy, Chief
Bureau of Radiological Health
South Carolina Dept. of Health
and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201

County Manager of York County
York County Courthouse
York, South Carolina 29745

Richard P. Wilson, Esq.
Assistant Attorney General
S.C. Attorney General's Office
P.O. Box 11549
Columbia, South Carolina 29211

Senior Resident Inspector
Route 2, Box 179N
York, South Carolina 29745

Mr. M. S. Tuckman
Vice President, Catawba Site
Duke Power Company
P. O. Box 256
Clover, South Carolina 29710

Mr. M. E. Patrick
Compliance
Duke Power Company
Oconee Nuclear Site
P. O. Box 1439
Seneca, South Carolina 29679

Mr. Robert B. Borsum
Babcock & Wilcox
Nuclear Power Division
Suite 525
1700 Rockville Pike
Rockville, Maryland 20852

Manager, LIS
NUS Corporation
2650 McCormick Drive, 3 Floor
Clearwater, Florida 34619-1035

Senior Resident Inspector
U. S. Nuclear Regulatory Commission
Route 2, Box 610
Seneca, South Carolina 29678

Mr. J. W. Hampton
Vice President, Oconee Site
Duke Power Company
P. O. Box 1439
Seneca, South Carolina 29679

Office of Intergovernmental Relations
116 West Jones Street
Raleigh, North Carolina 27603

County Supervisor of Oconee County
Walhalla, South Carolina 29621

Piedmont Municipal Power Agency
121 Village Drive
Greer, South Carolina 29651

Duke Power Company

McGuire Nuclear Station
Catawba Nuclear Station
Oconee Nuclear Station

cc:
Mr. A.V. Carr, Esq.
Duke Power Company
422 South Church Street
Charlotte, North Carolina 28242-0001

County Manager of Mecklenburg County
720 East Fourth Street
Charlotte, North Carolina 28202

Mr. R. O. Sharpe
Compliance
Duke Power Company
McGuire Nuclear Site
12700 Hagers Ferry Road
Huntersville, North Carolina 28078-8985

J. Michael McGarry, III, Esq.
Winston and Strawn
1400 L Street, N.W.
Washington, DC 20005

Senior Resident Inspector
c/o U.S. Nuclear Regulatory Commission
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Regional Administrator, Region II
U.S. Nuclear Regulatory Commission
101 Marietta Street, N.W., Suite 2900
Atlanta, Georgia 30323

Mr. Frank Modrak
Project Manager, Mid-South Area
ESSD Projects
Westinghouse Electric Corporation
MNC West Tower - Bay 241
P. O. Box 355
Pittsburgh, Pennsylvania 15230

Dr. John M. Barry
Department of Environmental Health
Mecklenburg County
1200 Blythe Boulevard
Charlotte, North Carolina 28203

Mr. Dayne H. Brown, Director
Department of Environmental,
Health and Natural Resources
Division of Radiation Protection
P.O. Box 27687
Raleigh, North Carolina 27611-7687

Mr. Alan R. Herdt, Chief
Project Branch #3
U.S. Nuclear Regulatory Commission
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

Ms. Karen E. Long
Assistant Attorney General
N. C. Department of Justice
P.O. Box 629
Raleigh, North Carolina 27602

Mr. R. L. Gill, Jr.
Licensing
Duke Power Company
P.O. Box 1007
Charlotte, North Carolina 28201-1007

Mr. T. C. McMeekin
Vice President, McGuire Site
Duke Power Company
12700 Hagers Ferry Road
Huntersville, North Carolina 28078-8985

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATING TO TOPICAL REPORT DPC-NE-3000

"THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY"

OCONEE NUCLEAR STATIONS, UNITS 1, 2, AND 3

MCGUIRE NUCLEAR STATIONS, UNITS 1 AND 2

CATAWBA NUCLEAR STATIONS, UNITS 1 AND 2

DOCKET NOS. 50-269, 50-270, 50-287, 50-369, 50-370, 50-413 AND 50-414

1.0 INTRODUCTION

Duke Power Company (DPC) submitted Topical Report DPC-NE-3000, "The Thermal-Hydraulic Transient Analysis Methodology, Oconee Nuclear Station, McGuire Nuclear Station, and Catawba Nuclear Station" in a letter dated September 29, 1987 (Ref. 1), as revised by a letter dated May 11, 1989 (Ref. 2). Additional information was also provided in References 3 to 10. This topical report documents the development of the thermal-hydraulic simulation models for the Oconee, McGuire, and Catawba plants using RETRAN-02 and VIPRE-01 computer codes and provide DPC's responses to Generic Letter 83-11, "Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions" (Ref. 11).

RETRAN-02 is a large and sophisticated computer code developed to simulate a wide spectrum of thermal-hydraulic transients for both pressurized water reactors and boiling water reactors (Ref. 12). VIPRE-01 is an open channel code designed to evaluate DNBR and coolant state for steady state and transient core thermal-hydraulic analyses (Ref. 13). Both RETRAN-02 and VIPRE-01 have been approved for PWR licensing calculations with generic limitations (Refs. 14 to 15).

Generic Letter 83-11 requests that each licensee or vendor who intends to use large, complex computer codes to perform their own safety analyses to demonstrate their proficiency to use the codes by submitting code verification performed by themselves. To demonstrate their technical competence in using the RETRAN computer code and qualify their RETRAN models for thermal-hydraulic transient simulation, DPC provided in the RETRAN portion of this topical report: (1) detailed descriptions of the plant nodalizations, control system models, code models, and code options selected for use in the analysis, (2) analyses benchmarked against start-up test data and plant operational transient data from the Oconee, McGuire, and Catawba plants.

In the SER for VIPRE-01, the staff requests each user to document and submit a separate report which, (1) describes how they intend to use VIPRE, and (2) provides justification for specific modeling assumptions, choices of particular

models and correlations, and input values of plant specific data such as turbulent mixing coefficient and grid loss coefficient. DPC previously submitted VIPRE-01 models for use in steady-state which have been addressed in specific SERs. VIPRE-01 models for transient applications are addressed in this SER.

2.0 STAFF EVALUATION

The staff review and evaluation of the Topical Report DPC-NE-3000 addresses: (1) DPC's competence in using the RETRAN and VIPRE computer codes, (2) the degree to which the topical report and supplemental information satisfy requirements in the VIPRE-01 and RETRAN SERs; and, (3) the ability of the RETRAN simulations to match plant operational data. The review of this topical was performed with technical assistance from International Technical Services, Incorporated (ITS) and its review findings are contained in the Technical Evaluation Report (TER) which is attached. The staff has reviewed the TER and concurred with its findings.

3.0 FINDINGS AND CONCLUSIONS

The staff has reviewed the Topical Report DPC-NE-3000, which documents the development of the thermal-hydraulic simulation models for the Oconee, McGuire, and Catawba plants. Overall we conclude that the licensee has demonstrated a high degree of technical competence in using RETRAN-02 and VIPRE-01 computer codes. Specific findings and conclusions regarding the RETRAN and VIPRE models are discussed below.

RETRAN FINDINGS

We find that DPC's RETRAN-02 models to be acceptable for the simulation of the symmetric non-LOCA thermal-hydraulic transients for the McGuire, and Catawba Nuclear Units, subject to the limitations listed below. However, the RETRAN-02 models for Oconee have not been shown to be adequate for best estimate nor licensing calculations, and are therefore not approved for either of these applications.

(1) With respect to analyzing transients which result in a reduction in steam generator secondary water inventory, use of the RETRAN-02 steam generator modeling is acceptable, only for transients in that category for which the secondary side inventory for the effective steam generator(s) relied upon for heat removal never decreases below an amount which would cover enough tube height to remove decay heat.

(2) All generic limitations specified in the RETRAN-02 SER (Reference 14).

VIPRE FINDINGS

We find that the subject topical report, together with DPC responses, contains sufficient information to satisfy the VIPRE-01 SER requirement that each VIPRE-01 user submit a document describing proposed use, sources of input variables, and selection and justification of correlations as it relates to use by DPC for FSAR Chapter 15 analyses regarding Oconee, McGuire and

Catawba. We further find that the manner in which the code is to be used for such analyses, selection of nodalization, models, and correlations provides, except as listed below, adequate assurances of conservative results and is therefore acceptable. Furthermore, the use of the DPC developed statistical core design methodology as approved in the Staff Safety Evaluation Report on DPC-NE-2004, is approved for the transient application subject to the same conditions.

The following items are limitations regarding VIPRE-01 application presented in DPC-NE-3000 and its supplemental materials:

(1) Determination of acceptability is based upon review of selection of models/correlations for transients involving symmetric core neutronic and thermal-hydraulic conditions only. Thus, the VIPRE-01 models are approved for use in analyzing symmetric transients only;

(2) When using the DPC developed SCD method, the licensee must satisfy the conditions set forth in the staff's safety evaluation of DPC-NE-2004;

(3) Whenever DPC intends to use other CHF correlations, power distribution, fuel pin conduction model or any other input parameters and default options which were not part of the original review of the VIPRE-01 code, DPC must submit its justification for NRC review and approval;

(4) Core bypass flow should be determined on cycle-by-cycle bases;

(5) All generic limitations specified in the VIPRE-01 SER.

4.0 REFERENCES

1. Letter from H. B. Tucker (DPC) to USNRC, "Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, Response to Generic Letter 83-11," September 29, 1987.

2. Letter from H. B. Tucker (DPC) to USNRC, Attachment "DPC-NE-3000 Revision 1," May 11, 1989.

3. Letter from H. B. Tucker (DPC) to USNRC, Attachment "Duke Power Responses to NRC Questions Dated April 7, 1989 Regarding DPC-NE-3000," June 15, 1989.

4. Letter from H. B. Tucker (DPC) to USNRC, "Response to Questions Regarding Differences Between Duke Topical Reports DPC-NE-2003 and DPC-NE-3000," June 19, 1989.

5. Letter from H. B. Tucker (DPC) to USNRC, "Duke Power Response to NRC Questions Regarding Steam Generator Heat Transfer Modeling with the RETRAN Code," August 9, 1989.

6. Letter from H. B. Tucker (DPC) to USNRC, Attachment 1 "Responses to NRC Questions on the McGuire/Catawba Sections of DPC-NE-3000" and Attachment 2 "Revisions to Section 4 of DPC-NE-3000," September 13, 1989.

7. Letter from H. B. Tucker (DCP) to USNRC, "Response to NRC Questions on DPC-NE-3000 Dated July 25, 1989," February 20, 1990.

8. Letter from M. S. Tuckman (DPC) to USNRC, "Supplemental Information to Assist in Review of Topical Reports DPC-NE-3000 and DPC-NE-2004," August 29, 1991.

9. Letter from H. B. Tucker (DPC) to USNRC, "Handouts Presented in the October 7 & 8, 1991 Meeting with NRC Staff and Contract Reviewers," October 16, 1991.

10. Letter from H. B. Tucker (DPC) to USNRC, "Final Response to Questions Regarding the Topical Reports Associated with the M1C8 Reload Package," November 5, 1991.

11. Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions (Generic Letter No. 83-11), USNRC, February 8, 1983.

12. "RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems," EPRI NP-1850-CCM Revision 2, EPRI, November 1984.

13. "VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores," EPRI NP-2511-CCM Revision 2, EPRI, July 1985.

14. Letter, C. O. Thomas (NRC) to T. W. Schnatz (UGRA), September 4, 1984, (Transmittal of RETRAN-02 Safety Evaluation Report).

15. Letter, C. E. Rossi (NRC) to J. A. Blaisdell (UGRA), May 1, 1986, (Transmittal of VIPRE-01 Safety Evaluation Report).

16. "Oconee Nuclear Station Core Thermal-Hydraulic Methodology Using VIPRE-01," DPC-NE-2003, August 1988.

Date: November 15, 1991

TECHNICAL EVALUATION
OF THE THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY
TOPICAL REPORT DPC-NE-3000
FOR THE
DUKE POWER COMPANY
OCONEE, MCGUIRE AND CATAWBA NUCLEAR STATIONS
Part 1

1.0 INTRODUCTION

DPC-NE-3000, dated July 1987 (Ref. 1), documents results of a series of studies performed by Duke Power Company (DPC) to support the development of thermal-hydraulic transient analysis methods and provides DPC's response to Generic Letter 83-11 (Ref. 2). These methods were developed using the RETRAN-02 (Ref. 3) and VIPRE-01 (Ref. 4) computer codes, both of which have been approved, subject to conditions (Refs. 5 & 6). The stated objective of the subject report was for DPC to demonstrate DPC capability and technical competence through RETRAN analysis of its Oconee plants (which are B&W plants) and its McGuire and Catawba plants (which are Westinghouse plants).

The purpose of this review, which is based upon a review of the submitted materials (Refs. 1, 7-13), is to determine (i) the degree of DPC's technical competence demonstrated in the transient analyses, (ii) acceptability of the RETRAN plant models by review of the accuracy of the results obtained using the computer codes and submitted models and (iii) adequacy of DPC's documentation of its VIPRE-01 models to fulfill VIPRE SER requirements.

This technical evaluation report (TER) is divided into two parts: Part 1 presents our evaluation (in accordance with the RETRAN SER) of DPC's use of the RETRAN computer code and the acceptability of the DPC RETRAN models for Oconee and McGuire/Catawba plants; Part 2 contains an evaluation (in accordance with the VIPRE SER) of DPC's intended method for use of the VIPRE computer code in transient application for the same plants.

2.0 EVALUATION

Acceptability of DPC's application of the RETRAN computer code for thermal-hydraulic calculations of the transient behavior of its Oconee and McGuire/Catawba plants is discussed below.

2.1 Oconee Plant Model

DPC developed two Oconee RETRAN models: (1) a one-loop plant model to be used where there is little asymmetry between loop responses and (2) a two-loop plant model to be used when asymmetric conditions are expected in the analysis. Detailed descriptions of the plant nodalizations and models selected for use in the analysis are presented in Chapter 2 of the topical report.

In the one-loop model, DPC models both steam generators and the accompanying hot and cold legs by one hot leg, one once-through steam generator (OTSG) and one cold leg. The core and steam generator nodalizations are the same as those in the two-loop plant model.

The base two-loop Oconee plant model consists of two separate loops each containing one hot leg, an OTSG and two cold legs. The OTSG is nodalized with equal height shell and tube side volumes except at the bottom of the steam generator. DPC stated that the specific degree of detail selected (i.e. the number of nodes) for the OTSG is necessary to model the void distribution in the OTSG.

The modeling of OTSGs is very difficult because in normal operation the steam in the upper portion of the SG is super heated and the SG tubes are partially uncovered (in marked contrast to U-tube type plants). Therefore the primary-to-secondary heat transfer rate is a function of the two-phase mixture height on the secondary side and the predicted transient behavior is strongly dependent upon the two-phase modeling on the secondary side of the steam generator. The mixture interface location and its transient behavior are

very difficult to model with RETRAN, facts which DPC has acknowledged (Ref. 10).

DPC used the non-equilibrium pressurizer option to model the pressurizer (PZR) for best-estimate safety analysis. Other model options are used as necessary to obtain conservative results for Chapter 15 type analyses.

Although the DPC responses to NRC questions referred to their experience with three sets of nodalizations and to sensitivity studies performed to arrive at the base nodalization, DPC did not justify selection of built-in RETRAN thermal-hydraulic models and correlations. Furthermore, although the nodalization study indicates that the model was converged, it did not indicate accurate convergence to the mixture level on the secondary side.

In addition, DPC presented qualitative arguments supporting the selection of various nodalizations for other plant components (such as the reactor vessel) and the selection of the use of the certain models such as the bubble rise model and the non-equilibrium model.

The Oconee base model is based on the Unit 1 thermal design flow, since it is lower than Units 2 and 3 and is conservative with respect DNB. The RETRAN initial conditions for computed RCS flow as well as other key plant parameters were adjusted by DPC on a transient-by-transient basis to better match the plant data as noted later.

RETRAN control systems were developed and used extensively by DPC to specify transient boundary conditions, such as automatic plant actions and operator actions as well as control actions by modulating valves, changing fill rates or reactivity and simulation of trip actuation. The control system was also used to compute the steam generator level by emulating the plant measurement devise by taking DP across SG pressure taps. In addition, uncertainty in the degree of SG tube fouling generally resulted further in large discrepancies between the predicted and measured data as discussed in the following sections.

2.1.1 Oconee RETRAN Model Qualification

DPC chose to demonstrate the adequacy of the base plant model for both Oconee and McGuire/Catawba plants through comparison of RETRAN analyses to available plant data, providing reasonably thorough analyses of the transients analyzed. However, DPC provided only limited justification for its plant nodalization, input selection, and selection of particular correlations built into the code, and did not present any description of its RETRAN control systems models in the topical report. DPC took the position that the test of the model was in its ability to reproduce plant data, notwithstanding the fact that it is widely recognized that modeling of a once-through steam generator is difficult with RETRAN (as is evident from results of DPC benchmark analysis).

Therefore, this evaluation is based upon a review of the ability of the base model (best-estimate model) to benchmark startup test data and several operational transient data over a wide range of plant conditions.

2.1.2 Benchmark Analyses

For the purpose of benchmarking the base Oconee RETRAN models, DPC analyzed 11 tests and transients, one of which was a transient which occurred at Arkansas Nuclear One - Unit 1, a sister plant.

The one-loop model was used for six analyses: (1) Loss of Main Feedwater, (2) Turbine Bypass Valve Failure Following Reactor Trip, (3) Loss of Offsite Power, (4) Steady State Natural Circulation Comparisons, (4) Control Rod Group Drop, and (6) Main Feedwater Pump Trip.

The two-loop model was used in the five remaining analyses: (1) Steam Generator Overfeed Following Reactor Trip, (2) Overcooling Following Loss of ICS Power, (3) Reactor Coolant Pump Coastdowns, (4) Turbine Bypass Valve Failure, and (5) Reactor Trip from Three Reactor Coolant Pump Operation.

2.1.2.1 Loss of Main Feedwater

DPC analyzed the loss of main feedwater event which occurred in August 1984 at Oconee Nuclear Station Unit 3 while it was operating at full power. Letdown was manually isolated in the first 10 seconds and RCS makeup flow was increased manually. Only one high pressure injection (HPI) pump operated during the transient. All three emergency feedwater (EFW) pumps started immediately following the loss of the MFW pumps, and contributed to maintaining SG levels.

The modeling of this transient was revised and resubmitted by DPC (Ref. 8) to better model the boundary conditions. In the revised analysis, RCS flow and T-ave were adjusted to match the plant data which resulted in T_{hot} and T_{cold} being initialized at slightly different values. Since the EFW flow data were unavailable, DPC inferred the EFW flowrate from the SG levels and used a RETRAN control system to simulate throttling of EFW to match the simulated SG level with the plant data.

DPC provided a thorough analysis for this transient. Following the trip, results indicated a modest over-prediction of primary-to-secondary heat transfer and, after the PZR spray setpoint was first reached at roughly 450 seconds into the transient, the predicted RCS pressure cycled at approximately double the frequency of the plant data until about 900 seconds into the transient. Thereafter until the EFW flow was reestablished, the predicted pressure cycled at only a slightly higher frequency than the data. During the period between the beginning of the transient and about 1100 seconds, DPC computed the PZR level to be lower than the data, and the predicted hot and cold leg (average since one loop represents both cold legs) temperatures were predicted to be lower than the plant data implying an overprediction of the primary-to-secondary heat transfer.

After reestablishment of the EFW, the computed average cold leg temperature matched the loop B data but was roughly 10 degrees above the loop A data, the computed hot leg temperatures agreed with the data and the predicted

pressurizer level was about 35 inches higher than the measured data, while the RCS pressure was predicted to decrease at roughly twice the measured rate.

DPC explained these modest differences between the predicted and plant data as being due to several factors:

(1) the code tended to couple too closely between SG temperature and RCS temperature during low SG flow conditions (which were present during the EFW stages of this transient) due, in part, to overprediction of the boiling length/mixture level caused by the lack in RETRAN of an unequal phase velocity model in the SG tube region;
(2) the overprediction of pressure decrease following reestablishment of EFW at 1310 seconds was due to pressurizer modeling which did not model the expected stratification of fluid which would accompany an insurge of cooler primary loop water, which would affect pressure response during the outsurge which accompanied the renewed EFW flow; and
(3) the lack of accurate modeling in RETRAN of interphase heat transfer which was very important in modeling the impact of pressurizer spray.

The last two factors may also have been at responsible for the facts that the PZR spray was predicted to cycle twice as frequently as the data during the period between 450 to 900 seconds and at approximately the same rate between 900 to 1300 seconds.

2.1.2.2 Turbine Bypass Valve Failure Following Reactor Trip

The turbine bypass valve failure occurred after an anticipatory reactor trip occurred on a main turbine trip signal. The failure was due to a malfunction in the turbine bypass system. Letdown was manually isolated in the first 10 seconds and makeup flow was increased by manually opening a second makeup valve. Main feedwater remained available throughout the event. The turbine

bypass valves were manually closed.

DPC adjusted the RCS and MFW flows to obtain the measured primary and secondary temperatures.

The DPC analysis predicted the global trend for the key plant parameters. However, the fine structure of this transient was not well predicted, with the RCS temperatures and RCS pressure being consistently underpredicted. With RCS temperatures and pressure consistently underpredicted, the PZR level would be expected to also be consistently underpredicted. However, the PZR level was overpredicted at times and underpredicted at other times during this transient. DPC stated that the "RCS pressure data ... may not be ... accurate".

An offset in the SG level, developed between the predicted results and the data after the first 10 seconds of the transient, was attributed to fouling of the SGs, causing SG level data to be in error. RETRAN did not predict the repressurization of SG pressure after the TBVs closure. DPC stated that this may be due to discrepancy in SG secondary side inventory and primary-to-secondary heat transfer rate. In addition, DPC stated that changes in slope in the data may be due to lifting and reseating of the main steam relief valves.

2.1.2.3 Steam Generator Overfeed Following Reactor Trip

Following the turbine trip, due to an Integrated Control System failure, the MFW pumps did not run back properly, resulting in overfeeding the steam generators. This led to a pump trip on high level in SG "A".

For this analysis DPC matched the initial SG levels to the plant data since the fouling in the SG was deemed less significant at the time of this transient.

The computed values of the key predicted plant parameters agreed well with the plant data. Steam generator secondary side mixture levels on the other

hand, after starting at the same levels, drifted apart (RETRAN predicting lower than the data) to maintain about the same offset after 40 seconds into the transients. DPC attributed this discrepancy to overprediction of primary-to-secondary heat transfer, which was consistent with the moderate underprediction of primary temperatures.

2.1.2.4 Overcooling Following Loss of ICS Power

Due to a spurious low hotwell level signal, Oconee Unit 3 tripped the hotwell pumps at 99% full power operation. At 73 seconds the power supply to the ICS was lost for a period of 150 seconds. During the same period, the turbine bypass valves failed at an unknown partially open position. This resulted in a loss of SG pressure control and overcooling.

DPC specified as boundary conditions the reactor power runback, MFW flow data, EFW and HPI actuation, a post-trip auxiliary steam demand, and the steam relief flowrate through a turbine control system.

Since so much was unknown after the ICS was lost and due to the partially stuck opened turbine bypass valves at an unknown position, only the first 73 seconds of this analysis was reviewed.

The repressurization of the RCS beginning at about 30 seconds was over-predicted by the code by 150 psi and the PZR level was slightly overpredicted. This was attributed by DPC to be due to the code's neglect of heat transfer between the steam and liquid regions of the PZR during the compression of the steam which accompanies the insurge.

The cold leg temperature increases were similarly overpredicted by the code during this same period, indicating underprediction of primary-to-secondary heat transfer, which was consistent with the underprediction of SG levels, and was probably also related to minor imprecisions in the modeling of power runback during the first 55 seconds of the transient.

2.1.2.5 Loss of Offsite Power at Arkansas Nuclear One - Unit 1

While operating at 100% power, Arkansas Nuclear One Unit 1 experienced a loss of offsite power. Stable natural circulation was established and maintained for more than one hour before the offsite power was restored.

DPC used as boundary conditions a one second MFW flow coastdown, EFW and HPI flows, ANO-1 MSSV lift setpoints and SG pressure vs. time control.

Although primary and secondary pressures were well predicted, the hot-to-cold leg delta T was overpredicted by nearly a factor of 2 at around 100 seconds, which was the time that natural circulation flows were set up. This implies that this analysis did not predict natural circulation flows very well. However, by roughly 150 seconds, the prediction nearly matched the data, implying a much better computation of natural circulation at this stage. DPC attributed the mismatch in the RCS temperatures during the early portion of the transient to differences in the predicted RCS flow and the actual flow during the coastdown.

2.1.2.6 Reactor Coolant Pump Coastdowns

A series of RCP coastdown tests were conducted as part of the startup testing. All of these tests were performed at hot zero power conditions considering all possible numbers of pumps available.

For this analysis, DPC stripped the two-loop model to include only those components pertinent to the benchmark remained.

The predicted and test results compared favorably, except in cases where reverse flow thorough the pump(s) occurred. For these cases, discrepancies ranged from 10 to 20% of full flow. DPC stated that where the divergent results were obtained, the divergence was in part due to suspect plant data. In addition, other discrepancies were said to occur for operating regimes in quadrants in which relatively little test data had been obtained, and therefore to not be necessarily indicative of code errors.

DPC further stated that the pump coastdown cases are not limiting with respect to the plant operating limits and that DPC does not perform transient analyses to determine operating limits with pump coastdown flow rates which are non-conservative with respect to plant data.

2.1.2.7 Steady State Natural Circulation Flow Comparisons

The RETRAN predictions were compared to calculated natural circulation flow rates from various tests and events at lowered-loop 177 fuel assembly B & W units at the end of a loss of offsite power simulation. Predictions varied from data by as much as a factor of two, with RETRAN consistently overpredicted the RCS natural circulation flows, a result which is consistent with the observed results of the ANO-1 analyses discussed above.

DPC attributed these discrepancies to prediction of a higher mixture level in the secondary side of the steam generators due to the lack of an unequal phase velocity model in RETRAN.

2.1.2.8 Control Rod Group Drop

The Group 6 control rods dropped when Oconee Unit 1 was operating at 100% power.

RCS makeup flow, MFW flow and steam generator pressure control are among the boundary conditions specified for the analysis. DPC increased the PZR surge line loss coefficient by a factor of 5 over its nominal value for analysis of this transient.

The computed plant parameters exhibited the same trend as those measured during the event. DPC stated that the increase in surge line loss coefficient was necessary to accurately model strong outsurges.

2.1.2.9 Main Feedwater Pump Trip

The 1B MFW pump tripped on low hydraulic oil pressure at Oconee Unit 1.

DPC used the reactor and turbine control valve controls, Unit Load Demand signal to the reactor control and MFW flows as boundary conditions.

The computed RCS temperatures were underpredicted slightly due to the overprediction of primary-to-secondary heat transfer, otherwise the computed key parameters agreed reasonably with those measured during the event.

2.1.2.10 Turbine Bypass Valve Failure

Following an increase in the steam generator "A" pressure signal at 100% full power at Oconee Unit 1, the turbine bypass valves opened. The erroneous pressure signal increased by 128 psi in 8 seconds, with the turbine bypass valves opening ~80%, while the actual SG pressure decreased ~25 psi during this period. After 14 seconds the erroneous SG pressure signal decreased and the bypass valves closed.

The boundary conditions used by DPC were reactor and turbine control, SG pressure signal to the turbine bypass controller, MFW flow and a reduction in the turbine bypass valve setpoint.

Since the main steam pressure response was not well predicted, the balance of the plant parameters were not well predicted.

2.1.2.11 Reactor Trip from Three Reactor Coolant Pump Operation

Oconee Unit 3 was operating at 74% full power with the B2 RCP secured. A component failure within the ICS caused a reduction in FW flow to the "A" SG. After 23 seconds, the reactor tripped on high RCS pressure.

SG levels were initially matched, but the SG "A" pressure was much higher than the data. The boundary conditions specified by DPC for the code were control rod movement, kinetics parameters, RCS makeup flow, MFW flow and SG pressure control.

The predicted RCS pressure dropped more than 100 psi below the drop in the data, and was attributed to overprediction of primary-to-secondary heat transfer due to inaccurate steam generator modeling.

2.1.3 Summary

In its modeling of the Oconee plant transient results, difficulties in accurately modeling primary-to-secondary heat transfer with the RETRAN two-phase flow and heat transfer models were a consistent source of erroneous computations (discrepancies between the predicted and measured data). These secondary-side originated difficulties also caused errors in primary-side results.

In addition, the RETRAN results consistently indicated inaccurate modeling of natural circulation flow.

Furthermore, DPC has observed that the pressurizer surge line loss factor must be increased by roughly a factor of 5 during the outsurge portion of any transient containing a strong outsurge.

Finally, DPC's model indicates an inability to accurately model reverse flow through stopped RCPs during coastdown of the other RCPs.

2.2 McGuire and Catawba Plant Model

Since these are not identical Westinghouse 4-loop plants, DPC developed different RETRAN models starting from the same basic model. Modifications were made in each analysis to better model the specific plant introducing some design differences between McGuire and Catawba plants and unit-dependent differences between two units of McGuire and Catawba. However, DPC assumed that the differences between the plants were small enough that model qualification through benchmark analysis of one should be considered to support the model developed for the other.

In addition, DPC developed two different models of McGuire and Catawba Plants: (1) one-loop plant model and (2) two-loop model. The one-loop model is to be used when all four loops are expected to behave similarly so that there is no asymmetrical condition. The two-loop model is to be used when asymmetric conditions are expected in the plant during the transient, thus one affected loop was modeled separately while the other three loops are lumped together. Although no details were presented, DPC also developed a three-loop model using the same basic approach.

A detailed description of the plant nodalization and models selected for use in transient analysis was presented in Chapter 3 of the topical report. The steam generator model contained a multiple number of volumes in the secondary side. DPC selected the RETRAN internal model for all volumes after an extensive series of parametric studies (Refs. 13 and 14). The mixture level prediction is made as a function of differential pressure across the location of pressure taps rather than to attempt to compute the mixture level. DPC is aware of the inability of its model to compute a mixture level.

The pressurizer is represented by a non-equilibrium volume.

RETRAN control systems were developed and used extensively by DPC to specify transient boundary conditions, such as automatic plant actions and operator actions as well as control actions by modulating valves, changing fill rates or reactivity and simulation of trip actuation. The control system is also used to compute the steam generator level by emulating the plant measurement devise by computing DP across the locations of the SG pressure taps. It is also used to convert a predicted mixture levels in the pressurizer into an indicated level and incorporating time delays into the predicted RCS loop temperatures to convert to the indicated temperatures. In all cases, DPC attempted to simulate the actual plant measuring devices.

2.2.1 McGuire/Catawba RETRAN Model Qualification

Although in general DPC chose to demonstrate the adequacy of the base plant

model for McGuire/Catawba (M/C) plants through comparison of RETRAN analyses to available plant data, in response to NRC questions, DPC provided (Refs. 13 and 14) details of sensitivity studies performed to assess adequacy of its M/C nodalization, in particular its steam generator model, and certain model and input selections. DPC provided thorough analyses of parametric sensitivity studies. The M/C plant RETRAN model was found to be acceptable not only in application for best-estimate analyses but also for licensing type analyses subject to the limitations set forth in the SERs on the topical reports DPC-NE-3001 and DPC-NE-3002.

This evaluation is based upon a review of the ability of the base model to benchmark startup test data and several operational transient data in a wide range of plant conditions.

2.2.2 Benchmark Analyses

For this objective, DPC performed benchmark analyses of 8 tests and plant transients, of which two were from the Catawba plants and the rest were from the McGuire plants.

The one-loop model was used for (1) Loss of Main Feedwater from 30% Power, (2) Steam Line PORV Failures, (3) Loss of Offsite Power and (4) Turbine Trip Test at 68 % Power.

The two-loop model was used for (1) loss of Main Feedwater to One Steam Generator and (2) Reactor Coolant Pump Trip at 89% Power.

For the reactor coolant pump flow coastdown tests, DPC simplified the base RETRAN models to only model the primary loop without any thermal modeling. The one-loop model simulated the four pump coastdown while two-, three- and four-loop models were also used to modeling consistency. The three-loop model was used for other combination of pump configuration during the tests.

The natural circulation test was simulated by use of two plant models: the one-loop as the base case and the three-loop model for the case with

sequential isolation of SGs.

2.2.2.1 Loss of Main Feedwater from 30% Full Power

In the benchmark analysis of the loss of main feedwater event from 30% full power, DPC used the one-loop McGuire Unit 2 RETRAN model.

For this analysis, DPC developed control systems: to match the pre-trip steam line pressure data, to match the post-trip steam line pressure response, and to regulate PZR spray flow. These as well as MFW and AFW flows were used as boundary conditions. Charging and letdown flows were not modeled.

The RETRAN results and plant data agreed reasonably well between 0 and 150 seconds. After roughly 150 seconds, DPC postulated two contributors to the discrepancies in pressurizer parameters between RETRAN results and plant data: (1) pressurizer backup heaters were predicted to de-energized by RETRAN but did not actually shut off, and (2) the absence of modeling of the charging and letdown system in the RETRAN model. The belief that charging and letdown actually had been activated at the plant was supported by a hand calculation by DPC.

The RETRAN control system used to compute the steam generator NR level was based upon the DP measurements between two pressure taps, and therefore was dependent upon nodalization. Anomalous behavior originating from the pressure and mass computation in the steam generator secondary (related to "pancaking") had little overall impact upon the global transient behavior in this analysis.

2.2.2.2 Loss of Main Feedwater to One Steam Generator

A two-loop McGuire Unit 2 model was used for this analysis. Boundary conditions used were MFW and AFW flows. Charging and letdown flows were not modeled.

The prediction of PZR pressure diverged (overpredicted) from the data. DPC

explained the early portion of the overprediction as being due to the absence of modeling of steam-liquid heat transfer in the PZR, and the latter portion as being due to an error in modeling the PZR heaters.

Imprecision in modeling the loop A steam line PORV and the condenser dump valves was postulated by DPC to be the source of the failure of the RETRAN computation to model the spikes in steam line pressure.

2.2.2.3 Steam Line PORV Failure

This was an event initiated by a test conducted at the Catawba Nuclear Station Unit 2 which went beyond the intended range due to an operator error. The plant was operating at 24% power when the test was initiated. When the control breakers were tripped, all four steam line PORVs opened and remained open for six minutes.

DPC specified AFW flow, auxiliary steam loads, charging and letdown flows and safety injection flow as boundary conditions. The steam line PORV junction area was adjusted to match the steam line depressurization rate.

Using the one-loop Catawba Unit 2 model, DPC obtained good agreement with the plant data for the key plant parameters presented in the topical report with the exception of the SG level. DPC stated that the underprediction was due to low initial SG inventory and uncertainty in AFW.

2.2.2.4 Reactor Coolant Pump Coastdown Tests

The reactor coolant (RCP) pump coastdown tests were performed as part of the pre-critical startup testing under isothermal conditions with the reactor subcritical. These tests serve to confirm the flow coastdown characteristics.

For this benchmark analyses, DPC used the model consisting of only the primary loops without any thermal modeling. In addition, both one- and three-loop models were used after unit specific models were developed to

determine impact of any unit design dependent differences.

RETRAN predicted parameters were comparable to those obtained during the tests. These results validated DPC's RCP model to simulate RCP coastdown characteristics over the range of flows indicated in the report.

2.2.2.5 Natural Circulation Testing

Two types of natural circulation tests were submitted to support natural circulation modeling for McGuire and Catawba: steady-state natural circulation tests conducted at 1% and 3% full power at both plants, although there is some uncertainty in the core power; and a test conducted at McGuire to evaluate the plant response to isolating two SGs in sequence after achieving a stable natural circulation condition with the reactor critical at approximately 1% power. In this latter test, SGs were isolated by closing the MSIV, isolating feedwater, and isolating blowdown.

For the steady-state test, the one-loop McGuire Unit 1 model was used for analysis while a three-loop McGuire Unit 1 model was used for the natural circulation with SG isolation test simulation.

The computed trend was in the same direction as the test data in the steady-state natural circulation tests; however, no further conclusion can be drawn from this comparison due to plant power level uncertainties.

In the natural circulation with SG isolation test simulation, the predicted and test data did not agree well.

The differences were attributed to inaccurate modeling of reactor power, overprediction primary-to-secondary heat transfer, potential steam leaks and ambient cooling from isolated SGs.

2.2.2.6 Reactor Coolant Pump Trip from 89% Full Power

An RCP trip from 89% full power occurred at McGuire Unit 1 when the DPC "C"

bus feeder breaker opened. Because of the asymmetric nature of the event, DPC used the two-loop McGuire Unit 1 RETRAN model for analysis. The RETRAN simulation was performed by adjusting the RCS flow to match core delta T. The steam line pressure data was input by DPC as a boundary condition during the simulation to better match the actual plant performance, since plant valve position data was unavailable and using a best-estimate resulted in discrepant results.

RETRAN predicted plant parameters were comparable to plant data. The difficulty in matching the steam generator level in the first 40 seconds of the transient was again attributed by DPC to non-physical mass redistributions caused by the RETRAN modeling of two phase flows in the steam generator secondary side.

2.2.2.7 <u>Loss of Offsite Power</u>

Plant data were obtained during the loss of offsite power event initiated by a spurious high power range flux rate which tripped the reactor at 100% full power operation. A one-loop plant model was used. The RCS flow was specified to match delta T.

Plant steam line pressure, MFW, AFW, charging and letdown flows, and status of PZR heater banks were specified as boundary conditions.

DPC's computation of the loss of offsite power event resulted in an underprediction in the pressurizer pressure beginning at about 100 seconds reaching a 150 psi underprediction by roughly 400 seconds and remaining there for the balance of the computation. The loop delta T's were similarly underpredicted by roughly 20%, with Thot being underpredicted by approximately 10 degrees and Tcold being matched. DPC attributed these differences to underprediction of loop hydraulic losses at low flow.

2.2.2.8 <u>Turbine Trip Test from 68% Full Power</u>

A Turbine Trip Test from 68% Full Power was conducted as an Operational

Transient Without Reactor Trip at the Catawba Nuclear Station Unit 1. This test is performed to demonstrate the effectiveness of plant control systems to stabilize the plant without tripping the reactor. In the one-loop Catawba Unit 1 RETRAN model, DPC stated that it built in detailed modeling of the pressurizer pressure controller and the plant control systems including operator actions.

The RCS flow was specified in the simulation to match delta T. The boundary conditions include the main feedwater flow rate and the reference T-ave as a function of time.

The results indicated only general trend agreement, since the power was inaccurately simulated after approximately 90 seconds and therefore the other plant parameters were not well matched.

2.2.3 Summary

DPC was able to get better agreement in the McGuire/Catawba benchmark analyses than in Oconee analysis, largely because the primary-to-secondary heat transfer was less dependent upon the secondary side modeling because the SG tubes remain covered in most transients.

However, as before, the RETRAN results consistently showed inaccurate modeling of natural circulation flow although this may be caused by uncertainties associated with test data.

In most instances when the measured data and RETRAN predicted results did not agree, the sources of differences were generally attributed by DPC to be due to inaccuracies or lack of sufficient details in the measured data.

Finally, the controller model of the steam generator level continuously gave spurious indications due to the manner in which RETRAN computed the steam generator pressures in the stacked volumes.

3.0 CONCLUSIONS

DPC topical reports DPC-NE-3000 and its supporting documents, including the DPC responses to NRC questions, were reviewed.

Based upon the submitted materials and through analysis of plant transient behavior using RETRAN, DPC has exhibited a high degree of staff technical competence, both in knowledge of the plants themselves and in understanding plant transient behavior. In addition DPC staff has demonstrated an excellent analytical knowledge of the code and code models. Furthermore, DPC staff has demonstrated sophistication in its use of the RETRAN control systems.

DPC's RETRAN models for the McGuire/Catawba nuclear power plants are generally acceptable, and acceptability extends to application to the licensing type analyses provided that analyses contain adequate conservatisms to produce acceptable results, and subject to the limitations set forth in the SERs on DPC-NE-3001 and 3002, and provided further that the following condition is satisfied:

> With respect to modeling under-cooling transients caused by loss of or reduction in feedwater flow, use of the steam generator modeling is acceptable for all transients in that category subject to the following condition:
>
> (1) if the affected steam generator(s) is/(are) relied upon for heat removal, the secondary side inventory never decreases below an amount which, if collapsed to zero void fraction, would cover enough tube height to remove decay heat.

DPC's RETRAN models for the Oconee plants require further justification of the steam generator model before it can be used in either best-estimate or licensing type analyses and in particular DPC must demonstrate that;

(1) its steam generator secondary side modeling produces conservative results for each such transient;

(2) its nodalization for the reactor vessel is appropriate for the transient to be analyzed and conservative;

(3) its selection of RETRAN internal models and correlations is conservative; and

(4) its RETRAN control systems are accurate and conservative.

4.0 REFERENCES (Part 1 - RETRAN)

1. "Thermal-Hydraulic Transient Analysis Methodology," DPC-NE-3000, July 1987.

2. Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions (Generic Letter No. 83-11), USNRC, February 8, 1983.

3. "RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems," EPRI NP-1850-CCM Revision 2, EPRI, November 1984.

4. "VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores," EPRI NP-2511-CCM Revision 2, EPRI, July 1985.

5. Letter, C.O. Thomas (NRC) to T.W. Schnatz (UGRA), September 4, 1984, (Transmittal of RETRAN-02 Safety Evaluation Report).

6. Letter, C.E. Rossi (NRC) to J.A. Blaisdell (UGRA), May 1, 1986, (Transmittal of VIPRE-01 Safety Evaluation Report).

7. Letter from H.B. Tucker (DPC) to USNRC, Attachment "DPC-NE-3000 Revision 1," May 11, 1989.

8. Letter from H.B. Tucker (DPC) to USNRC, Attachment "Duke Power Responses to NRC Questions Dated April 7, 1989 Regarding DPC-NE-3000," June 15, 1989.

9. Letter from H.B. Tucker (DPC) to USNRC, "Responses to Questions Regarding Differences Between Duke Topical Reports DPC-NE-2003 and DPC-NE-3000," June 19, 1989.

10. Letter from H.B. Tucker (DPC) to USNRC, "Duke Power Response to NRC Questions Regarding Steam Generator Heat Transfer Modeling with the RETRAN Code," August 9, 1989.

11. Letter from H.B. Tucker (DPC) to USNRC, Attachment 1 "Response to NRC

Questions on the McGuire/Catawba Sections of DPC-NE-3000" and Attachment 2 "Revisions to Section 4 of DPC-NE-3000," September 13, 1989.

12. Letter from M.S. Tuckman (DPC) to USNRC, "Supplemental Information to Assist in Review of Topical Reports DPC-NE-3000 and DPC-NE-2004," August 29, 1991.

13. Letter from H.B. Tucker (DPC) to USNRC, "Handouts Presented in the October 7 & 8, 1991 Meeting with NRC Staff and Contract Reviewers," October 16, 1991.

14. Letter from H.B. Tucker (DPC) to USNRC, "Final Response to Questions Regarding the Topical Reports Associated with the M1C8 Reload Package," November 5, 1991.

ITS/NRC/91-2
(Part 2)

TECHNICAL EVALUATION
OF THE THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY
TOPICAL REPORT DPC-NE-3000
FOR THE
DUKE POWER COMPANY
OCONEE, MCGUIRE AND CATAWBA NUCLEAR STATIONS
Part 2

1.0 INTRODUCTION

DPC-NE-3000, dated July 1987 (Ref. 1), documents results of a series of studies performed by Duke Power Company (DPC) to support the development of thermal-hydraulic transient analysis methods. Part 1 of this Technical Evaluation Report (TER) documents evaluation, in accordance with the RETRAN Safety Evaluation Report (SER) (Ref. 2), of DPC's use of the RETRAN computer code (Ref. 3) and the acceptability of the DPC RETRAN models for analysis of Oconee and McGuire/Catawba Nuclear Stations. Part 2 contains evaluation, in accordance with the VIPRE SER (Ref. 4), of DPC's intended use of the VIPRE-01 computer code (Ref. 5) in transient DNBR calculation and its conformity of the DPC submittals to the VIPRE SER requirements.

During the course of review of DPC-NE-3000, the chapter presenting Oconee VIPRE models was replaced in its entirety with Revision 1 of the topical report, at which time the McGuire/Catawba VIPRE model qualification chapter was added to the subject topical report as part of Chapter 3 (Ref. 6). Therefore, this review is based upon review of Revision 1 to DPC-NE-3000.

Two different VIPRE models for the core thermal-hydraulic analysis have been developed by DPC for use in steady-state, documented in DPC-NE-2003 and DPC-NE-2004, and transient applications for both types of plants (Refs. 7 and 8). Transient application of VIPRE-01 for both Oconee and McGuire/Catawba are

reviewed herein. DPC documented the differences between the models used for steady state and those used for transient applications (Refs. 6 and 9); the steady-state model is used in support of core reload analysis and the transient model is used for FSAR Chapter 15 type analysis. For these two applications, DPC uses different assumptions, nodalizations, thermal-hydraulic models and correlations, and other input data selections. Therefore, it was necessary for DPC to fully justify its intended use of VIPRE in transient applications.

The DPC submittal contains DPC's geometric representation of the core, its selection of thermal-hydraulic models and correlations, and a description of the methodology used for FSAR Chapter 15-type licensing transient analysis. Although DPC's basic methodology and conservative assumptions to be used for FSAR Chapter 15-type analysis are the same in both Oconee and McGuire/Catawba plants, evaluation is presented here separately for each type of plants.

2.0 EVALUATION

2.1 VIPRE Model Description

VIPRE-01 has been previously reviewed and approved for application to pressurized water reactor (PWR) plants in steady-state and transient analyses with heat transfer regimes up to critical heat flux. The VIPRE-01 SER includes conditions requiring each user to document and submit to the NRC for approval its procedure for using VIPRE-01 and to provide justification for its specific modeling assumptions, choice of particular two-phase flow models and correlations, heat transfer correlations, CHF correlation and DNBR limit, input values of plant specific data such as turbulent mixing coefficient and grid loss coefficient including defaults. This topical report was prepared to address these issues.

2.2 Oconee Core Analysis

The Oconee reactor core consists of 177 BAW Mark-BZ fuel assemblies. Each fuel assembly is a 15 x 15 array containing 208 fuel rods, 16 control rod

guide tubes, and one incore instrument guide tube.

2.2.1 Core Nodalization

In its sensitivity studies, DPC used the final set of thermal-hydraulic models and correlations which DPC intends to use in future licensing analysis.

2.2.1.1 Radial Noding Sensitivity

Since the VIPRE-01 code performs the thermal-hydraulic calculations simultaneously for all subchannels (a single-pass approach) and permits flexibility in selection of channel sizes and shapes, a sensitivity study was performed to determine the sensitivity of predicted DNBR to the subchannel model sizes. DPC intends to use the symmetrical case for the normal steady-state operation and most of the transients.

For asymmetrical cases, DPC will submit for NRC approval descriptions and justification of modeling of asymmetrical transients in separate submittals for NRC approval.

To assess nodalization sensitivity, DPC selected three different numbers of channels for core models using the same thermal-hydraulic correlations and models which DPC intends to use in future licensing analysis.

Sensitivity to the core model size was studied by comparing the results obtained with the coarse and fine size channel models. The coarse channel model was found to yield comparable MDNBRs as those obtained with the fine model. We therefore find DPC's use of the coarse channel model acceptable for Oconee thermal-hydraulic analysis.

2.2.1.2 Axial Noding Sensitivity

Using the coarse core model, three parametric calculations, each with BWC CHF correlation, were performed to assess sensitivity to the axial noding sizes.

The axial node lengths were selected by dividing the axial length into equal length of nodes. Two smaller node sizes correspond to the range of the code developer's recommended values. The results indicated that the mid-sized axial noding produced nearly identical MDNBR with those using the fine noding. We, therefore, find that use of the mid-sized uniform length axial nodes (Ref. 10) is acceptable for Oconee thermal-hydraulic analyses.

2.2.2 VIPRE-02 Input Data

DPC's approach to generation of input to the VIPRE-01 code was reviewed for acceptability. No review was conducted of the input data in comparison to the actual physical geometry.

2.2.2.1 Active Fuel Length

Since power is distributed over the length of the active fuel, a shorter aggregate fuel length yields higher power density, causing greater heat flux and is therefore conservative. DPC's choice for the active fuel length is conservative and acceptable. When a different assumption is used, DPC will justify its conservatism.

2.2.2.2 Spacer Grid Form Coefficients

Pressure losses across the spacer grids impact the axial pressure distribution and therefore the axial location of DNB. The spacer grid form loss coefficients were obtained from tests conducted by B&W. To determine the individual subchannel form loss coefficient, DPC stated that the vendor used its computer code, GRIL. The input data to the GRIL code are the individual subchannel geometry, drag areas and coefficients, and the coolant information. From this input, the code calculates individual subchannel loss coefficients, an overall grid loss coefficient and subchannel velocities based on single-phase flow input data by a iterative process. The calculated overall grid loss coefficient is matched with the measured value by adjusting the velocity field in the subchannel until consistency between the measured and predicted values is achieved. DPC has stated that the calculated

velocity profiles were compared by the vendor with the experimental data and showed good agreement (Ref. 11).

2.2.2.3 Core Bypass Flow

DNB is influenced by the aggregate flow rate past the location being examined, and therefore by the core bypass flow. Since the bypass flow depends on the number of control rod and burnable poison rod assemblies in the core, this is a cycle dependent parameter. Therefore, the core bypass flow data used in the analysis should be based on a bounding value or on cycle specific data. For the purpose of this submittal, the value DPC used is acceptable.

2.2.2.4 Inlet Flow Distribution

CHF is decreased and the probability of DNB is enhanced if flowrate is reduced due to a flow maldistribution. The use of 5% inlet flow maldistribution to the hot assembly with all four reactor coolant pumps operating was previously approved for Oconee FSAR analysis.

For operation with less than four reactor coolant pumps operating, more restrictive flow reduction factors are applied.

2.2.2.5 Flow Area Reduction Factor

DPC reduced the hot subchannel flow area by 2% to account for variations in as-built subchannel coolant flow area.

2.2.2.6 Radial Power Distribution

The reference design power distribution was developed using a radial-local hot pin peak which has been previously approved for Oconee FSAR analysis. DPC will submit for NRC approval a description and justification of applicability of its findings involving an asymmetrical radial power distribution.

2.2.2.7 Axial Power Distribution

The axial power shape used in the symmetric radial power distribution transients was a cosine shape with a peaking factor consistent with the current practice. DPC will justified any specific power shape for use on a case-by-case basis.

Prior to increasing the axial peaking factor, DPC will perform a complete evaluation of all potential safety concerns and submit it to the NRC for approval.

2.2.2.8 Hot Channel Factors

The power factor, F_q, used to account for variations in average pin power caused by differences in the fuel loading per rod is 1.0107 and is statistically determined from uncertainties associated with fuel.

DPC stated that their use of the local heat flux factor, F_q'', used to account for the uncertainty in the manufacturing tolerances, is consistent with the current application of the NRC approved methodology described in the DPC topical report NFS-1002.

2.2.2.9 Fuel Pin Conduction Model

DPC stated that for most of the transient analyses, the RETRAN heat flux boundary condition is used instead of the VIPRE-01 fuel pin conduction model. DPC further stated that for transient analyses in which the fuel enthalpy or cladding temperature is the protective criteria, the VIPRE-01 fuel pin conduction model may be used. DPC stated that evaluation of an appropriate approach would be made on a case-by-case basis for each analysis. DPC will provide justification for its selection of the conduction model.

2.2.2.10 Numerical Solution Technique

For the Oconee analyses presented in the submittal, DPC used the iterative solution method. However, should convergence be a problem, DPC will use the RECIRC solution method for Oconee FSAR type transient analyses.

2.2.3 VIPRE-01 Correlations

VIPRE-01 requires empirical correlations for the following models:

a. turbulent mixing
b. two-phase flow correlations (subcooled and saturated void, and void-quality relation)
c. critical heat flux

2.2.3.1 Turbulent Mixing

The lateral momentum equation requires two parameters: a turbulent momentum factor and a turbulent mixing coefficient.

The turbulent momentum factor (FTM) describes the efficiency of the momentum mixing: 0.0 indicating that crossflow mixes enthalpy only; 1.0 indicating that crossflow mixes enthalpy and momentum at the same strength. DPC selected values for both of these parameters are conservative.

2.2.3.2 Subcooled Void, Bulk Void and Two-Phase Flow Correlations

For subcooled and bulk void correlations, a sensitivity study using five different combinations of three subcooled and five bulk void correlations was performed using four cases varying only one boundary condition at a time. In all cases, the Columbia/EPRI two-phase friction multiplier was used. The results indicated that the DPC selected set of correlations predicted acceptably conservatively DNBRs relative to other combinations of correlations. DPC intends to use this combination in Oconee FSAR Chapter 15

analysis.

2.2.3.3 Critical Heat Flux Correlation

The B&W BWC CHF correlation using the LYNX-2 computer code has been reviewed and approved by the NRC for licensing analysis of BAW Mark-BZ fuel with Zircaloy grids with the design MDNBR limit of 1.18. The use of BWC correlation with VIPRE-01 has been also reviewed and approved by the NRC with the design MDNBR limit of 1.18 (Ref. 11).

Other correlations that may be utilized to cover other ranges of pressures are: W-3S (less than 1600 psia), MacBeth and Bowring (WSC-2) for low pressure and low flow conditions. DPC will provide justification when applying these correlation in future analyses.

2.2.4 Summary

We find that the subject topical report, together with DPC responses, contains sufficient information to satisfy the VIPRE-01 SER requirement that each VIPRE-01 user submit a document describing proposed use, sources of input variables, and selection and justification of correlations as it relates to use by DPC for FSAR Chapter 15 analyses.

For asymmetric transients, DPC intends to use other models not described in this submittal. Therefore, it is recommended that NRC approval be given for analysis of symmetric transients only.

In some instances, DPC selected default options since results are found to be insensitive to selection of parameters. In future licensing analyses, if changing any parameter results in less conservative prediction, DPC should submit justification of the change.

The B&W BWC CHF correlation with VIPRE-01 has been approved by the NRC with the design MDNBR limit of 1.18. DPC will provide justification as necessary when using other CHF correlation in future analyses.

Because the core bypass flow is cycle dependent, DPC will demonstrate, in future application, that its use of a particular core bypass flowrate is conservative.

Acceptability of DPC Oconee VIPRE-01 model is based upon selection of models/correlations supported by the sensitivity study results submitted. Should DPC change any of these items, DPC will submit justification for the change to the NRC for approval.

2.3 McGuire and Catawba Core Analysis

McGuire and Catawba Nuclear Stations each have two Westinghouse units and are assumed identical for the purpose of core thermal-hydraulic calculations. The analyses presented in the submittals assume BAW Mark-BW fuel assemblies which are assumed to be mechanically and hydraulically compatible with Westinghouse standard and optimized 17x17 fuel.

2.3.1 Core Nodalization

DPC used the final set of thermal-hydraulic models and correlations in the nodalization sensitivity studies which DPC intends to use in future licensing analysis.

2.3.1.1 Radial Noding Sensitivity

A parametric study was performed to determine the sensitivity of predicted DNBR to the subchannel model sizes. The thermal-hydraulic calculations were performed for three different core subchannel models using steady-state and transient conditions. Four transient cases were analyzed varying one boundary condition while keeping the others fixed.

The coarse channel model was found to yield acceptably conservative MDNBRs. Therefore, DPC intends to used the coarse channel model for FSAR type transient analyses for the McGuire and Catawba Nuclear Station.

However, for asymmetrical transients, DPC will submit a description and justification of modeling of asymmetrical transients coarse channel model in separate submittals.

2.3.1.2 Axial Noding Sensitivity

A sensitivity analysis for axial node length was performed with the coarse core channel model using three different sets of equal length axial nodes. Two finer node sizes correspond to the range of the code developer's recommended values. The results indicated that the mid size noding is adequately conservative. Therefore, we find that use of the mid-size uniform length axial nodes (Ref. 10) is acceptable for McGuire and Catawba thermal-hydraulic analyses.

2.3.2 VIPRE-01 Input Data

DPC's approach to generation of input to the VIPRE-01 code was reviewed for acceptability. No review was conducted of the input data in comparison to the actual physical geometry.

2.3.2.1 Active Fuel Length

For B&W's low densification fuel, the amount of fuel densification is off-set by the fuel thermal expansion. Therefore, it is more conservative to use the cold nominal active fuel length for calculation and this is acceptable.

2.3.2.2 Spacer Grid Form Coefficients

The same procedure used to determined these coefficients for Oconee core analysis was used for McGuire/Catawba grid form coefficients.

2.3.2.3 Core Bypass Flow

Since the bypass flow depends on the number of control rod and burnable

poison rod assemblies in the core, this is a cycle dependent parameter. Therefore, the core bypass flow data used in the analysis should be based on a bounding value or on justified cycle specific data. For the purpose of this submittal, the value DPC used is acceptable.

2.3.2.5 Inlet Flow Distribution

CHF is decreased and the probability of DNB is enhanced if flowrate is reduced due to a flow maldistribution. The use of 5% inlet flow maldistribution to the hot assembly with all four reactor coolant pumps operating yielded slightly more conservative results than a uniform inlet flow distribution.

For operation with less than four reactor coolant pumps operating, more restrictive flow reduction factors are applied.

2.3.2.6 Flow Area Reduction Factor

DPC reduced the hot subchannel flow area by 2% to account for variations in as-built subchannel coolant flow area.

2.3.2.7 Radial Power Distribution

The assembly and pin radial power distributions were selected assuming maximum peaking factors. A shape assumed for the assembly power distribution is designed to minimize flow redistribution. The same rational is used for the pin radial power distribution.

2.3.2.8 Axial Power Distribution

The axial power shape was selected to yield DNBR margin in the Chapter 15 transients and peaking margin compared to cycle specific power distributions. Use of this power shape and the radial power distribution is to use a design power distribution to ensure DNB protection.

2.3.2.9 Hot Channel Factor

The hot channel factor $F_{\Delta H}^{\epsilon}$ used for the McGuire/Catawba analysis is 1.03 and is the allowance on enthalpy rise to account for manufacturing tolerances. The value was determined by B&W.

2.3.2.10 Numerical Solution Technique

For the McGuire/Catawba analyses presented in the submittal, DPC used the RECIRC solution method. DPC will use the RECIRC solution method in future FSAR-type transient analyses (Ref. 10).

2.3.3 VIPRE-01 Correlations

VIPRE-01 requires empirical correlations for the following models:

a. turbulent mixing
b. two-phase flow correlations (subcooled and saturated void, and void-quality relation)
c. critical heat flux

2.3.3.1 Turbulent Mixing

The lateral momentum equation requires two parameters: a turbulent momentum factor and a turbulent mixing coefficient.

The turbulent momentum factor (FTM) describes the efficiency of the momentum mixing: 0.0 indicating that crossflow mixes enthalpy only; 1.0 indicating that crossflow mixes enthalpy and momentum at the same strength. DPC selected a conservative value for FTM.

Since the turbulent mixing coefficient determines the flow mixing rate, it is an important parameter. Based upon tests using a 5x5 heated bundle conducted by B&W, where the subchannel exit temperatures were measured, a mixing

coefficient was conservatively determined for B&W Mark-BW fuel which is proportional to the turbulence intensity (Ref. 10). For conservatism, DPC used a number smaller than the B&W determined coefficient and this reduced value will be used in the McGuire and Catawba core thermal-hydraulic analysis (Ref. 10).

2.3.3.2 Subcooled Void, Bulk Void and Two-Phase Flow Correlations

For subcooled and bulk void correlations, a sensitivity study using five different combinations of three subcooled void and five bulk void correlations was performed for steady-state and transient boundary conditions. The results indicated that the use of the DPC selected combination of correlations in conjunction with Columbia/EPRI two-phase friction multiplier predicted conservatively computed DNBR relative to other combinations of correlations. DPC intends to use this combination in McGuire and Catawba analysis.

This is consistent with the VIPRE-01 SER findings.

2.3.3.3 BWCMV Critical Heat Flux Correlation

Use of BWCMV CHF correlation with the LYNX2 code has been approved by the NRC for the DNBR limit of 1.21. Its use with VIPRE-01 has been also approved (Ref. 12).

2.3.4 Statistical Core Design Methodology

The DPC developed statistical core design methodology (SCD) statistically combines uncertainties associated with key parameters used in determination of the DNBR. Details of the methodology with respect to the steady-state application is documented in DPC-NE-2004. The transient application is performed in the same manner as described in that topical report.

During the review of DPC-NE-2004, in response to the NRC question, DPC provided results of sensitivity cases using models developed in DPC-NE-2004

and DPC-NE-3000. There were negligible differences between the predicted DNBRs (Refs. 13 and 14). Therefore, the SCD methodology developed in the DPC-NE-2004 is applicable in transient applications since the methodology allows enough margin in the DNBR limits to account for the small differences between two models. However, the same conditions cited in the technical evaluation report for DPC-NE-2004 are applicable to use of the SCD methodology in transient applications.

2.3.5 Summary

For asymmetric transients, DPC intends to use other models not described in this submittal. Therefore, it is recommended that NRC approval be given for use in analysis of symmetric transients only.

Because the core bypass flow is cycle dependent, DPC will demonstrate, in future application, that its use of a particular core bypass flowrate is conservative.

Acceptability of DPC M/C VIPRE-01 model is based upon selection of models/correlations supported by the sensitivity study results submitted. Therefore, whenever DPC changes any of these items documented in the topical report, DPC will submit justification for the change to the NRC for approval.

Furthermore, the use of the SCD methodology in transient application is acceptable provided that the range of applicability of the RSM is not violated. The conditions cited (Refs. 12 and 13) in the review of DPC-NE-2004 are applicable to transient application as well.

3.0 CONCLUSIONS

We find that the subject topical report, together with DPC responses, contains sufficient information to satisfy the VIPRE-01 SER requirement that each VIPRE-01 user submit a document describing proposed use, sources of input variables, and selection and justification of correlations as it relates to use by DPC for FSAR Chapter 15 analyses.

We further find that the manner in which the code is to be used for such analyses, selection of nodalization, models, and correlations provides, except as listed below, adequate assurances of conservative results and is therefore acceptable. Furthermore, the use of the DPC developed statistical core design methodology as approved in the Technical Evaluation Report on DPC-NE-2004 (Ref. 12) is approved for the transient application subject to the same conditions.

The following items are limitations regarding VIPRE-01 application presented in DPC-NE-3000 and its supplemental materials:

(1) Determination of acceptability is based upon review of selection of models/correlations for symmetric transients only. DPC submitted its asymmetric models in DPC-NE-3001 for NRC review and approval.

(2) When using the DPC developed SCD method, the licensee must satisfy the conditions set forth in Reference 12.

(3) Whenever DPC intends to use other CHF correlations, power distribution, fuel pin conduction model or any other input parameters and default options which were not part of the original review of the VIPRE-01 code, DPC must submit its justification for NRC review and approval.

(4) Core bypass flow should be determined on cycle-by-cycle bases.

4.0 REFERENCES (Part 2 - VIPRE)

1. "Duke Power Company - The Thermal-Hydraulic Transient Analysis Methodology - Oconee Nuclear Station, McGuire Nuclear Station, Catawba Nuclear Station," DPC-NE-3000, July 1987.

2. Letter, C.O. Thomas (NRC) to T.W. Schnatz (UGRA), September 4, 1984, (Transmittal of RETRAN-02 Safety Evaluation Report).

3. "RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems," EPRI NP-1850-CCM Revision 2, EPRI, November

1984.

4. Letter, C.E. Rossi (NRC) to J.A. Blaisdell (UGRA), May 1, 1986, (Transmittal of VIPRE-01 Safety Evaluation Report).

5. "VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores," EPRI NP-2511-CCM Revision 2, EPRI, July 1985.

6. Letter from H.B. Tucker (DPC) to USNRC, Attachment to "Thermal-Hydraulic Transient Analysis Methodology," May 11, 1989.

7. "Duke Power Company Oconee Nuclear Station Core Thermal-Hydraulic Methodology Using VIPRE-01," DPC-NE-2003, August 1988.

8. "Duke Power Company McGuire and Catawba Nuclear Stations Core Thermal-Hydraulic Methodology Using VIPRE-01," DPC-NE-2004, December 1988.

9. Letter from H.B. Tucker (DPC) to USNRC, "Response to Questions Regarding Differences Between Duke Topical Reports DPC-NE-2003 and DPC-NE-3000," June 19, 1989.

10. Letter from G.B. Swindlehurst (DPC) to USNRC, "Response to NRC Questions on DPC-NE-3000 Dated July 25, 1989," February 20, 1990.

11. "Technical Evaluation of the Core Thermal-Hydraulic Methodology Using VIPRE-01 Topical Report DPC-NE-2003 for the Duke Power Company Oconee Nuclear Station," ITS/NRC/89-2, July 3, 1989.

12. "Technical Evaluation of the Core Thermal-Hydraulic Methodology Using VIPRE-01 Topical Report DPC-NE-2004 for the Duke Power Company McGuire and Catawba Nuclear Stations," ITS/NRC/91-1, October 1991.

13. Letter from M.S. Tuckman (DPC) to USNRC, "Supplemental Information to Assist in Review of Topical Reports DPC-NE-3000 and DPC-NE-2004," August 29, 1991.

14. Letter from H.B. Tucker (DPC) to USNRC, "Handouts Presented in the October 7 & 8, 1991 Meeting with NRC Staff and Contract Reviewers," October 16, 1991.

Oconee Nuclear Station
McGuire Nuclear Station
Catawba Nuclear Station

THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY

DPC-NE-3000-A
Revision 1

December 1997

Nuclear Engineering Division
Nuclear Generation Department
Duke Power Company

Abstract

This report is the Duke Power Company response to Generic Letter 83-11, "Licensee Qualification for Performing Safety Analyses in Support of Licensing Action." G. L. 83-11 requires that licensees performing their own safety analyses demonstrate their analytical capabilities. Comparisons of computer code results to experimental data, plant operational data, or other benchmarked analyses were identified as areas of interest. This report describes the RETRAN-02 transient thermal-hydraulic models developed for the Oconee, McGuire, and Catawba Nuclear Stations, and the VIPRE-01 core thermal-hydraulic models developed for Oconee, McGuire, and Catawba Nuclear Stations. Comparisons of Oconee RETRAN model predictions to nine plant transients, and comparisons of McGuire/Catawba RETRAN model predictions to eight plant transients, are detailed. VIPRE model predictions are validated by comparisons to the COBRA-IIIC/MIT code for the Oconee core design. The report concludes that the analytical capability to perform non-LOCA transient thermal-hydraulic analyses has been demonstrated.

THERMAL-HYDRAULIC TRANSIENT
ANALYSIS METHODOLOGY

TABLE OF CONTENTS

List of Tables

List of Tables (cont.)

List of Tables (cont.)

List of Figures

List of Figures (cont.)

List of Figures (cont.)

List of Figures (cont.)

List of Figures (cont.)

List of Figures (cont.)

List of Figures (cont.)

List of Figures (Cont'd)

List of Figures (cont.)

List of Figures (cont.)

List of Figures (cont.)

List of Abbreviations

AFW	Auxiliary Feedwater
ANO	Arkansas Nuclear One
ANS	American Nuclear Society
ASP	Auxiliary Shutdown Panel
BWR	Boiling Water Reactor
BWST	Borated Water Storage Tank
B&W	Babcock & Wilcox
CCI	Control Components Inc.
CCP	Centrifugal Charging Pump
CFR	Code of Federal Regulations
CFT	Core Flood Tank
CHF	Critical Heat Flux
CLA	Cold Leg Accumulator
CNS	Catawba Nuclear Station
CVCS	Chemical and Volume Control System
DNBR	Departure from Nucleate Boiling Ratio
EFW	Emergency Feedwater
EHC	Electro-Hydraulic Control
EPRI	Electric Power Research Institute
ESFAS	Engineered Safety Features Actuation System
ESS	Engineered Safeguards System
FA	Fuel Assembly
FP	Full Power
FSAR	Final Safety Analysis Report
HEM	Homogeneous Equilibrium Model
HHSI	High Head Safety Injection
HPI	High Pressure Injection
ICS	Integrated Control System
ID	Inside Diameter
IHSI	Intermediate Head Safety Injection
LER	Licensee Event Report
LHSI	Low Head Safety Injection
LOCA	Loss of Coolant Accident
LPI	Low Pressure Injection
MDNBR	Minimum Departure from Nucleate Boiling Ratio
MFW	Main Feedwater
MIT	Massachusetts Institute of Technology
MNS	McGuire Nuclear Station
MS	Main Steam
MSIV	Main Steam Isolation Valve
MSRV	Main Steam Relief Valve
MWt	Megawatt Thermal
NNI	Non-Nuclear Instrumentation
NRC	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
OD	Outside Diameter
ONS	Oconee Nuclear Station

List of Abbreviations (cont.)

PI	Proportional Plus Integral
PORV	Pilot-Operated Relief Valve (ONS)
PORV	Power-Operated Relief Valve (MNS/CNS)
PWR	Pressurized Water Reactor
PZR	Pressurizer
QA	Quality Assurance
RCCA	Rod Cluster Control Assembly
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RPS	Reactor Protective System (B&W)
RPS	Reactor Protection System (W)
RTD	Resistance Temperature Detector
RWST	Refueling Water Storage Tank
Rx	Reactor
SDM	Shutdown Margin
SER	Safety Evaluation Report
SG	Steam Generator
SI	Safety Injection
TBS	Turbine Bypass System
TBV	Turbine Bypass Valve
TCS	Turbine Control System
TMF	Turbulent Momentum Factor
UHI	Upper Head Injection

1.0 INTRODUCTION

1.1 Objective

The objective of this report is to present the development and validation of thermal-hydraulic transient analysis methods at Duke Power Company in order to address the requirements of Generic Letter 83-11 "Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions" (Reference 1-1). This letter requires that licensees performing their own safety analyses demonstrate their capability and technical competence. In particular, comparisons of computer code results to experimental data, plant operational data, or other benchmarked analyses, were identified as areas of interest. This report provides the details of extensive benchmarking efforts which utilize actual plant transient data from the Oconee, McGuire, and Catawba Nuclear Stations for comparisons to system code predictions. The capabilities of the RETRAN-02 system simulation code (Reference 1-2) and the VIPRE-01 core thermal-hydraulic simulation code (Reference 1-3) are demonstrated using plant and core simulation models developed by Duke Power Company.

1.2 RETRAN-02 Code Description

RETRAN-02 was developed by Energy Incorporated for the Electric Power Research Institute (EPRI) to provide utilities with a code capable of simulating most thermal-hydraulic transients of interest in both PWRs and BWRs. RETRAN-02 has the flexibility to model any general fluid system by partitioning the system into a one-dimensional network of fluid volumes and connecting flowpaths or junctions. The mass, momentum, and energy equations are then solved by employing a semi-implicit solution technique. The time step selection logic is based on algorithms that detect rapid changes in physical processes and limit time steps to ensure accuracy and stability. Although the equations describe homogeneous equilibrium fluid volumes, phase separation can be modeled by separated bubble-rise volumes and by a dynamic slip model. The pressurizer and other volumes can be modeled as non-equilibrium volumes when such phenomena are present. Reactor power generation can be represented by either a point kinetics model or a one-dimensional kinetics model. Heat transfer across steam generator tubes and to or from structural components can be modeled. Special component models for centrifugal pumps, valves, trip logic, control systems, and other features useful for fluid system modeling are

available. The RETRAN-02 MOD003 code version is used for the analyses presented in this report.

1.3 VIPRE-01 Code Description

VIPRE-01 was developed for EPRI by Battelle Pacific Northwest Laboratories for steady-state and transient core thermal-hydraulic analysis. The basic structure and computational philosophy of the VIPRE-01 code are derived from COBRA-IIIC (Reference 1-4). The subchannel analysis approach is applied in both codes. With this approach the nuclear fuel element is divided into a number of quasi-one-dimensional channels that communicate laterally by diversion crossflow and turbulent mixing. Conservation equations of mass, axial and lateral momentum, and energy are solved for the fluid enthalpy, axial flowrate, lateral flow per unit length, and momentum pressure drop. The flow field is assumed to be incompressible and homogeneous, although models are added to reflect subcooled boiling and co-current liquid/vapor slip. VIPRE uses an implicit boundary value solution scheme where the boundary conditions are inlet enthalpy, inlet mass flowrate, and core exit pressure. The VIPRE-01 Cycle-01 code version is used for the analyses presented in this report.

1.4 Methodology Development

The development of inhouse plant transient simulation capability, which has evolved into the submittal of this report, began in April 1978. Initial efforts focused on following the development of the RETRAN-01 system simulation code (Reference 1-5) by EPRI. Following the first release of a production version of RETRAN-01 in December 1978, work began on assembling a simulation model of the Oconee Nuclear Station and was completed in July 1979. The Oconee Nuclear Station is a three unit site with similar 2568 MWt Babcock & Wilcox pressurized water reactors. The Oconee RETRAN model was then exercised during the next year by comparison to several plant transient events (References 1-6, 1-7), as well as some separate effects tests conducted at the plant. Based on the generally positive results of these initial transient simulation efforts, it was decided in mid-1980 to begin applications of the

technology towards the resolution of technical and safety concerns. Additional Oconee RETRAN model comparisons to plant transients are described in References 1-8 and 1-9.

A separate and parallel effort was initiated in June 1979 to develop core thermal-hydraulic analysis technology. Although most of this effort was directed towards steady-state core reload design, models for predicting the departure from nucleate boiling phenomenon during transients were also developed. The early transient analysis applications utilized the COBRA-IIIC/MIT code (Reference 1-10). Beginning in October 1983 with the EPRI release of the first production version of the VIPRE-01 code, subsequent transient core thermal-hydraulic simulations have been performed with VIPRE-01.

The McGuire and Catawba Nuclear Stations are both two unit sites with similar 3411 MWt Westinghouse 4-loop pressurized water reactors. Development of RETRAN plant transient simulation models for the McGuire and Catawba Nuclear Stations began in early 1981. The McGuire/Catawba RETRAN model benchmark analyses were completed just prior to this report.

1.5 Model and Code Qualification

The model and code qualification process can be thought of as a sequence of three major milestones. The first milestone is the verification of the computer code. Verification activities associated with the RETRAN-02 code culminated in the issuance of the NRC SER dated September 2, 1984 (Reference 1-12). The VIPRE-01 NRC SER was issued on May 1, 1986 (Reference 1-13). The SER approves the utilization of the licensed code version within the limits or restrictions imposed by the SER. The RETRAN-02 and VIPRE-01 code versions used in this report are identical to the versions reviewed in the NRC SERs, with the exception of minor error corrections. Duke Power is a member of the Utility Group for Regulatory Applications (UGRA) which requested and sponsored the NRC review of the RETRAN-02 and VIPRE-01 codes. The second milestone is the verification of the simulation model, i.e. the input deck that describes the system being simulated. This milestone has been completed for the Oconee and McGuire/Catawba RETRAN models and the Oconee VIPRE model. The RETRAN and VIPRE models are described in detail in Sections 2 and 3 of this report. The third milestone is the validation of the predictive capability of the code/ model by comparison to a standard. The

standard selected for validation of the RETRAN models is actual plant transient data. The results of these validation or benchmarking activities are detailed in Sections 4 and 5 of this report. The plant transients utilized for benchmarking were selected with attention to the overall goal of exercising the code and model to as broad a range of transient conditions and phenomena as possible. The recent operating history at Oconee and the entire operating histories at McGuire and Catawba were reviewed to identify transients or tests that presented worthwhile challenges to the code and model. Provided that the plant data was logged and available, the most dynamic transients were of the greatest interest. Typically the plant data includes a nearly complete set of parameters logged at a one second frequency, so that a very good characterization of the event is obtained. The transients that have occurred at Duke nuclear plants do not include many that can be characterized as significant, at least when compared to the design basis transient spectrum. Nevertheless, a good spectrum of different transient event types are available for benchmarking. The review for benchmarking data attempted to identify transient events at both Oconee and at McGuire or Catawba in each of the following transient type categories:

- Loss of coolant transients
- Loss of heat sink transients
- Overcooling transients
- Partial loss of forced flow transients
- Natural circulation transients
- Reactivity change transients
- Asymmetric transients
- Transients not resulting in a reactor trip
- Transients initiating below full power

A review of the contents of Sections 4 and 5 shows that the available plant transient data met most of the goals. Since there have not been any significant loss of coolant events at any Duke plants, no benchmark data for that type exist. The other transient types are well represented for both the B&W and Westinghouse plants. It should be noted that data was obtained from Arkansas Power & Light Company for a loss of offsite power event that occurred at Arkansas Nuclear One - Unit 1, which is a sister plant of Oconee. This data was used due to an absence of similar data at Oconee.

For each benchmark transient in Sections 4 and 5 the capability of the code and model to accurately simulate the plant response can be assessed. The primary phenomena of interest associated with each transient are highlighted. For several events it is pointed out that some degree of uncertainty exists in the timing of specific events and the performance of certain systems and components. This limitation is typical of plant data used for code comparisons. The quality of the data is sufficient for the purposes of this report.

Since applicable plant data does not exist for detailed validation of the Oconee VIPRE Model, comparisons to the COBRA-IIIC/MIT code are utilized. Very comparable core simulation models were developed for each code, such that when combined with a selection of similar code options, a meaningful code-to-code comparison could be obtained. A set of arbitrary transient cases was then simulated. The resulting VIPRE-01 and COBRA-IIIC/MIT predictions of local subchannel conditions and DNBR are presented in Section 2. Additional VIPRE validation by code comparison has been submitted by Duke Power Company in Reference 1-14 for Oconee and in Reference 1-15 for McGuire/Catawba.

1.6 Quality Assurance

The development, utilization, and documentation of transient analysis technology incorporated several stages of formal quality assurance (QA) activities. The major activities are controlled by formal QA procedural requirements as part of the Duke Power Company Quality Assurance Manual. Other activities are administratively controlled by workplace procedures or by training that serves to maintain a high level of consistency in the application of the codes and model. A major QA activity is the certification of computer codes to be used in safety-related analyses. Both the RETRAN-02 and VIPRE-01 code versions used for the analyses documented in this report have undergone this certification process.

A second major QA activity is the documentation of the simulation model. Due to the very large volume of information that is necessary to develop a model for a system simulation code such as RETRAN-02, a separate document is compiled to detail all calculations and references utilized in the model. These model documents describe a "base deck" which consists of all the code input necessary to initialize at 100% full power with all parameters at nominal conditions. A thorough review of the model document is performed along with a review of the derived input listing. The

model document and the base deck are then controlled such that any changes must be documented, reviewed, and approved prior to implementation. Applications of the base deck with analysis-specific modifications are performed such that the base deck itself is not modified. Modifications are added at the end of the base deck so that the QA review can be limited to the analysis-specific additions. A model document is not developed for the VIPRE-01 code models since the volume of calculations necessary to develop the model and code input is much less than that of a system code. The VIPRE models are documented and reviewed during the first application of a new model. Base deck configuration controls similar to that described above are utilized to ensure accountability and consistency in all applications of the model.

All safety-related analyses include an independent review by a qualified reviewer. The calculation file is then subject to approval by supervision. In the event that at a later date an error is identified or new information brings into question the results or conclusions of a calculation file, all individuals are responsible for bringing it to the attention of the cognizant supervisor. All such occurrences are logged, investigated, and dispositioned. A determination is made of the significance of the error and the potential reportability of the item per 10 CFR 50.73 or other regulation. All potentially affected calculation files are reviewed to evaluate the potential impact of the error or new information, and reanalyses are initiated as necessary. Final resolution of significant errors is contingent on management approval.

Analysis activities are subject to internal audit by the QA department on a periodic basis. Conformance with established procedures and QA requirements are evaluated. In addition, analysis activities have been inspected by NRC on two occasions. A special safety inspection was conducted during June 7-9, 1982, which focused on the subject of validation of the RETRAN computer code. The inspection report (Reference 1-16) stated that no deviations or violations were disclosed. The one unresolved item which resulted from the inspection has been addressed. The second inspection was conducted as part of a Safety System Functional Inspection of the Oconee Emergency Feedwater System (EFW), which was conducted during the period May 5 to June 11, 1986. An inspection of a calculation file which documented a RETRAN model of the EFW system identified several minor errors. The inspection report (Reference 1-17) states that these errors would not (and did not) substantially alter the conclusions of the analyses.

In summary, appropriate QA measures have been employed during the development of transient analysis codes and models, and during the application of the technology. The Duke QA system is structured to ensure configuration control, traceability, and accountability.

1.5 Methodology Applications

Thermal-hydraulic transient analysis methods have been and will continue to be used for a wide range of purposes. The most pertinent applications in the context of this report are those related to the resolution of licensing concerns. Licensing concerns include:

- Evaluation of the consequences of equipment failures and other items for documentation in LERs.
- Evaluation of the impact of proposed plant modifications, changes in Technological Specifications, and revisions to operating procedures on the design basis transients and accidents
- Reanalysis of design basis transients due to changes in plant parameters, such as those associated with a fuel reload
- Resolution of generic safety issues applicable to Duke nuclear stations
- Analytical basis for justification of continued operation under off-normal operating conditions

Other applications of the technology include:

- Analytical basis for Emergency Procedure Guidelines
- Data for validation of plant-specific control room simulators
- Developing responses to station concerns regarding plant transients
- Data for emergency drills
- Success criteria for PRA systems analysis

Based on a foundation of thorough analytical model development and substantial model benchmarking efforts, the capability to employ methodology applications towards the resolution of technical and safety concerns has been demonstrated.

1.8 References

1-1 Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions (Generic Letter No. 83-11), USNRC, February 8, 1983

1-2 RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM Revision 2, EPRI, November 1984

1-3 VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM Revision 2, EPRI, July 1985

1-4 COBRA-IIIC: A Digital Computer Program for Steady-State and Transient Core Thermal-Hydraulic Design Methodology, BNWL-1695, PNL, March 1973

1-5 RETRAN - A Program for One-Dimensional Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI CCM-5, EPRI, December 1978

1-6 Oconee RETRAN Model Comparisons With Plant Transient Data, Gregg B. Swindlehurst, Duke Power Co., Conference Proceedings: First International RETRAN Conference, EPRI WS-80-150, EPRI, April 1981

1-7 Oconee RETRAN Model Comparisons With Plant Transient Data, Gregg B. Swindlehurst, Duke Power Co., Nuclear Technology Vol. 54 No. 3, September 1981

1-8 Qualification of the Oconee RETRAN Model by Comparison With Plant Transient Data, S. P. Nesbit, R. J. Gerling, and G. B. Swindlehurst, Proceedings: Fifth International RETRAN Conference, April 1988

1-9 Qualification of the Oconee RETRAN Model by Comparison With Plant Transient Data, S. P. Nesbit, R. J. Gerling, and G. B. Swindlehurst, Duke Power Co., Nuclear Technology Vol. 83, December 1988

1-10 COBRA IIIC/MIT Computer Code Manual, R. W. Bowring, MIT, March 1976

1-11 Simulation of McGuire and Catawba Transient Data and Qualification of RETRAN Plant Model, H. J. Lee, M. E. Henshaw, P. A. Goodwin, R. S. Johnson, Duke Power Co., Proceedings: Fifth International RETRAN Conference, April 1988

1-12 Letter, C. O. Thomas (NRC) to T. W. Schnatz (UGRA), September 4, 1984, (Transmittal of RETRAN-02 Safety Evaluation Report)

1-13 Letter, C. E. Rossi (NRC) to J. A. Blaisdell (UGRA), May 1, 1986, (Transmittal of VIPRE-01 Safety Evaluation Report)

1-14 Duke Power Company Oconee Nuclear Station Core Thermal-Hydraulic Methodology Using VIPRE-01, DPC-NE-2003, August 1988

1-15 Duke Power Company McGuire and Catawba Nuclear Stations Core Thermal-Hydraulic Methodology Using VIPRE-01, DPC-NE-2004, December 1988

1-16 Letter, H. C. Dance (NRC) to W. O. Parker, Jr. (Duke), June 29, 1982, Inspection Report Nos. 50-269/82-25, 50-270/82-25, 50-287/82-25, and 50-369/82-22

1-17 Letter, J. M. Taylor (NRC) to H. B. Tucker (Duke), August 1, 1986, Safety System Functional Inspection Report Numbers 50-269/86-16, 50-270/86-16, and 50-287/86-16

2.0 OCONEE TRANSIENT ANALYSIS

2.1 Plant Description

2.1.1 Overview

The Oconee Nuclear Station consists of three 2568 MW thermal Babcock and Wilcox (B&W) pressurized water reactor (PWR) units located next to Lake Keowee near Clemson, South Carolina. Construction began on the plant in 1967, and the operating licenses were received on February 6, 1973, October 6, 1973, and July 19, 1974, for Units 1, 2, and 3, respectively. The three units are identical in most respects. Auxiliary systems are generally shared between Units 1 and 2, with separate systems for Unit 3. The Oconee units are similar in design to other current pressurized water reactors in most areas. Some unusual characteristics of Oconee include the use of once-through steam generators (SGs) to provide superheated steam, the use of the Keowee Hydro Station as the onsite emergency power source, and the provision for emergency condenser cooling via a gravity flow system in the event of a loss of all condenser circulating water pumps.

Each primary system has two hot legs, two SGs, and four reactor coolant pumps (RCPs). The primary coolant is heated in the core and flows to the SGs, where the energy is transferred to the secondary system. The coolant is then returned to the reactor vessel by the RCPs. The secondary system provides 460°F feedwater to the SGs, where the water is heated into steam and superheated to approximately 595°F. The steam passes through a high pressure and three low pressure turbines and is exhausted to the condensers. The condensate is purified and preheated before it is returned to the SGs.

The plant is controlled by the Integrated Control System (ICS). The ICS regulates overall load demand, steam flow to the turbine, feedwater flow to the SGs, and reactor power in order to provide stable operation and a smooth response to transients and power maneuvers.

Plant safety systems provide protection for various anticipated transients and design basis accidents. The Reactor Protective System (RPS) shuts down the nuclear chain reaction to prevent core damage and exceeding safety limits. The Engineered Safeguards System (ESS) provides emergency core cooling in the event of a loss coolant accident (LOCA). The Emergency Feedwater (EFW) System provides feedwater to the SGs for decay heat removal following a loss of the Main Feedwater (MFW) System.

2.1.2 Primary System

The Oconee Reactor Coolant System (RCS) is shown schematically on Figure 2.1-1.

2.1.2.1 Reactor Core

The reactor core consists of 177 fuel assemblies and the associated control rods. Each fuel assembly is a 15x15 array of 208 fuel pins, 16 control rod guide tubes, and one in-core instrumentation tube. Each fuel pin contains stacked UO_2 fuel pellets surrounded by Zircaloy-4 cladding, with a small gap between the pellets and the cladding. The Zircaloy control rod guide tubes provide a channel for control rod insertion. The instrumentation tube provides a channel for in-core neutron detectors and a core exit thermocouple. 69 of the fuel assemblies are actually provided with control elements, 61 of which are silver-indium-cadmium assemblies for overall power control and shutdown capability, and 8 of which are Inconel-600 part-length assemblies for axial power shaping. Some of the fuel assemblies which do not contain control rods have burnable poison rod assemblies. Their purpose is to reduce core reactivity at the beginning of cycle and therefore enable higher enrichment cores and longer fuel cycles.

2.1.2.2 Reactor Vessel

The reactor vessel consists of a cylindrical shell, a spherically dished bottom head, and a flange to which the removable reactor vessel upper head is bolted during operation. The minimum shell thickness is 8-7/16 inches of carbon steel, and the interior is clad with stainless steel. The general arrangement of the vessel is shown on Figure 2.1-2. Major regions of the vessel include the coolant inlet nozzles, the downcomer, the lower head, the core, the upper plenum, the upper head, the outlet annulus, and the outlet nozzles. Vessel penetrations include the incore instruments, the control rod assemblies, and the core flood lines. The incore instrument nozzles penetrate the lower head and extend into the reactor core region. The control rod assemblies penetrate the upper head and extend through the control rod guide tubes in the upper plenum into the reactor core. Two core flood lines empty into the downcomer and provide a pathway for core flood tank injection and low pressure injection. In addition there is a high point vent which comes off of one of the control rod assemblies near the top of the vessel.

The eight reactor vessel vent valves are unique to the B&W reactor design. These 14 inch flapper valves connect the outlet annulus to the downcomer. The valves are designed to open during a design basis cold leg pipe break in order to facilitate venting of steam out the break. During normal operation the valves are shut by the pressure differential between the downcomer

and the upper plenum. However, when the RCPs are tripped the pressure differential may be reversed due to density differences in the reactor vessel, causing the valves to open. This provides a flowpath for internal vessel circulation. The function of the reactor vessel vent valves is illustrated on Figure 2.1-3.

2.1.2.3 Reactor Coolant Loops

The RCS piping provides a pathway for the coolant to circulate between the reactor vessel and the SGs. Each of the two 36 inch ID hot legs connects the reactor vessel to one of the SGs. Two 28-inch ID cold legs connect each of the steam generators back to the reactor vessel. Each of the four cold legs contains a RCP. The minimum thicknesses of the hot and cold leg piping are 2-7/8 inches and 2-1/4 inches, respectively. The piping is carbon steel clad with stainless steel. The piping arrangement is shown on Figures 2.1-4 and 2.1-5. Oconee, like most B&W plants, has a lowered-loop piping configuration. This refers to the fact that the reactor vessel and the steam generator are at approximately the same elevation.

There are various piping penetrations for interfacing systems and components. These include the pressurizer surge line into one of the hot legs, the decay heat removal suction line off of the bottom of one of the hot legs, the hot leg high point vents at the top of each hot leg, the letdown line off of one of the cold legs, the high pressure injection (HPI) line into each of the cold leg pump discharges, and the pressurizer spray line off of one of the cold leg pump discharges. In addition there are many penetrations for RCS instrumentation such as temperature, pressure, and flow.

The high point of the primary system is located at the bend of the hot leg, before the pipe enters the SGs. This bend is commonly referred to as the "U-bend" or "candy cane." This feature is different from the Westinghouse and Combustion Engineering PWR design, in which the high point in the primary system loop is located at the top of the SG tubes.

2.1.2.4 Reactor Coolant Pumps

Each unit has four RCPs. Unit One has Westinghouse Model 93A pumps, while Units 2 and 3 have Bingham Type RQV pumps. Both types are centrifugal pumps which operate at a constant speed, and both utilize 9000 hp Westinghouse motors. The hydraulic characteristics of the pumps are similar, but the Bingham pumps provide approximately 5% more flow. The Westinghouse pump seals are a hydraulic controlled-leakage design, while the Bingham pumps use mechanical seals.

The units are designed for operation with fewer than four pumps operating. With three pumps operating the maximum power level is 75%. Power operation with two inactive pumps is prohibited.

2.1.2.5 Steam Generators

The two once-through SGs provide for energy removal from the primary system. The primary side of a SG consists of the upper head, the upper tubesheet, the tubes, the lower tubesheet, and the lower head. Primary coolant enters the SG upper head through a nozzle connected to the hot leg piping. The coolant flows down through the 52 foot long SG tubes into the SG lower head. Two nozzles connect the lower head to the cold legs. The SG upper and lower heads are made of carbon steel clad with stainless steel. The tubesheets are also carbon steel.

The Inconel-600 tubes are fixed at the upper and lower ends by the two foot thick tubesheets, which separate the primary and secondary sides. There are approximately 15,500 tubes per SG, each with a nominal OD of 5/8 inches and a thickness of 0.034 inches. A diagram of a once-through SG is shown on Figure 2.1-6.

2.1.2.6 Pressurizer

The pressurizer is a vertical cylindrical vessel with hemispherical upper and lower heads. A surge line penetrates the bottom of the pressurizer and connects it to one of the hot legs. The pressurizer maintains and controls RCS pressure and provides a steam surge volume and liquid water reserve to compensate for changes in reactor coolant density and inventory during operation. A diagram of the pressurizer is shown on Figure 2.1-7.

There are four banks of electric heaters in the lower region of the pressurizer, with a total capacity of 1638 kW. These heaters make up for ambient heat losses during normal operation and restore pressure during operational transients. There is an interlock which turns the heaters off on low pressurizer level, preventing them from being damaged due to uncovery.

The 2 1/2 inch pressurizer spray line connects one of the cold leg pump discharges to the pressurizer spray nozzle which is located at the top of the steam space. The spray valve opens when RCS pressure exceeds 2205 psig, providing approximately[ ]gpm of colder water to the top of the pressurizer where it condenses steam, thus reducing pressure.

The pressurizer pilot-operated relief valve (PORV) is a 1-3/32 inch Dresser relief valve located near the top of the pressurizer. The valve has a 100,000 lbm/hr steam relief capability, and it opens when RCS pressure exceeds 2450 psig.

The pressurizer code safety relief valves are 1.8 inch Dresser valves which also relieve fluid from the top of the pressurizer. The total rated relief capacity of both valves is greater than 630,000 lbm/hr steam. These spring-loaded valves are set to relieve at 2500 psig.

2.1.2.7 Makeup and Letdown

Normal makeup at Oconee is provided by a HPI pump drawing water from the letdown storage tank. A control valve in the injection line modulates to control pressurizer level at the setpoint, which is normally 220 inches. The maximum makeup capacity through this flowpath is approximately[ ]gpm at nominal system pressure. The makeup capacity can be augmented by starting a parallel HPI pump, opening the Engineered Safeguards injection valve which is parallel to the makeup control valve, or both. Makeup water is injected into the A1 and A2 cold leg pump discharge piping. The HPI System, both normal and emergency functions, is shown on Figure 2.1-8.

A small amount of makeup is also provided by RCP seal injection. Approximately 8 gpm is pumped into the seals of each pump, most of which enters the primary system, and the remainder of which returns via the seal leakoff pathway to the letdown storage tank. Seal injection is provided by the same HPI pump which furnishes normal makeup. If seal injection flow is low, then a second HPI pump is automatically started in order to restore an adequate flow rate.

Letdown is taken from the B1 cold leg pump suction piping through coolers and demineralizers to the letdown storage tank. Normal letdown flow is approximately 70 gpm. After reactor trip, the operators isolate letdown in order to minimize the decrease in pressurizer level which occurs as the reactor coolant cools and contracts.

2.1.2.8 Instrumentation

A large number of instruments monitor the primary system in order to provide information to the operators, inputs to the plant control systems, and signals for the actuation of the RPS and the ESS. Core instrumentation includes neutron power indication (ionization chambers), self-powered incore neutron detectors, and core-exit thermocouples. RCS temperatures are measured by resistance temperature detectors (RTDs) near the top of the hot leg and in the cold

leg pump suction. Loop flow is measured by a Gentille ΔP device in each hot leg. Pressure is measured by pressure taps in each hot leg. The pressurizer contains water level, pressure, and water temperature instruments. In addition, inadequate core cooling instrumentation includes a level measurement for each hot leg and in the reactor vessel (above the level of the bottom of the hot leg). The subcooling margin in each loop and at the core exit is also displayed for operator guidance.

2.1.3 Secondary System

Oconee uses a regenerative-reheat Rankine cycle to convert the thermal energy produced in the reactor core to electric power. Energy is removed from the primary system in the SGs, where feedwater is boiled and then superheated. The steam is exhausted through a high pressure turbine, moisture separator-reheaters, and three low pressure turbines to the condensers. Hotwell pumps take suction from the condenser hotwells and discharge to the condensate booster pumps. After the condensate booster pumps, the condensate passes through the F, E, D, and C feedwater heaters to the suction of the steam-driven MFW pumps. The MFW pumps discharge through the B and A feedwater heaters to the SGs.

2.1.3.1 Steam Generators

The SGs remove energy from the primary system during normal operation, at hot shutdown, and between Decay Heat Removal System conditions (less than 250°F) and hot shutdown. A typical generator is shown on Figure 2.1-6. At full power 5.4 million lbm/hr feedwater enters each SG downcomer through an external feedwater ring which contains 32 MFW nozzles. The downcomer consists of the annular section in the lower part of the SG which is separated from the SG shell region by a baffle plate. The downcomer is open to the SG shell at the aspirator port at the top of the downcomer, and through the water ports at bottom. The condensing action of the relatively cold MFW draws steam from the shell through the aspirator port, and this steam preheats the feedwater from approximately 460°F to near saturation (535°F) at the bottom of the downcomer. The feedwater enters the shell region through the water ports and flows vertically upward. Heat from the primary system boils the feedwater as it rises, and the quality approaches 1.0 approximately halfway up the generator. In the upper portion of the generator the steam is superheated to 590-595°F, close to the primary inlet temperature of 602°F. At the top of the SG the steam flows radially outward through the gap between the baffle and the upper tubesheet, and then downward through the steam outlet annulus. Two 26 inch OD lines exit the steam outlet annulus near the midsection of the generator, and those lines join into the 36 inch OD main steam

line which goes to the high pressure turbine. The nominal SG outlet pressure at full power operation is 910 psig.

Fifteen tube support plates provide structural support for the SG tubes. These plates are distributed axially along the generator at approximately 3 foot intervals. The plates have broached holes at the tubes to allow steam to pass, but they still represent a significant constriction to the flow. Each generator has a lane without tubes extending radially from the middle to the edge. This lane allows some of the interior tubes to be inspected. In addition, there is a small untubed region in the center of the generator. The height of the SG secondary side is 52 feet.

The effective heat transfer area in a once-through SG is directly proportional to the SG level, since the nucleate boiling heat transfer that takes place in the lower, two-phase region is much greater than the heat transfer to single-phase steam which occurs in the upper part of the SG. During normal operation there is no SG level control (except for low level and high level limits); instead, the plant ICS directs the MFW System to provide adequate feedwater to remove the energy produced in the primary system. As primary power goes up, the required heat transfer area is greater, so the SG level increases. At low power the level is maintained at the low level limit (31 inches above the lower tubesheet). At full power operation the level can go as high as 385 inches, or 60% of the total tube length. The high level limit prevents the indicated level from reaching the elevation of the aspirator ports, ensuring that adequate preheating of feedwater in the downcomer can occur.

The elevations of the top and bottom of the reactor core are 57 inches and 198 inches, respectively, above the lower tubesheet of the SG. In order to promote stable natural circulation flow, the thermal center for heat removal must be above the thermal center for heat addition to the primary system. Therefore, during a loss of forced primary system flow, the required SG level automatically increases to 248 inches above the lower tubesheet, ensuring an adequate level for natural circulation flow.

The SGs have penetrations to allow EFW to be injected on the upper portion of the tubes. EFW flows through an external feedwater header, which contains six active nozzles, onto the periphery of the SG tube bundle. The injection elevation is very close to the upper tube sheet. This high elevation injection location is preferred for situations where forced flow is lost in the primary system, because it raises the thermal center for heat removal and thus enhances natural circulation flow in the RCS.

2.1.3.2 Main Feedwater

The MFW System consists of the MFW pumps, the A and B feedwater heaters, and the piping and valves between the pumps and the SGs. The MFW pumps have common suction and discharge lines, so neither of the two pumps is aligned to a particular SG. The variable-speed pumps are turbine-driven by either main steam or low pressure steam. The nominal feedwater temperature at the outlet of the A feedwater heaters is 460°F, at a pressure of approximately 1000 psia. MFW flow to each SG is controlled by the MFW control valves.

The feedwater piping at Oconee is very diverse. The MFW system is normally aligned to the MFW header at the top of the downcomer, but it can be realigned to discharge into the emergency feedwater header at the top of the SG. This realignment is automatic when all four RCPs are tripped, or it can be accomplished by the operators. In addition, the EFW System, which normally discharges into the EFW header, can be manually realigned to discharge into the MFW header if the normal flowpath is unavailable.

2.1.3.3 Main Steam

The main steam lines carry the high pressure, high temperature steam from the SGs to the high pressure turbine. Two 26 inch lines exit each SG and join together into a single 36 inch line. The 36 inch line leaves the Reactor Building and runs to the Turbine Building. Near the high pressure turbine the 36 inch line splits into two 24 inch lines, each containing a turbine stop valve. Downstream of the turbine stop valve the lines from each SG join together in the steam chest, which is simply a large pipe that provides pressure equalization. Four lines leave the steam chest to enter the high pressure turbine, and each line contains a turbine control valve. A schematic diagram of this arrangement is shown on Figure 2.1-9.

Process steam is taken off of each steam line in order to power station auxiliaries. These include the auxiliary steam header, the MFW pumps, the turbine-driven EFW pump, the condensate steam air ejectors, and the steam seals. In addition, main steam is used to reheat the steam between the high and low pressure turbines. Various steam drains and traps are also provided on each steam line. Furthermore, main steam relief is provided by eight main steam relief valves (MSRVs), two turbine bypass valves (TBVs), and one manual atmospheric dump valve per steam line.

The MSRVs provide overpressure protection to the steam lines and SGs. The valve opening setpoints range between 1050 and 1104 psig, and the total relief capacity through the valves is

greater than the nominal full power steam flow rate. The TBVs control steam pressure prior to putting the turbine online and after turbine trip. The four valves (two per steam line) have a total capacity of 25% nominal full power steam flow. The atmospheric dump valves provide the capability for main steam relief in the unlikely event that the TBVs are inoperable and SG depressurization below the main steam relief valve reseat setpoint is required.

Steam line isolation is accomplished by the turbine stop valves, which close automatically upon a turbine trip. However, all penetrations for process steam and steam relief are upstream of the turbine stop valves, so each penetration must be closed individually if complete steam generator isolation is required.

2.1.3.4 Turbine-Generator

The turbine-generator converts the thermal energy of steam produced in the SGs into mechanical shaft power and then into electrical energy. The turbine-generator of each unit consists of a tandem (single shaft) arrangement of a double-flow high pressure turbine and three identical double-flow low pressure turbines driving a direct-coupled generator at 1800 rpm. Turbine-generator functions under normal and abnormal conditions are monitored and controlled automatically by the Turbine Control System (TCS), which includes redundant mechanical and electrical trip devices to prevent excessive overspeed of the turbine-generator. Once the turbine is brought online (at 15%-20% rated power), the turbine control valves maintain the steam line pressure immediately upstream of the stop valves at 885 psig during steady-state operation. The pressure setpoint can be biased by the ICS to accommodate load changes and unanticipated operational transients. The turbine stop valves close rapidly to preclude turbine damage after the receipt of a turbine trip signal.

2.1.3.5 Instrumentation

A wide variety of secondary system instrumentation is available to the operators. Many of the indications are also used as inputs to the ICS. Pressure is available at the MFW pump discharge, the SG outlet, and the steam line upstream of the turbine. Fluid temperature is indicated in each part of the MFW System, the SG downcomer, the steam generator outlet, and the inlet of the turbine. Feedwater flow is available over a low range (0-1 million lbm/hr) and a high range (0-6 million lbm/hr) for both SGs. Four different SG level indications - startup range, extended startup range, power range, and full range - are provided, with the ranges indicated on Figure 2.1-10.

The SG level instruments are ΔP devices, with the taps located at various elevations in the downcomer and shell. ΔP devices measure the weight of fluid between two taps, not the actual mixture or froth level of a fluid. The void fraction in the SG changes from 0 to 1 over most of the height of the generator, and there is really no precise transition between liquid water and steam. In addition, the ΔP between two taps is composed of two components: gravitational (the weight of the fluid between the taps) and frictional (the pressure drop caused by irrecoverable hydraulic losses in the fluid and between the fluid and the steam generator components). The frictional ΔP increases with fluid velocity, and is a significant fraction of the total pressure drop at high flow, high power conditions. Furthermore, the frictional component changes over the life of the plant due to fouling of the SG tubes and the tube support plates. It should also be noted that the operating range level indication is temperature compensated, while the other three ranges are not. Temperature compensation adjusts the level indication to account for the fact that while the instrument is calibrated at cold conditions, the fluid is much hotter and much less dense at power operation. Therefore, the ranges that are not temperature compensated indicate a collapsed liquid level that is approximately 30% too low at hot conditions.

The various level ranges are used for distinct purposes. The startup range is used for monitoring and control at zero or low power conditions, when the water inventory is low and the level is close to the lower tubesheet. The extended startup range is safety-grade and is used for automatic control of EFW. The operate range covers the middle portion of the SG and is used during power operation, when the SGs have a significant water inventory. The full range covers the entire height of the SG, and it is primarily used for evolutions which take place while shutdown, such as wet layup.

2.1.4 Control Systems

Nuclear plants include a large number of control systems which monitor and adjust the performance of individual components and systems. In this section the control systems which have a major effect on the overall transient response of the plant are discussed.

2.1.4.1 Non-Nuclear Instrumentation

The major function of Non-Nuclear Instrumentation (NNI) is to monitor process variables in the RCS and the secondary side of the plant. NNI also performs the control functions of RCS makeup and RCS pressure control. The control features of NNI are discussed in this section.

NNI controls RCS makeup flow by throttling the makeup control valve to maintain the pressurizer level at the setpoint, which is normally 220 inches. The makeup control flowpath is a 2-1/2 inch line around the normally closed 4 inch emergency injection control valve. The makeup capacity through this flowpath is approximately[ ]gpm at system pressure. A proportional plus integral (PI) controller adjusts makeup flow to compensate for changes in RCS inventory or density. After reactor trip the reactor coolant contracts, causing a sharp drop in pressurizer level. Normal makeup control is unable to quickly compensate for this drop, and operator action is usually taken to increase makeup by opening the emergency injection control valve.

NNI also controls RCS pressure through the pressurizer heaters, spray, and PORV. There are four banks of pressurizer heaters which compensate for ambient heat loss in steady-state operation and restore system pressure following reactor trip. The 126 kW control bank operates on PI control to maintain RCS pressure at the setpoint, which is normally 2155 psig. These heaters are usually partially energized to make up for ambient heat loss and condensation due to the small amount of pressurizer spray bypass flow. The three backup banks, with a total capacity of 1386 kW, have on-off control with staggered initiation setpoints of 2130 psig, 2115 psig, and 2100 psig. They are generally off, except following reactor trip when the large pressurizer outsurge causes a sharp decrease in RCS pressure. There is an interlock which removes power from the heaters when pressurizer level decreases below 80 inches. The interlock prevents the heaters from being uncovered while they are energized.

The pressurizer spray is used to reduce RCS pressure during operational transients. The spray is controlled by a solenoid valve in the 2 1/2 inch pressurizer spray line. When open, it allows the relatively cold water from the RCP discharge to flow into the top of the pressurizer, where it condenses steam and thus acts to reduce pressure. The valve opens when RCS pressure exceeds 2205 psig and closes when pressure drops below 2155 psig. The nominal spray valve capacity is [ ]gpm. In addition, there is a 1/2 inch bypass flowpath around the spray valve which allows a constant flow of 1-10 gpm through the spray line. The bypass flow keeps the spray nozzle at a constant temperature, precluding thermal shock to the nozzle when the main spray valve opens.

NNI controls the action of the pressurizer PORV. The PORV opens to relieve fluid to the pressurizer quench tank when RCS pressure exceeds 2450 psig, and it reseats when pressure goes below 2400 psig. The valve design capacity is 100,000 lbm/hr steam at 2300 psig. The lift setpoint used to be lower than the high RCS pressure reactor trip setpoint in order to help to prevent reactor trips during overpressure transients. However, after the Three Mile Island Unit 2 accident in 1979 the PORV lift setpoint was raised to be higher than the reactor trip setpoint.

The primary automatic functions of the PORV now are to prevent challenging the pressurizer code safety valves and to provide low temperature overpressure protection.

2.1.4.2 Turbine Control System

The TCS adjusts the position of the turbine control valves to maintain the turbine header pressure at the control setpoint (normally 885 psig). There are four turbine control valves in parallel, and they move sequentially rather than all at once. Normally the turbine control valves are opened to put the turbine on line at approximately 15% power. At lower power levels the Turbine Bypass System (TBS) controls steam pressure.

2.1.4.3 Integrated Control System

The ICS provides the proper coordination of the reactor, feedwater, and turbine during normal operation and anticipated transients. The ICS maintains the proper conditions during steady-state operation by balancing power production and heat removal. The feed-forward and feedback features of the ICS make the units capable of smooth, responsive changes in load. The ICS is also designed to enable the units to withstand certain transients (e.g. RCP trip, MFW pump trip) without tripping the reactor. ICS feedwater control and turbine bypass control also influence unit behavior following reactor trip.

B&W plants are generally considered to be more sensitive than other PWRs to secondary system perturbations. This is due to the relatively low secondary inventory and variable effective heat transfer that is characteristic of the once-through SG. Thus an effective control system is necessary for the reliable operation of a B&W plant. At the same time the responsiveness of the units makes it possible to rapidly adjust load and prevent unnecessary reactor trips.

The plant can be operated in the integrated, reactor-following, or turbine-following modes. In reactor-following mode, load changes are accomplished by changing steam flow, and the rest of the plant adjusts to the change by con-trolling steam pressure at the setpoint. In a turbine-following system, the overall power is changed by altering reactor power, and the turbine changes its output by controlling steam pressure at the setpoint. The integrated mode combines the advantages of the other two modes by incorporating feed-forward features which provide rapid load response and stable steam pressure control. The ICS functioning in the integrated mode is the normal operating mode at Oconee.

A complete description of the ICS would be prohibitively involved for this report. Instead, a functional description of the system is provided, focusing on the four subsystems of the ICS - unit load demand (ULD), integrated master, reactor control, and feedwater control.

Unit Load Demand

The ULD produces the demand signal for the turbine, reactor, and MFW. This is normally based on the demand for electricity in the electric distribution grid. Since the Oconee units are currently operated in a base-loaded mode, that demand is usually 100% of the maximum power level. The unit operators change the ULD to start up or shut down the plant and to perform planned power maneuvers. In addition, the ULD will be automatically limited by any of the following conditions: loss of one or more RCPs, a 5% mismatch between feedwater flow and feedwater demand, a 5% mismatch between reactor power and power demand, loss of one feedwater pump, an asymmetric rod pattern in the reactor core, and a loss of load. This automatic feature increases the chance of withstanding one of these transients without sustaining a reactor trip by limiting the demand to the available capability of the unit.

Integrated Master

The integrated master controls the turbine header pressure setpoint to match generated megawatts with the unit load demand. The setpoint is 885 psig in steady-state, and it is adjusted during power maneuvers by the feed-forward features of the ICS. The integrated master also controls the TBVs both before and after reactor trip. Before reactor trip, the bypass valves provide steam pressure control prior to putting the turbine on line, and they furnish steam overpressure relief during transients. After reactor trip, the TBVs control steam pressure to 1010 psig, thus maintaining the RCS at approximately 550°F.

The integrated master also contains a feed-forward feature. In the integrated master the ULD signal is modified by the turbine header pressure error before being passed along to the SG and reactor subsystems. This provides for a quicker and smoother response to load changes.

Reactor Control

The reactor control subsystem is designed to maintain a constant average coolant temperature between 15% power and 100% power. The load demand signal from the Integrated Master is adjusted by the error between T-ave and the setpoint (normally 579°F) to give a reactor demand. When the indicated reactor power is outside a 1% deadband, the control rods are moved to adjust power to the setpoint.

Feedwater Control

The feedwater subsystem (also known as the SG subsystem) is designed to maintain MFW flow equal to the feedwater demand from the integrated master, maintain the proper feedwater ratio between the two SGs, ensure that the turbine inlet steam is at least 35°F superheated, and maintain the SG levels between the maximum and minimum levels. Adjustments to feedwater flow are made by varying the position of the feedwater flow control valves. The feedwater pump speed is controlled to maintain a constant feedwater control valve P; therefore, the pump speed will also change with feedwater flow. Feedwater is ratioed between the SGs by a circuit which controls the difference in primary system cold leg temperatures to a setpoint (usually zero). The Btu limits monitor primary and secondary system thermodynamic properties to ensure that 35°F superheat is obtained from each generator, as required for proper high pressure turbine operation. The feedwater demand to each generator is modified to prevent the indicated level from exceeding the maximum (95% on the operate range) or the minimum (25 inches on the startup range). An additional feature of the ICS is the cross-limits, which act to keep the RCS heat addition and heat removal at consistent values. The feedwater-to-reactor cross limit adjusts reactor demand down if the indicated feedwater flow drops significantly below the feedwater demand. The reactor-to-feedwater cross limit adjusts feedwater demand up or down if the reactor power is significantly higher or lower than the reactor demand. The cross limits minimize the severity of operational upsets and, together with the Btu limits, reduce feedwater demand after reactor trip to be consistent with the low decay heat power levels.

2.1.5 Safety Systems

Various systems are required to ensure that the plant does not exceed its licensed limits during design basis transients. The major safety-related systems which affect the plant transient response are discussed in this section.

2.1.5.1 Reactor Protective System

The RPS monitors parameters related to safe operation of the core and trips the reactor to protect against fuel and cladding damage. In addition, by tripping the reactor and limiting the energy input into the coolant, the RPS protects against RCS structural damage caused by high pressure. A two out of four logic scheme is used to sense a trip condition. When any two protective channels trip, power is removed to the control rod drives of the safety rods (control rod banks 1-4) and the regulating rods (control rod banks 5-7). These rods fall into the reactor core and shut down the nuclear chain reaction.

The RPS will initiate a reactor trip on the following conditions:

1) High power (neutron flux)
2) High flux/flow ratio - the combination of reactor power, reactor coolant flow, and imbalance (a measure of axial flux asymmetry) exceeds the allowable limit
3) Pump monitor - the reactor power exceeds the allowable limit determined by the number of RCPs in operation
4) High hot leg temperature
5) Variable low pressure - the combination of RCS pressure and hot leg temperature is outside the allowable range
6) High RCS pressure
7) Low RCS pressure
8) High Reactor Building pressure
9) Both MFW pumps tripped
10) Main turbine trip with reactor power >20%

The latter two trips are anticipatory functions which were added after the TMI-2 accident. They do not provide direct protection against exceeding a safety limit, but for many transients they will trip the reactor before a high RCS pressure trip is required. The high Reactor Building pressure trip also does not perform a direct safety function. It is a backup for the low RCS pressure trip that would be expected following a loss of coolant accident (LOCA).

2.1.5.2 Engineered Safeguards System

The ESS is designed to provide borated water injection into the RCS and containment cooling to mitigate a LOCA. The system will also provide injection in the event of a significant depressurization caused by excessive primary-to secondary heat transfer, such as a steam line break. In addition, the ESS will accomplish containment isolation and cooling and penetration room ventilation during an accident situation. The constituents of the ESS are discussed below.

<u>High Pressure Injection System</u>

The HPI System consists of three pumps which take suction from the borated water storage tank (BWST) and inject water into each RCS cold leg pump discharge pipe. The A and B pumps are in parallel and inject water into the A loop of the RCS; the C pump injects into the B loop. One pump through either train will deliver at least[ ]gpm at normal system pressure (2155 psig). In normal operation either the A or B pump runs to provide RCS makeup and RCP seal injection. All three HPI pumps receive start signals on low RCS pressure (<1600 psig) or high Reactor

Building pressure (4 psig). The same signal automatically switches the suction source from the letdown storage tank to the BWST, and opens the emergency injection valves.

Core Flooding System

The Core Flooding System is a passive part of the Emergency Core Cooling System that performs no function in normal operation. The system consists of two core flood tanks (CFTs), each of which are connected to the reactor vessel by an injection line. The tanks are pressurized to 600 psig by nitrogen. Each 1410 ft tank contains 1040 ft of borated water which, following a large break LOCA, is discharged into the reactor vessel. Each injection line contains two check valves which isolate the tanks from system pressure during normal operation, but open to allow flow during a design basis accident.

In addition to large break LOCAs, the CFTs will inject water into the RCS during any major depressurization event. This includes large steam line breaks and some small break LOCAs.

Low Pressure Injection System

The Low Pressure Injection (LPI) System consists of two pumps which take suction from the BWST and inject water into the reactor vessel downcomer through the core flood tank lines. In normal operation the LPI pumps are idle; they receive a start signal on low RCS pressure (<500 psig) or high Reactor Building pressure (>4 psig). The same signal opens the suction valves from the BWST and the discharge valves to the RCS. Due to the low discharge head of the LPI pumps, they do not actually deliver flow until the RCS pressure is much lower than 500 psig. The pumps have a capacity of 3000 gpm with a discharge head of 150 psi. The LPI System, like the HPI System, is comprised of two separate and independent trains.

Following depletion of the BWST inventory, the LPI pumps can be manually realigned to take suction from the Reactor Building sump. In this mode the injection water is cooled by an LPI cooler in each discharge line.

There is a spare LPI pump in parallel with the other two at each unit. The spare pump performs no ESS function. In addition to their accident mitigation function, the LPI pumps and coolers provide shutdown decay heat removal when the RCS is below 250°F and the SGs are no longer active.

Containment Systems

The other constituents of the Engineered Safeguards Systems are the Reactor Building Cooling System, the Penetration Room Ventilation System, and the Reactor Building Isolation System.

These systems do not have a major impact on the RCS transient response, and thus are not described in detail in this report.

2.1.5.3 Emergency Feedwater System

The EFW System is designed to provide feedwater to the SGs in the event of a complete loss of MFW. The capacity of the system is adequate to remove decay heat and stored energy from the primary system in either forced or natural circulation modes. If necessary, the EFW System will provide feedwater sufficient to enable cooldown from power operation to cold shutdown. A simplified schematic diagram of the system is shown on Figure 2.1-11.

The EFW System consists of two motor-driven and one turbine-driven pump per unit. The turbine-driven pump feeds both SGs, while each of the motor-driven pumps is aligned to one SG. The capacity of the turbine-driven pump is approximately twice that of a motor-driven pump, and only one motor-driven pump is required to mitigate a loss of MFW event. All three pumps take suction from the upper surge tanks which contain at least 30,000 gallons of feedwater at approximately 90°F. Suction can also be taken from the condenser hotwell, which contains in excess of 100,000 gallons. All three pumps receive a start signal following either of two indications that MFW is lost - low MFW pump hydraulic oil pressure or low steam generator level. The pumps discharge into one injection line per SG. A flow control valve in each line automatically controls the flow to each SG to maintain a constant level. The level setpoint automatically varies between 25 inches on the startup range if the RCPs are on and 242 inches on the startup range (50% on the operate range) if the RCPs are off. The operators can also take manual control of the system.

EFW discharges into the SGs through the EFW header near the top of the shell region. When the RCS is in forced circulation mode, the cold EFW travels down the length of the tubes (approximately 50 feet) to build up a 31 inch pool in the bottom of the generator. This results in more effective heat transfer than the normal post-trip situation, in which the much hotter MFW enters the generator through the MFW nozzles and flows down the downcomer rather than the SG tubes. The upper injection location also enhances natural circulation by raising the thermal center for heat removal toward the top of the steam generator.

2.1.5.4 Steam Line Break Detection and Mitigation Circuitry

The Steam Line Break Detection and Mitigation Circuitry uses steam generator outlet pressure as the initiating parameter for automatic feedwater isolation. When a steam line break is sensed by

steam generator outlet pressure falling below the setpoint, both trains of MFW control valves, MFW block valves, startup feedwater control valves and startup feedwater block valves are closed. Additionally, both MFW pumps are tripped. Tripping both MFW pumps will trip the reactor, trip the turbine and start the motor-driven EFW pumps. The circuitry also stops the turbine-driven EFW pump.

2.1.6 Dissimilarities Between Units

All three Oconee units are similar, but some differences in components and configurations do exist. The primary systems are essentially identical, while the balance of plant systems tend to differ, although not usually in function as much as in form.

The major difference between units in the primary system is the RCPs. Unit 1 has Westinghouse pumps, while Units 2 and 3 have Bingham pumps. Although the piping configuration is somewhat different in the cold legs, there is no significant difference in overall primary system volume. The Bingham pumps provide slightly more flow than the Westinghouse pumps.

The pressurizer location varies between units. The pressurizer is on Loop A at Unit 1, while it is on Loop B at Units 2 and 3. Similarly, the pressurizer spray line is attached to the A1 cold leg pump discharge pipe of Unit 1 and the B1 pipe of Units 2 and 3.

There can be both mechanical and nuclear differences between the reactor cores of the three units. Fuel assembly design changes are implemented from time to time to enhance fuel performance. These changes can have an impact on the characteristics of the core. For example, Oconee now uses Mark BZ fuel assemblies, which incorporate Zircaloy spacer grids for enhanced neutron economy. However, some Mark B assemblies with the smaller Inconel spacer grids remain in the cores, since only one-third of the assemblies are replaced during each reload. In addition, the number of burnable poison assemblies in the core varies between unit and cycle, and this parameter has a small effect on core bypass flow. Furthermore, the nuclear characteristics of each core vary somewhat between cycle and unit, so parameters such as moderator coefficient, Doppler coefficient, and control rod worth will change.

The maximum available HPI flow varies slightly between units. The differences are attributable to piping dissimilarities and variations in performance between HPI pumps.

There are several noticeable differences between the Oconee SGs. The generators of Units 1 and 2 incorporate an external EFW header, while the Unit 3 generators had an external header added in 1982. The internal headers at Unit 3 are still present, but they have been structurally stabilized and hydraulically isolated from the EFW System. In addition, the B generator of Unit 3 has an additional 73 tubes that were inadvertently left out of the inspection lane during fabrication. As a result of the additional carryover in the lane, the steam outlet temperature from this generator is only 570°F, as opposed to 590-595°F in the other generators at full power. Furthermore, the number of tubes plugged varies between all six generators.

As with HPI flow, the maximum available EFW flow is slightly different for each unit and each SG. The differences are due in part to dissimilarities in piping layout and pump performance, and also to the fact that the motor-driven EFW pumps of Unit 1 are of a slightly different design than those of Units 2 and 3. The turbine-driven EFW pumps are the same model for all three units.

The MFW and main steam piping are different between each unit and each SG. These differences are due to variations in balance of plant layout.

(Pages 2-20 to 2-22 intentionally deleted)

Oconee Reactor Coolant System Schematic

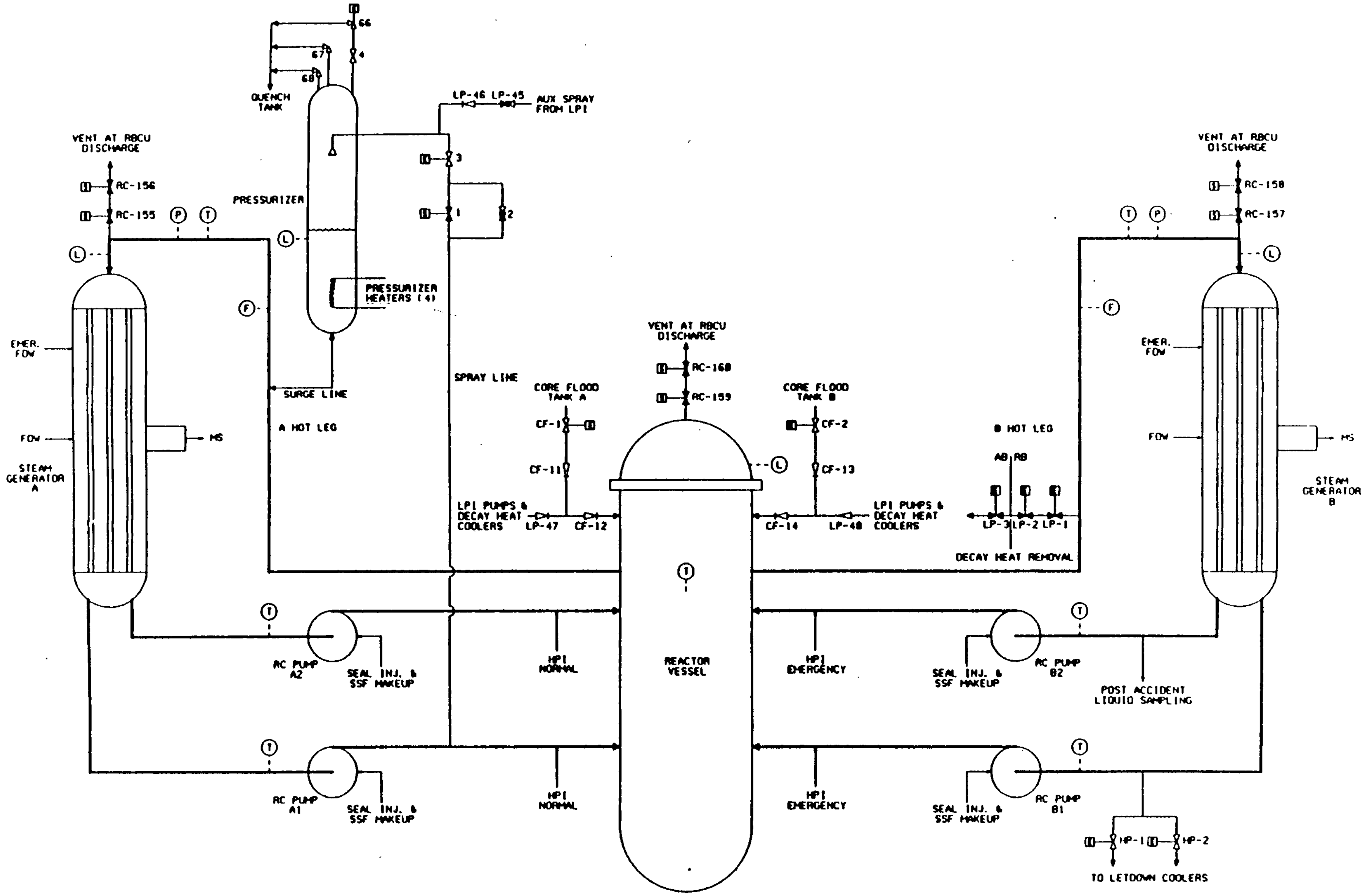


Figure 2.1-1

Figure 2.1-2

Oconee Reactor Vessel

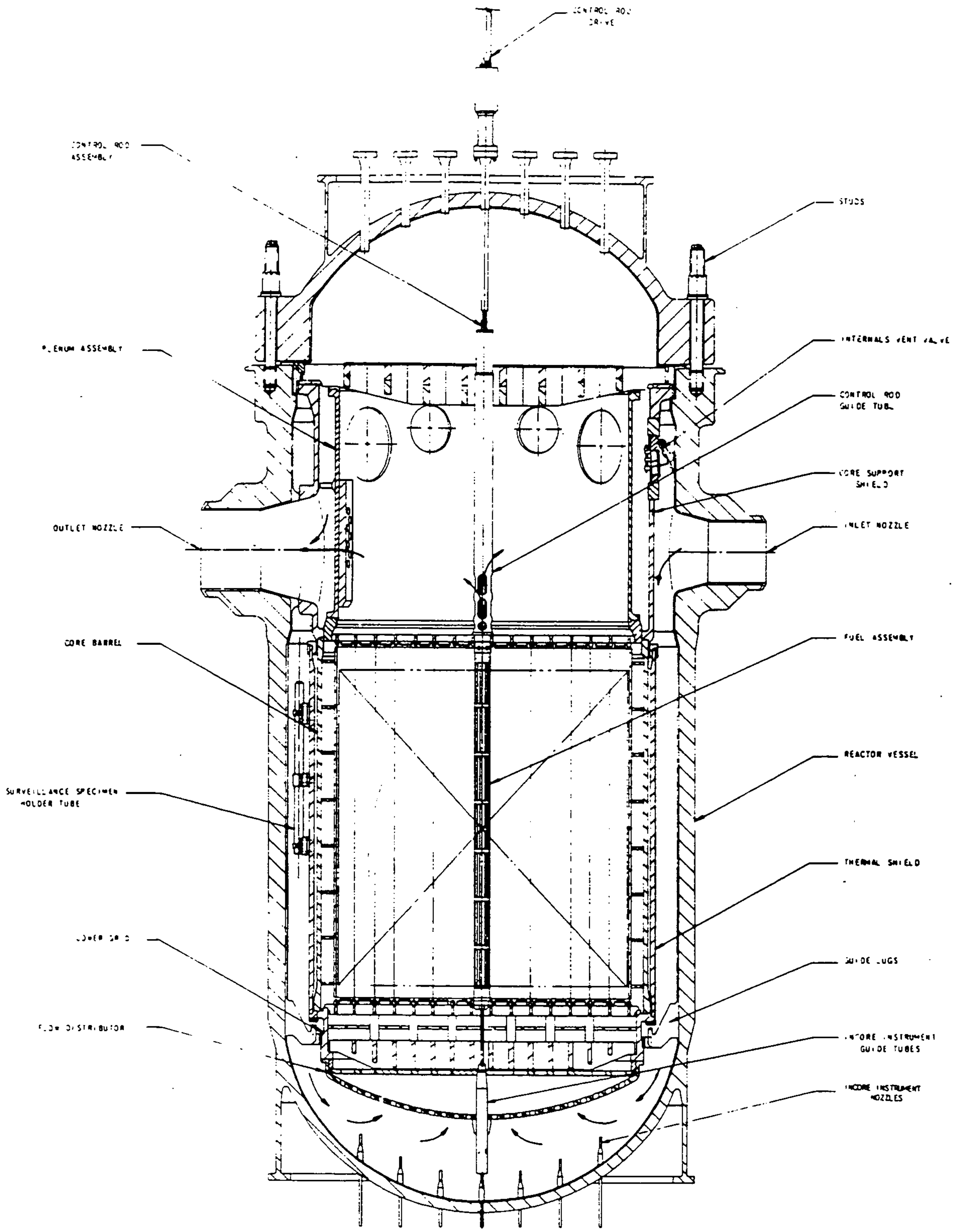


Figure 2.1-3

Oconee Reactor Vessel Vent Valves

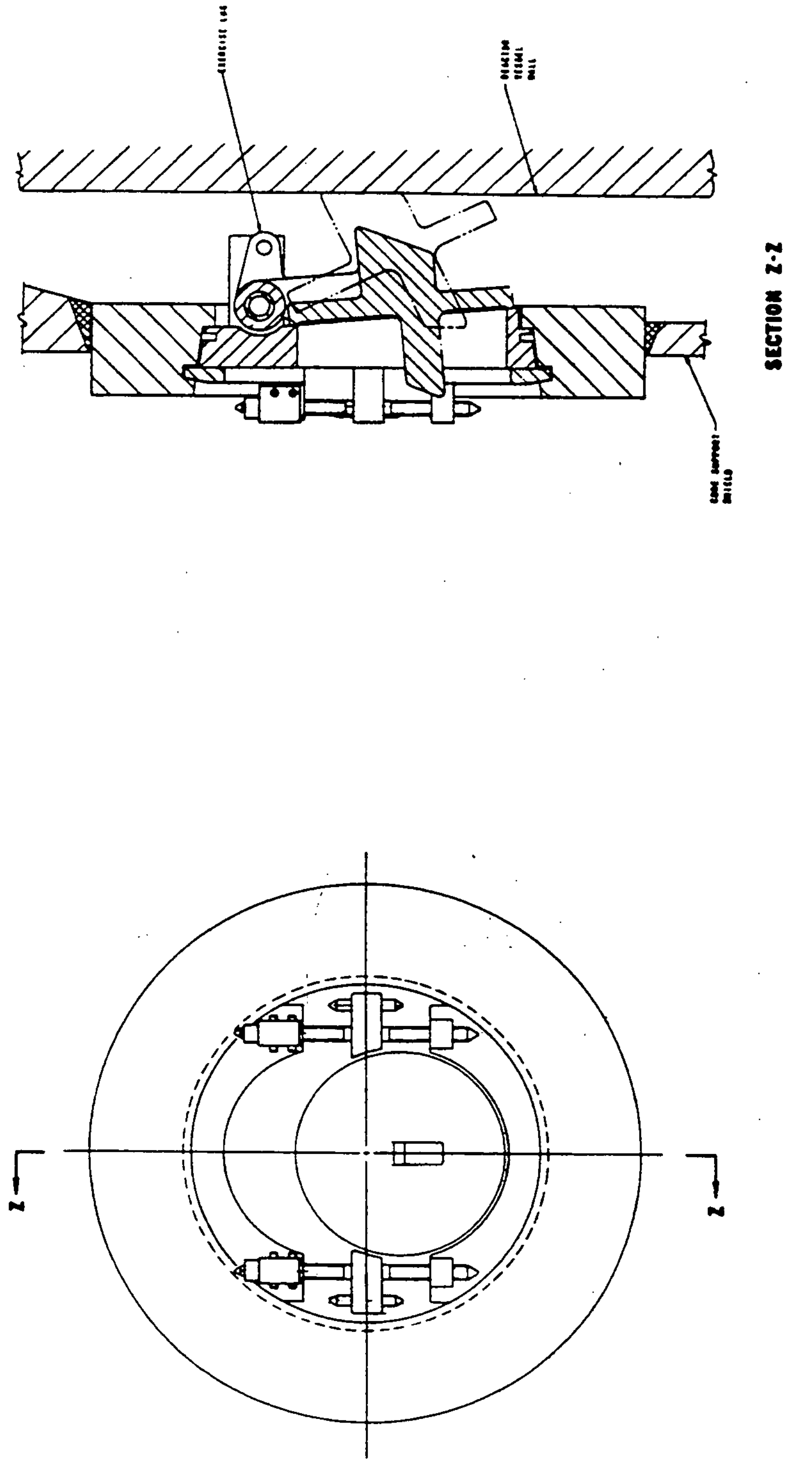


Figure 2.1-4

Oconee Reactor Coolant Piping

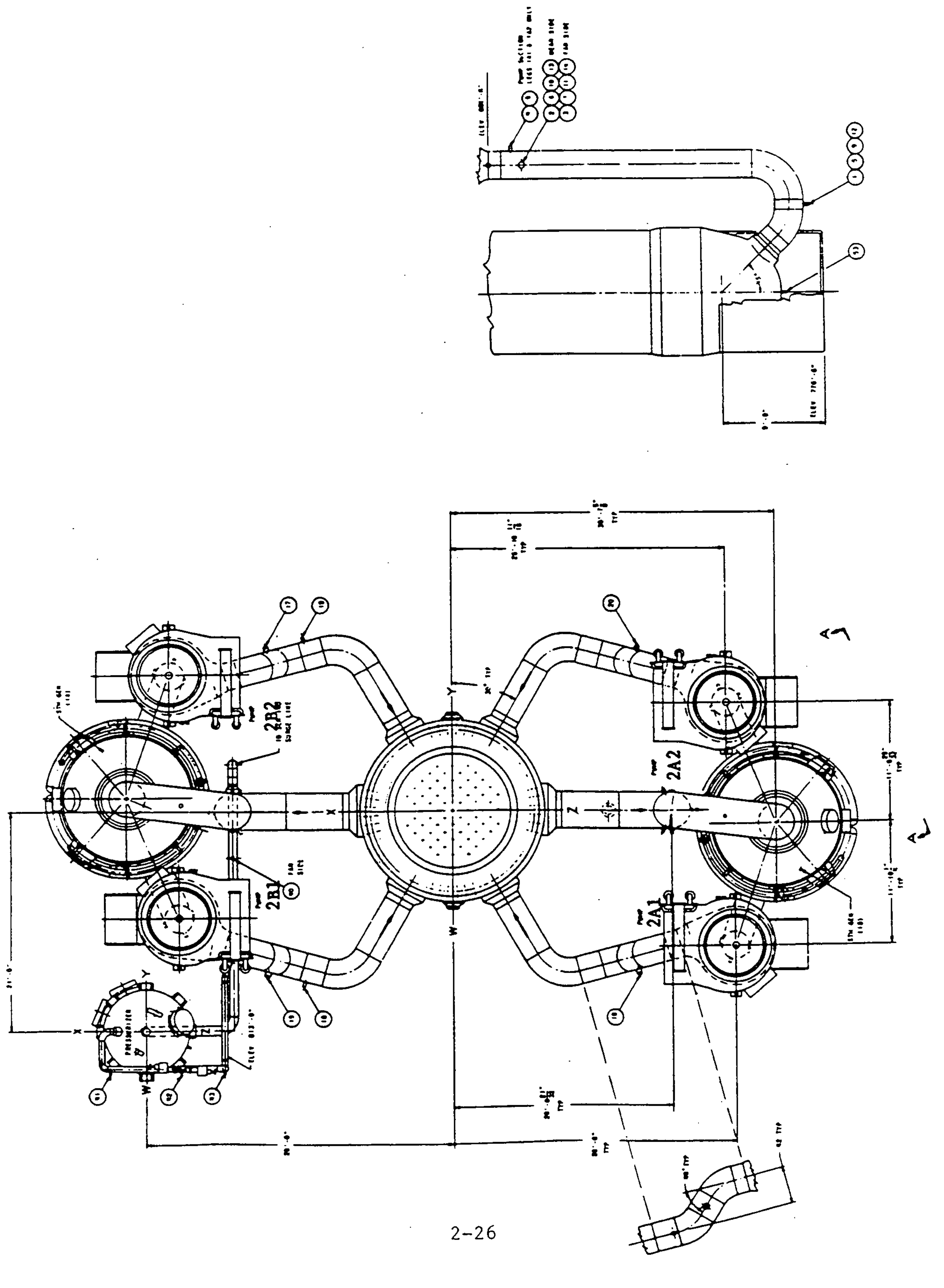


Figure 2.1-5

Oconee Reactor Coolant Piping

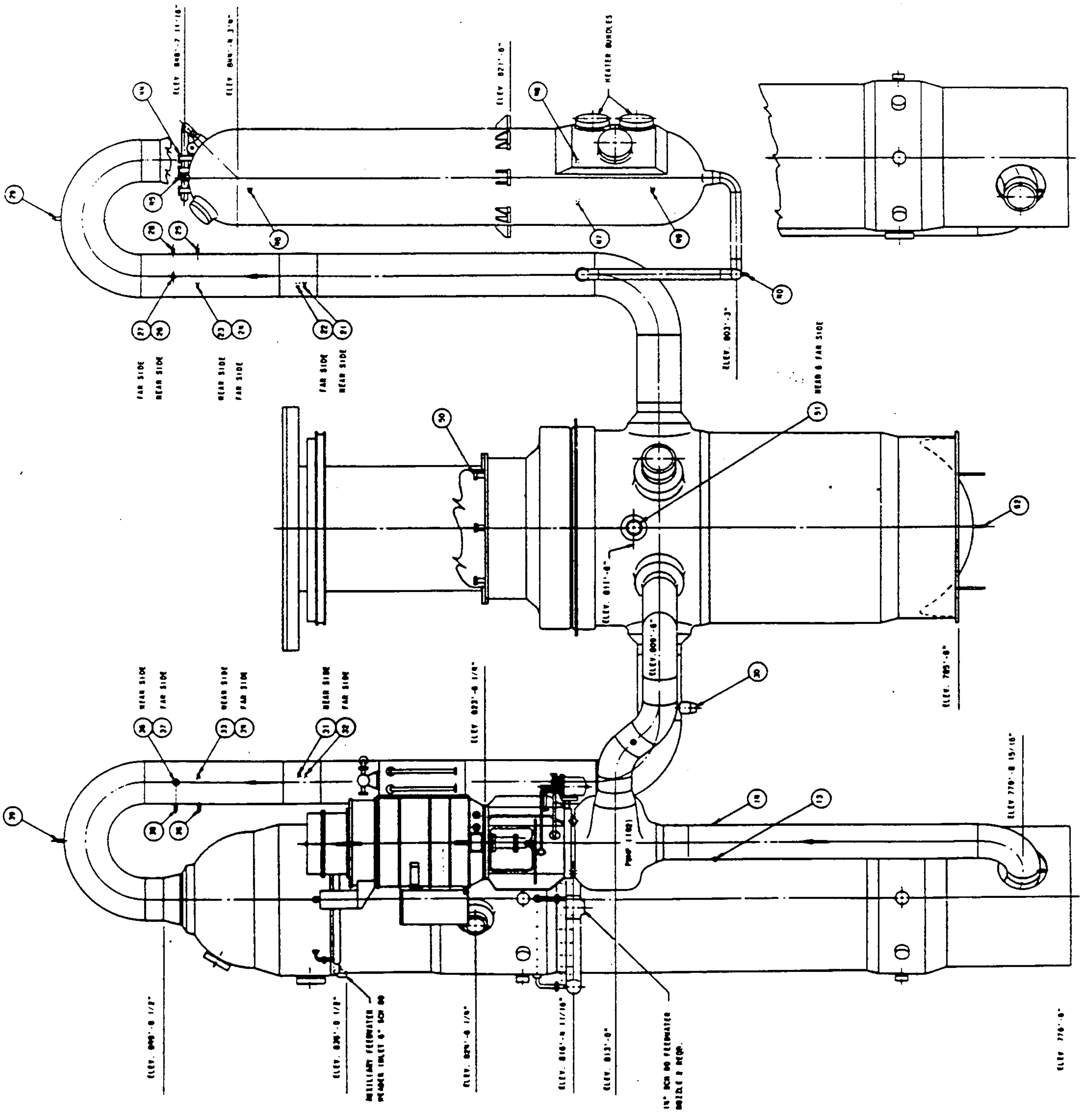


Figure 2.1-6

Oconee Once-Through Steam Generator

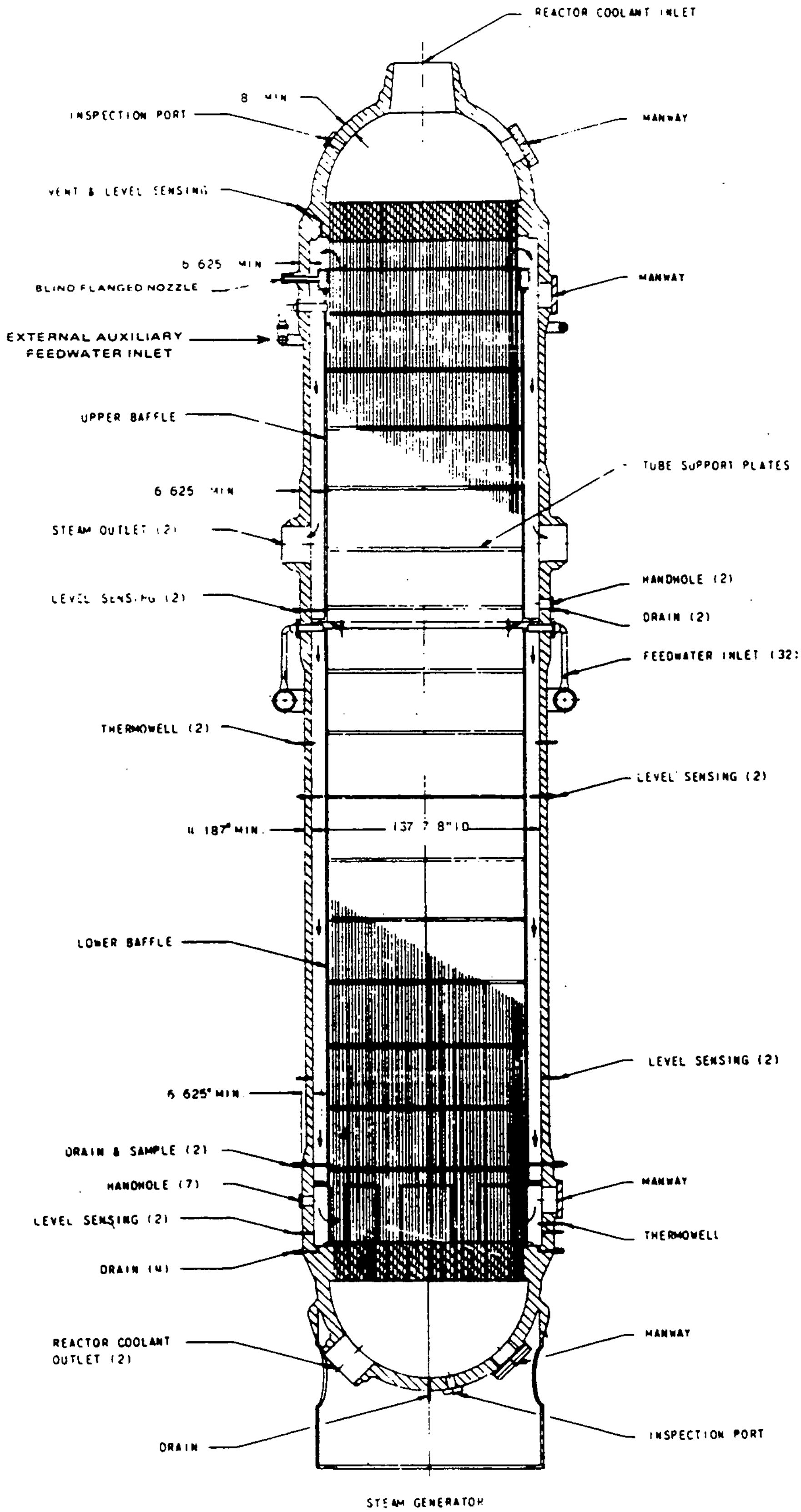


Figure 2.1-7

Oconee Pressurizer

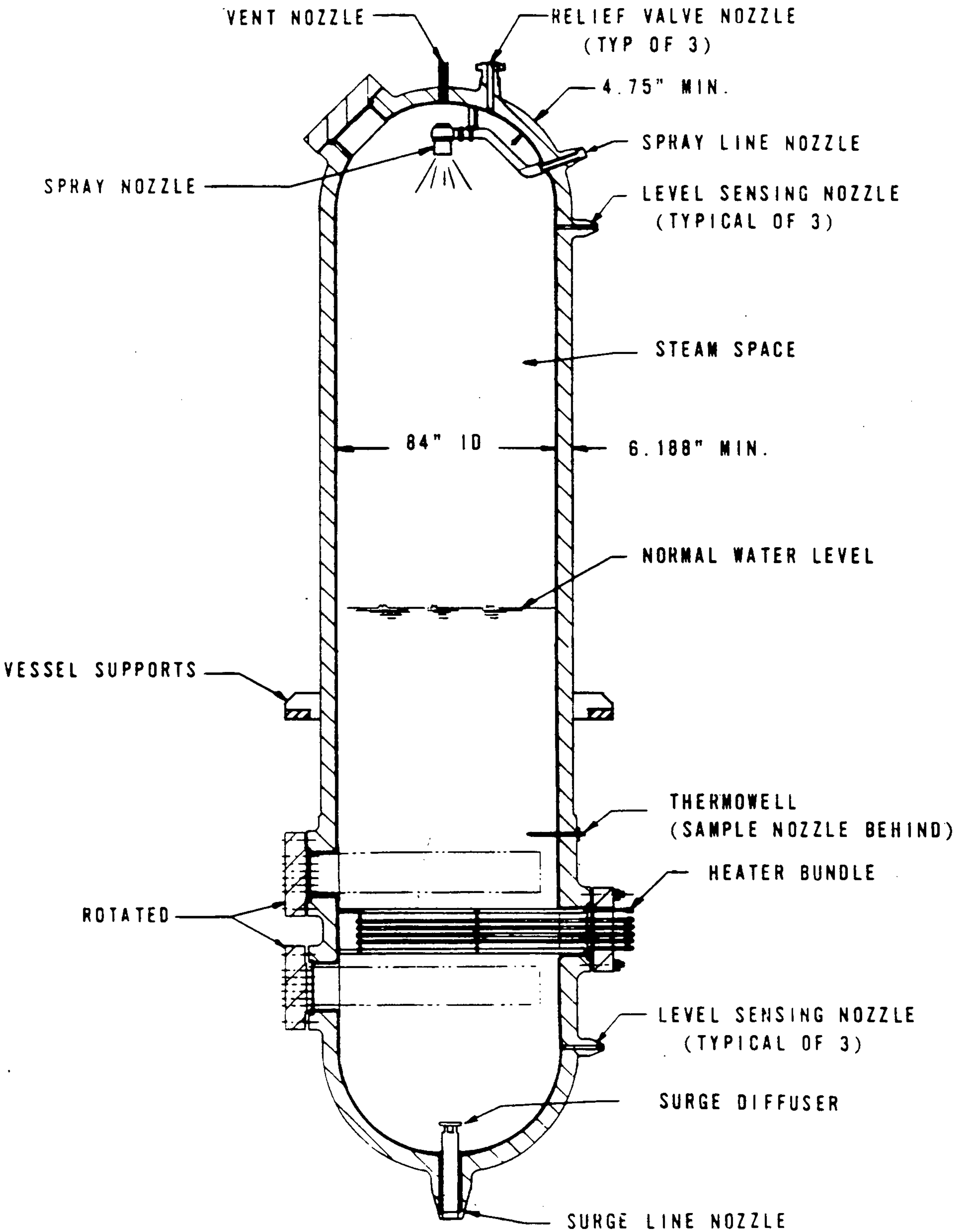
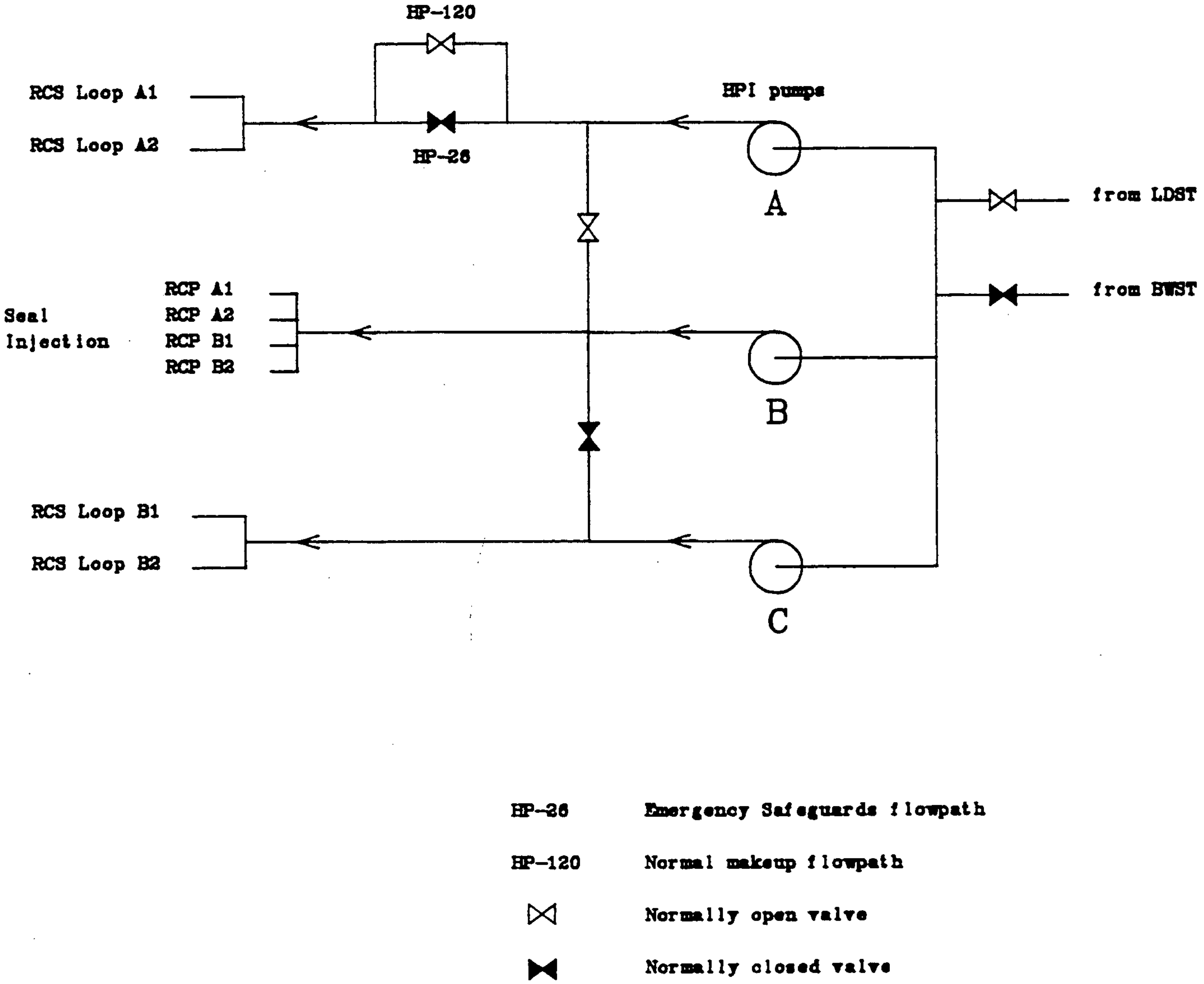


Figure 2.1-8

Oconee HPI System

Simplified Schematic



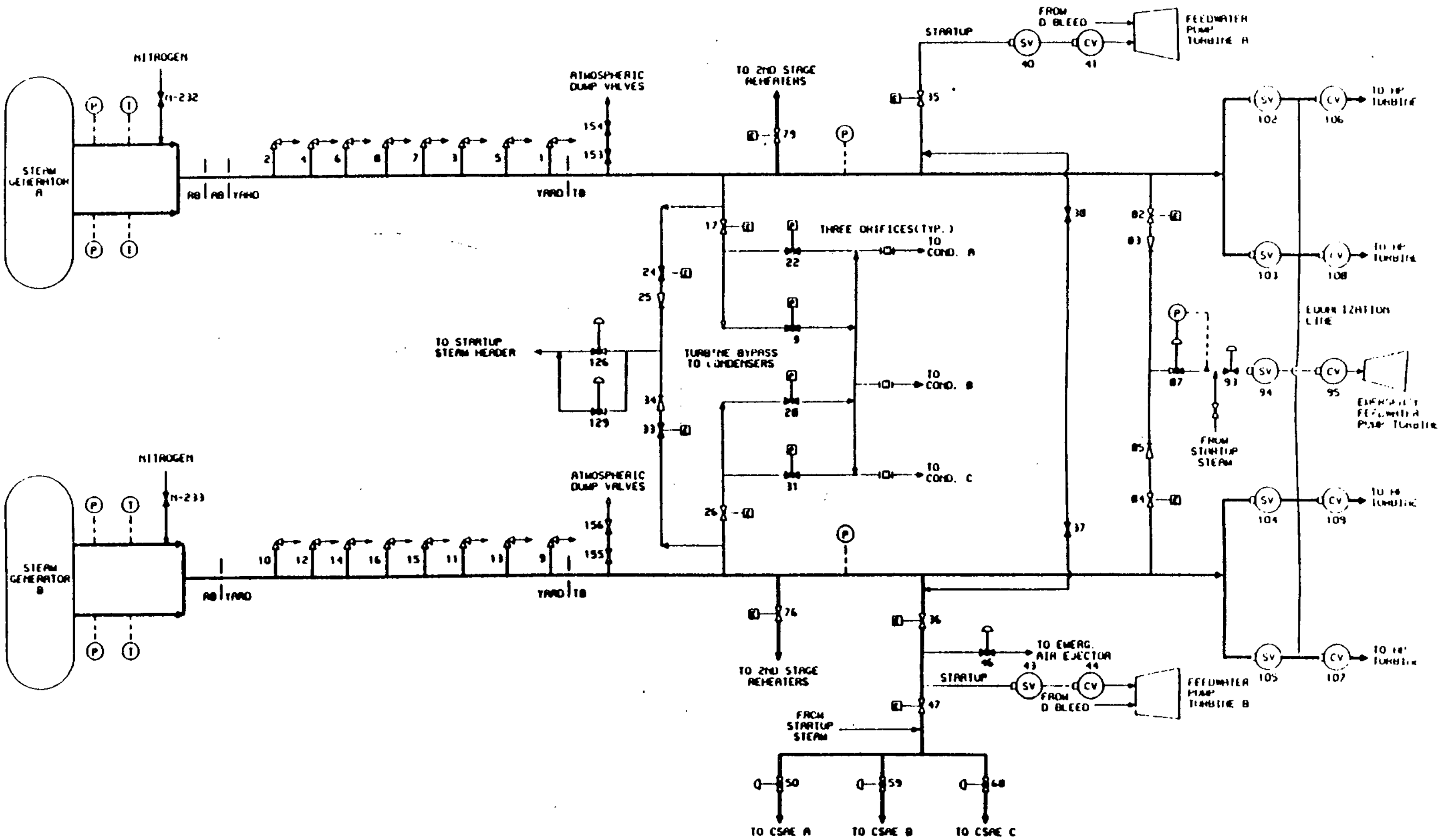
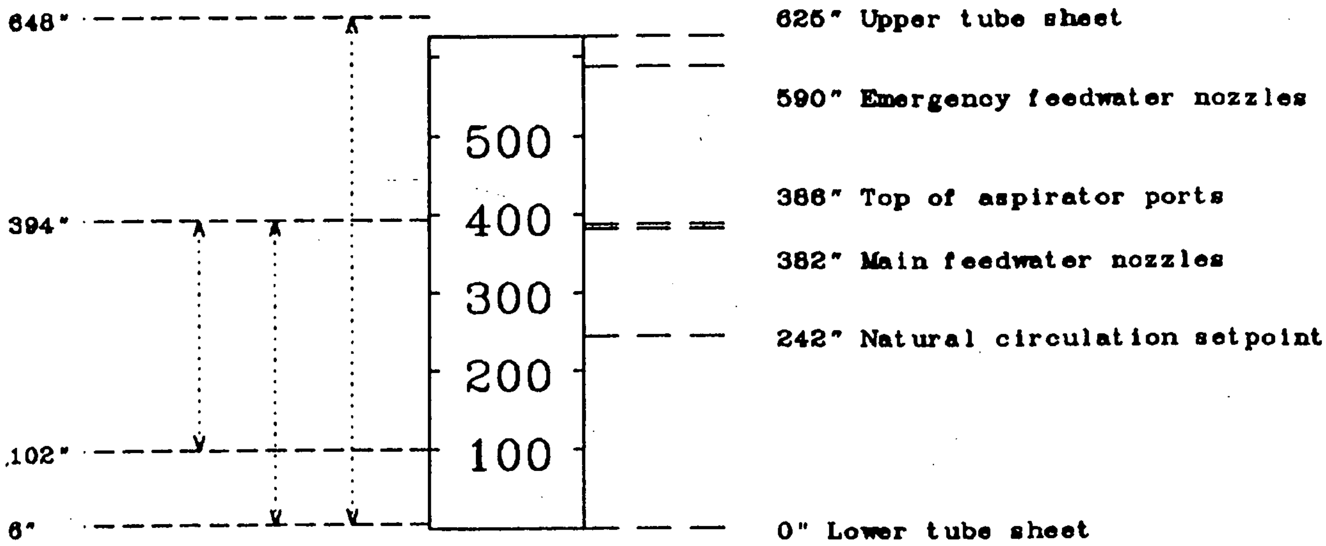


Figure 2.1-9
Oconee Main Steam Schematic

Oconee SG Level Instruments



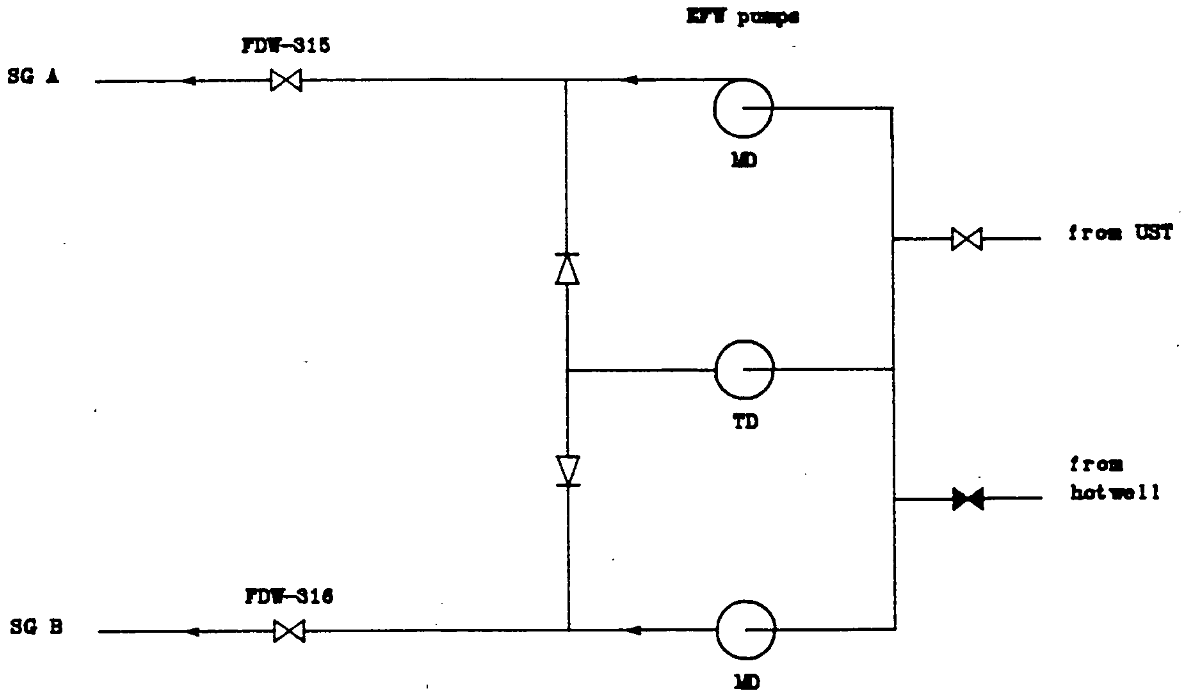
Startup Range: 6-256" Indication, 6-394" Taps
Extended Startup Range: 6-394" Indication and Taps
Operate Range: 0-100% Indication Over 102-394" Range and Taps
Full Range: 6-648" Indication and Taps

Figure 2.1-10

Figure 2.1-11

Oconee EFW System

Simplified Schematic



FDW-315	SG A flow control valve
FDW-316	SG B flow control valve
	Normally open valve
	Normally closed valve
	Check valve
MD	Motor-driven
TD	Turbine-driven

2.2 Oconee RETRAN Model

The complete two loop, four cold leg Oconee RETRAN model nodalization is shown on Figure 2.2-1. The model is configured like Unit 1, with the pressurizer on the A loop. A one loop model, shown on Figure 2.2-2, is used for transients which exhibit a sufficient amount of symmetry. For certain applications the amount of detail in these nodalizations is excessive and can be reduced to save computer time, while on occasion additional detail is required.

The primary system model is symmetric relative to the two loops. The A loop components (volumes, junctions, and conductors) are assigned a 100 series number. The B loop component numbering scheme is the same, except that they are assigned a 200 series number. Thus Volume 113 is identical to Volume 213, except that the former is in the A loop and the latter in the B loop.

2.2.1 Primary System Nodalization

2.2.1.1 Reactor Vessel

The reactor vessel is modeled by[ ]fluid volumes. The boundaries between the volumes are chosen due to actual physical separations, or to provide an additional level of detail in the hydrodynamic calculation.

<u>Downcomer</u>

[

]

to the cold legs. Flow enters through the four cold legs and exits into the lower plenum.

<u>Lower Plenum</u>

The reactor vessel lower plenum is represented by[ ]. Flow from the downcomer goes through the lower plenum into the core.

<u>Core</u>

[ ]represent the reactor core region from the[ ]There is no physical separation between [ ]. Flow enters from the lower

plenum and discharges into the upper plenum. The [ ] to provide a more accurate simulation of the temperature profile in the core at power.

The core bypass region is modeled by [ ] The bypass flow channels include the control rod guide tubes and instrument tubes inside the fuel assemblies, as well as the area between the core baffle plate and the core barrel which is exterior to the fuel assemblies. All of the bypass constituents are [ ]. The control rods are assumed to be [ ] Flow enters the bypass from the lower plenum and exits into the upper plenum.

<u>Upper Plenum</u>

The upper plenum of the reactor vessel, which extends from the [ ] In the upper plenum the coolant flows upward from the core and then turns radially outward to leave the vessel through the outlet annulus. Some of this flow goes through a series of small holes in the plenum cylinder (the plate which separates the upper plenum from the outlet annulus). The majority of the flow continues upward and then goes through a set of larger holes which are also in the plenum cylinder, but at a higher elevation. The upper plenum is [ ] into the outlet annulus. There is [ ]. Another flowpath involving the upper plenum is the one between the lower portion of the upper plenum, just above the active fuel, and the control rod guide assemblies. Some flow goes through the guide assemblies into the vessel head.

<u>Control Rod Guide Assemblies</u>

The 69 control rod guide assemblies, [ ] in the RETRAN model, extend from the top of the core through the plenum cover and discharge into the reactor vessel upper head. Some flow enters the guide assemblies through holes located just above the top of the core, while the rest of the flow comes directly from the fuel assemblies and the control rod guide tubes. Due to modeling limitations, in the model the flow enters the control rod guide assemblies from the lower upper plenum volume.

<u>Upper Head</u>

The reactor vessel upper head is a large cylindrical and hemispherical region which extends between the upper plenum and the vessel head itself. It is modeled by RETRAN [ ] Flow enters the region through the control rod guide assemblies which penetrate the plenum cover. There is a circumferential gap between the plenum cover and the vessel shell through

which flow leaves the upper head and enters the outlet annulus. The only structural components in the interior of the upper head are parts of the Control Rod Drive System.

<u>Outlet Annulus</u>

The outlet annulus, the annular region between the plenum cylinder and the core support shield, is represented by [ ] before exiting the vessel through the hot leg nozzles.

[ ] the outlet annulus to the downcomer. [ ] of the eight reactor vessel vent valves, which provide internal vessel circulation under low flow conditions. [ ]

2.2.1.2 Reactor Coolant Loops

[ ] to represent the hot and cold leg piping. In addition, [ ] to model each RCP. The volumes in the A loop are discussed here and are identical to the corresponding volumes in the B loop.

[ ]

[ ] represent the SG outlet piping to the RCPs. [ ] by the RETRAN centrifugal pump model. The pump discharge piping is simulated by [ ]. Each extends outward from the pump, bends down a slight amount, and runs horizontally into the reactor vessel. The vessel inlet nozzles [ ]

2.2.1.3 Steam Generators

The SG upper head is modeled by [ ]. The 52 foot length of the SG tubes is represented by [ ] The detailed nodalization allows an accurate simulation of the SG density gradient, which is an especially important consideration during natural

circulation. The RETRAN [ ] A nominal value for the number of tubes plugged (1%) is assumed. The SG lower head [ ] is similar to the upper head. As with the upper head, the fluid volume in the [ ]

2.2.1.4 Pressurizer

The Oconee pressurizer is represented by [ ] connect it to the RCS. [ ] which runs between the bottom of the pressurizer to the A hot leg. The hydraulic losses associated with the surge line [ ] models the pressurizer spray line which connects one of the cold leg pump discharge volumes to the top of the pressurizer. The loss coefficient associated with [ ] The PORV and safety valve junctions are modeled at the top of the pressurizer.

Phase separation in the pressurizer is simulated by the [ ] In some cases [ ] between the liquid and vapor regions.

2.2.1.5 Core Flood Tanks

The two CFTs and their associated injection lines are [ ] The RETRAN air model is used to simulate the nitrogen overpressure in the tanks. [ ] allows the tanks to discharge when the RCS pressure drops below 600 psig.

2.2.2 Secondary System Nodalization

2.2.2.1 Main Feedwater Lines

[ ] represents the MFW lines between the [ ] and the SGs. Fluid volume and piping elevations are conserved, but the detail of the piping run is not included. The loss coefficient of the [ ]

2.2.2.2 Steam Generators

The SG downcomer is modeled by [ ] in the downcomer, with a steam-liquid mixture near the top, and essentially saturated liquid at the bottom. [ ] represents the aspirator ports, which provide a recirculation flowpath for saturated steam to preheat the feedwater. [ ] represents the water ports, through which feedwater flows into the SG shell.

[ ] RETRAN volumes are used to simulate the shell side next to the SG tubes. The bottom [ ] around the elevation of the normal post-trip SG level setpoint.

The RETRAN [ ], to assist in providing a good full power initialization.

Emergency feedwater injection is modeled [ ] near the top of the tubes. This approach is taken to [ ] to the bottom of the SG.

The steam outlet annulus, [ ]

2.2.2.3 Main Steam Lines

[ ] represents the flow to the high pressure turbine. [ ] models the steam relief function of the TBVs. The two TBVs on each steam line [ ] simulate the eight MSRVs; the two sets of valves which [ ]

2.2.3 Heat Conductor Nodalization

2.2.3.1 Reactor Core

[ ] are used to model the fuel pins in the reactor core. The conductors are separated into [ ]. Material properties (thermal conductivity and heat capacity) are [ ]. The fuel gap [ ] to give the [ ] fuel temperature, which varies with core average burnup. This approach is used to properly account for the stored energy in the fuel. The RETRAN core conductor model is used for these conductors in order to allow power generation in the fuel material. 2.7% of the power generated in the core is assigned to direct heating of the moderator rather than deposition of energy in the fuel pellets.

2.2.3.2 Steam Generators

[ ] heat conductors are used to represent the tubes in each of the SGs. The [ ] conductors to represent the remaining length of the tubes. The nominal Inconel-600 heat capacity is used, but the input [ ]

2.2.3.3 Structural Conductors

These conductors represent the plant components which do not generate power or conduct heat from the primary to the secondary, but which can affect the plant transient response by transferring energy to or from the working fluid. The stored energy and heat capacitance of these conductors tend to dampen changes in RCS conditions. During an overcooling event the structural conductors transfer heat to the primary coolant and thus retard the cooldown. Conversely, during an overheating transient the structural conductors act as a heat sink and reduce the magnitude of the increase in the primary coolant temperature. The effect of the structural conductors is most apparent during long-term transients. During short transients which do not exhibit severe undercooling or overcooling, the heat transferred from the structural conductors is insignificant relative to the large amount of decay heat in the core. However, the

structural conductors represent a significant heat load for long-term cooldown, once decay heat has decreased.

The key parameters for the structural conductors are the mass and the heat transfer area. These determine the initial stored energy and the effectiveness as a heat sink. In order to [

] structural conductors are modeled as [

] the coolant. Those structures which are

[ ] conductor.

Certain structural components are not included in the model because they are considered to have no potential impact on a plant transient. These components include the [

] Passive heat conductors representing the pressurizer walls are included in the Oconee model. The pressurizer vessel metal is [

]

The conductors which are used in the Oconee base model are listed and described in Table 2.2-1.

2.2.4 Control System Models

2.2.4.1 Process Variable Indications

RETRAN control systems are used to take the calculated plant thermodynamic conditions and put them into the form in which they are output by the plant instrumentation. This provides indications which are useful for comparison to plant data and which are familiar to the plant operators and engineering personnel.

<u>RCS Pressure</u>
The fluid pressure at the elevation of the hot leg pressure tap is converted to gauge pressure by subtracting 14.7 psi. This pressure is an input to RPS and ES functions in the model.

Pressurizer Level

The level indication is derived from the pressure difference between two taps in the pressurizer. The pressure difference is converted to an equivalent water level, which is then converted to a 0-100% reading. A RETRAN control system is used to simulate this process using the [ ] This level is input to the interlock which turns off the pressurizer heaters on low pressurizer level.

Hot Leg Temperature

The hot leg temperature is indicated by RTDs located in thermowells in the hot leg piping. A change in fluid temperature is not indicated immediately at the plant due to the time required to transfer heat through the thermowell to the RTD and change the temperature of the measuring device. Experimental data indicates that the time delay can be approximated by [ ] hot leg fluid temperature. A RETRAN control system is used to apply this [ ] to the hot leg water temperature to obtain the transient temperature response that would be seen at the plant. The output is used in the high temperature and variable low pressure reactor trips.

SG Pressure

In a manner similar to the RCS pressure indication, the fluid pressure at the outlet of the steam generator is adjusted by a RETRAN control system to output pressure in psig. This pressure is used as an input to the TBV controller.

SG Level

The operate range SG level instrument displays level from 0-100%, as shown on Figure 2.1-10. The level indication is derived from the pressure difference between two taps in the steam generator. The pressure difference is converted to an equivalent water level, which is then converted to a 0-100% reading. A RETRAN control system is used to simulate this process using the [ ]. The output operate range level indication performs no control or trip function in the RETRAN base model.

2.2.4.2 Reactor Protective System Functions

Two RPS functions are modeled with control systems - the variable low pressure trip and the flux/flow trip. The variable low pressure trip uses an algebraic relationship to determine whether the indicated RCS pressure and temperature are within the acceptable envelope. The flux/flow trip compares the flux/flow ratio to ensure that the RCS flow is large enough at a given power level to provide adequate heat removal from the core. The plant flux/flow trip also accounts for

the axial flux imbalance, but [

]

2.2.4.3 Plant Control Systems

RETRAN control systems are used to model the performance of the plant control systems during transient analyses. The Oconee model [

]

2.2.4.4 Transient Boundary Conditions

The RETRAN control system models can effectively model known transient boundary conditions, including those produced by automatic plant actions and those resulting from operator action. In general, RETRAN control systems simulate control actions by modulating valves, changing positive or negative fill flow rates, changing reactivity, and activating or defeating trips.

Operator actions can significantly affect the plant response during plant transients. Experience at Oconee has shown that the operators will promptly take action in order to prevent reactor trips or, failing that, to ensure a normal post-trip response. A common response is for the operators to put feedwater control in manual in an attempt to correct a sudden change in feedwater flow following an ICS malfunction. Following a trip, the operators monitor MFW (or EFW) flow to ensure that proper SG level control is maintained. In many cases the operators will also put the TBVs in manual to control SG pressure. It is also common procedure, following a trip, for the operators to isolate letdown flow and increase makeup flow (by starting another HPI pump,

opening an injection valve, or both) in order to more quickly turn around the rapid decrease in pressurizer inventory and restore the normal operating level.

The normal procedure to simulate [

]

2.2.4.5 Reactor Vessel Vent Valves

A RETRAN control system is used to calculate the [ ] in the reactor vessel vent valves (2.1.2.2). The valve position and frictional loss coefficient as a function of ΔP across the valve are known based on test data. A control system is used to [ ] The control system also determines the [ ] In normal operation the downcomer pressure is significantly higher than the pressure in the outlet annulus, so the vent valves are closed. It is only after all four reactor coolant pumps are tripped that vent valve flow will occur.

2.2.5 Boundary Condition Models

2.2.5.1 Fill Junctions

Fill junctions are used to specify flow between a volume and an infinite source or sink. Positive fill junctions provide flow into a volume, while negative fill junctions remove mass from a volume. The flow rate can be specified as a function of time or pressure in the volume, or it can be controlled by a control system.

Systems which provide flow to the RCS or the SGs are modeled by [ ]. These include MFW, EFW, and HPI. The flow of steam from the turbine header to the turbine is modeled by a [ ]. For most applications there is a reactor trip at the beginning of the problem, either immediately before or after a turbine trip, so the steam flow to the turbine is cut off. For applications which do not involve a rapid turbine trip, the flow through the steam line [ ].

2.2.5.2 Critical Flow and Time Dependent Volumes

The RETRAN critical flow model, in conjunction with a time dependent volume, is used to model flow through relief valves on the RCS and the main steam lines. Relief valves are modeled by junctions between the associated upstream volumes and a time dependent volume, which is an infinite sink with a user-specified backpressure. The Henry (subcooled) and Moody (saturated) choking option is used with the relief valve junctions. Because of the large pressure differences between the upstream volumes and the time dependent volume, RETRAN calculates any flow through the junctions to be choked. Since the best estimate flow rates of saturated steam through the valves are known, [

]. The choked flow model then automatically calculates the flow rate as the fluid conditions in the upstream volume change. This modeling technique is used for the [

]

2.2.6 Code Models

2.2.6.1 Power Generation

RETRAN offers the user several options for modeling core power generation. Several different methods are used, depending on the application. For a best estimate transient analysis, the point kinetics model is generally used. This model calculates neutron power assuming that the flux shape is constant while the magnitude changes with time. The code uses one prompt neutron group and six delayed groups. A moderator temperature coefficient and a fuel temperature coefficient are used to account for reactivity feedback from changes in those parameters. Control rod scram worths are input in order to model reactivity insertion after reactor trip. Post-trip decay heat energy is calculated with a model of eleven delayed gamma emitters, plus a contribution for heavy element (U-239 and Pu-239) decay. The resulting decay heat is a close fit to the proposed 1971 ANS Standard (Reference 2-1). The point kinetics model is adequate for most PWR applications.

For a benchmark analysis which [

]

[ ]

For benchmarks in which [ ]

2.2.6.2 Centrifugal Pumps

The RETRAN centrifugal pump model is used to simulate the performance of the RCPs. For benchmark analyses the pump input data is [ ]; for other applications, the flow is typically specified to be 112.5% of 88,000 gpm per pump, and the head is taken to be that of the [ ]

2.2.6.3 Valves

The basic RETRAN valve model is used for most of the valves in the Oconee base model. With this model the valves open and reseat according to the action of their associated trips. Modeled in this manner are the pressurizer spray, PORV, and safety valves; the core flood tank discharge check valves; the turbine stop valves; and the MSRVs. The turbine bypass valves use the RETRAN valve model option in which the junction area is controlled by a control system, which opens or shuts the valves based on SG pressure. The reactor vessel vent valves are also controlled by a control system, with the [ ]

2.2.6.4 Phase Separation

RETRAN has two methods of modeling phase separation within a fluid volume: the bubble rise model and slip. The bubble rise model [ ] in the Oconee model, while slip [ ] used.

The bubble rise model is a correlation which allows the enthalpy in a volume to vary with height. It is a semi-empirical fit to data from a number of high pressure blowdown experiments. The void fraction in the volume is assumed to vary linearly with height from the bottom of the volume to the mixture level. Above the mixture level, the fluid is 100% steam. The model is [ ] which have a definite separation between vapor and liquid, i.e. [ ]. In addition, the bubble rise model is [ ]

Phase separation is not normally expected in the [ ] because it usually remains in a subcooled state. In some cases, however, voids may develop in the [ ]. The bubble rise model is [ ]

Slip models provide for unequal velocities between the liquid and vapor phases. Since Oconee is a PWR with subcooled water in the primary coolant loops, unequal phase velocities normally exist only in the steam generator secondary side. RETRAN has two slip models: algebraic slip and dynamic slip. The algebraic slip model uses a drift flux approach to calculating the relative velocity between the vapor and liquid phases, while the dynamic slip model uses a differential equation to determine the inter-phase velocity difference. Current RETRAN development efforts are geared toward improving the dynamic slip model and providing a true two-phase representation of transient fluid behavior. Extensive testing has shown that the current dynamic slip model [ ] in the base model.

For applications in which there is significant voiding and phase separation in the primary system (notably small break LOCA or extended loss of feedwater), the dynamic slip model can provide a reasonable simulation of two-phase phenomena in the RCS. In these instances the dynamic slip option [ ].

2.2.6.5 Non-Equilibrium Pressurizer

RETRAN has a general non-equilibrium volume option which can be used with any bubble rise volume. This option allows the liquid and vapor regions of the volume to have different temperatures. The [

]

Accurate modeling of the pressurizer is necessary to correctly predict the transient RCS pressure response. During normal operation the pressurizer is at near equilibrium conditions - heat from the pressurizer heaters balances condensation from pressurizer spray bypass flow and ambient heat losses, so both the liquid and vapor regions of the pressurizer are essentially at saturation. During a pressurizer outsurge, such as that characteristically seen immediately following reactor trip, the pressure decreases as the steam bubble expands. Bulk flashing of the saturated liquid occurs as the pressure decreases, and the temperature in the liquid decreases with the pressure along the saturation line. In both cases the standard RETRAN homogeneous equilibrium model (HEM) technique will adequately simulate pressurizer phenomena.

During a pressurizer insurge, however, non-equilibrium effects can be significant. Subcooled water from the hot leg mixes with the saturated water in the pressurizer liquid region to produce a somewhat subcooled liquid region or, in some cases, a layered effect of saturated water over subcooled liquid. As the liquid level increases the steam bubble compresses and, since the steam behaves like an ideal gas, the temperature increases. The overall result is superheated steam above subcooled liquid, separated by a layer of saturated water. Since the temperature of the steam is higher than both the liquid and the pressurizer walls, the steam will tend to condense on the metal and the steam-water interface, reducing the pressure and temperature of the vapor. A one volume HEM representation of the pressurizer would instantaneously mix the subcooled fluid from the hot leg with all of the saturated fluid in the pressurizer, and it would not account for the different temperatures in the liquid and vapor regions. It is evident that a HEM representation of the pressurizer cannot account for the important phenomena during an insurge.

Use of the non-equilibrium option enhances the ability of a one volume pressurizer model to simulate the transient response during an insurge. Since the liquid region is considered separately from the steam bubble, an insurge does not result in rapid condensation of the pressurizer vapor. The non-equilibrium option allows the steam bubble to superheat during an insurge. The non-equilibrium option also includes the ability to specify a heat transfer coefficient between the pressurizer vapor and liquid regions, so inter-phase heat transfer can be modeled.

However, this model is somewhat non-mechanistic, since the heat transfer coefficient is user-input rather than being calculated based on fluid conditions.

Another facet of the non-equilibrium representation is the pressurizer spray junction model. Using the spray junction option causes the spray water to condense steam while moving through the pressurizer steam bubble, thus removing both energy and mass from the region, rather than simply mixing with the fluid in the vapor region and de-superheating the steam. The spray junction model is used since it is considered to be more mechanistic than a normal junction for this application.

The non-equilibrium pressurizer model is used for best estimate safety analysis for Oconee. This model does not fully account for condensation effects in the pressurizer steam space and thus over-predicts RCS pressure during an insurge. However, it is superior to an equilibrium modeling approach. For some applications it is appropriate to use [

]

2.2.6.6 Non-Conducting Heat Exchangers

The RETRAN non-conducting heat exchanger model allows energy to be transferred to or from a fluid volume without using a conductor. This model is used to simulate the energy addition to the pressurizer liquid from the pressurizer heaters. [

]

It is also possible to use a non-conducting heat exchanger to model the [

]

[

]

2.2.6.7 Local Conditions Heat Transfer

The local conditions heat transfer model may be defined for a stack of at least two heat conductors which are connected to the same separated volume. The model allows the heat transfer coefficient of the conductors to vary based on the axial change in fluid conditions in the volume. For example, in a two conductor stack if the midpoint of one conductor is below the mixture level of the adjacent volume, and the midpoint of the other conductor is above the mixture level, the code will calculate different heat transfer regimes and coefficients for the two conductors.

The local conditions model is [ ] in the Oconee base model. Although the void fraction of the separated volume may vary with height, the temperature of that volume must be constant. Thus a [

]. For long-running analyses in which [

].

2.2.7 Code Options

2.2.7.1 Steady-State Initialization

The RETRAN steady-state initialization option is used to obtain stable initial conditions for each transient analysis. This option greatly simplifies the specification of the initial conditions of a RETRAN run. The steady-state initialization routine solves the mass, momentum, and energy equations without the time-dependent terms and thus obtains consistent initial values with a minimal amount of input data.

Primary system conditions at Oconee are set by specifying [

]

[

]

The initial SG power removal fraction is normally set at 0.5 for each generator in order to provide a symmetric initialization. In special cases the heat removal from one generator may exceed that of the other. For example, when initializing the model with one of the RCPs off, the SG in the loop with two operating pumps removes most of the power, so the power removal fractions must be adjusted accordingly.

2.2.7.2 Iterative Numerics

The iterative numerics option is used for time step control. Iterative numerics is a semi-implicit numerical solution method which allows the results of the time step advancement to be evaluated before the solution is accepted. Predictive algorithms are used to calculate an appropriate time step size which will give a stable, accurate solution to the fluid conservation equations. If a converged solution is not achieved in a given number of iterations, a reduced time step size is used. This is similar to restarting a job with smaller time steps, but it has the advantage of being automatic.

2.2.7.3 Enthalpy Transport

The enthalpy transport option is used to account for situations in which the fluid in a volume exchanges a significant amount of energy with an external source or sink. In those situations, the fluid enthalpy will vary between the volume inlet, center, and outlet, and the enthalpy transport option accounts for this variation. The option is [

]

The enthalpy transport option is [

]

2.2.7.4 Temperature Transport Delay

The temperature transport delay option accounts for the fact that temperature changes move through piping as a front, while the finite difference HEM approach instantaneously and homogeneously mixes the incoming fluid with the contents of a volume. Using the temperature transport delay option with a volume treats the movement of fluid more mechanistically by establishing a mesh substructure within the volume to track temperature front movement.

The temperature transport delay option is used for [

]

2.2.7.5 Heat Transfer Map

Two sets of heat transfer correlations are available for use with RETRAN02. The forced convection map is a set of heat transfer correlations which cover single phase, two-phase, and supercritical fluid conditions. The correlations are generally appropriate for the fluid velocities associated with forced flow. The combined map uses the same heat transfer relationships as the forced map, except that correlations more appropriate for low flow conditions are used if the Reynolds number is less than 2500 (single-phase) or if the mass flux is less than 200,000 lbm/ft-hr (two-phase). The combined map also includes a correlation for condensation.

The forced convection map is [

] for most applications.

The standard RETRAN-02 forced convection heat transfer map does not have a correlation for condensing heat transfer. A code change has been implemented to add the condensation heat transfer correlation to the forced convection heat transfer map.

For transient situations of very low flow which are outside the range of conditions covered by the plant benchmark analyses, the combined map may be necessary to provide reasonable results.

2.2.7.6 Film Boiling

The available correlations for use in the film boiling heat transfer regime include Groeneveld 5.7, Groeneveld 5.9, and Dougall-Rohsenow (Reference 2-3, Section III.3.2.5). The Dougall-Rohsenow correlation is based on liquid flow at low pressure. Groeneveld 5.9 is based on data from vertical and horizontal flow in round tubes and vertical flow in annuli, while Groeneveld 5.7 is based on the annuli data alone. [ ] is used in the Oconee model because it is considered that the basis of that correlation is most similar to situations which would be encountered during PWR transients. The choice of the film boiling correlation is [ ] initial conditions.

2.2.7.7 Critical Heat Flux

There are three options for the calculation of critical heat flux in the forced convection heat transfer map. The default option is a combination of three correlations: B&W-2, Barnett, and modified Barnett. A General Electric correlation or a Savannah River Laboratory correlation may be specified instead of the default. If the mass flux is less than 200,000 lbm/hr-ft, then an interpolation between the chosen correlation and a minimum value is used to calculate the critical heat flux. These correlations are discussed in Reference 2-3, Section III 3.3. The Oconee model employs the [ ] initial conditions.

2.2.7.8 Volume Flow Calculation

The [ ] option method is used for calculating the volume flow for momentum flux. This choice is [ ].

- The lack of a good, general purpose phase separation model for use in a once-through SG impairs the ability of the code to perform some analyses. The HEM representation of the fluid in the SG secondary side leads to mixture levels which are too high under low flow conditions. As a result, the code tends to slightly over-predict the primary-to-secondary heat transfer in such circumstances. In addition, the inability to model counter-current flow necessitates the non-mechanistic modeling of the location of emergency feedwater injection. Generally accurate simulation of primary-to-secondary heat transfer can be achieved without detailed modeling of phase separation. The overall model response to EFW injection has proven to be more than adequate without mechanistic modeling of the injection location.

- The lack of a general non-equilibrium modeling capability detracts from the ability of the code to simulate some small break LOCA behavior. This limitation must be recognized whenever such applications are undertaken.

In general, the overall experience with modeling the Oconee transient response using RETRAN has been good. Despite the shortcomings in the above areas, the code has been proven capable of accurately simulating the transient thermal-hydraulic behavior of a B&W 177 fuel assembly lowered-loop plant.

(Pages 2-56 to 2-60 intentionally deleted)

The standard RETRAN-02 forced convection heat transfer map does not have a correlation for condensing heat transfer. A code change has been implemented to add the condensation heat transfer correlation to the forced convection heat transfer map.

For transient situations of very low flow which are outside the range of conditions covered by the plant benchmark analyses, the combined map may be necessary to provide reasonable results.

2.2.7.6 Film Boiling

The available correlations for use in the film boiling heat transfer regime include Groeneveld 5.7, Groeneveld 5.9, and Dougall-Rohsenow (Reference 2-3, Section III.3.2.5). The Dougall-Rohsenow correlation is based on liquid flow at low pressure. Groeneveld 5.9 is based on data from vertical and horizontal flow in round tubes and vertical flow in annuli, while Groeneveld 5.7 is based on the annuli data alone. [ ] is used in the Oconee model because it is considered that the basis of that correlation is most similar to situations which would be encountered during PWR transients. The choice of the film boiling correlation is [ ] initial conditions.

2.2.7.7 Critical Heat Flux

There are three options for the calculation of critical heat flux in the forced convection heat transfer map. The default option is a combination of three correlations: B&W-2, Barnett, and modified Barnett. A General Electric correlation or a Savannah River Laboratory correlation may be specified instead of the default. If the mass flux is less than 200,000 lbm/hr-ft, then an interpolation between the chosen correlation and a minimum value is used to calculate the critical heat flux. These correlations are discussed in Reference 2-3, Section III 3.3. The Oconee model employs the [ ] initial conditions.

2.2.7.8 Volume Flow Calculation

The [ ] option method is used for calculating the volume flow for momentum flux. This choice is [ ].

2.2.7.9 Wall Friction

RETRAN calculates the pressure drop due to wall friction using the Fanning friction factor, which is a function of Reynolds number. Several options are available to model the change in wall friction due to two-phase effects. The Baroczy, homogeneous, or Beattie multipliers can be applied to the calculated single phase pressure drop. The [ ] model is used in the Oconee RETRAN model.

2.2.8 Dissimilarities Between Units

The differences between the units at Oconee are insignificant enough that one base model is adequate for all three units. Several adjustments to this model are made for benchmark analyses. The unit-specific main feedwater and main steam line characteristics are input, and the nodalization is adjusted to reflect the appropriate location of the pressurizer. The pump head which is characteristic of a particular unit is used, and the RCS flow rate is matched. Unit specific HPI and EFW capacities are used. The RETRAN kinetics input is based on the specific cycle and time-in-cycle of the benchmark transient. These adjustments ensure that the initial conditions are matched as closely as possible and that the boundary conditions are accurate.

For safety analyses which are applicable to all three units, the [ ] geometries are used, and the pressurizer is located on Loop A. The [ ] pump capacity is used and RCS flow is assumed to be the transient analysis design flow. The EFW and HPI capacities are taken from the bounding unit, which varies depending on whether maximum or minimum flow is conservative. Kinetics parameters are based on Unit 1, Cycle 11, which is considered to be typical of current cores. None of the differences between the units has a significant effect on the plant transient response. The variation of reactor kinetics parameters with cycle and time-in-cycle can have a significant impact if the transient does not begin with reactor trip.

2.2.9 Summary of Experience

The major positive conclusions concerning the application of the code and its models are listed below.

- The basic constitutive equations accurately describe the fluid behavior in the RCS and the SGs during operational transients.

- The nodalization scheme is extremely flexible, allowing the user to construct a detailed plant model or to conduct separate effects analyses on components such as the pressurizer or the core flood tanks. This flexibility has also enabled the modeling of other plant systems, including HPI, EFW, and the condensers.

- The heat transfer package provides a good representation of heat transfer, both single phase and two-phase.

- The water properties are accurate in the range of application.

- Steady-state initialization greatly simplifies the process of obtaining a desired set of initial conditions when compared to other thermal-hydraulic systems analysis codes.

- Iterative numerics generally provides reasonable time step control and reduces the necessity of restarting jobs to circumvent time step-related errors.

- The generalized restart and reedit capabilities of RETRAN are very useful, and they significantly increase the efficiency with which the code is used.

- The time dependent volume, fill, and critical flow models allow a complete and reasonable specification of fluid boundary conditions for various types of analyses.

- The non-equilibrium pressurizer model provides an accurate simulation of RCS pressure trends.

- The point kinetics model adequately predicts the reactor power response to the types of reactivity changes which arise during typical operational transients.

- The reactor coolant pump model accurately reflects the interaction of the pumps and the primary fluid during normal pump operation and coastdown.

- The control system models and trip logic are extremely flexible and useful for modeling automatic control actions as well as operator action.

Similar to other one dimensional HEM codes, the current models in RETRAN-02 have been found to have shortcomings in some areas when simulating particular phenomena. These areas are discussed below.

- The lack of a good, general purpose phase separation model for use in a once-through SG impairs the ability of the code to perform some analyses. The HEM representation of the fluid in the SG secondary side leads to mixture levels which are too high under low flow conditions. As a result, the code tends to slightly over-predict the primary-to-secondary heat transfer in such circumstances. In addition, the inability to model counter-current flow necessitates the non-mechanistic modeling of the location of emergency feedwater injection. Generally accurate simulation of primary-to-secondary heat transfer can be achieved without detailed modeling of phase separation. The overall model response to EFW injection has proven to be more than adequate without mechanistic modeling of the injection location.

- The lack of a general non-equilibrium modeling capability detracts from the ability of the code to simulate some small break LOCA behavior. This limitation must be recognized whenever such applications are undertaken.

In general, the overall experience with modeling the Oconee transient response using RETRAN has been good. Despite the shortcomings in the above areas, the code has been proven capable of accurately simulating the transient thermal-hydraulic behavior of a B&W 177 fuel assembly lowered-loop plant.

(Pages 2-56 to 2-60 intentionally deleted)

Table 2.2-1

Oconee Base Model Heat Conductors

Conductor Number	Adjacent Volume Number	Description	Material

Table 2.2-1 (continued)

Conductor Number	Adjacent Volume Number	Description	Material

Figure 2.2-1

Oconee RETRAN Model
Nodalization Diagram
(two-loop)

Figure 2.2-2

Oconee RETRAN Model
Nodalization Diagram
(one-loop)

2.3 Oconee VIPRE Model

2.3.1 Core and Fuel Assembly Description

The Oconee reactor core consists of 177 BAW Mark-BZ fuel assemblies (Figure 2.3-1). Spacer grids, end fittings, fuel rods, and guide tubes form the basic structure of a fuel assembly as shown in Figure 2.3-2. The lower and upper end spacer grids are made of Inconel, while the six intermediate spacer grids are made of Zircaloy-4. Each fuel assembly is a 15 by 15 array containing 208 fuel rods, 6 control rod guide tubes, and one incore instrument guide tube. The fuel rod consists of dished-end, cylindrical pellets of uranium dioxide clad in cold-worked Zircaloy-4. The fuel assembly and fuel rod dimensions, and other related fuel parameters used in the thermal-hydraulic analyses are given in Table 2.3-1.

2.3.2 Model Development

2.3.2.1 One-Pass Hot Channel Analysis

VIPRE-01 (Reference 2-4) is capable of performing one-pass hot channel analysis. A subchannel is defined as the flow area between adjacent fuel rods in an array. By definition, the hot channel in a PWR core is the subchannel with the most limiting departure from nucleate boiling ratio (DNBR) on one of its adjacent fuel rods. In one-pass analysis the objective is to model the hot subchannel and those nearest to it in detail, and then surround these with larger and larger lumped channels proceeding outward toward the periphery of the core. In this way the entire core can be modeled with a limited number of channels, while maintaining a fine level of detail and accuracy in the area of the hot subchannel. This methodology is an improvement on the multi-pass or "cascade" approach used in other methodologies, where two or three separate simulations in series are necessary using boundary conditions taken from the preceding ones. One-pass analysis is not only more efficient but it allows for explicit modeling of the coupling between the hot subchannel and the rest of the core.

2.3.2.2 Transient Analysis Models

The geometry setup for one-pass analysis is based on the location of the hot subchannel. For a given geometry and inlet fluid condition, the location of the hot subchannel is determined by the pin radial-local power distribution and the critical heat flux (CHF) correlation utilized. Figures 2.3-3 and 2.3-4 show the assembly radial and pin radial-local power distributions, respectively, used to analyze transients resulting in symmetrical core radial power distributions. These power distributions originated from [ ] with modifications. The major modification is the [ ] in the hot

assembly. However, the maximum pin radial-local peak of [ ] and the maximum assembly radial peak of [ ] are preserved.

Three core models, comprised of [ ] channels, have been developed as shown in Figures 2.3-5 to 2.3-7. The detailed [ ] channel model has been constructed in order to identify the location of the hot subchannel and to show that the simplified models can accurately predict the local coolant flow rate and thermal-hydraulic properties of the core and most importantly of the hot channel.

In the [ ] channel model, the [ ] is modeled as an array of subchannels (Figure 2.3-5) while the [ ] is modeled as six lumped channels. Twenty fuel assemblies in the same eighth-core of the hot assembly are modeled as individual channels as shown in Figure 2.3-5. Finally, the [ ] Utilizing the BWC CHF correlation (Reference 2-5), the hot subchannel is identified to be [ ] channel. However, should CHF correlations other than the BWC correlation be utilized (for example: the BAW2 correlation), the hot subchannel can be identified as [ ] subchannel.

After the location of the hot subchannel has been identified, the [ ] channel model (Figure 2.3-6) is constructed to show that [ ].

Since, depending on the CHF correlation utilized, [ ]

2.3.2.3 Simplified Models Justification

To show that the simplified model can properly and correctly predict the local coolant flow rate and thermal-hydraulic properties for steady-state and transient analyses, simplified model results are

compared to results from the more detailed models. If the simplified model results are equivalent or conservative compared to the more detailed model results, then it is justified to use the simplified models for analyses. MDNBRs presented in this section are calculated with the BWC critical heat flux correlation.

Steady-State Comparisons

Input Conditions:	Power	= 78.123 kW/rod (112%FP)
	Pressure	= 2135 psia
	Core flow	= 2.4996 Mlbm/hr-ft^2
	Inlet enthalpy	= 555.0 Btu/lbm

Results for this case are presented in Table 2.3-2. The similarity of all the results verifies that the simplified [ ] channel model can be used without impacting the accuracy of more detailed and expensive models.

Transient Comparisons

An arbitrary transient case with the inlet core mass flow rate ramped from 100% to 75% and power ramped from 100% to 80% of their initial state values has been run for 2.0 seconds. Results are given in Table 2.3-3.

Results show that the agreement between the predictions of MDNBR during the transient as well as other local fluid parameters is excellent. The capability of the simplified model for transient analysis has been demonstrated.

Conclusion

In conclusion, the results of both detailed and simplified nodalizations are very similar for both steady-state and transient cases. Thus, instead of using the more detailed and expensive models, the simplified [ ] channel model will be used for core thermal-hydraulic analyses for normal symmetrical transients. For transients resulting in asymmetrical flow distributions or inlet coolant temperature gradients outside the hot assembly, such as the steam line break, the [ ] channel model may be modified so that [ ] can be modeled for proper simulation of the inlet temperature gradients. Also, the RECIRC solution method must be utilized instead of the iterative

method because of the large density gradient between channels and because of the low flow velocity due to the reactor coolant pumps tripping in the offsite power unavailable situation.

2.3.2.4 Axial Noding

In general, VIPRE predictions are sensitive to axial noding in that enough nodes must be provided to resolve the detail in the flow field and in the axial power profile. However, once a point of sufficient accuracy is reached, VIPRE is relatively insensitive to further axial refinement. In order to demonstrate the correctness of the above statement, five cases were analyzed with the [ ] channel model divided into [ ] axial increments corresponding to [ ] inches per active fuel node, respectively. The results in Table 2.3-4 show that for [ ] or more axial nodes, the local coolant conditions are insensitive to the number of axial increments. The hot channel MDNBR changes by only [ ] when the number of nodes are decreased from [ ]. Since the MDNBR [ ] This indicates that [ ] axial nodes is a sufficiently large number for accurately calculating hot channel conditions. However, [ ] axial nodes will be used for thermal-hydraulic transient analyses.

2.3.3 Code Option and Input Selections

2.3.3.1 Thermal-Hydraulic Correlations

Flow correlations are used in VIPRE-01 to model two-phase flow effects. In the flow solution, correlations model the effects of two-phase flow and friction pressure losses, subcooled boiling, and the relationship between flowing quality and void fraction.

For transient analyses, the subcooled void, the bulk void, and the two-phase friction multiplier are modeled by using the [

].

Turbulent Mixing Correlations

The energy and momentum equations of the VIPRE-01 code contain terms describing the exchange of energy and momentum between adjacent channels due to turbulent mixing. The effect of turbulent mixing is empirically accounted for in VIPRE-01. The turbulent cross flow, w', has the form:

$$w' = A \times Re^{B} \times S \times G$$

Where: Re = Reynolds number
S = gap width, inches
G = mass flux, $lbm/sec\text{-}ft^2$
A = [ ]
B = [ ]

Turbulent crossflow mixing is a subchannel phenomena, and is not generally applicable to lumped channel analysis. The turbulent cross flow is correlated in terms of flow exchange through a single gap. In lumped channel modeling, the crossflow mixing must be reduced to take into account the effects of lumping many gaps such that

$$w' = w'/N_R \quad \text{(Reference 2-4)}$$

where N_R = number of rod rows between adjacent channel centroids. Thus, for MK-BZ fuel which has 15x15 fuel rods in an assembly, the mixing coefficient, A, between two lumped assembly channels becomes

$$A = [\qquad]$$

However, the mixing coefficients between any two lumped channels are set to [ ]

The turbulent momentum factor (FTM) tells how efficiently the turbulent crossflow mixes momentum. For the [ ].

Turbulent mixing in two-phase flow is generally assumed to be [ ]

Pressure Losses

Pressure losses due to frictional drag are calculated in the code for both axial and transverse flow. The friction factor for the pressure loss in the axial direction is determined from empirical correlation as:

$$f = A \times Re^{B}$$

The code evaluates both a turbulent and laminar set of coefficients and selects the maximum. The values selected for parameters A and B are based on smooth tubes and are taken from Reference 2-4.

Turbulent Flow:	A = [ ]	B = [ ]
Laminar Flow:	A = [ ]	B = [ ]

The coefficient of form drag in the gap between adjacent channels is on the order of [ ] for the transverse pressure loss (Reference 2-4). Thus, it is set equal to [ ] for transient analyses.

Local Hydraulic Form Loss

The local hydraulic form loss coefficient is set as a constant to model the irrecoverable axial pressure loss as shown below.

$$\Delta P = KG^2/2\rho g_c$$

Where:
- K = spacer grid form loss coefficient
- G = mass flux, lbm/sec-ft^2
- ρ = density, lbm/ft^3
- g_c = 32.174 lb-ft/sec^{2}lb$_f$

The spacer grid form loss coefficients for the resident fuel assemblies, currently the MK-BZ fuel assembly, are used in the transient analyses.

Critical Heat Flux Correlations

One of the critical heat flux correlations used to perform DNB analysis is the B&W BWC CHF correlation. The BWC CHF correlation has been reviewed and approved by the NRC for licensing analysis of BAW 15 x 15 Mark-BZ geometry fuel with Zircaloy grids. Using the LYNX-2 open subchannel code (Reference 2-6), the design MDNBR limit of 1.18 was determined. The range of use for the BWC correlation is:

Pressure, psia	1600 to 2600
Mass velocity, 10^6 lbm/hr-ft^2	0.43 to 3.8
Quality, %	-20 to +26

The design MDNBR limit of 1.161 has been achieved using VIPRE-01 (Reference 2-7). However, a design DNBR of 1.18 will be used for transient analysis. The statistical core design methodology (SCD) of Reference 2-14 may also be used. The SCD methodology is generally used unless the analysis parameters are not bounded by the ranges considered in the methodology. A typical SCD limit using VIPRE-01 and the BWC correlation is 1.43.

For transients with system pressure less than 1600 psia, the W-3S CHF correlation will be utilized. The range of use for the W-3S correlation is (Reference 2-4):

Pressure, psia	1000 to 2300
Mass velocity, 10^6 lbm/hr-ft^2	1.0 to 5.0
Quality, (equilibrium)	-0.15 to 0.15

However, it has been shown recently (Reference 2-8) that the W-3S correlation is also applicable for pressure and mass flux as low as 700 psia and 0.5×10^6 lbm/hr-ft^2, respectively.

Other CHF correlations that have been reviewed and approved by the NRC may also be used to perform DNBR analyses.

2.3.3.2 Conservative Factors

The use of conservative factors depends on whether or not the statistical core design methodology (SCD) of Reference 2-14 is used. The SCD methodology is generally used unless the analysis parameters are not bounded by the ranges considered in the methodology. The SCD approach includes all of the conservative factors described below except the reduction of the hot assembly flow. If the SCD approach is not used, then all of the conservative factors all applied in the VIPRE analyses.

Reduction of the Hot Channel Flow Area

The hot subchannel flow area is reduced by 2% for the hot unit subchannel, and by 3% (Reference 2-7) for the hot instrument subchannel to account for variations in as-built subchannel flow areas.

Reduction of the Hot Assembly Flow

Based on the vessel model flow tests and Oconee core pressure drop measurement, the reductions in the hot assembly flow due to flow maldistribution are shown on the next page (Reference 2-9).

Operation	Flow reduction factor
4-pump	0.950
3-pump	[
2-pump	]

Hot Channel Factors

The hot channel factor is the B&W power factor, F_q. The power factor, F_q, is computed statistically from the average or overall variation on rod diameter, enrichment, and fuel weight per rod. It is applied to the heat generation rate in the pin; thus it will have an effect on all terms that are computed from this heat rate with the exception of the heat flux for DNB ratio computation. The value of F_q used is 1.0132.

2.3.3.3 Fuel Pin Conduction Model

For most of the transient analyses, the RETRAN heat flux boundary condition is used; the fuel pin conduction model will not be used in the VIPRE-01 transient models. This means that heat is added directly from the cladding surface to the fluid as a boundary condition on the calculation, and the heat transfer solution is not required. However, for transient analyses in which the fuel enthalpy or cladding temperature is the protective criteria (for example: rod ejection, rod withdrawal accident at rated power, and locked rotor), the VIPRE fuel pin conduction model may be used with the neutron power as the transient forcing function.

2.3.3.4 Power Distribution

Radial Power Distribution

For transients resulting in symmetrical power distributions, the 15 x 15 1/8 core assembly radial power distribution and hot assembly pin radial-local power distributions shown in Figures 2.3-3 and 2.3-4 are applied. The hot assembly has a radial peak of[ ]Figure 2.3-3), and contains the maximum pin radial-local peak of[ ](Figure 2.3-4). For transients resulting in asymmetric radial power

distributions, nuclear design analyses generate radial power distributions. Radial power distribution as a function of transient time is then input to VIPRE-01.

Axial Power Distribution

For transients resulting in symmetric radial power distributions, the [ ] axial power shape is typically applied (Figure 2.3-8). For transients resulting in asymmetric radial power distributions, nuclear design analyses generate axial power distributions during transients. On a case-by-case basis, either these axial power distributions or the [ ] shape will be utilized as justified.

2.3.3.5 Flow Rate

Vessel Flow Rate

For all three Oconee units, the transient thermal-hydraulic analyses will typically be based on 105.5% (107.5% for SCD) of the original design flow rate of 88,000 gpm per pump. Reactor coolant flow rates for various reactor coolant pump operating configurations are as follows (Reference 2-10):

4 pumps = 100.0% of the total flow

3 pumps = 74.7% of the total flow

2 pumps = 49.0% of the total flow

Where: Total flow = 1.075 x 4 x 88,000 gpm

Core Bypass Flow

The difference between the reactor vessel flow and the reactor core flow is defined as that part of the flow that does not contact the active heat transfer surface area. Some flow bypasses the heat transfer area primarily through three different paths. They are (1) through the core shroud, (2) between all interfaces separating the inlet and outlet regions, and (3) through the control rod guide tubes and instrument tubes. The amount of flow through paths (1) and (2) is fixed. However, the flow through path (3) depends on whether the assemblies contain control components or not; thus, the core bypass flow is determined by the number of empty fuel assemblies. An empty fuel assembly is simply an assembly without a control rod, axial power shaping rod, lumped burnable poison rod, orifice rod, or source rod assembly. The number of empty fuel assemblies may vary from fuel cycle to fuel cycle. A correlation of percent bypass flow versus the number of empty fuel assemblies is utilized. For current Oconee reload designs, a

maximum bypass flow of[ ]% has been determined corresponding to a maximum number of[ ]empty assemblies. The typical range of bypass flow is [ ]

2.3.3.6 Direct Coolant Heating

The amount of heat generated in the coolant is 2.7% of the total power (Reference 2-11).

2.3.3.7 Miscellaneous

Miscellaneous inputs for VIPRE-01 are shown below. These parameters control the execution of the run. Default values for these inputs are used for the transient analyses (Section 2.12.1, Volume 2, of Reference 2-4).

Solution option	Iterative solution
Maximum number of external iterations	20 (30 for[ ]ch. Model)
Maximum number of internal iterations	50
Pressure/energy convergence limit for internal iterations	0.00001
Minimum number of external iterations	2
Cross flow convergence limit	0.1
Axial flow convergence	0.001
Damping factor for cross flow	0.9
Damping factor for axial flow	0.9

2.3.4 Discussions of Modeling Differences Between DPC-NE-3000 and DPC-NE-2003 Reports

The modeling and input differences between this report (transient analysis) and DPC-NE-2003 (steady-state analysis) (Reference 2-7) are described below. These differences are due to modeling requirements unique to transient DNBR analyses, or incorporating additional conservatism to minimize the impact of changes in core reload design methods or fuel assembly design.

<u>Model Geometry</u>

The geometry setups for the transient analysis models are different from those of steady-state analysis because the DNBR calculations associated with FSAR Chapter 15 transient analyses require more

flexible models than the calculations associated with steady-state core reload design require. The steady-state analysis models only need to simulate the most limiting region of the core and symmetrical core phenomena. The geometry setup of the transient models must be capable of simulating the whole core, and also situations including asymmetrical core radial power distributions, core flow maldistributions, and inlet coolant temperature gradients. The transient models also [ ] that are not needed for steady-state analysis.

Core Radial Power Distributions

The steady-state and transient analysis models utilize different assembly radial and hot assembly pin radial-local power distributions. The transient analysis core radial power distribution originated from [ ] as mentioned in Section 2.3.2.2 and has a maximum hot assembly radial power of [ ] whereas the steady-state analysis model has a maximum hot assembly power of [ ] Nevertheless, the maximum pin peak value of [ ] is utilized by both steady-state and transient analysis models. Furthermore, in the transient models the [ ] peaks; whereas in the steady-state models, [ ] peak. The transient model pin peaks are therefore slightly more limiting and ensure that conservative DNBR results will be maintained for any future core reload design with a maximum pin peak of [ ].

Axial Node Size

In the transient analysis models, the axial node size within the active fuel length is [ ] inches per node; whereas in the steady-state models, it is [ ] inches per node. However, Section 2.3.2.4 shows that DNBR is insensitive for axial node size less than [ ] inches per node.

Turbulent Momentum Factor

In the transient analysis models, the turbulent momentum factor (FTM) is specified as [ ] to indicate that the turbulent crossflow mixes enthalpy only and not momentum; whereas FTM is set to [ ] in the steady-state models. The use of [ ] for FTM would provide conservative results.

Lumped Channel Turbulent Mixing Coefficient

The turbulent mixing coefficient, ABETA, is [ ] in the transient analysis models; whereas in the steady-state models ABETA of the [ ] channels. The use of [ ] channel ABETA provides conservative results.

Gap/Length Factor

In the steady-state models, the gap/length factor is calculated [ ]; whereas the [ ] is used in the transient models due to the fact that the [ ] geometries. However, this parameter is recognized as being insensitive.

2.3.4 Comparison with COBRA-IIIC/MIT

As mentioned in Section 1.0, the basic structure and computational philosophy of the VIPRE-01 code are derived from C0BRA-IIIC (Reference 2-12). The COBRA family of codes, including several NSSS vendor versions, are in wide use in the nuclear industry. Thus, it is appropriate to compare the steady-state as well as transient results calculated by these two codes.

2.3.4.1 COBRA-IIIC/MIT Code Description

The COBRA-IIIC/MIT code (Reference 2-13) developed at MIT for EPRI. The organization of the code is based on C0BRA-IIIC, but allows for larger problems, a faster solution scheme, and simplified data input. A complete description of the modifications is documented in the EPRI code manual for C0BRA-IIIC/MIT. For all practical purpose the two codes are essentially based on the same set of equations and will solve the same problems with very similar results. C0BRA-IIIC/MIT has expanded capabilities and several additional or replacement correlations; however, none of the modifications significantly affect the basic calculations of heat transfer and fluid flow.

The version of the COBRA-IIIC/MIT code used in the comparison is COBRA-IIIC/ MIT-DUKE-02. The DUKE-02 version consists only of error corrections and editorial changes so that the constitutive equations, correlations, and solution schemes of the C0BRA-IIIC/MIT code have been preserved.

2.3.4.2 COBRA[ ]Channel Simplified Model

COBRA-IIIC/MIT also has the capability to perform one-pass analysis similar to VIPRE-01. A [ ] channel simplified model (Figure 2.3-9) has been constructed for the purpose of C0BRA-VIPRE code comparisons. This[ ]channel model, which is identical in geometry to the VIPRE[ ]channel model described in Section 2.3.2.2, simulates the B&W MK-B4 fuel assembly by using the BAW-2 CHF correlation to determine the MDNBR. (The BAW2 CHF correlation is used because there is no BWC CHF correlation in the COBRA-IIIC/MIT-DUKE-02 code.) The[ ]channel VIPRE model has been modified for the Mark-B4 fuel simulation. (The difference between the Mark-B4 fuel and the Mark-BZ

fuel is the spacer grid.) The two[ ]channel models are essentially identical with the exception of the difference in indexing the subchannels and rods.

2.3.4.3 COBRA-IIIC/MIT Code Options

Although the VIPRE-01 code was derived from the COBRA-IIIC code with similar basic structure and computational philosophy, VIPRE-01 contains a greater selection of correlations for CHF, two-phase flow, solution schemes, and other features than COBRA-IIIC/MIT. However, by selecting similar code options and utilizing identical thermal-hydraulic boundary conditions, a valid comparison of the two codes can be performed. Table 2.3-5 shows the thermal-hydraulic correlations used in the VIPRE-01 and COBRA-IIIC/MIT comparison.

2.3.4.4 COBRA-VIPRE Steady-State Comparison

Four cases with different operating conditions have been compared. The intent of this comparison is to show that VIPRE-01 gives similar predictions to COBRA-IIIC/MIT in a wide operating range. The first case represents the normal operating condition with nominal power, pressure, core flow, and inlet enthalpy values. The second case compares low power and low mass flux condition results. The third case compares high power, low pressure, and low inlet enthalpy condition results. The fourth case compares high pressure, and high inlet enthalpy results.

The operating condition values for these four cases are listed below:

<u>Case 1</u>

Power	= 0.1775 MBtu/hr-ft^2(100% FP)
Pressure	= 2226 psia
Core flow	= 2.584 Mlbm/hr-ft^2
Inlet enthalpy	= 554.6 Btu/lbm

<u>Case 2</u>

Power	= 0.1495 MBtu/hr-ft^2
Pressure	= 2226 psia
Core flow	= 1.628 Mlbm/hr-ft^2
Inlet enthalpy	= 554.6 Btu/lbm

Case 3

Power	= 0.1988 MBtu/hr-ft^2
Pressure	= 1900 psia
Core flow	= 2.574 Mlbm/hr-ft^2
Inlet enthalpy	= 553.7 Btu/lbm

Case 4

Power	= 0.1988 MBtu/hr-ft^2
Pressure	= 2300 psia
Core flow	= 2.714 Mlbm/hr-ft^2
Inlet enthalpy	= 579.0 Btu/lbm

Table 2.3-6 shows the calculated hot channel MDNBR and local fluid properties for all four cases. The VIPRE-01 results agree extremely well with those of COBRA-IIIC/MIT for every operating condition. The largest MDNBR difference is only [ ]% (Case 4).

2.3.4.5 COBRA-VIPRE Transient Comparison

An arbitrary transient case with the inlet core mass flow rate ramped from 100% to 75% and power ramped from 100% to 80% of their initial state values has been run for 2.0 seconds. Results are given in Table 2.3-7. Again the results agree very well.

2.3.4.6 COBRA-VIPRE Comparison Conclusions

In conclusion, the overall evaluation is that the VIPRE-01 computer code gives essentially identical solutions to those of COBRA-IIIC/MIT. The very slight differences in predictions which do exist can be explained by slight differences in the solution method or model options.

2.3.5 Summary of Experience

The VIPRE-01 code was developed to meet the utility need for a versatile and user-oriented analytical tool for performing core thermal-hydraulic design. VIPRE-01 includes numerous modeling options and correlations in order to satisfy a wide spectrum of utility needs. The model development and analysis results documented in this section demonstrate that VIPRE-01 is well suited for Oconee transient analysis. Some of the highlights of this application of the VIPRE-01 code include:

- The nodalization reduction and optimization study performed to justify the use of simplified models was highly successful. Although the intent of this effort was to reduce computer usage, there was no significant loss of accuracy in the predicted thermal-hydraulic conditions or MDNBR.

- VIPRE-01 accepts all necessary boundary conditions that originate either from the plant transient simulation code or the core neutronics simulation code. Included is the capability to subject different boundary conditions to different segments of the core model. For example, different transient inlet enthalpies, heat flux transients, and even different transient pin radial powers or axial flux shapes can be modeled. With this capability virtually any desired application is achievable.

- The results of a comparison between VIPRE-O1 and COBRA-IIIC/MIT showed excellent agreement. This was not unexpected due to the similar origins of the codes. Furthermore, this comparison highlights the similarity between most open-channel one-pass thermal-hydraulic codes that are currently in use for PWR core simulation.

- The selection of code options is consistent with the experience base developed by the utilities that have been utilizing VIPRE-01.

It is expected that the VIPRE-01 code will be utilized indefinitely for Oconee transient core thermal-hydraulic applications. The modeling capabilities and the analysis results provided in this section demonstrate that VIPRE-01 can be utilized for accurate and conservative prediction of DNBR during plant transients. This technology remains at or near the current state-of-the-art. Applications will include reanalysis of those FSAR Chapter 15 transients requiring a DNBR evaluation, evaluation of operational events, and resolution of regulatory concerns.

Table 2.3-1

Mark-B Fuel Assembly

Component Dimensions Used for Thermal-Hydraulic Analysis

Fuel Pin Diameter	0.431 in.
Control Rod Guide Tube Diameter	0.531 in.
Instrumentation Guide Tube Diameter	0.555 in.
Effective Pin Pitch	0.567 in.
Assembly Flow Area	40.389 $in.^2$
Assembly Wetted Perimeter	309.907 in.
Assembly Heated Perimeter	281.474 in.
Unit Channel Flow Area	0.176 $in.^2$
Unit Channel Wetted Perimeter	1.353 in.
Unit Channel Heated Perimeter	1.353 in.
Control Rod Guide Tube Channel Flow Area	0.157 $in.^2$
Control Rod Guide Tube Channel Wetted Perimeter	1.432 in.
Control Rod Guide Tube Heated Perimeter	1.015 in.
Instrumentation Guide Tube Channel Flow Area	0.152 $in.^2$
Instrumentation Guide Tube Channel Wetted Perimeter	1.451 in.
Instrumentation Guide Tube Channel Heated Perimeter	1.015 in.
Peripheral Channel Flow Area	0.102 $in.^2$
Peripheral Channel Wetted Perimeter	0.677 in.
Peripheral Channel Heated Perimeter	0.677 in.
Corner Channel Flow Area	0.065 $in.^2$
Corner Channel Wetted Perimeter	0.338 in.
Corner Channel Heated Perimeter	0.338 in.
Active Fuel Length	142.29 in.

(Pages 2-81 to 2-84 intentionally deleted)

Table 2.3-2

Steady-State Results Comparison

Model	MDNBR (BWC)	MDNBR at Axial Location (in.)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR	Mass Flux at MDNBR ($Mlbm/hr-ft^2$)	Pressure Drop up to MDNBR (psi)

Table 2.3-3

Transient Results Comparison

Time (sec)	MDNBR (BWC) M1*	MDNBR (BWC) M2**	MDNBR (BWC) M3***	Axial Location at MDNBR (in.) M1	Axial Location at MDNBR (in.) M2	Axial Location at MDNBR (in.) M3
0.0						
0.2						
0.4						
0.6						
0.8						
1.0						
1.2						
1.4						
1.6						
1.8						
2.0						

Time (sec)	Enthalpy at MDNBR (Btu/lbm) M1	Enthalpy at MDNBR (Btu/lbm) M2	Enthalpy at MDNBR (Btu/lbm) M3	Void Fraction at MDNBR M1	Void Fraction at MDNBR M2	Void Fraction at MDNBR M3
0.0						
0.2						
0.4						
0.6						
0.8						
1.0						
1.2						
1.4						
1.6						
1.8						
2.0						

Time (sec)	Mass Flux at MDNBR ($Mlbm/hr-ft^2$) M1	Mass Flux at MDNBR ($Mlbm/hr-ft^2$) M2	Mass Flux at MDNBR ($Mlbm/hr-ft^2$) M3	Pressure Drop up to MDNBR Location (psi) M1	Pressure Drop up to MDNBR Location (psi) M2	Pressure Drop up to MDNBR Location (psi) M3
0.0						
0.2						
0.4						
0.6						
0.8						
1.0						
1.2						
1.4						
1.6						
1.8						
2.0						

*M1 - [ ] Channel Model
**M2 - [ ] Channel Model
***M3 - [ ] Channel Model

Table 2.3-4

Active Fuel Node Size Comparison

Number of Active Fuel Rods	
MDNBR (BWC)	
MDNBR Axial Location (in.)	
Enthalpy (Btu/lbm)	
Void Fraction	
Mass Flux (Mlbm/hr-ft^2)	
Pressure Drop up to MDNBR (psi)	

Table 2.3-5

Correlations Used in the COBRA-VIPRE Comparison

Flow Correlations	
Subcooled Void	[
Bulk Void	
Two-phase Friction Multiplier	
Hot Wall Friction Correction	]
Turbulent Mixing Correlations	
Single-phase Mixing	$w' = ARe^{B}SG$ with A =[ ] B =[ ]
Two-phase Mixing	[
Turbulent Momentum Factor	]
Friction Loss Correlations	
Axial Friction Loss	f_{tub} =[ ]
Lateral Resistance	[ ]
Spacer Grid Pressure Loss	$\Delta P = KG^2/2\rho g_c$
Critical Heat Flux Correlation	BAW2

Where:

Re = Reynolds number

S = gap width, inches

G = mass flux, $lbm/sec\text{-}ft^2$

K = spacer grid form loss coefficient

ρ = density, lbm/ft^3

g_c = 32.174 $lbm \cdot ft/sec^2 - lbf$

Solution Method	Direct Method

Table 2.3-6

VIPRE-01 - COBRA-IIIC/MIT Steady-State
Results Comparison

Case	MDNBR (BAW-2)		Enthalpy at MDNBR		Void Fraction at MDNBR		Mass Flux at MDNBR	
	VIP	COB	VIP	COB	VIP	COB	VIP	COB
1								
2								
3								
4								

Case	Pressure Drop up to MDNBR (psi)		MDNBR Axial Location (in.)	
	VIP	COB	VIP	COB
1				
2				
3				
4				

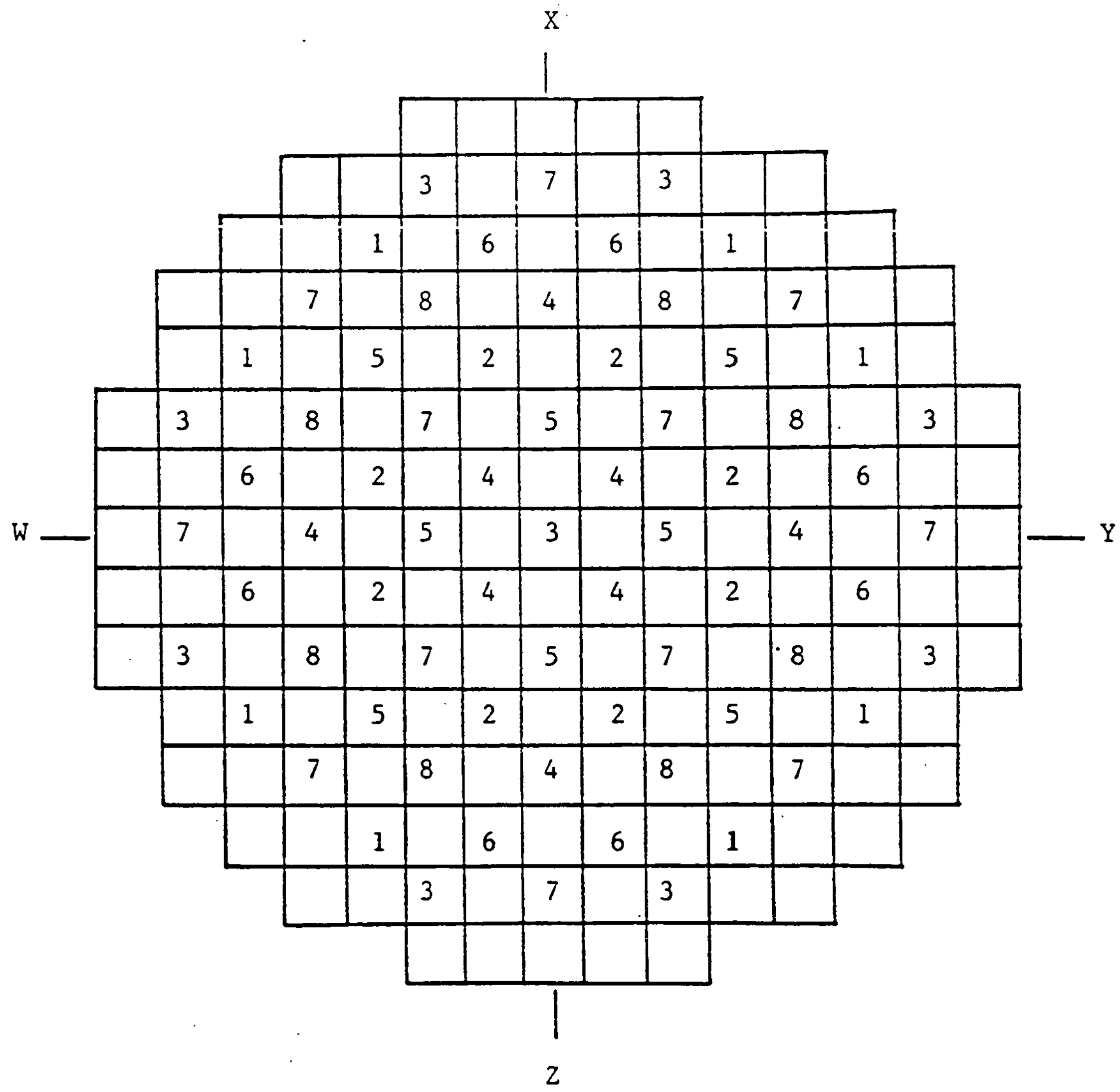
Table 2.3-7

VIPRE-01 - COBRA-IIIC/MIT Transient
Results Comparison

Time	MDNBR (BAW-2)		Axial Location at MDNBR (in.)		Enthalpy at MDNBR (Btu/lbm)	
(Sec)	VIP	COB	VIP	COB	VIP	COB
0.0						
0.2						
0.4						
0.6						
0.8						
1.0						
1.2						
1.4						
1.6						
1.8						
2.0						

Time	Void Fraction at MDNBR		Mass Flux at MDNBR ($Mlbm/hr-ft^2$)		Pressure Drop up to MDNBR (psi)	
(Sec)	VIP	COB	VIP	COB	VIP	COB
0.0						
0.2						
0.4						
0.6						
0.8						
1.0						
1.2						
1.4						
1.6						
1.8						
2.0						

Figure 2.3-1. ONS Reactor Core Cross Section



X Control Rod Group Number

Figure 2.3-2 ONS Fuel Assmebly

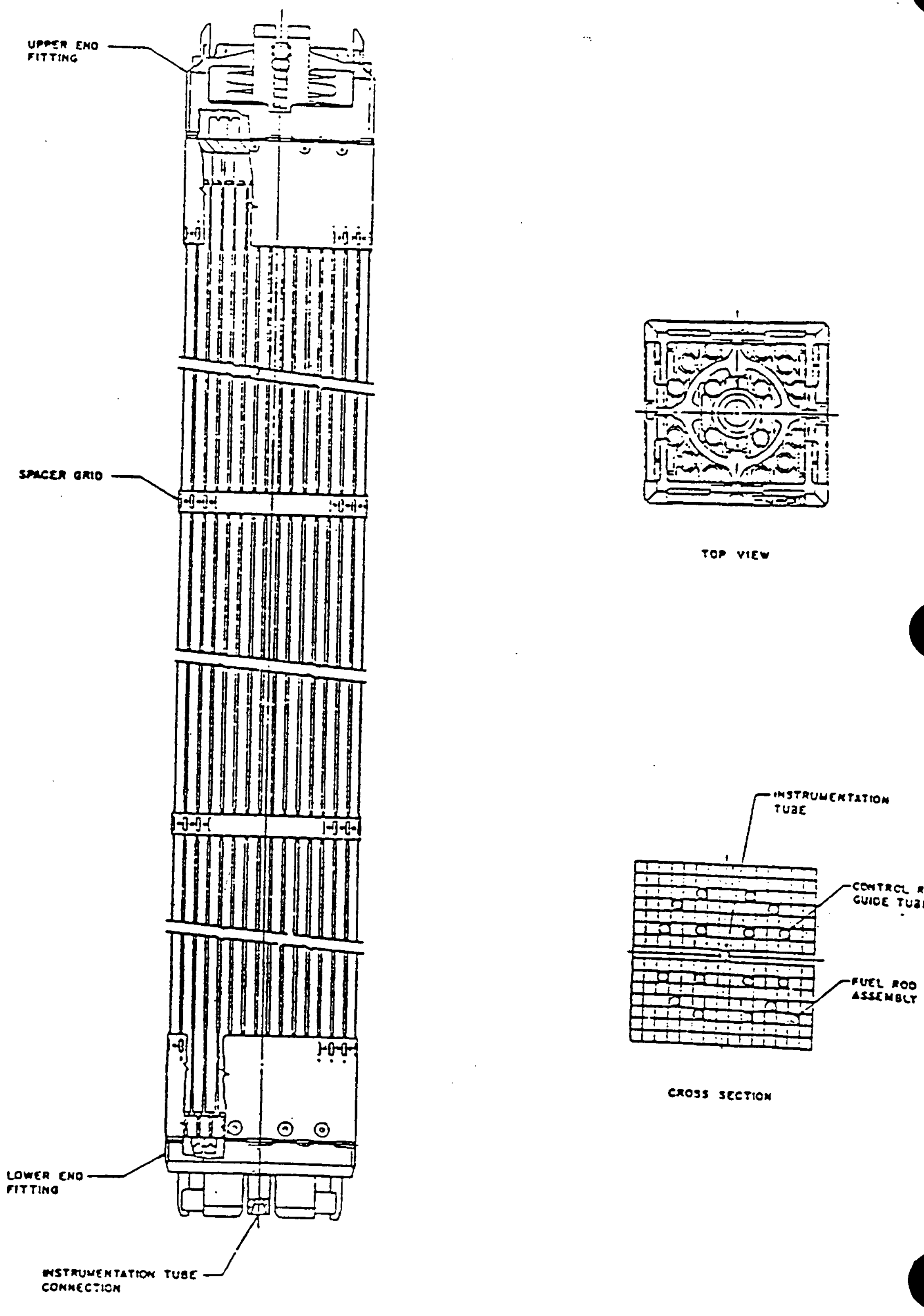
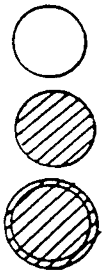


Figure 2.3-3. Assembly Radial Power for Transient Resulting in Symmetrical Power Distributions

Figure 2.3-4. Hot Assembly Pin Radial-Local Power for Transient Resulting in Symmetrical Power Distributions



Fuel Rod

Control Rod

Instrumentation Guide Tube

Figure 2.3-5. VIPRE[ ] Channel Model

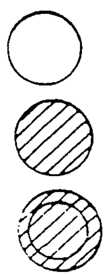
[

]

Figure 2.3-6. VIPRE[ ]Channel Model

Figure 2.3-7. VIPRE[ ]Channel Model

[ ]



Fuel Rod

Control Rod

Instrumentation Guide Tube

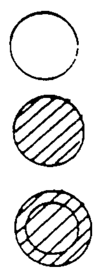
Figure 2.3-8. [ ] Axial Shape Peaked at X/L = [ ]

P/Po

X/L

Figure 2.3-9. COBRA[ ]Channel Model

[ ]



Fuel Rod

Control Rod

Instrumentation Guide Tube

2.4 References

2-1 Decay Energy Release Rates Following Shutdown of Uranium-Fueled Thermal Reactors, Proposed ANS Standard, American Nuclear Society, October 1971.

2-2 American National Standard for Decay Heat Power in Light Water Reactors, ANSI/ANS-5.1, American Nuclear Society, August 29, 1979.

2-3 RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM Revision 2, EPRI, November 1984.

2-4 VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM Revision 2, EPRI, July 1985.

2-5 BWC Correlation of Critical Heat Flux, BAW-10143P-A, April 1985.

2-6 LYNX2 - Subchannel Thermal-Hydraulic Analysis Program, BAW-10130, October 1976.

2-7 Duke Power Company Oconee Nuclear Station Core Thermal-Hydraulic Methodology Using VIPRE-01, DPC-NE-2003, August, 1988.

2-8 Prairie Island Nuclear Generating Plant Final Safety Analysis Report, Northern States Power Company.

2-9 Oconee FSAR Section 4.4.

2-10 Oconee Nuclear Station Technical Specifications, DPC.

2-11 Decay Heat Peaking, BAW-10033, October, 1971.

2-12 COBRA-IIIC: A Digital Computer Program for Steady-State and Transient Core Thermal-Hydraulic Design Methodology, BNWL-1695, PNL, March 1973.

2-13 COBRA IIIC/MIT Computer Code Manual, MIT, March 1976.

2-14 Thermal-Hydraulic Statistical Core Design Methodology, DPC-NE-2005-PA, Duke Power Company, February 1995

3.0 MCGUIRE/CATAWBA TRANSIENT ANALYSIS

3.1 Plant Description

3.1.1 Overview

The McGuire and Catawba Nuclear Stations each consist of two 3411 MW thermal Westinghouse pressurized water reactor units. McGuire is located next to Lake Norman near Huntersville, N.C. Construction began on the plant in 1971, and full power operating licenses were received on June 12, 1981 and March 3, 1983 for Units 1 and 2 respectively. Catawba is located next to Lake Wylie near Fort Mill, S.C. Construction began on the plant in 1974, and full power operating licenses were received on January 17, 1985 and May 15, 1986 for Units 1 and 2 respectively. The four units are identical in most respects. The main unusual characteristic of the plants is the use of a dual containment ice condenser design. This features separation of the containment vessel and reactor building by a sub-atmospheric pressure region to inhibit leakage and the use of stored, borated ice to absorb the energy released during high energy line breaks inside containment.

Each primary system has four loops, each with a steam generator, reactor coolant pump and associated piping. The primary coolant is heated in the core and flows to the steam generators, where the energy is transferred to the secondary system. The coolant is then returned to the reactor vessel by the reactor coolant pumps. At full power the secondary system provides 440°F feedwater to the steam generators, where the feedwater is boiled to steam at approximately 1000 psia. The steam passes through a high pressure and three low pressure turbines and is exhausted to the condensers. The condensate is purified and preheated before it is returned to the steam generators.

Plant safety systems provide protection for various anticipated transients and design basis accidents. The Reactor Protection System shuts down the nuclear chain reaction to prevent damaging the core and exceeding safety limits. The Engineered Safeguards Systems provide numerous functions to mitigate design basis accidents, particularly emergency core cooling in the event of a loss of Reactor Coolant System inventory and auxiliary feedwater for decay heat removal.

3.1.2 Primary System

The McGuire/Catawba Reactor Coolant System is shown in Figure 3.1-1.

3.1.2.1 Reactor Core

The reactor core consists of 193 fuel assemblies and the associated control rods. Each fuel assembly is a 17x17 array of 264 fuel rods, 24 guide thimbles, and one in-core instrumentation tube. Each fuel rod contains stacked UO_2 fuel pellets surrounded by Zircaloy-4 cladding, with a small gap between the pellets and the cladding. The Zircaloy guide thimbles provide a channel for control rod insertion. The instrumentation tube provides a channel for incore neutron detectors. 53 of the fuel assemblies are provided with rod cluster control assemblies for power control and shutdown capability. McGuire Unit 1 uses silver-indium-cadmium absorber rods. The other three units use a hybrid B_4C design. Some of the fuel assemblies which do not contain control rods have burnable poison rod assemblies. Their purpose is to reduce core reactivity at the beginning of cycle and therefore enable higher enrichment cores and longer fuel cycles. Figures 3.1-2 through 3.1-5 show a fuel assembly, a fuel rod, a Ag-In-Cd rod cluster control rod assembly, and a B_4C absorber rod.

3.1.2.2 Reactor Vessel

The reactor vessel consists of a cylindrical shell, a hemispherical bottom head, and a flange to which the removable reactor vessel upper head is bolted during operation. The minimum shell thickness is 8.46 inches of carbon steel, and the interior is clad in stainless steel. Major regions of the vessel include the coolant inlet nozzles, the downcomer, the lower plenum, the core, the upper plenum, the upper head, and the outlet nozzles. Vessel penetrations include the incore instrument sheaths, the control rod mechanism housings, and the upper head injection lines. The incore instrument sheaths penetrate the lower head and the associated conduits extend into the reactor core region. The control rod mechanism housings penetrate the upper head and extend through the upper plenum. Four capped upper head injection lines extend through the upper head. In addition there is a high point vent line which comes off the top of the vessel.

The upper support plate is shaped like an inverted top hat as illustrated in Figure 3.1-6. Around the "rim" are holes which, together with mating holes in the core barrel flange, contain[ ] nozzles through which a portion of the vessel inlet flow is diverted upward to cool the upper head. Currently[ ]of the nozzles are open, which results in an upper head flow of approximately [ ]% of the total vessel inlet flow. This is a sufficient flowrate to maintain the upper head at the cold leg temperature. Flow passes between the upper head and upper plenum through four different types of structures: flow columns, UHI support columns, 17x17 guide tubes, and 15x15 guide tubes. The flow and support columns are hollow tubes extending from the top of the upper

core plate through the upper support plate. The guide tubes also start at the upper core plate but extend further up into the upper head. Most of the 17x17 guide tubes actually house RCCAs. The remainder, as well as the 15x15 guide tubes, serve only as flow paths. The support columns terminate in bottom nozzles directly above the corresponding fuel assembly outlet nozzles. Most of the support columns contain core exit thermocouples.

3.1.2.3 Reactor Coolant Loops

The reactor coolant piping provides a pathway for the coolant to circulate between the reactor vessel and the steam generators. Each of the four 29-inch ID hot legs connects the reactor vessel to one of the steam generators. One 31-inch ID pump suction pipe connects each of the steam generators to the reactor coolant pump. One 27.5-inch ID cold leg connects each reactor coolant pump to the reactor vessel. The minimum thicknesses of the hot leg, pump suction, and cold leg piping is 2.42 inches, 2.58 inches, and 2.30 inches, respectively. The piping is carbon steel clad with stainless steel.

There are various piping penetrations for interfacing systems and components. These include the pressurizer surge line into the loop B hot leg, the decay heat removal suction line(s) off of the bottom of the hot legs, the letdown line off of the loop C cold leg, the safety injection lines into each of the cold legs, and the pressurizer spray lines off of the A and B cold legs. In addition there are many penetrations for Reactor Coolant System instrumentation such as temperature, pressure, flow, and level. The high point of the primary loops is the top of the steam generator tubes.

3.1.2.4 Reactor Coolant Pumps

Each unit has four Westinghouse Model 93A reactor coolant pumps (RCPs). These are centrifugal pumps which operate at a constant speed and utilize 7000 hp Westinghouse motors. The pump seals are of a hydraulic controlled-leakage design. Within the discharge nozzle of each pump is a weir plate completely blocking[ ] inches of the circular flow channel into the cold leg piping. This prevents safety injection water which has accumulated in the bottom of the cold leg from flowing back through the pump and blocking the loop seal in the pump discharge piping during a LOCA.

3.1.2.5 Steam Generators

Four recirculating steam generators (SGs) provide for energy removal from the primary system. The primary side of a SG consists of the inlet plenum, the tubesheet, the tubes, and the outlet plenum. Primary coolant enters the SG inlet plenum through a nozzle connected to the hot leg piping. The coolant flows up and down the U-shaped SG tubes into the SG outlet plenum. A nozzle connects the outlet plenum to the pump suction piping. The SG inlet and outlet plena are made of carbon steel clad with stainless steel. The tubesheet is also carbon steel.

The preheat SGs consist of Inconel-600 tubes that are fixed at the ends by the 21 inch thick tubesheet, which separates the primary and secondary sides. There are approximately 4600 tubes per SG. Each tube has a nominal OD of 3/4 inches and a thickness of 0.043 inches.

The preheat SGs used at McGuire and Catawba are of two basic types. Catawba Unit 2 has the counter flow D5 design shown in Figure 3.1-7. The other three units have the split flow D2/D3 design shown in Figure 3.1-8. Differences between the two designs are discussed in Section 3.1.6.

The preheat steam generators at McGuire Units 1 and 2 and Catawba Unit 1 will be replaced with new feedring steam generators manufactured by Babcock & Wilcox International. The design of the feedring steam generators (FSGs) is shown in Figure 3.1-12. There are 6633 tubes per FSG that are made of Inconel-690. The tubes are fixed at the ends by the 27 inch thick tubesheet which is made of carbon steel and clad with stainless steel. Each tube has a nominal OD of 0.6875 inches and a thickness of 0.04 inches. Differences between the preheat and feedring designs are discussed in Section 3.1.6.

3.1.2.6 Pressurizer

The pressurizer is a vertical cylindrical vessel with hemispherical upper and lower heads. A surge line penetrates the bottom of the pressurizer and connects it to one of the hot legs. The pressurizer maintains and controls the RCS pressure and provides a steam surge chamber and liquid water reserve to compensate for changes in reactor coolant density during operation. A diagram of the pressurizer is shown on Figure 3.1-9.

There are four banks of electric heaters in the lower region of the pressurizer, with a total capacity of 1800 kW. These heaters make up for ambient heat losses during normal operation

and restore pressure during operational transients. There is a low level interlock which prevents the heaters from being damaged due to uncovery during operation.

The pressurizer spray lines connect two of the cold legs to the pressurizer spray nozzle, which is located at the top of the steam space. Spray valve position is modulated by a proportional plus integral controller providing a maximum of approximately 900 gpm of colder water to the top of the pressurizer where it condenses steam, thus reducing pressure.

The three pressurizer PORVs are CCI drag valves located on lines connected to the top of the pressurizer. Each valve has a 210,000 lbm/hr steam relief capability and opens when RCS pressure exceeds approximately 2335 psig.

The three McGuire pressurizer code safety valves are 2.15 inch Crosby valves which also relieve fluid from the top of the pressurizer. The three Catawba code safety valves are 2.25 inch Dresser valves. The total relief capacity of the valves at each station is greater than 1,200,000 lbm/hr steam. These spring-loaded valves are set to relieve at 2485 psig.

3.1.2.7 Charging and Letdown

Normal charging at McGuire and Catawba is provided by a centrifugal charging pump (CCP) drawing water from the volume control tank. A control valve in the charging line modulates to control pressurizer level at the programmed setpoint, which is a function of reactor coolant average temperature. Makeup capacity through this flowpath is approximately 140 gpm at nominal system pressure. The makeup capacity can be augmented by starting a parallel CCP, opening the Engineered Safeguards injection flowpath, which is parallel to the charging flowpath, or both. Normal charging injects into the A cold leg piping. An alternate charging line injects into the D cold leg piping. A small amount of makeup is also provided by RCP seal injection. Approximately 8 gpm is pumped into the seals of each pump, most of which enters the primary system, and the remainder of which returns via the seal leakoff pathway to the volume control tank. Seal injection is provided by the same CCP which furnishes normal charging. Letdown is taken from the C loop pump suction piping through heat exchangers and demineralizers to the volume control tank. Normal letdown flow is approximately 75 gpm.

3.1.2.8 Instrumentation

A large number of instruments monitor the primary system in order to provide information to the operators, inputs to the plant control systems, and signals for the actuation of the Reactor

Protection System (RPS) and the Engineered Safety Features Actuation System (ESFAS). Core instrumentation includes neutron power indication (ionization chambers), movable incore neutron detectors, and core-exit thermocouples. RCS temperatures are measured by resistance temperature detectors (RTDs) in the hot leg and pump suction piping . Loop flow is measured by elbow taps in each pump suction leg. Pressure is measured by pressure taps in two of the four hot legs (B and C at Catawba, C and D at McGuire). The pressurizer contains water level, pressure, and water temperature instruments. In addition, inadequate core cooling instrumentation includes a static level measurement for the reactor vessel from top to bottom and a dynamic pressure drop measurement for bulk void fraction indication.

3.1.3 Secondary System

McGuire and Catawba use a regenerative-reheat Rankine cycle to convert the thermal energy produced in the reactor core to electric power. Energy is removed from the primary system by feedwater boiled in the SGs. The steam is exhausted through a high pressure turbine, moisture separator-reheaters, and three low pressure turbines to the condensers. Hotwell pumps take suction from the condenser hotwells and discharge to the condensate booster pumps. The condensate passes through G and F feedwater heaters upstream of the booster pumps and then through E, D, and C feedwater heaters to the suction of the steam-driven main feedwater (MFW) pumps. The MFW pumps discharge through the B and A feedwater heaters to the SGs.

3.1.3.1.1 Preheat Steam Generators

The SGs remove energy from the primary system during normal operation, at hot standby, and if necessary at hot shutdown. A typical generator is shown in Figures 3.1-7 and 3.1-8. At full power most of the approximately 3.8 million lbm/hr feedwater enters each SG preheater through the 16 inch lower nozzle. The downcomer consists of the annular section in the lower part of the SG which is separated from the SG shell region by the cylindrical wrapper. Recirculated water flows under the wrapper and into the bundle region surrounding the U-tubes containing the primary coolant. Water emerging from the preheater region mixes with the recirculation flow in the bundle region. Heat transferred from the U-tubes boils some of the secondary fluid in the bundle region, and the resulting two phase mixture enters the primary and secondary separators. In the separators the steam is dried to a minimum quality of 0.9975 before passing through the outlet nozzle into the steam line. The separated liquid collects in the downcomer. The nominal SG outlet pressure at full power operation is 1000 psia.

Tube support plates provide structural support for the SG U-tubes. The plates are distributed axially along the tube bundle and are more closely spaced near the bottom. They have clearance holes through which the U-tubes pass. In addition there are circulation holes in the plates to allow fluid to pass up the tube bundle at higher flow rates. Each tube bundle has a lane under the bend apex at the top of the tube bundle. This lane allows some of the interior tubes to be inspected. In addition there are untubed regions through which vertical stayrods pass. These stayrods connect the tube support plates for additional support. The height of the tallest U-tube is approximately 28 feet above the top of the tubesheet.

The elevations of the top and bottom of the reactor core are 155" and 299", respectively, below the top of the lower tubesheet of the SG. In order to promote stable natural circulation flow the thermal center for heat removal must be above the thermal center for heat addition to the primary system. This condition is therefore automatically satisfied because of loop geometry. The SGs have an upper nozzle to allow auxiliary feedwater (AFW) to be injected into the downcomer above the tubes.

3.1.3.1.2 Feedring Steam Generators

The feedring steam generator (FSG) is shown in Figure 3.1-12. At full power, most of the approximately 3.8 million lbm/hr feedwater is delivered to the feedring through the main feedwater nozzle and gooseneck. The 32 J-tubes connected to the feedring distribute the feedwater axi-symmetrically around the downcomer, where the feedwater mixes with the recirculation flow. The downcomer consists of the annular section in the lower part of the FSG which is separated from the shell region by the cylindrical wrapper. Recirculated water flows under the wrapper and into the bundle region surrounding the U-tubes containing the primary coolant. Heat transferred from the U-tubes boils some of the secondary fluid in the bundle region, and the resulting two-phase mixture enters the primary and secondary separators. In the separators, the steam is dried to a minimum quality of 0.9975 before passing through the steam outlet nozzle into the steam line. The separated liquid collects in the downcomer. The nominal FSG outlet pressure at full power is 1020 psia.

A lattice bar grid arrangement provides structural support for the U-tubes while minimizing resistance to fluid flow. The lattice grids are distributed axially along the tube bundle, with one high resistance lattice grid at the bottom of the bundle and eight low or medium resistance lattice grids above the high resistance lattice grid. The height of the tallest U-tube is approximately 35 feet above the top of the tubesheet.

The elevations of the top and bottom of the reactor core are 170" and 314", respectively, below the top of the tubesheet of the FSG. Thus, the difference in thermal centers promotes stable natural circulation flow.

The FSGs have an auxiliary feedwater nozzle approximately 3 feet above the main feedwater J-tubes to allow auxiliary feedwater to be injected into the downcomer above the tubes.

3.1.3.2 Main Feedwater

The MFW System consists of the MFW pumps, the A and B feedwater heaters, and the piping and valves between the pumps and the SGs. The MFW pumps have common suction and discharge lines, so neither of the two pumps is aligned to particular SGs. The variable-speed pumps are turbine-driven by either main steam or low pressure steam. The nominal feedwater temperature at the outlet of the A feedwater heaters is 440°F, at a pressure of approximately 1100 psia. MFW flow to each SG is controlled by the MFW control valves.

The MFW flow is normally aligned predominantly to the lower nozzle during power operation. At low power levels MFW is swapped to inject into the upper nozzle. AFW is aligned only to the upper nozzle.

For the FSGs, main feedwater flow is normally aligned to the main feedwater nozzle during power operation. It is not expected that main feedwater will be swapped to inject into the auxiliary feedwater nozzle at lower power levels for FSG operation at McGuire. For FSG operation at Catawba, MFW is swapped to inject into the upper nozzle at lower power levels. Auxiliary feedwater is aligned only to the auxiliary feedwater nozzle.

3.1.3.3 Main Steam

The main steam lines carry the high pressure, high temperature steam from the SGs to the high pressure turbine. One 32" line exits each SG and expands to a 34" line. The 34" line leaves the Reactor Building and enters the Doghouse. Inside the Doghouse there is a main steam isolation valve (MSIV) on each line. Downstream of the MSIV each line leaves the Doghouse, goes across the yard and enters the Turbine Building. From then on the configuration is station specific and is discussed in Section 3.1.6.4.

Process steam is taken off of the steam headers to power station auxiliaries. These include the auxiliary steam header, the MFW pumps, the turbine-driven AFW pump, the condensate steam

air ejectors, and the steam seals. In addition, main steam is used to reheat the steam between the high and low pressure turbines. Various steam drains and traps are also provided on each steam line. Main steam relief is provided by five steam line safety valves and one Power Operated Relief Valve (PORV) per steam line. Downstream of the MSIVs, further steam relief is provided by condenser dump valves and atmospheric dump valves.

The steam line safety valves provide overpressure protection to the steam lines and SGs. The valve opening setpoints range between 1170 and 1230 psig. The total relief capacity through the valves is greater than the nominal full power steam flow rate. The condenser dump valves control steam pressure prior to putting the turbine on-line and after turbine trip. The nine valves have a total capacity of 40% of nominal full power steam flow. The atmospheric dump valves provide additional steam relief for load rejection transients. These valves have a total capacity of 45% of nominal steam flow. The two sets of valves, together with the steam line PORVs, are designed to allow a full load rejection without tripping the reactor or opening the steam line safety valves.

3.1.3.4 Turbine-Generator

The turbine-generator converts the thermal energy of steam produced in the SGs into mechanical shaft power and then into electrical energy. The turbine-generator of each unit consists of a tandem (single shaft) arrangement of a double-flow high pressure turbine and three identical double-flow low pressure turbines driving a direct-coupled generator at 1800 rpm. Turbine-generator functions under normal and abnormal conditions are monitored and controlled automatically by the Turbine Control System, which includes redundant mechanical and electrical trip devices to prevent excessive overspeed of the turbine generator. Once the turbine is brought online (at approximately 10% rated power) the turbine control valves maintain the first stage (impulse chamber) pressure at a programmed value that is proportional to power level. The turbine stop valves close rapidly to preclude turbine damage after the receipt of a turbine trip signal.

3.1.3.5 Instrumentation

A wide variety of secondary system instrumentation is available to the operators. Pressure is available at the MFW pump discharge and on the steam lines upstream and downstream of the MSIVs. Fluid temperature is indicated for each part of the Main Feedwater System and for the steam lines. Feedwater flow is available for each SG. Two SG level indications, wide range and narrow range, are provided, with the ranges indicated on Figures 3.1-7 and 3.1-8. Two FSG level

indications, wide range and narrow range, are provided with the ranges indicated on Figure 3.1-12. The SG level instruments are ΔP devices, with the taps located at various elevations in the downcomer and shell. ΔP devices measure collapsed liquid levels, not the actual mixture or froth level of a fluid. The two level ranges are used for distinct purposes. The narrow range covers the middle portion of the SG and is used during normal operation, when the SGs have a significant water inventory. The wide range covers the middle and lower portions and is primarily used for evolutions which take place while at shutdown, such as wet layup.

3.1.4 Control Systems

Nuclear plants include a large number of control systems which monitor and adjust the performance of individual components and systems. In this section the control systems which have a major effect on the overall transient response of the plant are discussed.

3.1.4.1 Pressurizer Pressure Control

The Pressurizer Pressure Control System controls the three pressurizer PORVs, the two pressurizer spray valves, the bank of proportional control heaters, and the three banks of backup heaters. Either channel 1 or channel 3 of the pressurizer pressure instrumentation is used as an input signal. This signal directly controls two of the three PORVs, causing them to lift at 2335 psig and reseat at [ ] psig. To control the other components an error signal is formed by subtracting the reference pressure setpoint, 2235 psig, from the input signal. This error signal is then input to a proportional plus integral controller. The controller output signal operates the remaining components according to the following setpoints, with zero psi indicating controller output at the reference pressure.

Backup heaters on	-25 psi
Backup heaters off	[ ] psi
Control heaters full on	-15 psi
Control heaters off	+15 psi
Spray valves begin to open	+25 psi
Spray valves full open	+75 psi
Pressurizer PORV NC-34 reseats	[ ] psi
Pressurizer PORV NC-34 opens	+100 psi

3.1.4.2 Rod Control

The Rod Control System enables the nuclear unit to follow load changes automatically, including the acceptance of step load increases or decreases of 10 percent and ramp increases or decreases of 5 percent per minute, within the load range of 15 percent to 100 percent, without reactor trip, steam dump, or pressure relief, subject to possible xenon limitations. The system is also capable of restoring coolant average temperature to within the programmed temperature deadband following a change in load. Manual control rod operation may be performed at any time. The Rod Control System controls the reactor coolant average temperature by regulation of control rod bank position. The reactor coolant loop average temperatures are determined from hot leg and cold leg measurements in each reactor coolant loop.

The error between the programmed reference temperature (based on turbine impulse chamber pressure) and the highest of the average measured temperatures (which is processed through a lead-lag compensation unit) from each of the reactor coolant loops constitutes the primary rod control signal. An additional control input signal is derived from the reactor power versus turbine load mismatch signal. This additional control input signal improves system performance by enhancing response and reducing transient peaks. The system is capable of restoring coolant average temperature to the programmed value following a change in load. The programmed coolant temperature increases linearly with turbine load from zero to full power.

The Rod Control System generates rod speed and direction signals which vary over the range of 5 to 45 inches per minute (8 to 72 steps/minute) depending on the magnitude of the input signal. The rod direction demand signal is determined by the positive or negative value of the input signal. Manual control is provided to move a control bank in or out at a prescribed fixed speed.

When the turbine load reaches approximately 15 percent of rated load, the operator may select the automatic mode, and rod motion is then controlled by the Rod Control System. A permissive interlock derived from measurements of turbine impulse chamber pressure prevents automatic control when the turbine load is below 15 percent. In the automatic mode, the rods are withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming equipment.

The five shutdown banks are always in the fully withdrawn position during normal operation, and are moved to this position at a constant speed by manual control prior to criticality. A reactor trip signal causes them to fall by gravity into the core. The four control banks are the only rods that can be manipulated under automatic control. Each control bank is divided into

two groups to obtain smaller incremental reactivity changes per step. All rod cluster control assemblies in a group are electrically paralleled to move simultaneously. There is individual position indication for each rod cluster control assembly.

3.1.4.3 Steam Dump Control

The Steam Dump Control System has three modes of operation: plant trip, load rejection, and steam header pressure.

Plant Trip Controller

Following reactor trip only the nine condenser steam dump valves are allowed to open. The atmospheric steam dump valves are interlocked closed. The condenser dump valves are organized into banks, two at McGuire and three at Catawba. The opening and closing of banks of valves is determined by a temperature error signal. One component of the error signal is the lead-lag compensated, auctioneered high coolant average temperature indication. From this is subtracted the no-load average temperature. The magnitude of this difference determines the operation of a given valve bank. Each bank has a trip setpoint, a reset setpoint, and a modulation range. The ranges are continuous, i.e., the trip setpoint of a given bank is at the bottom of the modulation range of the next bank. The reset setpoint for a given bank is [ ] below the trip setpoint. The trip setpoints are as follows:

McGuire	
Bank 1 (five valves)	[ ]°F
Bank 2 (four valves)	[ ]°F

Catawba	
Bank 1 (three valves)	[ ]°F
Bank 2 (three valves)	[ ]°F
Bank 3 (three valves)	[ ]°F

If the temperature error signal is at or above the trip setpoint, all valves in the corresponding bank trip fully open and are kept open until the error signal decreases below the reset setpoint for that bank. If the error signal never increases to the trip setpoint, the valve position is a linear function of the error signal with 100 percent open corresponding to the trip setpoint of that bank and zero percent open corresponding to the trip setpoint of the next lowest bank. Bank 1 is zero percent open when the error signal is zero.

Load Rejection Controller

Following a large, sudden load rejection or turbine trip without a reactor trip, all condenser dump valves and atmospheric dump valves may be enabled, depending on the magnitude of the load rejection. The load rejection controller operates in a manner similar to the plant trip controller

and is also driven by an error signal derived from a temperature difference. The components of the temperature difference are the average temperature, as used in the plant trip controller, and the reference temperature, which is based on turbine impulse chamber pressure and is therefore indicative of turbine power. There is a[ ]°F deadband on the temperature difference before the first bank begins to open in load rejection control mode. The trip setpoints are

McGuire		Catawba	
Bank 1 (five valves)	[ ]°F	Bank 1 (three valves)	[ ]°F
Bank 2 (four valves)	°F	Bank 2 (three valves)	°F
Bank 3 (four valves)	°F	Bank 3 (three valves)	°F
Bank 4 (four valves)	°F	Bank 4 (four valves)	°F
		Bank 5 (five valves)	°F

Steam Header Pressure Controller

Residual heat removal is maintained by the steam header pressure controller (manually selected) which controls the amount of steam flow to the condensers. This controller operates three of the condenser dump valves.

3.1.4.4 Pressurizer Level Control

The pressurizer water level is programmed as a function of coolant average temperature, with the highest average temperature (auctioneered) being used. The pressurizer water level decreases as the load is reduced from full load. This is a result of coolant contraction following programmed coolant temperature reduction from full power to low power. The programmed level is designed to match as nearly as possible the level changes resulting from the coolant temperature changes.

3.1.4.5 Steam Generator Level Control

Each McGuire steam generator is equipped with a three-element feedwater flow controller which maintains a programmed water level as a function of neutron flux. The three element feedwater controller regulates the feedwater valve by continuously comparing the feedwater flow signal, the water level signal, the programmed level and the pressure compensated steam flow signal.

The Catawba Digital Feedwater Control System (DFCS) automatically controls feedwater flow to each steam generator to maintain programmed steam generator water levels. The level setpoint is a function of nuclear power. At power levels above approximately 25 percent, the feedwater flow to individual steam generators is controlled by a three element DFCS which uses

temperature compensated feedwater flow, main steam flow, and steam generator water level as control parameters for the feedwater control valves. At power levels below approximately 25 percent, the DFCS automatically positions the feedwater bypass control valve and feedwater control valve to each steam generator based on the level setpoint.

3.1.4.6 Feedwater Pump Speed Control

The feedwater pump speed is varied to maintain a programmed pressure differential between the steam header and the feed pump discharge header. The speed controller continuously compares the actual ΔP with a programmed ΔP_{ref} which is a linear function of steam flow.

3.1.5 Safety Systems

Various systems are required to ensure that the plant does not exceed applicable limits during design basis transients. The major safety-related systems which affect the plant transient response are discussed in this section.

3.1.5.1 Reactor Protection System

The Reactor Protection System (RPS) monitors parameters related to safe operation of the core and trips the reactor to protect against fuel and cladding damage. In addition, by tripping the reactor and limiting the energy input to the coolant, the RPS protects against Reactor Coolant System structural damage caused by high pressure. A coincidence logic scheme is used to sense a trip condition. When the minimum number of channels trip, power is removed from the control rod drives of the shutdown banks, S_a - S_e, and the control banks, A-D. The rods fall into the reactor core and shut down the nuclear chain reaction.

The RPS will initiate a reactor trip on the following conditions:

1) Power range high neutron flux, high setting
2) Power range high neutron flux, low setting
3) Intermediate range high neutron flux
4) Source range high neutron flux
5) Loop temperature difference higher than the DNB limit (Overtemperature ΔT)
6) Loop temperature difference higher than the centerline fuel melt limit (Overpower ΔT)
7) Reactor coolant pump undervoltage
8) Reactor coolant pump underfrequency

9) High pressurizer pressure
10) Low pressurizer pressure
11) High pressurizer level
12) Low reactor coolant loop flow
13) Low-low steam generator level
14) Power range neutron flux high positive rate
15) Safety injection
16) Turbine trip while above a certain power level (48% at McGuire and 69% at Catawba)

Trips 2, 3, and 4 are enabled only at various low power levels. Trips 7, 8, 10, 11, and 12 are modified or disabled at various low power levels. Trips 1, 5, 6, 9, 13, 14, and 15 are always enabled while the reactor is critical.

3.1.5.2 Engineered Safeguards System

The Engineered Safeguards System consists of the Engineered Safety Features Actuation System (ESFAS) and various safeguards components. These components may also have dual functions, being used during normal operation as well serving as Engineered Safety Features. The ESFAS is divided into the following functions:

1) Safety injection
2) Containment heat removal
3) Containment isolation
4) Steam line isolation
5) Turbine trip and feedwater isolation
6) Auxiliary feedwater
7) Automatic switchover to recirculation
8) Loss of essential auxiliary power system

These functions and the components actuated by them are discussed below.

<u>Safety Injection</u>

The Safety Injection System can be divided into four subsystems:

1) Two high head safety injection (HHSI) pumps
2) Two intermediate head safety injection (IHSI) pumps
3) Two low head safety injection (LHSI) pumps

4) Four passive cold leg accumulator tanks (CLAs)

All six pumps start on a safety injection signal. This signal is automatically generated on any of the following conditions:

1) Pressurizer pressure decreases below 1845 psig
2) Containment pressure increases above 1.1 psig (McGuire) or 1.2 psig (Catawba)

The first actuation signal can be blocked when the reactor is being cooled down. The second actuation signal is always enabled.

The HHSI pumps have a shutoff pressure of approximately [ ] psig and runout flows of approximately [ ]. These flow rates are for operation through the boron injection flowpath which terminates in 1½" lines which inject into each cold leg. The HHSI pumps also provide normal charging and reactor coolant pump seal injection. On a safety injection signal the suction source for the HHSI pumps is automatically switched from the volume control tank to the Refueling Water Storage Tank (RWST).

The IHSI pumps have a shutoff pressure of approximately [ ] psig and runout flows of approximately [ ] The IHSI pumps initially inject through four 2" lines which empty into the 6" lines from the LHSI pumps. If injection flow is to be maintained after 7 hours, the IHSI pumps are realigned to inject into four 6" lines which connect directly to each hot leg. The IHSI pumps are normally aligned to the RWST.

The LHSI pumps have a shutoff pressure of approximately [ ] psig and runout flows of [ ] The LHSI pumps initially inject through four 6" lines which empty into the 10" lines from the cold leg accumulator tanks. If injection flow is maintained long enough to empty the RWST, the suction of the LHSI pumps is automatically swapped to the containment sump. The operator then aligns the HHSI and IHSI pumps to take suction from the LHSI pumps. If injection flow is to be maintained after 7 hours, the LHSI pumps are realigned to inject into the B and C hot leg piping instead of the cold legs into which they previously injected. This realignment prevents unacceptable concentration of boron following a LOCA.

The four CLAs constitute a passive part of the Emergency Core Cooling System that performs no function during normal operation. Each of the four tanks is connected to its corresponding cold leg by a 10" injection line. The tanks are pressurized to approximately 600 psig by nitrogen.

Each 1393 ft^3 tank contains 918 ft^3 of borated water at McGuire and 1020 ft^3 of borated water at Catawba which, following a large break LOCA, is discharged into its cold leg. Each injection line contains two check valves which isolate the tank from RCS pressure during normal operation, but open to allow flow during a design basis accident. In addition to large break LOCAs, the CLAs will inject water into the RCS during major depressurization events, e.g., some small break LOCAs.

In addition to actuating the pumps discussed above, a safety injection signal will do the following:

1) Start the motor driven AFW pumps
2) Initiate a Phase A containment isolation
3) Initiate a containment purge and exhaust isolation

Containment Heat Removal

The containment heat removal portion of the ESFAS and the components it controls, such as spray pumps and air return fans, do not play a major role in NSSS transient analysis and are not described here.

Containment Isolation

The containment isolation portion of the ESFAS and the isolation valves it controls are divided into two groups, Phase A and Phase B, depending on the signal which generated the isolation. Both signals can result in the closure of valves in lines which affect the NSSS. Although no general explanation is given here, such effects are modeled appropriately in the RETRAN analyses of applicable transients.

Steam Line Isolation

Steam line isolation occurs automatically from pressurization of the containment or uncontrolled depressurization of the steam lines. The containment pressure setpoint is 2.9 psig (McGuire) or 3.0 psig (Catawba). Steam line isolation on uncontrolled steam line depressurization depends on plant status. For normal pressurized operation steam line pressure is compared with a setpoint of 775 psig. For depressurized operation the operator blocks this actuation to allow cooldown with the SGs. The blocking enables an automatic isolation on any steam line pressure rate more negative than -100 psi/second. A steam line isolation signal closes the MSIVs, the MSIV bypass valves, and the steam line PORVs.

Turbine Trip and Feedwater Isolation

If narrow range SG level exceeds the high-high setpoint, 82% (McGuire), 82.4% (Catawba), or 83.9% (FSG), the ESFAS will initiate closure of the turbine stop valves and of all valves supplying MFW flow to the SGs. These actions protect the turbine from damage due to moisture entrainment and stop MFW flow to help prevent SG overfill. In addition MFW isolation can occur on high water level in one of the Doghouses. This protects against continued MFW addition for a feedwater line break in the Doghouse. Feedwater isolation signals will also be generated by safety injection or by low RCS average temperature coincident with reactor trip, although not technically a part of the McGuire ESFAS, as defined by Technical Specifications.

Auxiliary Feedwater

The Auxiliary Feedwater (AFW) System has two 50% capacity motor-driven pumps and one 100% capacity turbine-driven pump. One motor-driven pump is aligned to SGs A and B, the other to SGs C and D. The turbine-driven pump is aligned to all four SGs. The motor-driven pumps are automatically started on any of the following:

1) Low-low narrow range level in any SG
2) Safety injection
3) Loss of offsite power
4) Trip of both MFW pumps

The turbine-driven pump is automatically started on either of the following:

1) Low-low narrow range level in two or more SGs
2) Loss of offsite power

AFW flow is manually controlled by the operator following reactor trip to achieve and maintain the programmed narrow range SG level for zero power.

Automatic Switchover to Recirculation

On low RWST level the LHSI pump suction is automatically swapped from the RWST to the containment sump.

Loss of Essential Auxiliary Power System

Upon low voltage on the 4160 volt essential electrical busses, the diesel generators automatically start. The diesel generator load sequencers open the breakers for loads on the busses, close the diesel generator breakers to energize the busses, and then re-close the breakers for the various

load according to prescribed timed sequences. The presence of a safety injection signal starts the diesel generator safeguards loading sequence, while a loss of offsite power with no safety injection signal starts the diesel generator blackout loading sequence.

3.1.6 Dissimilarities Between Units and Stations

3.1.6.1 Steam Generator Type

The McGuire units and Catawba Unit 1 originally had split flow preheater regions. In such a preheater the MFW flow enters the middle of the region on the side and divides into two flow streams. The upper stream flows across a series of baffle plates and upward, counter to the direction of RCS flow in the U-tubes. This stream exits into the upper tube bundle on the cold leg side. The lower flow stream flows across a different series of baffle plates and downward, along the direction of RCS flow in the U-tubes. This stream exits into a mixing region below the preheater where it joins with recirculated flow from the downcomer and flows over the lower tube bundle on the hot leg side.

Catawba Unit 2 has a counterflow preheater region. In this preheater design the MFW flow enters the middle of the region, is diverted to the bottom, and divides into two streams. One stream flows across the tube bundle to the hot leg side and joins recirculated flow from the downcomer. The other flows across a series of baffle plates and upward, counter to the direction of RCS flow in the U-tubes. This stream exits into the upper tube bundle on the cold leg side.

In addition to the preheater, the Catawba Unit 2 SGs differ from those of the other units in several other respects. There are [ ] primary separators (risers) on the Catawba Unit 2 SGs but [ ] on SGs at the other units. Fitting the [ ] risers through the plate at the top of the tube bundle necessitated raising it to a higher and thus wider area in the transition cone. This results in a larger tube bundle region relative to the other units. The 4578 Catawba Unit 2 SG U-tubes are taller than the corresponding 4674 U-tubes on the other three units. The longer U-tubes at Catawba Unit 2 increase the resistance of the primary loop. This necessitated an increase in the rated head of the reactor coolant pumps for that unit to a value greater than the rated value for the reactor coolant pumps on the other three units. Finally, the split flow preheater configuration flow patterns necessitated a wide variation in programmed water level with power. The Catawba Unit 2 SG level program has a narrow variation in programmed water level as a function of power.

In order to correct U-tube wear problems associated with high MFW flow into the counterflow preheater region, the MFW flow delivery characteristics of the Catawba Unit 2 generators were modified. A flow restricting orifice was installed in the MFW line to the lower nozzle, limiting flow to this nozzle at full power to [ ]% of total flow. The remaining [ ]% of full power MFW flow is diverted to the upper nozzle. In contrast, the other units have upper nozzle MFW flows at full power of approximately [ ]% of total flow, enough to prevent heatup of the discharge lines and upper nozzle.

The preheat SGs at McGuire Units 1 and 2 and Catawba Unit 1 have been replaced with feedring SGs. The main difference between the preheat and feedring designs is the manner in which main feedwater is delivered to the steam generators. In the feedring SG, the main feedwater flow is delivered to the feedring through the main feedwater nozzle and gooseneck. The J-tubes connected to the feedring distribute the feedwater axi-symmetrically around the downcomer, where the feedwater mixes with the recirculation flow.

In addition, the feedring SGs differ from the preheat SGs in several other respects. Each FSG has a greater number of primary separators that are smaller than the preheat SG separators. The FSG tube bundle is taller than that of the preheat SGs and has a greater number of tubes. Thus, the FSGs have a much larger heat transfer area. The FSG level program is constant as a function of power, as is the Catawba Unit 2 SG level program.

3.1.6.2 Auxiliary Feedwater Runout Protection

Travel stops on the auxiliary feedwater discharge valves in the lines from each AFW pump to each SG are set to allow no more than a certain amount of flow to any SG assuming it is fully depressurized while the other SGs are at the setpoint of the steam line safety valves.

3.1.6.3 Steam Line Layout

The McGuire main steam lines exit the four SGs and go to the MSIVs in the Doghouse. Downstream of the MSIVs the 34" steam lines enter the side of a 48" diameter header. At one end of this header a 24" line goes to the eight atmospheric dump valves. From the other end another 24" line goes to the nine condenser dump valves. From the side of the header four 34" lines carry main steam to the turbine inlet via the stop and control valves. The McGuire arrangement is shown in Figure 3.1-10. At Catawba the arrangement is similar through the MSIVs. Downstream of the MSIVs each 34" line maintains its identity separately from the other lines, reducing to 28" each before reaching the turbine stop and control valves. At the stop

valves is a 35" equalization header connecting each steam line. Further upstream, a 28" line separates from each steam line. These four lines join to form a 28" header. At one end of this header a 24" line goes to the nine atmospheric dump valves. From the other end another 24" line goes to the nine condenser dump valves. The Catawba arrangement is shown in Figure 3.1-11.

3.1.6.4 Miscellaneous Differences

There are several miscellaneous differences between stations and units which affect transient analysis modeling:

1) The outlet nozzle on the McGuire Unit 1 reactor vessel is [ ] as the nozzles on the other three units, giving it a [ ] as the nozzles on the other units.

2) The number and types of the various upper internals structures is different for McGuire Unit 1 than for the other three units as shown below:

McGuire Unit 1	Other Units
[ ] 17 x 17 guide tubes	[ ] 17 x 17A guide tubes
[ ] 15 x 15 guide tubes	[ ] 15 x 15 guide tubes
[ ] support columns	[ ] support columns
[ ] flow columns	[ ] flow columns
[ ] thermocouple columns	[ ] thermocouple columns

3) McGuire Unit 1 has thermocouple instrumentation in the reactor vessel upper head while the other three units do not.

4) The original RCS average temperature program for McGuire Units 1 and 2 and Catawba Unit 1 was 588.2°F. With the replacement FSGs this temperature has been lowered to 585.1°F. The original RCS average temperature for Catawba Unit 2 was 590.8°F. This temperature has been lowered to 587.5°F.

5) Due to noise problems encountered with the pressurizer pressure transmitters on initial startup, the McGuire pressure signals have a 1 second lag imposed before being used for control and protection purposes. The Catawba pressure signals have no lag.

6) There are several minor setpoint differences between McGuire and Catawba, e.g., the ΔT reactor trip gains and time constants and the pressurizer level program.

7) Because of the variation in operating time among the four units, differences exist in the number of tubes plugged on the various SGs. These differences are modeled, where appropriate, in RETRAN transient analyses.

(Pages 3-23 to 3-25 intentionally deleted)

Figure 3.1-1
McGuire/Catawba Reactor Coolant System Schematic

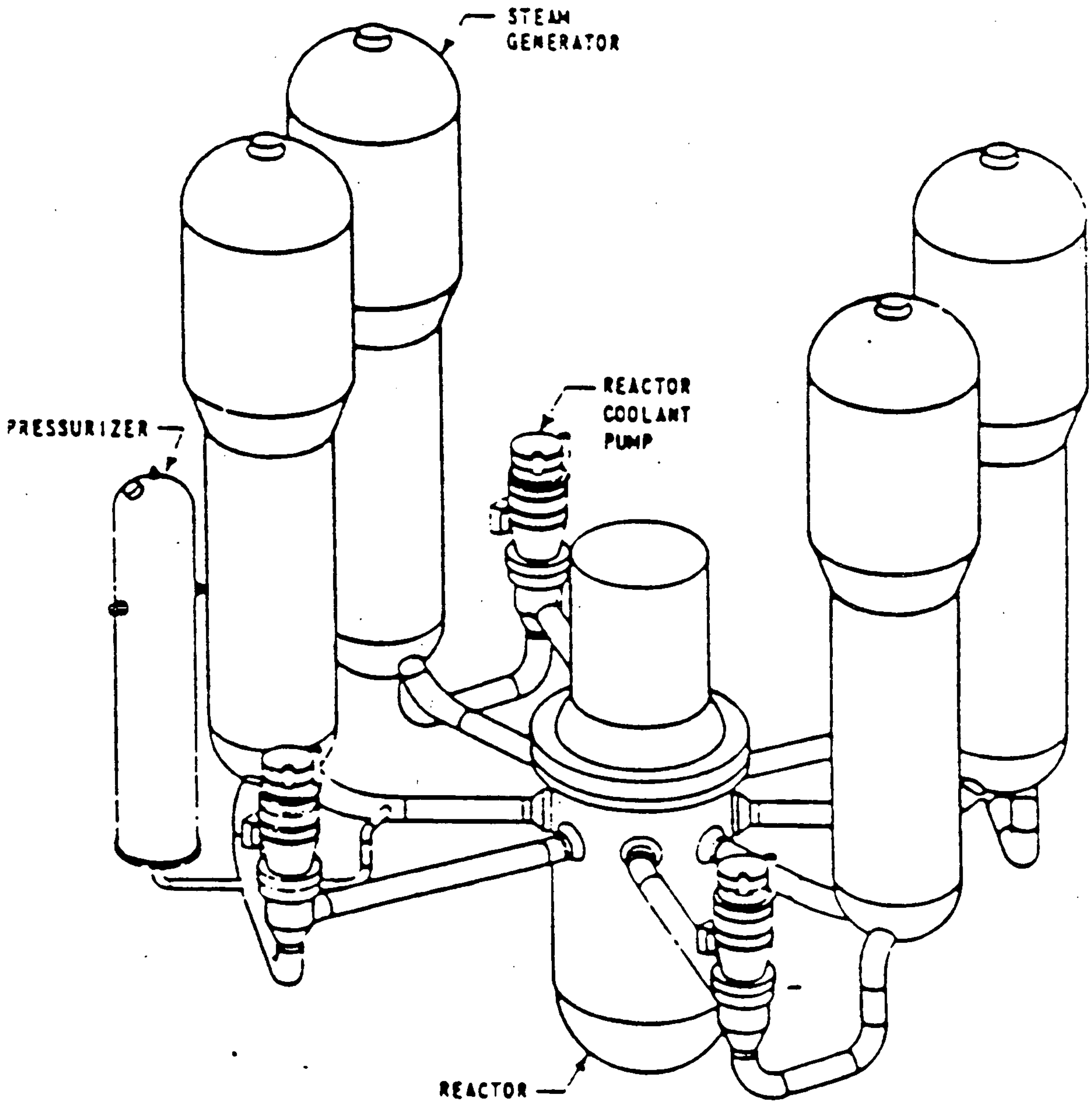


Figure 3.1-2
McGuire/Catawba Fuel Assembly

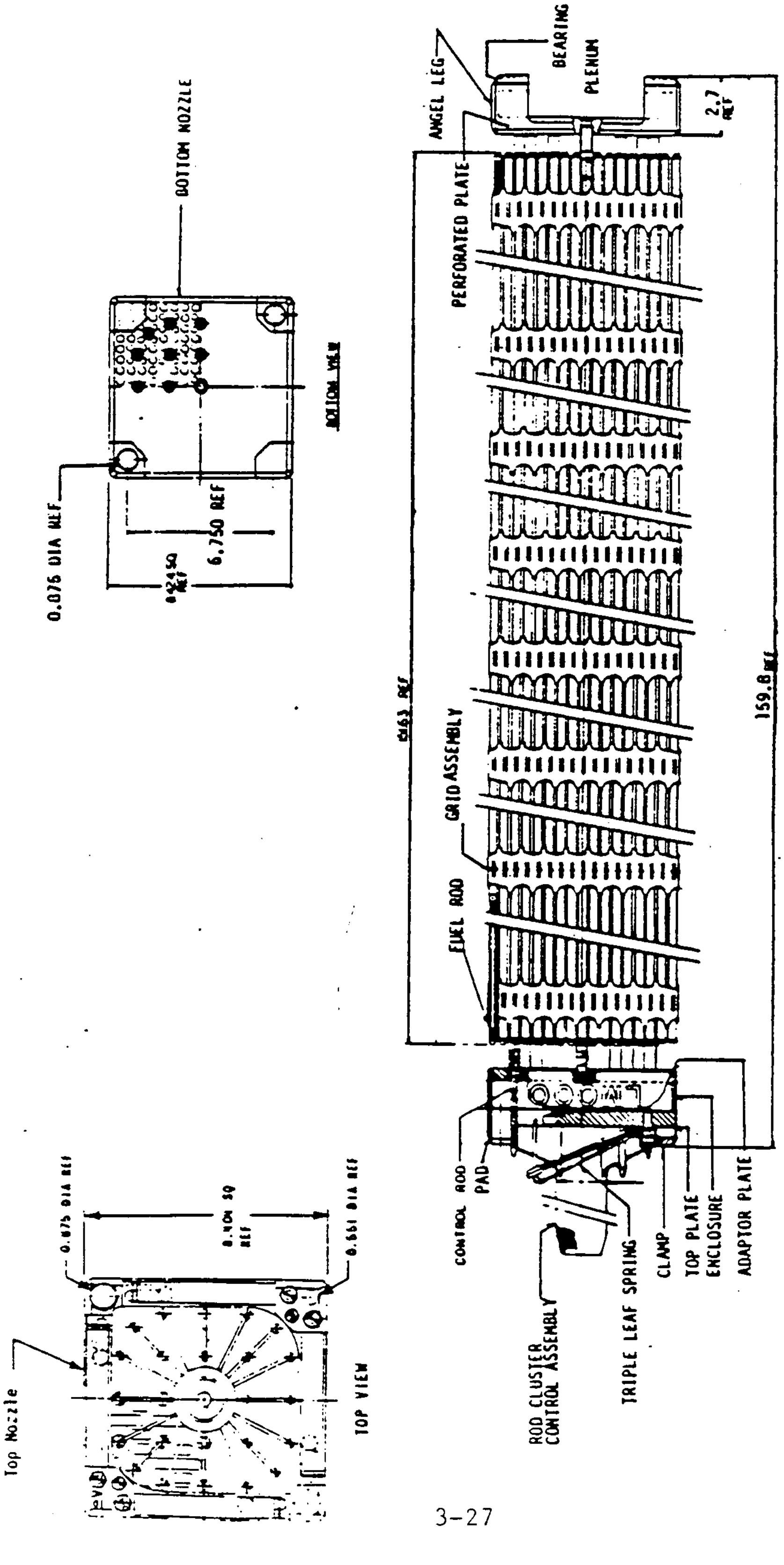
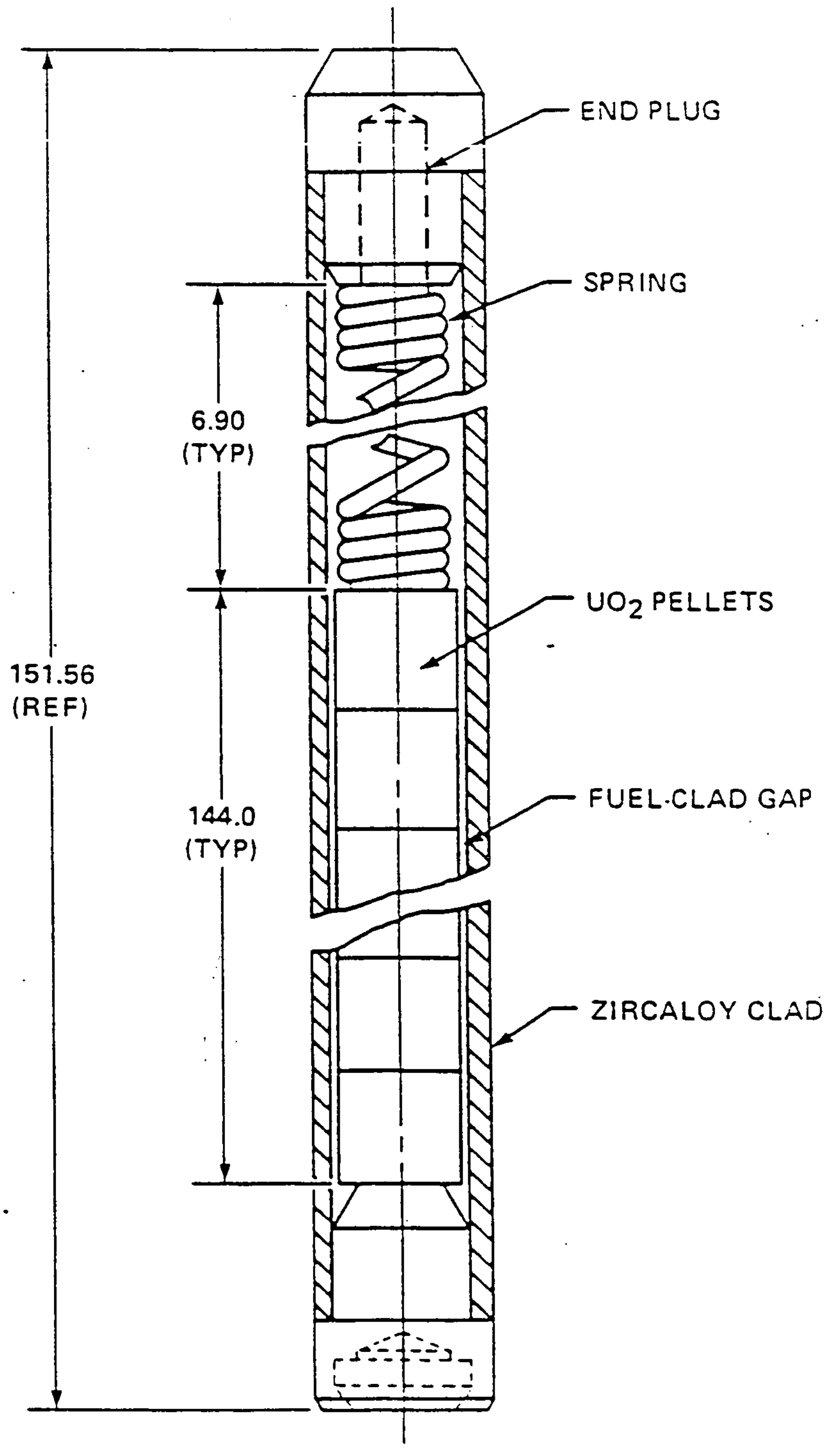


Figure 3.1-3
McGuire/Catawba Fuel Rod



SPECIFIC DIMENSIONS DEPEND ON DESIGN VARIABLES SUCH AS PRE-PRESSURIZATION, POWER HISTORY, AND DISCHARGE BURNUP

Figure 3.1-4
McGuire/Catawba Ag-In-Cd Rod Cluster Control Assembly

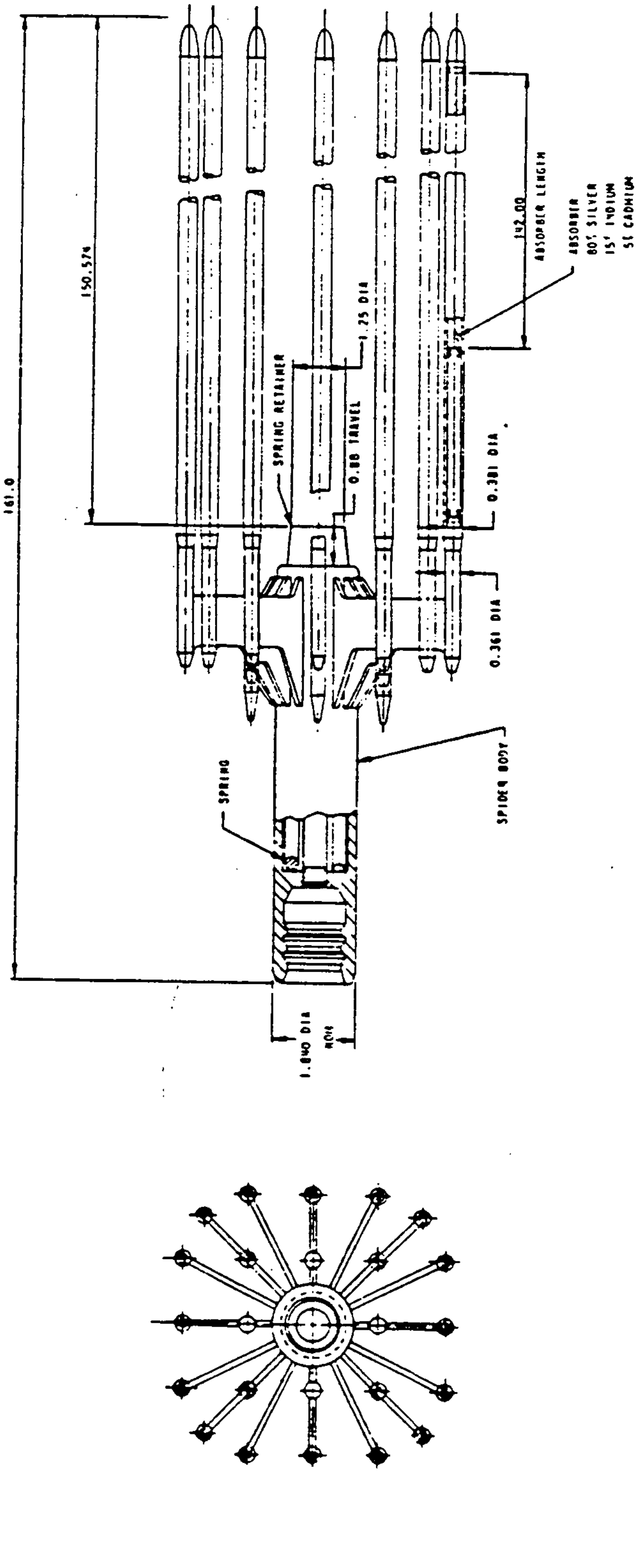


Figure 3.1-5
McGuire/Catawba B_4C Absorber Rod

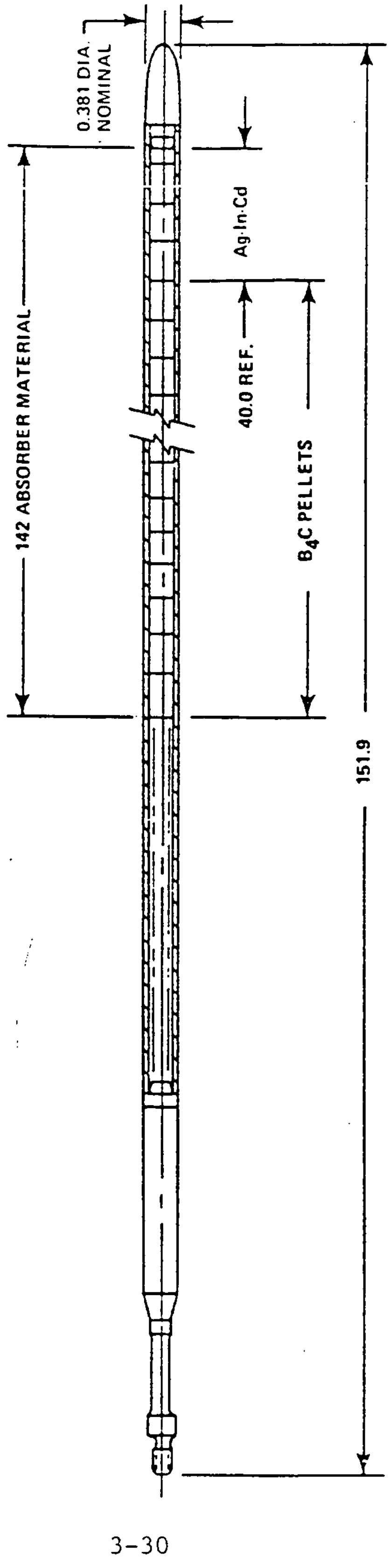


Figure 3.1-6
McGuire/Catawba Upper Internals

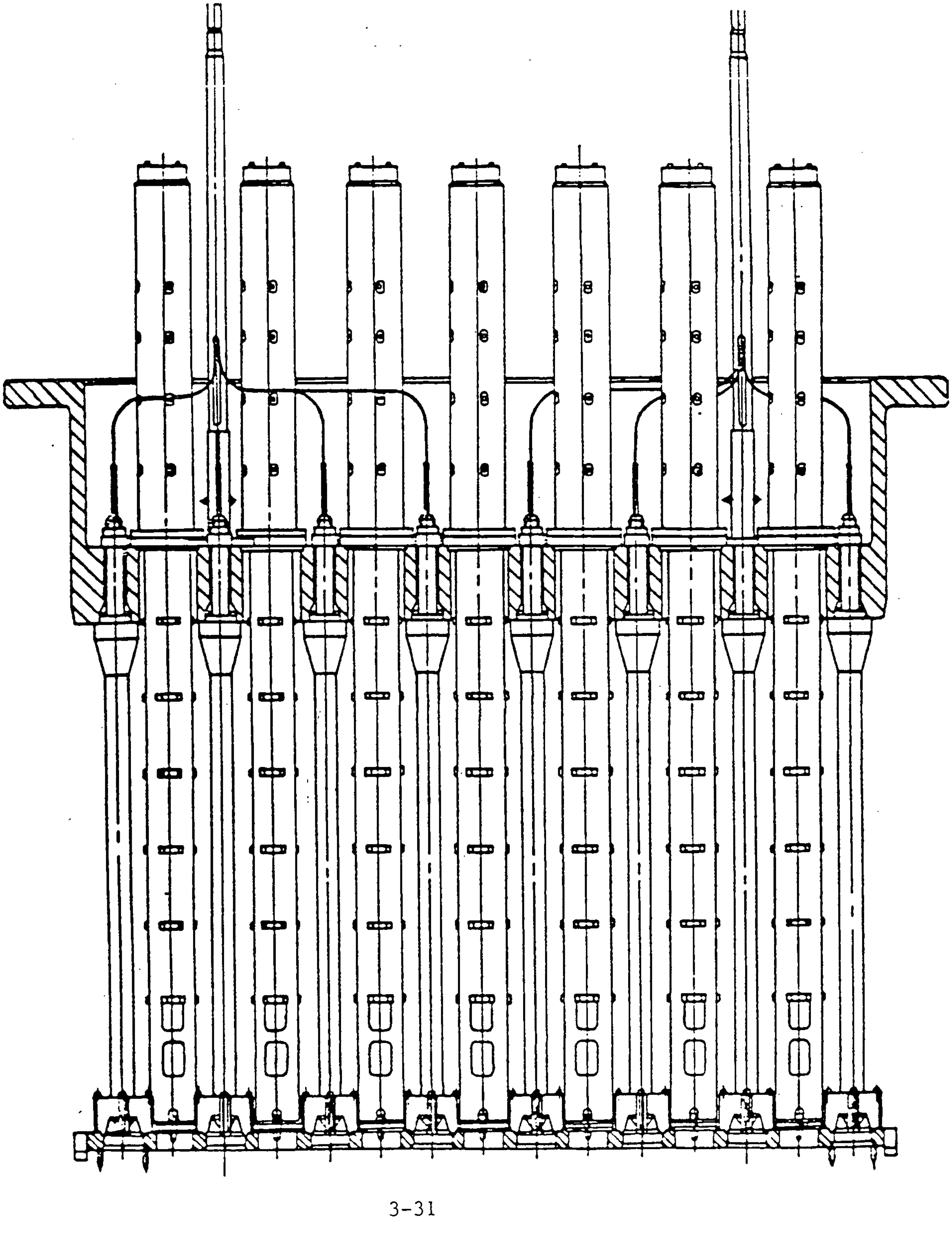
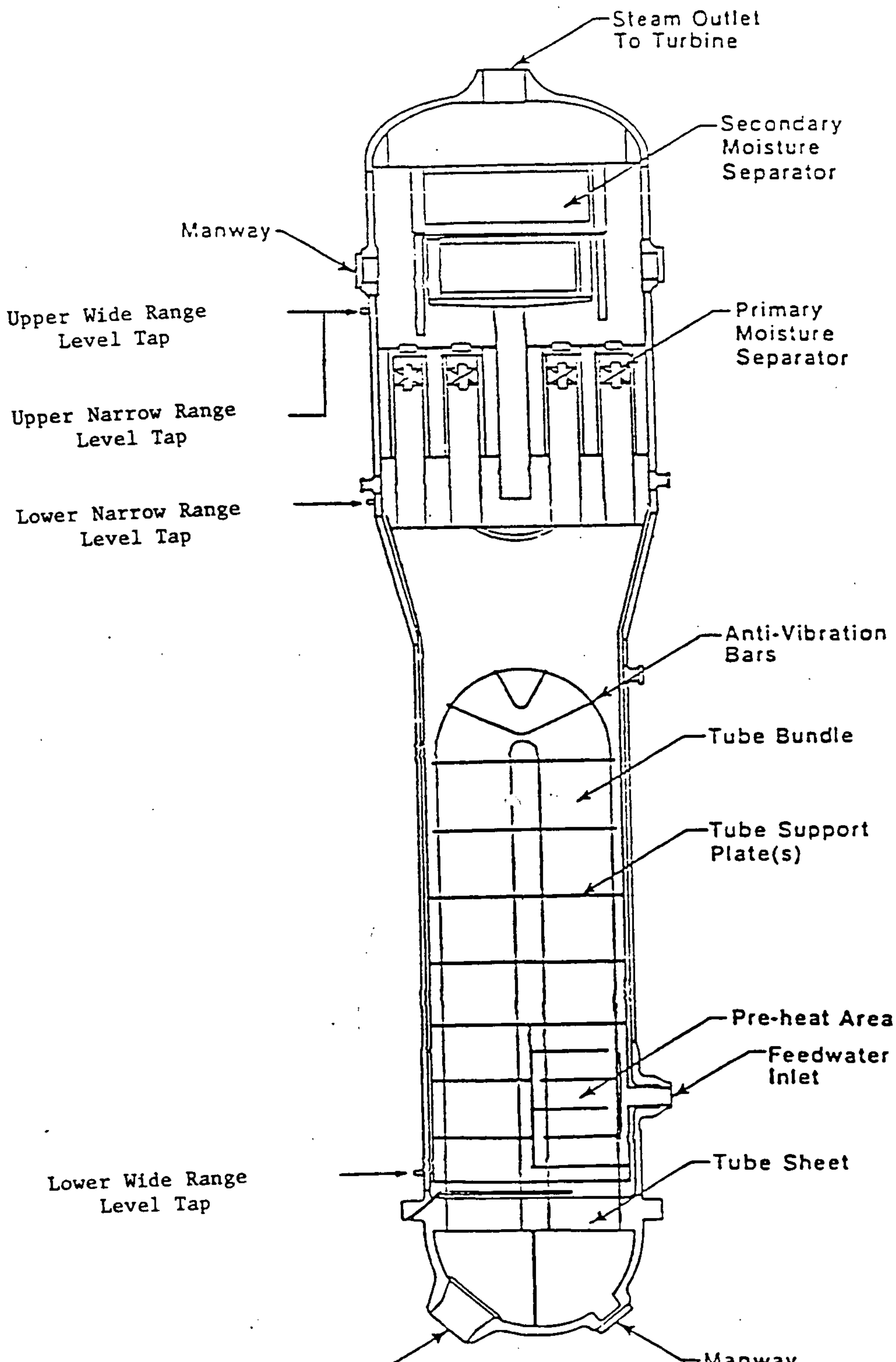
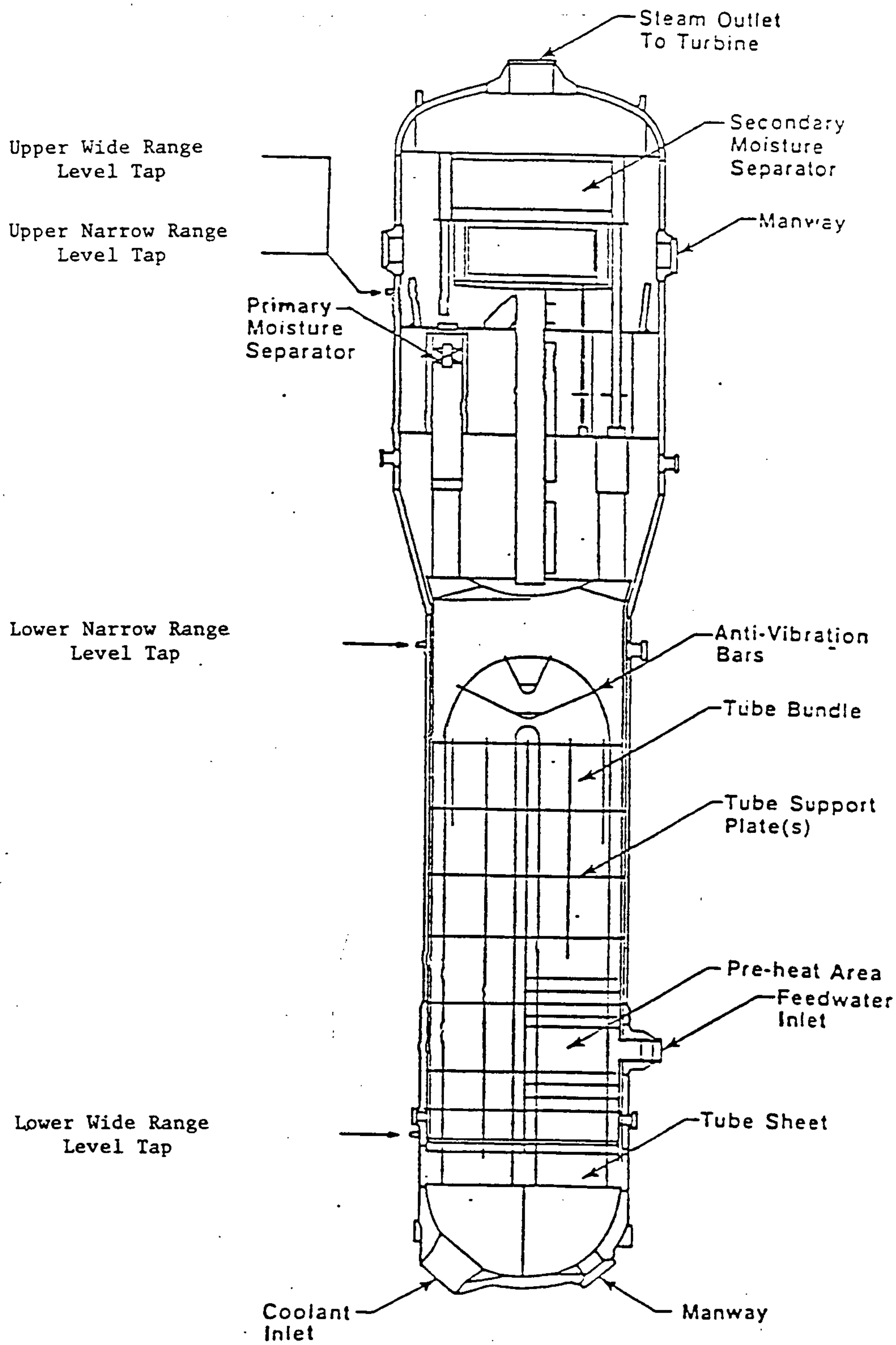


Figure 3.1-7
Counterflow Preheater Steam Generator



Counter Flow Preheat
Steam Generator
Catawba Unit 2

Figure 3.1-8
Split Flow Preheater Steam Generator



Split Flow Preheat
Steam Generator
McGuire Unit 1
McGuire Unit 2
Catawba Unit 1

Figure 3.1-9
McGuire/Catawba Pressurizer

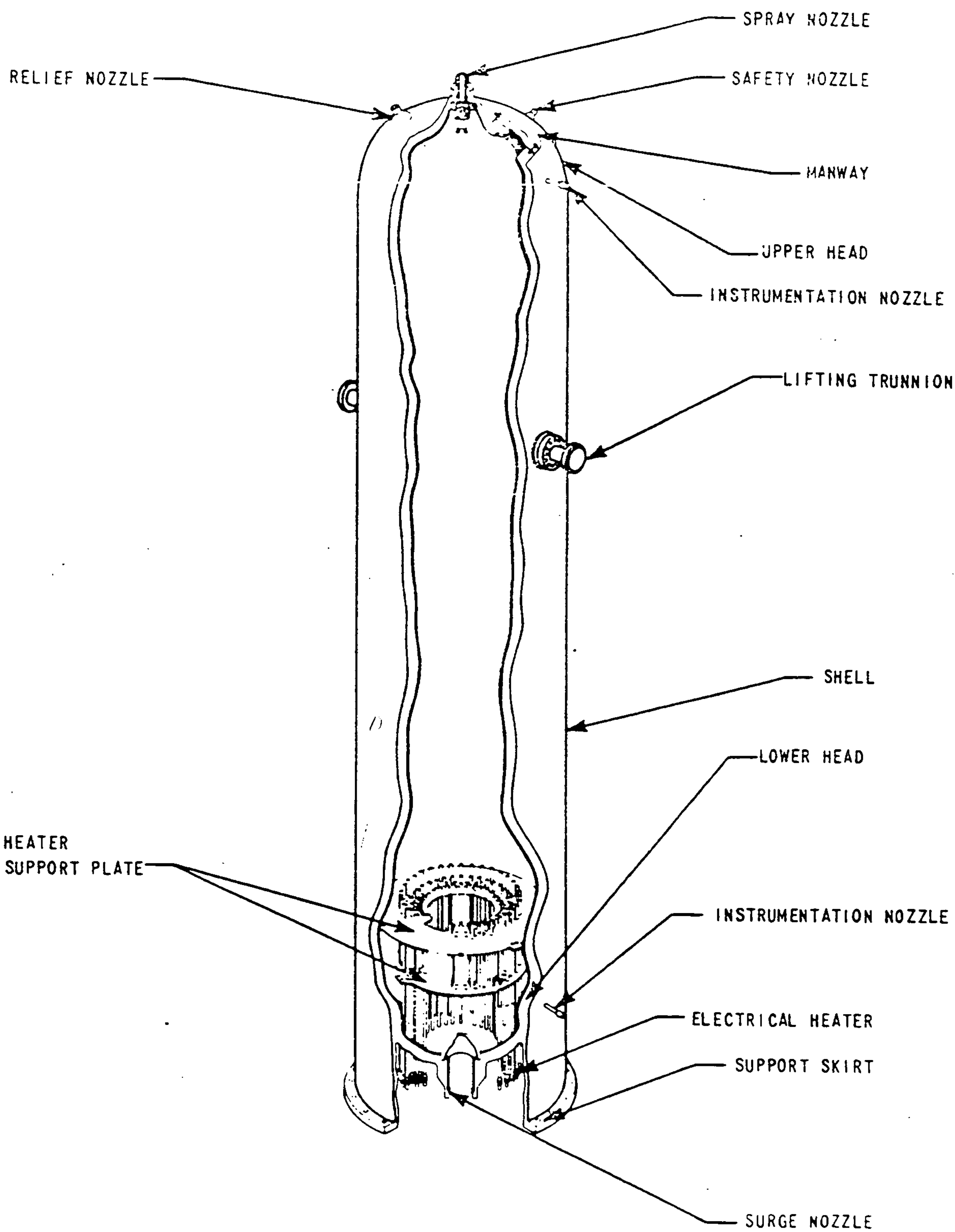


Figure 3.1-10
McGuire Main Steam Schematic

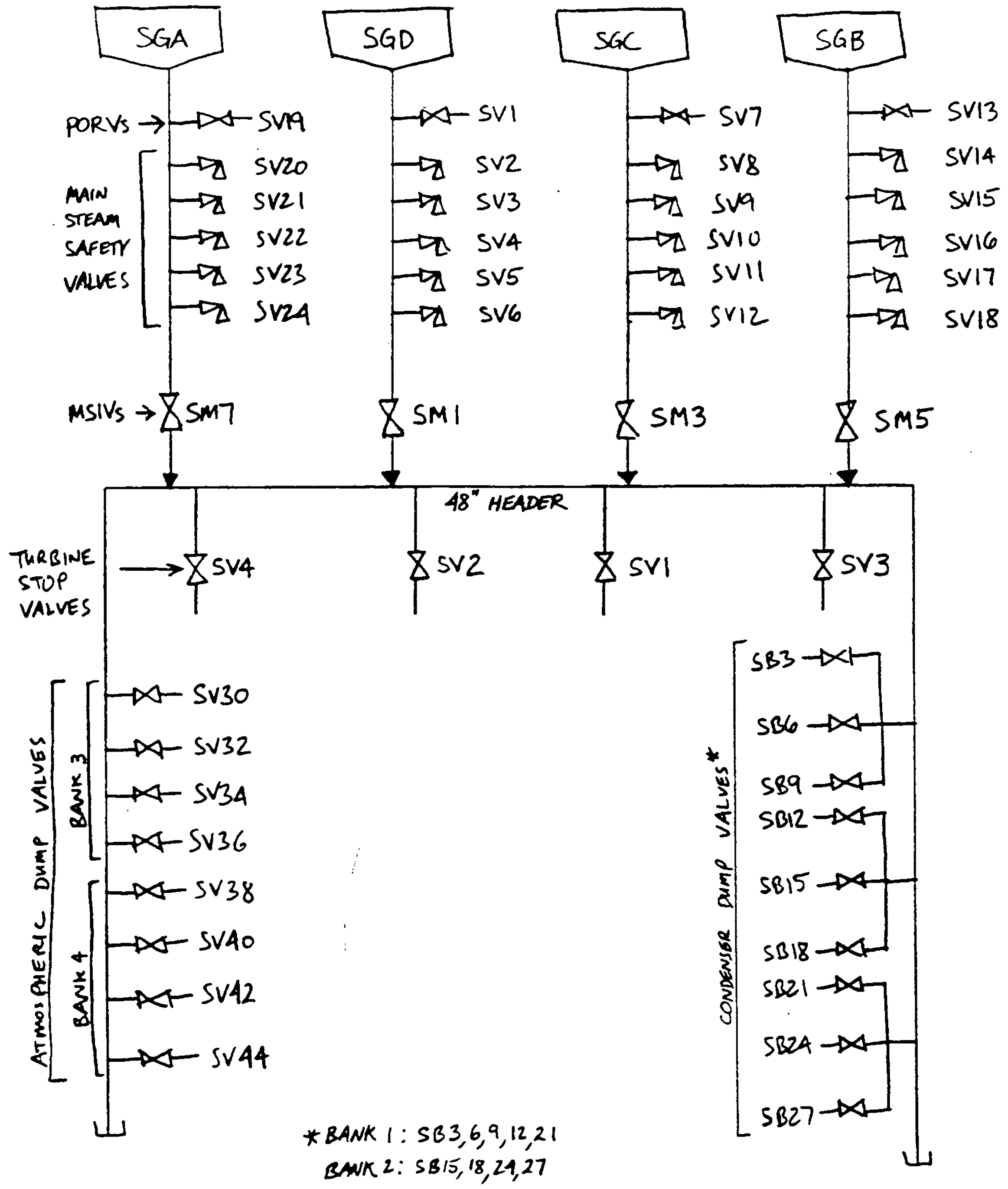


Figure 3.1-11
Catawba Main Steam Schematic

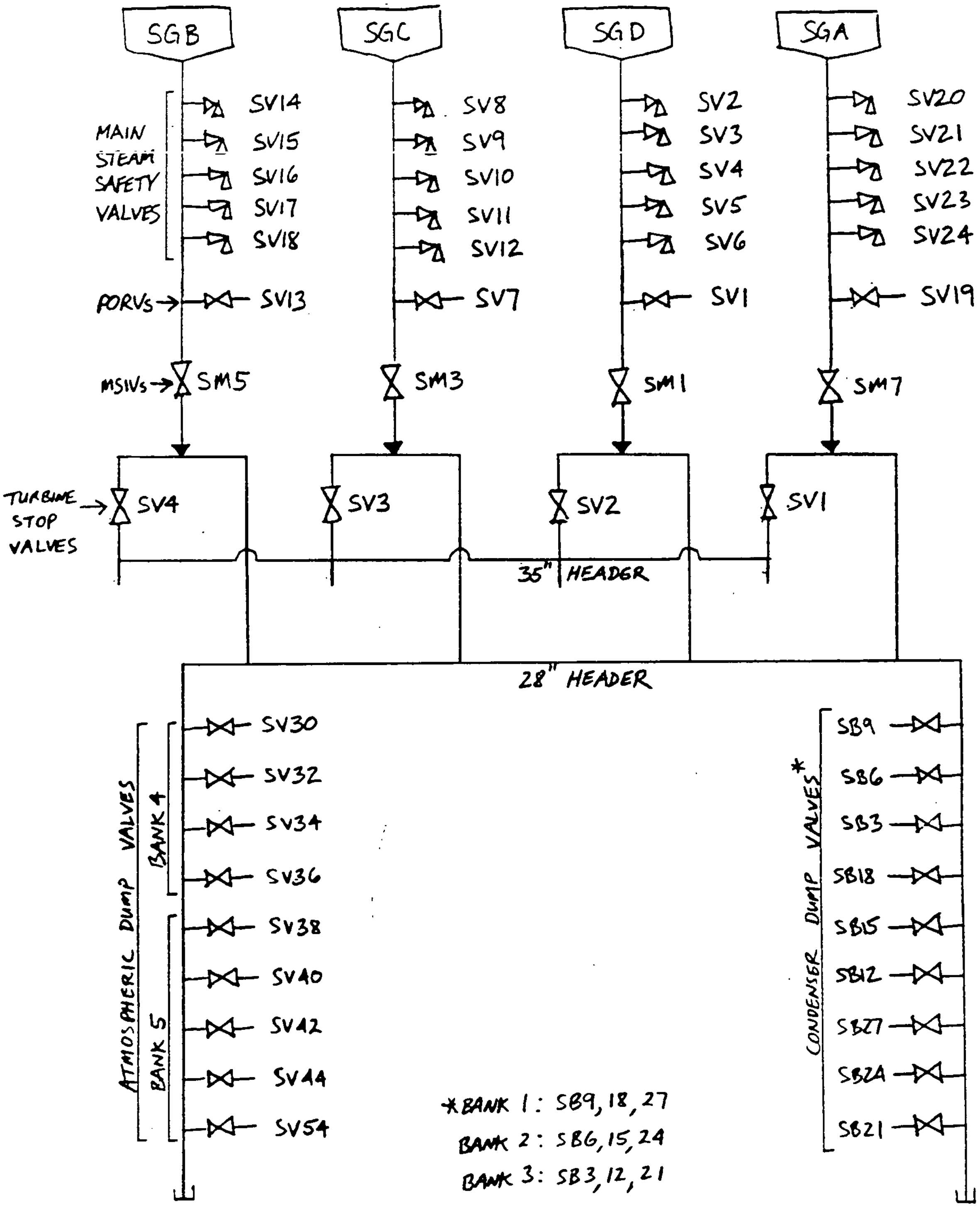
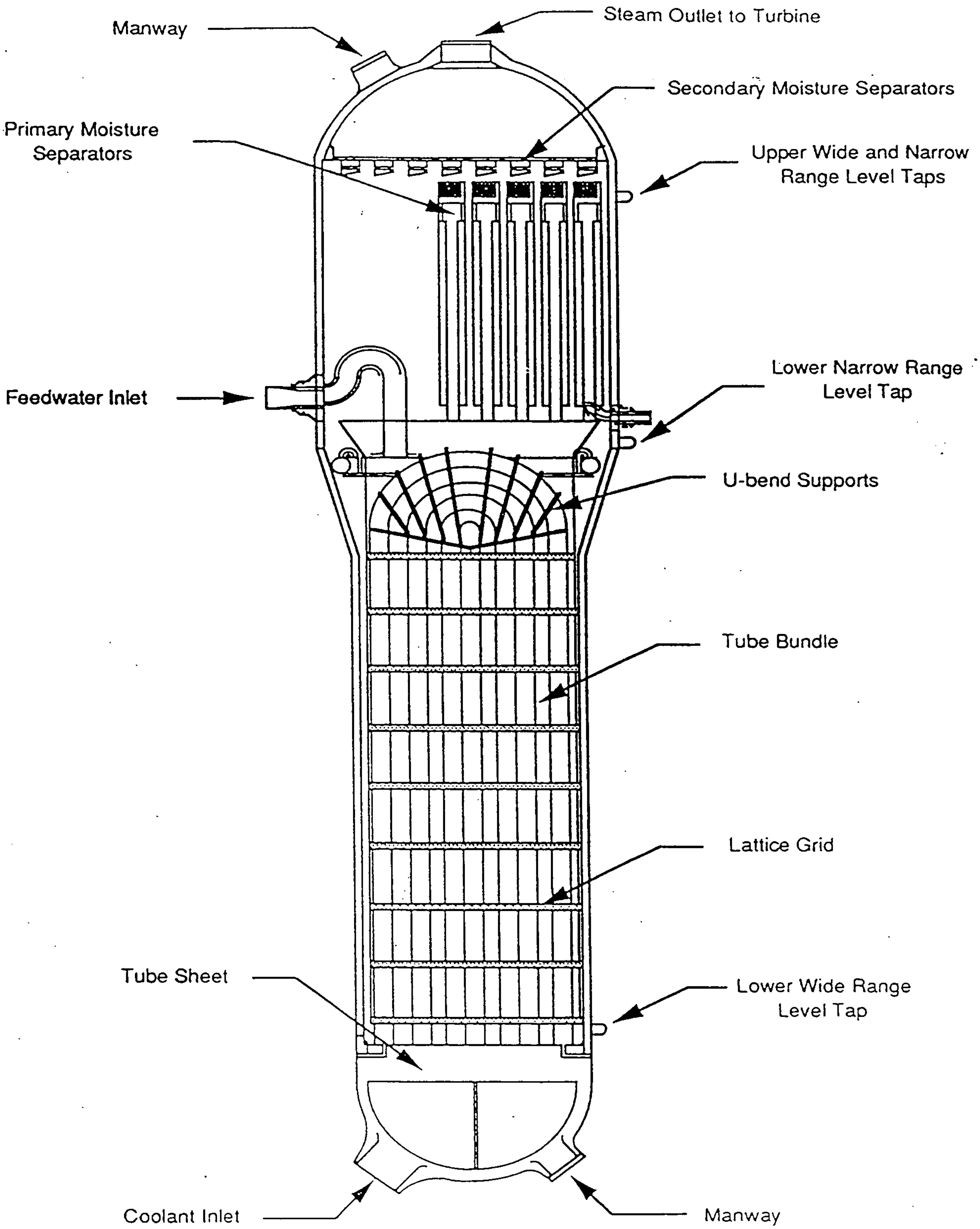


Figure 3.1-12
Replacement Steam Generator



Replacement Steam Generator

McGuire Unit 1
McGuire Unit 2
Catawba Unit 1

3.2 McGuire/Catawba RETRAN Model

The McGuire/Catawba RETRAN model nodalizations are shown in Figures 3.2-1 and 3.2-2 for the two-loop and one-loop models respectively. For feedring SG transient analysis, the feedring SG nodalization shown in Figure 3.2-3 replaces the preheat steam generator nodalization shown in Figures 3.2-1 and 3.2-2. The one-loop model is used for transients which exhibit a sufficient amount of symmetry. For certain applications the amount of detail is excessive and can be reduced to save computer time, while on occasion additional detail e.g., a three-loop model, is required.

The primary system model is symmetric relative to the two loops. The single-loop components (volumes, junctions, and conductors) have numbers in the 100s. The triple-loop component numbering scheme is the same, except that the numbers are in the 300s. Thus Volume 113 corresponds to Volume 313, the former being in the single loop and the later in the triple loop.

3.2.1 Primary System Nodalization

3.2.1.1 Reactor Vessel

The reactor vessel is modeled by[ ]fluid volumes. The boundaries between the volumes are chosen due to actual physical separations, or to provide an additional level of detail in the hydrodynamic calculation.

Downcomer

[

]. Flow enters through the four cold legs and exits into the lower plenum.

Lower Plenum

The reactor vessel lower plenum is represented by[

]Flow from the downcomer goes through the lower plenum into the core and the core bypass.

Core

[ ] represent the reactor core region from the[

] There is no physical separation between [

]. Flow enters from the lower

plenum and discharges into the upper plenum. The [ ] to provide a more accurate simulation of the temperature profile in the core at power.

Core Bypass

The core bypass region is modeled by [ ]. The bypass flow channels include the control rod guide tubes and instrument tubes inside the fuel assemblies. In addition, it includes the area between the core baffle plate and the core barrel which is exterior to the fuel assemblies. All of the bypass constituents are [ ]. The control rods are assumed to be [ ] Flow enters the bypass from the lower plenum and exits into the upper plenum.

Upper Plenum

The upper plenum of the reactor vessel, which extends from the [ ] In the upper plenum the coolant flows upward from the core and then turns radially outward to leave the vessel through the outlet nozzles. Another flowpath involving the upper plenum is the one between the lower portion of the upper plenum, just above the active fuel, and the control rod guide tubes and UHI support columns. Some flow goes through these structures into the vessel head.

Upper Head

The reactor vessel upper head is a large cylindrical and hemispherical region which extends between the upper plenum and the vessel head itself. It is modeled by RETRAN [ ] Flow enters the region through the [ ] unplugged spray nozzles from the top of the downcomer and leaves through the control rod guide tubes and UHI support columns. The only structural components in the interior of the upper head are parts of the Control Rod Drive System.

UHI Support Columns

The UHI support columns, cylindrical flowpaths from the lower part of the upper plenum to the lower part of the upper head, are represented [ ]. The flow column structure interior volumes are [ ]

Control Rod Guide Tubes

The control rod guide tubes, [ ] in the RETRAN model, extend from the top of the core through the upper support plate and discharge into the reactor vessel upper head. Some flow enters the guide tubes through slots in the tube sides in the upper plenum, while the rest of the flow comes directly from the fuel assemblies and control rod guide thimbles.

3.2.1.2 Reactor Coolant Loops

[ ] fluid volumes are used to represent the loop piping. In addition, [ ] to model each RCP. The volumes in the single loop are discussed here and correspond in location to the volumes in the triple loop.

[ ] represents the SG outlet piping to the RCPs.

[ ] by the RETRAN centrifugal pump model. The cold leg piping is simulated by [ ] extends outward from the pump and runs horizon-tally into the reactor vessel. The vessel inlet nozzles [ ].

3.2.1.3 Steam Generators

The SG volumes in the single loop are discussed here and correspond in location to the volumes in the triple loop. The SG inlet plenum is modeled by [ ]. The SG tubes are represented by [ ] The detailed nodalization allows an accurate simulation of the SG density gradient, which is an especially important consideration during natural circulation. The RETRAN [ ]. The percentage of plugged tubes that is modeled is specified based on the particular analysis. The SG outlet plenum, [ ], is similar to the inlet plenum. As with the inlet plenum, the fluid volume [ ].

3.2.1.4 Pressurizer

The McGuire/Catawba pressurizer is represented by [ ] connect it to the RCS. [ ], which runs from the bottom of the pressurizer to the B hot leg. [ ] models the pressurizer spray line, which connects each cold leg volume to the top of the pressurizer. The loss coefficients associated with [ ] The PORV and safety valve junctions are modeled at the top of the pressurizer.

Phase separation in the pressurizer is simulated by the [

]. In some cases an [
] between the liquid and vapor regions.

3.2.1.5 Cold Leg Accumulators

The four cold leg accumulators and their associated injection lines are [ ].
The RETRAN air model is used to simulate the nitrogen overpressure on top of the tanks.
[ ] allows the tanks to discharge when the RCS pressure drops below 600 psig.

3.2.2 Secondary System Nodalization

3.2.2.1 Main Feedwater Lines

[ ] represents the MFW lines between the [
] represents the MFW lines between the [ ] and the SGs.

3.2.2.2.1 Preheat Steam Generators

The preheat steam generator secondary side is modeled by a total of [ ] volumes. [
]. Both McGuire units and Catawba Unit 1 originally had split-flow preheat steam generators, which have [ ] full power feedwater flows out the top and side preheater outlets, [ ], respectively. Catawba Unit 2 has counter-flow preheat steam generators, which have [ ] during power operation. Flow through [

]

[ ]

The basis for the SG secondary nodalization is twofold. The tube bundle has been [ ] encountered there. The downcomer has been [ ]

The RETRAN [ ].

3.2.2.2.2 Feedring Steam Generators

The feedring SG secondary side is modeled by a total of [ ] volumes. The downcomer is

[ ]

[ ]

The basis for the FSG secondary nodalization is similar to that for the preheat SGs. The tube bundle [ ] encountered there. The downcomer has been [ ] The RETRAN [ ]

3.2.2.3 Main Steam Lines

[ ]. Downstream of the MSIVs the nodalization used is station and transient dependent. Section 3.1.3.3 describes the actual plant steam line layouts. Since flows from individual SGs at McGuire are not separated all the way to the turbine, [ ] At Catawba, [ ] at Catawba since the steam lines are separate between the MSIVs and the turbine stop valves. [ ] For load rejection transients the atmospheric dump header is modeled [ ].

The main steam lines are not physically different for the FSGs; however, the volume representing the main steam lines is [ ] for the FSG nodalization.

3.2.3 Heat Conductor Nodalization

3.2.3.1 Reactor Core

[ ] conductors are used to model the fuel rods in the reactor core. The conductors are separated into [ ]. Material properties (thermal conductivity and heat capacity) are [ ]. The fuel gap [ ] to give the [ ] fuel temperature, which varies with core average burnup. This approach is used to properly account for the stored energy in the fuel. The RETRAN core conductor model is used for these conductors in order to allow power generation in the fuel material. 2.6% of the power generated in the core is assigned to direct heating of the moderator rather than deposition of energy in the fuel pellets.

3.2.3.2 Steam Generator Tubes

[ ] heat conductors are used to represent the tubes in each of the SGs. There is [ ]. Material properties are [ ]

3.2.3.3 Structural Conductors

These conductors represent the plant components which do not generate power or conduct heat from the primary to the secondary, but which can affect the plant transient response by transferring energy to or from the working fluid. The stored energy and heat capacity of these conductors tend to dampen changes in RCS conditions. During an overcooling event the structural conductors transfer heat to the primary coolant and thus retard the cooldown. Conversely, during an overheating transient the structural conductors act as a heat sink and reduce the magnitude of the increase in the primary coolant temperature. The effect of the structural conductors is most apparent during long transients. During short transients which do not exhibit severe undercooling or overcooling, the heat transferred from the structural conductors is unimportant relative to the large amount of decay heat in the core. However, the structural conductors represent a significant heat load for long-term cooldown, once decay heat has decreased.

The key parameters for the structural conductors are the mass and the heat transfer area. These determine the initial stored energy and the effectiveness as a heat source or sink. In order to [ ]

[

]

Certain structural components are not included in the model because they are considered to have no potential impact on the plant transient. These components include the [

]

Passive heat conductors representing the pressurizer walls [ ] in the McGuire/Catawba model. The pressurizer vessel metal is [

].

The McGuire and Catawba tubesheet for both the preheat SGs and the feedring SGs is modeled by [

]

The heat conductors which are used in the McGuire/Catawba base model are listed and described in Table 3.2-1. The heat conductors which are used in the FSG model are listed and described in Table 3.2-2.

3.2.4 Control System Models

3.2.4.1 Process Variable Indications

RETRAN control systems are used to take the calculated plant thermodynamic conditions and put them into the form in which they are output by the plant instrumentation. This provides indications which are useful for comparison to plant data and which are familiar to the plant operators and engineering personnel.

Pressurizer Pressure

The fluid pressure at the elevation of the pressurizer upper pressure tap is converted to gauge pressure by subtracting 14.7 psi. This pressure is used as input to RPS and ESF functions in the model.

Pressurizer Level

The cross-sectional area of the RETRAN pressurizer volume is different than that of the plant pressurizer. This is due to the fact that the plant pressurizer is a right circular cylinder plus hemispherical top and bottom sections, while RETRAN volumes are right circular cylinders. Therefore, a control system is used to relate the pressurizer liquid level in the model to the level that would be indicated at the plant. This level is input to the interlock which turns off the pressurizer heaters on low pressurizer level and to the high pressurizer level reactor trip.

Wide Range RCS Loop Temperatures

The wide range hot leg and cold leg temperatures are indicated by RTDs located in thermowells in the loop piping. A change in fluid temperature is not indicated immediately at the plant due to the time required to transfer heat through the thermowell to the RTD and change the temperature of the measuring device. Experimental data indicates that the time delay can be approximated by a[ ]applied to the actual fluid temperature.

Narrow Range RCS Loop Temperatures

The narrow range hot leg and cold leg temperatures, as well as the average temperature and ΔT signals, are derived from RTDs located in bypass piping connected to the main coolant loops. A change in fluid temperature is not indicated immediately at the plant due to the time required for the change to propagate through the bypass loop and to change the temperature of the measuring device. Experimental data indicates that the time delay can be approximated by a[ ]applied to the actual fluid temperature. To simulate average temperature and ΔT indications, [ ] is applied consistent with the plant Technical Specifications since the control room indications are the same signals as those used for the RPS.

Steam Line Pressure

The volume pressures[ ]. This pressure is used as an input to the ESF functions in the model.

SG Level

The narrow range and wide range SG level instruments display level from 0-100%, as shown on Figures 3.1-7, 3.1-8, and 3.1-12. The level indication is derived from the pressure difference between taps in the steam generator. A RETRAN control system is used to simulate this process using the [ ]. The output narrow range level indication is input to the RPS and ESF functions in the model. The wide range indication is used for information only. Control system simulated level indications [ ].

3.2.4.2 Reactor Protection System Functions

Four RPS functions are modeled with control systems:

1) Overtemperature ΔT
2) Overpower ΔT
3) Low pressurizer pressure
4) Low-low SG narrow range level

The control systems for the ΔT trips compute the appropriate ΔT setpoints based on the Technical Specification equations and subtract the indicated ΔT values from these setpoints to determine whether trip occurs. The overtemperature ΔT trip equation reduces the ΔT setpoint for low coolant pressure and high coolant temperature to protect against departure from nucleate boiling. The overpower ΔT trip equation reduces the ΔT setpoint for high or increasing coolant temperature to protect against centerline fuel melt. Both ΔT trip equations also reduce the setpoints for excessive axial flux imbalance, [ ]. Lead-lag compensation is applied to the low pressurizer pressure reactor trip via a control system before the relevant value is compared against a fixed setpoint. The low-low SG narrow range level trip setpoint is a lagged programmed function of neutron flux for the preheat SGs. The feedring SG low-low narrow range level trip setpoint does not vary with neutron flux. A lagged value of indicated level is then compared with the setpoint to determine whether trip occurs.

3.2.4.3 Engineered Safeguards Functions

Four ESFAS functions are modeled with control systems:

1) Steam line isolation on low steam line pressure
2) ECCS pump start on safety injection
3) AFW pump start on low-low SG narrow range level
4) Turbine trip and MFW isolation on high-high SG narrow range level

The first three actions are coincident with reactor trip and use the same control systems. The fourth function is similar to the reactor trip on low-low SG narrow range level but uses a higher setpoint.

3.2.4.4 Plant Control Systems

RETRAN control systems are used to model the performance of certain plant control systems during transient analyses. These control systems fall into two general types. Some control systems, examples of which are given below, are modeled directly as designed. Other control systems are modeled indirectly. Indirect modeling is used when the desired control system action is known beforehand. This method saves time over direct modeling and can also be used to simulate controller action with undocumented setpoints, e.g. a field adjusted gain setting, or with failed components, e.g. a valve which cycles erratically.

Pressurizer Pressure Control
A proportional plus integral controller is used which models the actual plant controller including setpoints, signal range limits, and anti-windup limits.

Rod Control
The actual plant controller is modeled in detail for transients in which automatic rod control is deemed to be important. Since the turbine is not modeled in general, the turbine dependent Rod Control System inputs are predicted separately if unknown or are input from plant data if available.

Steam Dump Control
The actual plant controller is modeled with a [
] the opening and closing of the dump valves.

3.2.4.5 Transient Boundary Conditions

The RETRAN control system models can effectively model known or postulated transient boundary conditions, such as those resulting from operator action. In general, RETRAN control

systems simulate control actions by modulating valves, changing positive or negative fill flow rates, changing reactivity, and activating or defeating trips.

Operator actions significantly affect the plant response during almost all realistic plant transients. Experience at McGuire and Catawba has shown that the operators will promptly take action in order to prevent reactor trips or, failing that, to ensure a normal post-trip response. Following a trip, the operators monitor AFW flow to ensure that proper SG level is achieved. The normal procedure to simulate [

].

3.2.5 Boundary Condition Models

3.2.5.1 Fill Junctions

Fill junctions are used to specify flow between a volume and an infinite source or sink. Positive fill junctions provide flow into a volume, while negative fill junctions remove mass from a volume. The flow rate can be specified as a function of time or of pressure in the volume, or it can be controlled by a control system.

Systems which provide flow to the RCS or the SGs are modeled by [ ]. These include MFW, AFW, HHSI, and IHSI. The flow of steam through the turbine control valves is modeled by [ ]. For most applications there is a reactor trip at the beginning of the problem, either immediately before or after a turbine trip, so the steam flow to the turbine is cut off. For applications which do not involve a rapid turbine trip, the flow through the steam line [

].

3.2.5.2 Critical Flow and Fixed Pressure Boundary Conditions

The RETRAN critical flow model, in conjunction with a fixed pressure boundary condition volume, is used to model flow through relief valves on the RCS and the main steam lines. Relief valves are modeled by junctions between the associated upstream volumes and the fixed pressure volume, which is an essentially infinite sink with a user-specified backpressure. The Henry (subcooled) and Moody (saturated) choking option is used with the relief valve junctions. Because of the large pressure differences between the upstream volumes and the fixed pressure volume, RETRAN calculates any flow through the junctions to be choked. Since the design flow

rates of saturated steam through the valves are known, the [

]. The choked flow model then automatically calculates the flow rate as the fluid conditions in the upstream volume change. This modeling technique is used for the [

].

3.2.6 Code Models

3.2.6.1 Power Generation

RETRAN offers the user several options for modeling core power generation. Several different methods are used, depending on the application. For a best estimate transient analysis, the point kinetics model is generally used. This model calculates neutron power assuming that the flux shape is constant while the magnitude changes with time. The code uses one prompt neutron group and six delayed groups. A moderator temperature coefficient and a fuel temperature coefficient are used to account for reactivity feedback from changes in those parameters. Control rod scram worths are input in order to model reactivity insertion after reactor trip. Post-trip decay heat energy is calculated with a model of eleven delayed gamma emitters, plus a contribution for heavy element (U-239 and Pu-239) decay. The resulting decay heat is a close fit to the proposed 1971 ANS Standard (Reference 3-1). The point kinetics model is adequate for most PWR applications.

For a benchmark analysis in which [

]

3.2.6.2 Centrifugal Pumps

The RETRAN centrifugal pump model is used to simulate the performance of the RCPs. The input data are from the pump technical manuals with the exception of the [

]

[

]

3.2.6.3 Valves

The basic RETRAN valve model is used for most of the valves in the McGuire/ Catawba base model. With this model the valves open and reseat according to the action of their associated trips. Modeled in this manner are the pressurizer and steam line PORVs and safety valves, the cold leg accumulator discharge check valves, the turbine stop valves, the MFW isolation valves, and the MSIVs. The condenser dump and pressurizer spray valves use the RETRAN valve model option in which the junction area is controlled by a control system.

3.2.6.4 Phase Separation

RETRAN has two methods of modeling phase separation within a fluid volume: the bubble rise model and slip. The bubble rise model is [ ] in the McGuire/Catawba model, while slip [ ] used.

The bubble rise model is a correlation which allows the enthalpy in a volume to vary with height. It is a semi-empirical fit to data from a number of high pressure blowdown experiments. The void fraction in the volume is assumed to vary linearly with height from the bottom of the volume to the mixture level. Above the mixture level, the fluid is 100% steam. The model is [ ] which have a definite separation between vapor and liquid, i.e. the [ ]. In addition, the bubble rise model is [ ]

Slip models provide for unequal velocities between the liquid and vapor phases. Since McGuire and Catawba are PWRs with subcooled water in the primary coolant loops, unequal phase velocities normally exist only in the steam generator secondary side. RETRAN has two slip models: algebraic slip and dynamic slip. The algebraic slip model uses a drift flux approach to calculating the relative velocity between the vapor and liquid phases. The dynamic slip model is

[

]

For applications in which there is significant voiding and phase separation in the primary system (notably small break LOCA or extended loss of feedwater), the dynamic slip model can provide a reasonable simulation of two-phase phenomena in the RCS.

3.2.6.5 Non-Equilibrium Pressurizer

RETRAN has a general non-equilibrium volume option which can be used with any bubble rise volume. This option allows the liquid and vapor regions of the volume to have different temperatures. The [

]

Accurate modeling of the pressurizer is necessary to correctly predict the transient RCS pressure response. During normal operation the pressurizer is at near equilibrium conditions - heat from the pressurizer heaters balances condensation from pressurizer spray bypass flow and ambient heat losses - so both the liquid and vapor regions of the pressurizer are essentially at saturation. During a pressurizer outsurge, such as that characteristically seen immediately following reactor trip, the pressure decreases as the steam bubble expands. Bulk flashing of the saturated liquid occurs as the pressure decreases, and the temperature in the liquid decreases with the pressure along the saturation line. In both cases the standard RETRAN homogeneous equilibrium model (HEM) technique will adequately simulate pressurizer phenomena.

During a pressurizer insurge, however, non-equilibrium effects can be significant. Subcooled water from the hot leg mixes with the saturated water in the pressurizer liquid region to produce a somewhat subcooled liquid region or, in some cases, a layered effect of saturated water over subcooled liquid. As the liquid level increases the steam bubble compresses and, since the steam behaves like an ideal gas, the temperature increases. The overall result is superheated steam above subcooled liquid, separated by a layer of saturated water. Since the temperature of the steam is higher than both the liquid and the pressurizer walls, the steam will tend to condense on the metal and the steam-water interface, reducing the pressure and temperature of the vapor. A one volume HEM representation of the pressurizer would instantaneously mix the subcooled fluid from the hot leg with all of the saturated fluid in the pressurizer, and it would not account for the different temperatures in the liquid and vapor regions. It is evident that a HEM representation of the pressurizer cannot account for the important phenomena during an insurge.

Use of the non-equilibrium option enhances the ability of a one volume pressurizer model to simulate the transient response during an insurge. Since the liquid region is considered separately from the steam bubble, an insurge does not result in rapid condensation of the pressurizer vapor. The non-equilibrium option allows the steam bubble to superheat during an insurge. The non-equilibrium option also includes the ability to specify a heat transfer coefficient between the pressurizer vapor and liquid regions, so interphase heat transfer can be modeled. However, this model is somewhat non-mechanistic, since the heat transfer coefficient is user-input rather than being calculated based on fluid conditions.

Another facet of the non-equilibrium representation is the pressurizer spray junction model. Using the spray junction option causes the spray water to condense steam while moving through the pressurizer steam bubble, thus removing both energy and mass from the region, rather than simply mixing with fluid in the vapor region and desuperheating the steam. The spray junction model is used since it is considered to be more mechanistic than a normal junction for this application.

The non-equilibrium pressurizer model is used for best estimate safety analyses on McGuire and Catawba. This model does not fully account for condensation effects in the pressurizer steam space and thus overpredicts RCS pressure during an insurge. However, it is superior to an equilibrium modeling approach. For some applications it is appropriate to use [

]

3.2.6.6 Non-Conducting Heat Exchangers

The RETRAN non-conducting heat exchanger model allows energy to be transferred to or from a fluid volume without using a conductor. This model is used to simulate the energy addition to the pressurizer liquid from the pressurizer heaters. Two heater banks are modeled. Bank C is controlled by a proportional plus integral controller in the plant. Since RETRAN [

] Banks A, B, and D in the plant have simple on/off control which is duplicated in RETRAN. The total capacity of

Bank C [

]

It is also possible to use a non-conducting heat exchanger to model the [

]

3.2.6.7 Local Conditions Heat Transfer

The local conditions model allows the approximation of variable heat transfer in a volume in which void fraction varies substantially with elevation, particularly in the case of a separated volume with a variable mixture level. This model [

]

3.2.7 Code Options

3.2.7.1 Steady-State Initialization

The RETRAN steady-site initialization option is used to obtain stable initial conditions for each transient analysis. This option greatly simplifies the specification of the initial conditions of a RETRAN run. The steady-state initialization routine solves the mass, momentum, and energy equations without the time-dependent terms and thus obtains consistent initial values with a minimal amount of input data.

Primary system conditions for McGuire/Catawba models are set by specifying [

]

[

]

The initial SG power removal fraction is set at 0.25 for each generator in order to provide a symmetric initialization.

3.2.7.2 Iterative Numerics

The iterative numerics option is used for time step control. Iterative numerics is a semi-implicit numerical solution method which allows the results of the time step advancement to be evaluated before the solution is accepted. Predictive algorithms are used to calculate an appropriate time step size which will give a stable, accurate solution to the fluid conservation equations. If a converged solution is not achieved in a given number of iterations, a reduced time step size is used. This is similar to restarting a job with smaller time steps, but it has the advantage of being automatic.

3.2.7.3 Enthalpy Transport

The enthalpy transport option is used to account for situations in which the fluid in a volume exchanges a significant amount of energy with an external source or sink. In those situations, the fluid enthalpy will vary between the volume inlet, center, and outlet, and the enthalpy transport option accounts for this variation. The option is used [

].

The enthalpy transport option is useful in obtaining a good steady-state initialization at full power conditions. However, it can lead to anomalous results in low flow, low heat transfer situations, particularly in the two-phase volumes on the secondary side of the SG. When this situation occurs, the enthalpy transport option may be turned off during a generalized restart.

3.2.7.4 Temperature Transport Delay

The temperature transport delay option accounts for the fact that temperature changes move through piping as a front, while the finite difference HEM approach instantaneously and homogeneously mixes the incoming fluid with the contents of a volume. Using the temperature transport delay option with a volume treats the movement of fluid more mechanistically by establishing a mesh substructure within the volume to track temperature front movement.

The temperature transport delay option is used for [

]

3.2.7.5 Heat Transfer Map

Two sets of heat transfer correlations are available for use with RETRAN02. The forced-convection map is a set of heat transfer correlations which cover single-phase, two-phase, and supercritical fluid conditions. The correlations are generally appropriate for the fluid velocities associated with forced flow. The combined map uses the same heat transfer relationships as the forced map, except that correlations more appropriate for low flow conditions are used if the Reynolds number is less than 2500 (single-phase) or if the mass flux is less than 200,000 lbm/ft^2-hr (two-phase). The combined map also includes a correlation for condensation. The [ ] for McGuire/Catawba transient analysis.

3.2.7.6 Film Boiling

The available correlations for use in the film boiling heat transfer regime include Groeneveld 5.7, Groeneveld 5.9, and Dougall-Rohsenow (Reference 3-3, Section 111.3.2.5). The Dougall-Rohsenow correlation is based on liquid flow at low pressure. Groeneveld 5.9 is based

on data from vertical and horizontal flow in round tubes and vertical flow in annuli, while Groeneveld 5.7 is based on the annuli data alone. [ ] is used in the McGuire/Catawba model because it is considered that the basis of that correlation is most similar to situations which would be encountered during PWR transients. The choice of the film boiling correlation is [

] initial conditions.

3.2.7.7 Critical Heat Flux

There are three options for the calculation of critical heat flux. The default option for the combined heat transfer map is a combination of four correlations: B&W-2, Barnett, and modified Barnett for high flow rates and Kutateladze for low flow rates. A General Electric correlation or a Savannah River Laboratory correlation may be specified instead of the high flow rate-portion of the default option. These correlations are discussed in Reference 3-3, Section 111.3.2.5. The McGuire/Catawba model employs the [

] initial conditions.

3.2.7.8 Volume Flow Calculation

The [ ] option method is used for calculating the volume flow for momentum flux. This choice is [ ].

3.2.7.9 Wall Friction

RETRAN calculates the pressure drop due to wall friction using the Fanning friction factor, which is a function of Reynolds number. Several options are available to model the change in wall friction due to two-phase effects. The Baroczy, homogeneous, or Beattie multipliers can be applied to the calculated single phase pressure drop. The [ ] model is used in the McGuire/Catawba RETRAN model.

3.2.7.10 General Transport Model

The general transport model is used to calculate the boron concentration in [

] The boron is assumed to be soluble in the transport medium and to have no direct effect on the fluid equations. The basic equation computes the time rate of change of boron mass in a control volume from the net inflow through connected junctions.

3.2.8 Dissimilarities Between Units

The differences in RCS loop geometry are significant enough to warrant separate base models for each unit. For a given unit model the coolant loops are lumped or separated depending on the asymmetry of the transient being analyzed. Differences between units, including the major differences discussed in Section 3.1.6, are included in unit specific models depending on the degree to which such differences affect the transient being analyzed.

3.2.9 Summary of Experience

The major positive conclusions concerning the applications of the code and its models are listed below.

- The basic constitutive equations accurately describe the fluid behavior in the RCS and SGs during operational transients.

- The nodalization scheme is extremely flexible, allowing the user to construct a detailed plant model or to conduct separate effects analyses on components such as the pressurizer. This flexibility has also enabled the modeling of other plant systems, including HHSI, IHSI, and LHSI.

- The heat transfer package provides a good representation of heat transfer, both single phase and two-phase.

- The water properties are accurate in the range of application.

- Steady-state initialization greatly simplifies the process of obtaining a desired set of initial conditions.

- Iterative numerics generally provides reasonable time step control and reduces the necessity of restarting jobs to circumvent time step-related errors.

- The generalized restart and reedit capabilities of RETRAN are very useful, and they significantly increase the efficiency with which the code is used.

- The fixed pressure volume, fill, and critical flow models allow a complete and reasonable specification of fluid boundary conditions for various types of analyses.

- The non-equilibrium pressurizer model provides an accurate simulation of RCS pressure trends.

- The point kinetics model adequately predicts the reactor power response to the types of reactivity changes which arise during typical operational transients.

- The reactor coolant pump model accurately reflects the interaction of the pumps and the primary fluid during normal pump operation and coastdown.

- The control system models and trip logic are extremely flexible and useful for modeling automatic control actions as well as operator action.

Similar to other one-dimensional HEM codes, the current models in RETRAN have been found to have shortcomings in some areas and are incapable of adequately simulating particular phenomena. One recognized shortcoming is that the lack of a general non-equilibrium modeling capability detracts from the ability of the code to simulate some small-break LOCA behavior. This limitation must be recognized whenever such applications are undertaken.

In general, the overall experience with modeling the McGuire and Catawba transient response using RETRAN has been good. Despite shortcomings in some areas, the code has been proven capable of accurately simulating the transient thermal-hydraulic behavior of a Westinghouse PWR with preheater-type steam generators. Due to the relatively minor differences between the preheater-type steam generator and the feedring steam generator, the code should be capable of accurately simulating the transient thermal-hydraulic behavior with the feedring steam generators.

Table 3.2-1
McGuire/Catawba Preheat SG Base Model Heat Conductors

Conductor Number	Adjacent Volume Number(s)	Description	Material

Table 3.2-1 (cont.)
McGuire/Catawba Preheat SG Base Model Heat Conductors

Adjacent Conductor Number	Volume Number(s)	Description	Material

Table 3.2-1 (cont.)
McGuire/Catawba Preheat SG Base Model Heat Conductors

Adjacent Conductor Number	Volume Number(s)	Description	Material

Table 3.2-2
McGuire/Catawba Base Model
Feedring Steam Generator Heat Conductors

Adjacent Conductor Number	Volume Number(s)	Description	Material

(Page 3-63 intentionally deleted)

Figure 3.2-1
McGuire/Catawba RETRAN Model
Nodalization Diagram (two-loop)

Figure 3.2-2
McGuire/Catawba RETRAN Model
Nodalization Diagram (one-loop)

Figure 3.2-3
McGuire/Catawba RETRAN Model
Feedring Steam Generator
Nodalization Diagram

3.3 McGuire/Catawba VIPRE Model

3.3.1 Core and Fuel Assembly Description

The McGuire/Catawba reactor core consists of 193 fuel assemblies as shown in Figure 3.3-1. Spacer grids, end fittings, fuel rods, and guide tubes form the basic structure of a fuel assembly as shown in Figure 3.1-2. The lower and upper end spacer grids are made of Inconel, while the six intermediate spacer grids are made of Zircaloy-4. Each fuel assembly is a 17 by 17 array containing 264 fuel rods, 24 control rod guide tubes, and one incore instrument guide tube. The fuel rod consists of dished-end, cylindrical pellets of uranium dioxide clad in cold-worked Zircaloy-4. The fuel assembly and fuel rod dimensions, and other related fuel parameters used in the thermal-hydraulic analyses are given in Table 3.3-1.

3.3.2 Model Development

3.3.2.1 One-Pass Hot Channel Analysis

VIPRE-01 (Reference 3-4) is capable of performing one-pass hot channel analysis. A subchannel is defined as the flow area between adjacent fuel rods in an array. By definition, the hot channel in a PWR core is the subchannel with the most limiting departure from nucleate boiling ratio (DNBR) on one of its adjacent fuel rods. In one-pass analysis the objective is to model the hot subchannel and those nearest to it in detail, and then surround these with larger and larger lumped channels proceeding outward toward the periphery of the core. In this way the entire core can be modeled with a limited number of channels, while maintaining a fine level of detail and accuracy in the area of the hot subchannel. This methodology is an improvement on the multi-pass or "cascade" approach used in other methodologies, where two or three separate simulations in series are necessary using boundary conditions taken from the preceding ones. One-pass analysis is not only more efficient but it allows for explicit modeling of the coupling between the hot subchannel and the rest of the core.

3.3.2.2 Transient Analysis Models

The geometry setup for one-pass analysis is based on the location of the hot subchannel. For a given geometry and inlet fluid condition, the location of the hot subchannel is determined by the pin radial-local power distribution and the critical heat flux (CHF) correlation utilized. Figures 3.3-2 and 3.3-3 show the assembly radial and pin radial-local power distributions, respectively, used to analyze transients resulting in symmetrical core radial power distributions. These power distributions originated from [ ] power distributions. The major modification

is the [ ] in the hot assembly. However, the maximum pin radial-local peak of [ ] is preserved.

Three core models, comprised of [ ] channels, have been developed as shown in Figures 3.3-4 to 3.3-6. The detailed [ ] channel model has been constructed in order to identify the location of the hot subchannel and to show that the simplified models can accurately predict the local coolant flow rate and thermal-hydraulic properties of the core and most importantly of the hot channel.

In the [ ] channel model, the [ ] is modeled as an array of subchannels (Figure 3.3-4) while the [ ] are modeled as individual channels as shown in Figure 3.3-4. Finally, the [ ]. Utilizing the BWCMV CHF correlation (Reference 3-5), the hot subchannel is identified to be [ ] channel. However, should CHF correlations other than the BWCMV correlation be utilized (for example: the W3-S correlation), the hot subchannel can be identified as Channel [ ] subchannel. The solution method utilized for the calculation is the direct method.

After the location of the hot subchannel has been identified, the [ ] channel model (Figure 3.3-5) is constructed to show that [ ].

Since, depending on the CHF correlation utilized, [ ]

3.3.2.3 Simplified Models Justification

To show that the simplified model can properly and correctly predict the local coolant flow rate and thermal-hydraulic properties for steady-state and transient analyses, simplified model results are compared to results from the more detailed models. If the simplified model results are equivalent or conservative compared to the more detailed model results, then it is justified to use the simplified models for analyses. The solution method utilized is the RECIRC method. MDNBRs presented in this section are calculated with the BWCMV critical heat flux correlation.

<u>Steady-State Comparisons</u>

Input Conditions:	Power	= 66.945 kW/rod (100%FP)
	Pressure	= 2285.9 psia
	Core flow	= 2.5574 Mlbm/hr-ft^2
	Inlet enthalpy	= 562.4 Btu/lbm

Results for this case are presented in Table 3.3-2. The similarity of all the results verifies that the simplified[ ]channel model can be used without losing the accuracy of more detailed and expensive models.

<u>Transient Comparisons</u>

An arbitrary transient case with power maintained at 100% and the inlet mass flux ramped from 100% to 75% of its initial state value has been run for 2.0 seconds. Results are given in Table 3.3-3. Results show that the agreement between the predictions of MDNBR during the transient as well as other local fluid parameters is excellent. The capability of the simplified model for transient analysis has been demonstrated.

<u>Conclusion</u>

In conclusion, the results of both detailed and simplified nodalizations are very similar for both steady-state and transient cases. Thus, instead of using the more detailed and expensive models, the simplified[ ]channel model will be used for core thermal-hydraulic analyses for normal symmetrical transients. For transients resulting in asymmetrical flow distributions or inlet coolant temperature gradients outside the hot assembly, such as the steam line break, the [ ] channel model may be modified so that [ ]

can be modeled for proper simulation of the inlet temperature gradients. Also, the RECIRC solution method must be utilized because of the large density gradient between channels and because of the low flow velocity due to the reactor coolant pumps tripping in the offsite power unavailable situation.

3.3.2.4 Axial Noding

In general, VIPRE predictions are sensitive to axial noding in that enough nodes must be provided to resolve the detail in the flow field and in the axial power profile. However, once a point of sufficient accuracy is reached, VIPRE is relatively insensitive to further axial refinement. In order to demonstrate the correctness of the above statement, three cases were analyzed with the[ ]channel symmetrical power distribution model divided into [ ] axial increments corresponding to [ ]inches per active fuel node, respectively. The results in Table 3.3-4 show that for[ ]or more axial nodes, the local coolant conditions are insensitive to the number of axial increments. The hot channel MDNBR changes by only[ ]% when the number of nodes are decreased from[ ]. Since the MDNBR [

]This indicates that[ ]axial nodes is a sufficiently large number for accurately calculating hot channel conditions. However,[ ]axial nodes will be used for thermal-hydraulic transient analyses.

3.3.3 Code Option and Input Selections

3.3.3.1 Thermal-Hydraulic Correlations

Flow correlations are used in VIPRE-01 to model two-phase flow effects. In the flow solution, correlations model the effects of two-phase flow and friction pressure losses, subcooled boiling, and the relationship between flowing quality and void fraction. For transient analyses, the subcooled void, the bulk void, and the two-phase friction multiplier are modeled by using the

[

]

Turbulent Mixing Correlations

The energy and momentum equations of the VIPRE-01 code contain terms describing the exchange of energy and momentum between adjacent channels due to turbulent mixing. The effect of turbulent mixing is empirically accounted for in VIPRE-01. The turbulent cross flow, w', has the form:

$$w' = A \times Re^{B} \times S \times G$$

Where:

Re	=	Reynolds number
S	=	gap width, inches
G	=	mass flux, lbm/sec-ft^2
A	=	[
B	=	]

Turbulent crossflow mixing is a subchannel phenomenon, and is not generally applicable to lumped channel analysis. The turbulent cross flow is correlated in terms of flow exchange through a single gap. In lumped channel modeling, the crossflow mixing must be reduced to take into account the effects of lumping many gaps such that

$$w' = w'/N_R \quad \text{(Reference 3-4)}$$

where N_R = number of rod rows between adjacent channel centroids. Thus, for MK-BW fuel which has 17x17 fuel rods in an assembly, the mixing coefficient, A, between two lumped assembly channels becomes

$$A = [\quad]$$

However, the mixing coefficients between any two lumped channels are set to [ ].

The turbulent momentum factor (FTM) tells how efficiently the turbulent crossflow mixes momentum. For the [

]

Turbulent mixing in two-phase flow is generally assumed to be [ ]

Pressure Losses

Pressure losses due to frictional drag are calculated in the code for both axial and transverse flow. The friction factor for the pressure loss in the axial direction is determined from empirical correlation as:

$$f = A \times Re^{B}$$

The code evaluates both a turbulent and a laminar set of coefficients and selects the maximum. The values selected for parameters A and B are based on [ ]

Turbulent Flow:	A = [ ]	B = [ ]
Laminar Flow:	A = [ ]	B = [ ]

The coefficient of form drag in the gap between adjacent channels is on the order of [ ] for the transverse pressure loss (Reference 3-4). Thus, it is set equal to [ ] for transient analyses.

Local Hydraulic Form Loss

The local hydraulic form loss coefficient is set as a constant to model the irrecoverable axial pressure loss as shown below.

$$\Delta P = KG^2/2\rho g_c$$

Where:

	K	= spacer grid form loss coefficient
	G	= mass flux, lbm/sec-ft^2
	ρ	= density, lbm/ft^3
	g_c	= 32.174 lb-ft/sec^{2}lb$_f$

The spacer grid form loss coefficients for the MK-BW fuel assembly are used in the transient analyses.

Critical Heat Flux Correlations

One of the critical heat flux correlations used to perform DNB analysis is the B&W BWCMV CHF correlation. The BWCMV CHF correlation has been reviewed and approved by the NRC for licensing analysis of BAW 17 x 17 Mark-BW geometry fuel with Zircaloy grids. Using the LYNX-2 open subchannel code (Reference 3-6), the design MDNBR limit of 1.21 was determined. The range of use for the BWCMV correlation is:

Pressure, psia	1500 to 2455
Mass velocity, 10^6 lbm/hr-ft^2	1.0 to 3.5
Quality, (equilibrium)	-0.22 to 0.22

A statistical core design (SCD) limit of 1.40 (Reference 3-14) has been established for the BWCMV correlation using the VIPRE code (Reference 3-7). Either the SCD limit of 1.40 or the correlation limit of 1.21 will be used for transient core thermal-hydraulic analyses, with a sufficient margin applied to account for applicable DNBR parameters.

The second CHF correlation used to perform DNB analysis is the BWU-Z CHF correlation (Reference 3-11). The BWU-Z correlation was reviewed and approved by the NRC for use in McGuire/Catawba analyses in References 3-12 and 3-13. The range of applicability of the BWU-Z correlation is:

Pressure, psia	400 to 2465
Mass velocity, 10^6 lbm/hr-ft^2	0.36 to 3.55
Quality, (equilibrium)	< 0.74

A set of correlation limits for four pressure ranges have been determined to maintain a 95 percent confidence that 95 percent of the limiting fuel pins are not in film boiling:

Pressure Range (psia)	DNBR Limit
400-700	1.590
700-1000	1.199
1000-1500	1.125
1500-2400	1.193

An SCD limit, which incorporates many of the uncertainties, may also be applied as a MDNBR limit. A statistical core design (SCD) limit of 1.37 has been established for the BWU-Z correlation using the VIPRE code (Reference 3-14). Either the SCD limit of 1.37 or the pressure range dependent correlation limits will be used for transient core thermal-hydraulic analyses, with a sufficient margin applied to account for applicable DNBR penalties.

For transients with system pressure less than 1600 psia, the W-3S CHF correlation may also be used. The range of use for the W-3S correlation is (Reference 3-4):

Pressure, psia	1000 to 2300
Mass velocity, 10^6 lbm/hr-ft^2	1.0 to 5.0
Quality, %	-0.15 to 0.15

However, it has been shown recently (Reference 3-8) that the W-3S correlation is also applicable for pressure and mass flux as low as 700 psia and 0.5×10^6 lbm/hr-ft^2, respectively.

Other CHF correlations that have been reviewed and approved by the NRC may also be used to perform DNBR analyses.

3.3.3.2 Conservative Factors

When predicting DNBR with the BWCMV or BWU-Z correlations, the SCD design limit will generally be used. The SCD design limit accounts for all of the uncertainties (with one exception), and therefore additional conservative factors are unnecessary. Only the conservative factor to account for a possible core inlet flow maldistribution, which is detailed below, is applied with the SCD design limit.

If the SCD design limit is not used (all uncertainties explicitly considered) or if CHF correlations other than BWCMV or BWU-Z are used, then the following conservative factors are applied.

<u>Hot Channel Flow Area Reduction</u>
The hot subchannel flow area is reduced by 2% to account for variations in as-built subchannel flow areas (Reference 3-9).

Hot Assembly Flow Redution

The hot assembly inlet flow is conservatively reduced by 5% (Reference 3-9) from the nominal assembly flow. The flow to the remainder of the core is adjusted such that the entire core flow remains normalized.

Hot Channel Factors

The $F^{E}_{\Delta H}$ hot channel factor accounts for variation in the fabrication variables which affect the heat generation rate along the flow channel (pellet diameter, density, U_{235} enrichment, and fuel rod diameter). An $F^{E}_{\Delta H}$ value of 1.03 is considered conservative.

3.3.3.3 Fuel Pin Conduction Model

For most of the transient analyses, the RETRAN heat flux boundary condition is used; the fuel pin conduction model will not be used in the VIPRE-01 transient models. This means that heat is added directly from the cladding surface to the fluid as a boundary condition on the calculation, and the heat transfer solution is not required. However, for transient analyses in which the fuel enthalpy or cladding temperature is the protective criteria (for example: rod ejection, rod withdrawal accident at rated power, and locked rotor), the VIPRE fuel pin conduction model may be used with the neutron power as the transient forcing function.

3.3.3.4 Power Distribution

Radial Power Distribution

For transients resulting in symmetrical power distributions, the 17 x 17 1/8 core assembly radial and hot assembly pin radial-local power distributions shown in Figures 3.3-2 and 3.3-3 are applied. The hot assembly has a radial peak of [ ] (Figure 3.3-2), and contains the maximum pin radial-local peak of [ ] (Figure 3.3-3). For transients resulting in asymmetrical power distributions, nuclear design analyses generate core radial power distributions. Radial power distribution as a function of transient time is then input to VIPRE-01.

Axial Power Distribution

For transients resulting in symmetrical radial power distributions, a [ ] axial power shape is typically applied (Figure 3.3-7). For transients resulting in asymmetrical power distributions, nuclear design analyses generate axial power distributions during transients. On a

case-by-case basis, either these axial power distributions or a [ ] shape will be utilized as justified.

3.3.3.5 Flow Rate

Vessel Flow Rate

For McGuire/Catawba units, the transient thermal-hydraulic analyses will be based on the technical specifications flowrate, for example, a value of 382,000 gpm. For non-statistical analyses, a -2.2% penalty is applied to account for uncertainties. Reactor coolant flow rates for various reactor coolant pump operating configurations are as follows (Reference 3-10):

4 pumps = 100.0% of the total flow
3 pumps = 72.8% of the total flow
2 pumps = 46.0% of the total flow

Core Bypass Flow

The portion of the coolant flow which is not effective in cooling the fuel is considered bypass flow. There are five areas which contribute to the bypass flow:

1) Flow entering the control rod guide tubes and instrument tubes for control rod cooling
2) Leakage flow into the outlet nozzle through the gap between the reactor vessel and barrel
3) Flow through the spray nozzles into the upper head for head cooling purposes
4) Flow in the gap between the peripheral fuel assemblies and the adjacent baffle wall
5) Flow associated with the baffle-barrel region

The nominal core bypass flow is [ ]% (Reference 3-9) of the vessel flow. For non-statistical analyses, a [ ]% bypass flow is used to account for uncertainties.

3.3.3.6 Direct Coolant Heating

The amount of heat generated in the coolant is 2.6% of the total power (Reference 3-9).

3.3.3.7 Miscellaneous

Miscellaneous inputs for VIPRE-01 are shown below. These parameters control the execution of the run. Default values for these inputs are used for the transient analyses (Section 2.12.1, Volume 2, of Reference 3-4).

Solution option	RECIRC solution
Maximum number of external iterations	30
Maximum number of internal iterations	20
Minimum number of external iterations	2
Cross flow convergence limit	0.1
Axial flow convergence	0.0001
Damping factor for cross flow	0.9
Damping factor for axial flow	0.9

3.3.4 Discussions of Modeling Differences Between DPC-NE-3000 and DPC-NE-2004 Reports

The modeling and input differences between the DPC-NE-3000 (transient analysis) and DPC-NE-2004 (steady-state analysis) (Reference 3-7) reports are described below. These differences are due to modeling requirements unique to transient DNBR analyses, or incorporating additional conservatism to minimize the impact of changes in core reload design methods or fuel assembly design.

Model Geometry

The geometry setups for the transient analysis models are different from those of steady-state analysis because the DNBR calculations associated with FSAR Chapter 15 transient analyses require more flexible models than the calculations associated with steady-state core reload design require. The steady-state analysis models only need to simulate the most limiting region of the core and symmetrical core phenomena. The geometry setup of the transient models must be capable of simulating the whole core, and also situations including asymmetrical core radial power distributions, core flow maldistributions, and inlet coolant temperature gradients. The transient models also [

] that are not needed for steady-state analysis.

Core Radial Power Distributions

The steady-state and transient analysis models utilize different assembly radial and hot assembly pin radial-local power distributions. The transient analysis core radial power distribution originated from a [ ] power distribution as mentioned in Section 3.3.2.2 and has a maximum hot assembly radial power of [ ]; whereas the steady-state analysis model has a maximum hot assembly power of [ ]. Nevertheless, the maximum pin peak value of [ ] is utilized by both steady-state and transient analysis models. Furthermore, in the transient models the [ ] peaks; whereas in the steady-state models, [ ] peak. The transient model pin peaks are therefore slightly more limiting and ensure that conservative DNBR results will be maintained for any future core reload design with a maximum pin peak of [ ].

Axial Node Size

In the transient analysis models, the axial node size within the active fuel length is [ ] inches per node; whereas in the steady-state models, it is [ ] inches per node. However, Section 3.3.2.4 shows that DNBR is insensitive for axial node size less than [ ] inches per node.

Turbulent Momentum Factor

In the transient analysis models, the turbulent momentum factor (FTM) is specified as [ ] to indicate that the turbulent crossflow [ ]; whereas FTM is set to [ ] in the steady-state models. The use of [ ] for FTM would provide conservative results.

Lumped Channel Turbulent Mixing Coefficient

The turbulent mixing coefficient, ABETA, is [ ] in the transient analysis models; whereas in the steady-state models ABETA of the [ ] channels. The use of [ ] channel ABETA provides conservative results.

Gap/Length Factor

In the steady-state models, the gap/length factor is calculated [ ]; whereas the [ ] is used in the transient models due to the fact that the [ ] geometries. However, this parameter is recognized as being insensitive.

3.3.5 Summary of Experience

The VIPRE-01 code was developed to meet the utility need for a versatile and user-oriented analytical tool for performing core thermal-hydraulic design. VIPRE-01 includes numerous modeling options and correlations in order to satisfy a wide spectrum of utility needs. The model development and analysis results documented in this section demonstrate that VIPRE-01 is well suited for McGuire/Catawba transient analysis. Some of the highlights of this application of the VIPRE-01 code include:

- The nodalization reduction and optimization study performed to justify the use of simplified models was highly successful. Although the intent of this effort was to reduce computer usage, there was no significant loss of accuracy in the predicted thermal-hydraulic conditions or MDNBR.

- VIPRE-01 accepts all necessary boundary conditions that originate either from the plant transient simulation code or the core neutronics simulation code. Included is the capability to subject different boundary conditions to different segments of the core model. For example, different transient inlet enthalpies, heat flux transients, and even different transient pin radial powers or axial flux shapes can be modeled. With this capability virtually any desired application is achievable.

- The selection of code options is consistent with the experience base developed by the utilities that have been utilizing VIPRE-01.

It is expected that the VIPRE-01 code will be utilized indefinitely for McGuire/Catawba transient core thermal-hydraulic applications. The modeling capabilities and the analysis results provided in this section demonstrate that VIPRE-01 can be utilized for accurate and conservative prediction of DNBR during plant transients. This technology remains at or near the current state-of-the-art. Applications will include reanalysis of those FSAR Chapter 15 transients requiring a DNBR evaluation, evaluation of operational events, and resolution of regulatory concerns.

(Pages 3-80 to 3-82 intentionally deleted)

Table 3.3-1

Mark-BW Fuel Assembly

Component Dimensions Used for Thermal-Hydraulic Analysis

Fuel Pin Diameter	0.37468 in.
Control Rod Guide Tube Diameter	0.48288 in.
Instrumentation Guide Tube Diameter	0.48288 in.
Effective Pin Pitch	0.49690 in.
Assembly Flow Area	38.731 $in.^2$
Assembly Wetted Perimeter	348.679 in.
Assembly Heated Perimeter	310.749 in.
Unit Channel Flow Area	0.1367 $in.^2$
Unit Channel Wetted Perimeter	1.1771 in.
Unit Channel Heated Perimeter	1.1771 in.
Control Rod Guide Tube Channel Flow Area	0.1184 $in.^2$
Control Rod Guide Tube Channel Wetted Perimeter	1.2621 in.
Control Rod Guide Tube Heated Perimeter	0.8828 in.
Instrumentation Guide Tube Channel Flow Area	0.1184 $in.^2$
Instrumentation Guide Tube Channel Wetted Perimeter	1.2621 in.
Instrumentation Guide Tube Channel Heated Perimeter	0.8828 in.
Peripheral Channel Flow Area	0.0838 $in.^2$
Peripheral Channel Wetted Perimeter	0.5885 in.
Peripheral Channel Heated Perimeter	0.5885 in.
Corner Channel Flow Area	0.0506 $in.^2$
Corner Channel Wetted Perimeter	0.2943 in.
Corner Channel Heated Perimeter	0.2943 in.
Active Fuel Length	144.000 in.

Table 3.3-2

Steady-State Results Comparison

Model	MDNBR (BWCMV)	MDNBR at Axial Location (in.)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR	Mass Flux at MDNBR ($Mlbm/hr\text{-}ft^2$)	Pressure Drop up to MDNBR (psi)
[						]

Table 3.3-3

Transient Results Comparison

Time (sec)	MDNBR (BWCMV) M1	MDNBR (BWCMV) M2	MDNBR (BWCMV) M3	Axial Location at MDNBR (in.) M1	Axial Location at MDNBR (in.) M2	Axial Location at MDNBR (in.) M3
0.0						
0.2						
0.4						
0.6						
0.8						
1.0						
1.2						
1.4						
1.6						
1.8						
2.0						

Time (sec)	Enthalpy at MDNBR M1	Enthalpy at MDNBR M2	Enthalpy at MDNBR M3	Void Fraction at MDNBR M1	Void Fraction at MDNBR M2	Void Fraction at MDNBR M3
0.0						
0.2						
0.4						
0.6						
0.8						
1.0						
1.2						
1.4						
1.6						
1.8						
2.0						

Time (sec)	Mass Flux at MDNBR M1	Mass Flux at MDNBR M2	Mass Flux at MDNBR M3	Pressure Drop up to MDNBR M1	Pressure Drop up to MDNBR M2	Pressure Drop up to MDNBR M3
0.0						
0.2						
0.4						
0.6						
0.8						
1.0						
1.2						
1.4						
1.6						
1.8						
2.0						

M1 = [ ] Channel Model
M2 = [ ] Channel Model
M3 = [ ] Channel Model

Table 3.3-4

Active Fuel Node Size Comparison

Number of Active Fuel Rods	
MDNBR (BWCMV)	
MDNBR Axial Location (in.)	
Enthalpy (Btu/lbm)	
Void Fraction	
Mass Flux ($Mlbm/hr\text{-}ft^2$)	
Pressure Drop up to MDNBR (psi)	

Figure 3.3-1

MNS/CNS Reactor Core Cross Section

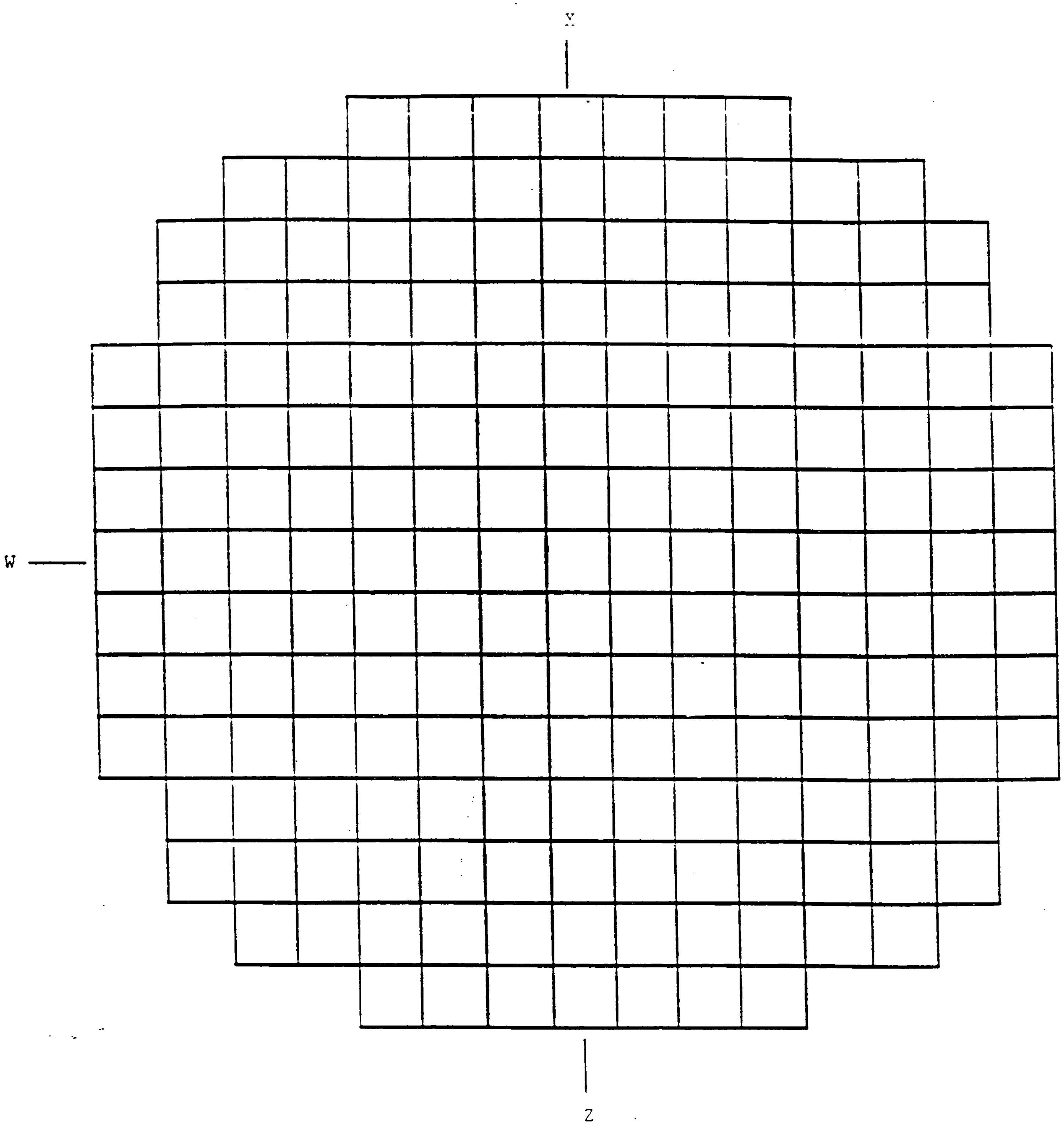


Figure 3.3-2

Assembly Radial Power for

Transient Resulting In

Symmetrical Power Distributions

Figure 3.3-3

Hot Assembly Pin Radial-Local Power
For Transient Resulting In
Symmetrical Power Distributions

Fuel Rod

Control Rod

Control Rod with Ferrules

Instrumentation Guide Tube

Figure 3.3-4

VIPRE[ ] Channel Model

Figure 3.3-5

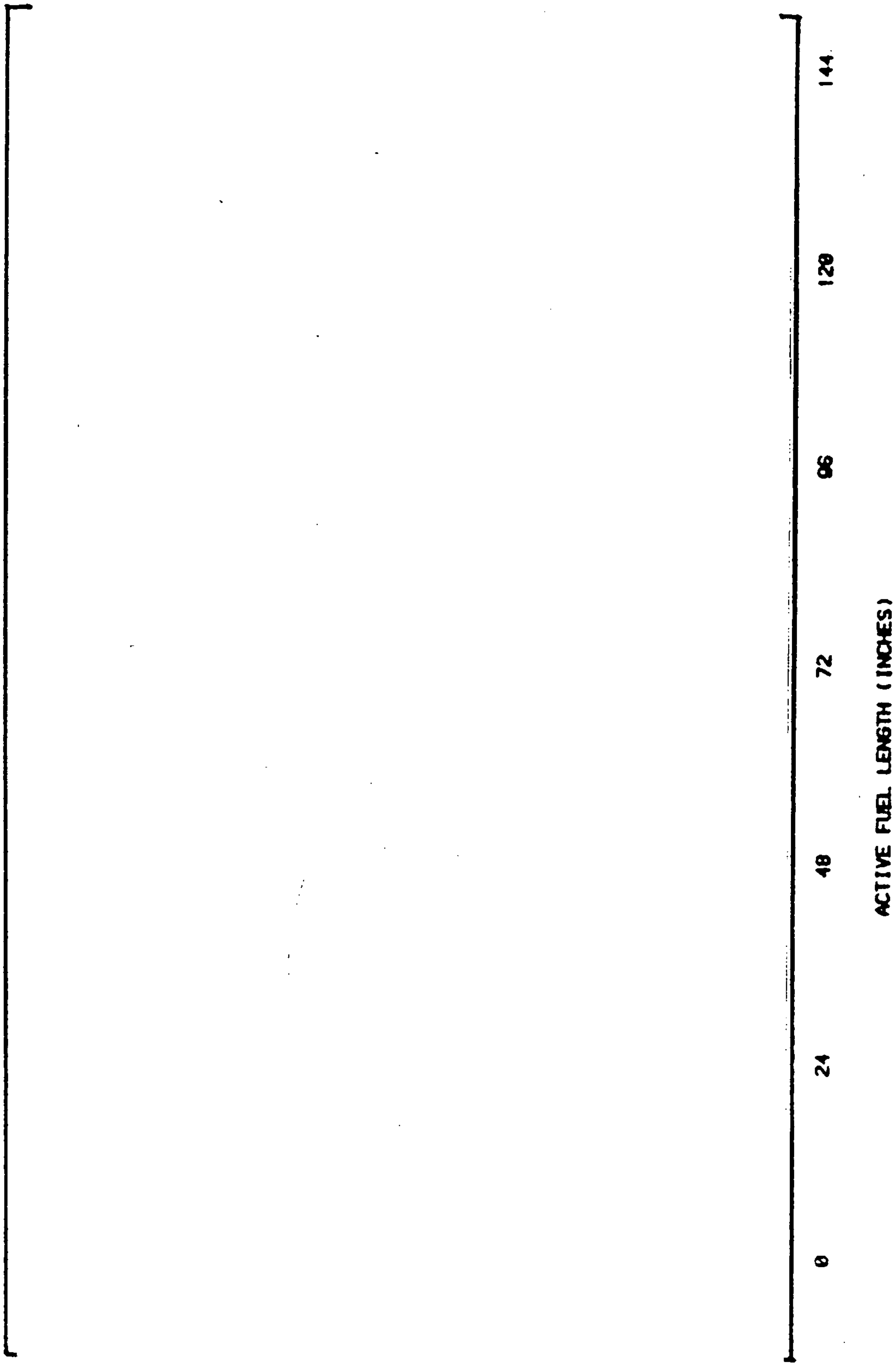
VIPRE[ ] Channel Model

Figure 3.3-6

VIPRE[ ] Channel Model

Figure 3.3-7

[ ]Axial Shape
Peaked at X/L = [ ]



3.4 References

3-1 Decay Energy Release Rates Following Shutdown of Uranium-Fueled Thermal Reactors, Proposed ANS Standard, American Nuclear Society, October 1971

3-2 American National Standard for Decay Heat Power in Light Water Reactors, ANSI/ANS-5.1, American Nuclear Society, August 29, 1979

3-3 RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM Revision 2, EPRI, November 1984

3-4 VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM Revision 2, EPRI, July 1985

3-5 BWCMV Correlation of Critical Heat Flux, BAW-10159P-A, May 1986

3-6 LYNX2 - Subchannel Thermal-Hydraulic Analysis Program, BAW-10130, October 1976

3-7 Duke Power Company McGuire and Catawba Nuclear Stations Core Thermal-Hydraulic Methodology Using VIPRE-01, DPC-NE-2004, December 1988

3-8 Prairie Island Nuclear Generating Plant Final Safety Analysis Report, Northern States Power Company

3-9 McGuire FSAR Section 4.4

3-10 McGuire Nuclear Station Technical Specifications, DPC

3-11 The BWU Critical Heat Flux Correlations, BAW-10199P, BWFC, November 1994

3-12 Letter, H. N. Berkow (NRC) to M. S. Tuckman (Duke), November 7, 1996

3-13 Letter, P. S. Tam (NRC) to M. S. Tuckman (Duke), February 20, 1997

3-14 Thermal-Hydraulic Statistical Core Design Methodology, DPC-NE-2005-PA, Duke Power Company, February 1995

4.0 OCONEE RETRAN BENCHMARK ANALYSES

The nine plant transients selected for benchmarking the Oconee RETRAN model include a broad spectrum of initial conditions, initiating events, and transient evolutions. A large set of plant transient monitor data is recorded, typically at a one second frequency, during a transient. The simulation is conducted by first initializing the RETRAN model as close as possible to the plant initial conditions. Next, boundary conditions such as actuation of interfacing pumps and valves and operator actions are identified and modeled. In some instances a data void or an atypical plant response, due for example to a spurious valve opening, may require assuming a boundary condition. The simulation is then performed for a duration that includes the plant parameter responses of interest. The results of the simulation are then compared to the plant data for a set of parameters that characterize the overall plant response. The end result provides an assessment of the capability of the Oconee RETRAN model and the RETRAN-02 code to simulate certain thermal-hydraulic phenomena and the category of transients typical of the benchmarked event.

4.1 Loss of Secondary Heat Transfer

4.1.1 Oconee Nuclear Station Unit 3
Loss of Main Feedwater
August 14, 1984

Transient Description

Oconee Unit 3 was operating at 100% full power when an anticipatory reactor trip occurred on the loss of both main feedwater (MFW) pumps. A rapid pressurizer outsurge, which is characteristic of the normal post-trip response, immediately followed the reactor trip. The Reactor Coolant System (RCS) inventory contracts due to a sudden reduction in the RCS average temperature. The temperature reduction results from a transitional mismatch between the reactor heat source and the steam generator heat sink. Letdown was manually isolated in the first 10 seconds and reestablished at 850 seconds, and RCS makeup flow was increased by manually opening a second makeup valve. Only one

high pressure injection (HPI) pump operated during the transient. All three emergency feedwater (EFW) pumps started immediately following the loss of the MFW pumps and controlled steam generator (SG) levels to the normal post-trip value of 25 inches on the extended startup range level indication. RCS pressure decreased to a minimum value of 1832 psig at 50 seconds while the pressurizer level decreased to a minimum level of 76 inches at 60 seconds. RCS pressure and pressurizer level then recovered to normal post-trip operating values as RCS conditions stabilized.

At a later time during the transient, EFW flow was inadvertently isolated due to a valve alignment error. Flow was lost at approximately 940 seconds and was reestablished at approximately 1310 seconds. RCS temperatures increased approximately 20 degrees during this time period as SG levels decreased below the 25 inch level control setpoint. Both of these parameters returned to normal post-trip values after EFW flow and then MFW flow were reestablished.

Discussion of Important Phenomena

Several important phenomena occurred during the transient which challenged the capability of RETRAN and the Oconee RETRAN Model to accurately simulate the plant response. These phenomena include steam generator secondary void fraction profile and primary-to-secondary heat transfer (including the effect of SG dryout), main steam relief and secondary pressure control capabilities, non-equilibrium pressurizer behavior, and the effect of pressurizer spray. These phenomena will be important, each to a varying degree, for most of the simulations discussed in this chapter of the report. Therefore, they will only be discussed in great detail in this first benchmark analysis.

Accurate simulation of the steam generator void fraction profile is important since it determines the effective boiling length in the generator and thus the primary-to-secondary heat transfer rate. This is especially important during low SG level conditions and when EFW is delivered at a higher elevation than MFW (see Section 2.2.2.2 for a discussion of the modeling of this phenomenon). The heat transfer rate then determines the RCS temperature response and consequently the pressurizer level response through the expansion and contraction of the reactor coolant. The RCS pressure response is then mainly affected by

changes in pressurizer level. Therefore, it is evident that accurate steam generator modeling is necessary in order to achieve an accurate overall plant transient simulation.

Accurate simulation of pressurizer phenomena is also important since these phenomena determine the RCS pressure response. Non-equilibrium effects accompanying the compression of the steam bubble during the pressurizer refilling phase are the most important of these. The efficiency of the pressurizer spray in desuperheating/condensing the steam bubble has a large effect on the RCS pressure response. Heat transfer between the liquid and vapor regions at the interface can be important, as can heat transfer to the pressurizer vessel. The importance of these phenomena can vary significantly, and is transient specific.

Secondary pressure control also has a major effect on the post-trip primary-to-secondary heat transfer rate, and therefore the RCS temperature and pressure response. The main steam code safety relief valves lift in the first few seconds after turbine trip in order to relieve the steam that continues to be generated after reactor trip. The safety valves then reseat as the steaming rate decreases in order to limit the RCS temperature reduction. The immediate post-trip RCS temperature response as well as the magnitude of the pressurizer outsurge and the RCS pressure decrease is determined by the action of the relief valves in conjunction with the SG level. The Turbine Bypass System (TBS) valves also open immediately following turbine trip in order to assist in steam relief, by steaming to the condenser. Once the relief valves have reseated, the turbine bypass valves continue to steam and control SG pressure to the post-trip setpoint. Thereafter, RCS temperature is controlled by the Turbine Bypass System.

Model Description and Boundary Conditions

The plant response during this event showed little asymmetry between loops so the one-loop Oconee RETRAN Model (Figure 2.2-2) was used for the analysis. In addition, the Unit 3 specific feedwater and main steam line models were incorporated into the model. The parameters used as initial conditions were matched, where possible, to the plant data. The parameters which deviate from the plant data use the base model steady state full power values.

Initial Conditions

	Model	Plant
Power Level	100% (2568.0 MWt)	100% (2568.0 MWt)
RCS Pressure	2136 psig	2136 psig
PZR Level	222 inches	222 inches
T hot	600.3 °F	601.1 °F (ave)
T cold	556.1 °F	555.3 °F (ave)
SG Pressure	910 psig	891 psig (ave)
SG Level (OR)	55%	68% (ave)
SG Level (SUR)	163 inches	160 inches
MFW Temperature	455 °F	455 °F (ave)
RCS Flow	148 x 10^6 lbm/hr	148 x 10^6 lbm/hr
MFW Flow	10.8 x 10^6 lbm/hr	10.8 x 10^6 lbm/hr

The base model SG level (55% operating range) used in the simulation is
[

]

The problem boundary conditions used are cycle specific post-trip delayed neutron power and decay heat, MFW flow, EFW flow, HPI flow, and a reduction in the turbine bypass valve setpoint. [ ]

[

]

The EFW flow used in the simulation is based on an interpretation of event report and the available transient monitor data. All three pumps start immediately after the trip with flow throttled to control SG level to 25 inches. A maximum of approximately [ ] gpm total flow is available from the three EFW pumps. However, this flowrate is not delivered immediately as the pumps must come up to speed and the inventory in the steam generators must boil off to the 25 inch setpoint. Normal EFW flow into the steam generators continued until 948 seconds. At this time, the EFW valves were inadvertently closed and the turbine-driven EFW pump was shut off. This condition remained until the valves were manually opened at 1310 seconds. Level control was then reestablished via the two motor-driven EFW pumps still running, with a maximum of [ ] gpm assumed to be available. It should be noted that EFW flow data is not available, and therefore to accurately simulate the EFW flow a control system is used to throttle EFW in order to match the simulated level to the plant data.

MFW flow was lost at the beginning of the transient. Later on in the event a MFW pump was restarted. At approximately 27 minutes the MFW pump speed had increased sufficiently that the discharge pressure was higher than the SG pressure and MFW flow to the SGs resumed. From that time through the end of the simulation MFW flow was adjusted in order to match the RETRAN SG level to the plant data.

The HPI flow used in the simulation consists of the maximum possible injection from one pump between 57 and 211 seconds, and normal pressurizer level control via the makeup flowpath at all other times. Nominal letdown flow of 75 gpm is modeled from 850 seconds to the end of the simulation. The turbine bypass setpoint is reduced from the normal post-trip value of 1010 psig to 995 psig to match the actual SG pressure response as indicated by the data.

Simulation Results

The simulation begins with the anticipatory reactor trip on loss of main feedwater and continues for 30 minutes. The simulation is terminated at the point where EFW is reestablished and all major plant parameters have returned to normal post-trip values. The sequence of events is given in Table 4.1.1-1, and the results of the simulation are compared to the plant data in Figures 4.1.1-1 through 4.1.1-6.

The RCS pressure response (Figure 4.1.1-1) shows the predicted pressure decreasing slightly below the plant data during the initial contraction of the RCS inventory after the trip. There is a consistently larger decrease in the predicted RCS temperatures at this same time (see Figures 4.1.1-3 and 4.1.1-4.) This indicates that RETRAN is predicting a slightly greater heat transfer rate through the steam generators. The model then tracks the RCS repressurization with the pressure reaching the pressurizer spray setpoint of 2205 psig at 478 seconds as compared to 461 seconds in the data. The predicted pressurizer spray cycling frequency is higher than the data until approximately 900 seconds and then compares better with the data. The predicted RCS pressure agrees well with the data after EFW is restablished and the RCS heatup stops (1310 seconds). However, the RCS pressure decrease following restoration of EFW at 1310 seconds is overpredicted by RETRAN. This

is attributed to two causes. First, RETRAN has more subcooled water in the pressurizer since a larger insurge is predicted during the loss of all feedwater between 940 and 1310 seconds. Second, the RETRAN pressurizer model liquid region is at a uniform subcooled temperature following an insurge, while the plant pressurizer is expected to have stratification in the liquid region, specifically a saturated or slight subcooled region on top of more subcooled water from the hot leg. Both factors result in a code prediction of less pressurizer liquid flashing during a outsurge and thus a greater pressure decrease.

The pressurizer level response is shown in Figure 4.1.1-2. The RETRAN prediction trends the plant data, similar to the predicted RCS pressure response, during the initial post-trip outsurge and the subsequent refill from primary system makeup. After the normal pressurizer level of 220 inches is recovered, primary makeup is secured, but pressurizer level continues to increase due to the heatup of the RCS. This heatup is caused by the lack of feedwater as a result of the inadvertent closure of the EFW control valves from 940 to 1310 seconds. RETRAN overpredicts the insurge during this period, possibly due to some leakage past the EFW control valves in the plant. Following restoration of EFW at 1310 seconds, the predicted pressurizer level stabilizes, but at a higher value than the data. Following restoration of MFW at 1632 seconds, the level decreases in a manner consistent with the plant.

The predicted RCS temperature response (Figure 4.1.1-3 and 4.1.1-4) up to the point of EFW isolation at 940 seconds is typical for a normal reactor trip. The temperatures then increase due to the termination of EFW. The model predicts a slightly greater increase than the data in this time period (23 °F as compared to 18 °F). As previously mentioned, the smaller temperature increase at the plant may be attributable to leakage past the EFW control valves. This temperature increase is the driving force for the increase in pressurizer level and RCS pressure, and results in the prolonged period of pressurizer spray cycling.

The SG pressure response is shown in Figure 4.1.1-5. The main steam relief valves open and reseat correctly and then the turbine bypass valves control SG pressure at 995 psig. The simulated Turbine Bypass System controller allows a

slight undershoot in the SG pressure before controlling to the setpoint. The plant data for the "B" steam generator, however, shows the same undershoot, at a slightly later time. Therefore, it does not contribute significantly to the initial RCS contraction and cooldown. Another discrepancy exists later in the event when EFW flow is terminated and SG levels decrease. The plant data showed a decrease in the "B" SG pressure during this time period. This is due to steam leakage, mainly from auxiliary steam loads, in the "B" steam line. Since a single-loop model was used for this simulation, steam leakage was not modeled and therefore this response is not simulated. It is noted that this response had no impact on any other plant parameters, since the SGs were not an active heat sink at the time.

The SG level response is shown in Figure 4.1.1-6. The predicted level response shows a slight undershoot to the data, similar to the SG pressure, in the first minute of the simulation. The predicted level is then controlled to the post-trip setpoint of 25 inches. The RETRAN level tracks the data closely for the remainder of the transient, which is expected since the SG level is used as a boundary condition to determine MFW and EFW flow.

Analysis of Simulation Results

The ability of the Oconee RETRAN model to accurately predict the plant response during this event is primarily determined by two factors: once-through steam generator heat transfer modeling and pressurizer modeling. Steam generator heat transfer determines the magnitude and rate of change of primary system temperatures, and thereby influences RCS pressure and pressurizer level. The level and pressure on the SG secondary are also affected by the primary-to-secondary heat transfer. The compression and expansion of the pressurizer steam bubble determines the RCS pressure and pressurizer level response. These factors, as they pertain to the results of this benchmark transient, are discussed in detail below.

The [ ] heat transfer map (2.2.7.5), provides reasonably accurate primary and secondary temperature profiles at full power steady-state condi-

tions. The amount of SG exit superheat matches plant data, and predicted secondary mass inventory is close to other code-predicted reference values.

After trip, the code generally overpredicts primary-to-secondary heat transfer, as reflected in several of the plant data indications. First and foremost, RCS hot and cold leg temperatures decrease more rapidly than the plant data (Figures 4.1.1-3 and 4.1.1-4). This indicates that the calculated boiloff of the SG secondary inventory is more rapid than the data, and this fact is reflected by the SG level comparison (Figure 4.1.1-6). In addition, since the code underpredicts the RCS temperature, it also underpredicts RCS pressure and pressurizer level (Figures 4.1.1-1 and 4.1.1-2).

The overprediction of post-trip primary-to-secondary heat transfer is attributed to the lack of an unequal phase velocity model in the SG secondary (2.2.6.4). This causes the code to overpredict the boiling length, which effectively determines the heat transfer area in a once-through steam generator, and results in closer coupling between the RCS T-cold and the steam generator saturation temperature. It should be noted, however, that the disagreements between predicted and measured plant parameters are not extreme, and that they tend to lessen as steady-state post-trip conditions are approached. Thus there is only a limited impact on the transient results. During the latter portions of the transient, the overall SG heat transfer agreement is good based on the available data, and differences are attributed primarily to the uncertainty in feedwater flow boundary conditions.

A [ ] of the pressurizer is used in the Oconee model in order to take advantage of the [ ] option (2.2.6.5). The liquid flow into and out of the pressurizer is primarily determined by the shrinkage or expansion of the reactor coolant, which relates back to SG heat transfer, and makeup and letdown. During most of the transient the insurge/outsurge rate is predicted accurately enough to allow an assessment of the other factors which influence RCS pressure response, i.e. heat transfer to the pressurizer steam space from the metal walls and from the liquid region, condensation of steam by the pressurizer spray, and flashing of water in the pressurizer liquid space.

Pressurizer level increases between 60 and 1320 seconds, first in response to makeup and then as a result of the RCS heatup (Figure 4.1.1-2). RETRAN overpredicts the pressurization resulting from this sustained insurge, as reflected by the pressurizer spray cycling frequency. This is primarily attributed to the lack of a mechanistic interphase heat transfer model in RETRAN, since the other phenomena which act to reduce RCS pressure during an insurge [

] It is known that interphase heat transfer rates can be significant, especially during pressurizer spray operation when the steam-water interface is somewhat agitated.

There are two means of implementing an [

]

The predicted pressurizer level decreases slightly between 1320 and 1550 seconds, and then rapidly between 1150 and 1800 seconds. The code greatly overpredicts the corresponding RCS pressure decrease relative to the plant data during this time frame. This is attributed to the fact that the RETRAN model does not account for the [

] is employed, and the model gives reliable results except in certain situations, such as the one discussed here.

In conclusion, a good comparison between predicted and measured plant parameters is demonstrated. Those instances in which the prediction differs from the data are attributable to uncertainties in the transient boundary conditions or limitations of the code models. The identified limitations are understood and do not preclude the use of the code and model for this type of application.

Table 4.1.1-1

Oconee Nuclear Station Unit 3
Loss of Main Feedwater
August 14, 1984

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
Rx/Turbine and MFW pumps trip*	0	0
Letdown isolated, EFW pumps start*	0-10	0-10
Minimum RCS pressure	50	50
HPI flow increased*	57	57
Minimum pressurizer level	60	52
HPI flow reduced*	211	211
PZR spray setpoint reached	461	478
Letdown reestablished	850	850
EFW flow isolated*	948	948
PZR level reaches 220 inches	993	1011
EFW flow reestablished*	1310	1310
MFW flow reestablished*	1632	1632
End of simulation	N/A	1800

Note: The asterisks designate boundary conditions

ONS-3 LOSS OF MAIN FEEDWATER

8/14/84 EVENT

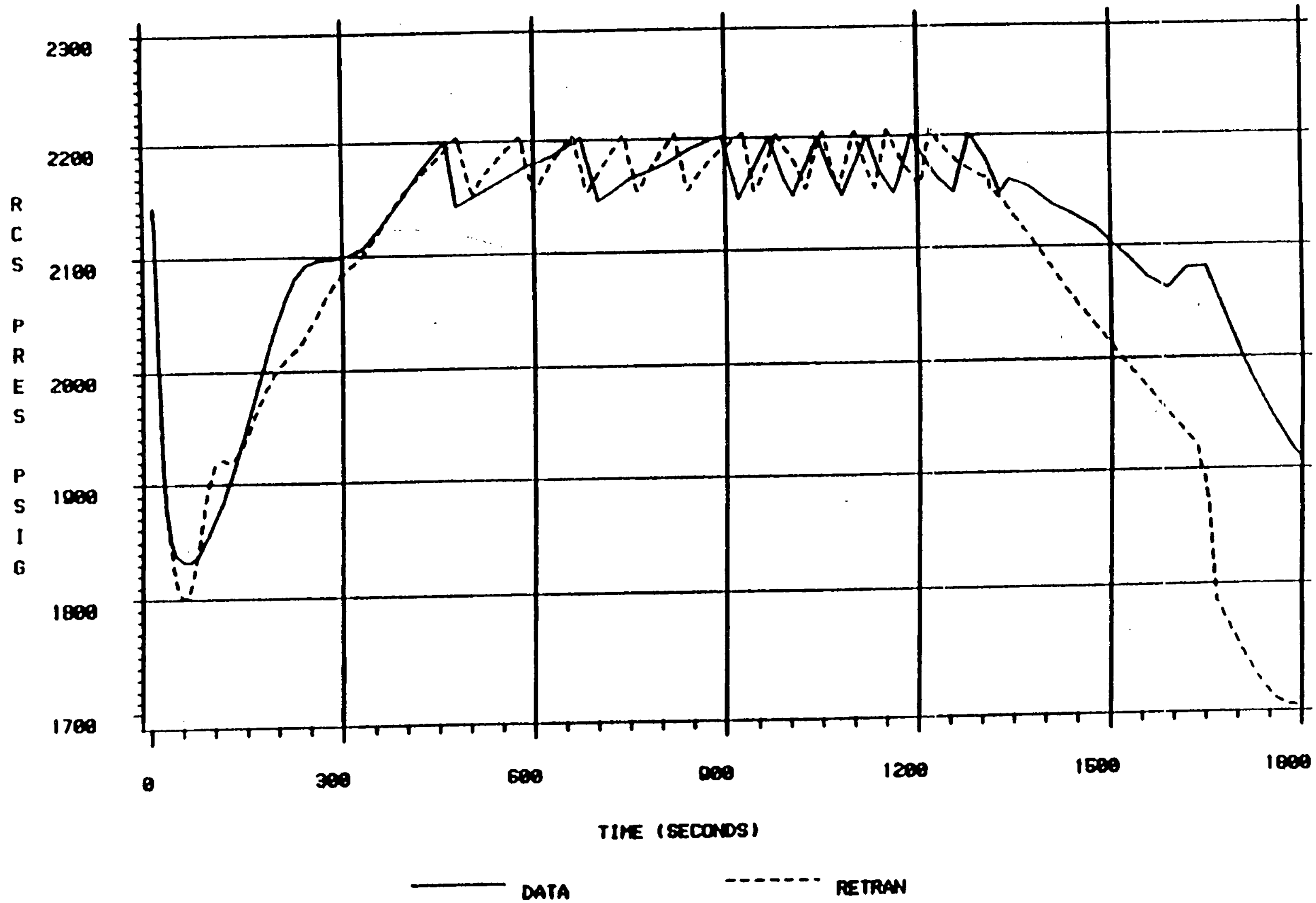


Figure 4.1.1-1

ONS-3 LOSS OF MAIN FEEDWATER

8/14/84 EVENT

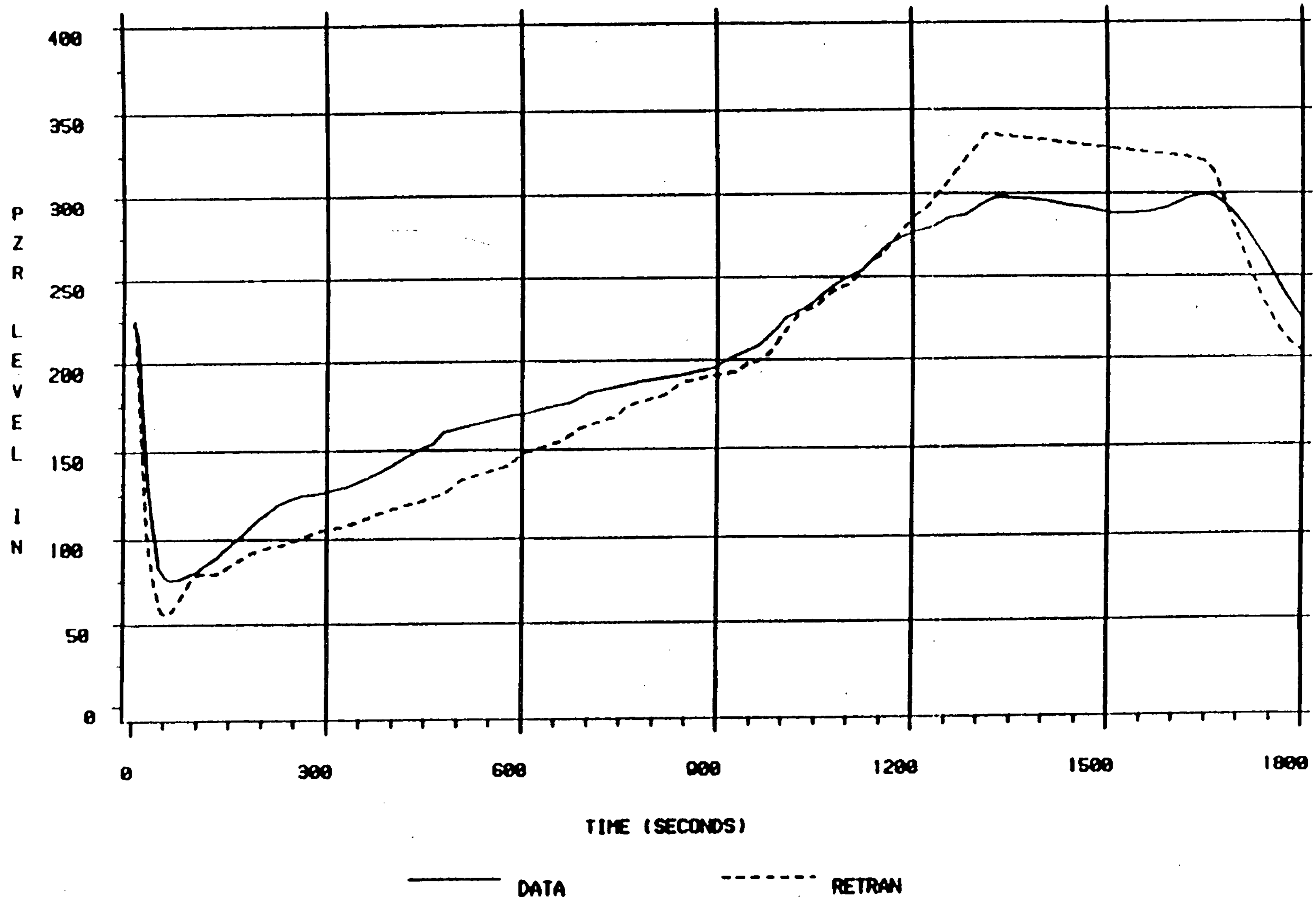


Figure 4.1.1-2

ONS-3 LOSS OF MAIN FEEDWATER

8/14/84 EVENT

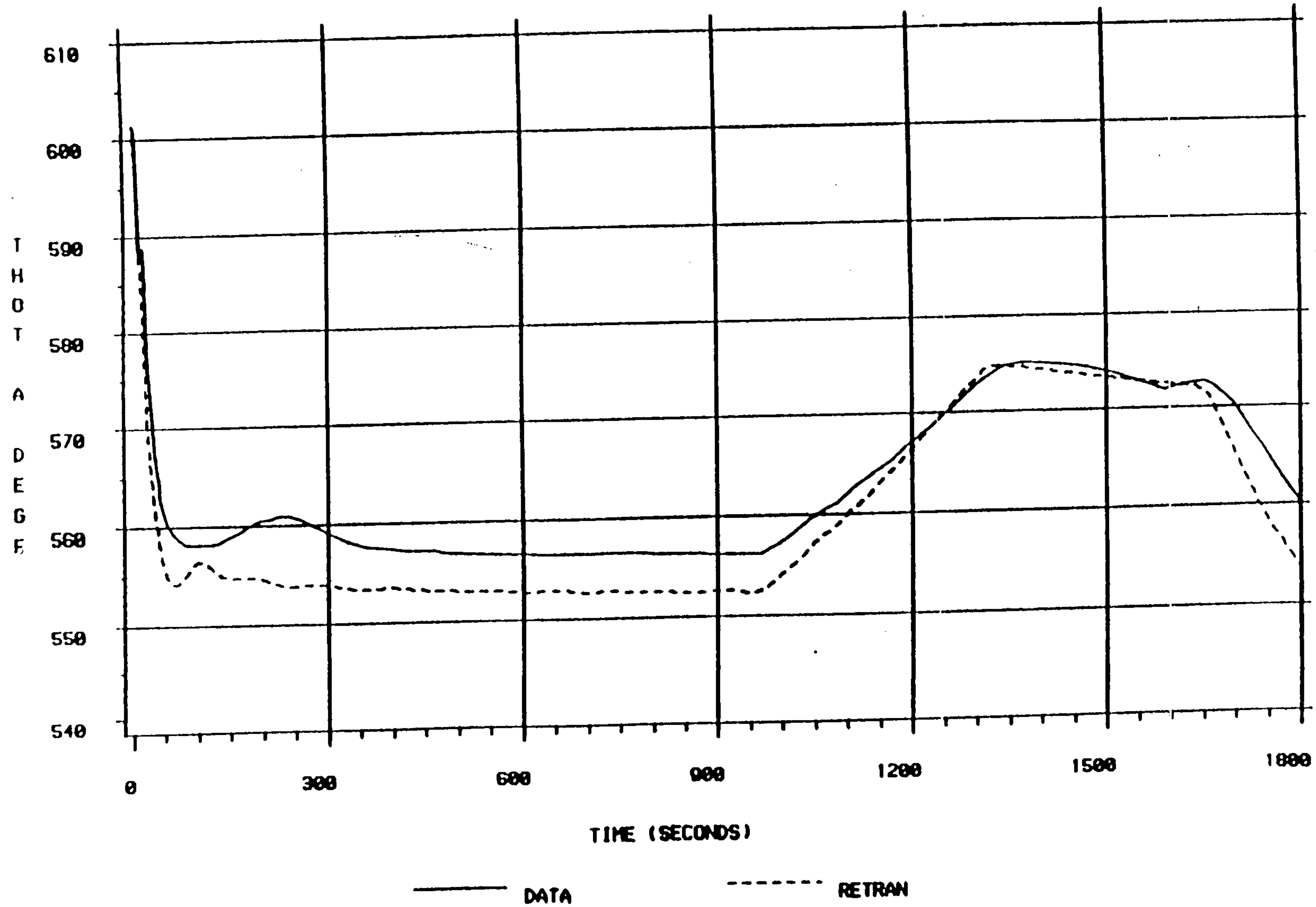


Figure 4.1.1-3

ONS-3 LOSS OF MAIN FEEDWATER

8/14/84 EVENT

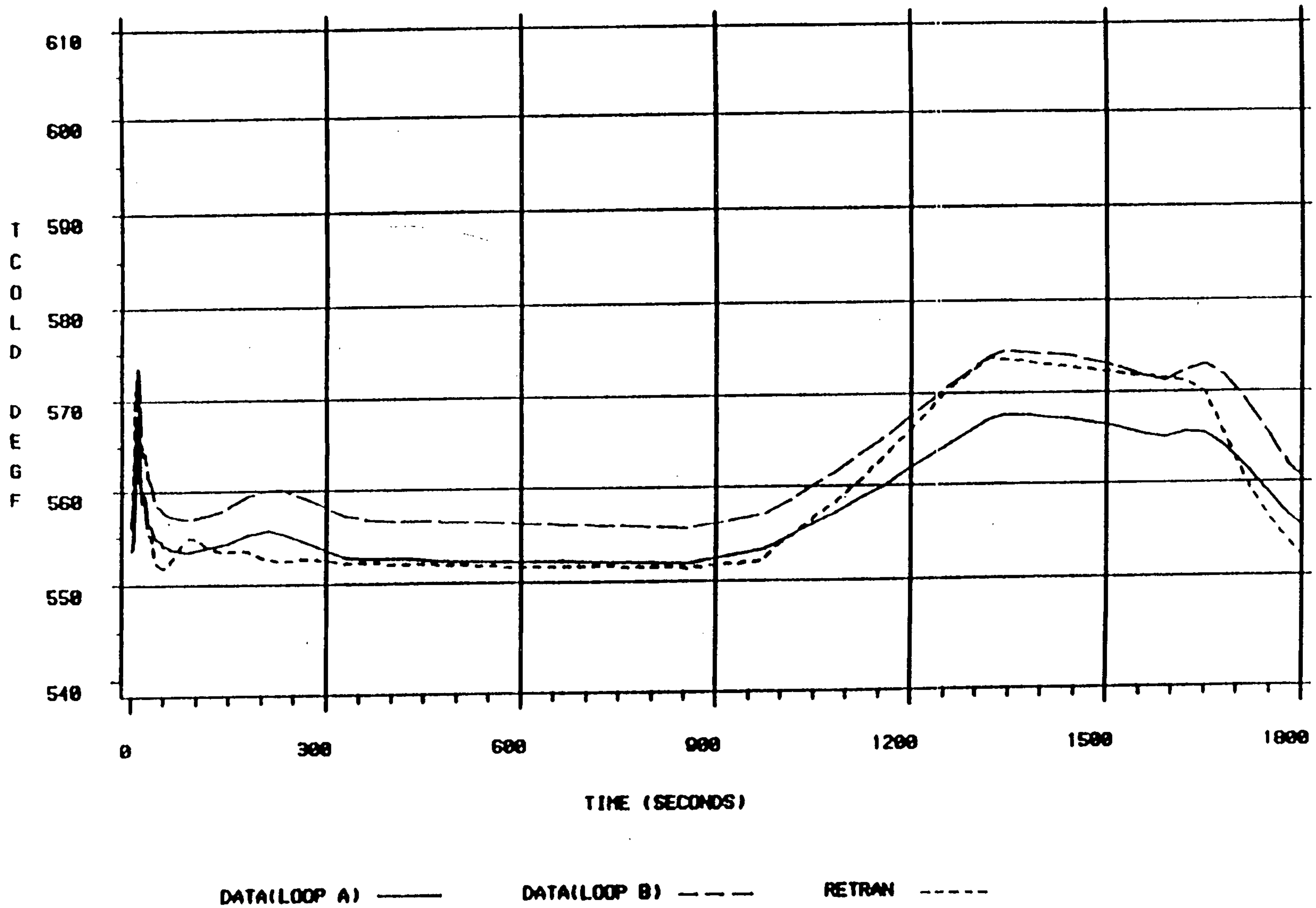


Figure 4.1.1-4

ONS-3 LOSS OF MAIN FEEDWATER

8/14/84 EVENT

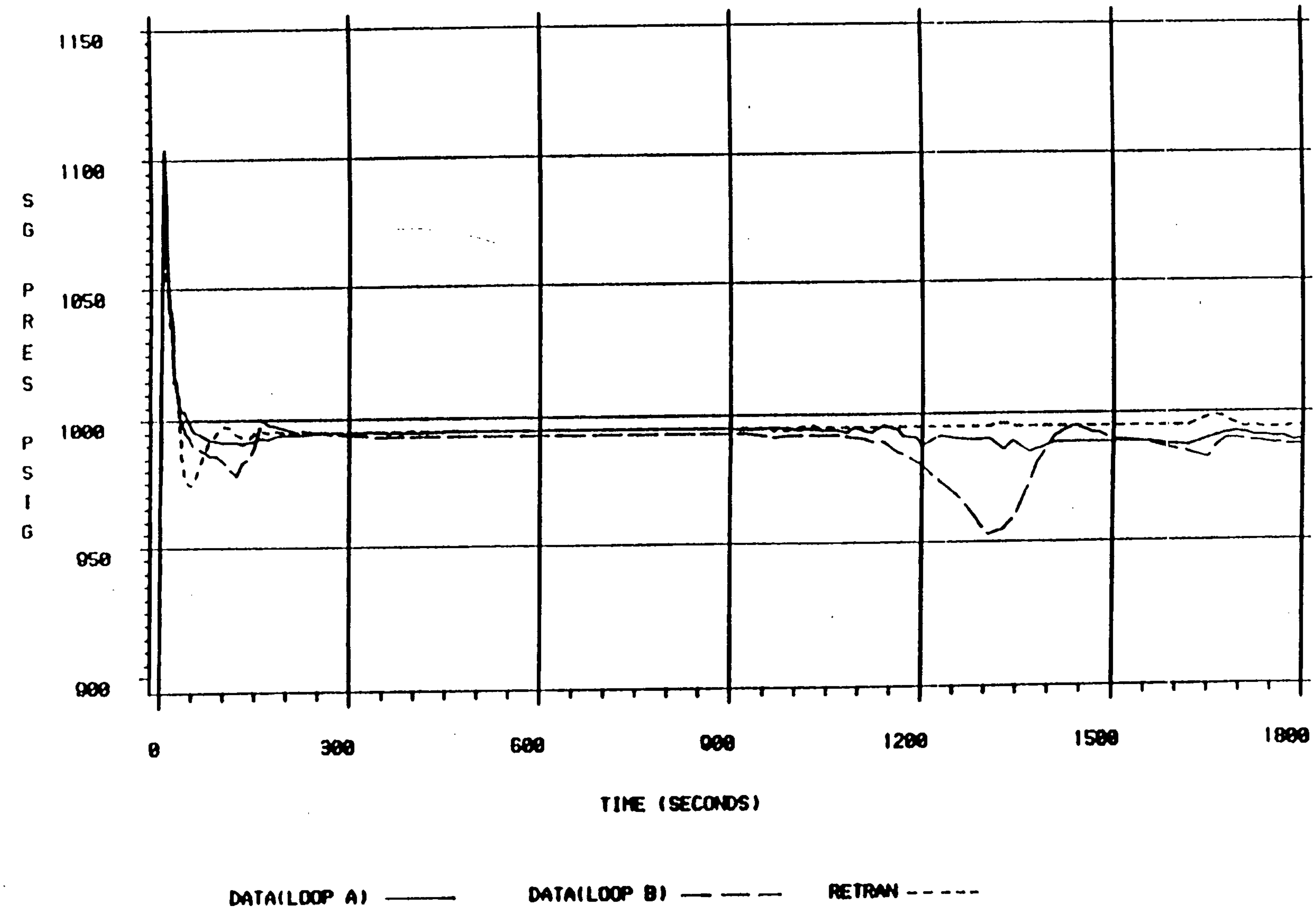


Figure 4.1.1-5

ONS-3 LOSS OF MAIN FEEDWATER

8/14/84 EVENT

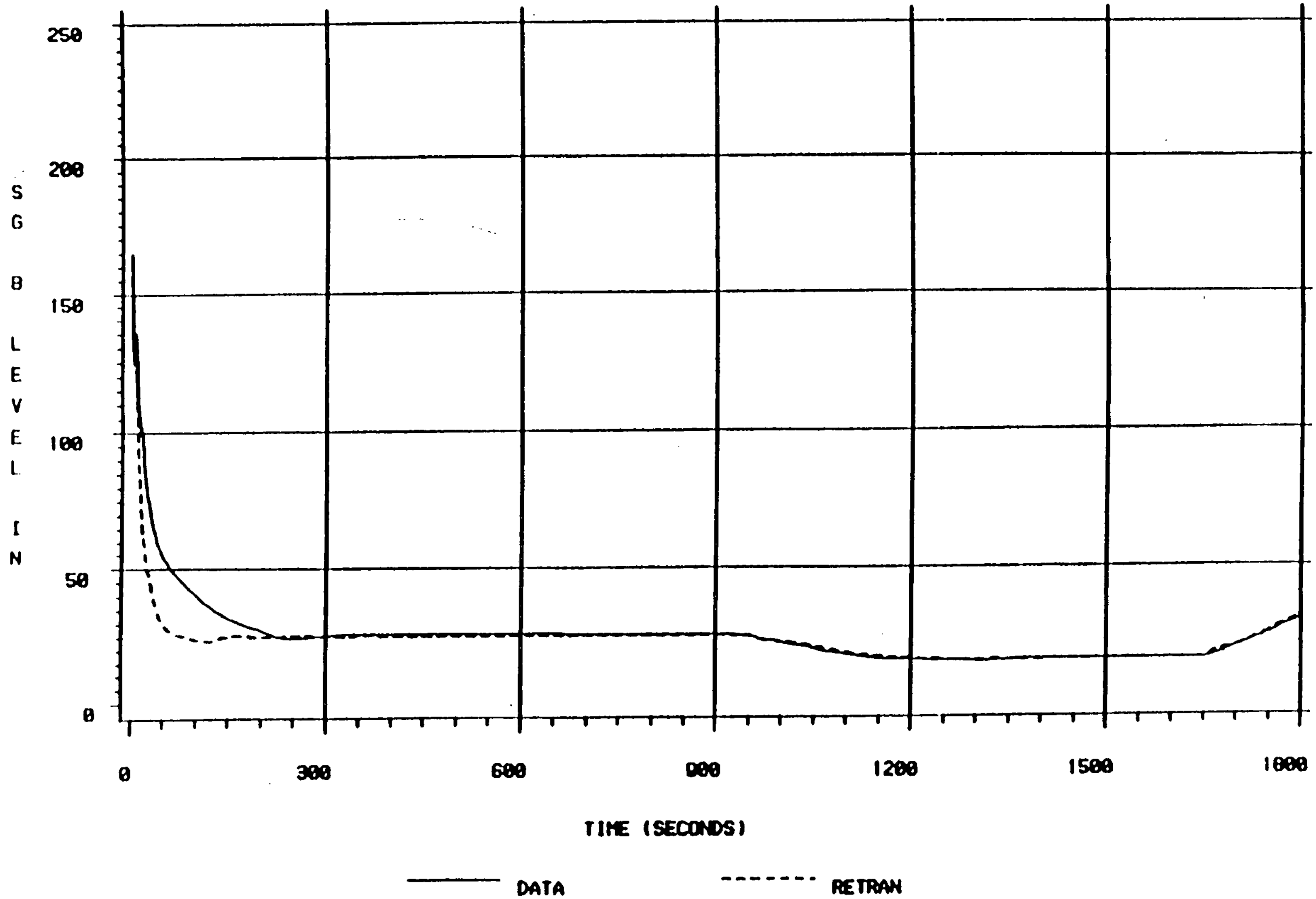


Figure 4.1.1-6

4.2 Excessive Secondary Heat Transfer

4.2.1 Oconee Nuclear Station Unit 1
Turbine Bypass Valve Failure Following Reactor Trip
September 10, 1982

Transient Description

Oconee Unit 1 was operating at 85% full power when an anticipatory reactor trip occurred on a main turbine trip signal. The main turbine Electro-Hydraulic Control (EHC) System initiated the turbine trip. Due to a malfunction in the Turbine Bypass System, the turbine bypass valves failed to control steam generator (SG) pressure to the normal post-trip value of 1010 psig. Instead, pressure decreased to approximately 860 psig before the valves began to close automatically. Shortly thereafter the operators manually closed the valves. The result of the extended depressurization was an overcooling of the Reactor Coolant System (RCS). RCS pressure decreased to a minimum of 1664 psig and pressurizer level decreased to 4 inches before recovering. The RCS cold leg temperature decreased to a minimum of 544 °F. Letdown was manually isolated in the first 10 seconds and RCS makeup flow was increased by manually opening a second makeup valve. Only one high pressure injection (HPI) pump operated during the transient. Main feedwater (MFW) was available throughout the event. Once the turbine bypass valves were closed, the plant returned to a normal post-trip condition.

Discussion of Important Phenomena

Several important phenomena occurred during the transient which challenged the capability of RETRAN and the Oconee RETRAN Model to accurately simulate the plant response. These phenomena include steam generator secondary void fraction profile and primary-to-secondary heat transfer, main steam relief and secondary pressure control capabilities, and pressurizer behavior. In this particular event the most significant of these is the increase in primary-to-secondary heat transfer due to the excessive steaming.

Model Description and Boundary Conditions

The plant response during this event showed little asymmetry between loops so the one-loop Oconee RETRAN Model (Figure 2.2-2) was used for the analysis. The parameters used as initial conditions were matched, where possible, to the plant data. The plant data used for this analysis was interpreted from transient monitor plots and post-trip review program data. The transient monitor digital data was not available for this event.

	Model	Plant
Power Level	85% (2182.8 MWt)	85% (2182.8 MWt)
RCS Pressure	2124 psig	2124 psig
PZR Level	215 inches	215 inches
T hot	596.3 °F	596.8 °F
T cold	559.1 °F	559.1 °F
SG Pressure	897.5 psig	897.5 psig
SG Level	141 inches (XSUR)	155 inches (XSUR)
	41% (OR)	57% (OR)
MFW Temperature	441.6 °F	441.6 °F
RCS Flow	149×10^6 lbm/hr	144×10^6 lbm/hr
MFW Flow	9.0×10^6 lbm/hr	8.9×10^6 lbm/hr

The RCS and MFW flows are adjusted to give the correct primary and secondary temperatures. Since SG level decreases with power level, an adjustment to the nominal level at 100% power must be made. The 100% full power level in the plant prior to the trip was approximately[

]

The problem boundary conditions used are cycle specific post-trip delayed neutron power and decay heat, MFW and HPI flow, and a reduction in the turbine bypass valve setpoint. The MFW and HPI flows used in the simulation are from the post-trip review program data for this event. The turbine bypass valve setpoint is reduced from the normal post-trip value of 1010 psig to 880 psig to match the actual SG pressure response as indicated by the data.

Simulation Results

The simulation begins with the anticipatory reactor trip on main turbine trip and continues for 120 seconds. The simulation is terminated at the point where the plant has recovered from the overcooling event and the major parameters of interest have approached their normal post-trip values. The sequence of events is given in Table 4.2.1-1, and the results of the simulation are compared to the plant data in Figures 4.2.1-1 through 4.2.1-6.

Due to the unavailability of the digital transient monitor data, the plant data was interpreted from the analog transient monitor plots and the post-trip review printout (which is given in ten second intervals). Therefore, the figures may not contain the exact maximum or minimum values for a particular parameter. Also, many of the inflections and changes in slope may not be accounted for, particularly due to the lifting and reseating of the main steam relief valves. However, the trend for all the parameters plotted is correct.

The RCS pressure response is shown in Figure 4.2.1-1. The RETRAN predicted pressure decreases faster than the data during the initial contraction of the RCS inventory after the trip. There is a consistent trend in the pressurizer level (see Figure 4.2.1-2) and hot leg temperature (see Figure 4.2.1-3) during this time period. This indicates that RETRAN may be predicting a slightly greater heat transfer rate through the steam generators at this time. The predicted RCS pressure also decreases farther than the data during the time when the minimum value occurs at approximately 80 seconds. As discussed earlier, the plant data for this event is not optimal and the RCS pressure data in particular may not be as accurate as the other parameters since it is a wide range pressure indication. The predicted pressure trends the data well towards the end of the simulation once the turbine bypass valves are closed.

The pressurizer level response is shown in Figure 4.2.1-2. The RETRAN prediction trends the plant data in a manner similar to the predicted RCS pressure response during the initial post-trip outsurge. However, the predicted level response shows better agreement with the data in the second minute than does RCS pressure. The predicted RCS temperatures (see Figures 4.2.1-3 and 4.2.1-4) also show better agreement during this time period. This indicates that the steam generator heat transfer rate is being predicted accurately by RETRAN and supports the assertion that the plant RCS pressure data is not highly accurate.

The SG pressure response is shown in Figure 4.2.1-5. The close agreement to the data seen in the first 80 seconds of the simulation (to the point at which the turbine bypass valves are closed) indicates that the main steam relief valves lift and reseat correctly, and that the steam blowdown rate through the turbine bypass valves is accurately modeled.

The predicted SG repressurization following closure of the TBVs is not as great as the plant data indicates. This indicates that some differences may exist in the inventory and heat transfer rate in the RETRAN and plant steam generators at that time.

The SG level response in Figure 4.2.1-6 shows a consistent offset from the plant data (which was incorporated in the initial conditions of the model) until the time when the turbine bypass valves begin to close. After the valves are closed the predicted level and the data merge as level approaches the minimum level controlling setpoint. The level offset is due to [

]

Table 4.2.1-1

Oconee Nuclear Station Unit 1
Turbine Bypass Valve Failure
Following Reactor Trip
September 10, 1982

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
Rx/Turbine trip*	0	0
HPI flow increased*	0-10	0-10
Turbine bypass valves fail to reseat at SG pressure of 1010 psig	28	30
Minimum RCS pressure and pressurizer level, minimum cold leg temperature, minimum SG pressure, turbine bypass valves closed	80	80
End of simulation	N/A	120

Note: Asterisks designate boundary conditions

ONS 1 TURBINE TRIP 9/10/82

RETRAN AND PLANT DATA

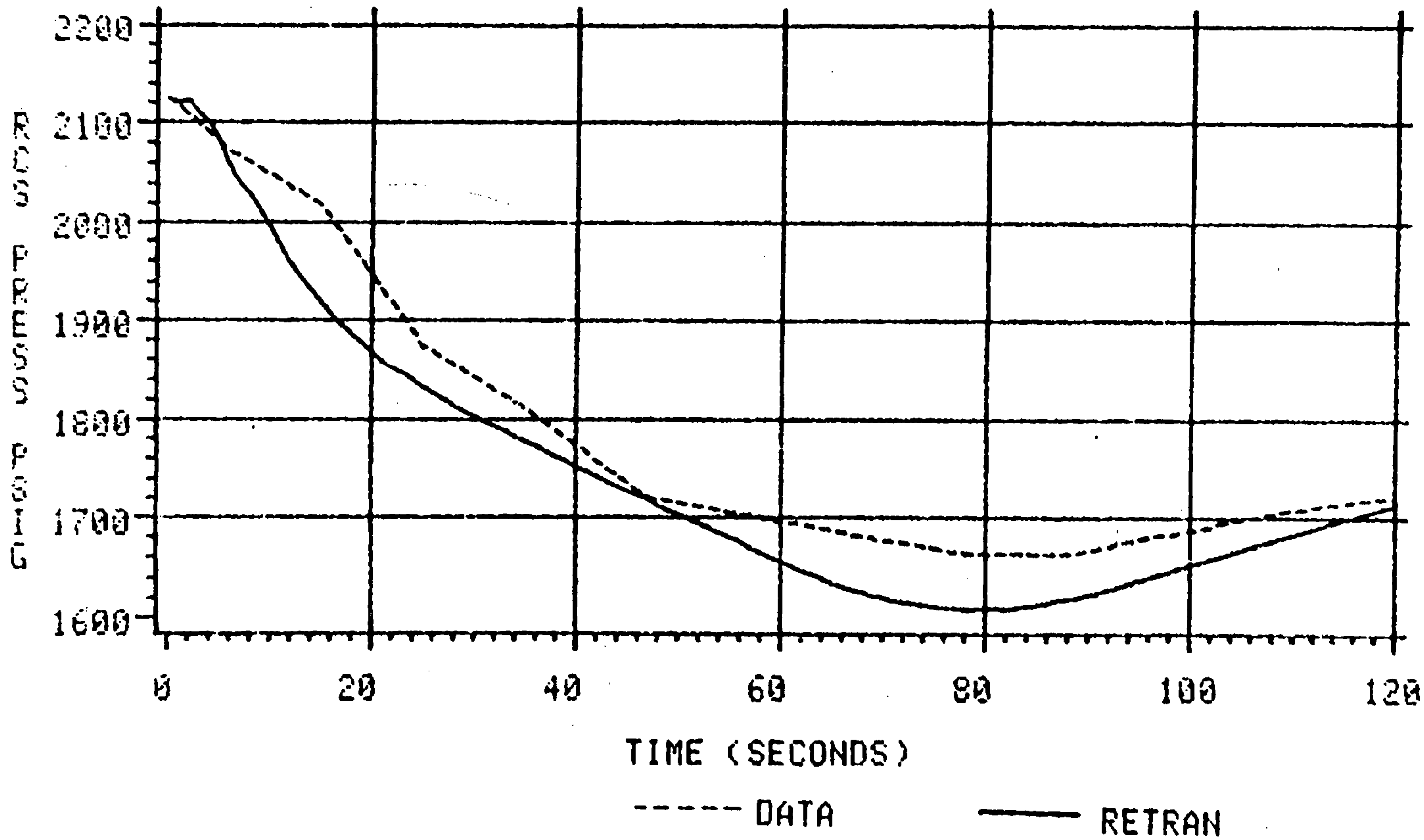


Figure 4.2.1-1

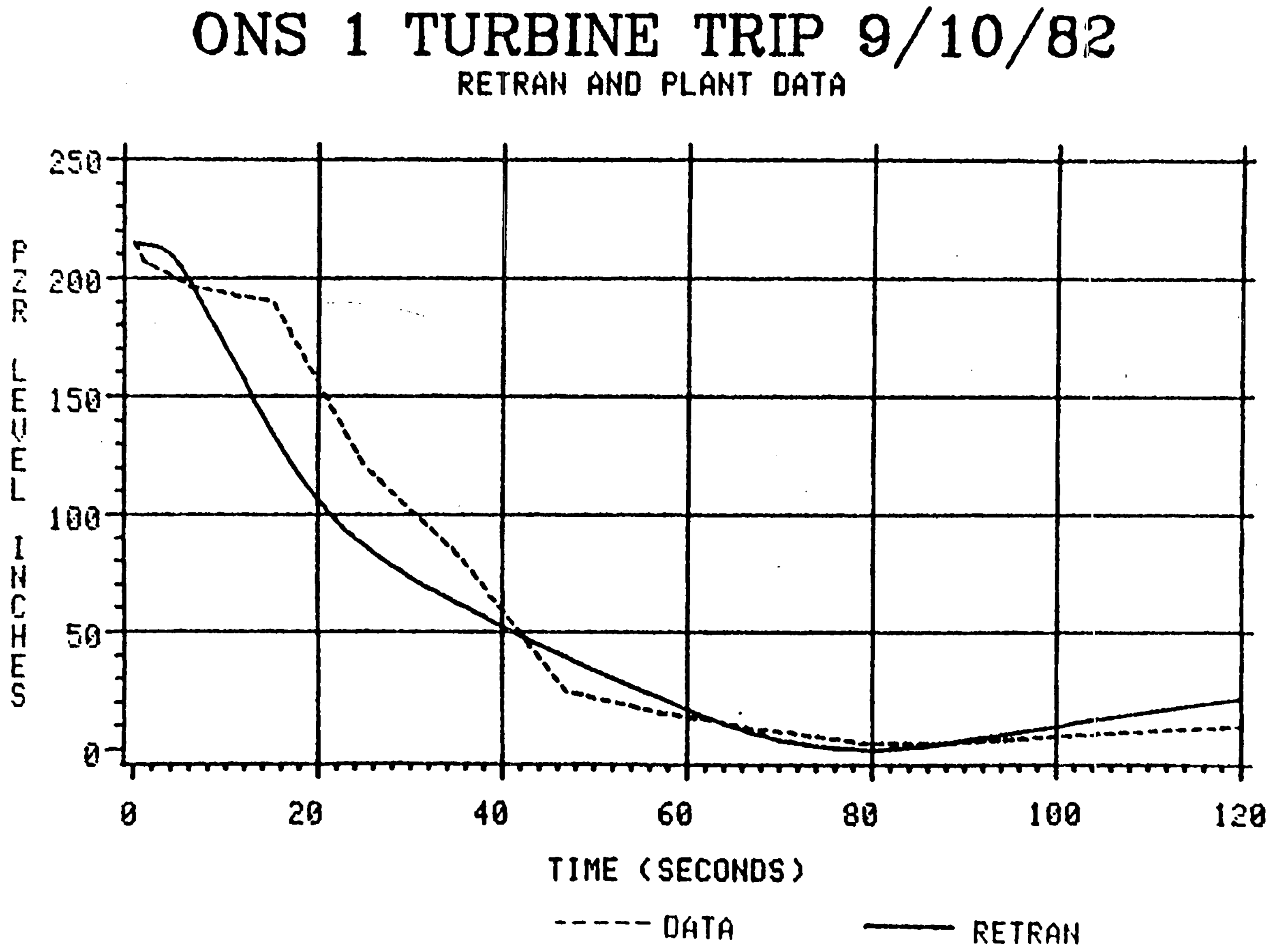

ONS 1 TURBINE TRIP 9/10/82
RETRAN AND PLANT DATA
PZR LEVEL INCHES
250
200
150
100
50
0
0
20
40
60
80
100
120
TIME (SECONDS)
----- DATA
RETRAN

Figure 4.2.1-2

ONS 1 TURBINE TRIP 9/10/82

RETRAN AND PLANT DATA

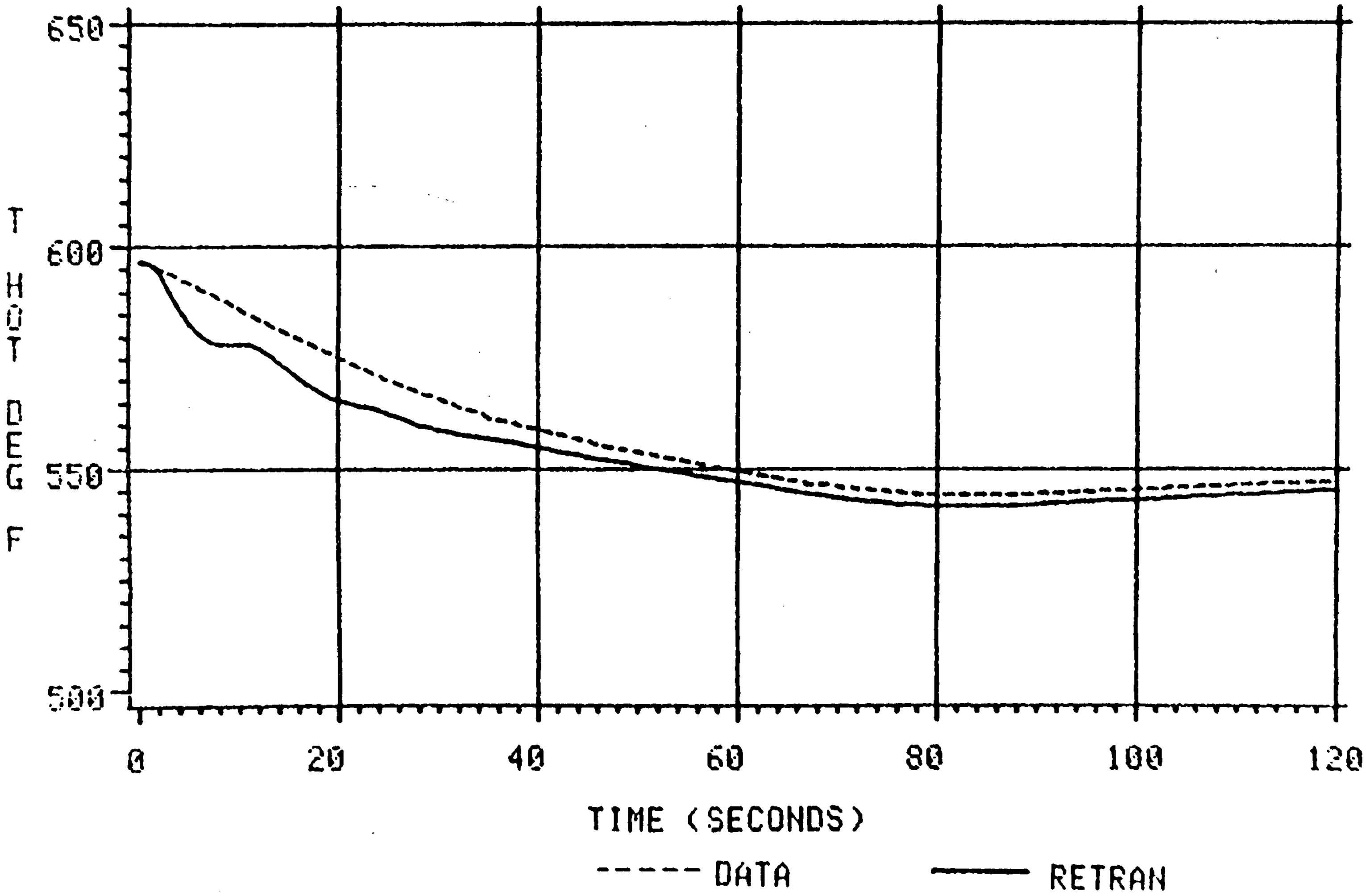


Figure 4.2.1-3

ONS 1 TURBINE TRIP 9/10/82

RETRAN AND PLANT DATA

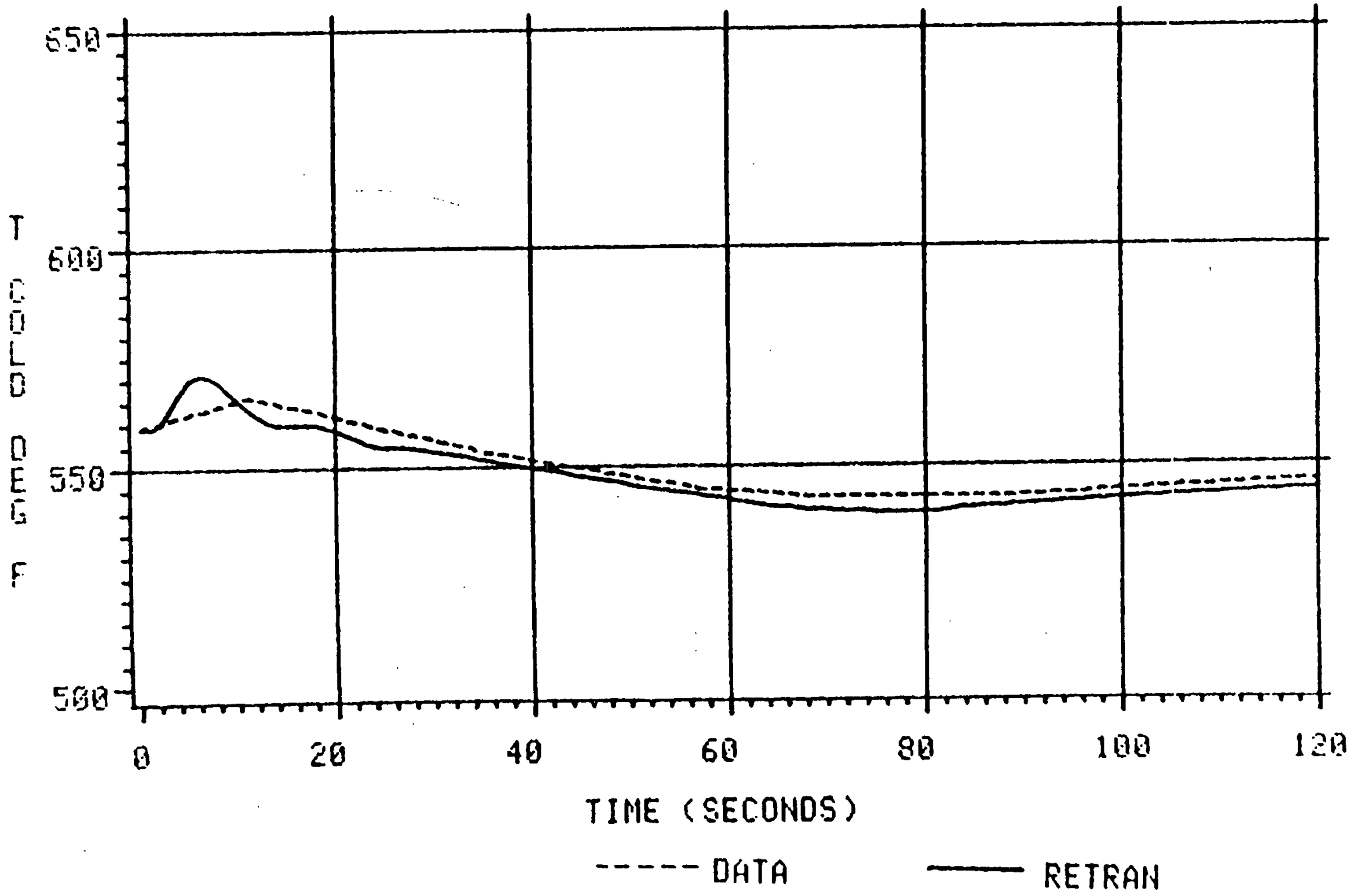


Figure 4.2.1-4

ONS 1 TURBINE TRIP 9/10/82

RETRAN AND PLANT DATA

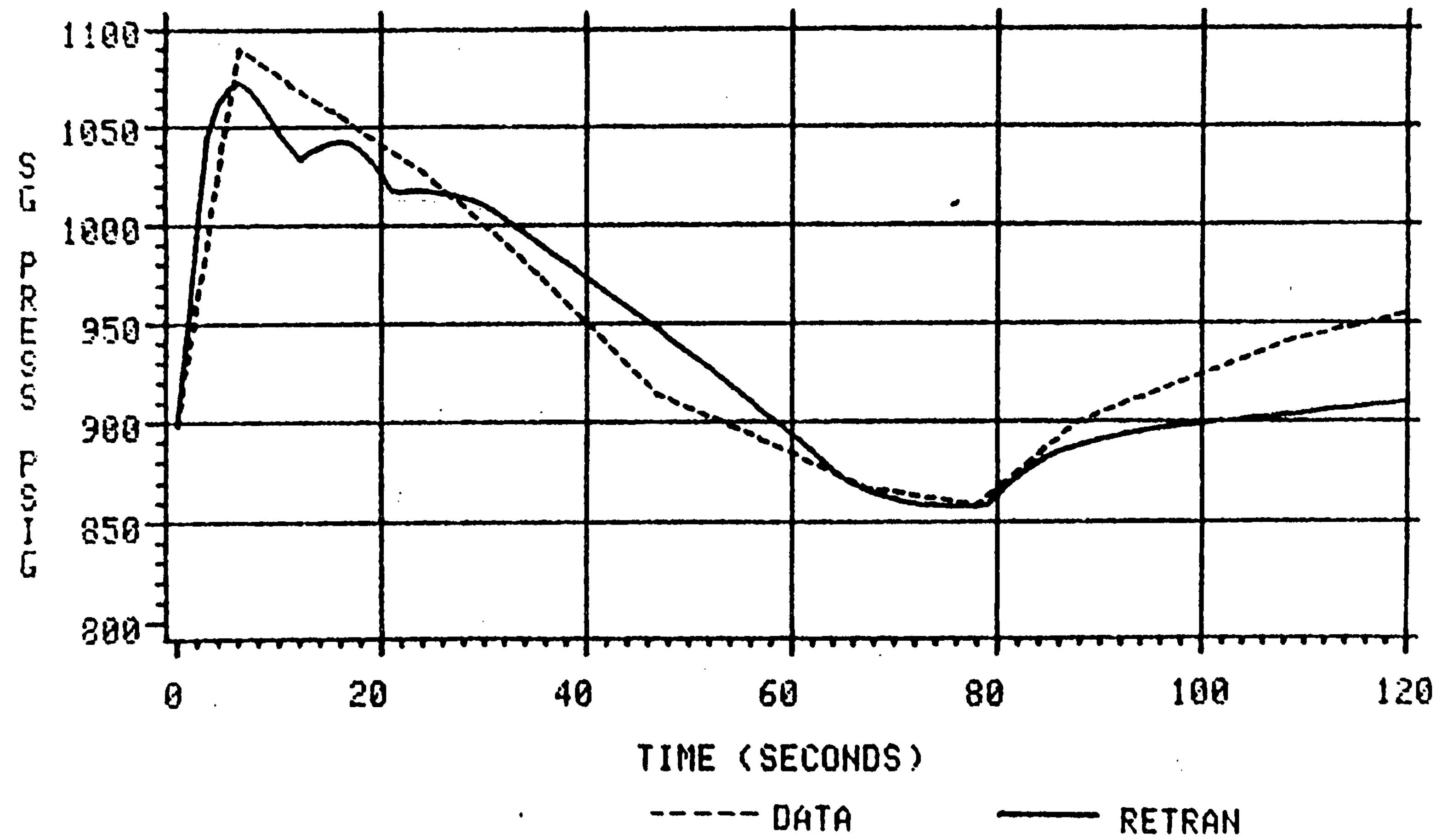


Figure 4.2.1-5

ONS 1 TURBINE TRIP 9/10/82

RETRAN AND PLANT DATA

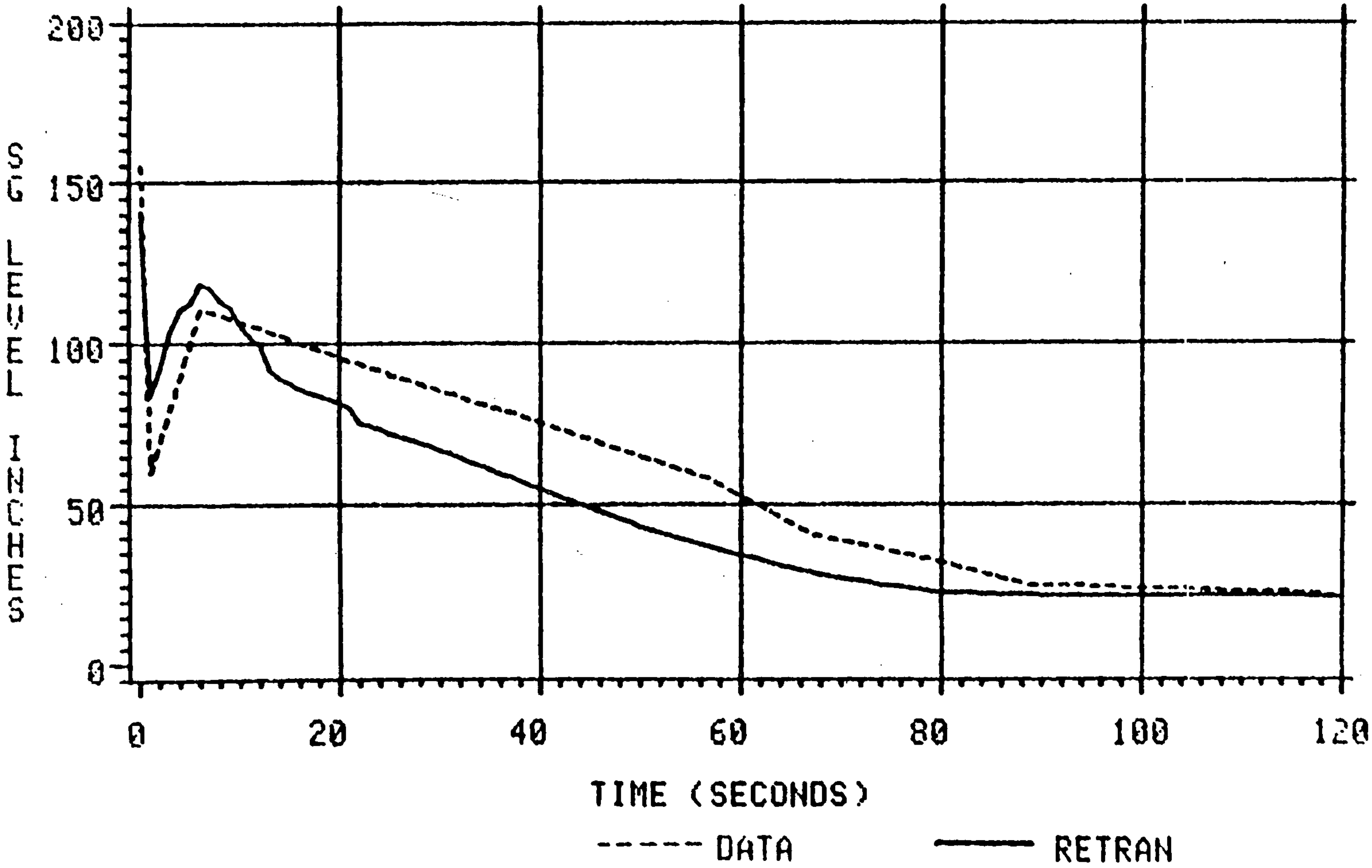


Figure 4.2.1-6

4.2.2 Oconee Nuclear Station - Unit 3
Steam Generator Overfeed Following Reactor Trip
March 14, 1980

Transient Description

Oconee Unit 3 was operating at 100% full power when an anticipatory reactor trip occurred on a main turbine trip signal. The main turbine Electro-Hydraulic (EHC) System initiated the turbine trip. Due to an Integrated Control System (ICS) failure, the main feedwater (MFW) pumps did not run back properly in response to the reduced demand signal. This resulted in overfeeding the steam generators, and caused both pumps to trip automatically on high level in steam generator (SG) "A" at approximately 2 minutes into the event. Both motor-driven and the turbine driven emergency feedwater (EFW) pumps then started and feedwater was reestablished to the steam generators. Makeup to the RCS was increased after the trip by opening a second makeup valve and starting a second high pressure injection (HPI) pump.

The post-trip plant response indicated little asymmetric behavior between the "A" and "B" loops even though the overfeeding of the steam generators was very asymmetric. The RCS pressure and pressurizer level post-trip responses were below normal for a turbine trip. The RCS pressure decreased to 1762 psig at approximately 60 seconds before recovering and the pressurizer level decreased to 50 inches at the same time. The post-trip SG pressures drifted below the 1010 psig setpoint in the second minute after the trip due to the overfeed and the auxiliary steam demand. Once the MFW pumps tripped and EFW was initiated, a normal cooldown resumed and SG pressures increased.

Discussion of Important Phenomena

Several important phenomena occurred during the transient which challenged the capability of RETRAN and the Oconee RETRAN Model to accurately simulate the plant response. These phenomena include steam generator secondary void fraction profile and primary-to-secondary heat transfer, main steam relief, and pressurizer behavior. In this particular event, the SG overfeed is the most significant of these. The model prediction of the heat transfer resulting

from the overfeed, and the slight secondary depressurization due to the overfeed, are of particular interest.

Model Description and Boundary Conditions

The plant response during this event showed a significant asymmetric overfeed to the steam generators so the two-loop Oconee RETRAN Model (see Figure 2.2-1) was used for this simulation. In addition, the Unit 3 specific feedwater and main steam line models were incorporated into the model. The parameters used as initial conditions were matched, where possible, to the plant data. The plant data used for this analysis consists of digital transient monitor data and post-trip review program data.

Initial Conditions

	Model	Plant
Power Level	100% (2568.0 MWt)	100% (2568.0 MWt)
RCS Pressure	2139 psig	2139 psig
PZR Level	228 inches	228 inches
T hot	600.3 °F "A"	600.3 °F "A"
	600.3 °F "B"	601.2 °F "B"
T cold	556.5 °F "A"	556.5 °F "A"
	554.0 °F "B"	556.7 °F "B"
SG Level	61% (OR) "A"	61% (OR) "A"
	68% (OR) "B"	68% (OR) "B"
SG Pressure	910 psig "A"	898 psig "A"
	910 psig "B"	895 psig "B"
MFW Temperature	454 °F	454 °F
RCS Flow	145×10^6 lbm/hr	149×10^6 lbm/hr
MFW Flow	5.5×10^6 lbm/hr "A"	5.3×10^6 lbm/hr "A"
	5.4×10^6 lbm/hr "B"	5.3×10^6 lbm/hr "B"

Unlike several other benchmark analyses, the initial SG levels in the analysis were set equal to the plant data. This approach was taken for two reasons.

[

]

The problem boundary conditions used are cycle specific post-trip delayed neutron power and decay heat, MFW and HPI flow, and a reduction in the turbine

bypass valve setpoint. The MFW flow used in the simulation comes from the transient monitor and the post-trip review program. The HPI flow consists of normal makeup from one pump for the first 30 seconds and the maximum possible injection from two pumps from 30 to 120 seconds. The turbine bypass valve setpoint is reduced from the normal post-trip value of 1010 psig for both steam generators to 1004 psig for SG "A" and 992 psig for SG "B". These values match the actual SG pressure response as indicated by the data.

Simulation Results

The simulation begins with the anticipatory reactor trip on main turbine trip and continues for 120 seconds. The simulation ends at the point where the steam generator overfeed is terminated by the trip of the MFW pumps and the major plant parameters have started to return to normal post-trip values. The sequence of events is given in Table 4.2.2-1, and the results of the simulation are compared to the plant data in Figures 4.2.2-1 through 4.2.2-10.

The RCS pressure response is shown in Figure 4.2.2-1. The RETRAN predicted pressure response trends the plant data with only slight deviations at 20 and 60 seconds. The pressurizer level response shown in Figure 4.2.2-2 trends the plant data closely for the entire simulation. This is due mainly to the accurate steam generator heat transfer prediction immediately after the trip and during the overfeed.

The RCS temperature response is shown in Figures 4.2.2-3 through 4.2.2-6. The predicted temperature response trends the data well, in particular after the first 20 seconds. A discrepancy does exist immediately following the trip which can be attributed to the time lags associated with the plant RTDs. This time lag is approximately [ ] seconds and was not accounted for in the RETRAN model used in this simulation.

The SG pressure response is shown in Figures 4.2.2-7 and 4.2.2-8. The RETRAN prediction of the SG pressure trends the plant data closely for both steam generators. The reseating action of the main steam safety valves and the resulting pressure response compares well. The slight depressurization due to the overfeed, and the repressurization at the time that the MFW pumps trip is also predicted.

The SG level responses are shown in Figures 4.2.2-9 and 4.2.2-10. Beginning at 40 seconds, a nearly constant offset in indicated level is maintained in both steam generators. This reflects an accurate comparison during the overfeeding phase of the transient. The cause for the development of the offset during the initial post-trip phase cannot be ascertained, but is most likely associated with the uncertainty in the total delivered feedwater during the SG pressurization following turbine trip.

Table 4.2.2-1

Oconee Nuclear Station Unit 3
Steam Generator Overfeed
Following Reactor Trip
March 14, 1980

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
Rx/Turbine trip*	0	0
HPI flow increased*	30	30
Minimum RCS pressure, and minimum PZR level	60	60
MFW pumps trip on high SG level*	113	113
End of simulation	N/A	120

Note: Asterisks designate boundary conditions

ONS-3 TURBINE TRIP

3/14/80 EVENT

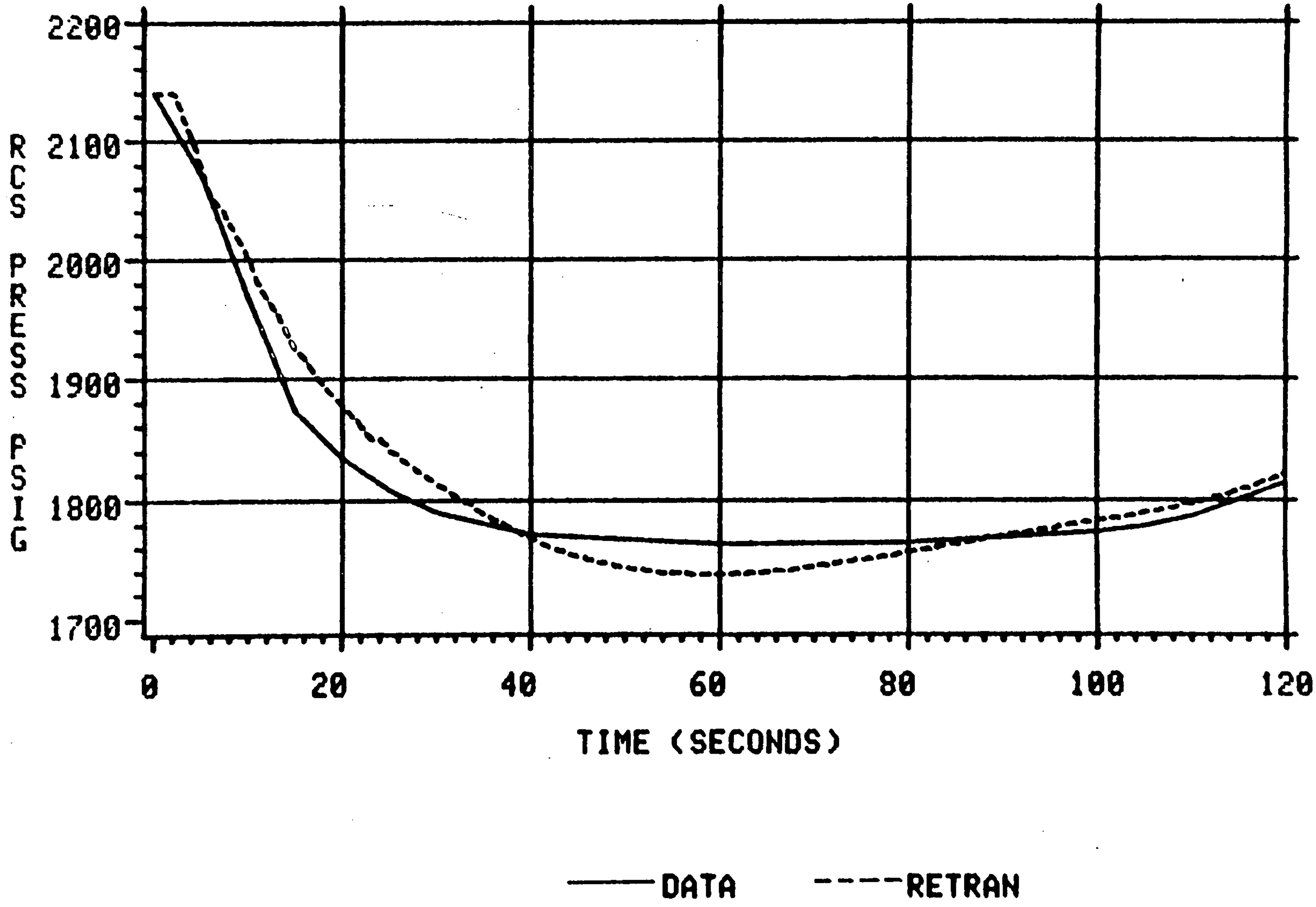


Figure 4.2.2-1

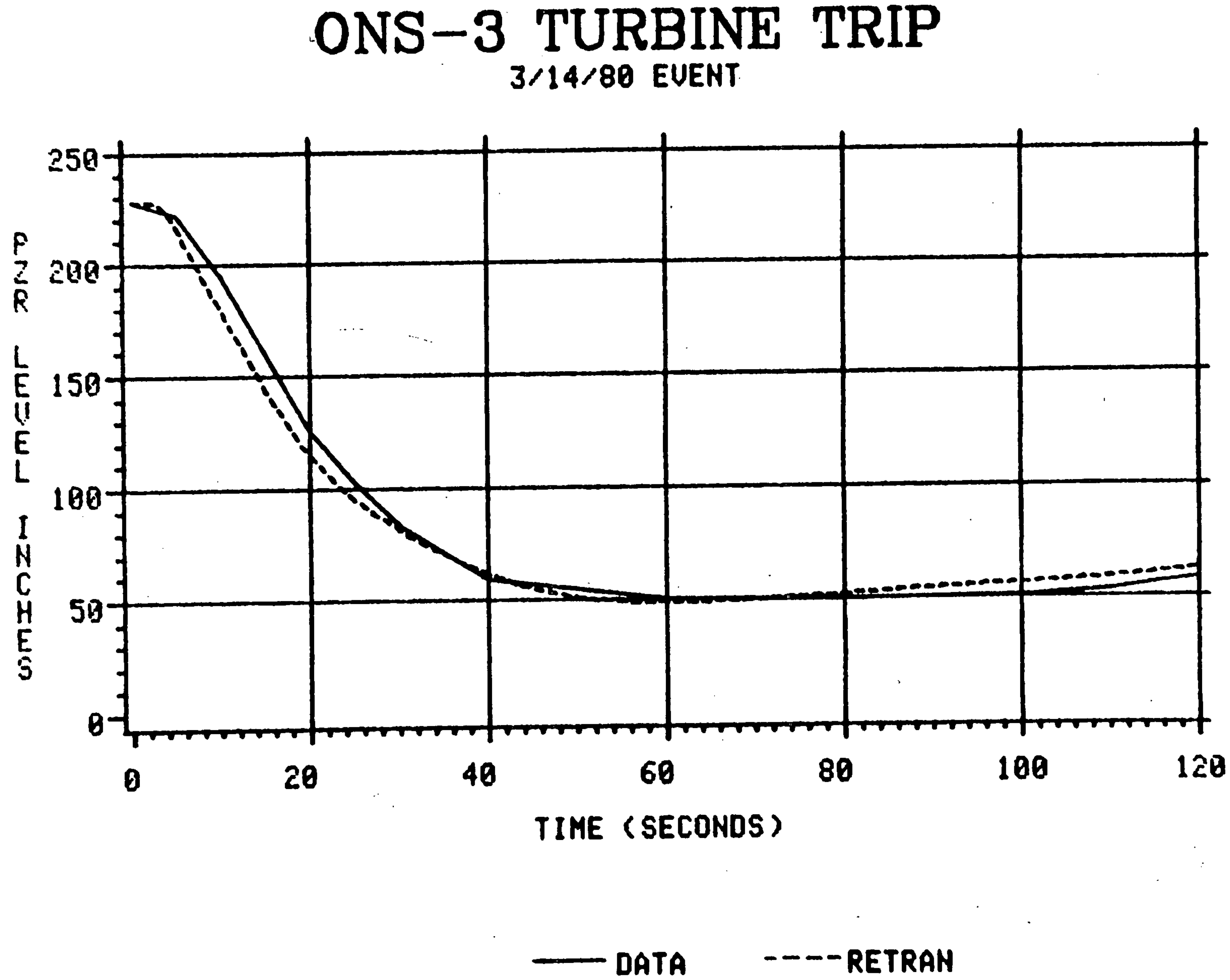

ONS-3 TURBINE TRIP
3/14/80 EVENT
PZR LEVEL INCHES
250
200
150
100
50
0
0
20
40
60
80
100
120
TIME (SECONDS)
DATA
RETRAN

Figure 4.2.2-2

ONS-3 TURBINE TRIP

3/14/80 EVENT

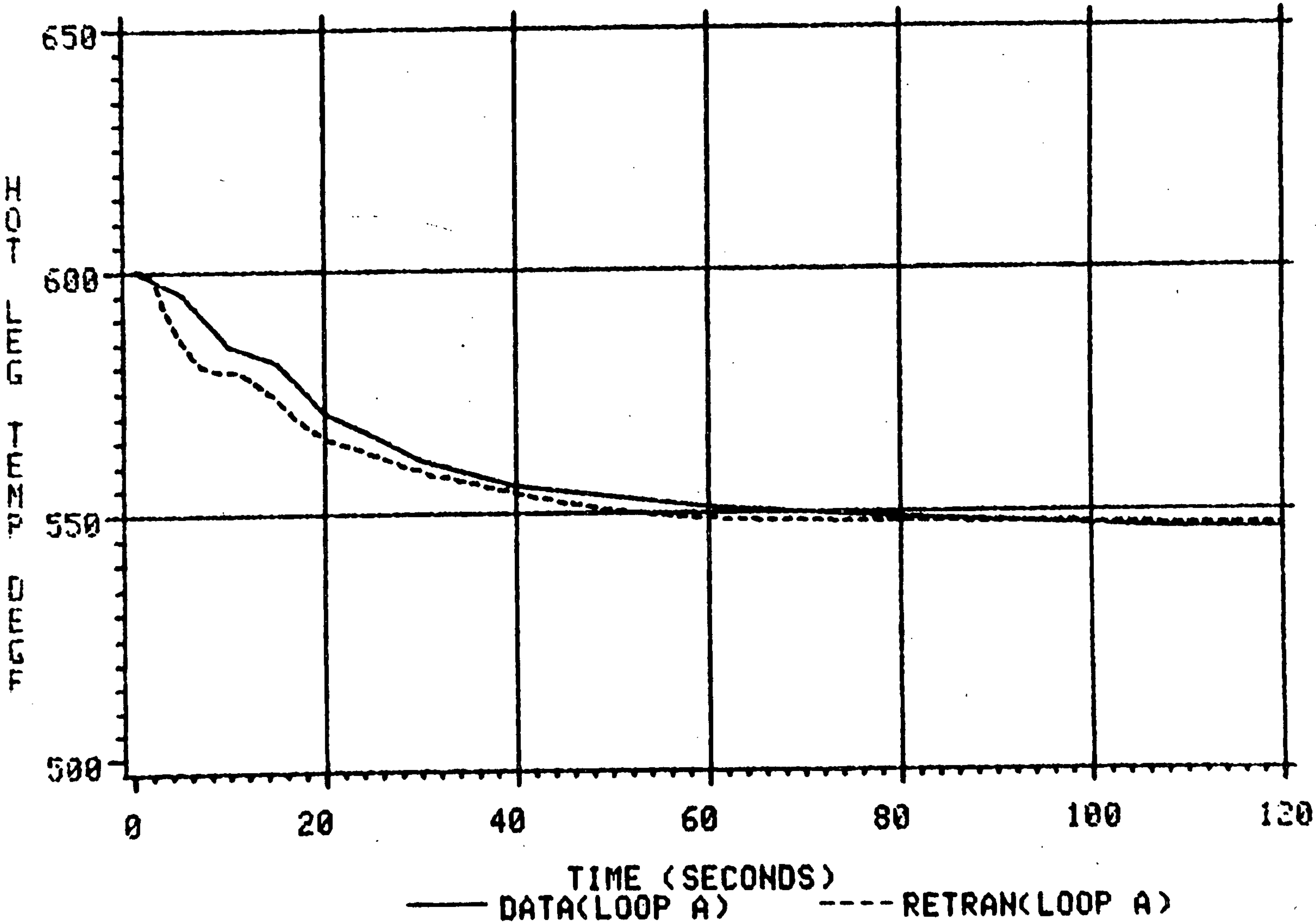


Figure 4.2.2-3

ONS-3 TURBINE TRIP

3/14/80 EVENT

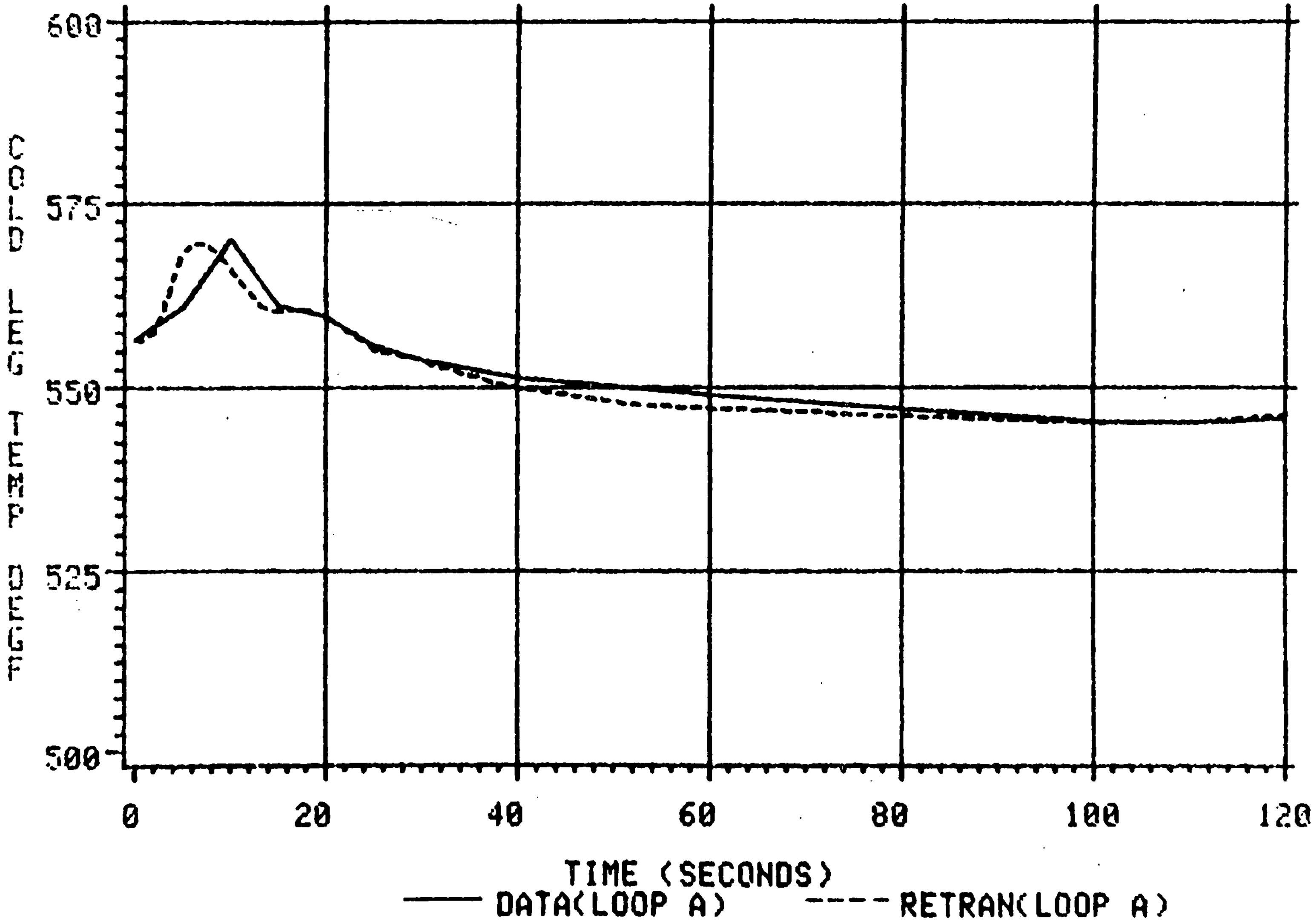


Figure 4.2.2-4

ONS-3 TURBINE TRIP

3/14/80 EVENT

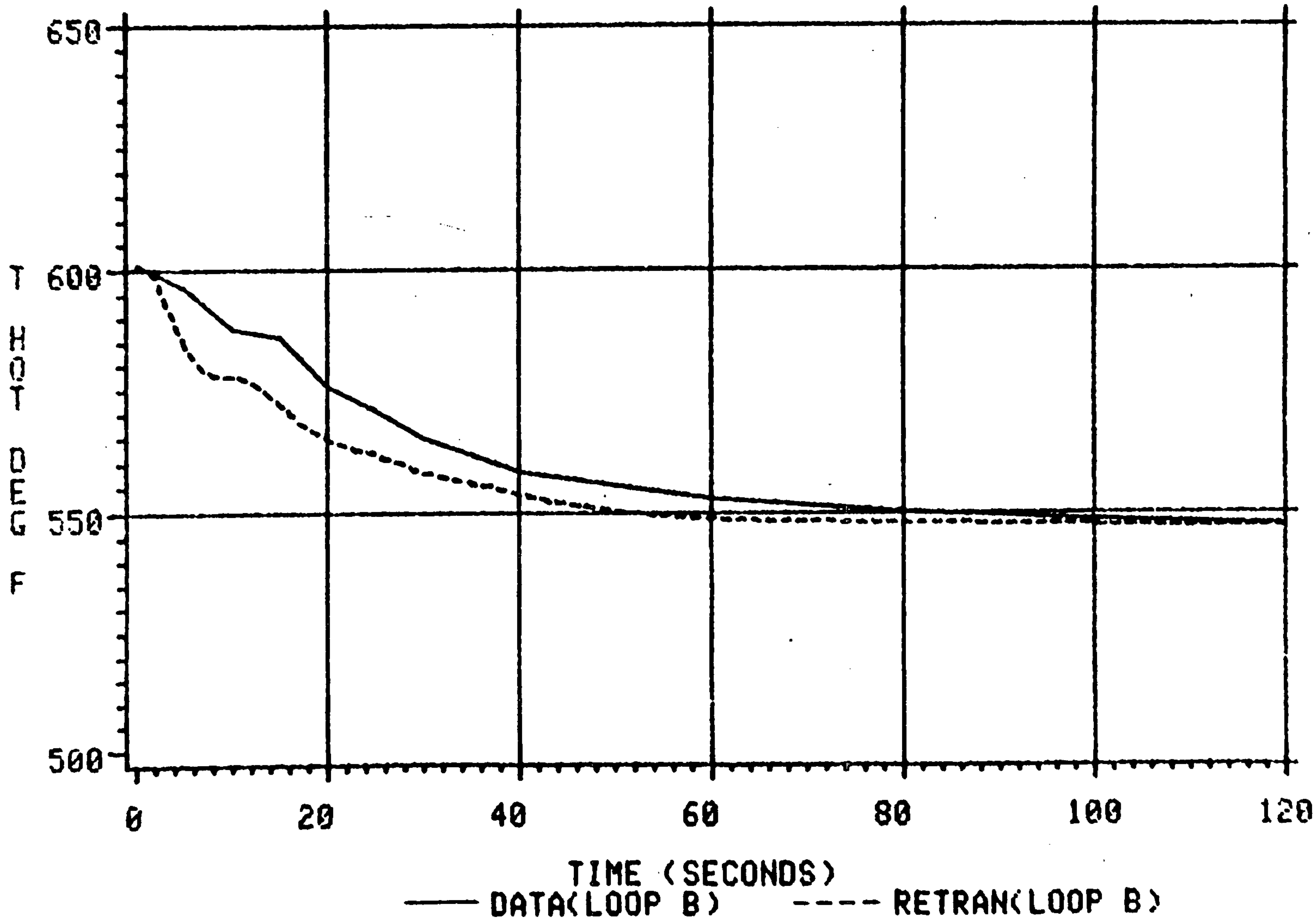


Figure 4.2.2-5

ONS-3 TURBINE TRIP

3/14/80 EVENT

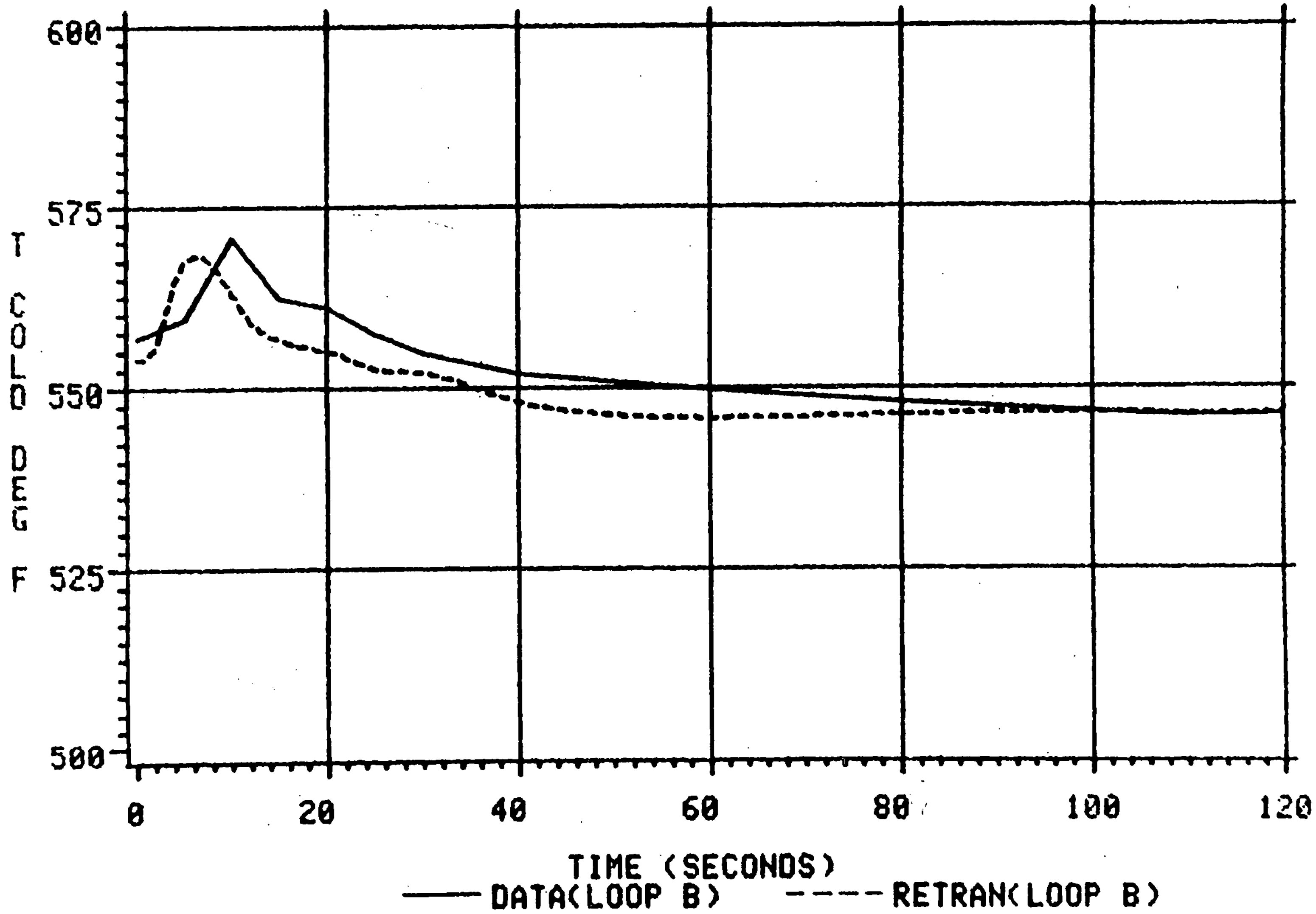


Figure 4.2.2-6

ONS-3 TURBINE TRIP

3/14/80 EVENT

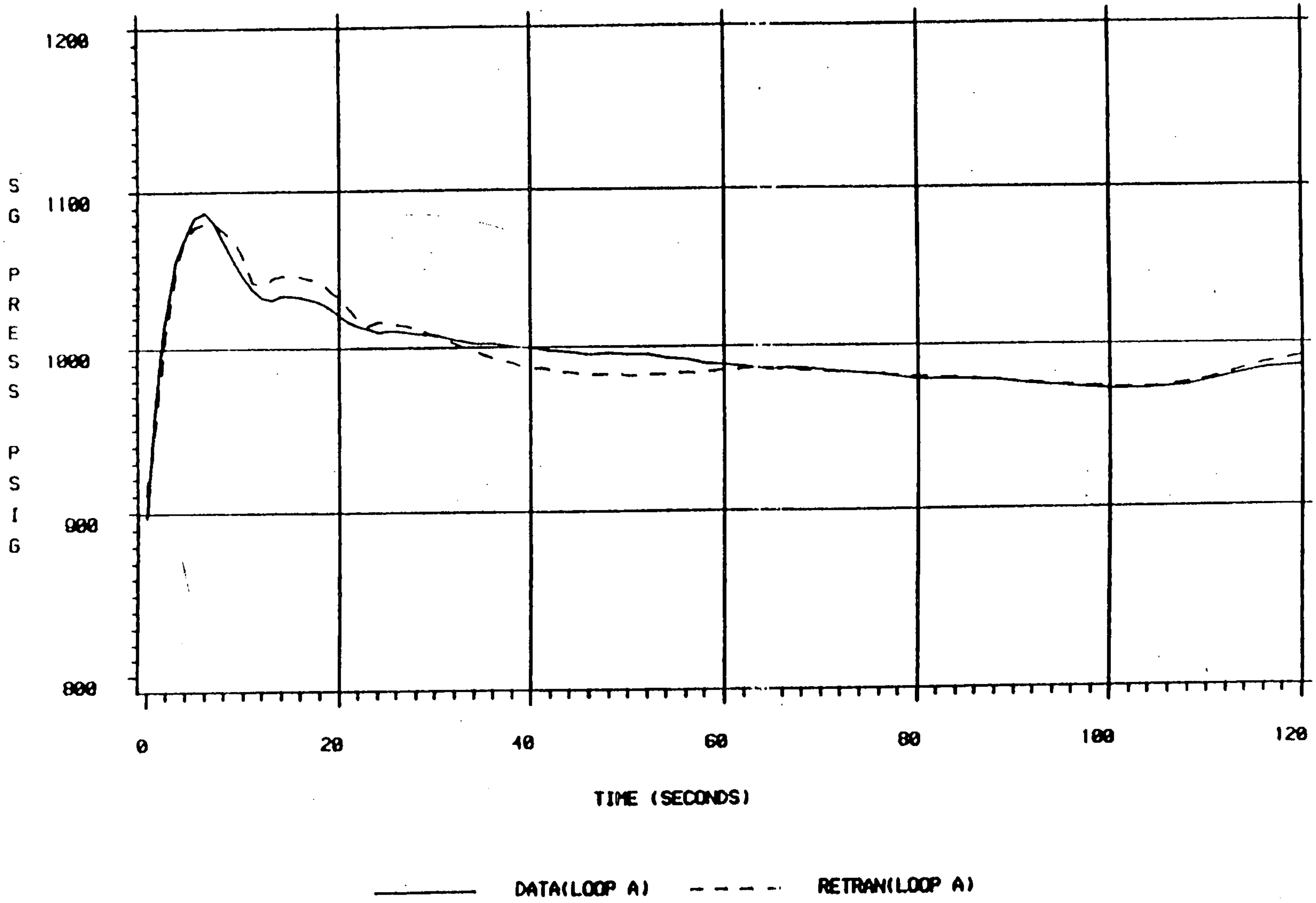


Figure 4.2.2-7

ONS-3 TURBINE TRIP

3/14/80 EVENT

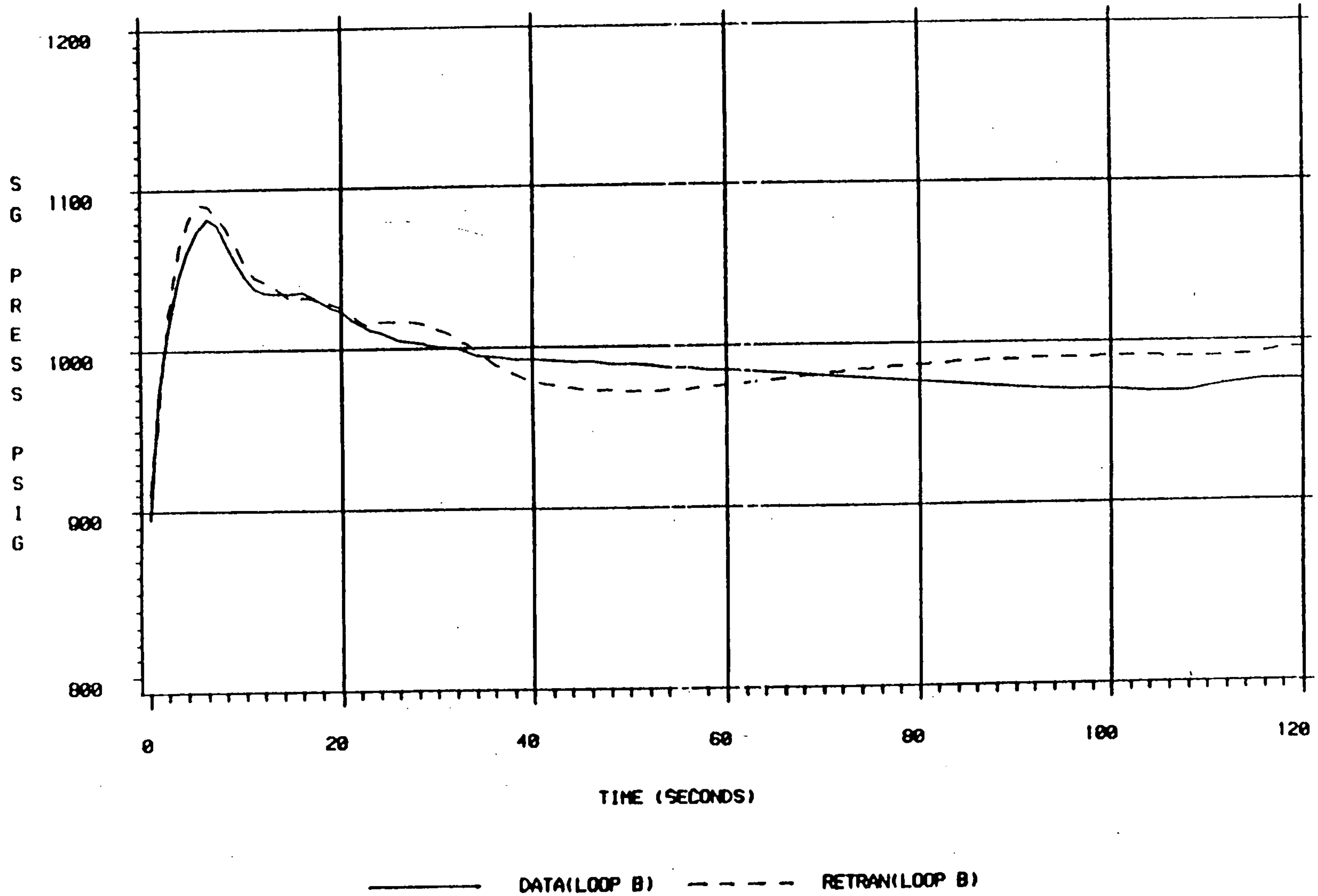


Figure 4.2.2-8

ONS-3 TURBINE TRIP

3/14/80 EVENT

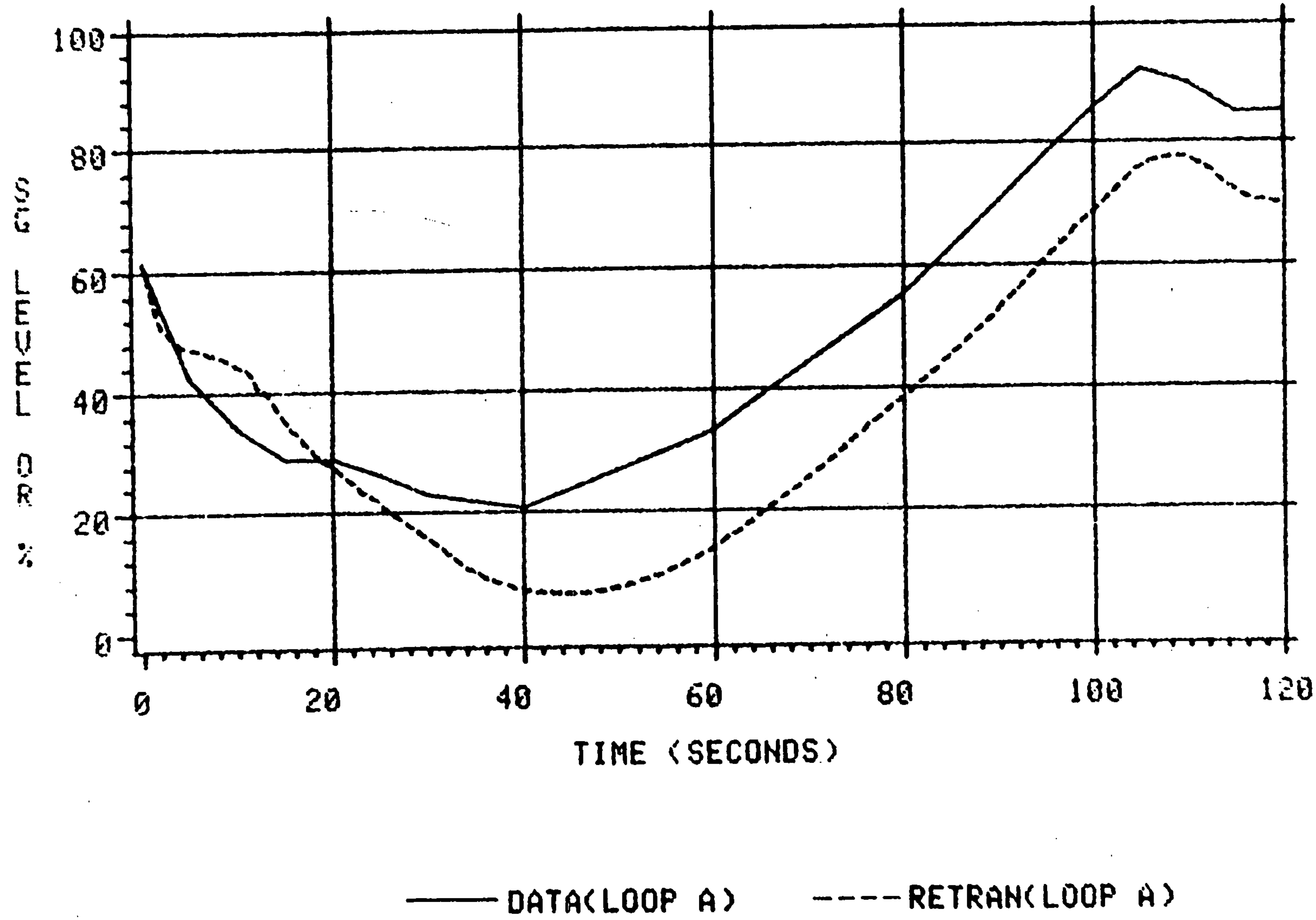


Figure 4.2.2-9

ONS-3 TURBINE TRIP

3/14/80 EVENT

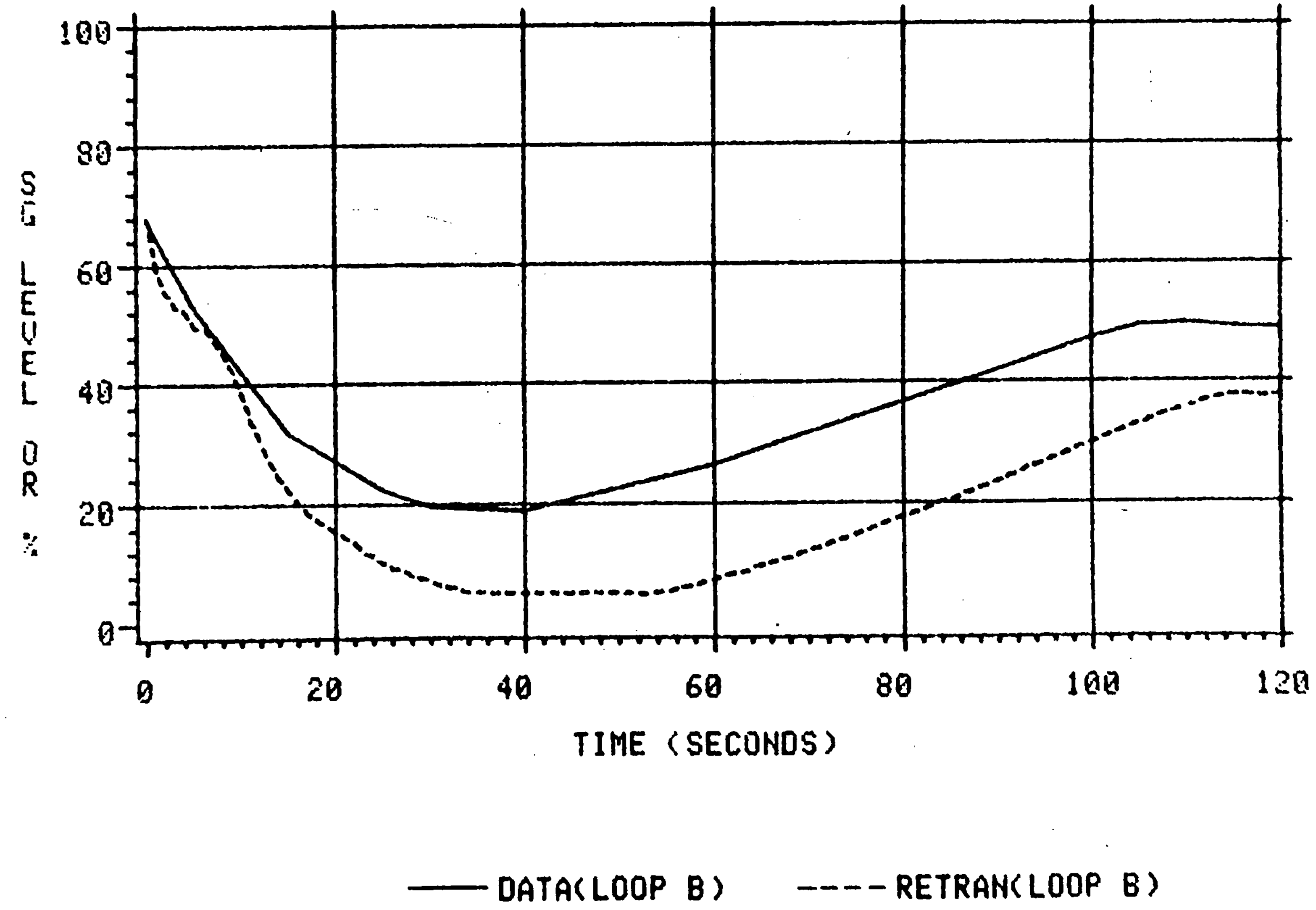


Figure 4.2.2-10

4.2.3 Oconee Nuclear Station Unit 3
Overcooling Following Loss of ICS Power
November 10, 1979

Transient Description

Oconee Unit 3 was operating at 99% full power when a spurious low hotwell level signal tripped the hotwell pumps. One condensate booster pump then tripped on low suction pressure, and the Integrated Control System (ICS) initiated a reactor runback due to low feedwater flow. The reactor/feedwater mismatch resulted in a reactor trip on high Reactor Coolant System (RCS) pressure at 55 seconds from 71% power. At 73 seconds the power supply to the ICS was lost for a period of 150 seconds. Both main feedwater pumps tripped as designed, and all three emergency feedwater pumps started automatically. Two additional high pressure injection (HPI) pumps were started at 154 seconds. With the loss of ICS power a large percentage of the control room instrumentation displayed invalid indications. Once power was restored to the ICS, the affected instrumentation functioned normally.

During the loss of ICS power (73-223 seconds), the turbine bypass valves apparently failed to an unknown partially open position, between 0 and 50% open. This resulted in a loss of steam generator pressure control and overcooling. Consequently, RCS pressure decreased to 1671 psig and pressurizer level decreased to less than 11 inches indicated level at 223 seconds. When ICS power was restored, the turbine bypass valves repositioned at 12% and 23% open on the "A" and "B" steam generators, respectively, and remained in this position for the next 20-30 minutes. The continued loss of pressure control resulted in further overcooling. At 535 seconds a hotwell pump and condensate booster pump were restarted. By this time both steam generators pressures had decreased to 400 psig, less than the developed head of the hotwell/booster pump combination, and an overfeed of SG "B" resulted. The overfeed continued for 225 seconds until the feedwater control valves were closed. SG "B" level reached 85% on the operating range, well in excess of the normal post-trip level of 25 inches on the startup range. The overfeed enhanced the overcooling transient, with RCS cold leg temperatures decreasing below the normal post-trip value of 550 °F to 455 °F in 15 minutes, and to 420 °F in 30 minutes. At 30 minutes plant conditions had stabilized.

Discussion of Important Phenomena

Due to the complexity of the transient, many phenomena occurred which challenge the predictive capability of the Oconee RETRAN Model. During the initial reactor runback due to low feedwater flow, the resulting degradation in primary-to secondary heat transfer due to decreasing SG inventory is of interest. Subsequently, the overcooling due to continued turbine bypass steaming and sustained feedwater delivery by the EFW pumps, and then the MFW pump overfeed, result in significant heat transfer phenomena. Prior to the MFW overfeed, the "A" SG and possibly the "B" SG approach a boiled-dry condition, another significant phenomenon.

The primary system response is dominated by the contraction of the primary inventory due to the overcooling, and then the refilling of the RCS by the HPI System. The initial expansion of the primary inventory during the loss of feedwater phase also challenges the non-equilibrium pressurizer modeling.

During this transient essentially all plant data, except RCS pressure, were unavailable from 73 to 223 seconds. Although no data exists in this timeframe, the presence or absence of any major phenomena can be assessed if the simulation compares well with the data before and after the data void. Any assumptions necessary to model unknown system and component performance during this timeframe can also be assessed.

Model Description and Boundary Conditions

This event was characterized by asymmetric boundary conditions on the SG secondary side, and so the two-loop Oconee RETRAN Model (Figure 2.2-1) was used in the analysis. The parameters used as initial conditions are mainly taken from the base model initialization due to the similarity of the event initial conditions. Several parameters were modified to be event specific.

Initial Conditions

	Model	Plant
Power Level	100% (2568 MWt)	99.2% (2548 MWt)
RCS Pressure	2134.3 psig	2134.3 psig
PZR Level	217.4 inches	217.4 inches
T-hot	601.9 °F	600.5 °F (ave)
T-cold	555.2 °F	556.5 °F (ave)
RCS Flow	140 x 10^6 lbm/hr	147 x 10^6 lbm/hr
SG Pressure	910.0 psig	902.9 psig (ave)
SG Levels	63.0%, 69.9% OR	63.0%, 70.5% OR
MFW Flow	10.8 x 10^6 lbm/hr	10.8 x 10^6 lbm/hr
MFW Temperature	460.0 °F	454.3 °F

The small deviations in reactor power level and hot and cold leg temperatures are consistent with the deviation in RCS flow. Since this event resulted in large changes in all parameters, these small initial discrepancies are insignificant. The small deviation in initial steam generator pressure is also insignificant. Initial steam generator levels were closely matched in order to accurately simulate the pre-trip decrease in steam generator inventory following the feedwater transient. [

]

The boundary conditions used include the reactor power runback, event specific delayed neutron power and decay heat, MFW flow data, EFW and HPI actuation, a post-trip auxiliary steam demand, and a turbine control system. The reactor power runback data from 4 - 55 seconds has been corrected to account for the [

] All three EFW pumps actuate on the MFW pump trip

caused by the loss of ICS power. The EFW flow is throttled by a control system to maintain the minimum post-trip steam generator level. The second and third HPI pumps were started at 154 seconds. These EFW and HPI boundary conditions are assumed in the simulation since actual performance cannot be confirmed by plant data.

The most important boundary condition in this analysis is the steam relief flowrate resulting from the partially failed-open turbine bypass valves. It is assumed that the valves failed to the 50% open position during the loss of ICS power. Subsequent to the restoration of ICS power the valves repositioned to 11.9% (SG "A") and 22.5% (SG "B"). The relief capacity of these valves in a partially open position is not known. It is assumed that the capacity is a linear function of valve position. This assumption is known to underpredict the capacity at positions between 0 - 50% open.

Simulation Results

The simulation begins with the partial loss of feedwater and continues for 14 minutes. The simulation is terminated shortly after the overfeed of the "B" SG is manually terminated and the overcooling rate stabilizes. The sequence of events is given in Table 4.2.3-1, and the results of the simulation are presented in Figures 4.2.3-1 through 4.2.3-22.

The first 73 seconds of the transient, that phase prior to the loss of ICS power, constitute a gradual loss of heat sink event. The reactor power response, which consists of the runback from 99% to 71% power between 4 seconds and the reactor trip on high pressure at 55 seconds, is shown in Figure 4.2.3-1. The initial RCS pressure response, shown in Figure 4.2.3-2, indicates that RETRAN predicts a faster rate of pressurization than the data. The predicted time of reactor trip is 42 seconds rather than 55 seconds. Insights into the cause of this discrepancy exist in the pressurizer level and RCS temperature responses. The initial pressurizer level comparison is given in Figure 4.2.3-3. RETRAN only slightly overpredicts the pressurizer insurge, which is the driving force behind the rate of RCS pressurization. The deviation in the pressure comparison is partially due to this slight overprediction in pressurizer level. The remaining contribution is due to

[

] The initial hot and cold leg comparisons are shown in Figures 4.2.3-4 through 4.2.3-7. The trends are very consistent with the data, with the predicted cold leg temperatures increasing slightly faster than the data. This indicates that RETRAN predicts a more rapid degradation of the heat sink due to the reduction in feedwater flow. The initial main feedwater flow transient data used as boundary conditions are shown in Figure 4.2.3-8. The resulting predicted decrease in steam generator levels are in excellent agreement with the data as shown in Figures 4.2.3-9 and 4.2.3-10.

The time interval from 73 to 223 seconds corresponds to the duration of the loss of ICS power. During this interval only RCS pressure data, shown in Figure 4.2.3-11, exists for comparison to the prediction. RETRAN underpredicts the actual pressure transient. By observing the longer term responses in pressurizer level (Figure 4.2.3-12) and RCS temperature (Figures 4.2.3-13 through 4.2.3-16), in particular when the lost indications are restored at 223 seconds, the enhanced overcooling predicted by RETRAN is evident. The source of the overprediction of the rate of overcooling appears in the comparison of the SG pressures in Figures 4.2.3-17 and 4.2.3-18. Due to the assumed failure position of the turbine bypass valves during the loss of ICS power, SG "A" pressure is underpredicted by 180 psig and SG "B" by 150 psig, at 223 seconds. The trends in other parameters are consistent with this deviation.

Between 223 and 535 seconds the overcooling process continues as the EFW pumps deliver excess feedwater and steaming through the turbine bypass valves continues. The turbine bypass valves are now positioned at 11.9% and 22.5%, respectively, so the steaming rate has decreased. The reduction in the steaming rate is confirmed by the increase in SG pressures at 223 seconds, with the exception of the "B" SG data. The rate of depressurization is also influenced by a decrease in SG inventory during this time period. The SG downcomer level is shown in Figures 4.2.3-19 and 4.2.3-20. It is apparent that the steam generators are near a boiled-dry condition in SG "A" after 360 seconds, and in SG "B" between 300 and 535 seconds. Since both cold leg temperatures continue to decrease during this period, the delivered EFW inventory must be boiling off and not accumulating on the SG lower tube sheet. RETRAN continues

to overpredict primary-to-secondary heat transfer. At 535 seconds the "B" steam generator is overfed by the hotwell/booster pump combination. The MFW flowrate is shown in Figure 4.2.3-21, and the resulting change in steam generator level is shown in Figure 4.2.3-22. The rate of overcooling increases in the data, although the predicted rate remains approximately the same. This deviation may result from the prediction of [

]

The pressurizer level and RCS pressure data show that RCS inventory remained relatively stable between 360 and 660 seconds. It is suspected that HPI flow was being manually throttled during this time period, although no confirmatory data exists. Since the RETRAN simulation modeled unthrottled HPI flow during this time period, the deviations between the predictions and data are consistent. The good comparison between the predicted pressurizer level and data between 660 and 840 seconds suggests that full HPI flow was restored at 660 seconds.

The absence of a complete knowledge of the sequence of events for this event, which was complicated by the loss of data indications caused by the loss of ICS power, does not detract from many insights gained by the simulation. In fact, it is possible to infer some important aspects of system and component performance from the simulation.

Table 4.2.3-1

Oconee Nuclear Station Unit 3
Overcooling Following Loss of ICS Power
November 10, 1979

Event Description	Time (sec) Plant	RETRAN
Partial loss of feedwater*	0	0
Reactor runback begins*	4	4
Reactor trip on high RCS pressure	55	42 (Note 1)
Loss of ICS power*	73	75 (Note 2)
- MFW pumps trip		
- EFW pumps start		
- Turbine bypass valves fail open		
- Most instrumentation indications lost		
Three HPI pumps injecting*	154	154
ICS power restored*	223	223
- Turbine bypass valves partially close		
- Instrumentation indications restored		
SG "A" boiled dry (EFW still delivering)	335	N/A (Note 3)
SG "B" boiled dry (EFW still delivering)	385	N/A (Note 3)
SG "B" overfeed begins*	535	535
SG "B" overfeed ends*	760	760
End of simulation	N/A	840

Note: Asterisks designate boundary conditions

Note 1: Simulated reactor power includes matching the reactor trip time at 55 seconds. The simulated pressure would have resulted in a predicted trip at the same pressure setpoint at 42 seconds.

Note 2: Different data sources give different times for the loss of ICS power. The simulation assumed 75 seconds, but some of the data indicates that 73 seconds is more accurate.

[ ]

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

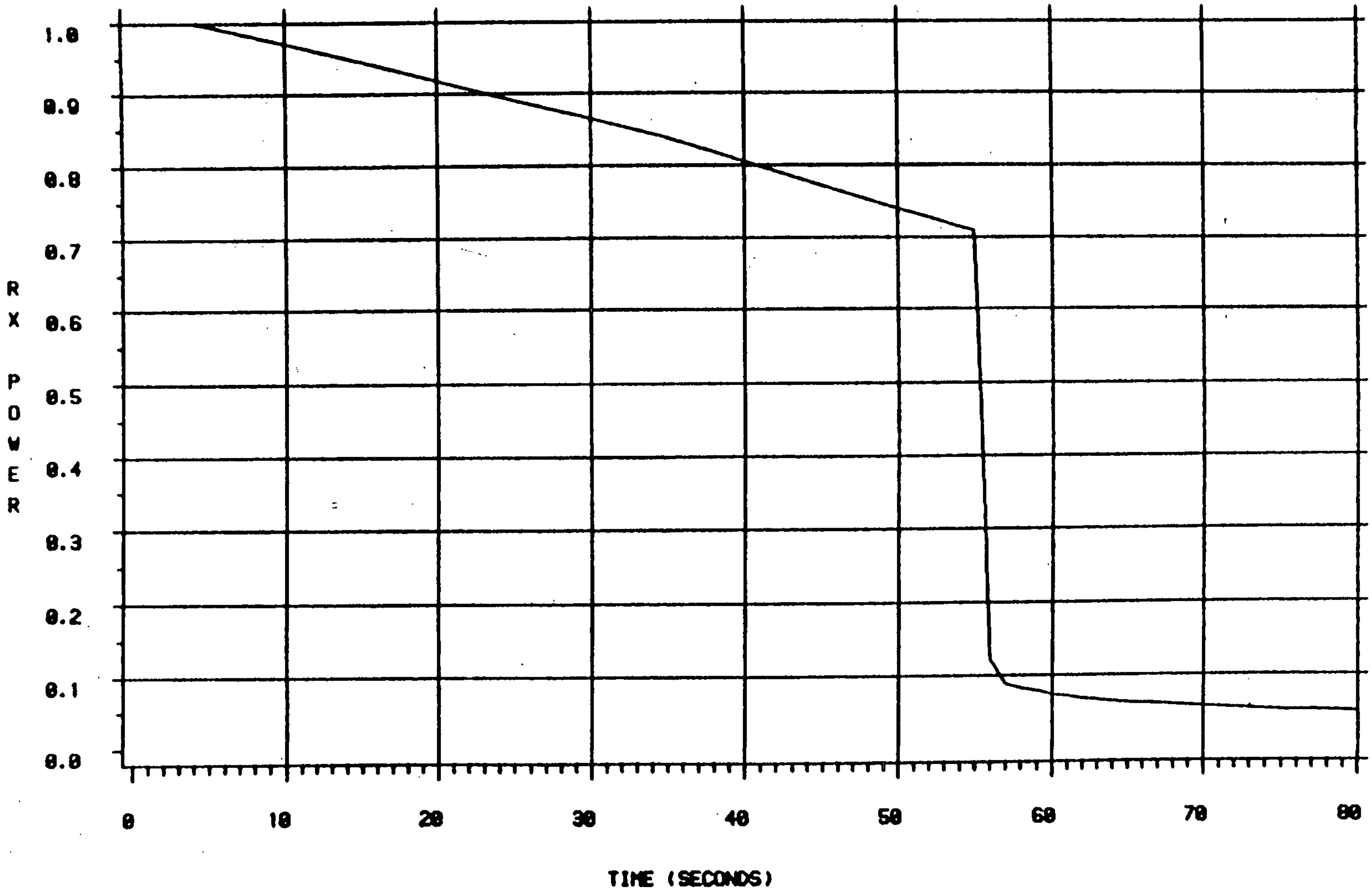


Figure 4.2.3-1

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

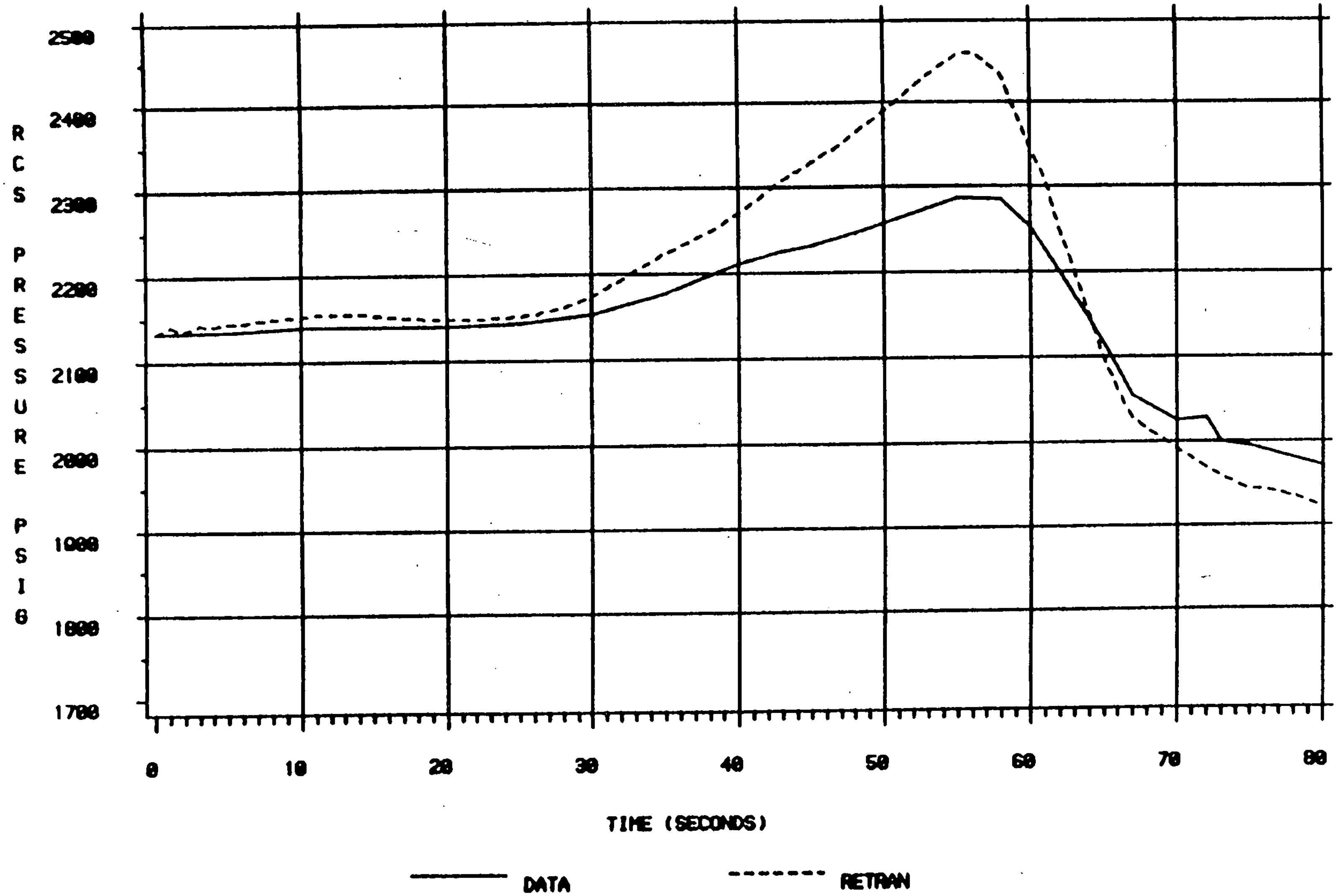


Figure 4.2.3-2

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

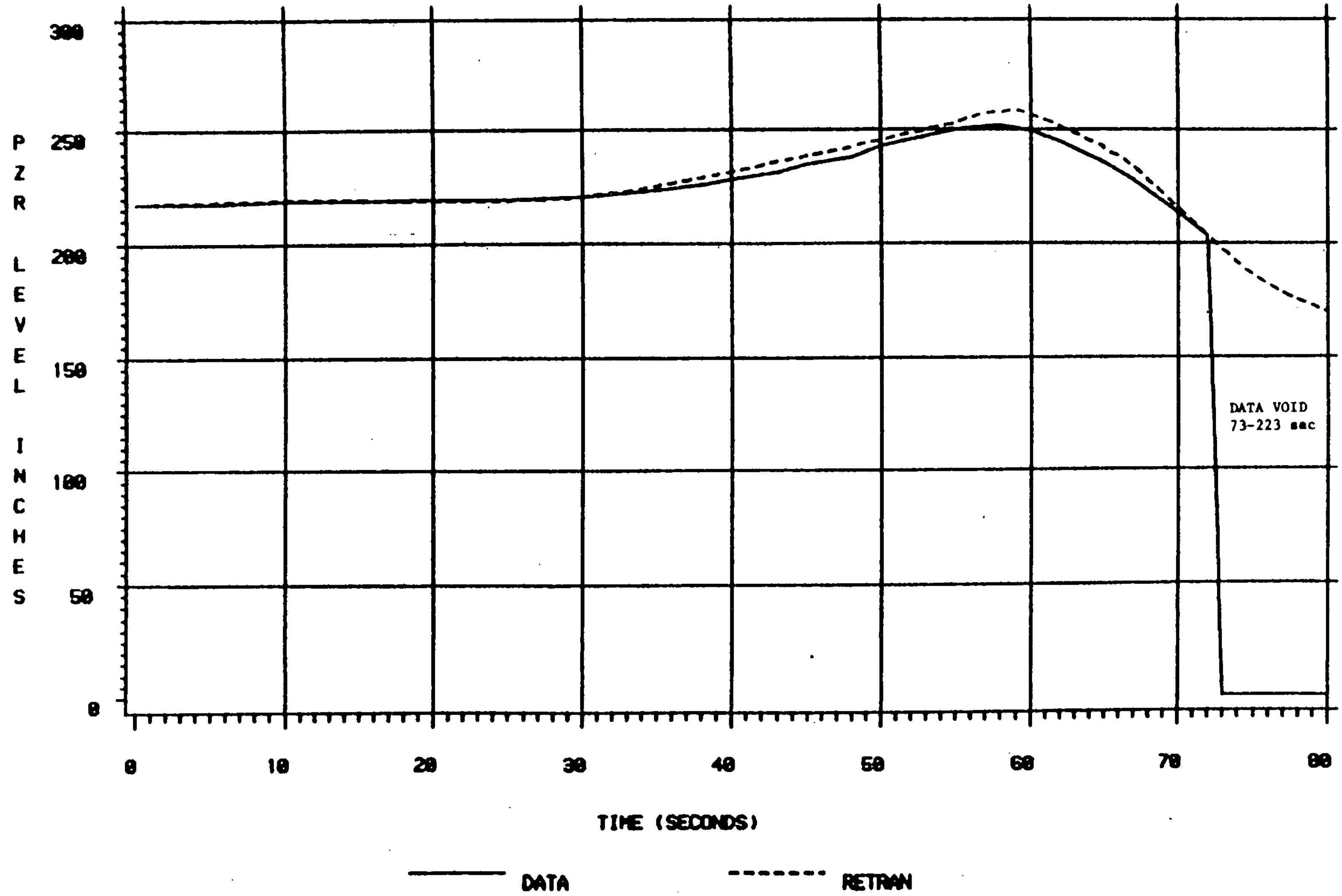


Figure 4.2.3-3

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

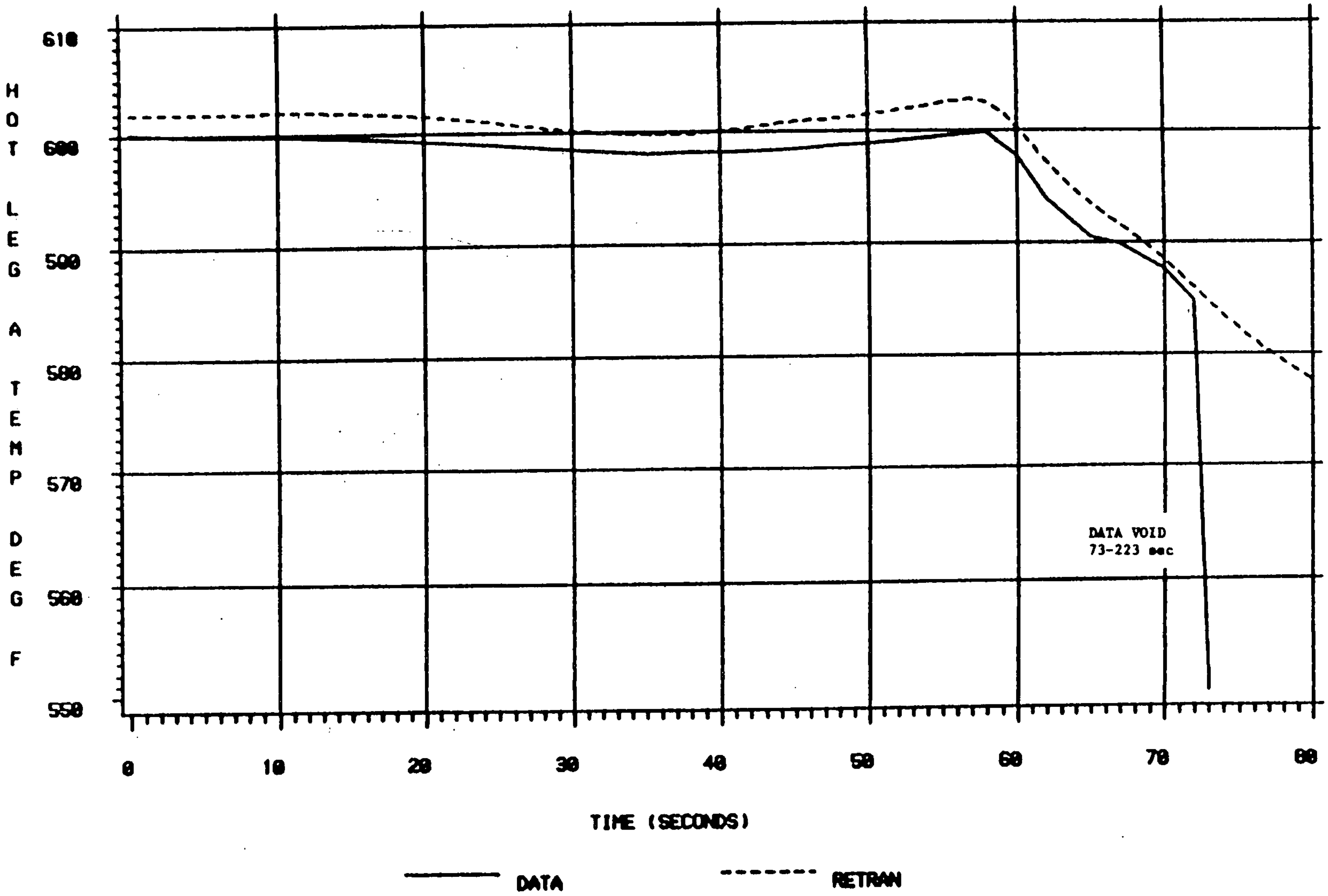


Figure 4.2.3-4

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

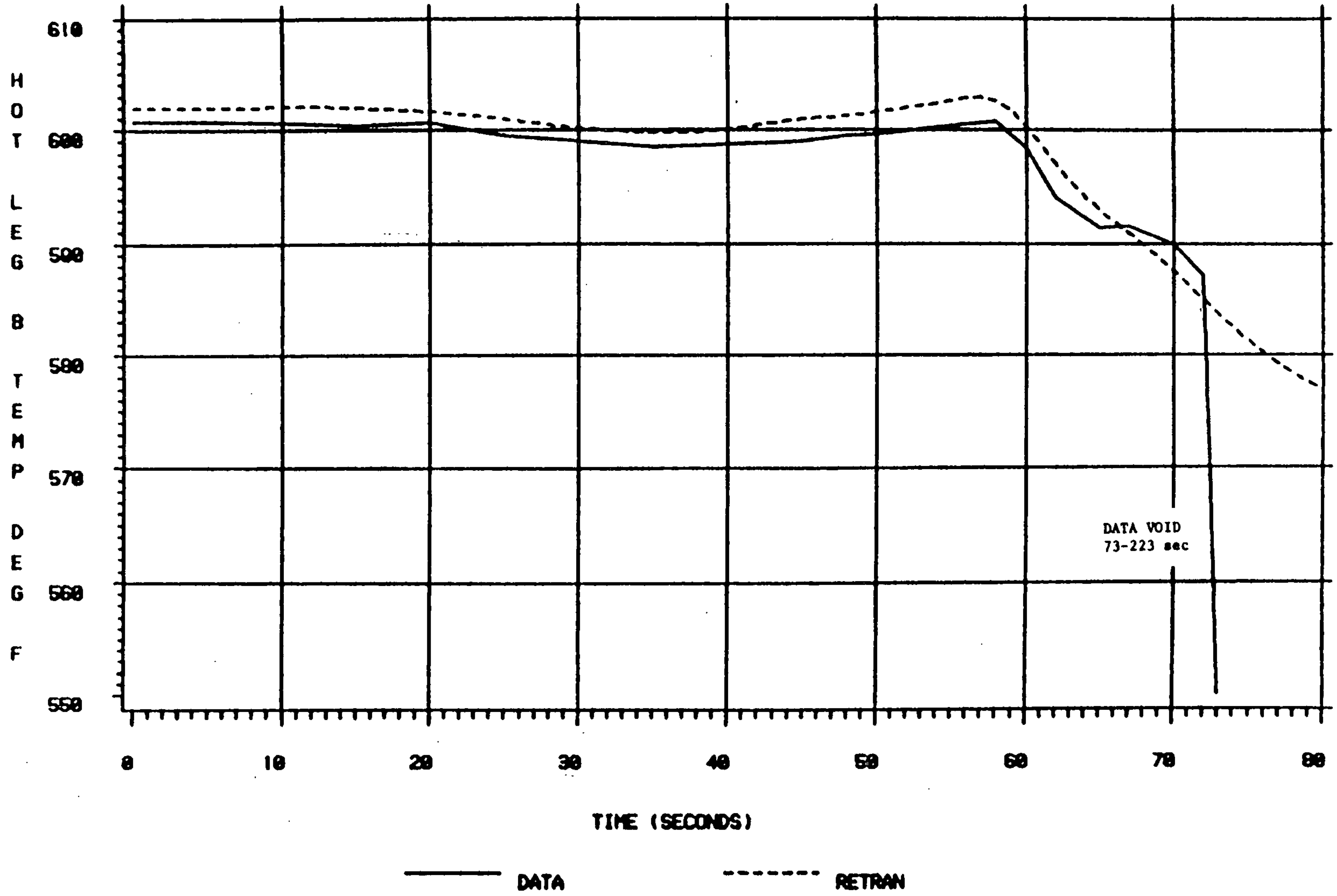


Figure 4.2.3-5

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

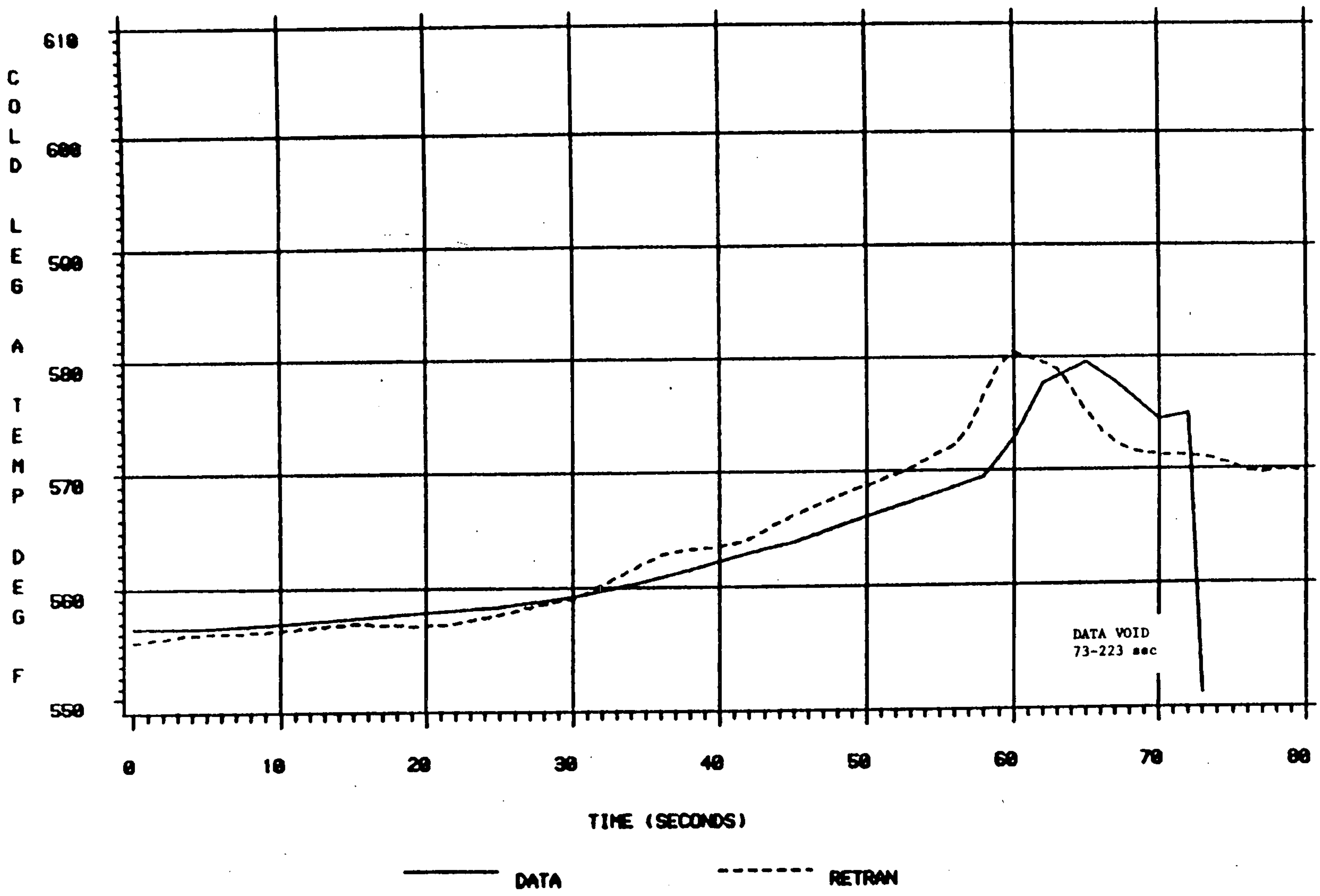


Figure 4.2.3-6

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

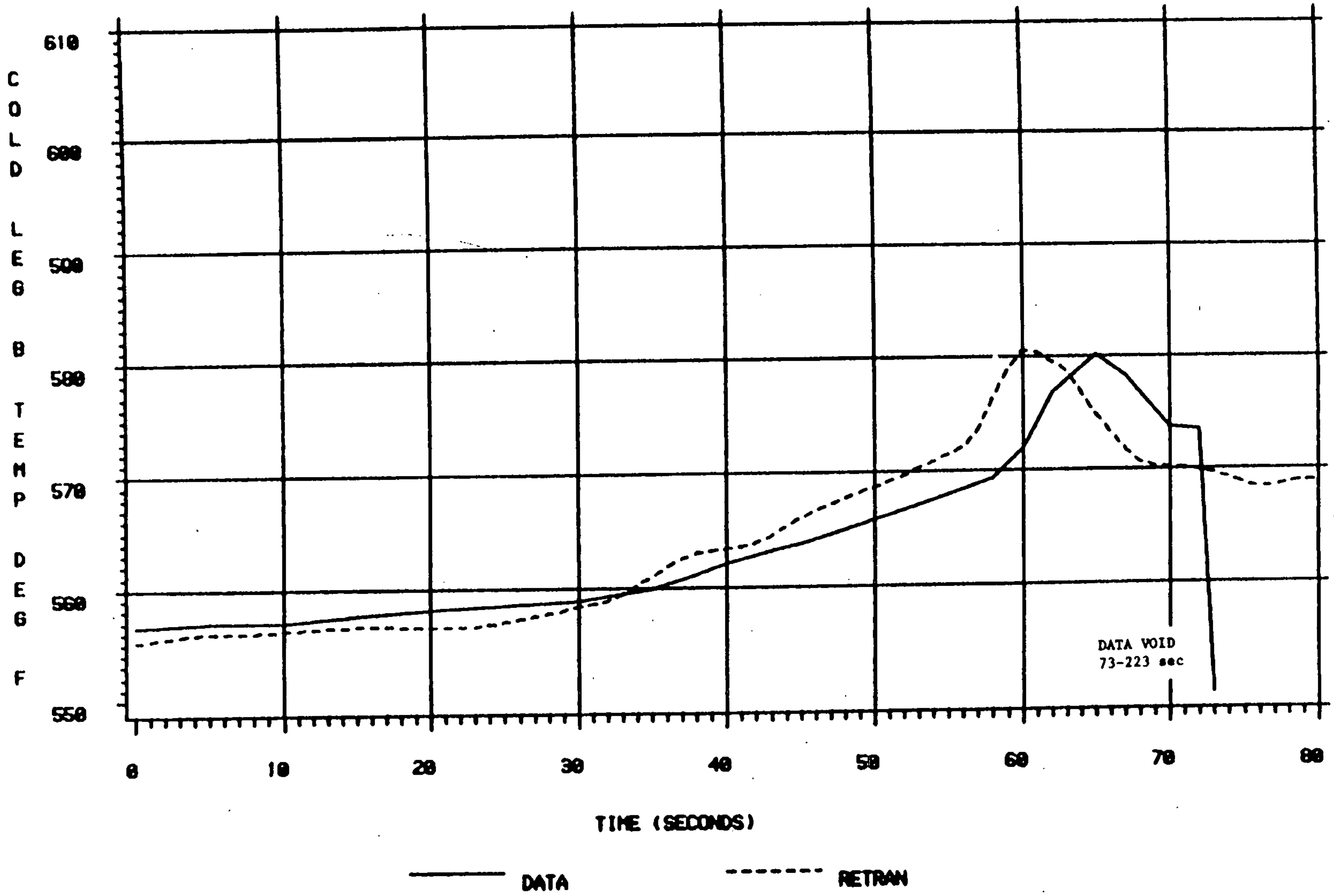


Figure 4.2.3-7

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

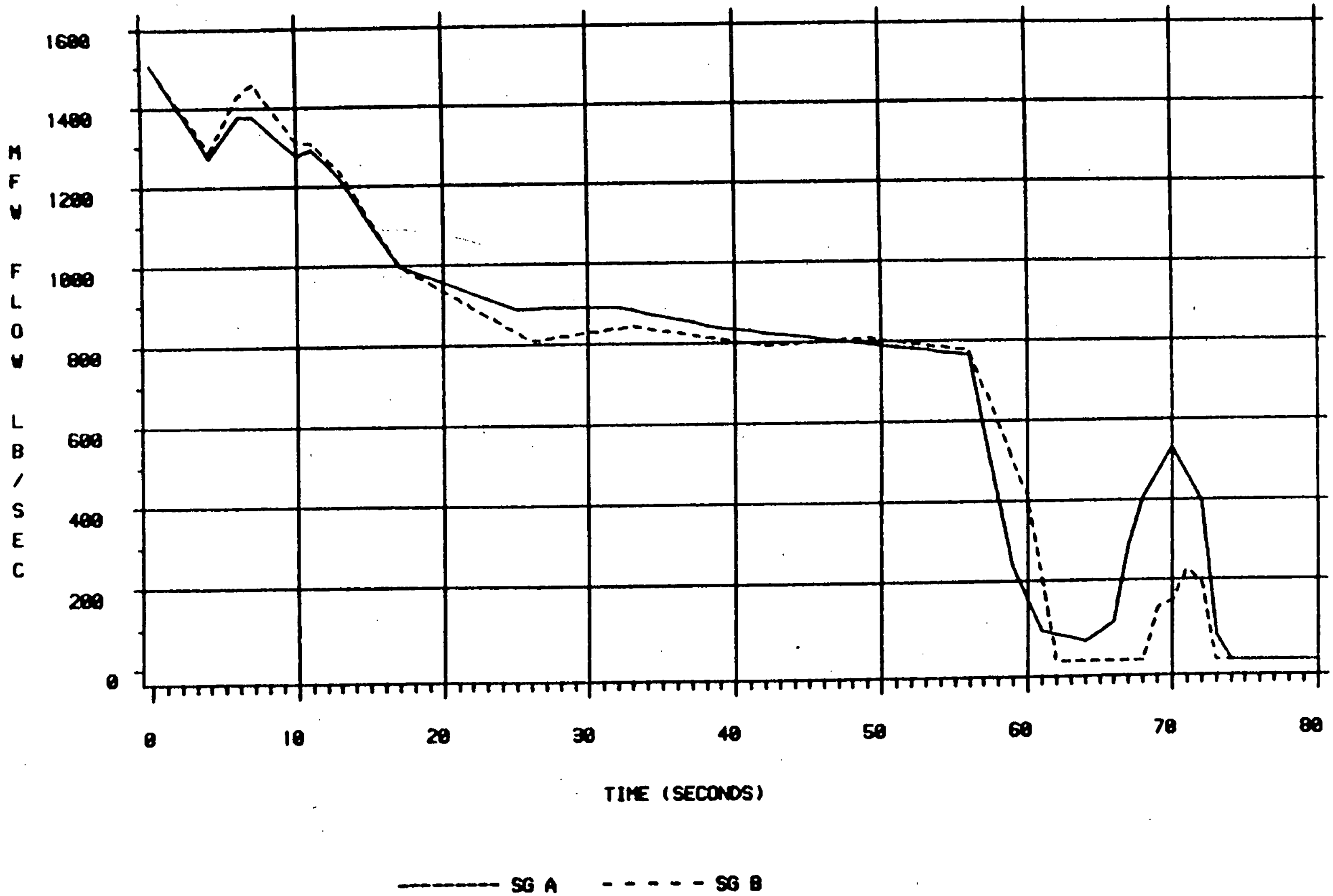


Figure 4.2.3-8

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

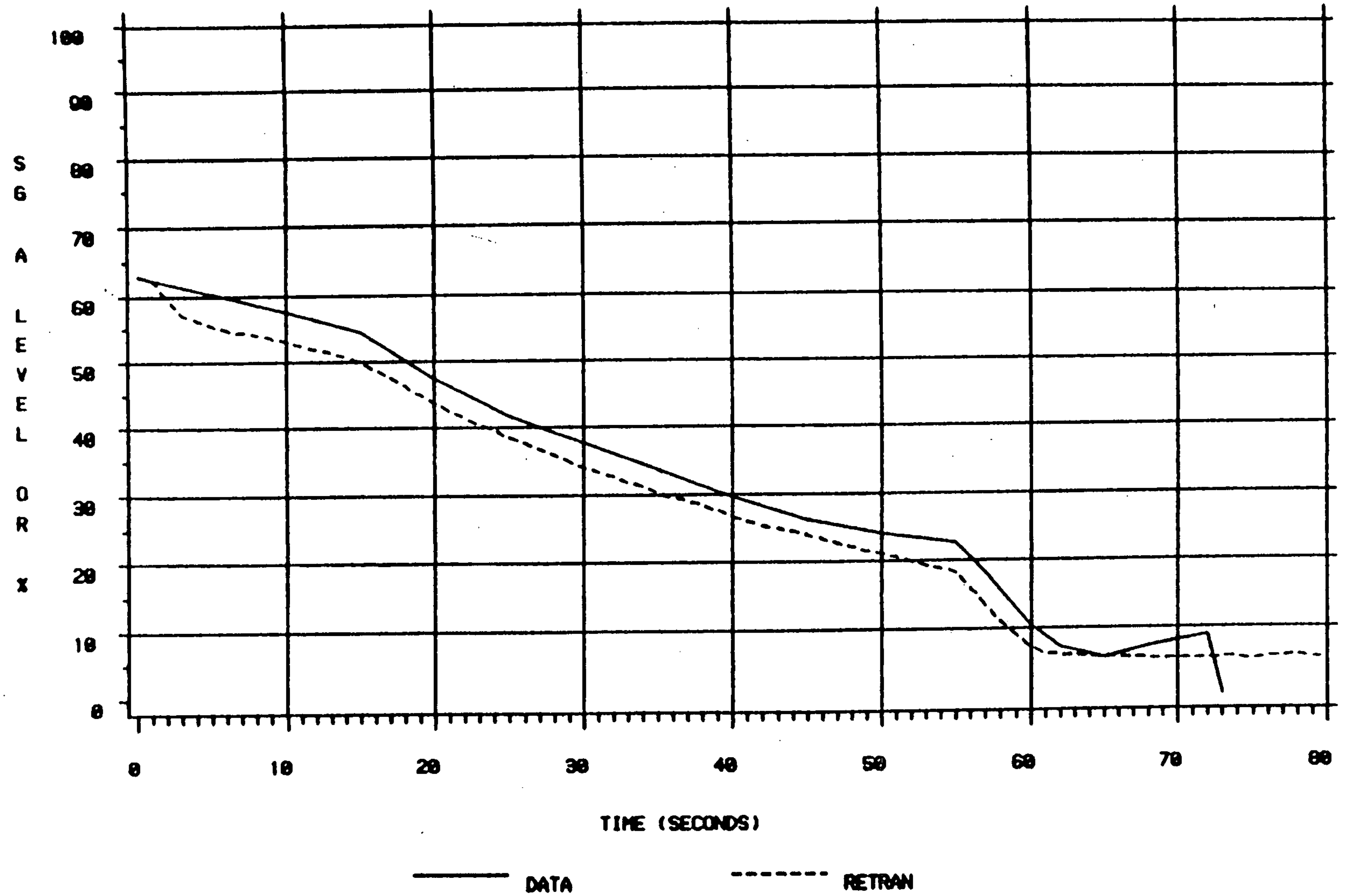


Figure 4.2.3-9

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

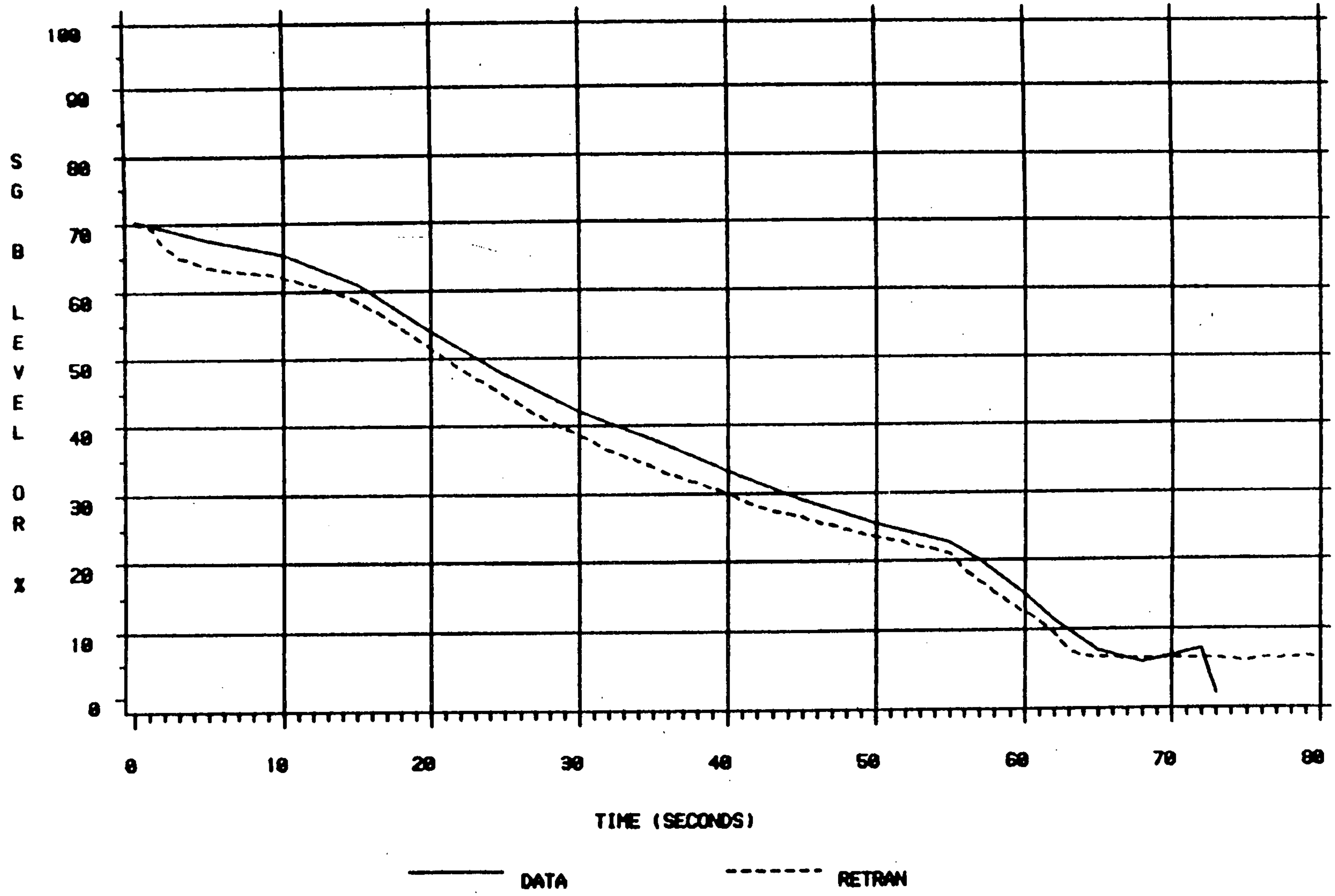


Figure 4.2.3-10

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

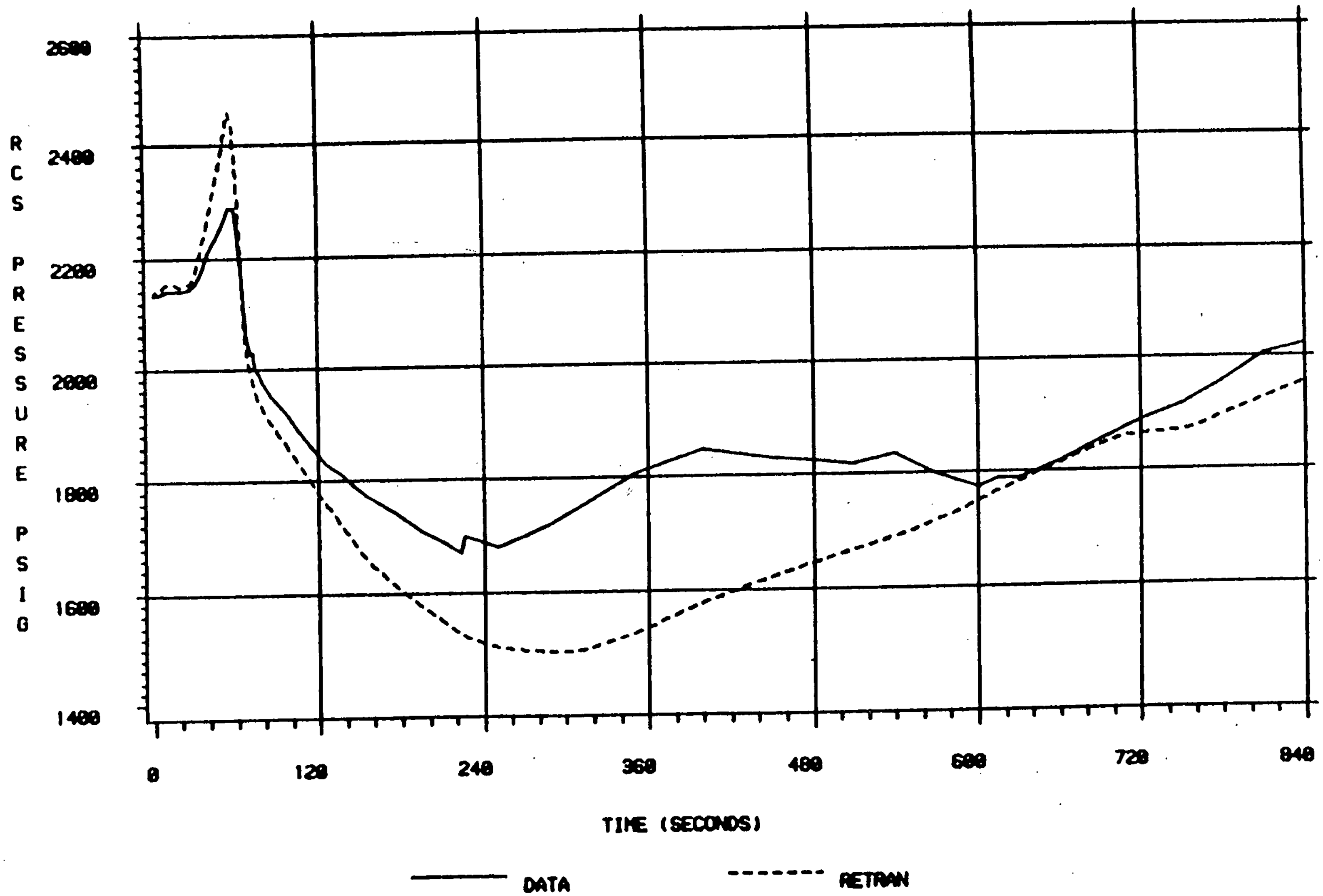


Figure 4.2.3-11

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

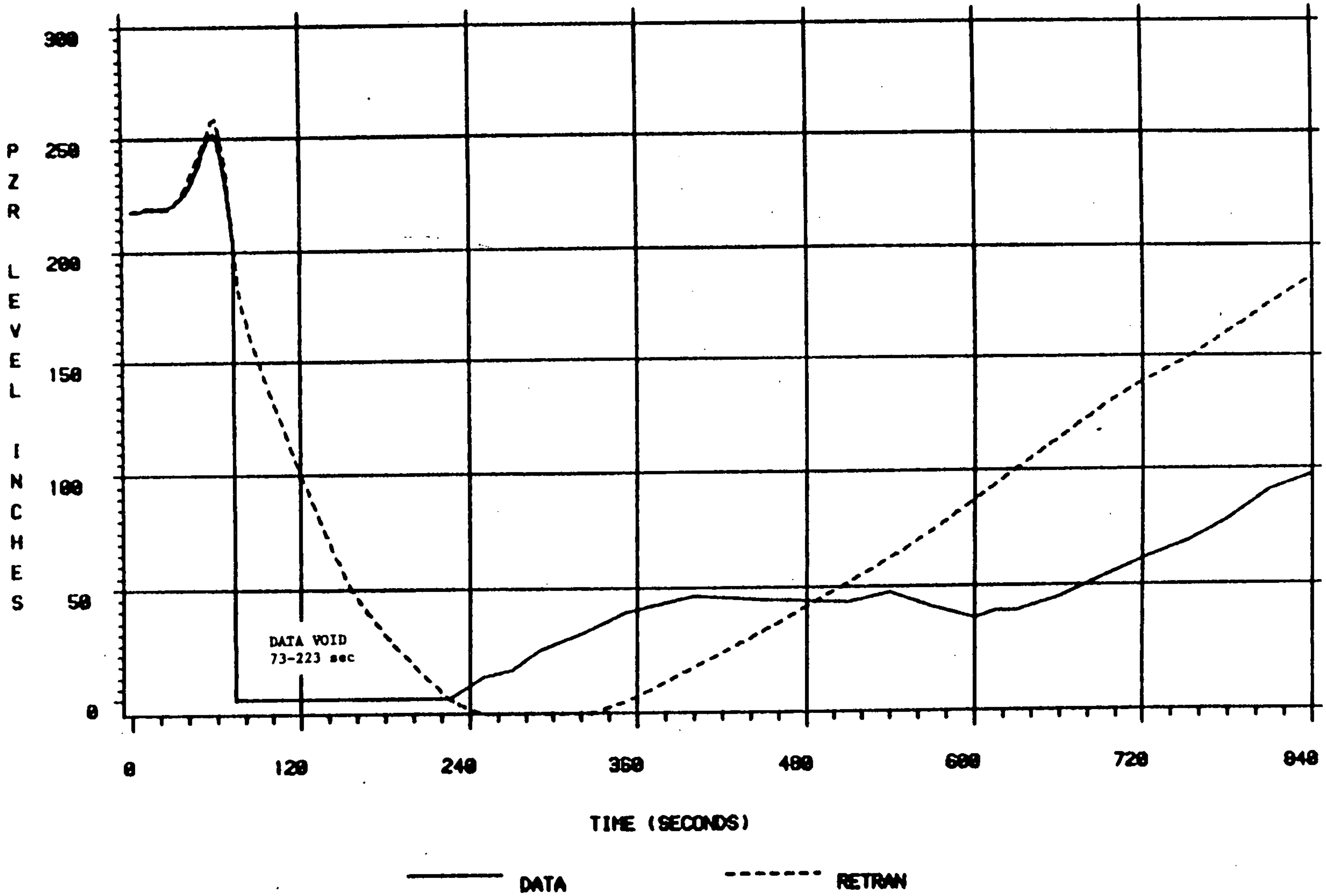


Figure 4.2.3-12

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

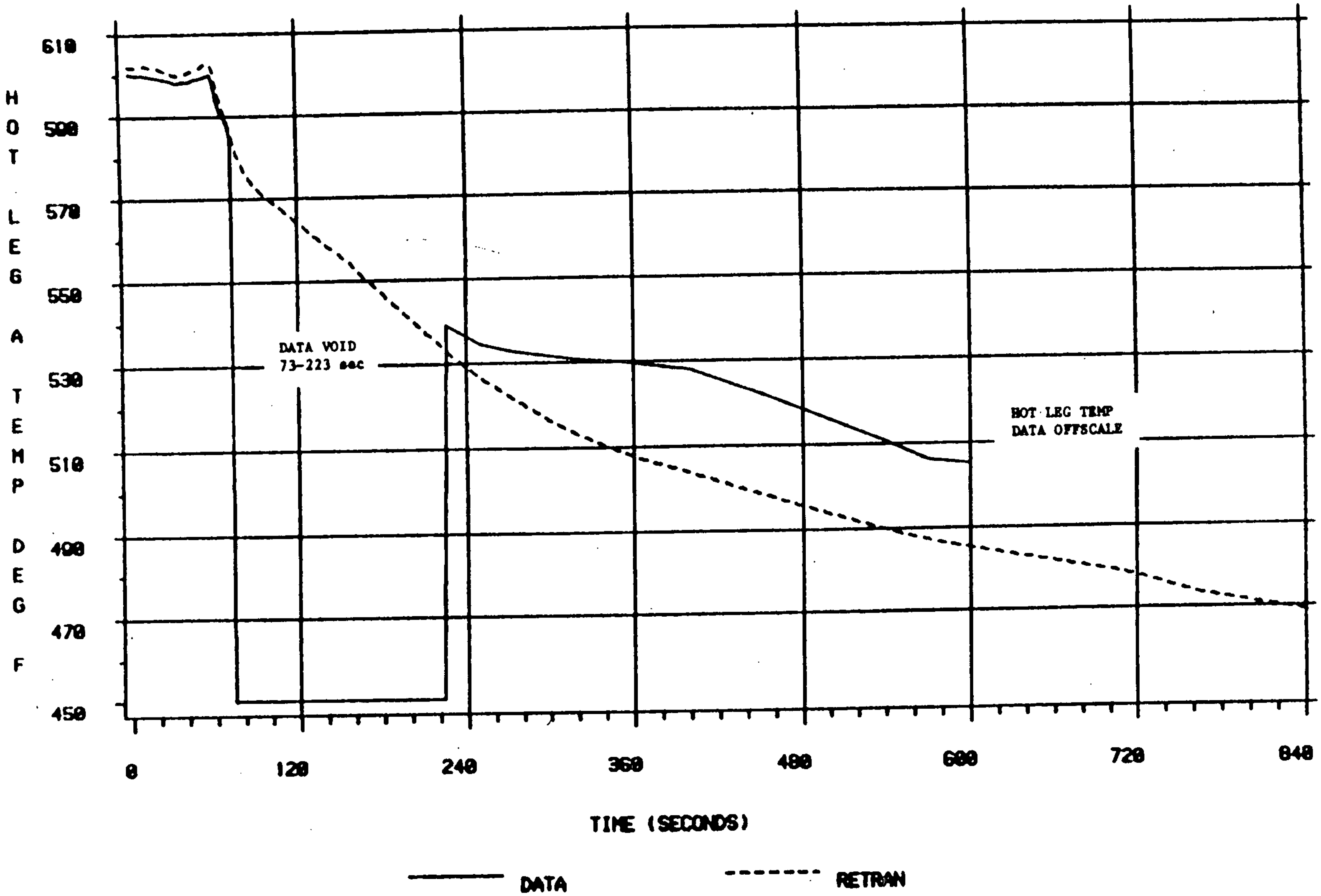


Figure 4.2.3-13

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

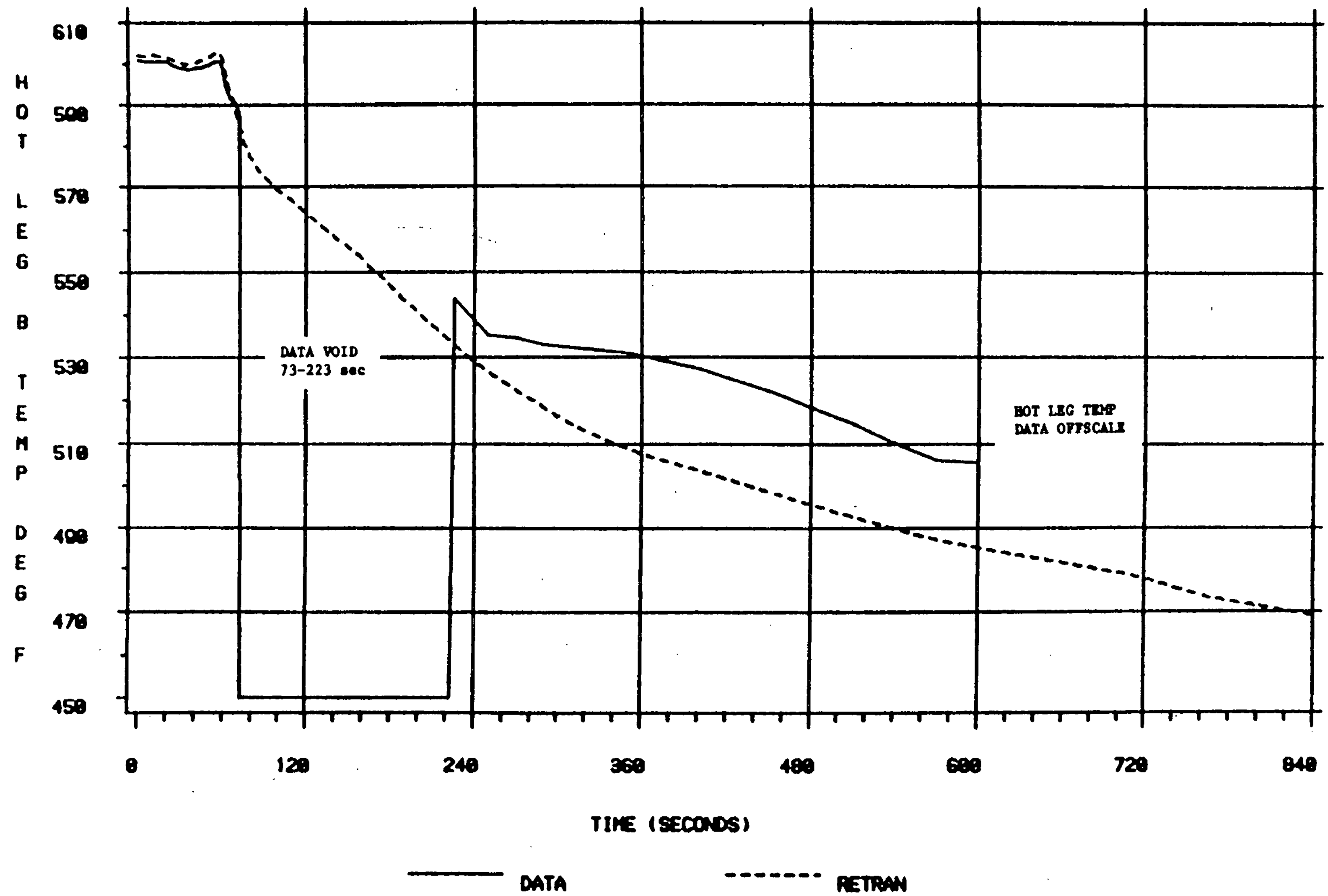


Figure 4.2.3-14

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

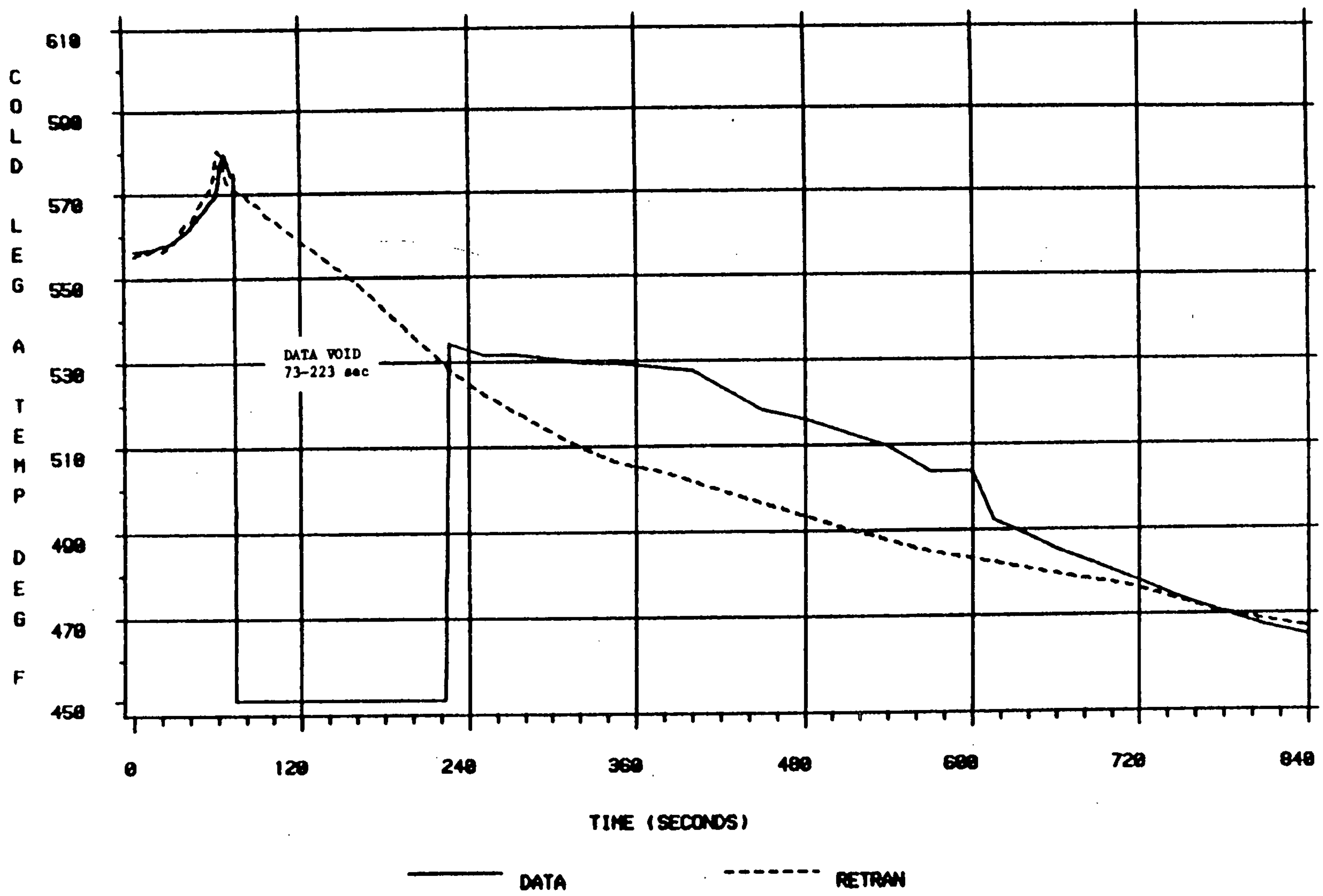


Figure 4.2.3-15

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

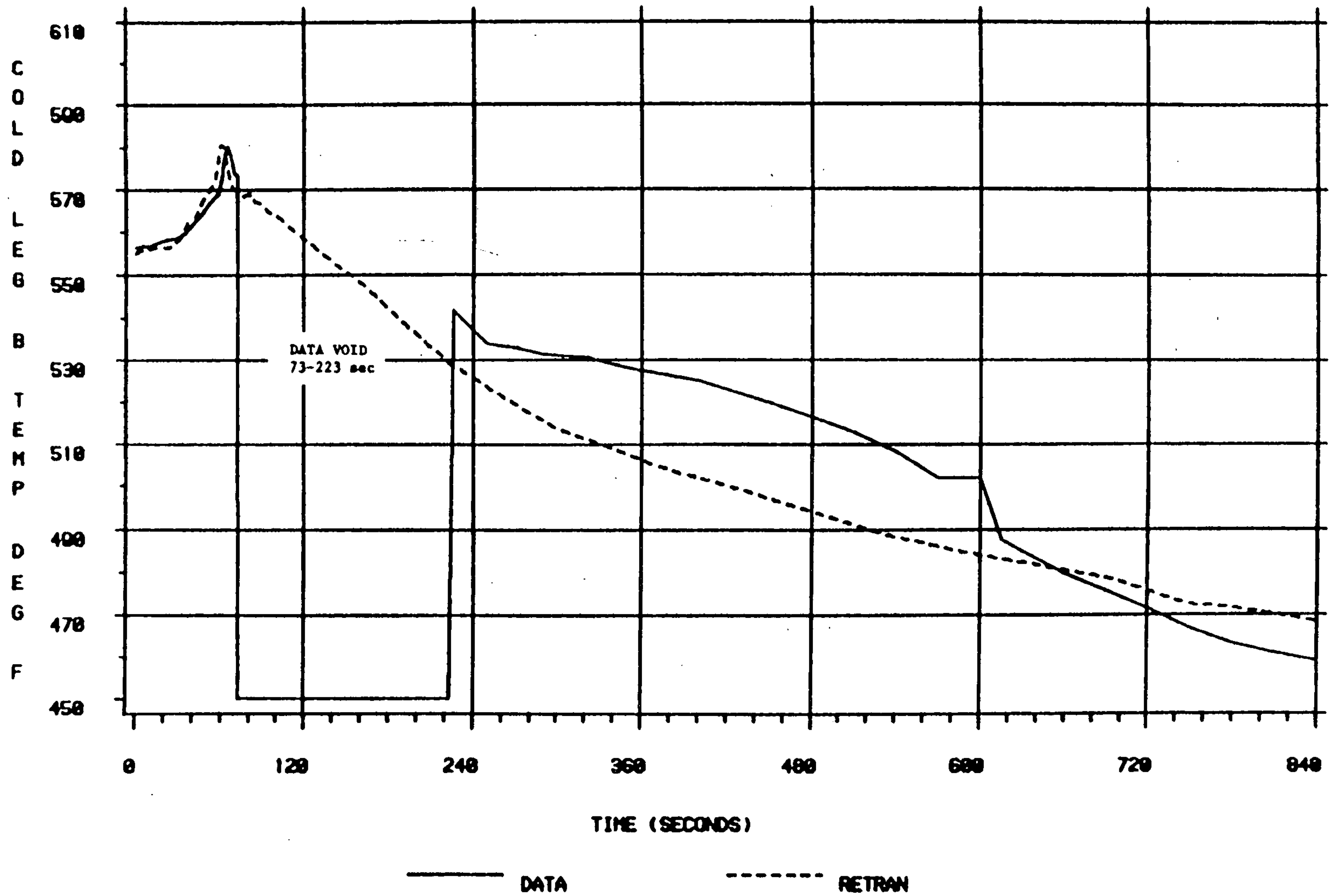


Figure 4.2.3-16

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

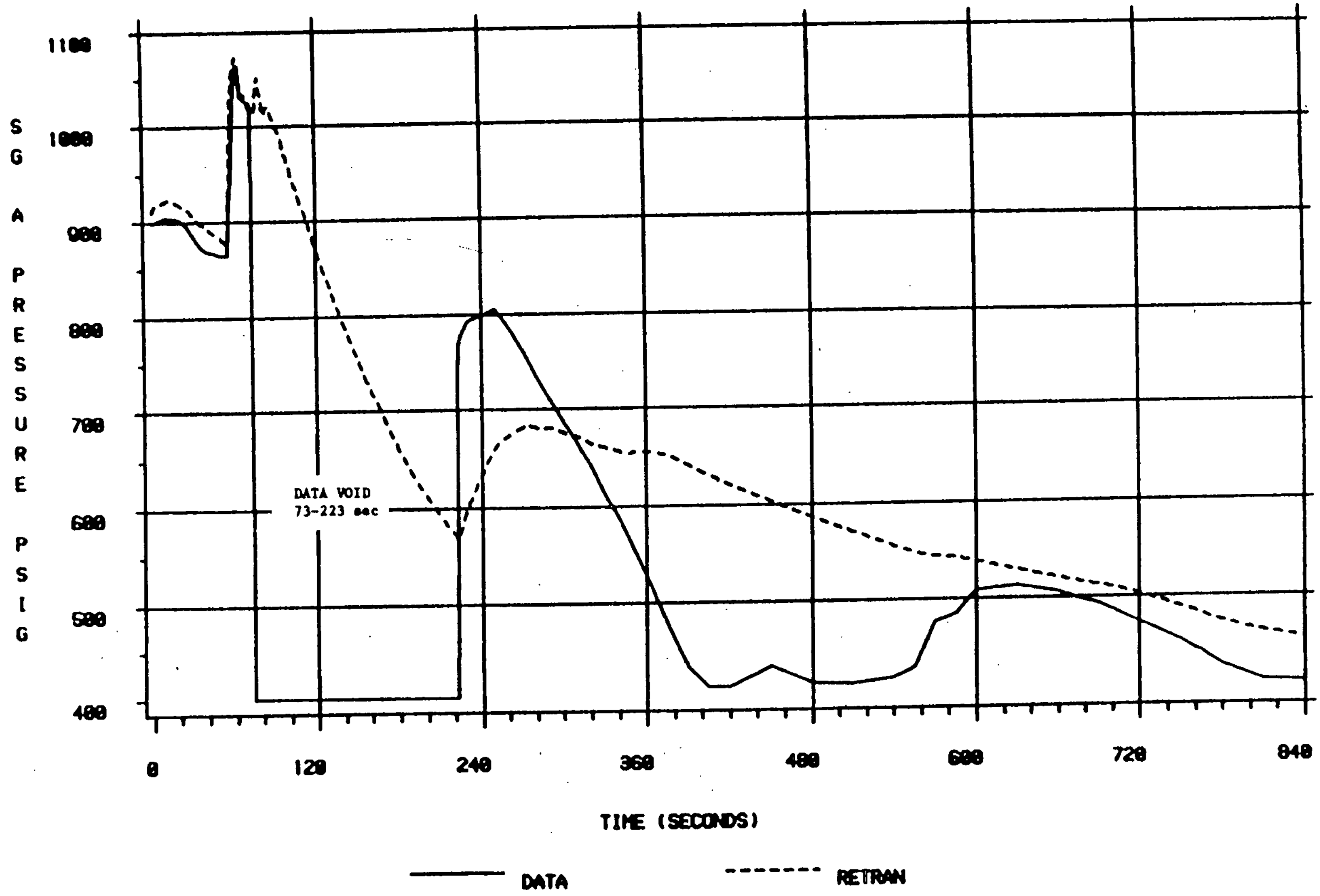


Figure 4.2.3-17

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

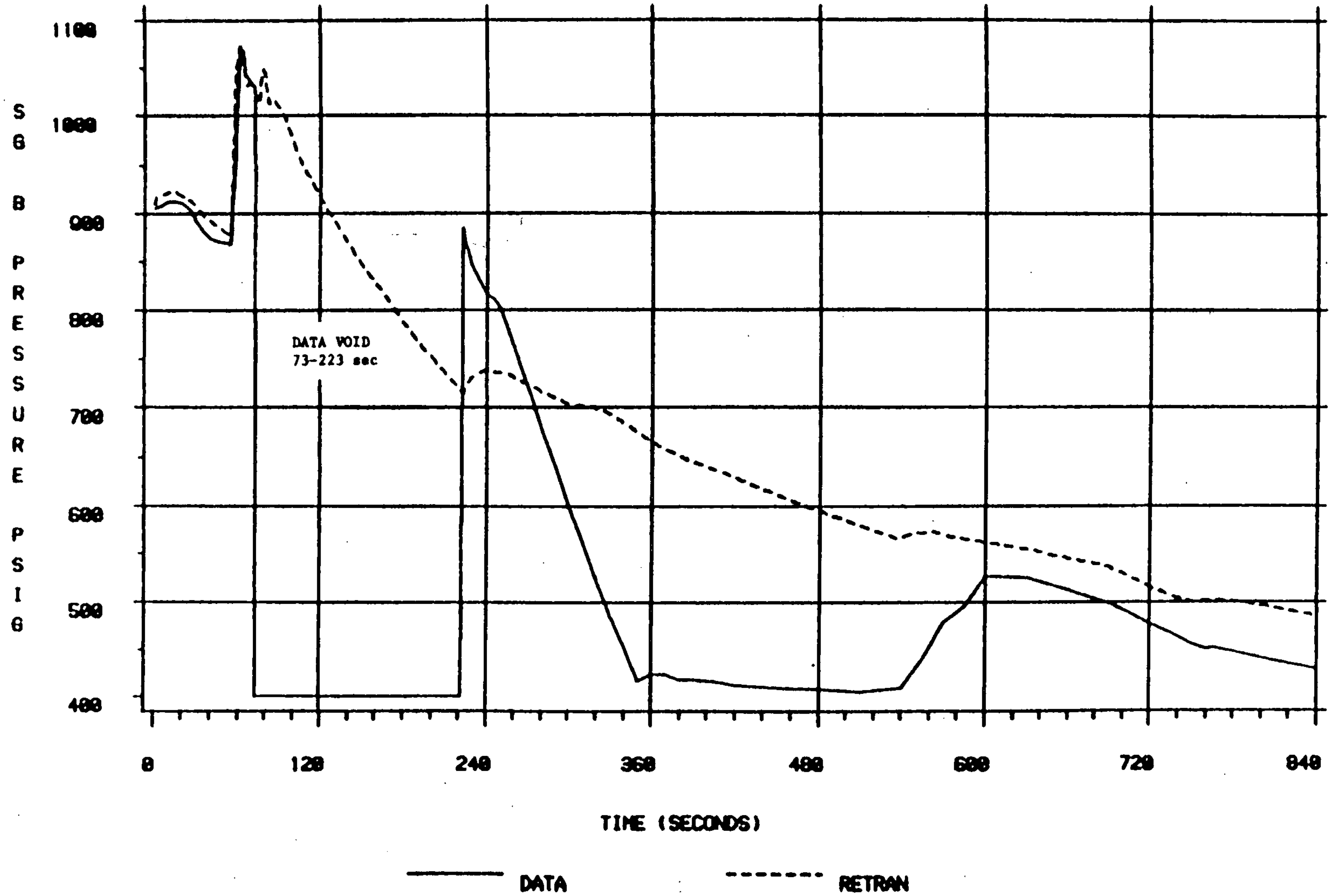


Figure 4.2.3-18

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

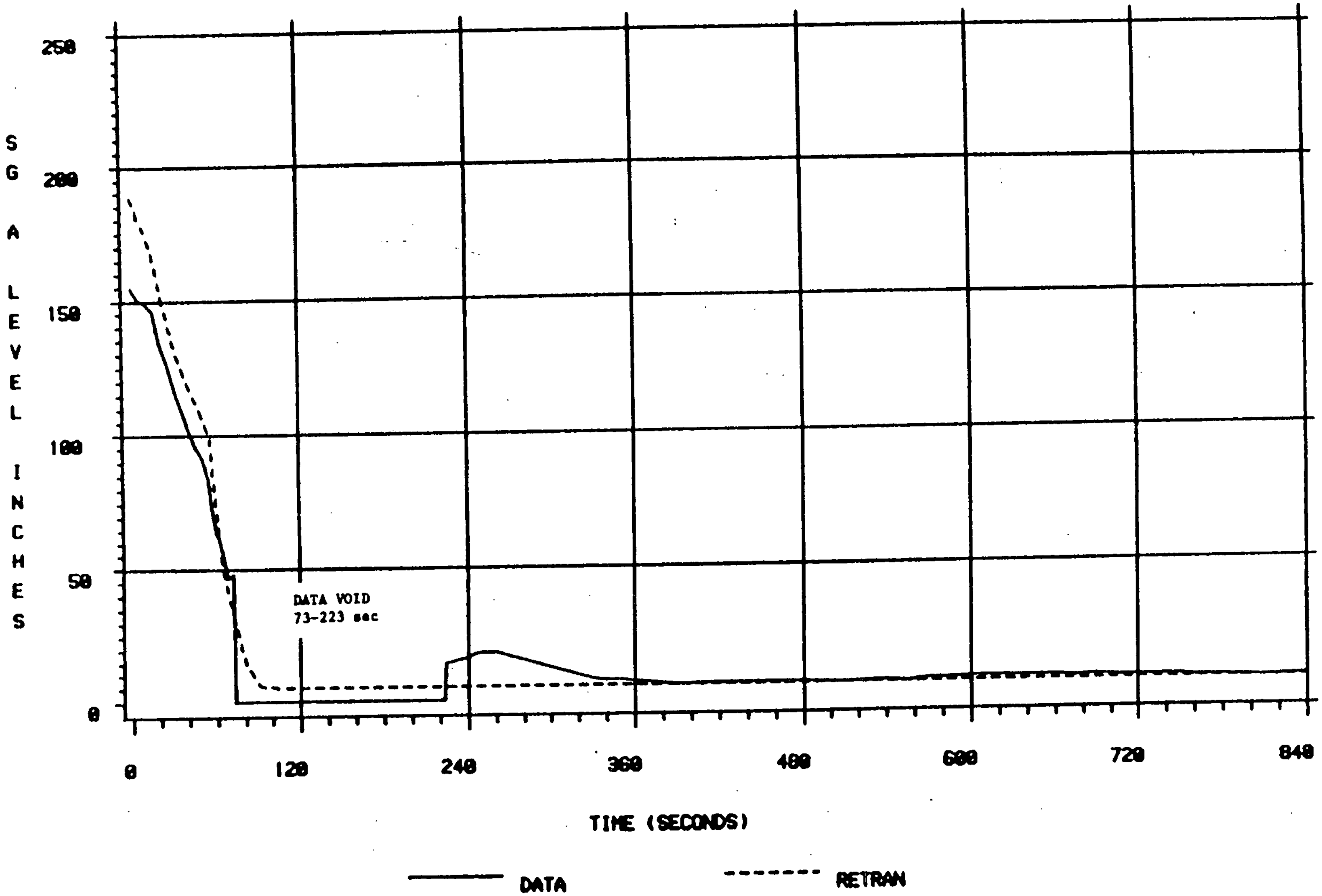


Figure 4.2.3-19

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

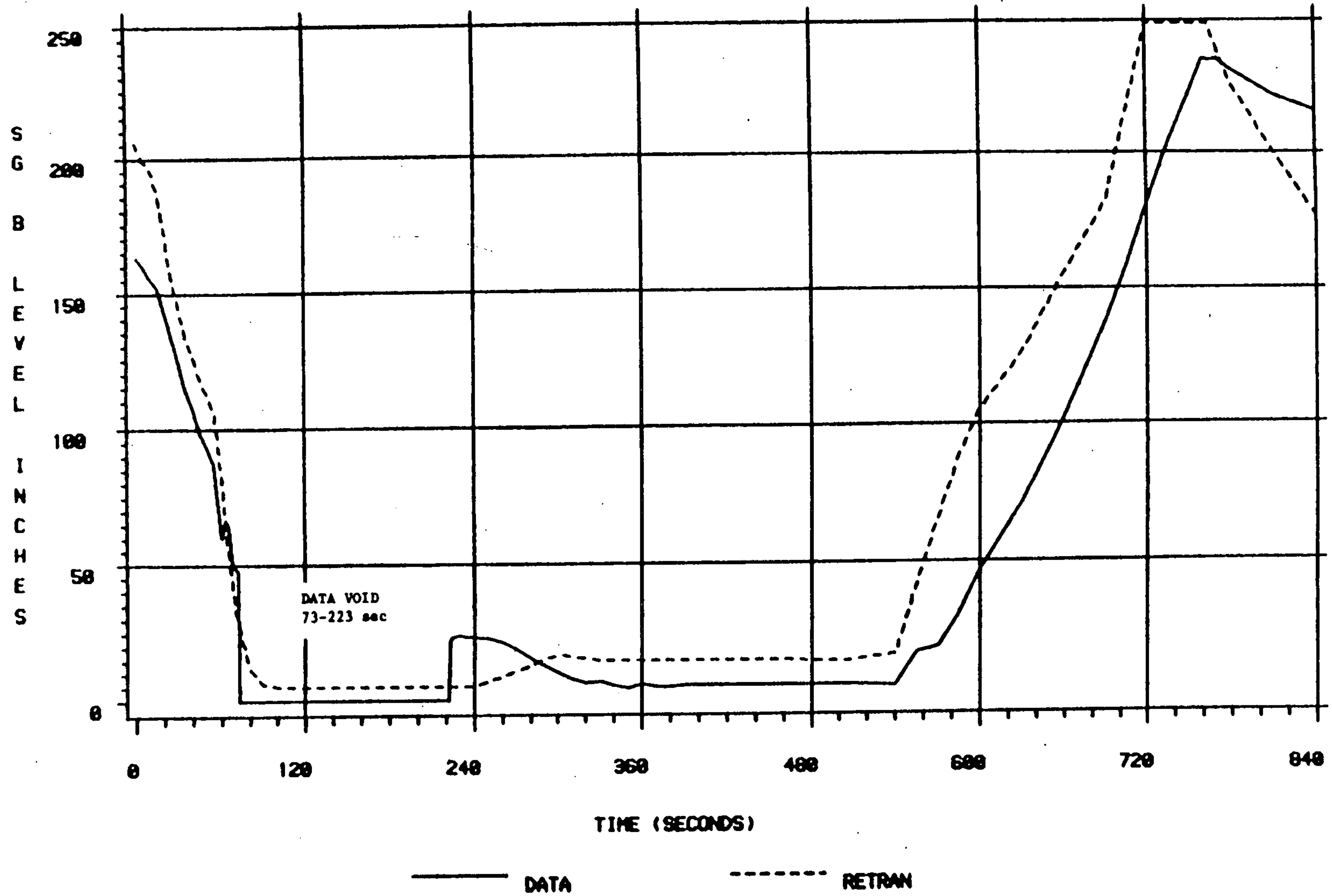


Figure 4.2.3-20

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

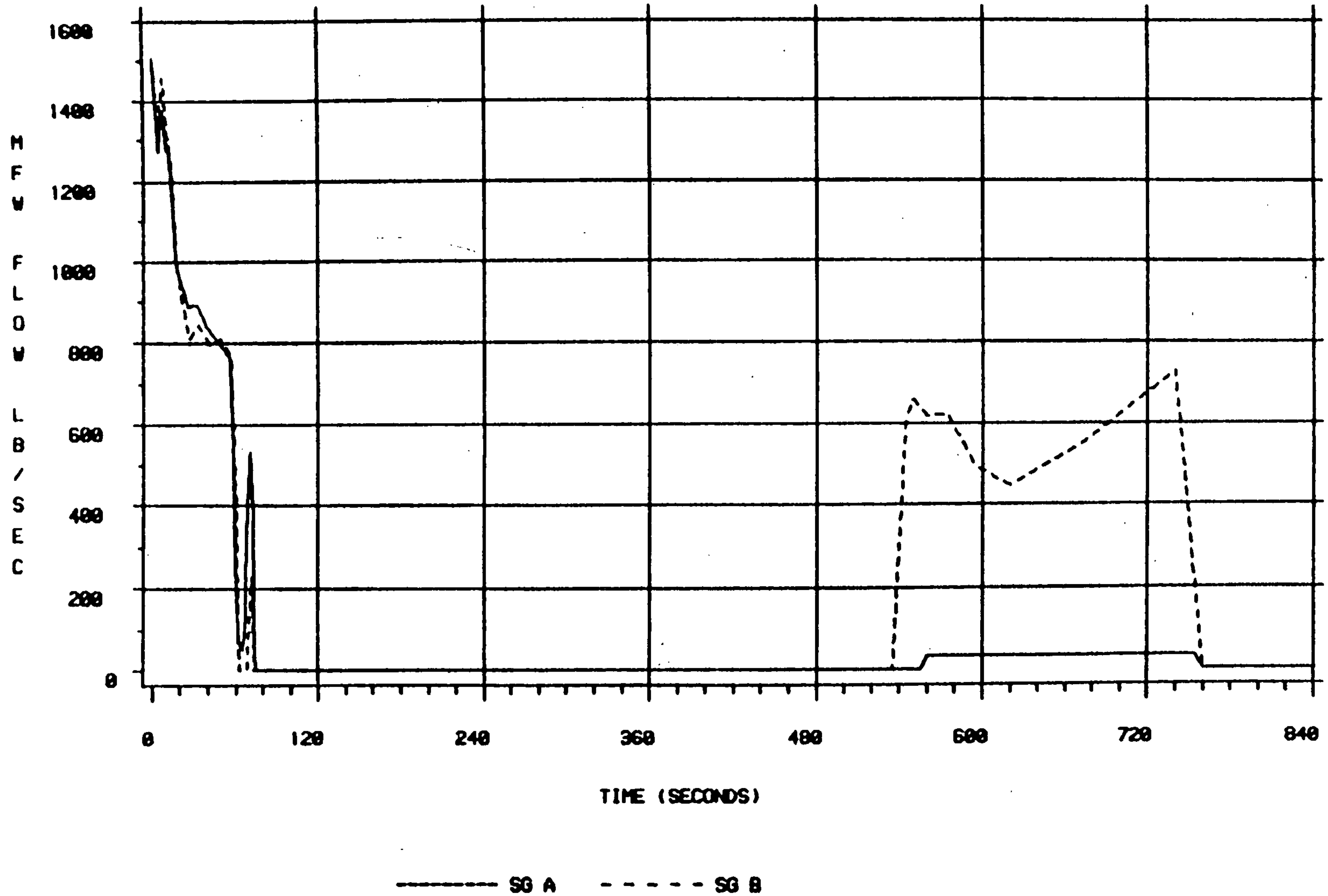


Figure 4.2.3-21

OVERCOOLING FOLLOWING LOSS OF ICS POWER

ONS 3 - 11/10/79

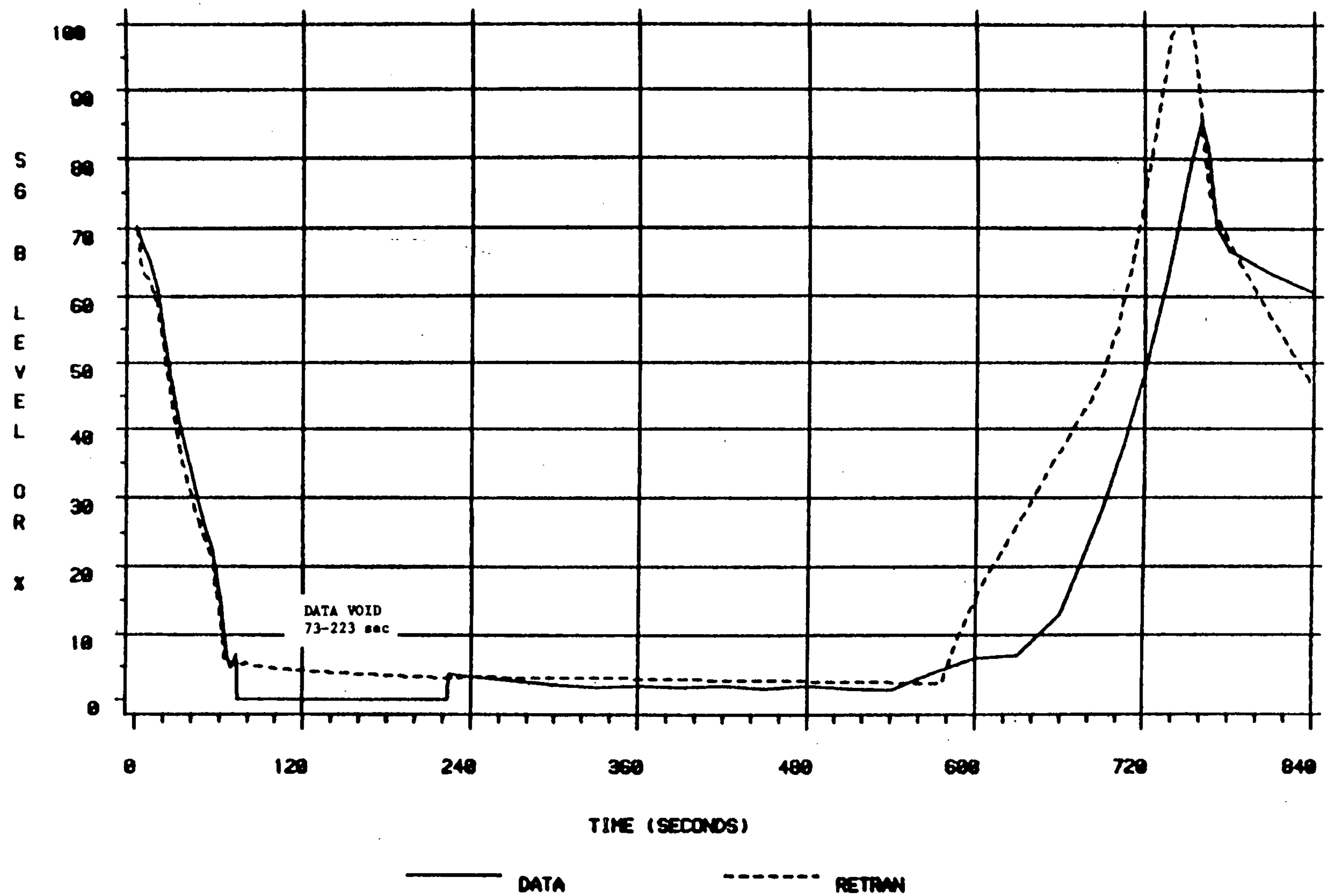


Figure 4.2.3-22

Loss of Forced Circulation

4.3.1 Arkansas Nuclear One - Unit 1
Loss of Offsite Power
June 24, 1980

Transient Description

Arkansas Nuclear One Unit 1 (ANO-1) was operating at 100% full power when a loss of offsite power occurred. The main turbine intercept and governor valves went closed creating a mismatch between reactor power and steam generator demand. This resulted in the RCS pressure increasing rapidly. A manual reactor runback was initiated at approximately the same time the reactor tripped on high RCS pressure. The reactor coolant, main feedwater (MFW) and condenser circulating water pumps also tripped on the reactor/turbine trip.

Shortly after the reactor trip the turbine driven emergency feedwater (EFW) pump was started and immediately tripped on overspeed. Approximately 30 seconds after the trip normal makeup was established. EFW flow was finally established approximately 90 seconds after the reactor trip. Shortly after this, RCS makeup flow was increased by manually starting a second high pressure injection (HPI) pump.

The plant remained in this state with stable natural circulation established and EFW removing decay heat for more than one hour before offsite power was restored.

Discussion of Important Phenomena

Several important phenomena occurred during the transient which challenged the capability of RETRAN and the Oconee RETRAN Model to accurately simulate the plant response. These phenomena include the transition to and the development of natural circulation, primary-to-secondary heat transfer under low flow conditions, main steam relief, RCS flow coastdown, and pressurizer behavior.

Accurate simulation of the steam generator inventory and void profile is important since it determines the effective heat transfer surface area in the generator and thus the primary-to-secondary heat transfer. This is especially important for this transient because all feedwater is lost for the first 90 seconds after the reactor trip. As the inventory is boiled off, the thermal center of the steam generator is lowered, which inhibits the initiation of natural circulation until EFW is restored.

Secondary pressure control is also important in determining the steam generator heat transfer and thus the RCS temperature and pressure response. During this event, power to the air-operated turbine bypass and atmospheric dump valves is lost. These valves gradually go closed as air pressure is lost, therefore losing their ability to control pressure to the post-trip setpoint (approximately 1000 psig). This caused an increase in heat transfer as the valves relieved more steam than necessary.

The RCS flow coastdown is important to predict accurately in this transient because it affects the transition to natural circulation.

Model Description and Boundary Conditions

The ANO-1 plant is very similar to Oconee. Both are Babcock & Wilcox (B&W) 177 fuel assembly (FA) plants with the same Nuclear Steam Supply Systems (NSSS). The plant response during this event showed little asymmetry between loops so the one-loop Oconee RETRAN Model (see Figure 2.2-2) was used for the analysis. The base Oconee model initial conditions were used for this analysis with only a small adjustment to the RCS pressure. The plant-specific data used for this analysis was interpreted from various sources.

Initial Conditions

	Model	Plant
Power Level	100% (2568 MWt)	100% (2568 MWt)
RCS Pressure	2162.1 psig	2162.1 psig
PZR Level	180 inches	180 inches
T hot	602.0 °F	600.9 °F
T cold	555.3 °F	556.9 °F
T ave	578.7 °F	578.9 °F
SG Pressure	910 psig	909 psig
SG Level	55% (OR)	72% (OR)
RCS Flow	139.7×10^6 lbm/hr	139.4×10^6 lbm/hr
MFW Flow	10.9×10^6 lbm/hr	10.7×10^6 lbm/hr

The problem boundary conditions used are the pre-trip power response as well as the post-trip delayed neutron power and decay heat, a one second MFW flow coastdown, EFW and HPI flows, ANO-1 MSSV lift setpoints, and SG pressure vs. time control.

[ ] Oconee 3 core characteristics at the approximate time in cycle as ANO-1 during the transient are used for both calculations.

The EFW flow used comes from ANO-1 plant data. The HPI flow is assumed to be the same as Oconee. It should be noted that the values for the high RCS pressure trip setpoint (2300 psig) and the RC pump inertia (70000 lbm-ft) at the ANO-1 plant are the same as those for the Oconee plant, and are already in the base model.

Simulation Results

The simulation begins with the closure of the main turbine intercept and governor valves on the loss of offsite power and continues for 300 seconds. The simulation was terminated at 300 seconds because acceptable plant data was only available to this point. Continuous plant data was not available for any of the parameters during this event. However, enough data points were available to accurately determine the plant response. The sequence of events is given in Table 4.3.1-1, and the results of the simulation are compared to the plant data in Figures 4.3.1-1 through 4.3.1-7.

The RCS pressure response is shown in Figure 4.3.1-1. The reactor trip on high RCS pressure is predicted by RETRAN at 3.9 seconds as compared to 4.1 seconds in the plant. This indicates that the pressurizer insurge, produced by the turbine intercept valves closing, is being predicted satisfactorily. The predicted RCS pressure response trends the data closely throughout the simulation. Since the SG pressure is being controlled throughout the event (see Figure 4.3.1-4) and no feedwater is being delivered for the first 94 seconds, the SG heat transfer is largely dependent on the inventory and void profile in the steam generator. The predicted RCS temperatures (see Figure 4.3.1-3) trend the data closely, therefore, the modeling of the initial steam generator inventory is accurate.

The pressurizer level response given in Figure 4.3.1-2, as stated above, trends the plant data closely for the entire simulation. This is due mainly to the accurate steam generator heat transfer prediction during the simulation.

The RCS temperature response shown in Figure 4.3.1.3. RETRAN predicts a slightly greater ΔT across the loop during the initial cooldown after the trip. This is possibly due to differences in the predicted RCS flow coastdown and the actual coastdown. By the end of the simulation the predicted temperatures agree closely with the data.

The SG pressure response shown in Figure 4.3.1-4. As stated earlier, the SG pressure vs. time is input as a boundary condition. The SG level response is

shown in Figure 4.3.1-5. There is no plant data for comparison for this parameter, therefore, the figure is given as additional information. It is evident from the figure, however, that the level response is characteristic of a temporary loss of all feedwater. The level decreases below 20 inches in the first 90 seconds of the event and then recovers as feedwater is reestablished at 94 seconds.

At the end of the simulation the ΔT in the prediction closely matches the data. This means that the natural circulation flowrate is predicted very well, with RETRAN predicting 2.4% flow at 300 seconds (see Figure 4.3.1-7). Since the plant ΔT data has not yet stabilized, the natural circulation flowrate is not fully developed. This is consistent with the RETRAN prediction since the SG level has not reached the controlling setpoint, and SG pressure is not stable.

Table 4.3.1-1

Arkansas Nuclear One - Unit 1
Loss of Offsite Power
June 24, 1980

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
Main turbine intercept and governor valves close*	0	0
Reactor trip on high RCS pressure, reactor coolant and MFW pumps trip	4.1	3.9
Turbine driven EFW pump starts and trips immediately on overspeed*	21	21
Normal makeup is established*	34	34
EFW flow established*	94	94
RCS makeup increased*	104	104
End of simulation	N/A	300

Note: Asterisks designate boundary conditions

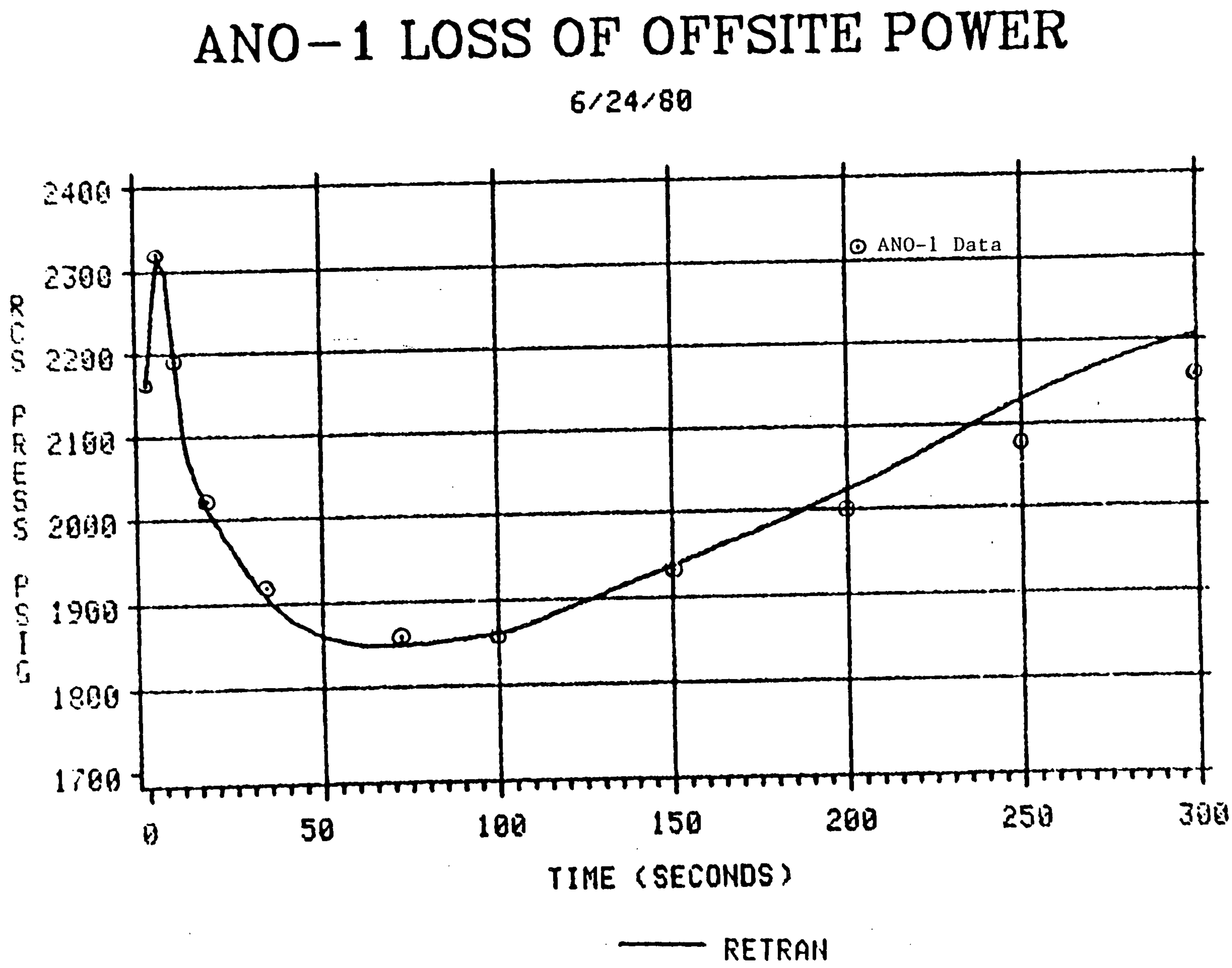

ANO-1 LOSS OF OFFSITE POWER
6/24/80
2400
2300
2200
2100
2000
1900
1800
1700
RCS PRESS PSIG
ANO-1 Data
0
50
100
150
200
250
300
TIME (SECONDS)
RETRAN

Figure 4.3.1-1

ANO-1 LOSS OF OFFSITE POWER

6/24/80

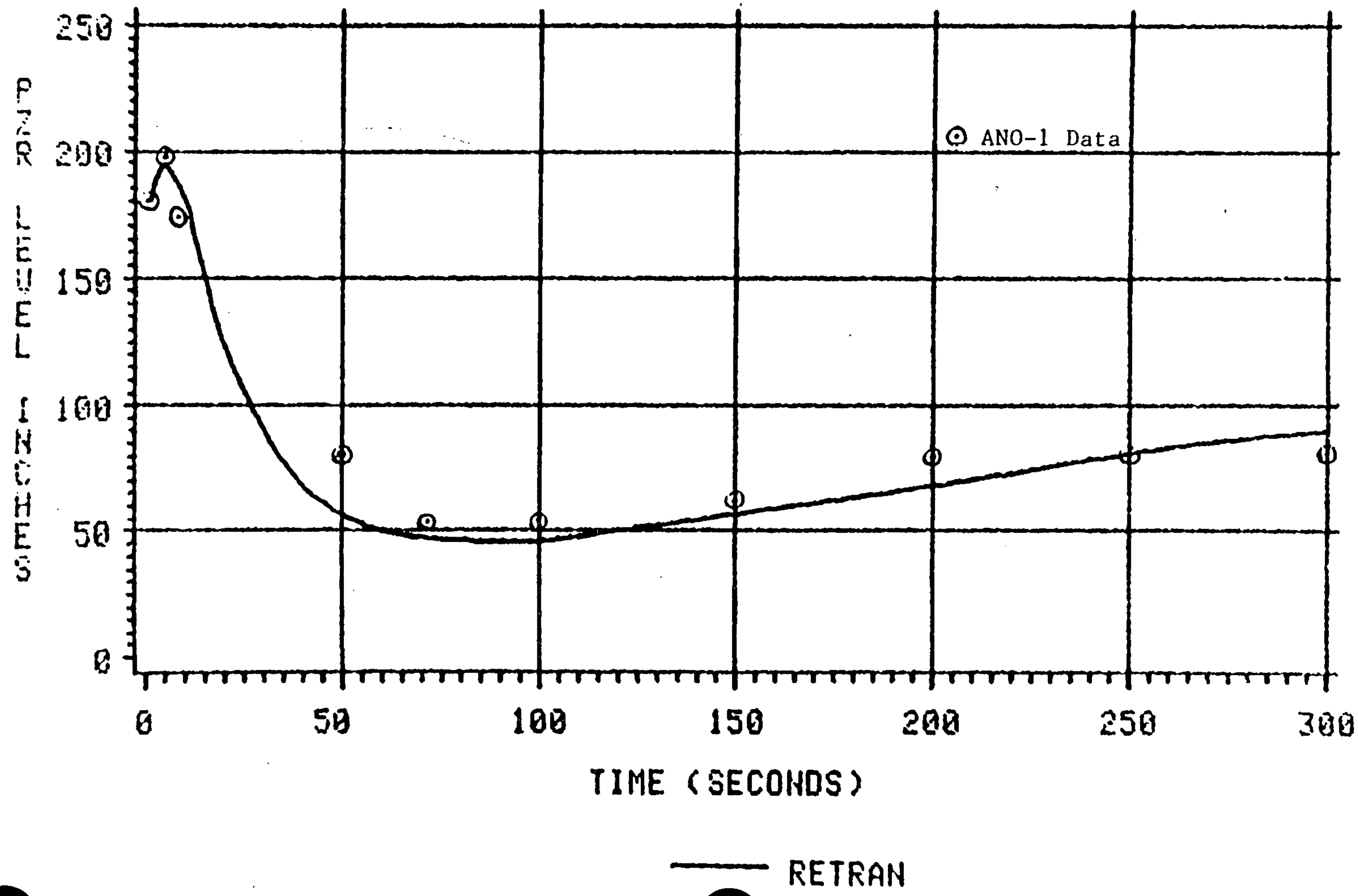


Figure 4.3.1-2

ANO-1 LOSS OF OFFSITE POWER

6/24/80

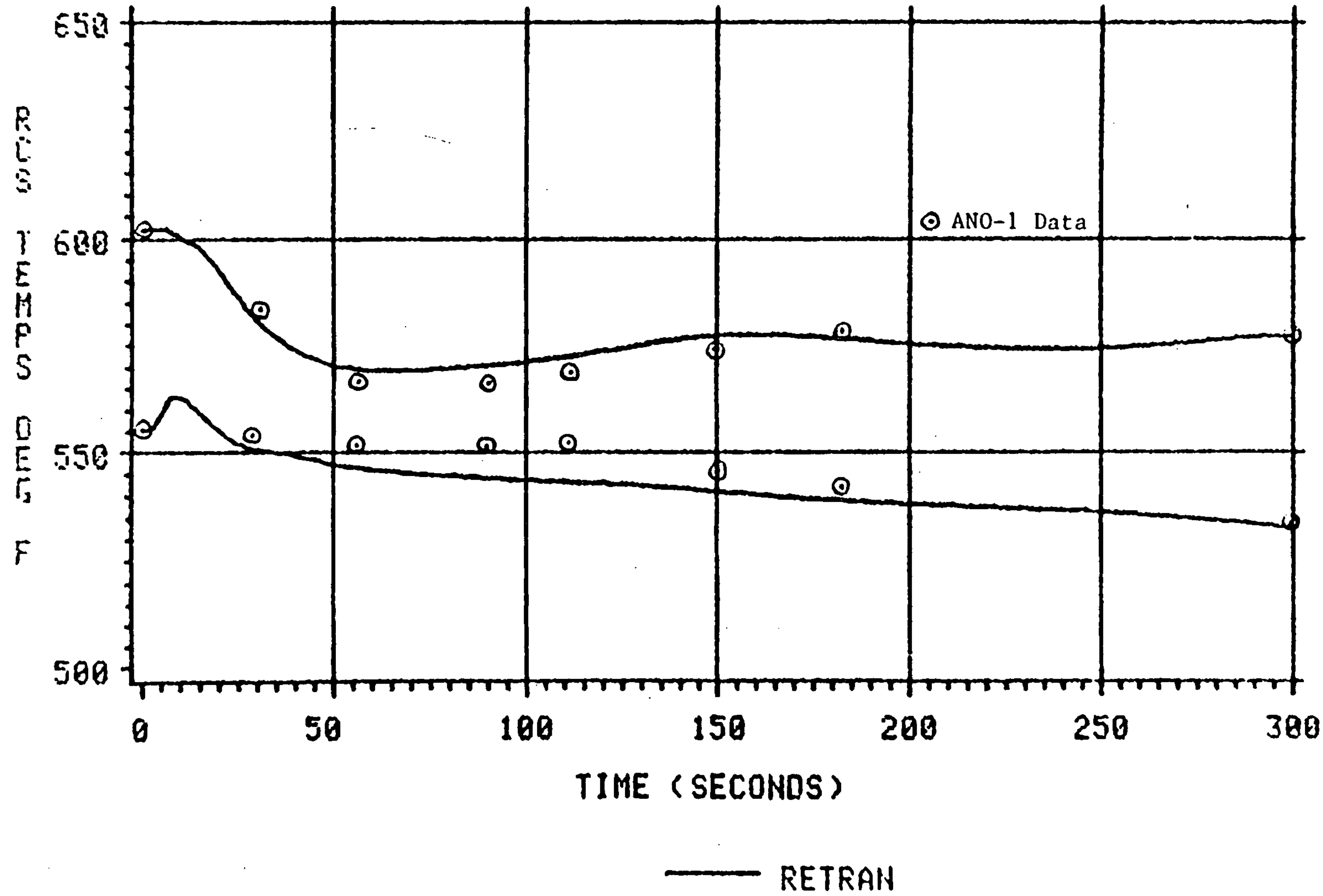


Figure 4.3.1-3

ANO-1 LOSS OF OFFSITE POWER

6/24/80

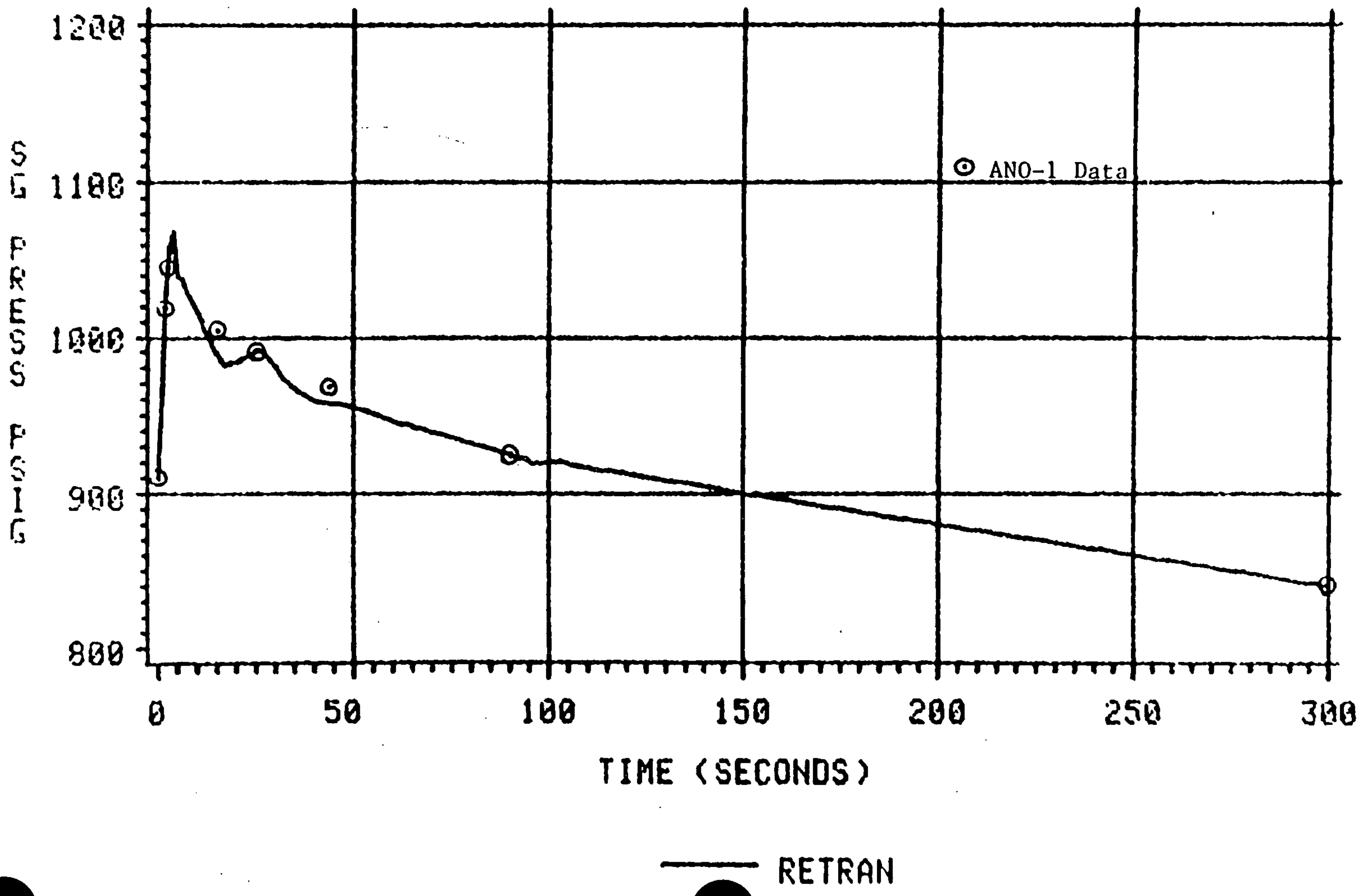


Figure 4.3.1-4

ANO-1 LOSS OF OFFSITE POWER

6/24/80

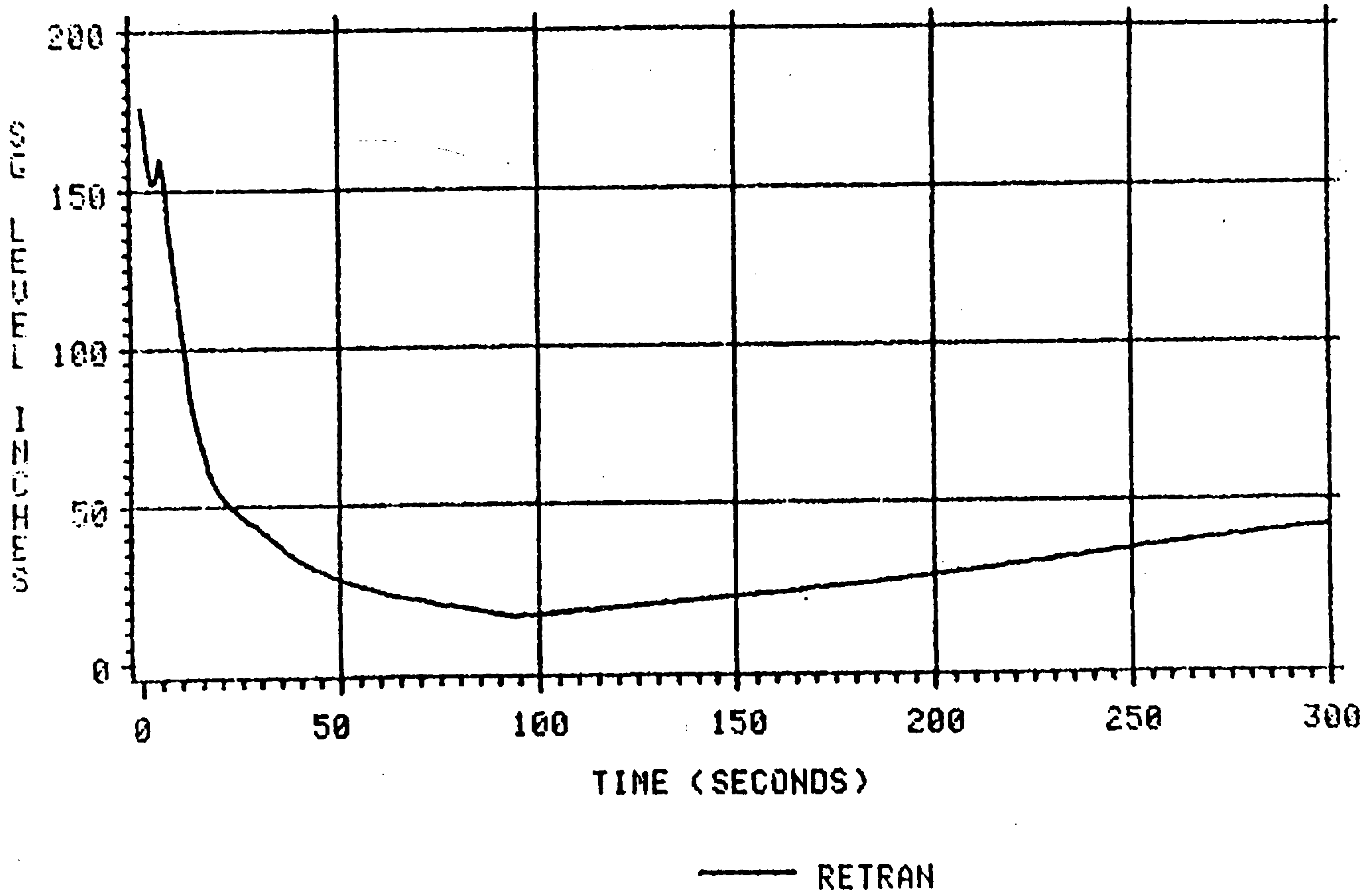


Figure 4.3.1-5

ANO-1 LOSS OF OFFSITE POWER

6/24/80

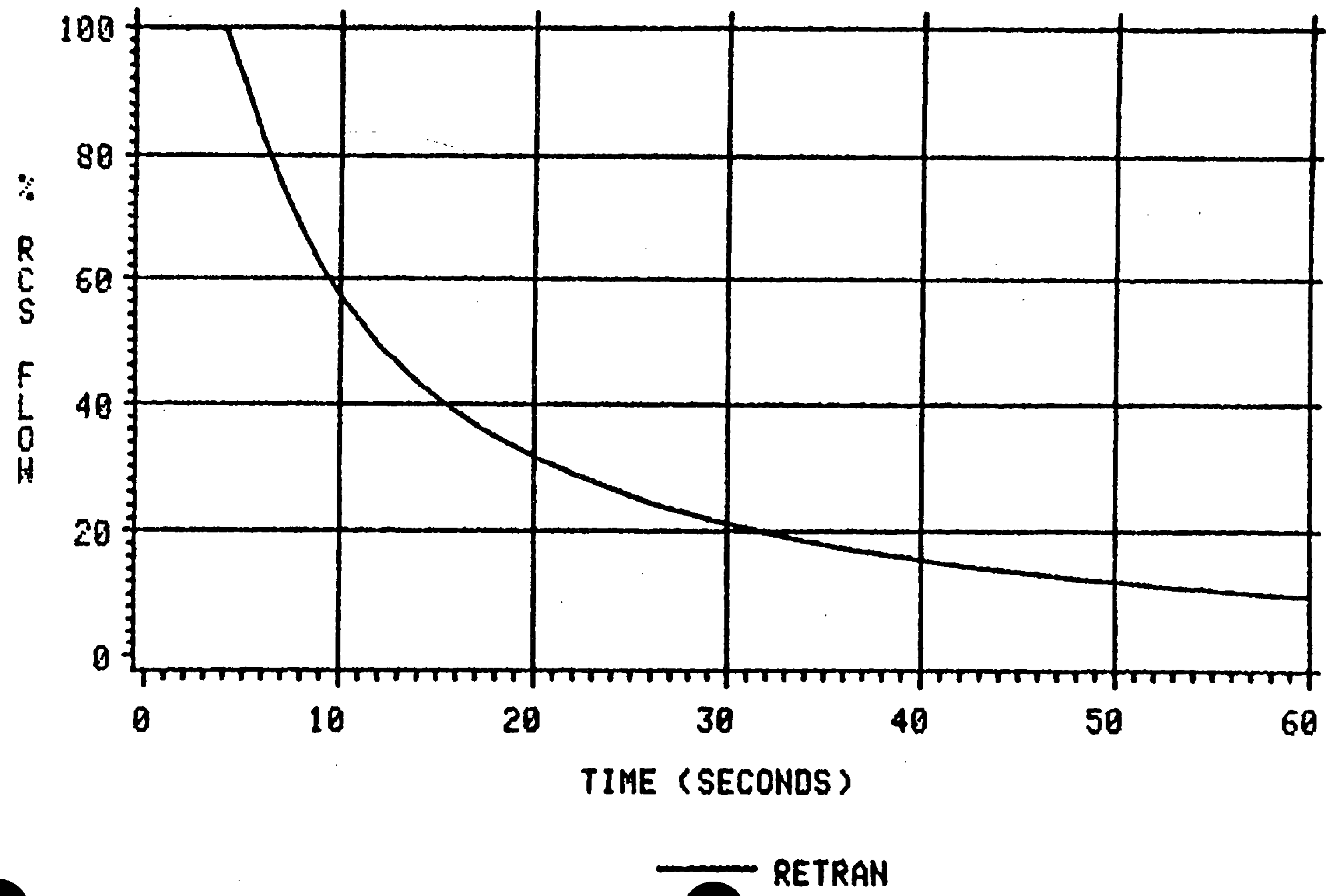


Figure 4.3.1-6

ANO-1 LOSS OF OFFSITE POWER

6/24/80

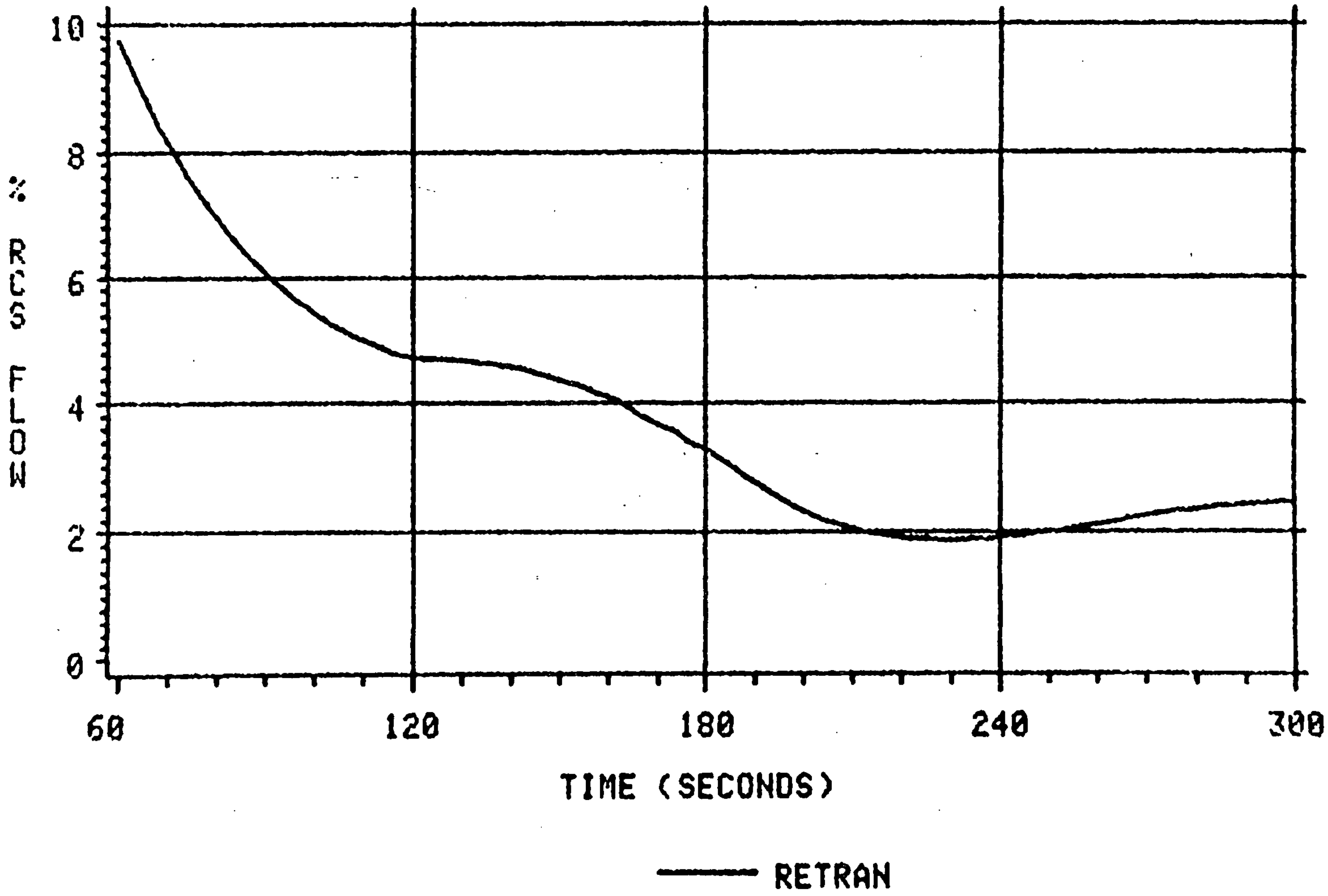


Figure 4.3.1-7

4.3.2 Oconee Nuclear Station - Unit 1
Reactor Coolant Pump Coastdowns
Unit Startup Tests

Transient Description

A series of reactor coolant pump (RCP) coastdowns were performed during pre-operational startup testing at Oconee Unit 1. All of the coastdown tests were performed at hot zero power (HZP) conditions (approximately 532 °F and 2155 psig, RCS temperature and pressure). The tests performed encompassed all possible pump combinations with respect to the number of pumps initially running and the number tripped. RCS flow data was taken for the first 30 seconds of the coastdown for most of the tests performed.

Discussion of Important Phenomena

Since the coastdown tests were conducted at hot zero power, only hydraulic phenomena are important. The significant phenomena include the interaction between the RCPs and the coolant during coastdown as well as the frictional losses associated with the coolant flow through the loops. The key facets in modeling the interaction between the RCPs and the coolant are the pump flywheel inertia, the homologous curve set, and the frictional torque representation. Accuracy in this area is reflected by satisfactory prediction of transient RCS flow. The steady-state flow splits are determined by the frictional losses in the RCS flowpaths, including reverse flow frictional losses in cold legs with an inactive pump and loops with two inactive pumps. Thus a comparison of predicted and observed steady state flows demonstrates the accuracy of the RCS loss coefficients at various flow rates, including reverse flow.

Model Description and Boundary Conditions

The simulations performed in this analysis did not require a [

] Therefore, the two-loop Oconee RETRAN Model (see Figure 2.2-1) is used with the [

]

The model was set up for four different HZP initializations. The differences between these initializations are simply a different configuration of pumps running initially and the corresponding RCS flow distribution plant data. The following table summarizes the four initializations:

Table 4.3.2-1

RCS Flow Initialization

Case #	# of Pumps Operating	Flow (x 10^{-6} lbm/hr)
1	4	145.0 (vessel)
2	3	109.0 (vessel)
	Loop A	33.0
	Loop B	76.0
	Idle pump reverse flow	-15.0
3	2 (1 in each loop)	74.0 (vessel)
	Loop A	37.0
	Loop B	37.0
	Idle pump reverse flow	-13.4
4	2 (same loop)	68.3 (vessel)
	Loop A	-12.2
	Loop B	80.5

The pump combinations for which simulations were performed are the following:

Table 4.3.2-2

Pump Trip Combinations

4/0
4/3
4/2 (1 per loop tripped)
4/2 (2 in same loop tripped)
4/1
3/0
3/2 (1 per loop after trip)
3/1 (1 per loop tripped)
3/1 (2 in same loop tripped)
2/1 (1 per loop prior to trip)
2/1 (2 in same loop prior to trip)
2/0 (1 per loop prior to trip)
2/0 (2 in same loop prior to trip)

Simulation Results

The results of the coastdown simulations are presented in Figures 4.3.2-1 through 4.3.2-13. Continuous plant data was available for the first 30 seconds for most of the cases simulated as well as the eventual steady-state vessel flow for partial pump operation.

The RETRAN simulations trend the data for the duration of the coastdown for most cases. It is evident that for some data the quality is suspect, since the expected smooth curve characteristic of a pump coastdown was not recorded. The table below gives the results of the predicted steady state flows. It is apparent from these results that all cases agree reasonably well with the data.

Table 4.3.2-2

Steady-State Core Flow

Pumps Operating	RETRAN (% of 4 pump flow)	DATA (% of 4 pump flow)
3	74.5	75.2
2 (1 per loop)	47.9	51.0
2 (same loop)	46.3	47.1
1	21.3	22.6

4-88

ONS RCP COASTDOWN

4/0

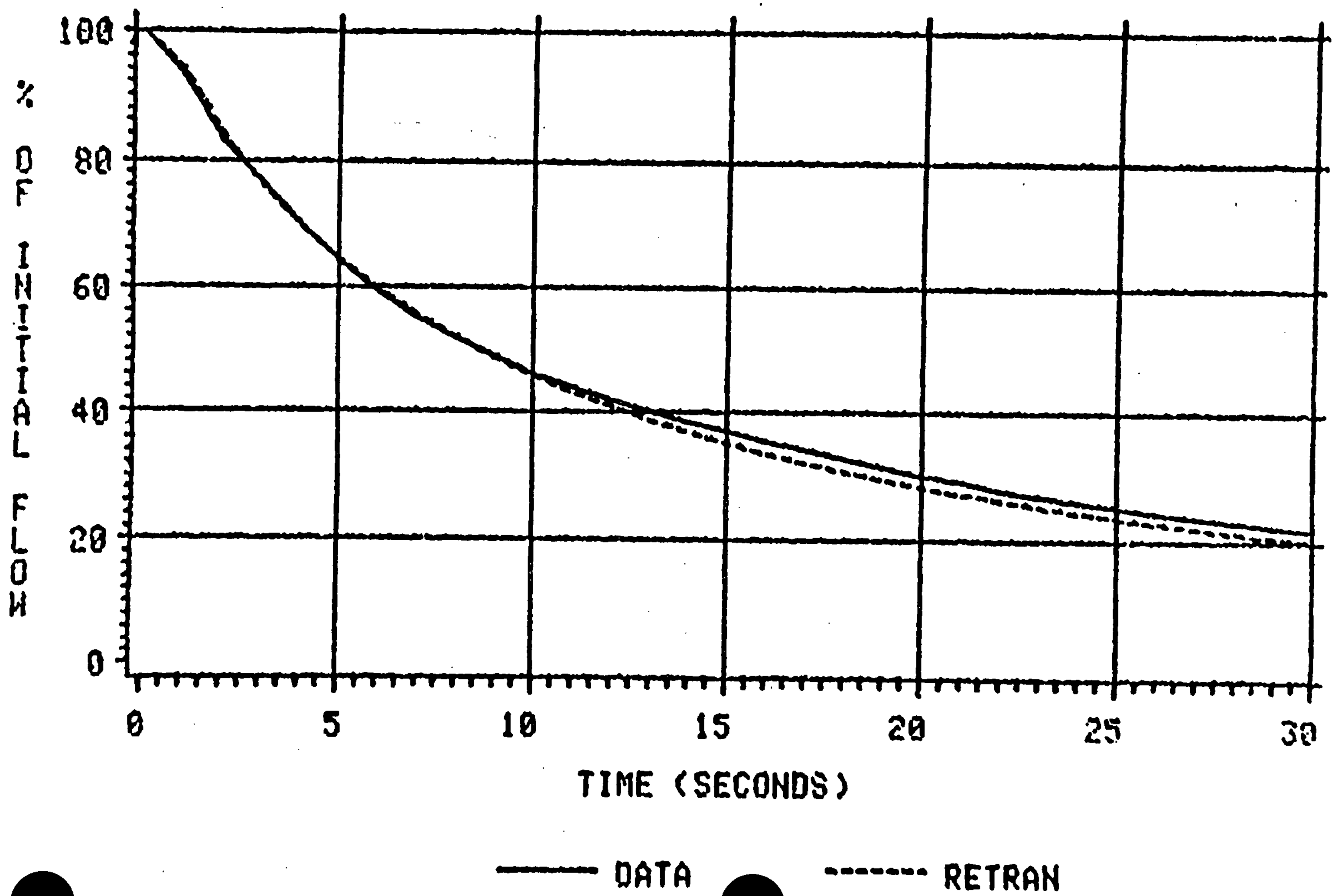


Figure 4.3.2-1

ONS RCP COASTDOWN

4/3

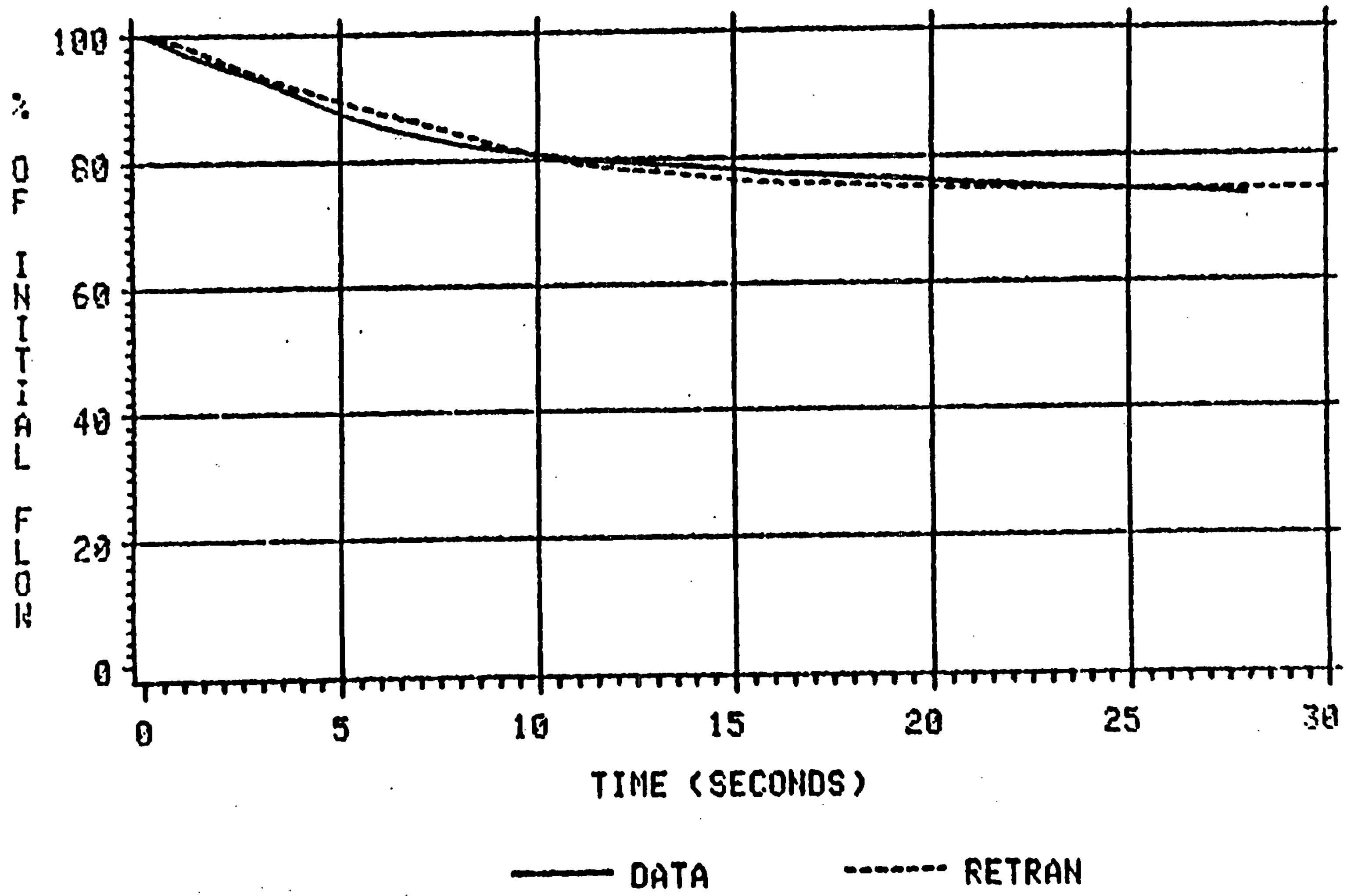


Figure 4.3.2-2

ONS RCP COASTDOWN

4/2 (1 IN EACH LOOP)

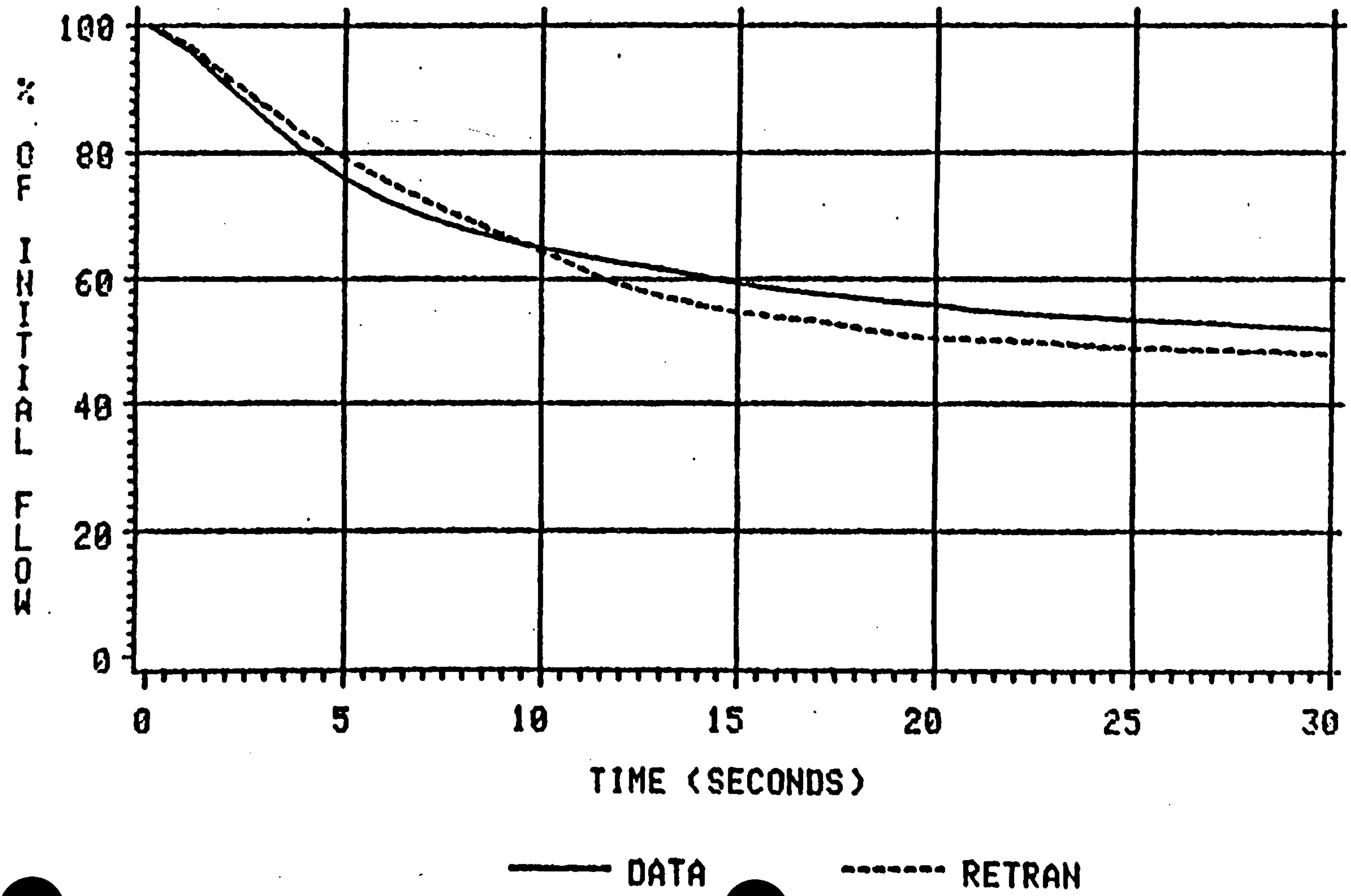


Figure 4.3.2-3

ONS RCP COASTDOWN

4/2 (BOTH IN SAME LOOP)

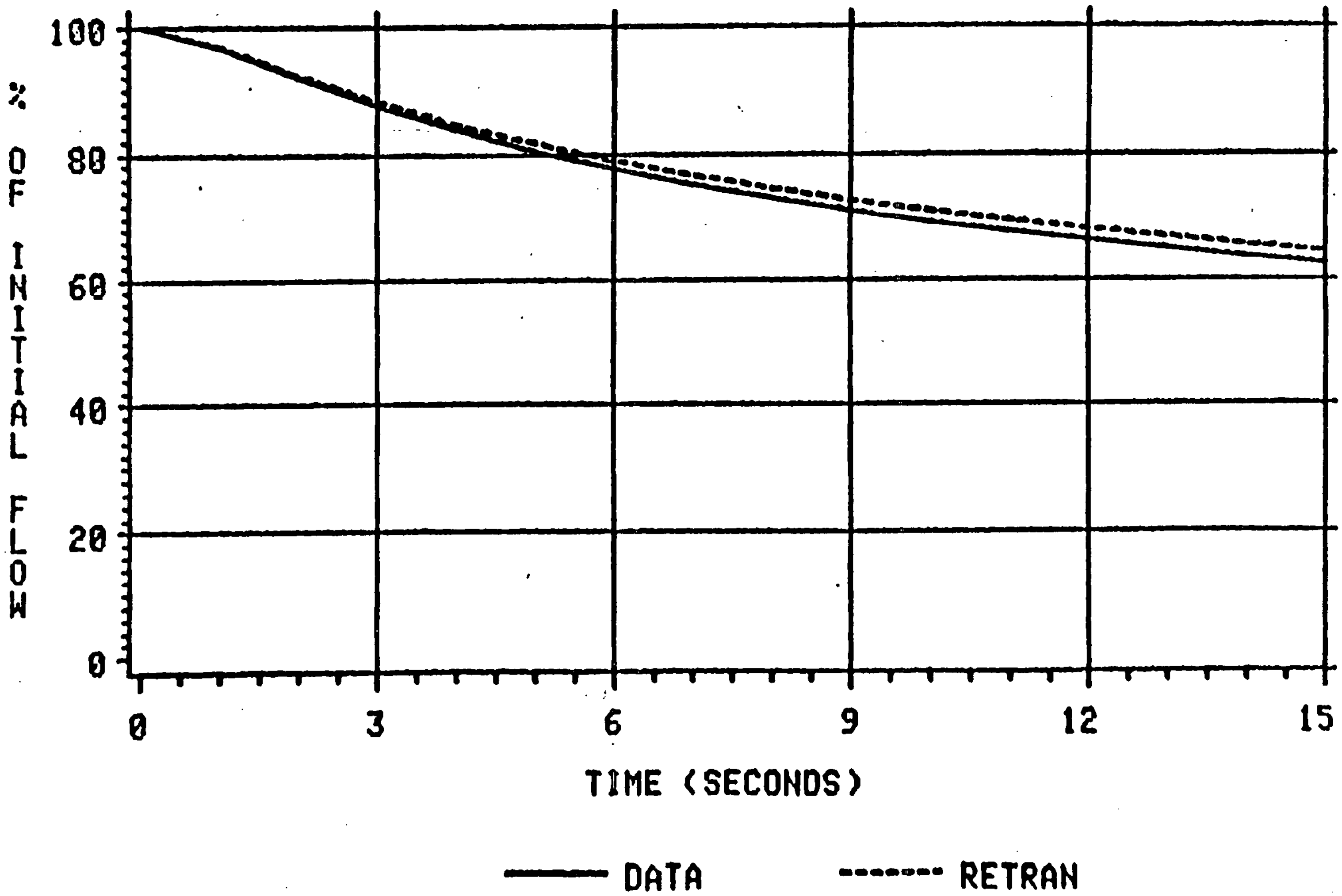


Figure 4.3.2-4

ONS RCP COASTDOWN

4/1

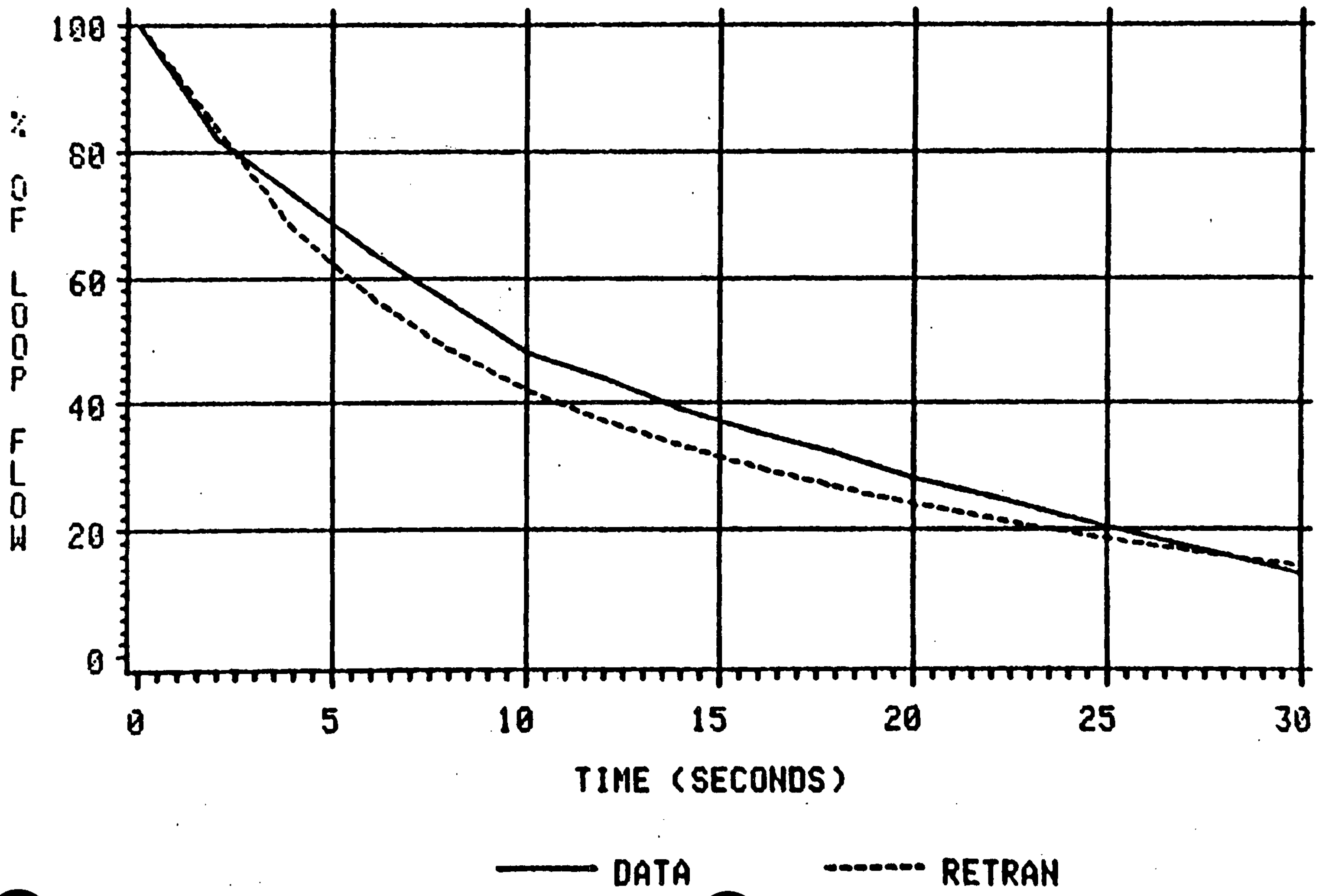


Figure 4.3.2-5

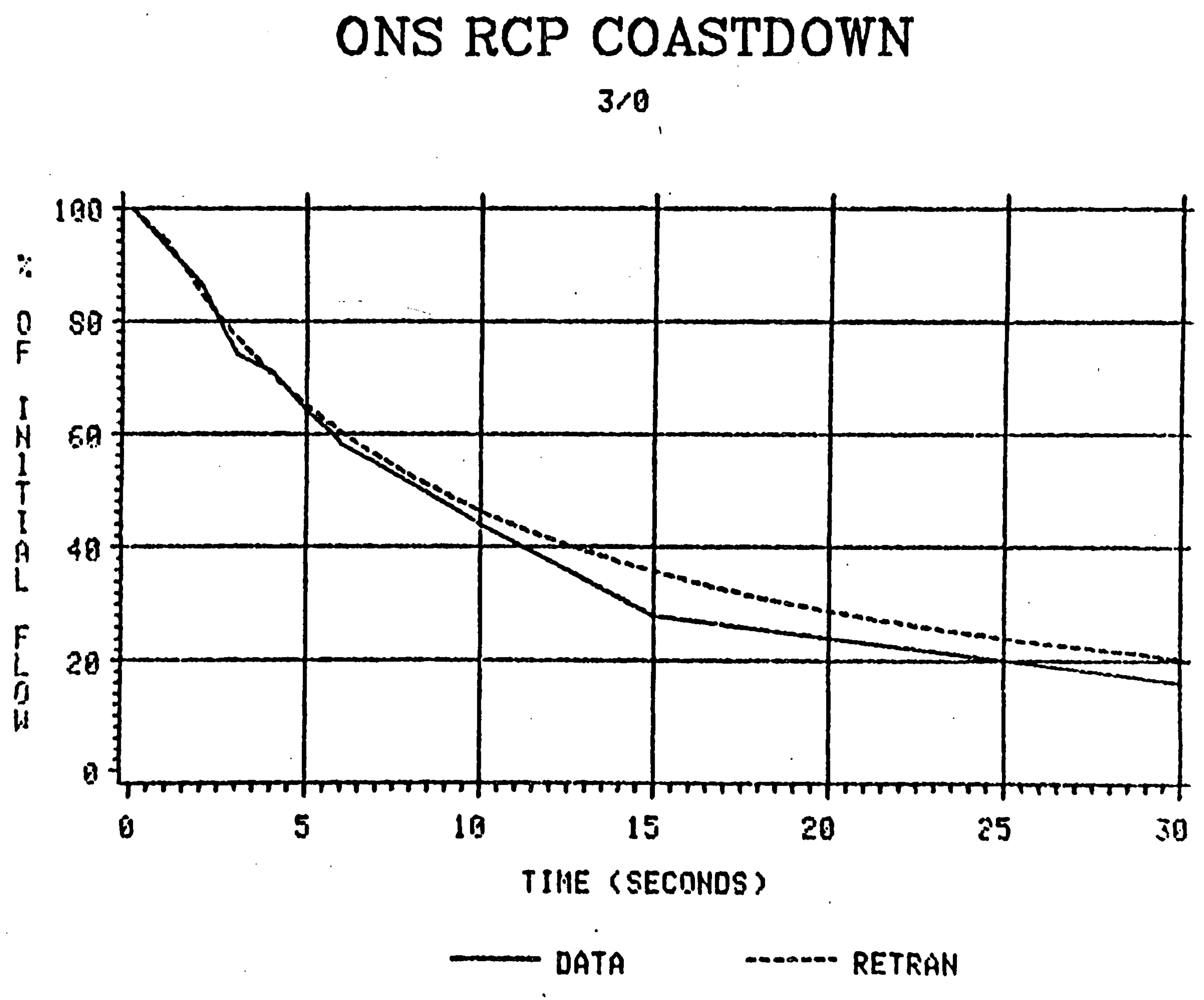

ONS RCP COASTDOWN
3/0
% OF INITIAL FLOW
100
80
60
40
20
0
0
5
10
15
20
25
30
TIME (SECONDS)
DATA
RETRAN

Figure 4.3.2-6

ONS RCP COASTDOWN

3/2 (1 PER LOOP RUNNING)

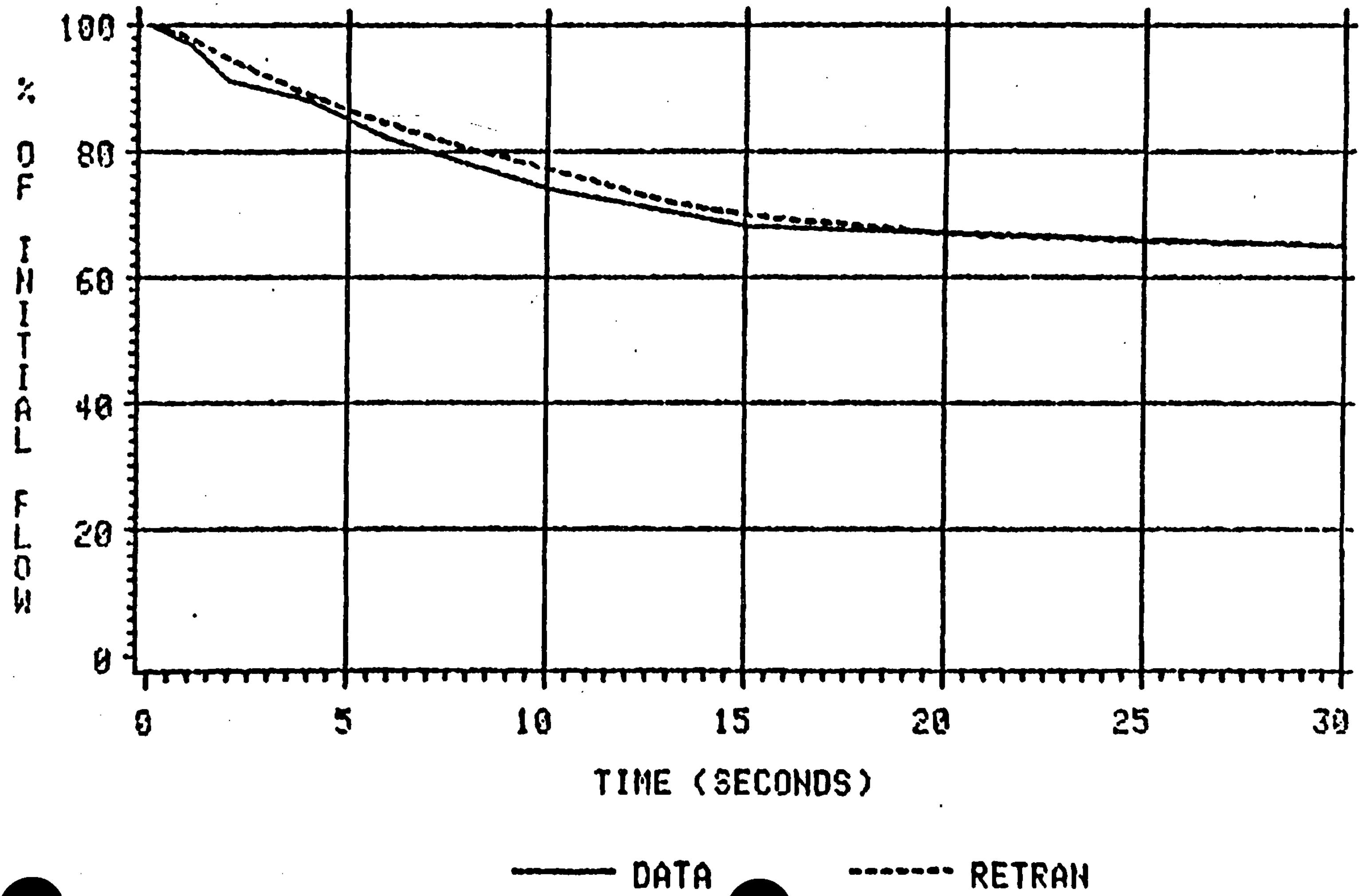


Figure 4.3.2-7

ONS RCP COASTDOWN

3/1 (1 PER LOOP TRIPPED)

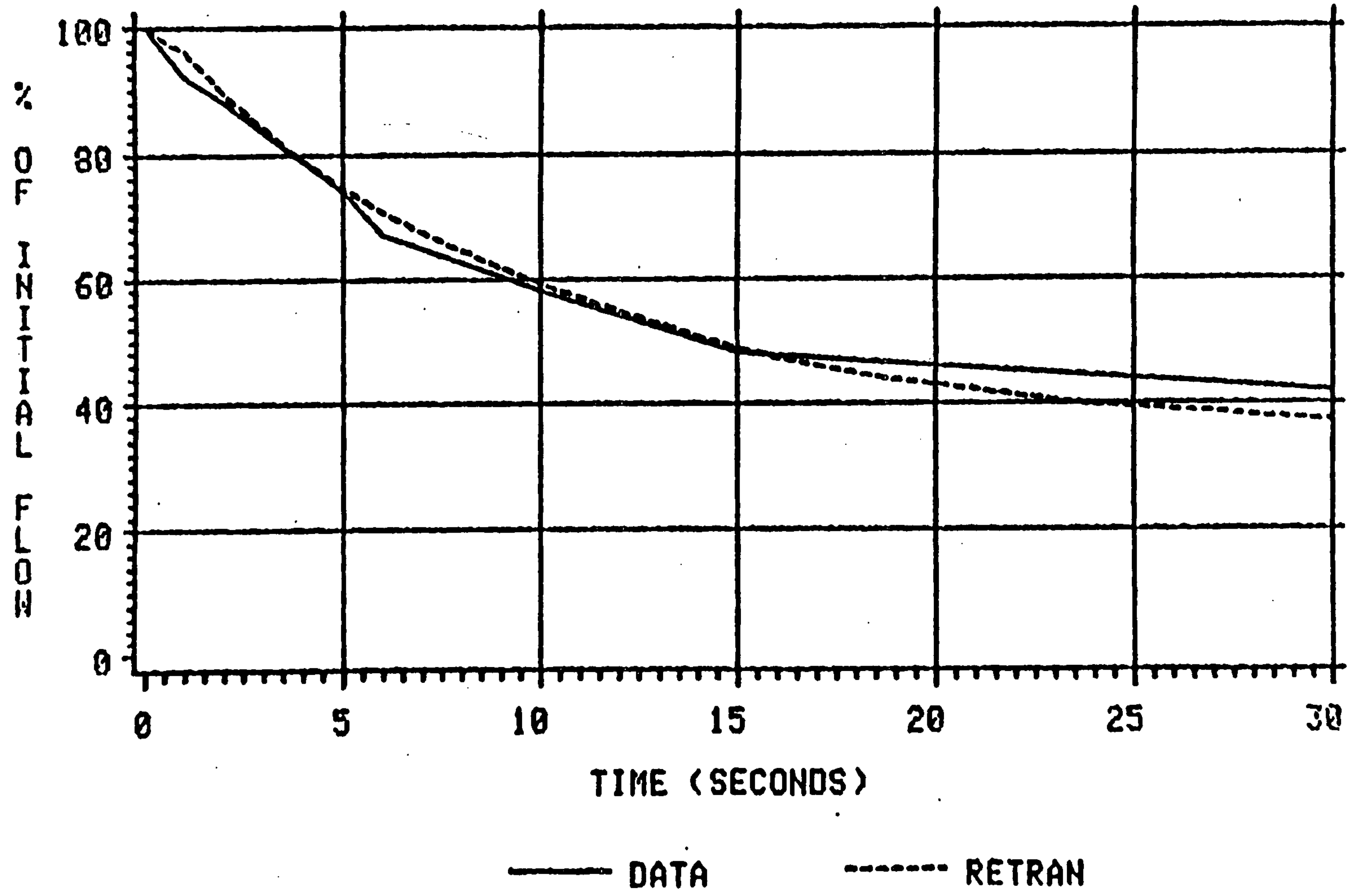


Figure 4.3.2-8

ONS RCP COASTDOWN

3/1 (BOTH TRIPPED SAME LOOP)

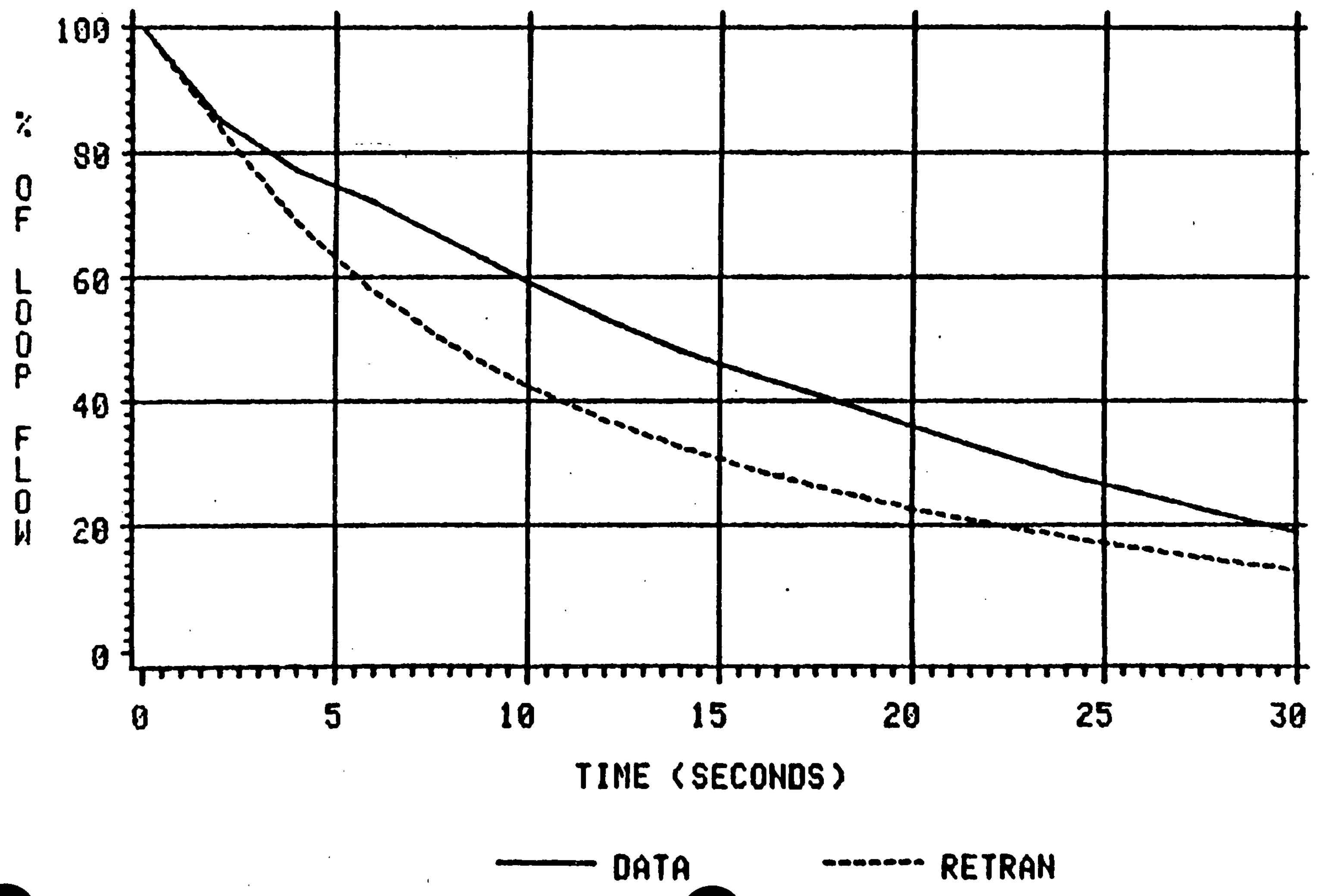


Figure 4.3.2-9

ONS RCP COASTDOWN

2/0 (ONE PER LOOP)

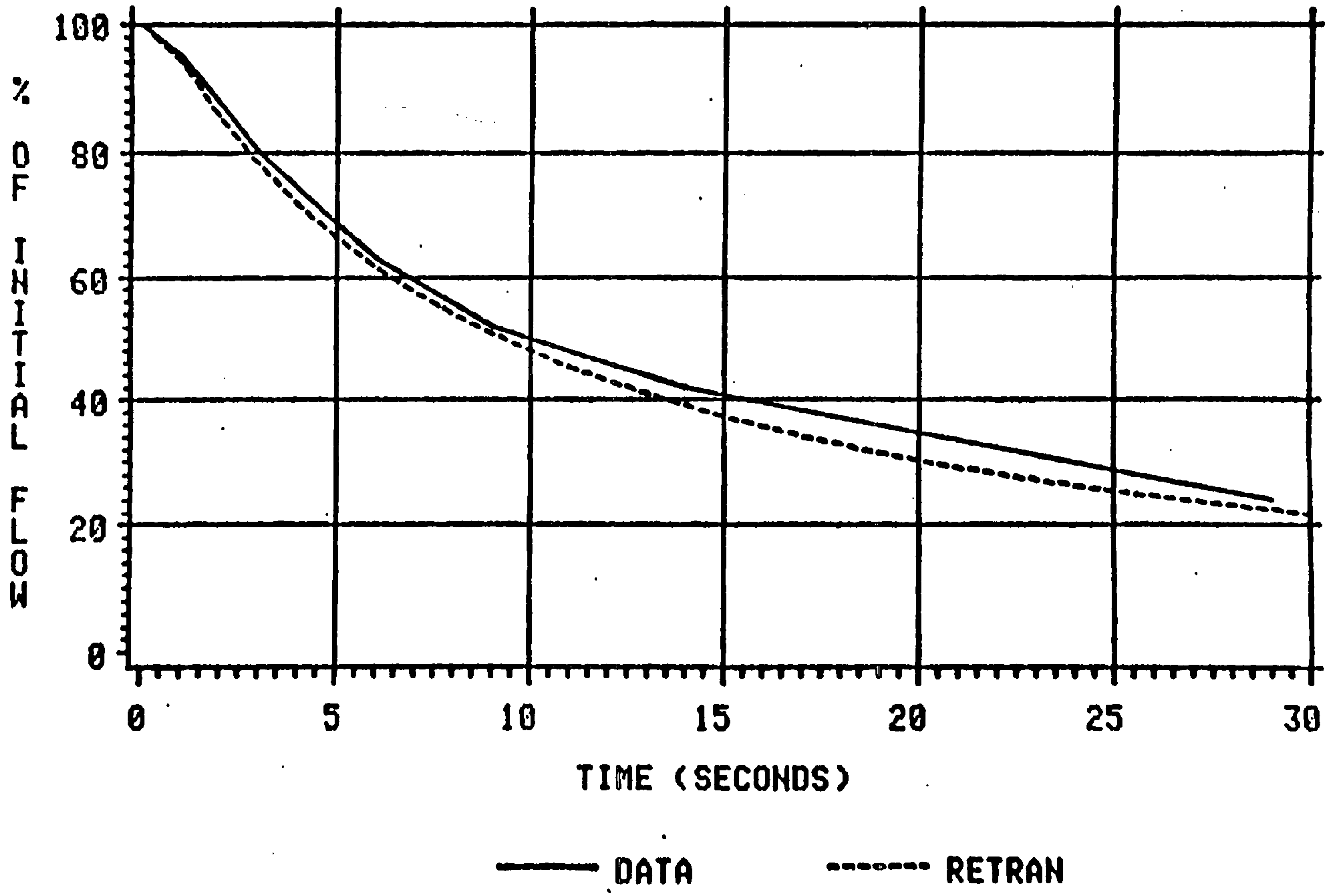


Figure 4.3.2-10

ONS RCP COASTDOWN

2/1 (ONE PER LOOP INITIALLY RUNNING)

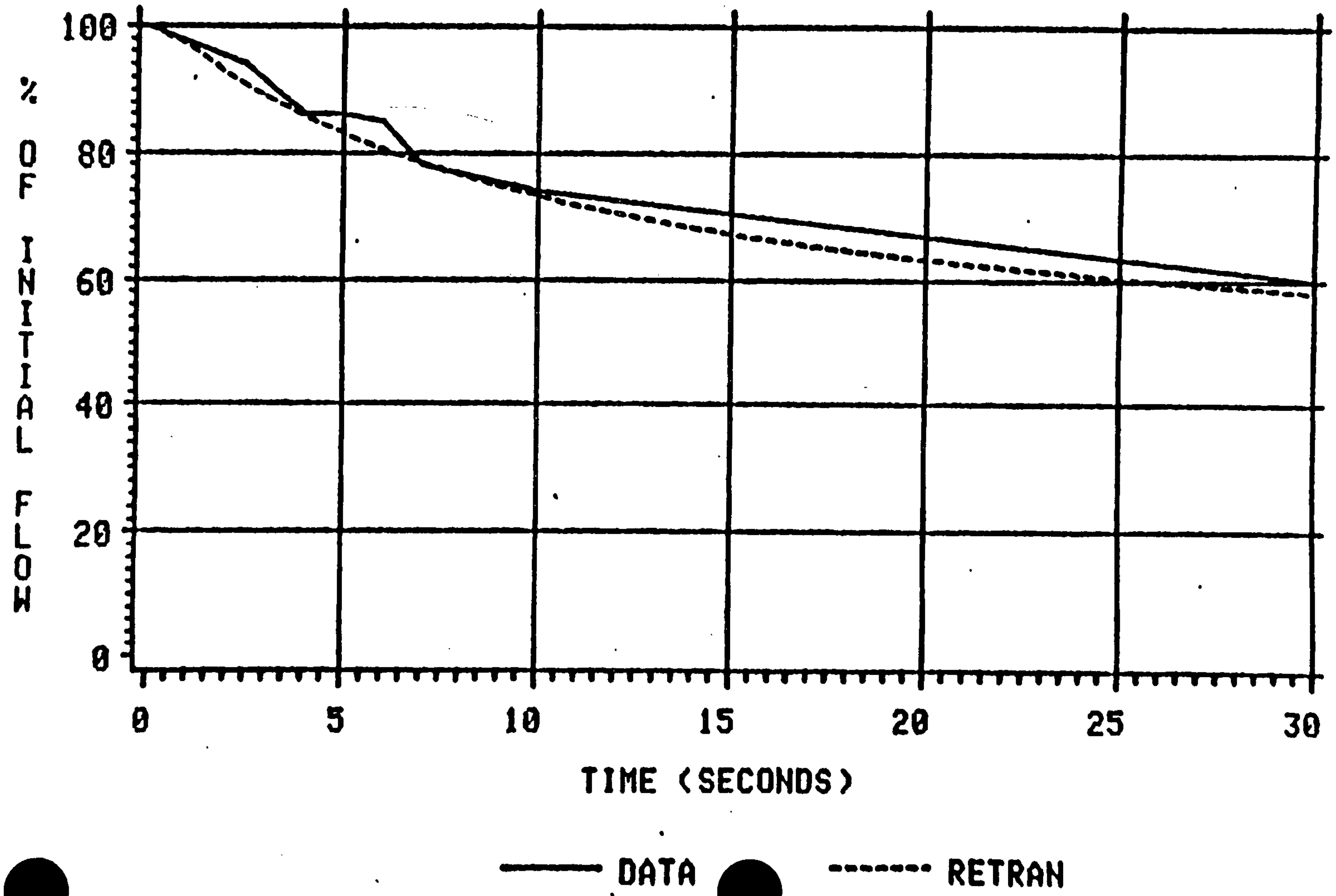


Figure 4.3.2-11

ONS RCP COASTDOWN

2/0 (SAME LOOP)

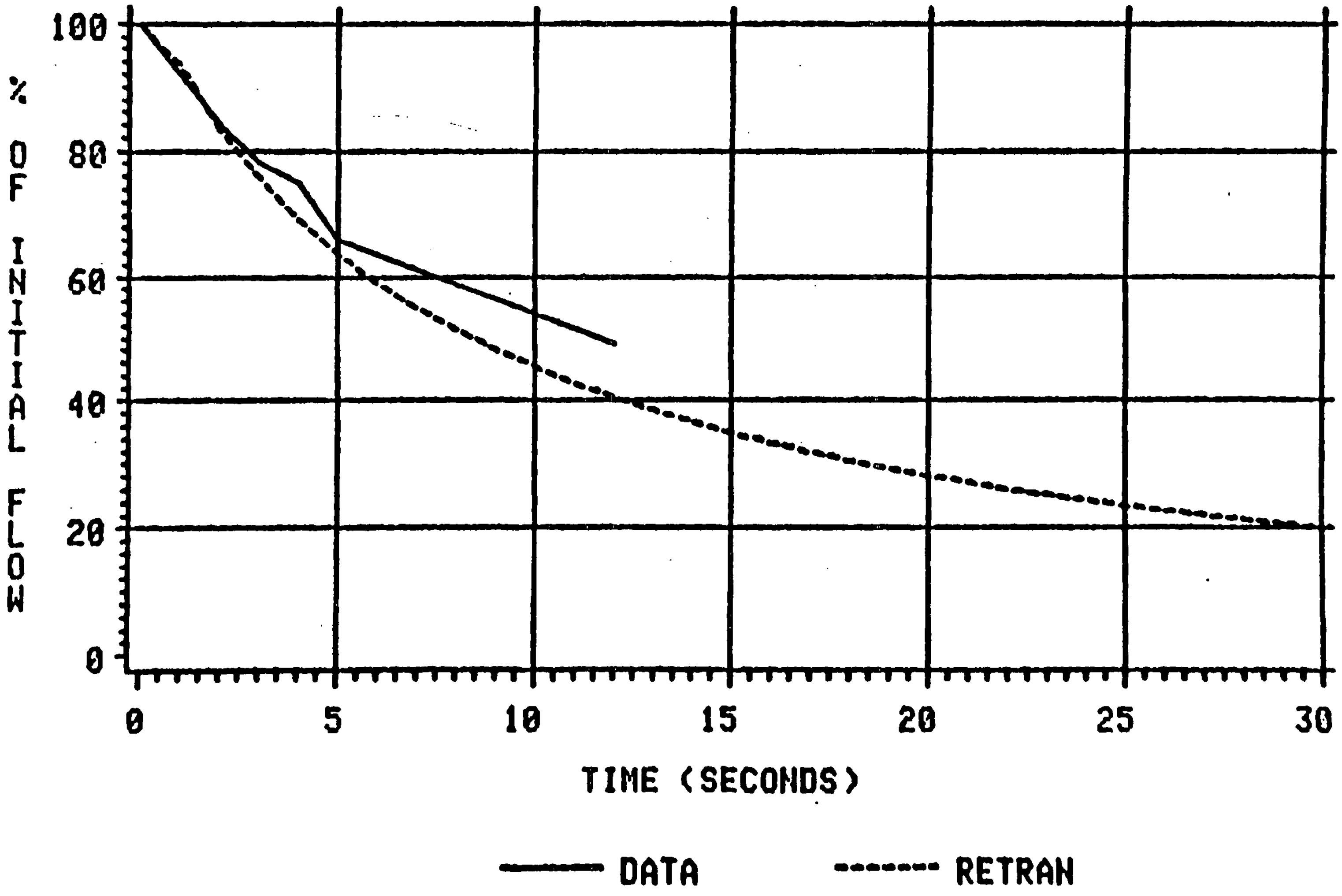


Figure 4.3.2-12

ONS RCP COASTDOWN

2/1 (SAME LOOP)

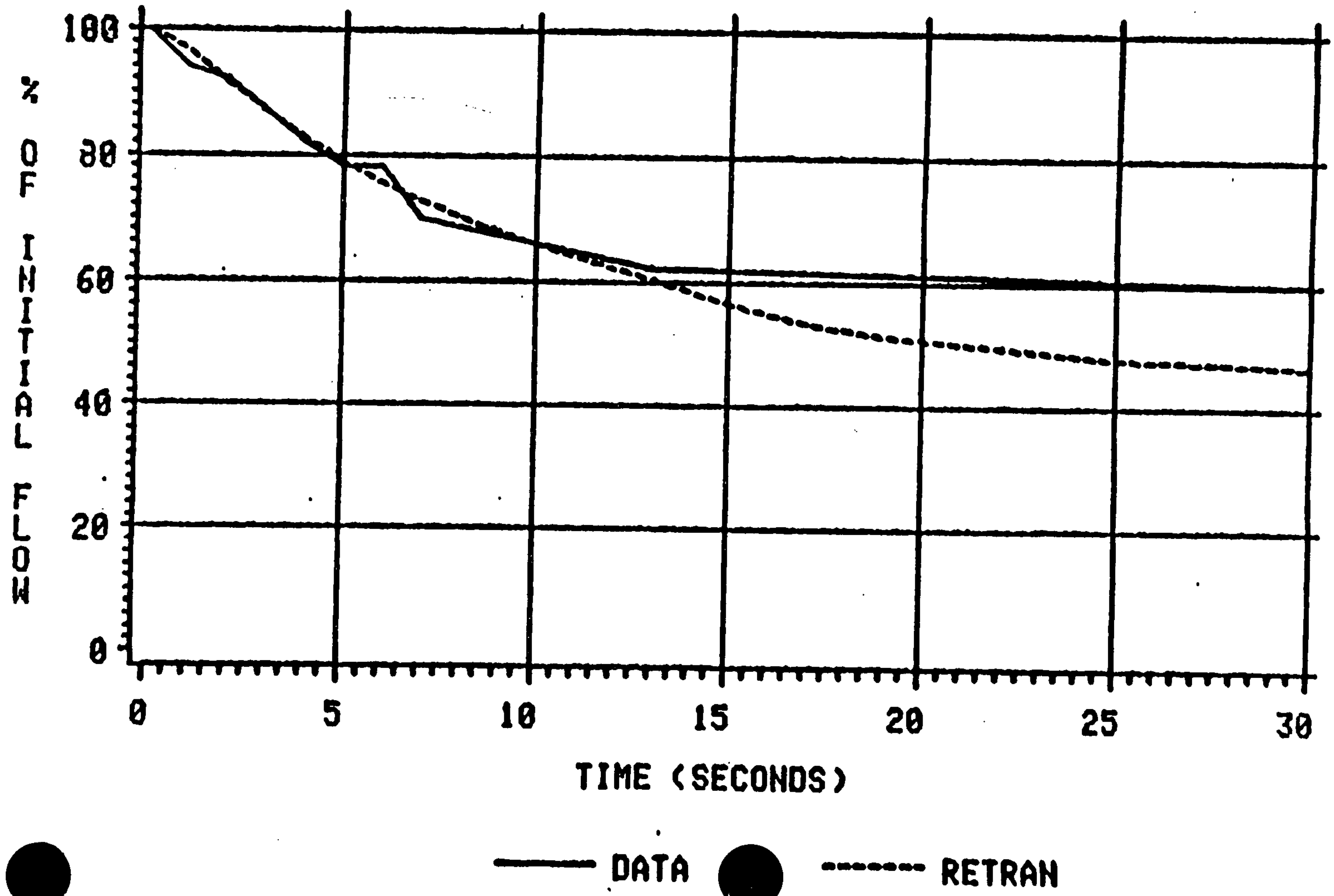


Figure 4.3.2-13

4.3.3 Oconee Nuclear Station
Steady State Natural Circulation Comparisons

Analysis Description

This analysis is the calculation of stable natural circulation flow rates and hot leg to cold leg temperature differences for various decay heat power levels. At the end of a loss of offsite power simulation, the core power level is set at various values from 80 MW down to 10 MW (at 10 MW decrements) and a new steady state value is achieved. Steam generator (SG) level is maintained at the normal natural circulation setpoint of 50% on the operating range. The RETRAN predictions are compared to calculated natural circulation flow rates from various tests and events at lowered-loop 177 fuel assembly Babcock and Wilcox units.

Discussion of Important Phenomena

The steady-state natural circulation flowrate is determined by the core power level, the elevation difference between the thermal centers, and the frictional losses around the loop. The key phenomena are therefore the primary-to-secondary heat transfer which determines the heat sink thermal center, and the frictional losses at the low loop flowrates characteristic of natural circulation. For each different core power level a different equilibrium loop flowrate will develop.

Model Description and Boundary Conditions

Due to the symmetry of the transient the one-loop Oconee RETRAN Model (Figure 2.2-2) is used. The steady state natural circulation flow calculations are made by restarting a best estimate loss of offsite power simulation at 15 minutes. At this point, the plant is in a stable natural circulation condition, with decay heat being removed by the steam generators. The steady state flow calculations are then made by artificially changing the decay heat power level from 80 MW to 10 MW, as previously described. Emergency feedwater maintains the desired SG level (50% on the operating range) during the simulation.

Simulation Results

The steady state natural circulation flow is analyzed at various core power levels. Predicted natural circulation flow rate as a function of power level is shown in Figure 4.3.3-1 along with data points from various B&W plants. The RETRAN RCS flow prediction curve is at a constant 50% SG level. The data points at 48.8 MW, 57 MW, 62.5 MW, and 80 MW are also at 50% SG level. The three data points below 30 MW were from varying SG conditions and are not considered accurate. The data point at 67 MW is from 40% SG level.

The figure shows the RETRAN prediction to be consistently trending the data with an offset of +0.5% of full flow for all of the data points at 50% SG level. A decrease in the natural circulation flow is evident in the data point at 67 MW and 40% SG level. RETRAN predicts a smaller drop in natural circulation flow due to the decreased SG level. It is indeterminate whether this discrepancy is due to inaccuracy in the data or a model insensitivity.

OCONEE NATURAL CIRCULATION FLOW

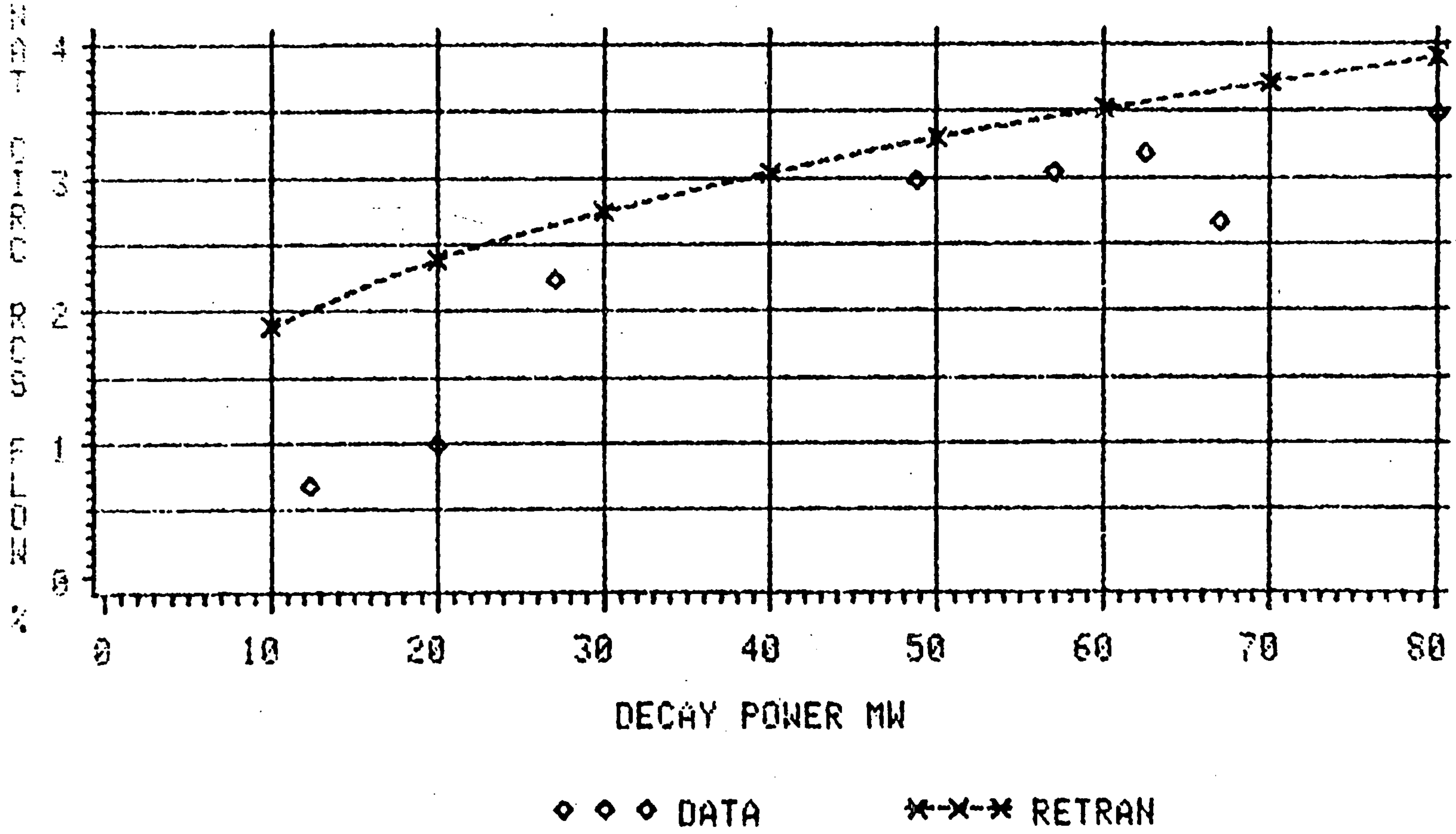


Figure 4.3.3-1

4.4 Reactivity Transient

4.4.1 Oconee Nuclear Station Unit 1
Control Rod Group Drop
August 8, 1982

Transient Description

Oconee Unit 1 was operating at 100% full power when the Group 6 control rods fell into the reactor core. Reactor power dropped almost immediately to approximately 36%, and the sudden mismatch between power generated in the core and power removed in the steam generators caused the primary coolant temperature to decrease. The resulting contraction of the coolant led to a rapid decrease in Reactor Coolant System (RCS) pressure, and the reactor tripped on variable low pressure approximately five seconds after the beginning of the event. The subsequent post-trip plant response was normal. Main feedwater (MFW) was continually available and the steam generator (SG) pressure control functioned as designed.

Discussion of Important Phenomena

Several important phenomena occurred during the transient which challenged the capability of RETRAN and the Oconee RETRAN Model to accurately simulate the plant response. These phenomena include steam generator secondary void fraction profile and primary-to-secondary heat transfer, main steam relief, and pressurizer behavior. In addition to these, for this particular event, the dynamic reactor response to the dropped control rod group and the response of the plant and the plant instrumentation to the core power decrease are very significant.

When control rod Group 6 dropped into the core, the large negative reactivity insertion caused a sudden decrease in reactor power. This negative reactivity was compensated for, to some extent, by positive reactivity feedback from the decreased moderator and fuel temperatures. The transient core power determined the pre-trip RCS temperature and pressure response and thus the reactor trip time.

Model Description and Boundary Conditions

The plant response during this event (particularly before the reactor trip) showed little asymmetry between loops so the one-loop Oconee RETRAN Model (Figure 2.2-2) was used for the analysis. In addition, the Unit 3 specific feedwater and main steam line models were incorporated into the model. The parameters used as initial conditions were matched, where possible, to the plant data. The plant data used for this analysis is digital transient monitor data and post-trip review program data.

Initial Conditions

	Model	Plant
Power Level	100% (2568 MWt)	100% (2568 MWt)
RCS Pressure	2133 psig	2133 psig
PZR Level	213 inches	213 inches
T hot	601.5 °F	601.3 °F "A", 601.5 °F "B"
T cold	554.8 °F	555.5 °F "A", 555.1 °F "B"
SG Pressure	910 psig	894 psig "A", 890 psig "B"
SG Level	55% (OR)	71% "A", 70% "B" (OR)
RCS Flow	140 x 10^6 lbm/hr	141 x 10^6 lbm/hr
MFW Flow	10.8 x 10^6 lbm/hr	10.9 x 10^6 lbm/hr

The SG level initial condition deviates from the plant data. The base model initial SG level is used (Refer to Section 4.1.1).

The problem specific boundary conditions used in this analysis include cycle specific control rod worth and reactor physics parameters, RCS makeup flow, decay heat, main feedwater flow, and steam generator pressure control.

The makeup flow used in the simulation consists of pressurizer level control via the normal makeup flowpath as operators did not increase makeup by opening a second valve or starting a second HPI pump. A [ ]

[

The main feedwater flow used in the simulation is from the transient monitor data and the post-trip review program data. Constant feedwater flow and steam flow were assumed until the reactor trip. There was no time for Integrated Control System action to significantly affect the plant response between the time that the control rod bank fell into the core and the time the reactor tripped on variable low pressure-temperature.

The turbine bypass valve setpoint is reduced from the normal post-trip value of 1010 psig to 1005 psig to match the actual SG pressure response as indicated by the data.

The model used for this analysis includes one significant change from the nominal base model. In this instance the [

] characteristic of the time immediately following reactor trip or after a large mismatch between power generated and power removed.

Simulation Results

The simulation begins with the dropped control rod group and continues for 120 seconds. The simulation is terminated at the point where all major plant parameters have returned to normal post-trip values. The sequence of events is given in Table 4.4.1-1, and the results of the simulation are compared to the plant data in Figures 4.4.1-1 through 4.4.1-8.

The normalized reactor power response is shown in Figure 4.4.1-1 and 4.4.1-2. Reactor power is predicted closely prior to the reactor trip. The predicted reactor trip occurs at approximately 4.6 seconds as compared with approximately 4.0 seconds in the plant. This indicates that the RETRAN point kinetics model and the boundary conditions used in the simulation are sufficiently accurate. RETRAN appears to overpredict the power in the latter portion of the simulation because the computer code output includes decay heat and delayed neutron power while the data represents delayed neutron power only.

The RCS pressure response is shown in Figure 4.4.1-3. The RETRAN predicted pressure response trends the data closely throughout the simulation as does the pressurizer level response seen in Figure 4.4.1-4. This is a result of the predicted RCS temperatures (see Figures 4.4.1-5 and 4.4.1-6) also trending the data closely, indicating that RETRAN is predicting the steam generator heat transfer adequately.

The RCS temperatures seen in Figures 4.4.1-5 and 4.4.1-6, as mentioned above, trend the data closely. The RETRAN cold leg temperature does increase more rapidly than the data immediately after reactor trip, [ ] In addition, the predicted cold leg temperature decreases to the steady-state post-trip value more rapidly than the data.

The SG pressure response is shown in Figure 4.4.1-7. The predicted pressure response trends the data closely with only slight difference in initial conditions (see page 4-77). This indicates that the SG pressure control used in the RETRAN model is adequate.

The SG level response is shown in Figure 4.4.1-8. The predicted level is [ ] The plant indication is based on a ΔP signal and is not compensated for temperature. The initial offset is due to the plant indication being low because of the lack of temperature compensation. Since the RETRAN indication is based on [

] However, the long term response of the model trends the data fairly closely, indicating the proper initial inventory and feedwater boundary conditions are used. This is further supported by the accurate prediction of the RCS temperature response.

Table 4.4.1-1

Oconee Nuclear Station Unit 1
Control Rod Group Drop
August 8, 1982

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
Group 6 control rods fall into core*	0	0
Rx trip on variable low pressure-temperature minimum reactor power	4.0	4.6
Minimum RCS pressure, minimum PZR level	60	60
End of simulation	N/A	120

Note: Asterisks designate boundary conditions

ONS 1 8/6/82 ROD DROP EVENT

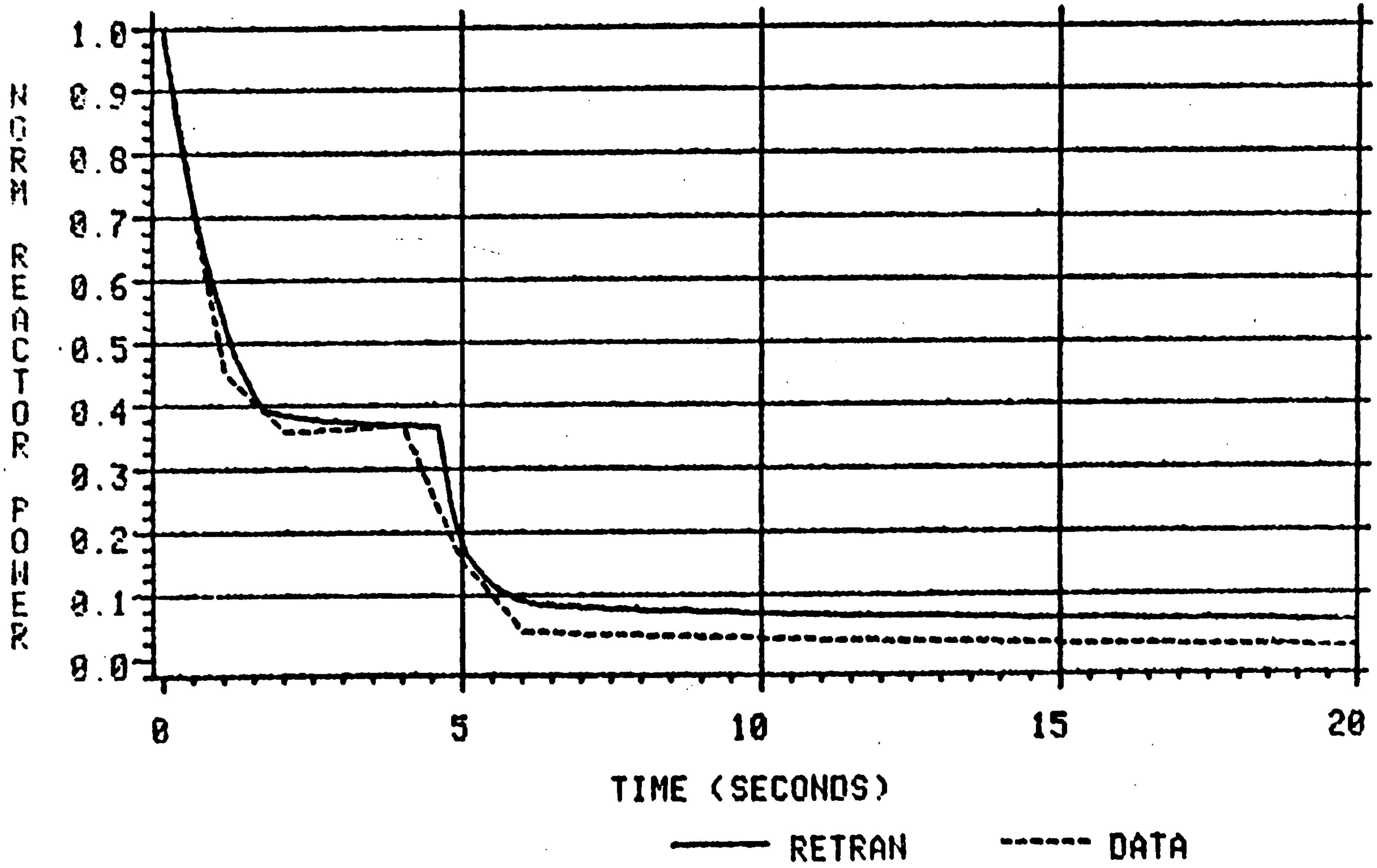


Figure 4.4.1-1

ONS 1 8/6/82 ROD DROP EVENT

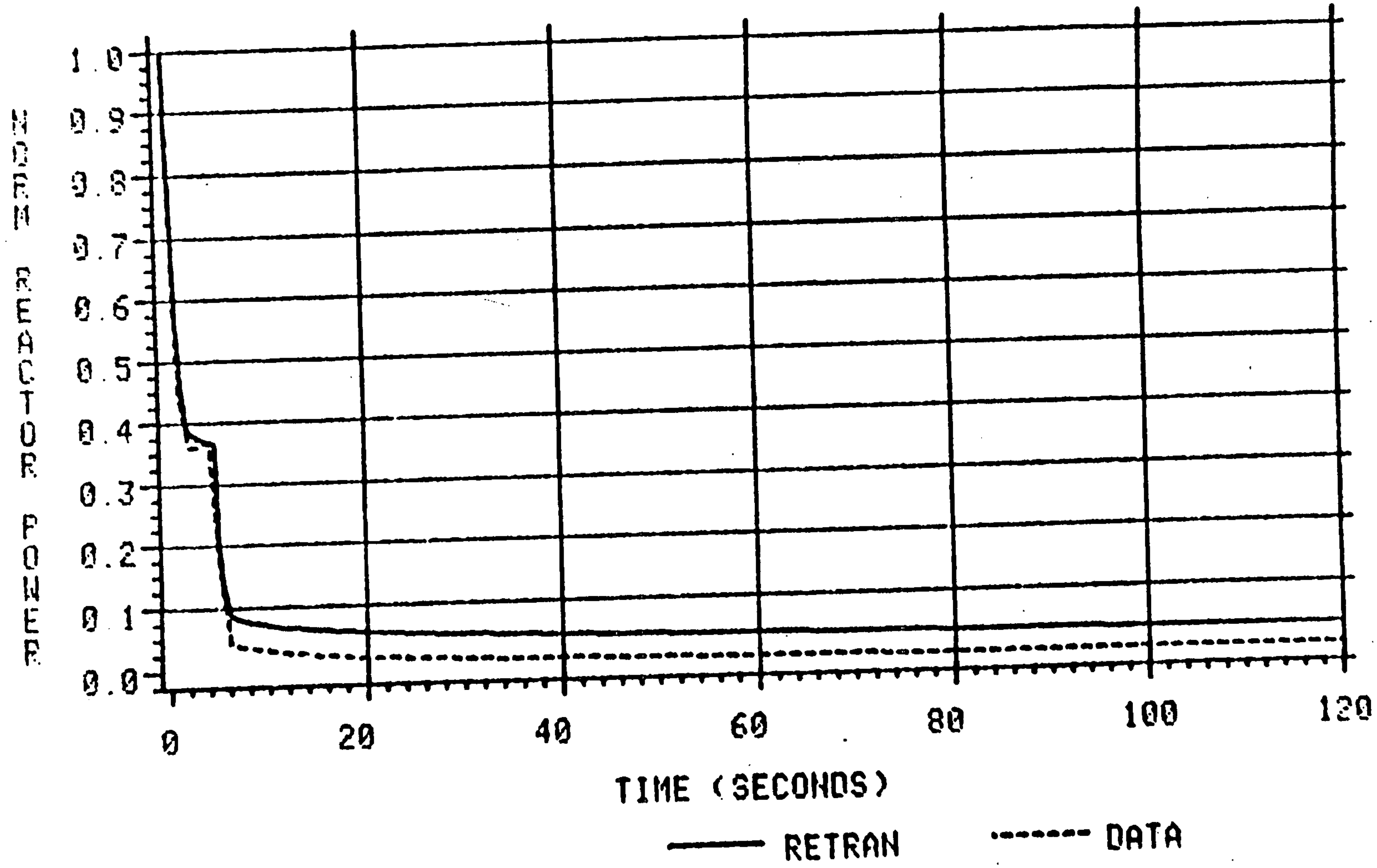


Figure 4.4.1-2

ONS 1 8/6/82 ROD DROP EVENT

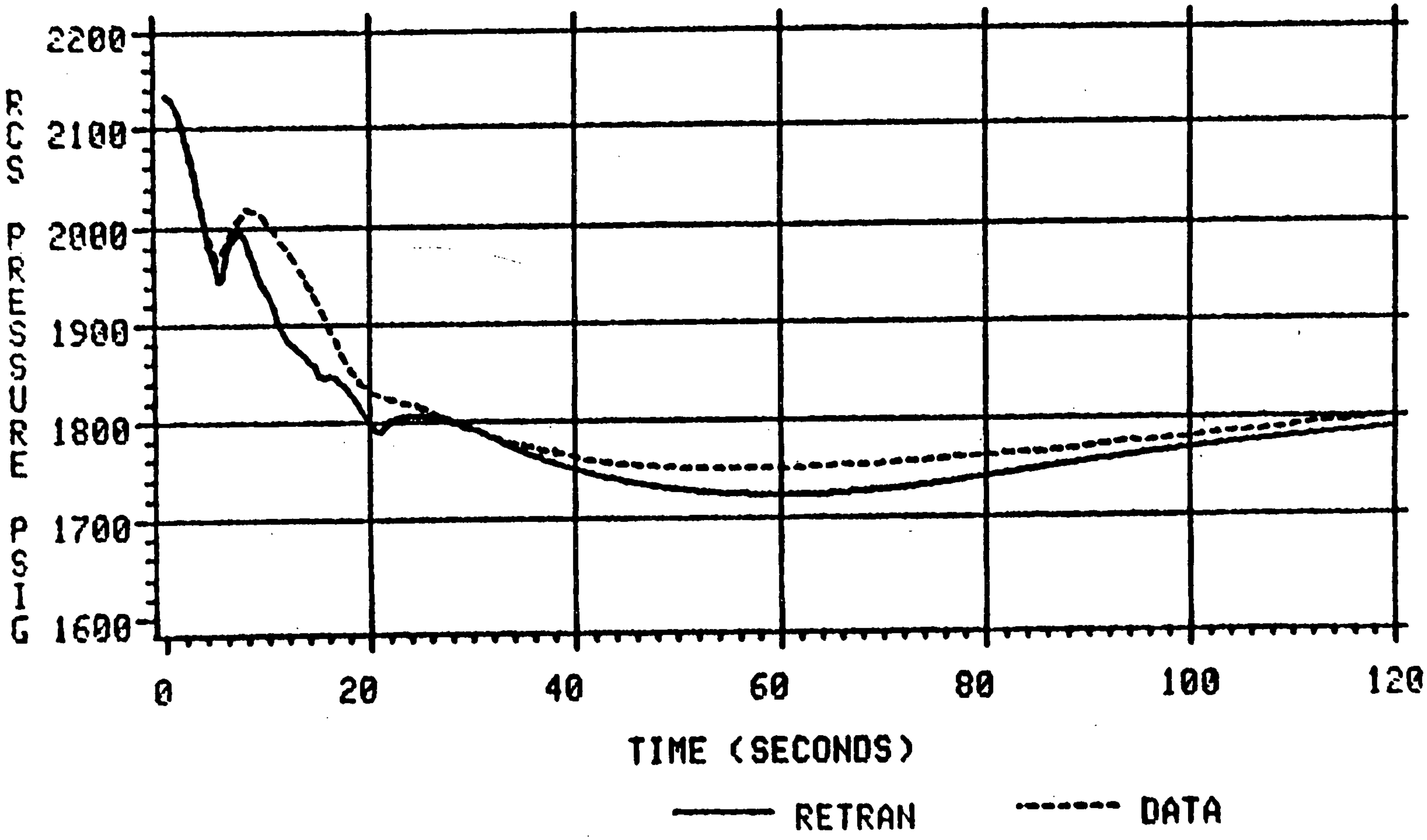


Figure 4.4.1-3

ONS 1 8/6/82 ROD DROP EVENT

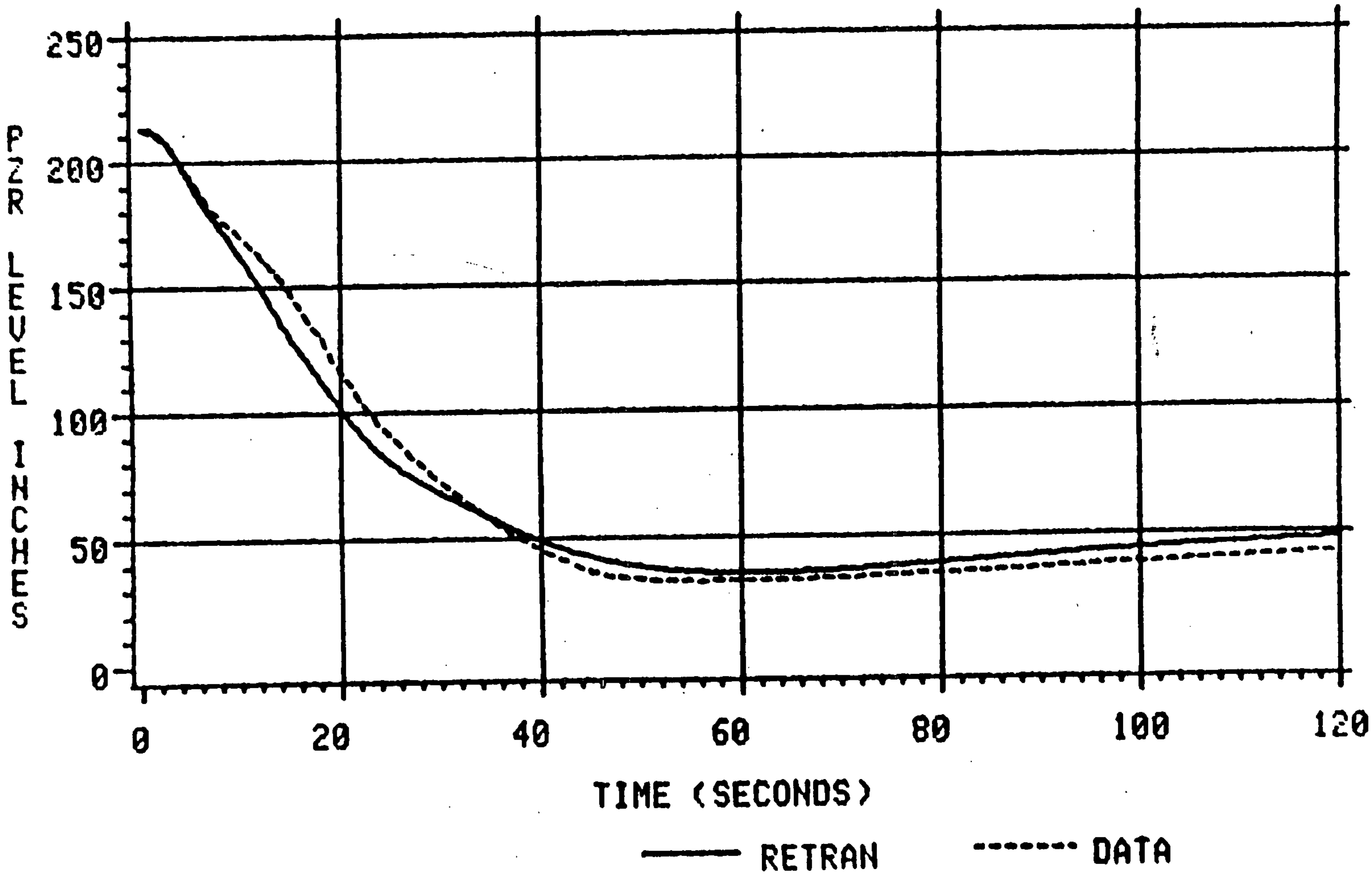


Figure 4.4.1-4

ONS 1 8/6/82 ROD DROP EVENT

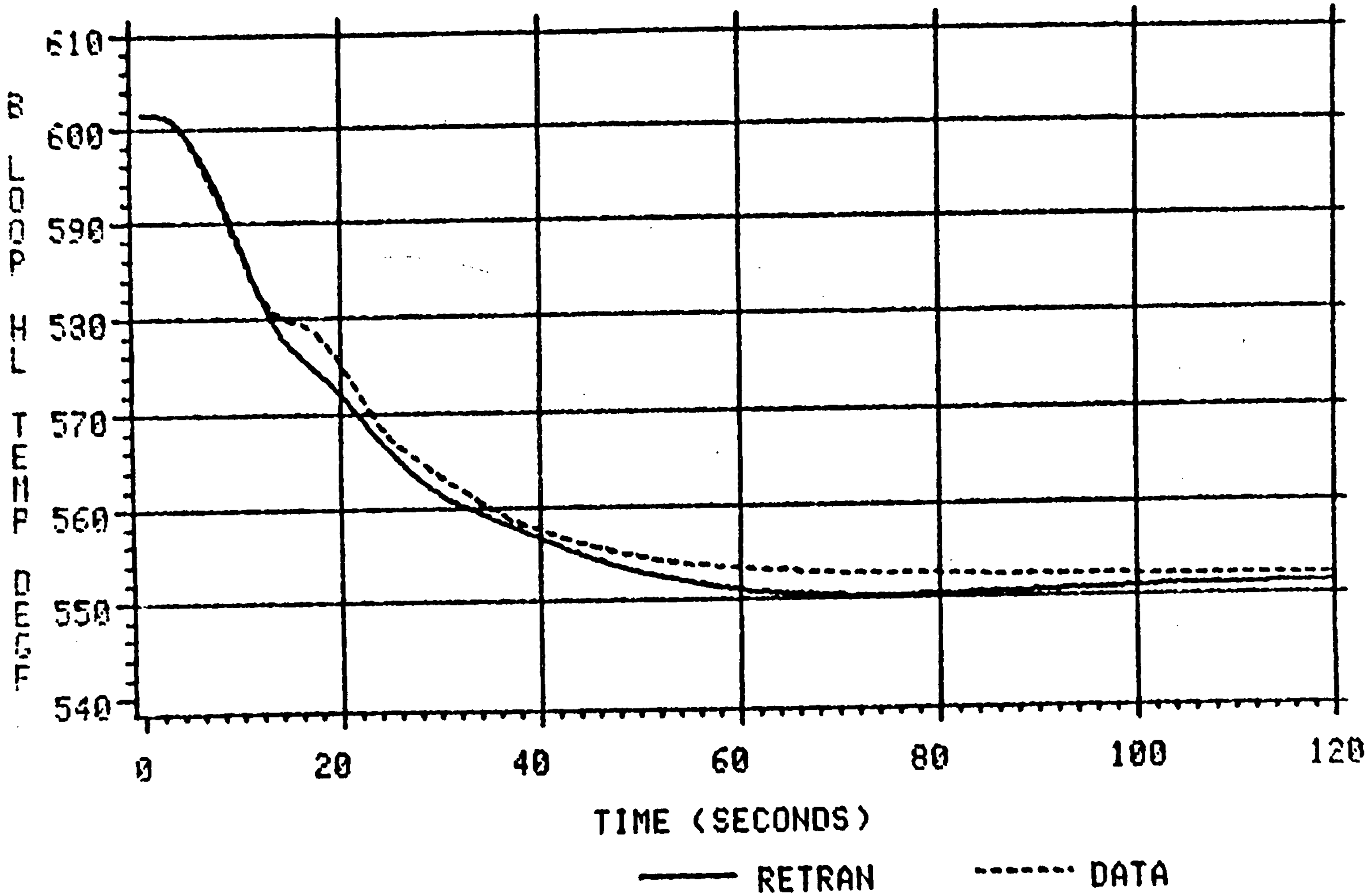


Figure 4.4.1-5

ONS 1 8/6/82 ROD DROP EVENT

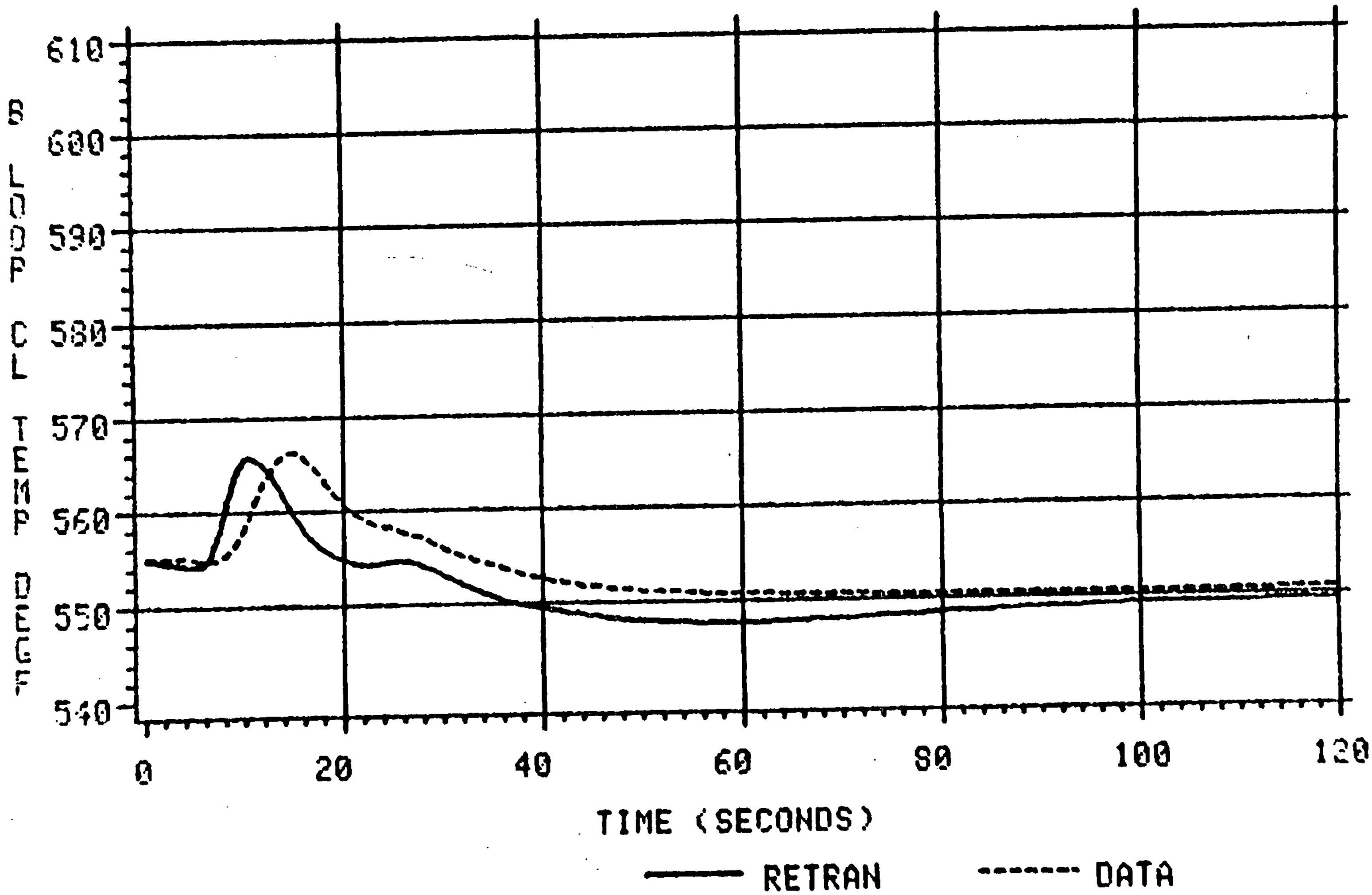


Figure 4.4.1-6

ONS 1 8/6/82 ROD DROP EVENT

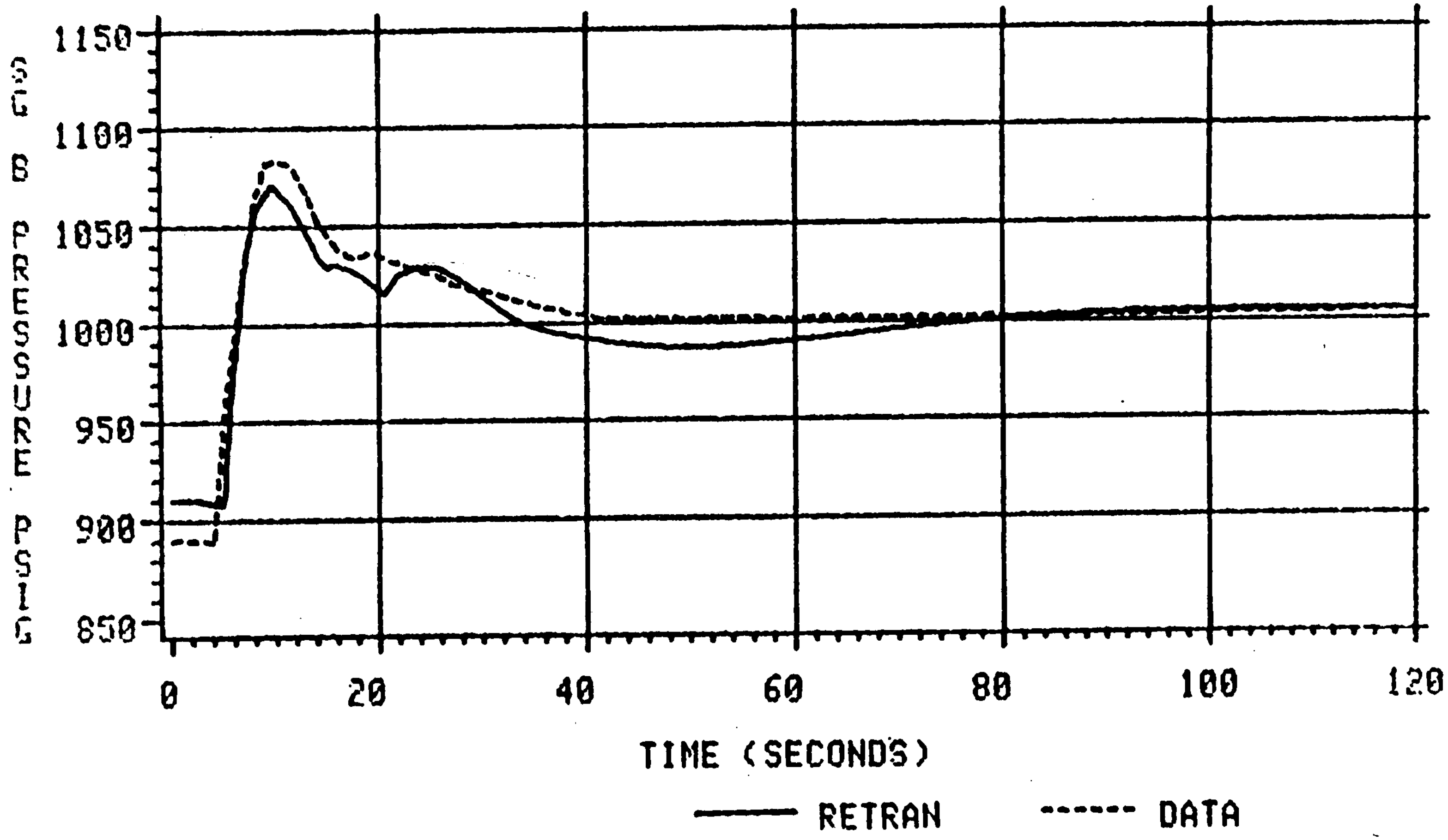
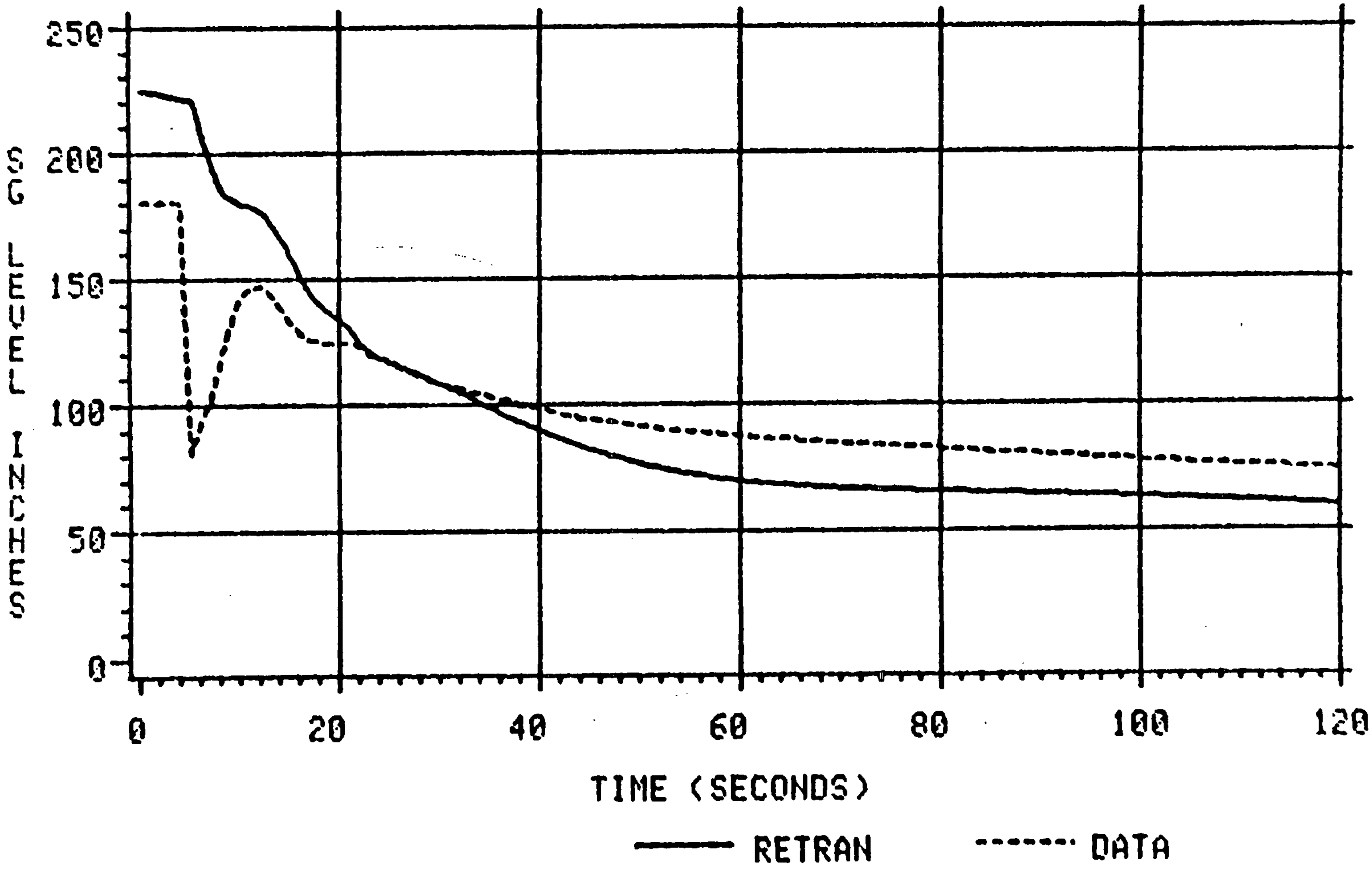


Figure 4.4.1-7

ONS 1 8/6/82 ROD DROP EVENT



PLANT DATA IS AVERAGE OF BOTH LOOPS

Figure 4.4.1-8

4.5 Operational Transients Without Reactor Trip

4.5.1 Oconee Nuclear Station Unit 1
Main Feedwater Pump Trip
July 15, 1985

Transient Description

Oconee Unit 1 was operating at 100% full power when the 1B main feedwater (MFW) pump tripped on low hydraulic oil pressure. The Integrated Control System (ICS) was in the fully automatic mode and a MFW pump trip reactor runback was initiated at 50% per minute. Seven seconds later feedwater to reactor cross limits were indicated by the ICS, reducing the runback to 20% per minute and putting the ICS in the tracking mode. Four seconds after that, the hydraulic oil pressure increased, reopening the MFW stop valves and clearing the pump trip indication. The automatic runback was stopped but, due to the cross limits which still existed, reactor power continued to run-back to approximately 80% by two minutes into the event. The unit stabilized at this point with MFW pump 1A delivering total feedwater flow.

The plant response during the transient was driven by the reduction in feed-water and the action taken by the ICS. Reactor Coolant System (RCS) temper-atures and pressure increased temporarily due to the initial reduction in feedwater. Steam generator (SG) levels decreased also as a result of the drop in feedwater flow. Reactor power was driven down by the action of the ICS to run back the unit load demand (ULD), thus inserting control rods. Reactor power was also driven down as a result of negative reactivity produced by the increase in RCS temperatures. Main steam pressure was maintained at a relatively constant value by the turbine control valve controller.

Discussion of Important Phenomena

Several important phenomena occurred during the transient which challenged the capability of RETRAN and the Oconee RETRAN Model the simulate the plant response. These phenomena include primary-to-secondary heat transfer, reactor kinetics and control, and secondary pressure control.

Accurate simulation of the heat transfer through the steam generators is important for this transient since it determines the RCS temperature response and thus the reactivity feedback. The heat transfer surface areas of the steam generators are determined from the initial water inventory and the void fraction profile used. The reactor kinetics parameters are very important for this transient. The reactor power response is determined by the reactivity feedback and control rod movement modeled. The secondary pressure response, via the turbine control valve modeling, is also important since it will influence the RCS response by affecting the RCS temperature.

Model Description and Boundary Conditions

This event has symmetric behavior in each loop, since each steam generator is fed by both MFW pumps. The reduction in feedwater flow following the loss of one pump is therefore the same for each generator. The one-loop Oconee RETRAN Model (Figure 2.2-2) is used to simulate the feedwater runback transient. Reactor control rod and main turbine control valve models are also added to the base model for this analysis. The steady state base model initial conditions are used, with only a small adjustment to RCS pressure and pressurizer level to match the plant data. The plant initial conditions were obtained from digital transient monitor data.

Initial Conditions

	Model	Plant
Power Level	100% (2568 MWt)	100% (2568 MWt)
RCS Pressure	2133 psig	2133 psig
PZR Level	223 inches	223 inches
T hot	601.9 °F	601.8 °F (ave)
T cold	555.2 °F	555.8 °F (ave)
MS Pressure	885 psig	889 psig
SG Level	55% (OR)	82% (OR)
RCS Flow	140×10^6 lbm/hr	142×10^6 lbm/hr
MFW Flow	10.8×10^6 lbm/hr	10.7×10^6 lbm/hr

The problem boundary conditions used are cycle specific kinetics parameters, reactor and turbine control valve controls, ULD signal to the reactor control and MFW flow. It should be noted that the [

]

Simulation Results

The simulation begins with the MFW pump trip and continues for 110 seconds. The simulation is terminated at the point where the reactor power level has stabilized following the runback transient. The sequence of events is given in Table 4.5.1-1, and the simulation results are compared to the plant data in Figures 4.5.1-1 through 4.5.1-7.

The normalized reactor power response is shown in Figure 4.5.1-1. The RETRAN prediction trends the data closely during the entire simulation. This indicates that the reactor control and the kinetics parameters used closely represent the conditions of the plant at the time. This is further confirmed by comparing predicted and measured RCS temperatures and control rod positions. The RCS temperatures (see Figures 4.5.1-4 and 4.5.1-5) trend the data in a similar manner, which provides the correct moderator feedback. The change in Group 7 control rod position in the RETRAN simulation shows a 26% insertion as compared with a 25% insertion for the plant measurement.

The RCS pressure response is shown in Figure 4.5.1-2. The simulated response shows the initial pressure increase resulting from the sudden reduction in feedwater starting slightly later than the data. This is a result of a similar trend present in the predicted cold leg temperature response (see Figure 4.5.1-5). The predicted RCS pressure then overshoots the data by approximately 30 psi. The pressurizer level response (Figure 4.5.1-3) shows the RETRAN prediction trending the data similar to the RCS pressure.

The RCS temperature response is shown in Figures 4.5.1-4 and 4.5.1-5. There is little change seen in the predicted hot leg temperature response and, as

mentioned above, the cold leg temperature responds slightly slower than the data. Since the main feedwater flow is input directly from the plant data as a boundary condition and the reactor power trends the data closely, the deviation in predicted temperatures can be attributed to slight differences in steam generator heat transfer.

The SG level response seen in Figure 4.5.1-6 shows the RETRAN predicted operating range level decreasing below the data slightly in the first part of the transient then trending the data for the rest of the simulation. The main steam pressure response (Figure 4.5.1-7) shows the RETRAN prediction trending the data for the entire simulation, and actually controls to the setpoint closer than the plant data.

Table 4.5.1-1

Oconee Nuclear Station Unit 1
Main Feedwater Pump Trip
July 15, 1985

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
1B MFW pump trip, reactor runback initiated at 50% per minute*	0	0
Feedwater to reactor cross limits reduce runback to 20% per minute*	7	7
Reactor runback stabilizes at approximately 80% power	120	120
End of simulation	N/A	120

Note: Asterisks designate boundary conditions

MFW RUNBACK TRANSIENT

ONS 1 7/15/85

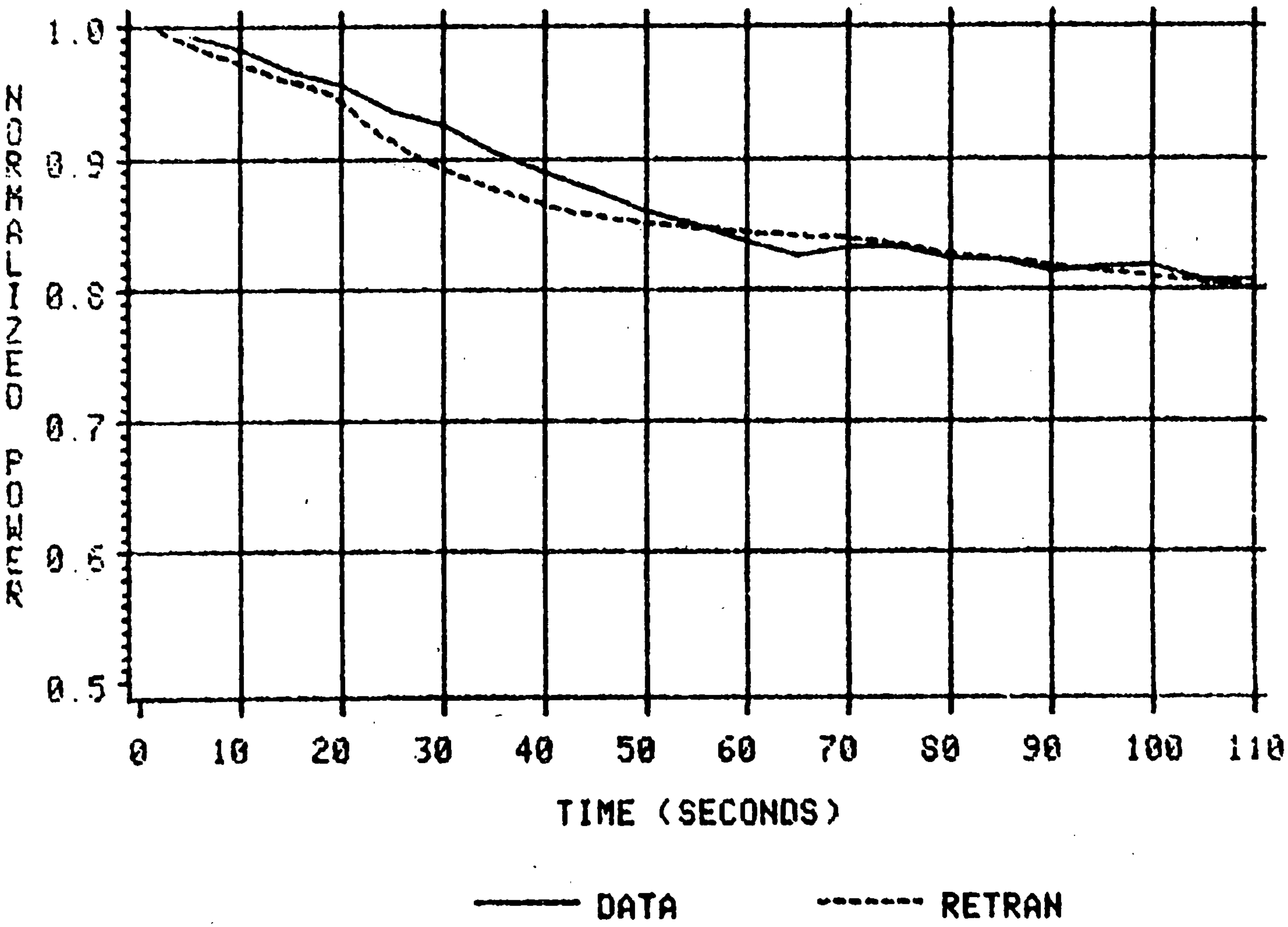


Figure 4.5.1-1

MFW RUNBACK TRANSIENT

ONS 1 7/15/85

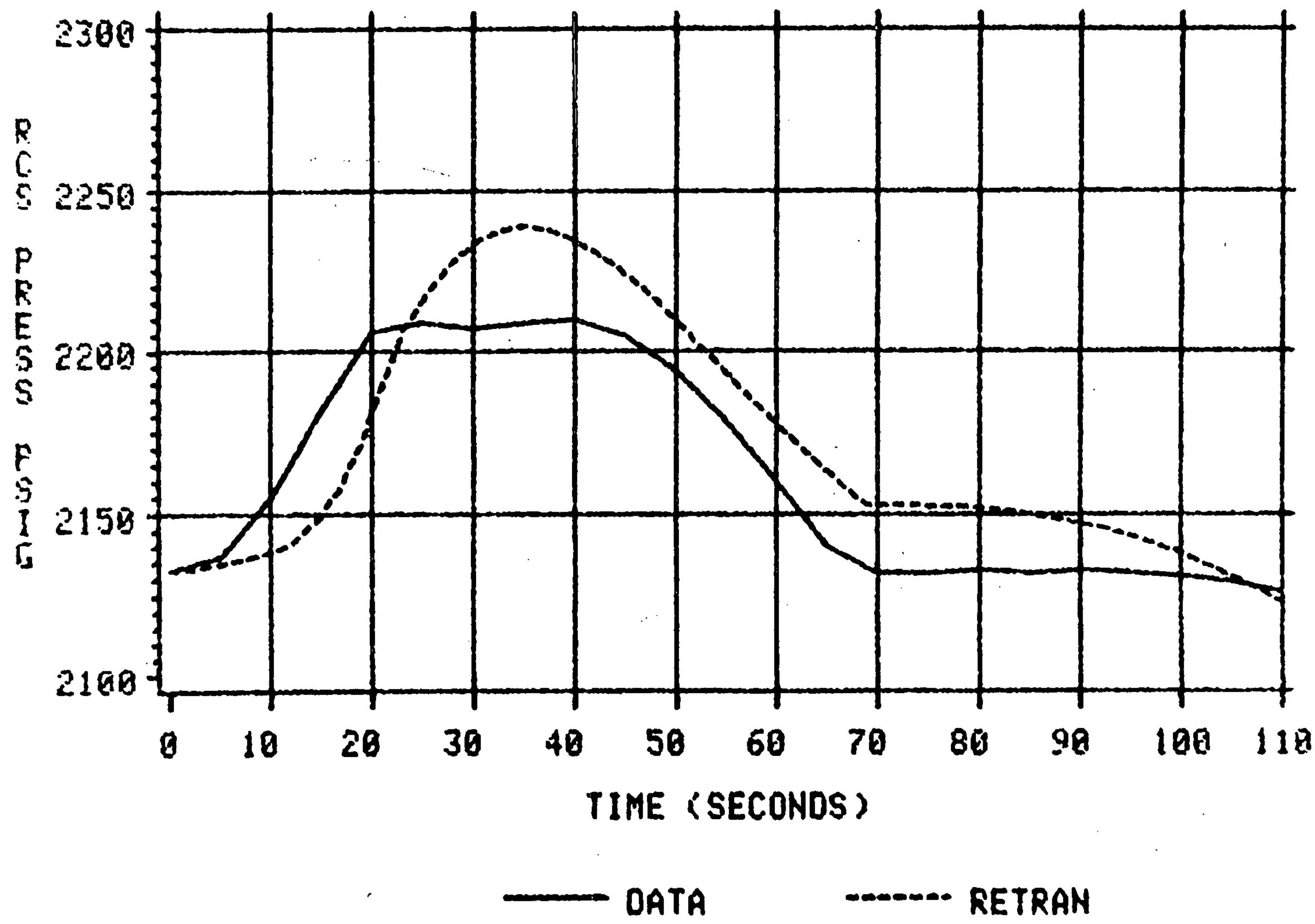


Figure 4.5.1-2

MFW RUNBACK TRANSIENT

ONS 1 7/15/85

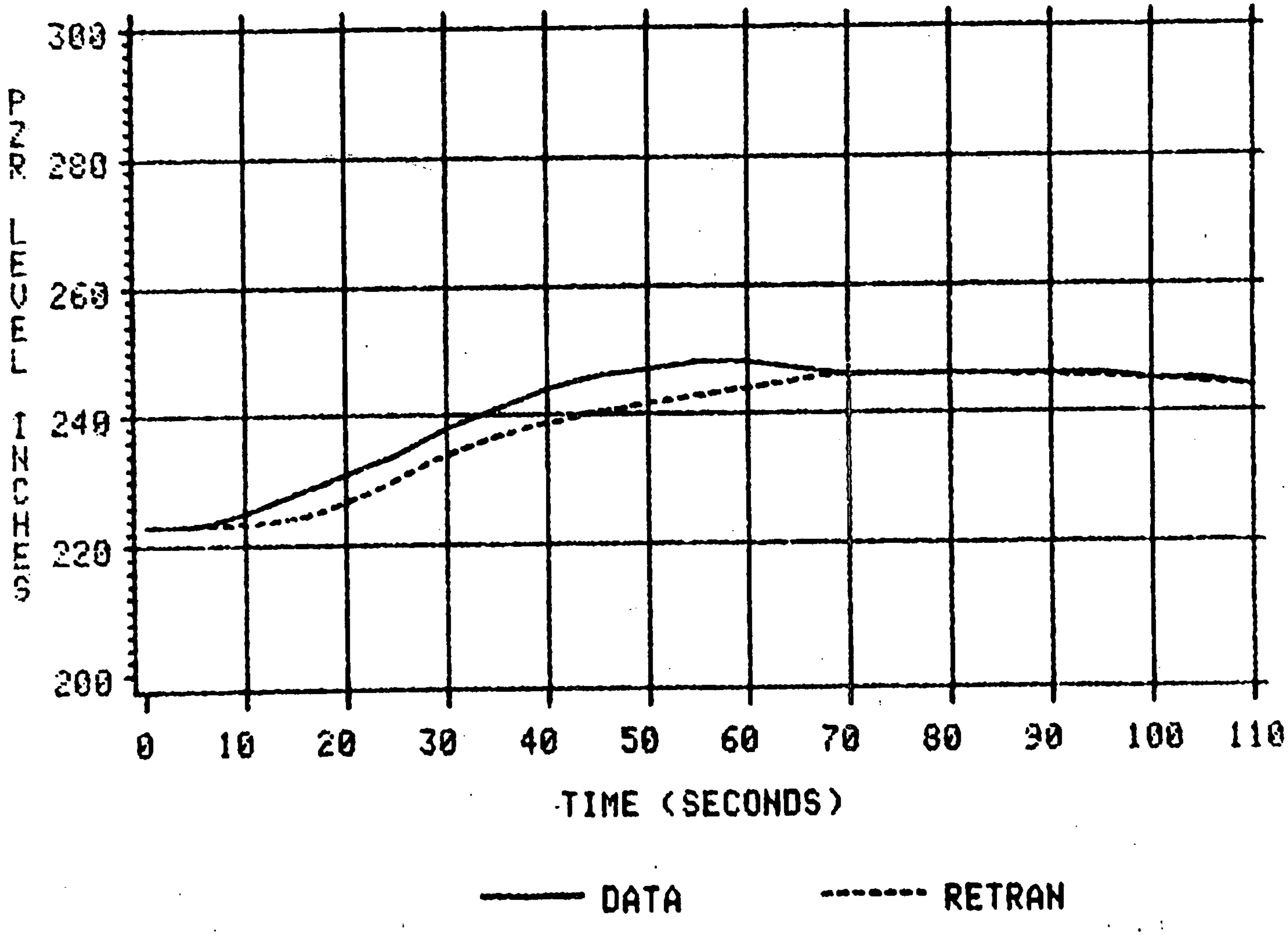


Figure 4.5.1-3

MFW RUNBACK TRANSIENT

ONS 1 7/15/85

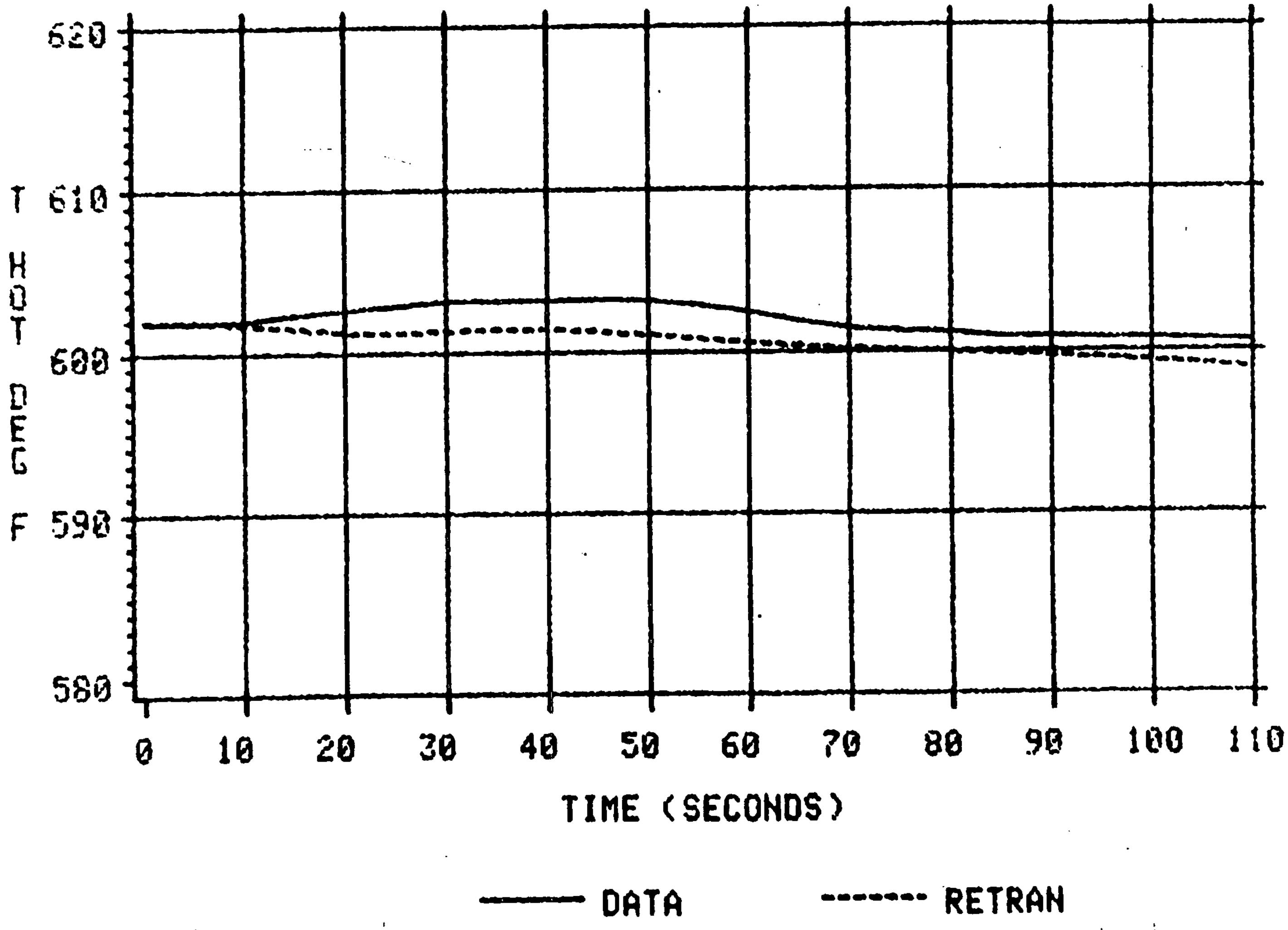


Figure 4.5.1-4

MFW RUNBACK TRANSIENT

ONS 1 7/15/85

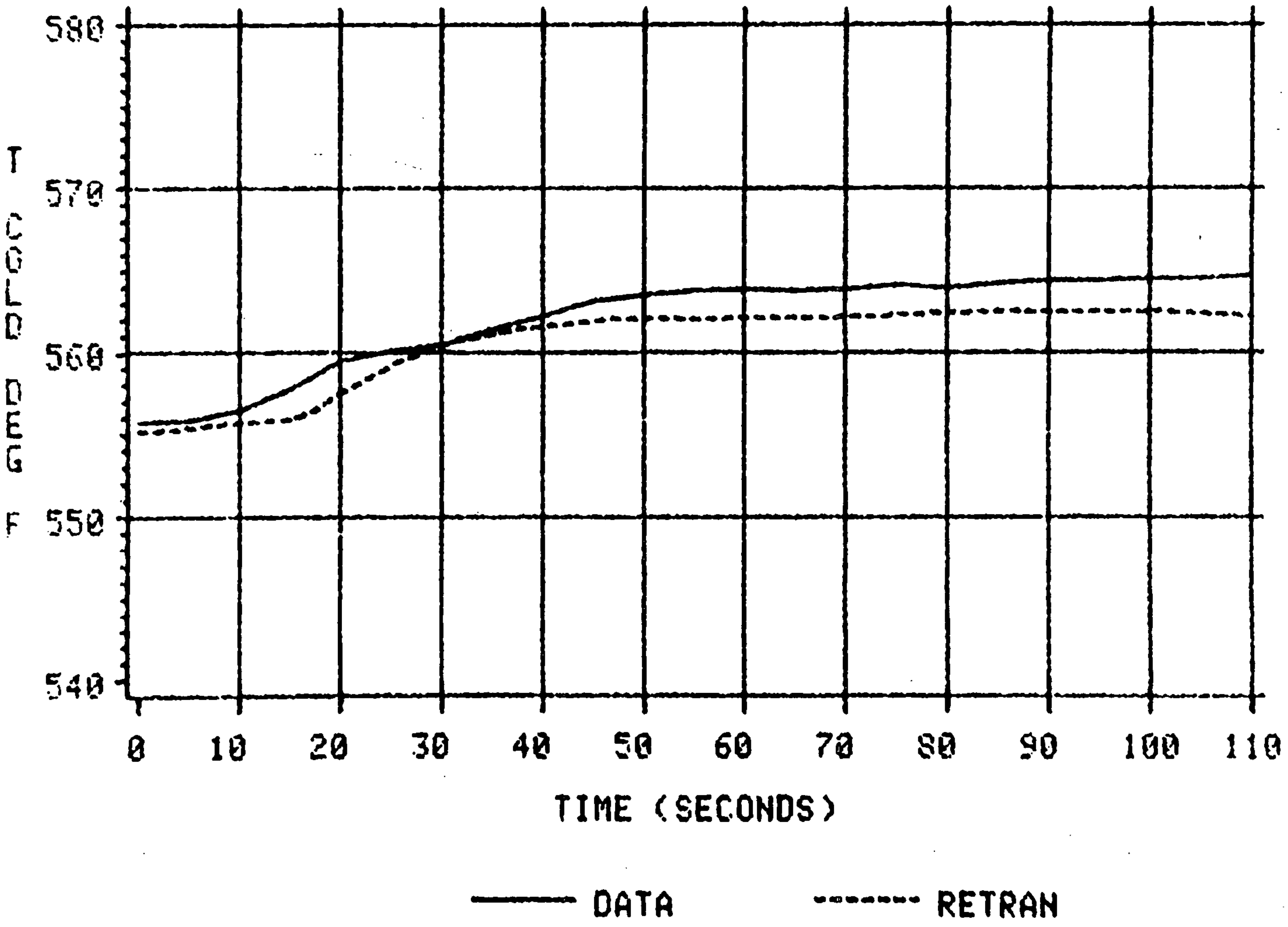


Figure 4.5.1-5

MFW RUNBACK TRANSIENT

ONS 1 7/15/85

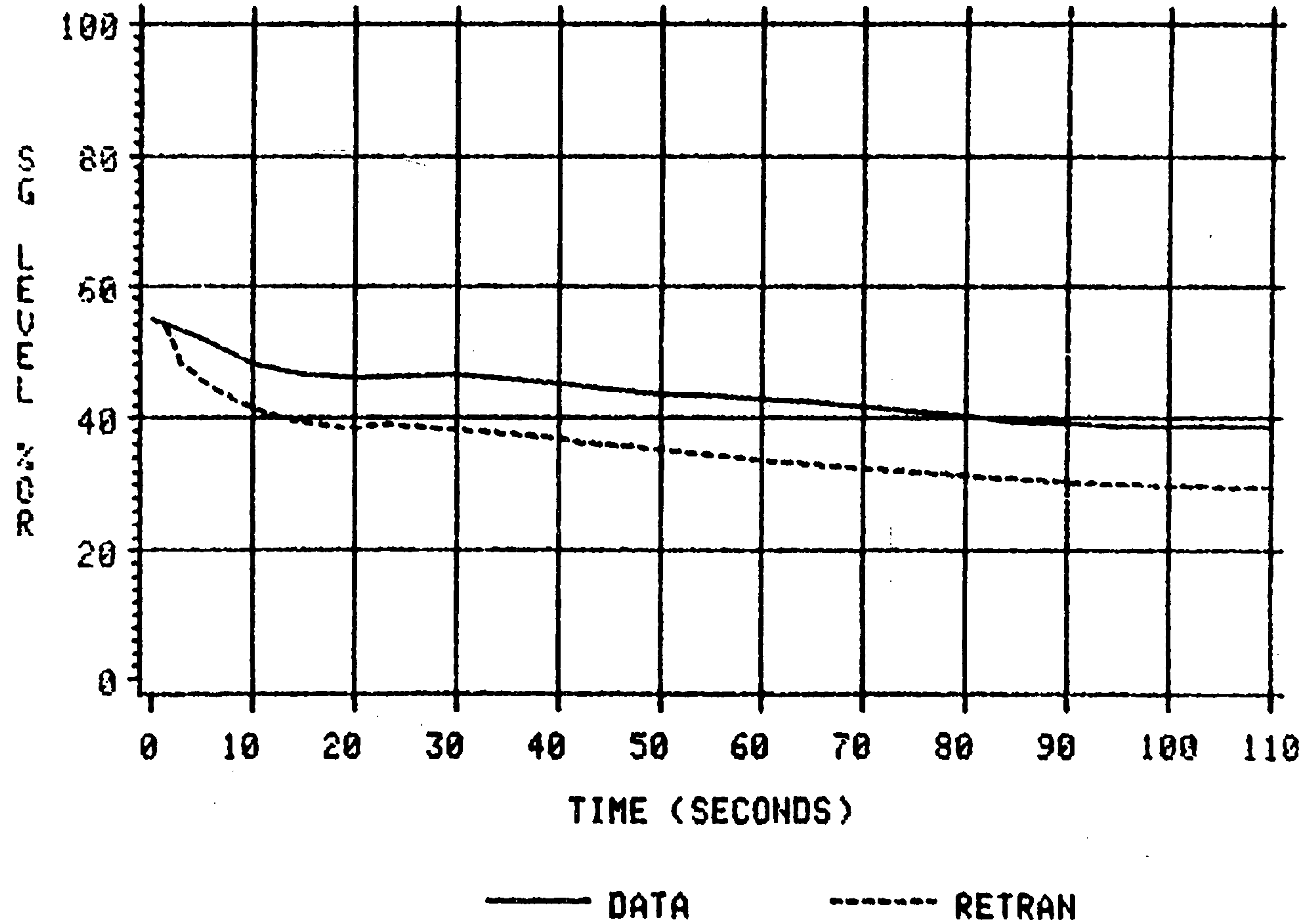


Figure 4.5.1-6

MFW RUNBACK TRANSIENT

ONS 1 7/15/85

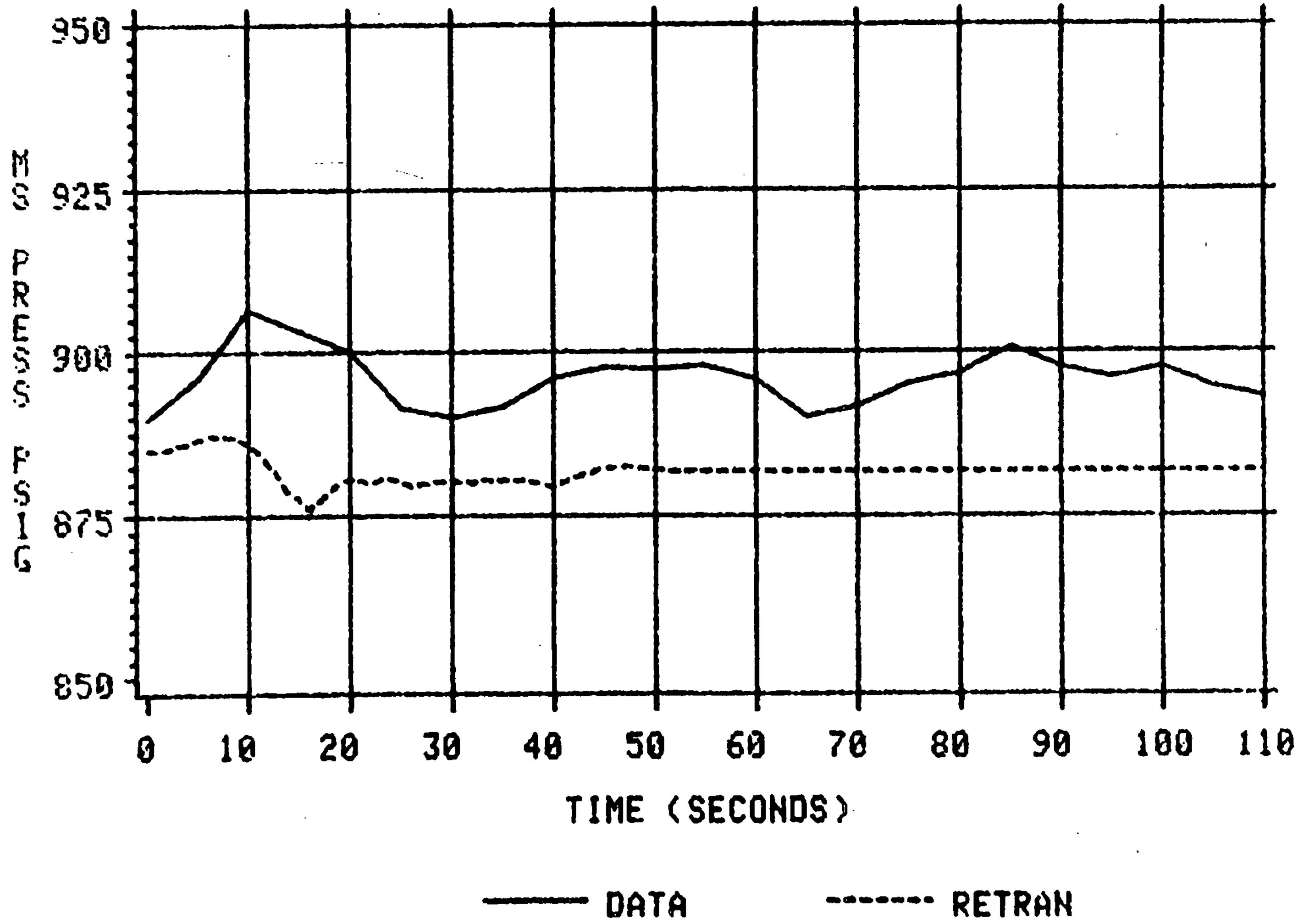


Figure 4.5.1-7

4.5.2 Oconee Nuclear Station - Unit 1
Turbine Bypass Valve Failure
May 4, 1981

Transient Description

Oconee Nuclear Station Unit 1 was operating at 100% full power when the steam generator "A" pressure signal began drifting upwards. Approximately 3 seconds later the "A" turbine bypass valves began to open. The erroneous pressure signal increased by 128 psi (to 1053 psig) in 8 seconds, with the turbine bypass valves opening approximately 80%. Actual SG pressure decreased approximately 25 psi during this period.

Reactor power increased to 103% during the initial stage of the transient. Positive reactivity was inserted in the core due to overcooling of the Reactor Coolant System (RCS) as a result of increased steam flow when the turbine bypass valves opened. A small amount of the power increase was also due to control rod motion as a decrease in electrical output at the main generator sent a signal to the Integrated Control System (ICS) to increase reactor power.

The erroneous SG pressure signal decreased and the turbine bypass valves went closed 14 seconds after initiation of the transient. The reactor power decreased to 98% in the next 6 seconds as actual main steam pressure increased toward the setpoint of 885 psig. The decrease and overshoot past full power was also due to the decreasing reactor demand signal being generated by the ICS. This caused the control rods to travel back into the core, inserting negative reactivity.

The RCS responded during the transient with only minor deviations from the initial conditions. The RCS pressure dropped approximately 20 psi before recovering and then increased approximately 6 psi above its initial value before finally reaching the original steady state value. Pressurizer level decreased 3 inches before recovering to its initial value.

The plant was able to return to steady state full power conditions, once the erroneous SG pressure signal returned to normal. All affected plant parameters were back to their initial steady state values 60 seconds after the initiation of the event.

Discussion of Important Phenomena

Several important phenomena occurred during the transient which challenged the capability of RETRAN to simulate the plant response. These phenomena include primary-to-secondary heat transfer and the dynamic reactor response.

Accurate simulation of the heat transfer through the steam generators is important for this transient since it determines the RCS temperature response and thus the reactivity feedback. The heat transfer surface areas of the steam generators are determined from the initial water inventory and void fraction profile used. The reactor kinetics parameters are very important for this transient. The reactor power response is determined by the reactivity feedback and control rod movement modeled. The secondary pressure response, controlled by the turbine bypass valves and the main turbine control valves, is the most important since it represents the driving force for the entire transient. The heat transfer through the steam generators, the RCS temperature response and thus the reactor power are controlled by the secondary pressure response.

Model Description and Boundary Conditions

In order to model the failure of the "A" turbine bypass valve in this event, a two-loop Oconee RETRAN Model (Figure 2.2-1) was used. In addition, reactor control rod and main turbine control valve models were added to the base model. The steady state base model initial conditions were used, with only a small adjustment to the RCS pressure to match the plant data. The plant initial conditions were obtained from digital transient monitor data.

Initial Conditions

	Model	Plant
Power Level	100% (2568 MWt)	100% (2568 MWt)
RCS Pressure	2134 psig	2134 psig
PZR Level	220 inches	221 inches
T hot	601.9 °F "A"	601.3 °F "A"
	601.9 °F "B"	601.7 °F "B"
T cold	555.2 °F "A"	556.4 °F "A"
	555.2 °F "B"	554.6 °F "B"
MS Pressure	890 psig	890 psig
SG Level	55% (OR)	69% "A", 70% "B" (OR)
RCS Flow	140×10^6 lbm/hr	140×10^6 lbm/hr
MFW Flow	10.8×10^6 lbm/hr	10.7×10^6 lbm/hr

The problem boundary conditions used are cycle specific kinetics parameters, reactor and turbine control, SG pressure signal to the turbine bypass controller, MFW flow, and a reduction in the turbine bypass valve setpoint. The turbine bypass setpoint was reduced from the normal post-trip value of 1010 psig to 960 psig, which is the normal setpoint when the plant is at power and on line.

Simulation Results

The simulation begins with the change in the SG pressure signal and continues for 60 seconds. The simulation is terminated at the point where the erroneous pressure signal terminates and all major plant parameters have returned to normal post-trip values. The sequence of events is given in Table 4.5.2-1, and the results of the simulation are compared to the plant data in Figures 4.5.2-1 through 4.5.2-9.

The normalized reactor power response is shown in Figure 4.5.2-1. The magnitude of the predicted power increase agrees closely with the data, reaching 103%, even though the cold leg temperatures do not decrease as much as the data (see Figures 4.5.2-5 and 4.5.2-7). The general shape of the predicted power response and timing of the changes in power are different than the data. This is due primarily to the predicted main steam pressure response (Figures 4.5.2-8 and 4.5.2-9) and its effect on the RCS temperatures. From the main steam pressure response it is evident that the predicted pressure decreases sooner and more steadily than the data. This causes the RCS temperatures and thus the power response to behave in a similar manner. The same behavior occurs when the false SG pressure signal terminates and the turbine bypass valves close.

The RCS pressure response is shown in Figure 4.5.2-2. The predicted pressure response is a result of the RCS temperature response, particularly the cold leg temperatures shown in Figures 4.5.2-4 and 4.5.2-6. The predicted pressure trend compares well with the data. The pressurizer level response in Figure 4.5.2-3 reflects the same trend as the RCS response.

The RCS temperature response is shown in Figures 4.5.2-4 through 4.5.2-7. As mentioned above, the RCS temperatures are driven by the main steam pressure during most of the transient. During the last 20 seconds of the transient, however, the temperatures are driven primarily by main feedwater. The trends are predicted well with only minor deviations.

Table 4.5.2-1

Oconee Nuclear Station Unit 1
Turbine Bypass Valve Failure
May 4, 1981

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
Plant operating at 100% full power	0	0
False SG pressure signal is initiated*	4	4
Turbine bypass valves begin to open	7	7
Turbine bypass valves begin to close	18	17
Minimum main steam pressure	18	18
Maximum power level reached	20	18
Minimum power level on overshoot	25	28
End of simulation	N/A	60

Note: Asterisks designate boundary conditions

ONS 1 TBV FAILURE W/O RX TRIP 5/4/81

RETRAN AND PLANT DATA

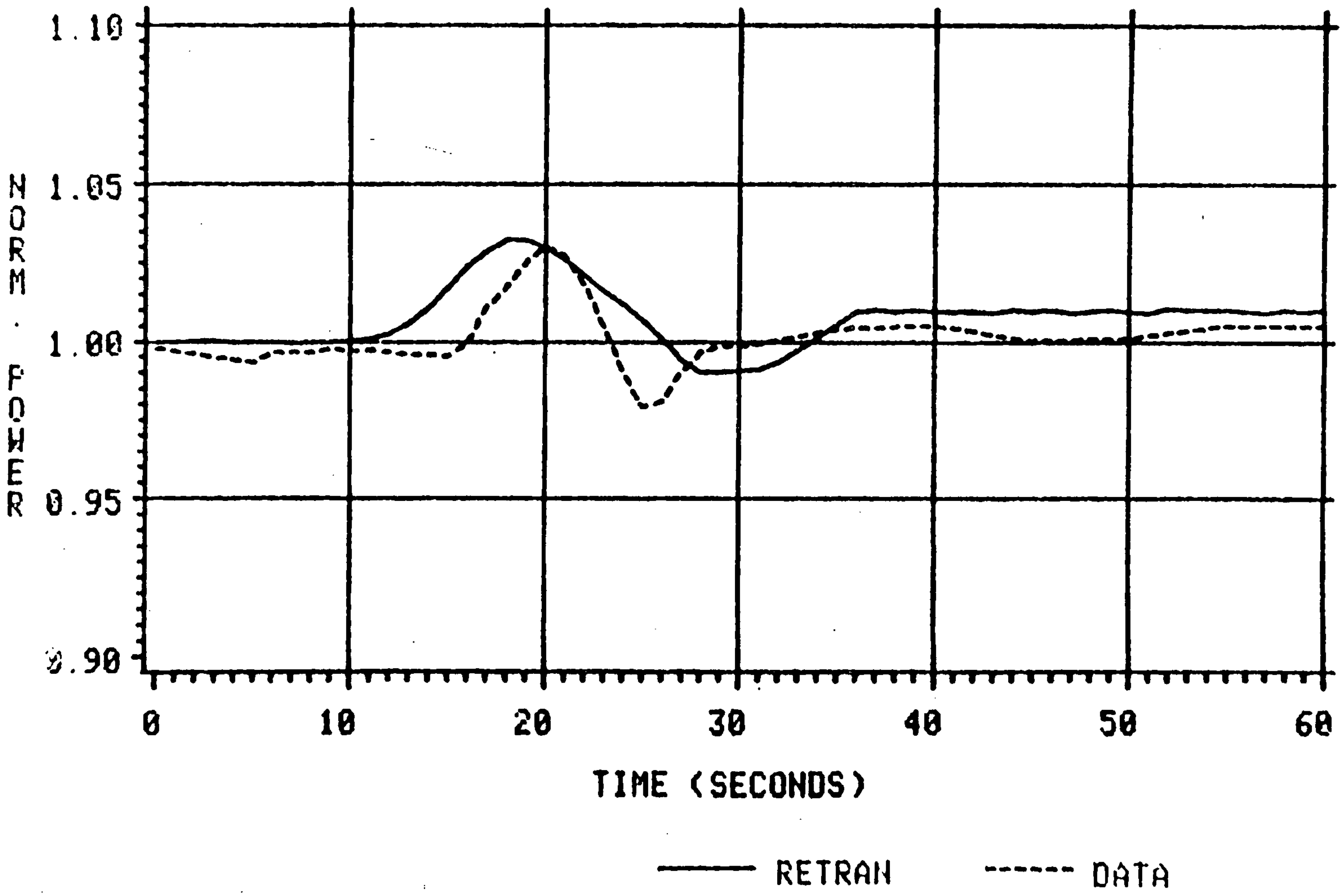


Figure 4.5.2-1

ONS 1 TBV FAILURE W/O RX TRIP 5/4/81

RETRAN AND PLANT DATA

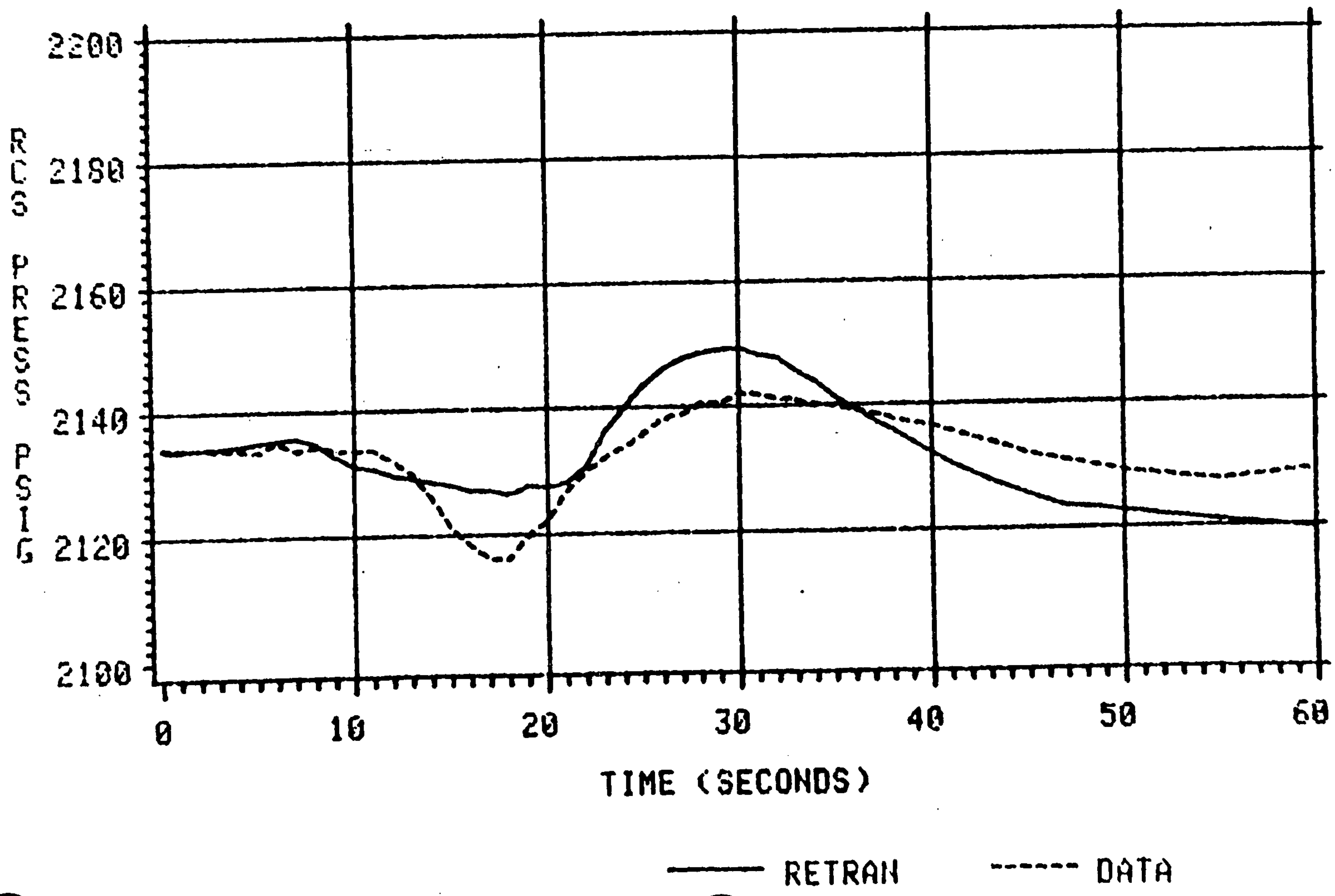


Figure 4.5.2-2

ONS 1 TBV FAILURE W/O RX TRIP 5/4/81

RETRAN AND PLANT DATA

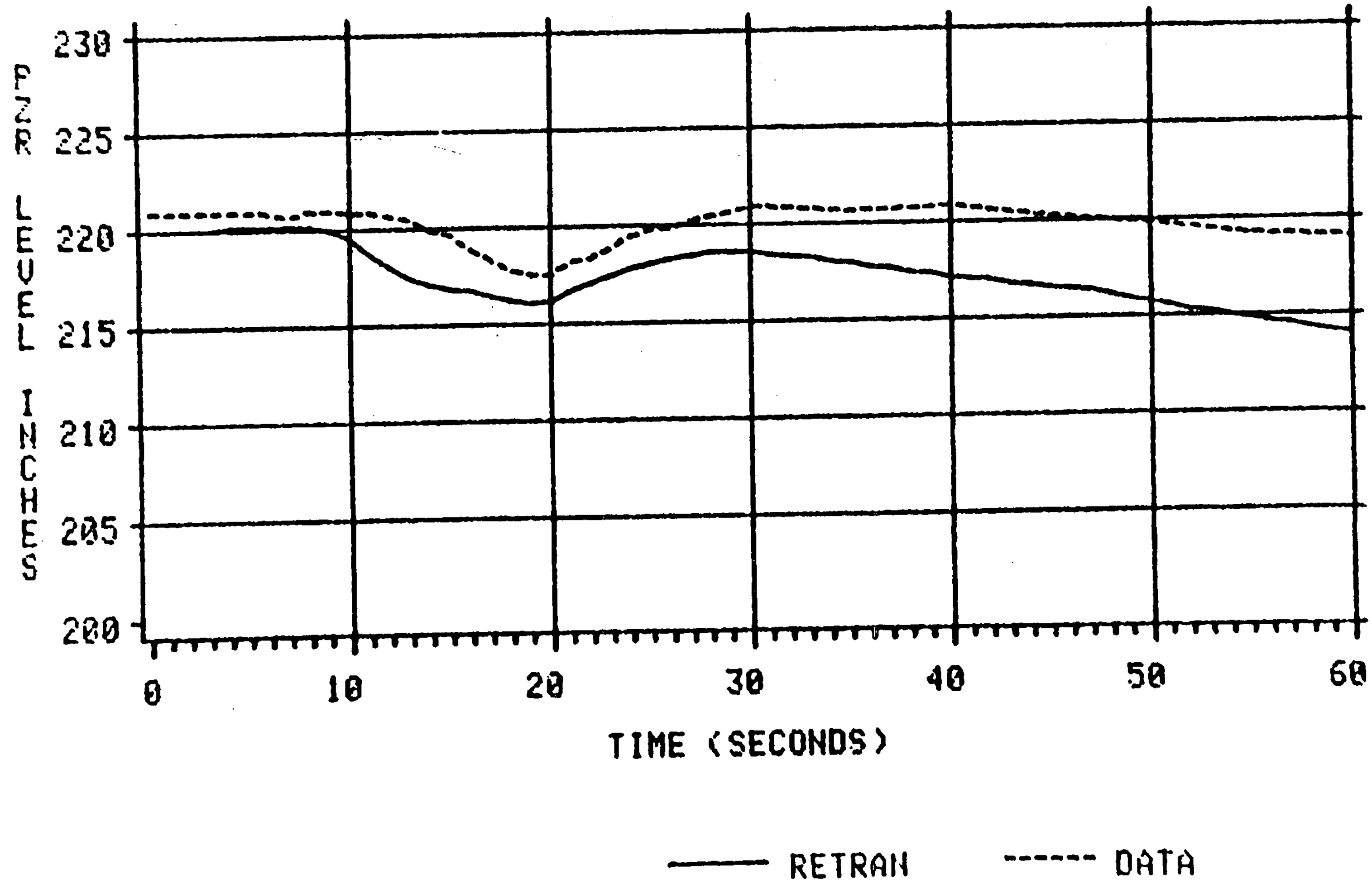


Figure 4.5.2-3

ONS 1 TBV FAILURE W/O RX TRIP 5/4/81

RETRAN AND PLANT DATA

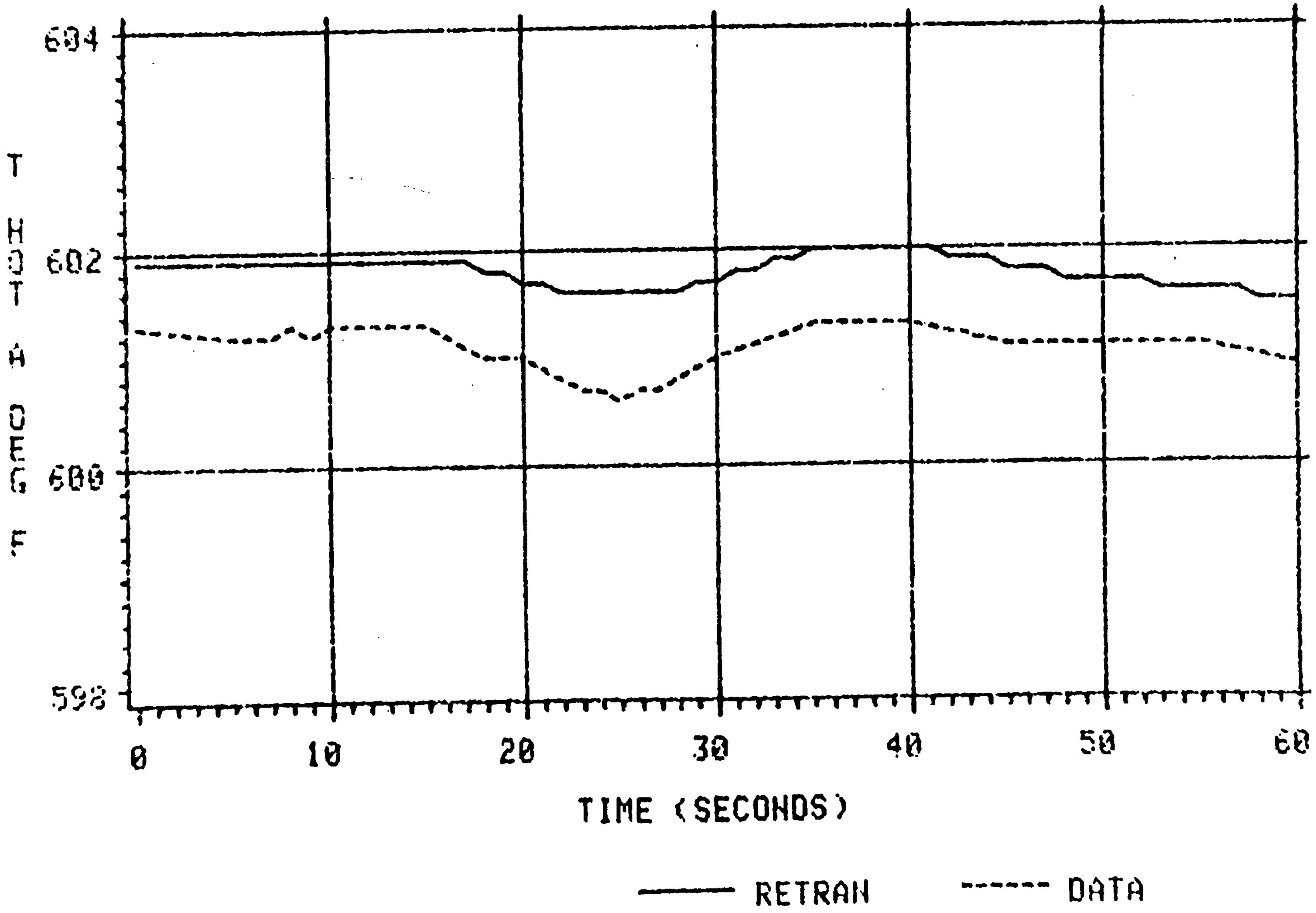


Figure 4.5.2-4

ONS 1 TBV FAILURE W/O RX TRIP 5/4/81

RETRAN AND PLANT DATA

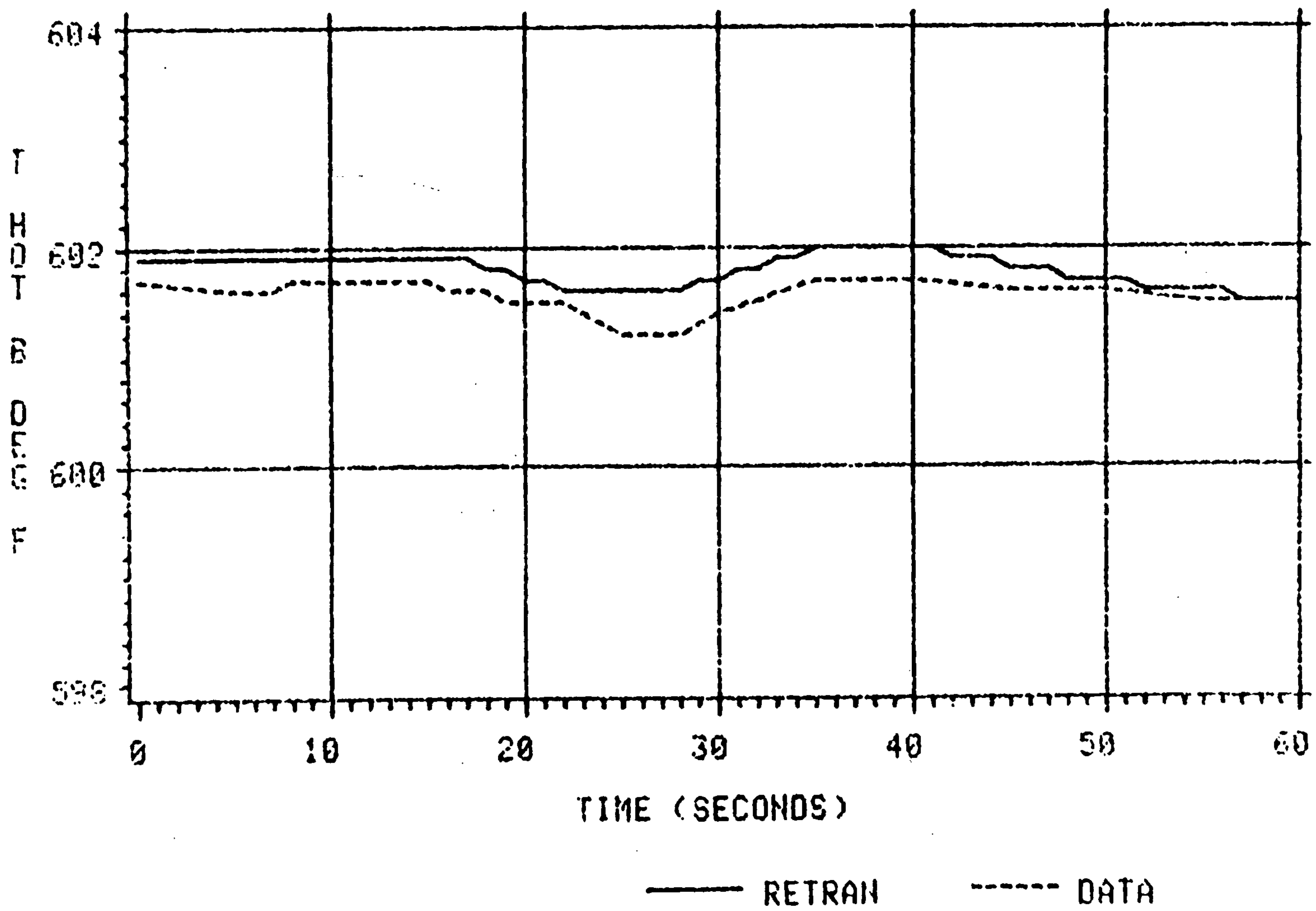


Figure 4.5.2-5

ONS 1 TBV FAILURE W/O RX TRIP 5/4/81

RETRAN AND PLANT DATA

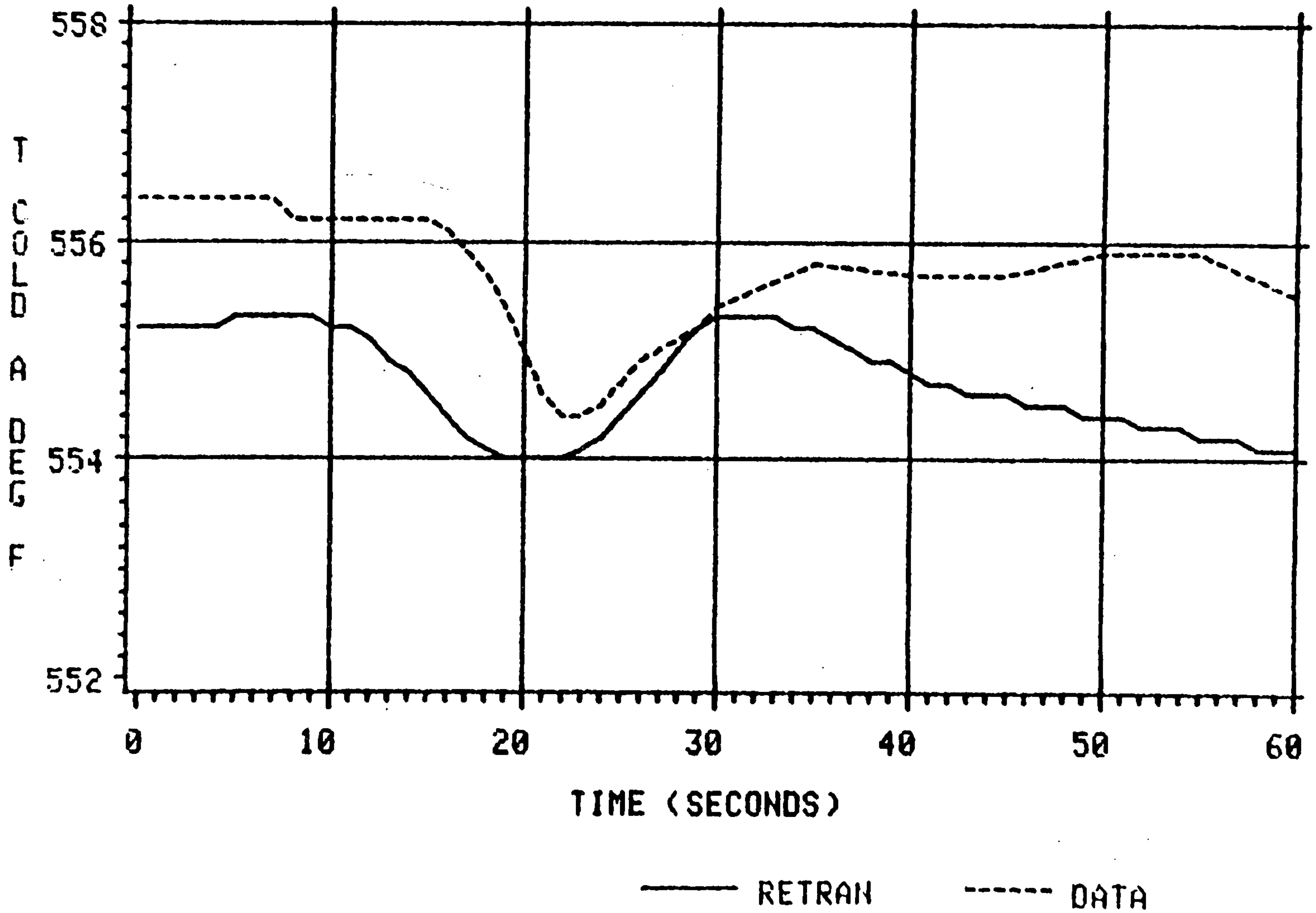


Figure 4.5.2-6

ONS 1 TBV FAILURE W/O RX TRIP 5/4/81

RETRAN AND PLANT DATA

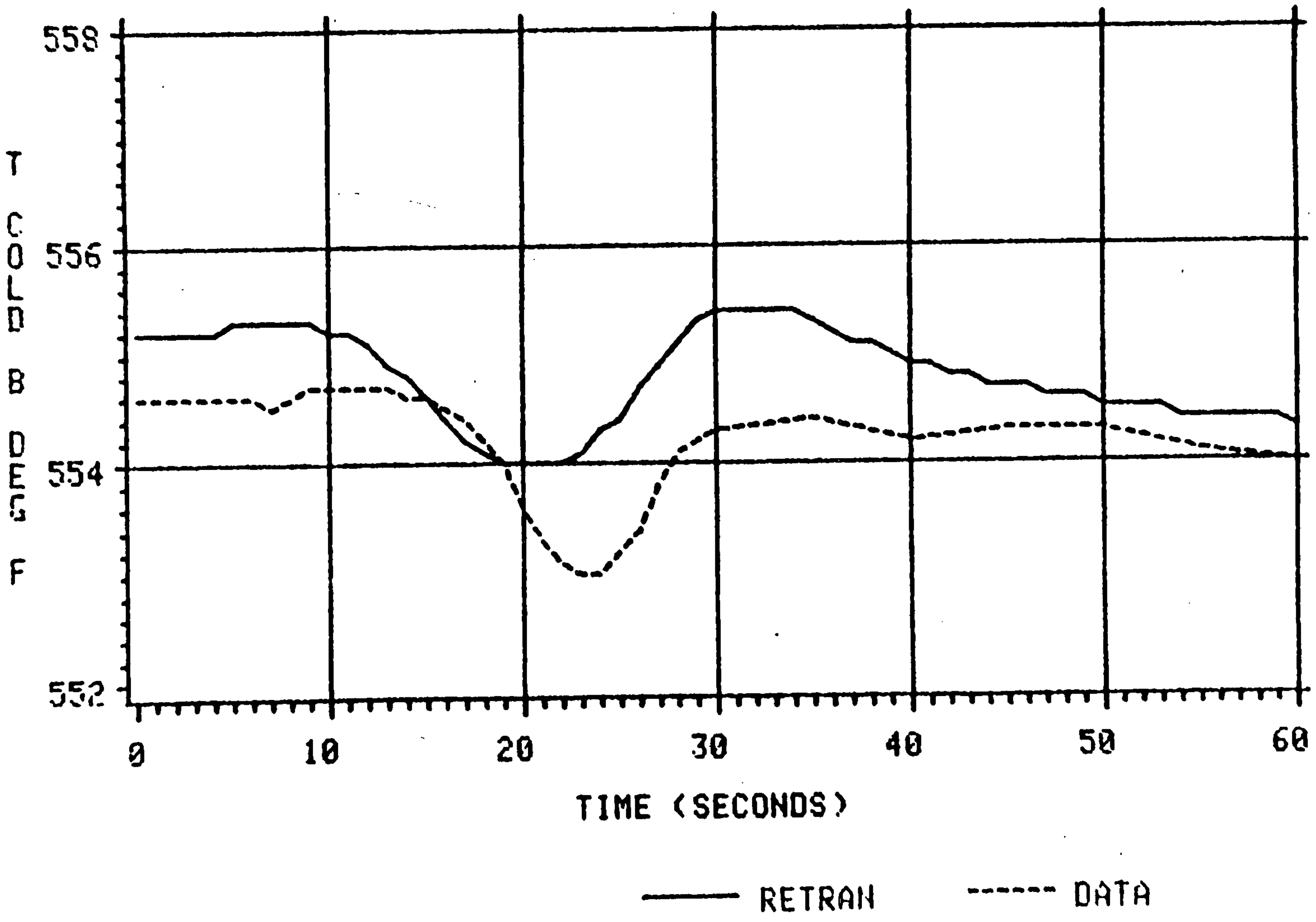
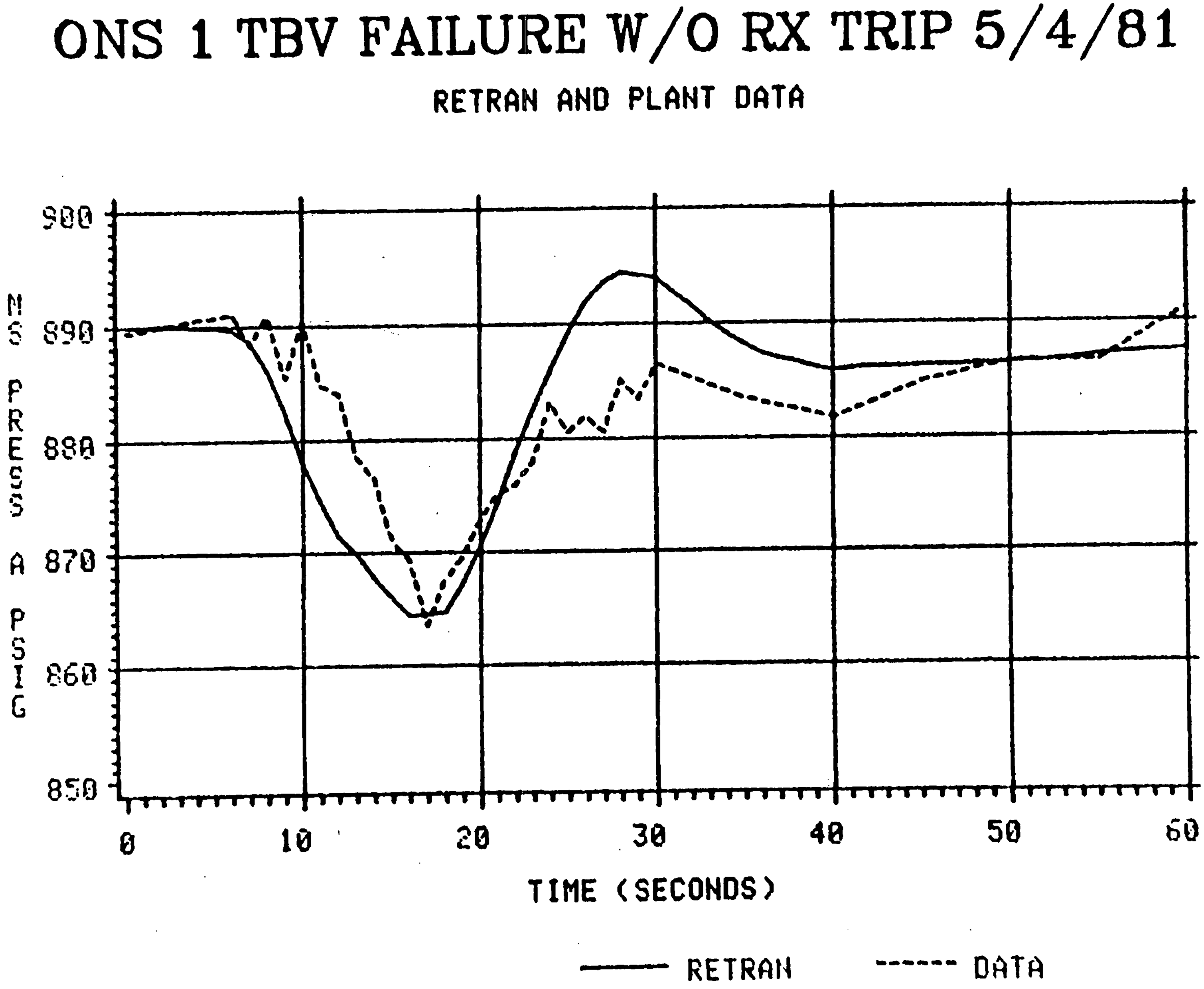


Figure 4.5.2-7

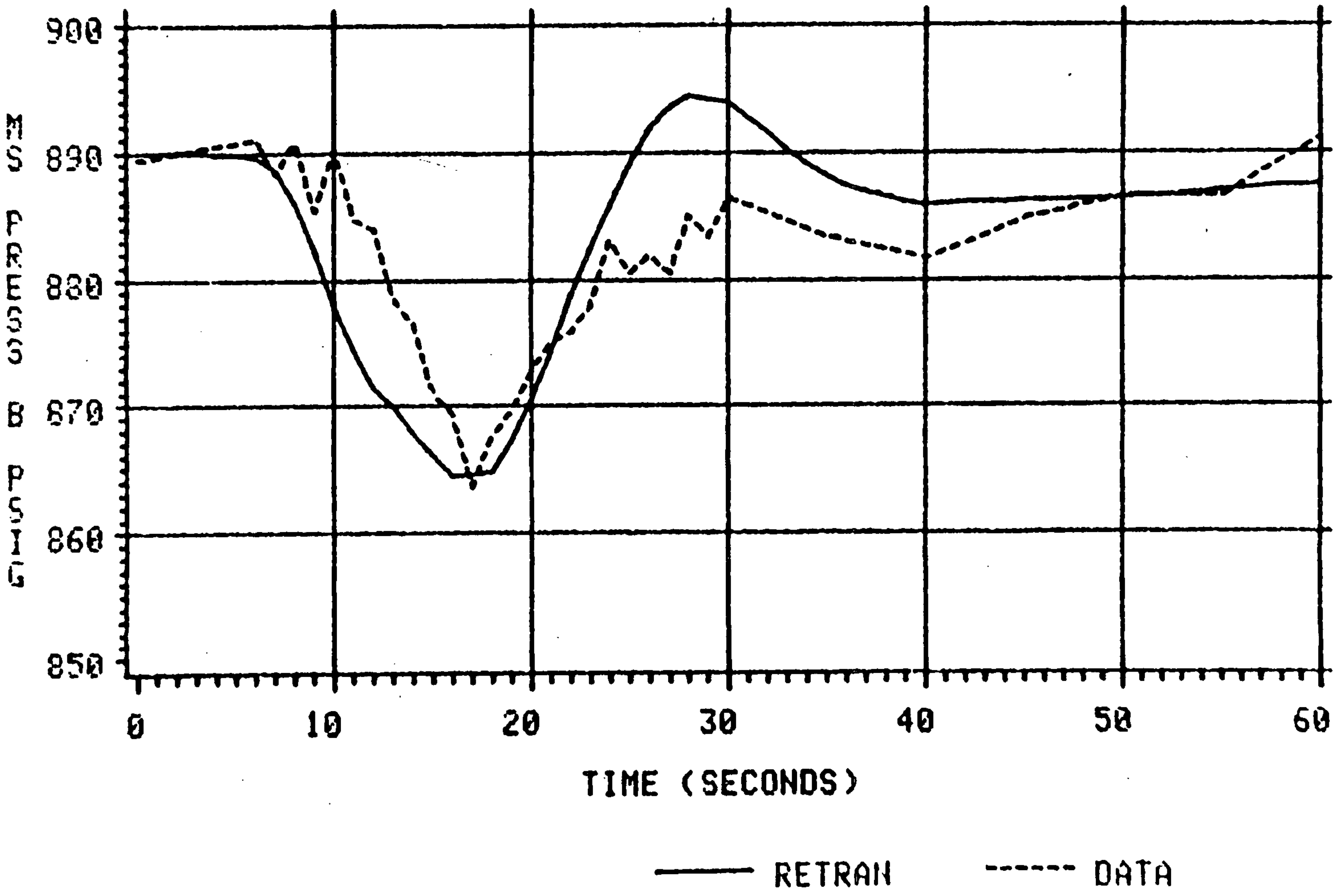


ONS 1 TBV FAILURE W/O RX TRIP 5/4/81
RETRAN AND PLANT DATA
MS PRESS A PSIG
900
890
880
870
860
850
0
10
20
30
40
50
60
TIME (SECONDS)
RETRAN
DATA

Figure 4.5.2-8

ONS 1 TBV FAILURE W/O RX TRIP 5/4/81

RETRAN AND PLANT DATA



4-143

Figure 4.5.2-9

4.6 Other Operational Transients

4.6.1 Oconee Nuclear Station Unit 3 Reactor Trip From Three Reactor Coolant Pump Operation July 23, 1985

Transient Description

Oconee Unit 3 was operating at 74% full power with the B2 reactor coolant pump (RCP) secured. At that time a component failure within the Integrated Control System (ICS) caused a reduction in feedwater flow to the "A" steam generator. To compensate, flow to the "B" steam generator was increased until a Btu limit was reached. The overall decrease in total feedwater flow caused a reduction in primary to secondary heat transfer and an increase in Reactor Coolant System (RCS) temperature and pressure, and pressurizer level. Approximately 23 seconds after the initiating event, the reactor tripped on high RCS pressure. The subsequent post-trip response was typical. The turbine trip on reactor trip caused the SG pressure to increase rapidly, and the main steam relief valves (MSRVs) lifted to relieve the excess pressure. After the MSRVs reseated, the SG pressure was controlled near the nominal 1010 psig setpoint by the action of the turbine bypass valves. The primary system depressurized as the RCS temperatures decreased toward the nominal post-trip value of approximately 555 °F. The operators opened a second RCS makeup valve and started on additional high pressure injection (HPI) pump to facilitate the recovery of the pressurizer level, which decreased rapidly due to the contraction of the reactor coolant. Normal main feedwater (MFW) control was available after the trip to maintain a minimum SG level and continue the plant cooldown.

Discussion of Important Phenomena

Several important phenomena occurred during the transient which challenged the capability of RETRAN and the Oconee RETRAN Model to accurately simulate the plant response. These phenomena include steam generator secondary void fraction profile and primary-to-secondary heat transfer, main steam relief, pressurizer behavior, and the pre-trip reactor dynamic response.

The most important phenomena during this event is the primary-to-secondary heat transfer, both before and after the reactor trip. This predominantly determines the RCS pressure and pressurizer level response. The RCS pressure response is particularly significant in the initial portion of this transient because it determines the timing of the reactor trip on high RCS pressure.

Accurate modeling of the reactor kinetic response is also important in order to determine the pre-trip response. As total feedwater flow decreases, the feedwater-to-reactor cross limit will cause the ICS to insert control rods and reduce reactor power. Reactor power will also be reduced to maintain a constant T-ave. Furthermore, the change in moderator temperature will produce reactivity feedback which will also affect reactor power.

Model Description and Boundary Conditions

The transient simulated begins from a steady state condition with only three reactor coolant pumps operating. Therefore, it is necessary to develop a model for this application. The model is based on the two-loop Oconee base model in Figure 2.2-1. Reactor power, flow rates, flow splits, and steam generator levels are characteristic of three pump operation. The three pump base model initial conditions are adjusted to match plant data where appropriate. The plant data used in this analysis is digital transient monitor data.

Initial Conditions

	Model	Plant
Power Level	74% (1900.3 Mwt)	74% (1900.3 Mwt)
RCS Pressure	2131 psig	2131 psig
Pressurizer Level	213 inches	213 inches
T hot	600.8 °F "A"	600.9 °F "A"
	599.8 °F "B"	601.1 °F "B"
T cold	557.1 °F "A"	556.7 °F "A"
	556.6 °F "B"	556.9 °F "B"
SG Pressure	911 psig "A"	881 psig "A"
	889 psig "B"	885 psig "B"
SG Level	69% (OR) "A"	69% (OR) "A"
	19% (OR) "B"	19% (OR) "B"
RCS Flow	109×10^6 lbm/hr	109×10^6 lbm/hr
MFW Flow	5.51×10^6 lbm/hr "A"	5.46×10^6 lbm/hr "A"
	2.15×10^6 lbm/hr "B"	2.36×10^6 lbm/hr "B"

The model temperature distribution is adjusted to match the loop A hot leg temperature, and the remainder of the primary system temperatures are determined by the flow splits and steam generator power removal fractions. The difference between plant hot leg temperatures is most likely due to imperfect mixing of the loop flows in the reactor vessel. The RETRAN modeling scheme produces perfect mixing, so the small difference in hot leg temperatures is due only to slight differences in loop pressures.

The SG pressures in the model are determined by the assumed 885 psig turbine header pressure, and the steam generator to turbine pressure drop (calculated by RETRAN based on loss coefficients from the full power base model). The SG "A" pressure is higher than the data, but this is not considered to have an

important effect on the course of the transient. For this benchmark analysis the initial SG levels are matched to the plant data [

]

The problem boundary conditions of this analysis include control rod movement, reactor kinetics parameters, the RCS high pressure trip setpoint, RCS makeup flow, decay heat and delayed neutron power, main feedwater flow, and SG pressure control.

Control rod motion based on the feedwater to reactor cross limits is modeled. These cross limits reduce the reactor demand when feedwater flow decreases more than 5% below feedwater demand. Cycle specific kinetics parameters and the differential rod worth of the Group 7 control rods is modeled. The RCS high pressure trip setpoint is assumed to be the nominal plant setpoint of 2290 psig. The HPI flow used in the simulation begins at 39 seconds with two pumps delivering flow through the second makeup valve. Letdown was isolated during the event immediately after the trip and normal makeup is not modeled.

A calculation of decay heat for this transient [

]

The main feedwater flow boundary condition is taken directly from the plant transient monitor data and the SG low level limit control is modeled. Pre-trip SG pressure control is provided by a model of the turbine control valves. The control valves are assumed to modulate to maintain steam header pressure at the 885 psig setpoint prior to the trip. After the trip SG pressure control is accomplished via nominal main steam relief valve and turbine bypass valve performance, except that the bypass valve control setpoint is adjusted to 990 psig on both SGs to match the observed long-term performance.

Simulation Results

The simulation begins with the failure in the ICS and continues for 180 seconds. The simulation is terminated at the point where all major plant parameters have returned to normal post-trip values. The sequence of events is given in Table 4.6.1-1, and the results of the simulation are compared to the plant data in Figures 4.6.1-1 through 4.6.1-17.

Reactor power and control rod position comparisons are shown in Figures 4.6.1-1 through 4.6.1-3. The pre-trip reactor power response is fairly close to the data, with RETRAN slightly lower. The post-trip prediction of RCS pressure (Figure 4.6.1-4), however, is not as close, as pressure is significantly underpredicted. The minimum predicted pressure is 1782 psig, compared to 1913 psig at the plant. The disagreement is due to the fact that the coolant temperatures predicted by RETRAN are several degrees lower than the data. This causes a greater pressurizer outsurge and RCS depressurization. The underprediction of temperatures can be attributed to the steam generator heat transfer in the RETRAN model. The greater effective heat transfer area in the steam generators which is predicted by RETRAN leads to excessive post-trip heat transfer in the simulation and a more rapid cooldown of the primary system.

The predicted pressurizer level response is compared to the data in Figure 4.6.1-5. The level response is similar to the RCS pressure, as would be expected. The initial insurge is slightly less than the data because the primary coolant heats up and expands less in the RETRAN calculation than in the actual transient prior to reactor trip.

The RCS temperature response is shown in Figures 4.6.1-6 through 4.6.1-13. The RCS temperatures, in general, compare favorably to the data prior to reactor trip. The loop A hot leg temperature is slightly low due to a lower reactor power prediction, but the loop A cold leg temperature prediction is close to the data. The loop B temperatures also compare well, although the decrease in loop B temperature is overpredicted by RETRAN. The post-trip temperature prediction is lower than the data, as discussed above.

The SG pressure response is shown in Figures 4.6.1-14 and 4.6.1-15. The immediate post-trip pressure prediction trends the data closely and the post-trip prediction undershoots the data temporarily. This action would tend to overcool the RCS temperatures slightly but not enough to account for the total difference in the temperature predictions.

SG level responses are given in Figures 4.6.1-16 and 4.6.1-17. The trend of the predicted level for each generator is similar to the data, indicating that the initial inventory and the feedwater boundary condition is reasonably accurate for this simulation. The SG level comparison indicates that the secondary inventory is not the cause of the excessive primary-to-secondary heat transfer.

Table 4.6.1-1

Oconee Nuclear Station Unit 3
Reactor Trip From Three
Reactor Coolant Pump Operation
July 23, 1985

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
ICS module fails, reducing A MFW flow, and B MFW flow increases to compensate*	0	0
B MFW flow limited by Btu limits*	1	1
Feedwater to reactor cross limits active*	8	8
Operators put MFW control in manual*	18	18
Reactor trip on high RCS pressure	22.5	24.1
Second makeup valve opened to increase flow*	36	36
Second HPI pump started to increase flow*	38	38
Second makeup valve close and pump secured*	53	53
End of simulation	N/A	180

Note: Asterisks designate boundary conditions

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

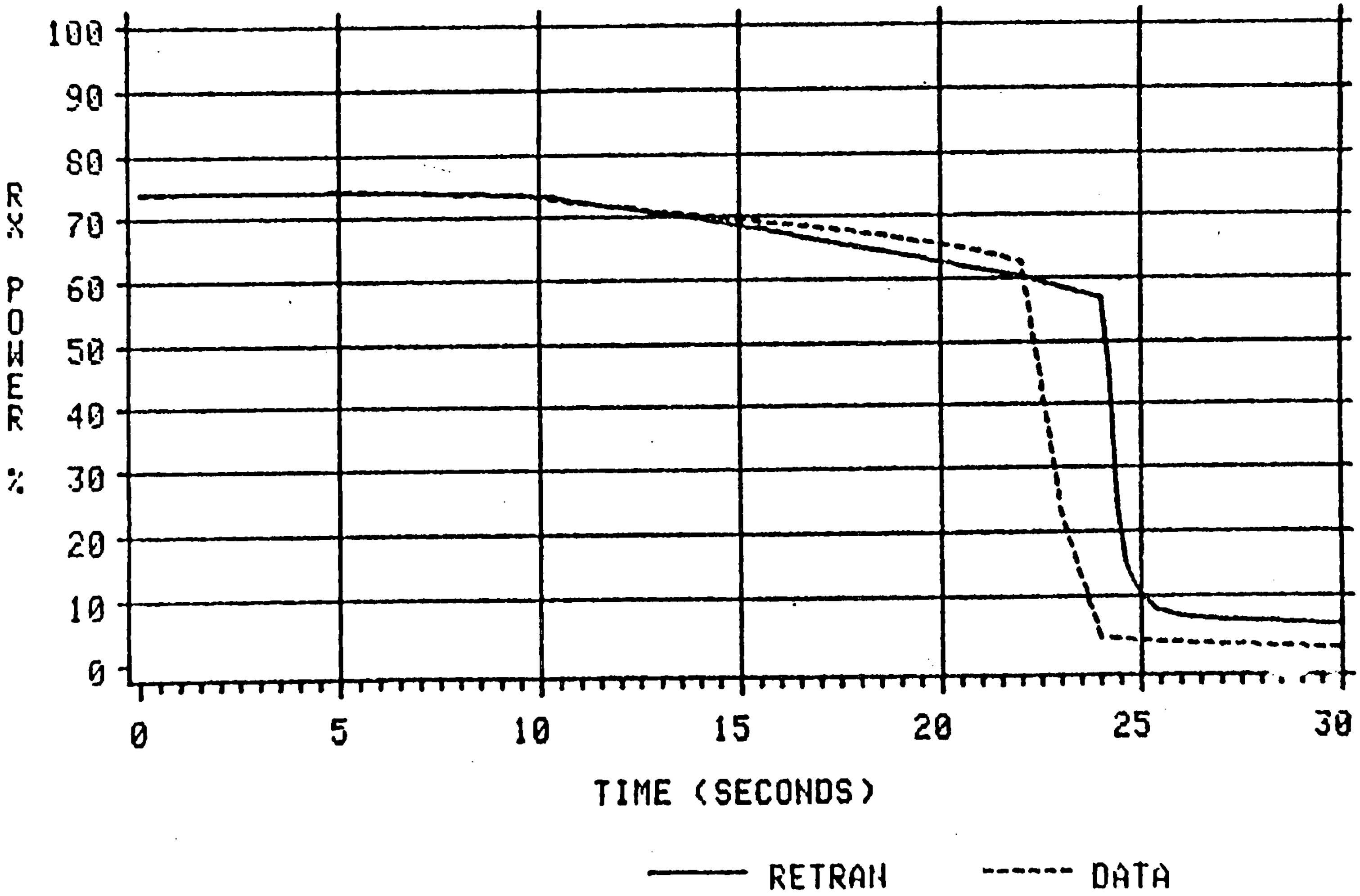


Figure 4.6.1-1

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

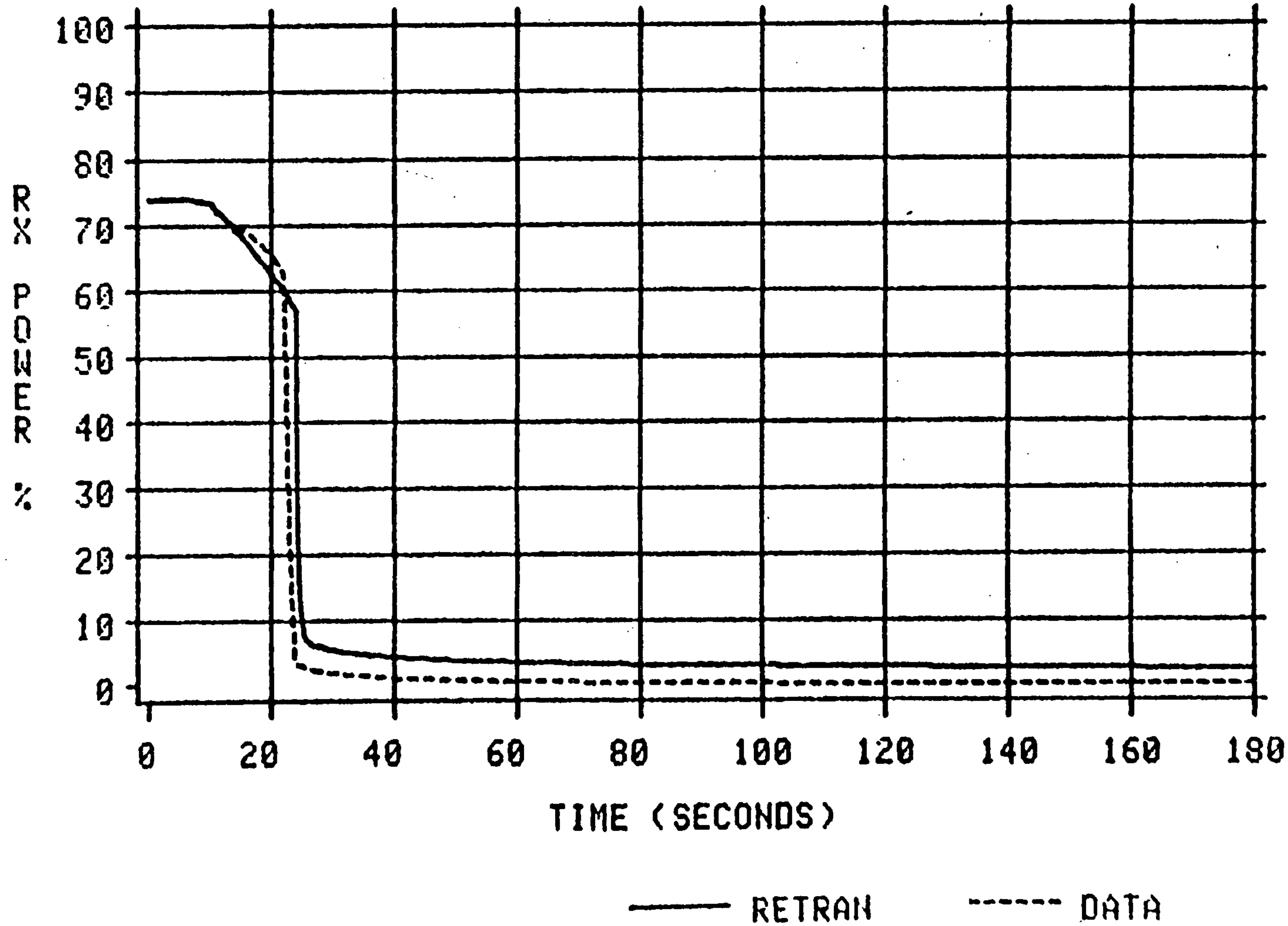


Figure 4.6.1-2

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

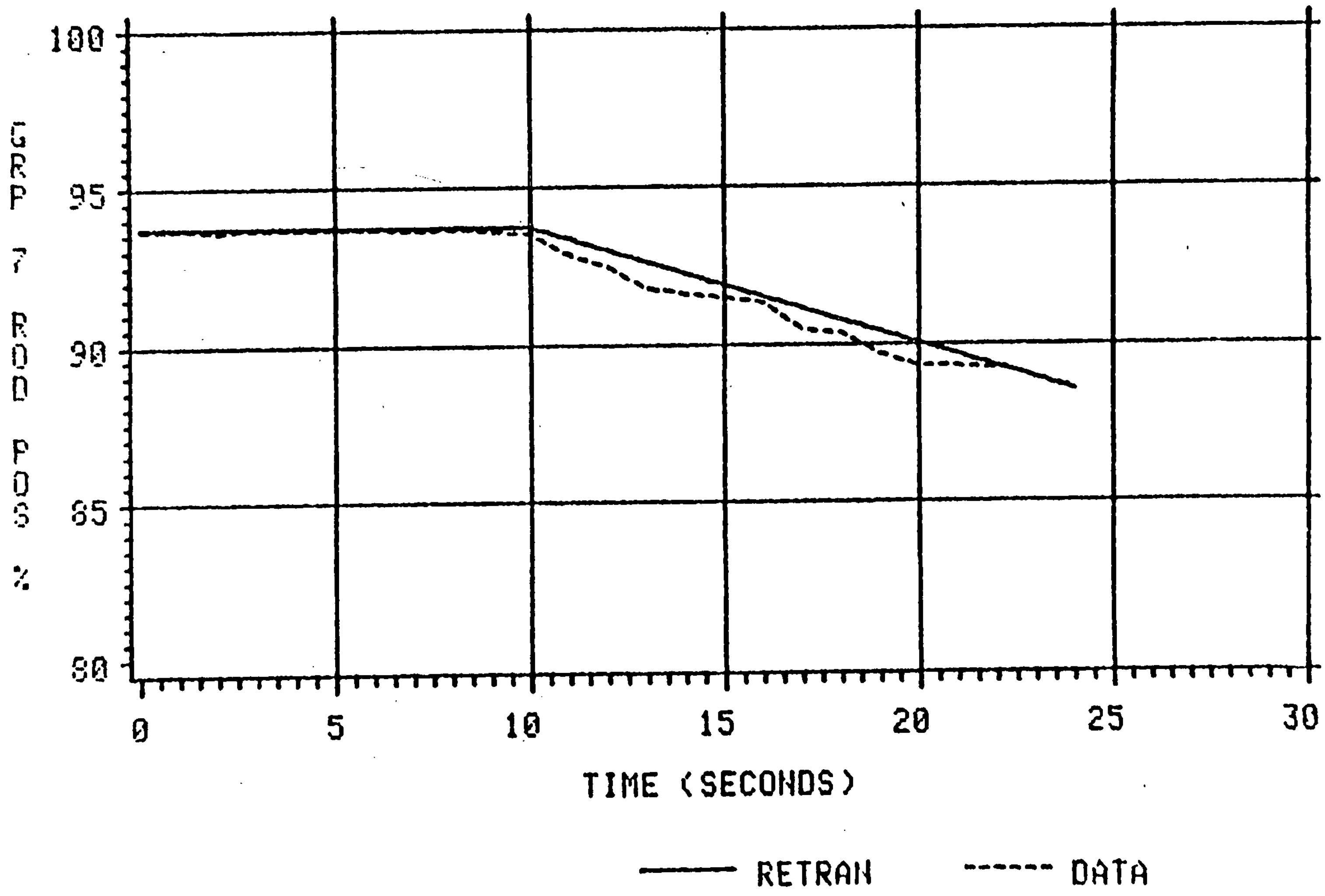


Figure 4.6.1-3

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

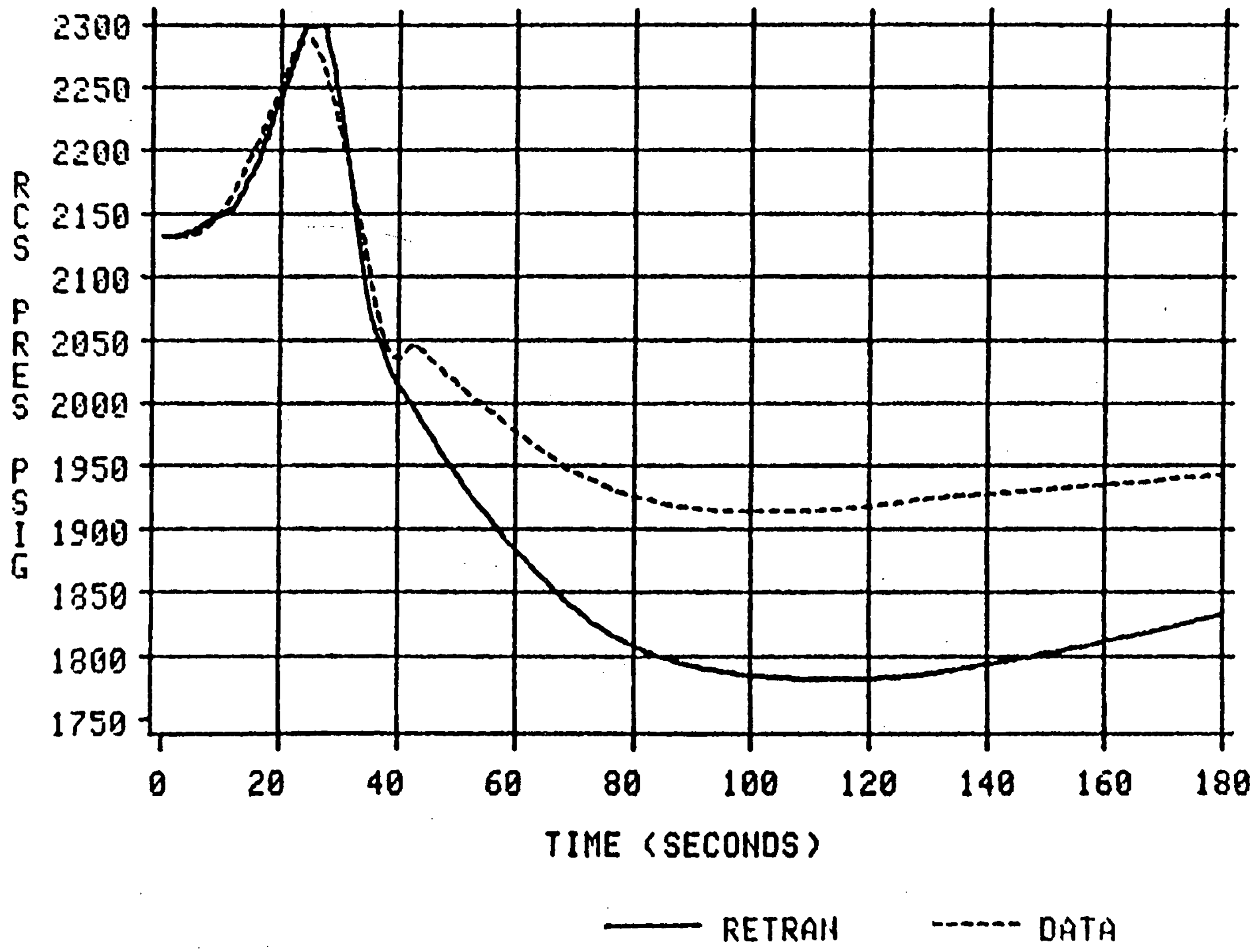


Figure 4.6.1-4

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

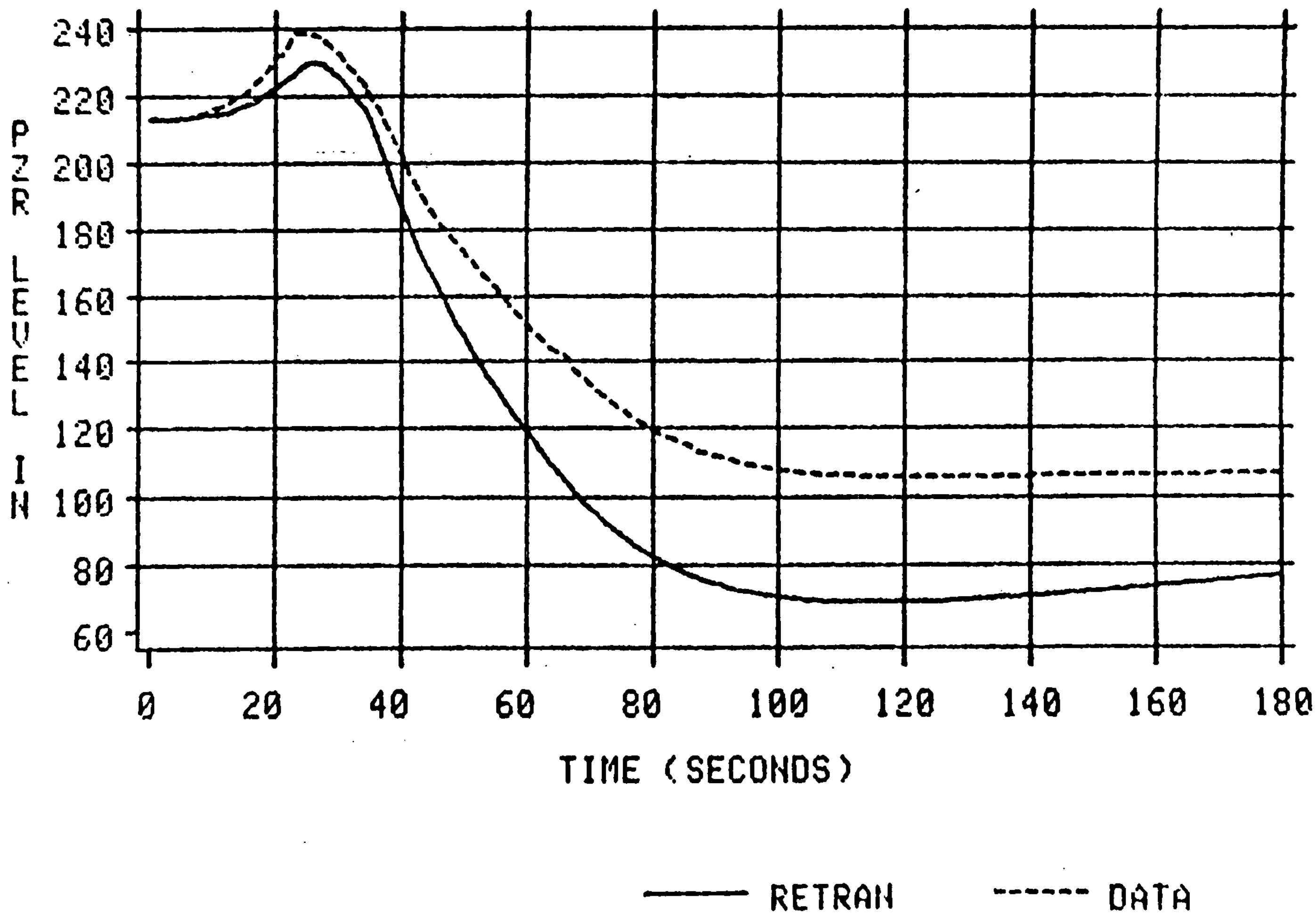


Figure 4.6.1-5

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

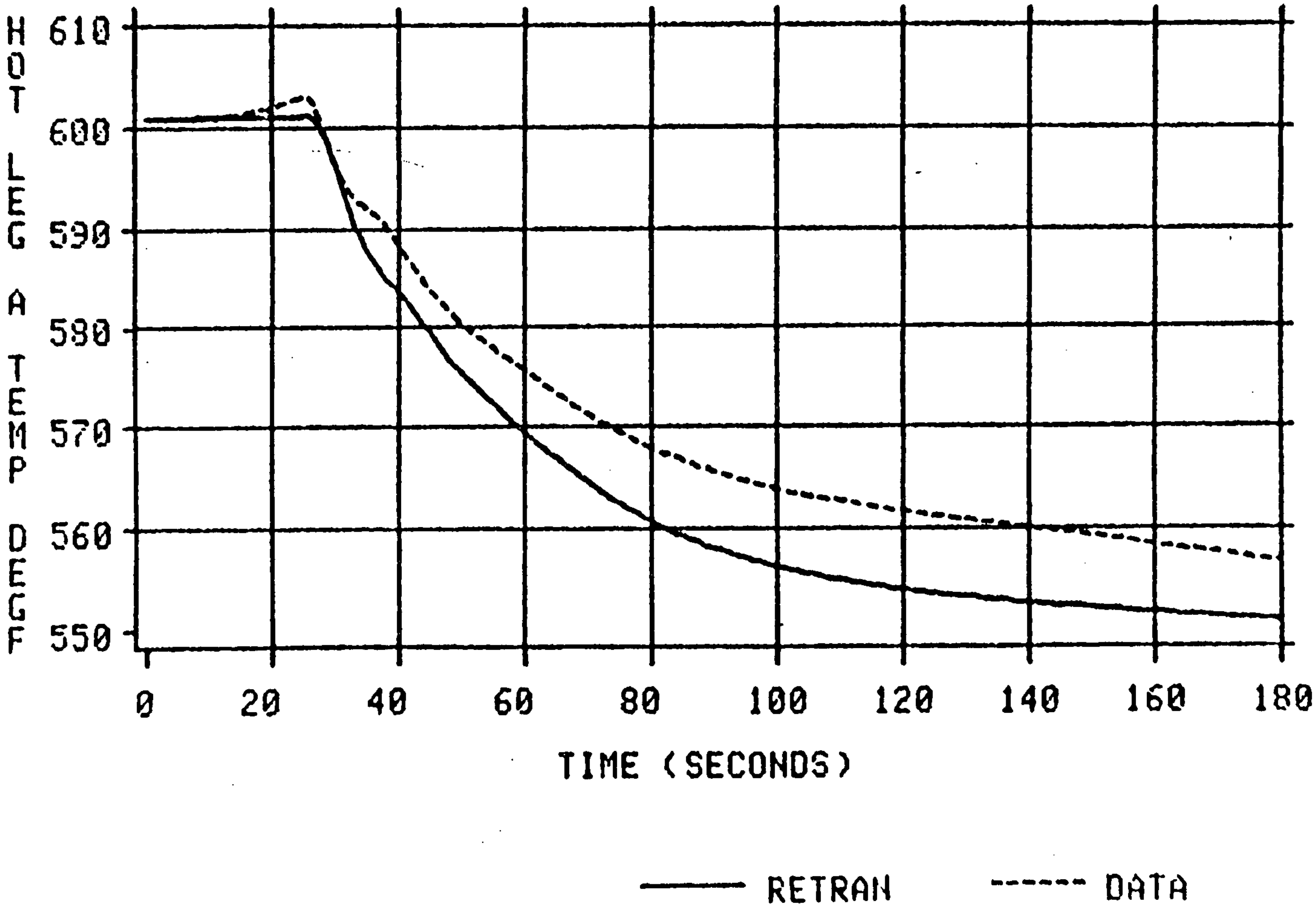


Figure 4.6.1-6

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

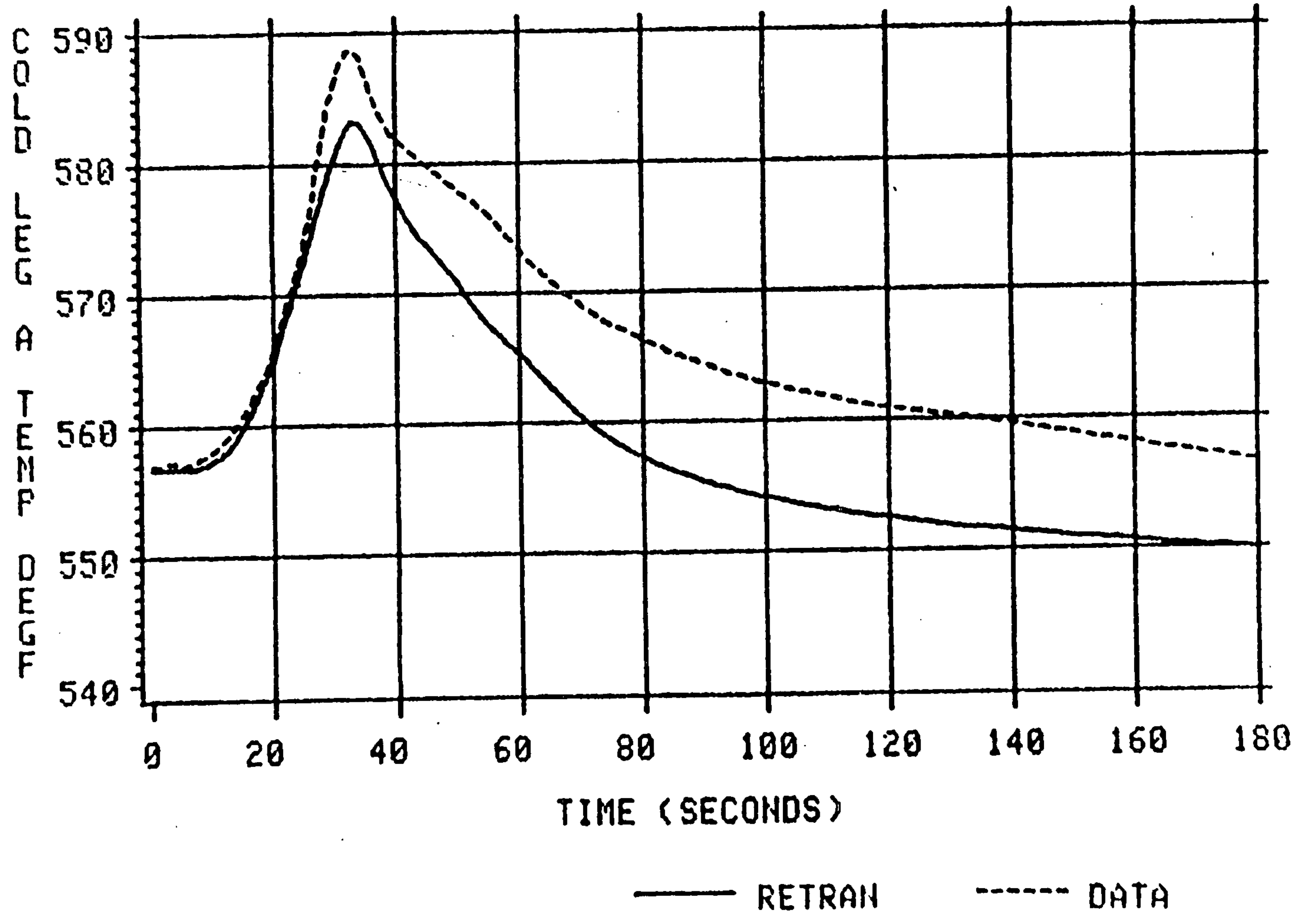
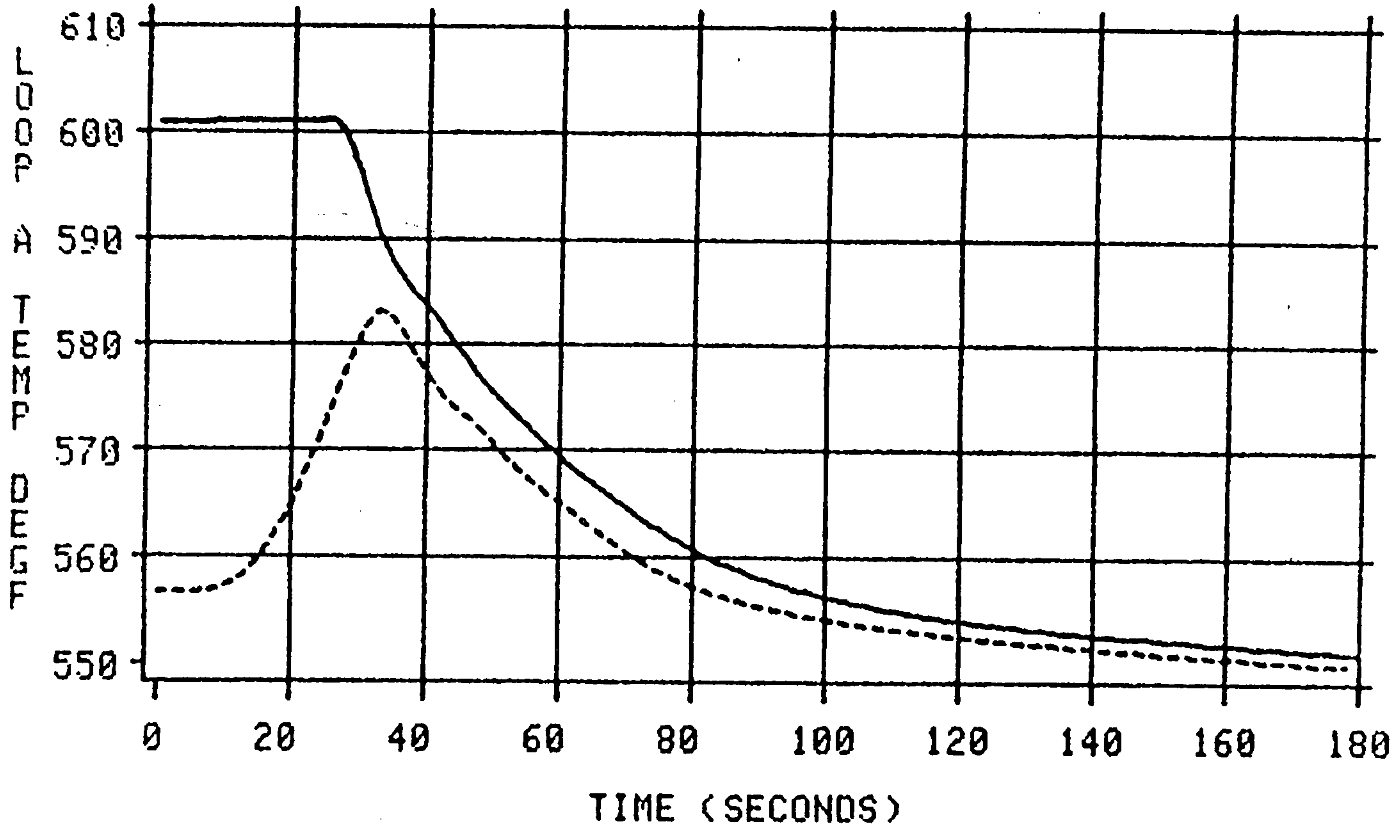


Figure 4.6.1-7

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION



SOLID LINE = T HOT   DASHED LINE = T COLD

RETRAN

Figure 4.6.1-8

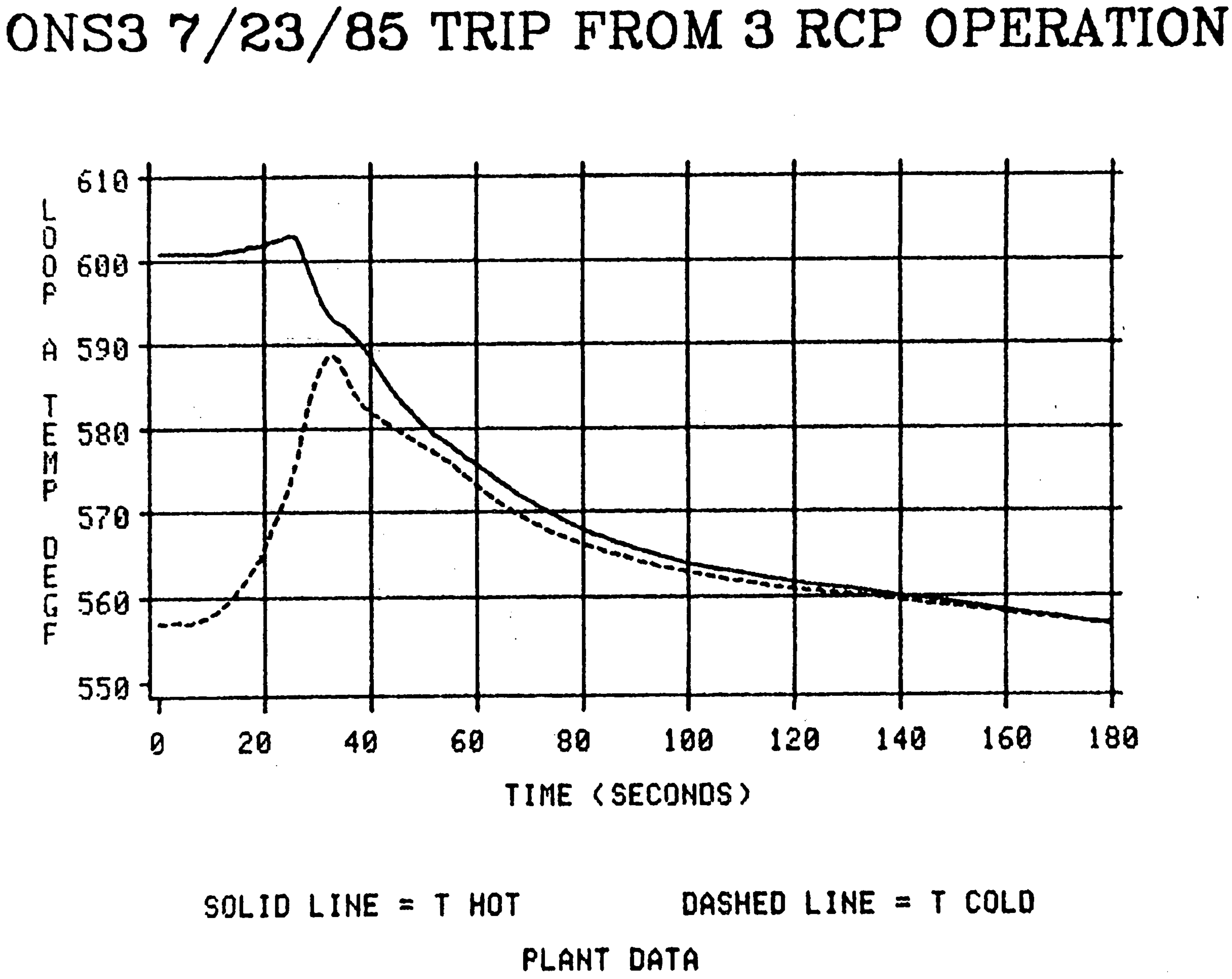

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION
610
600
590
580
570
560
550
LOOP A TEMP DEGF
0
20
40
60
80
100
120
140
160
180
TIME (SECONDS)
SOLID LINE = T HOT
DASHED LINE = T COLD
PLANT DATA

Figure 4.6.1-9

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

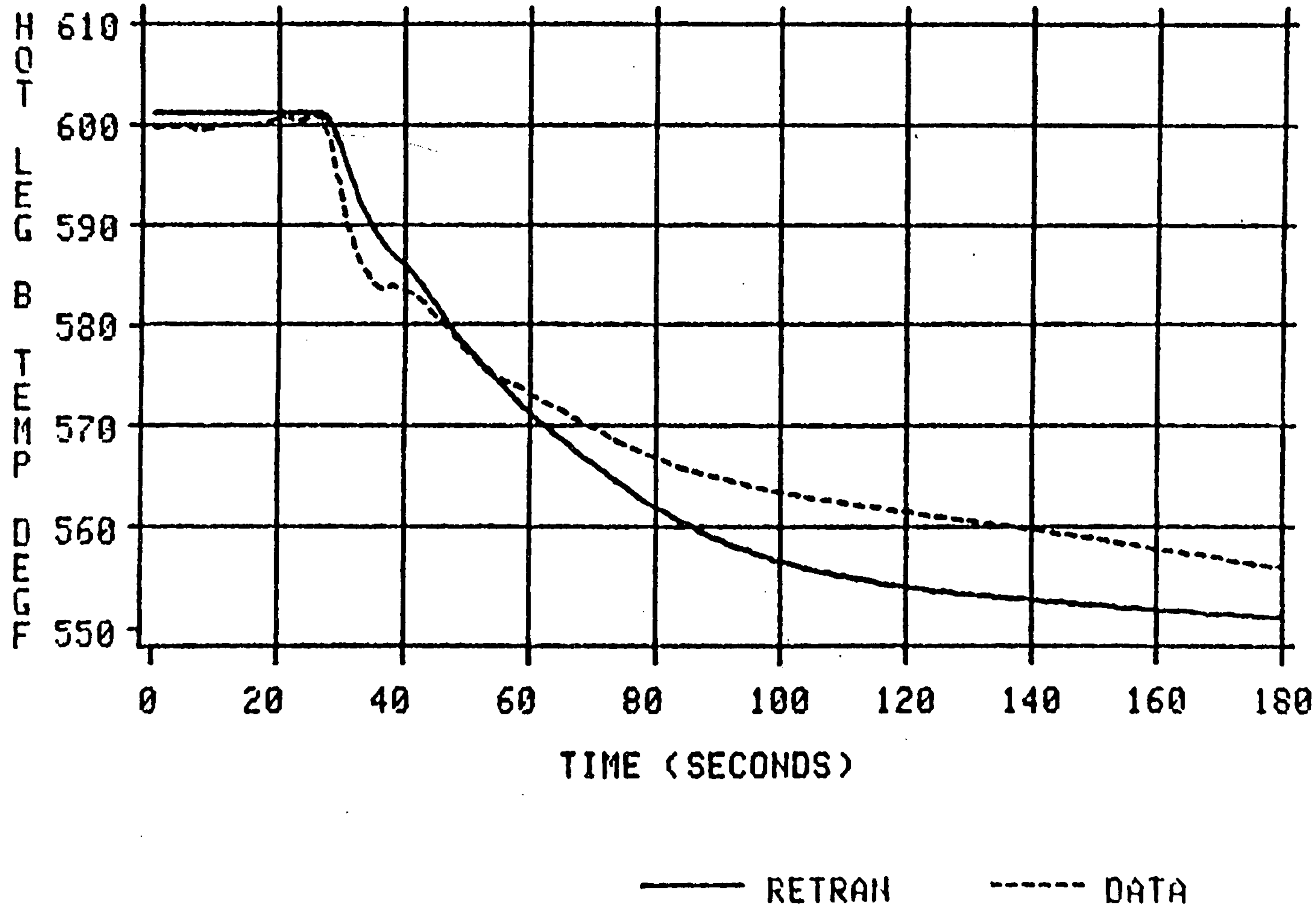


Figure 4.6.1-10

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

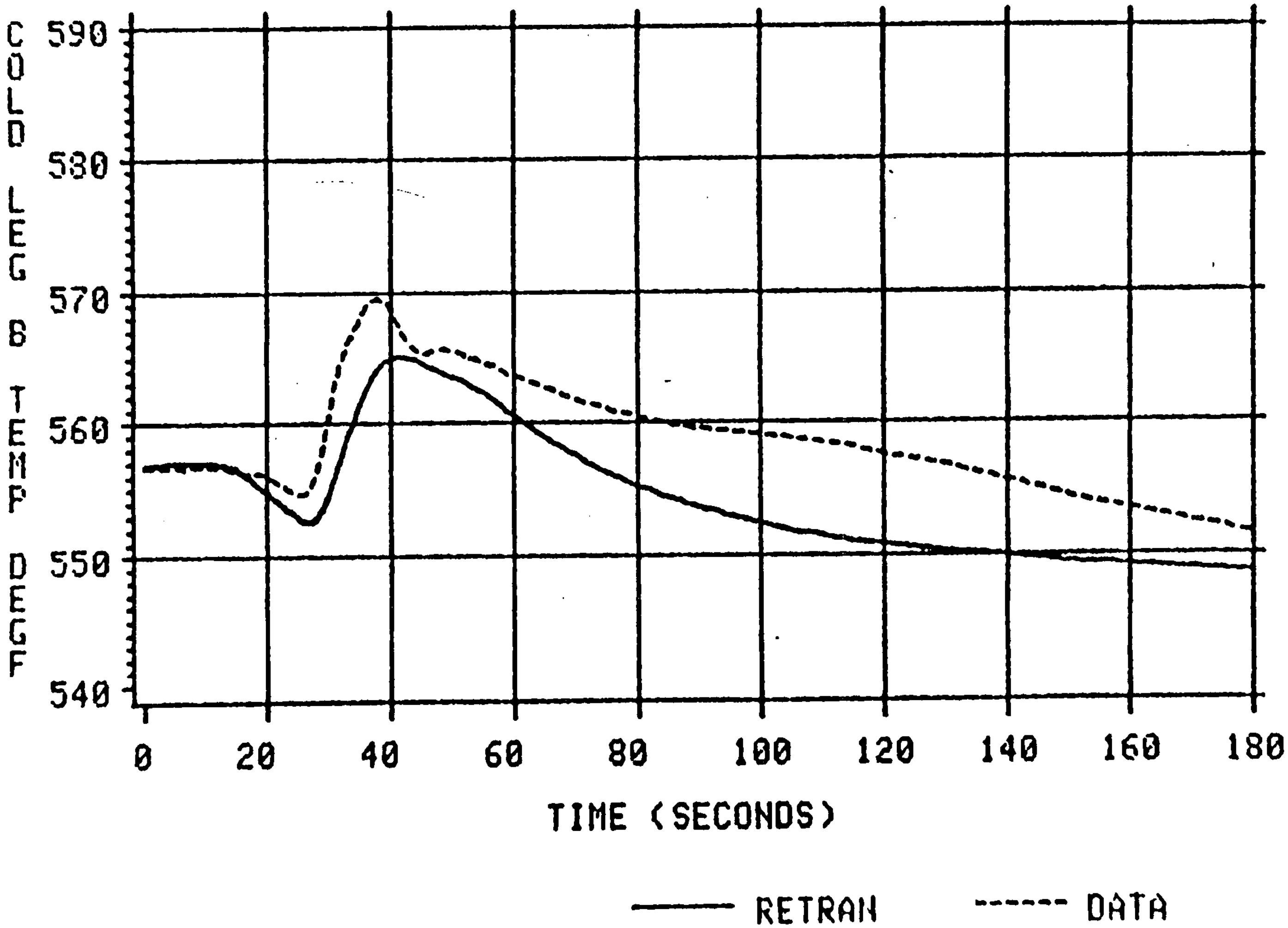
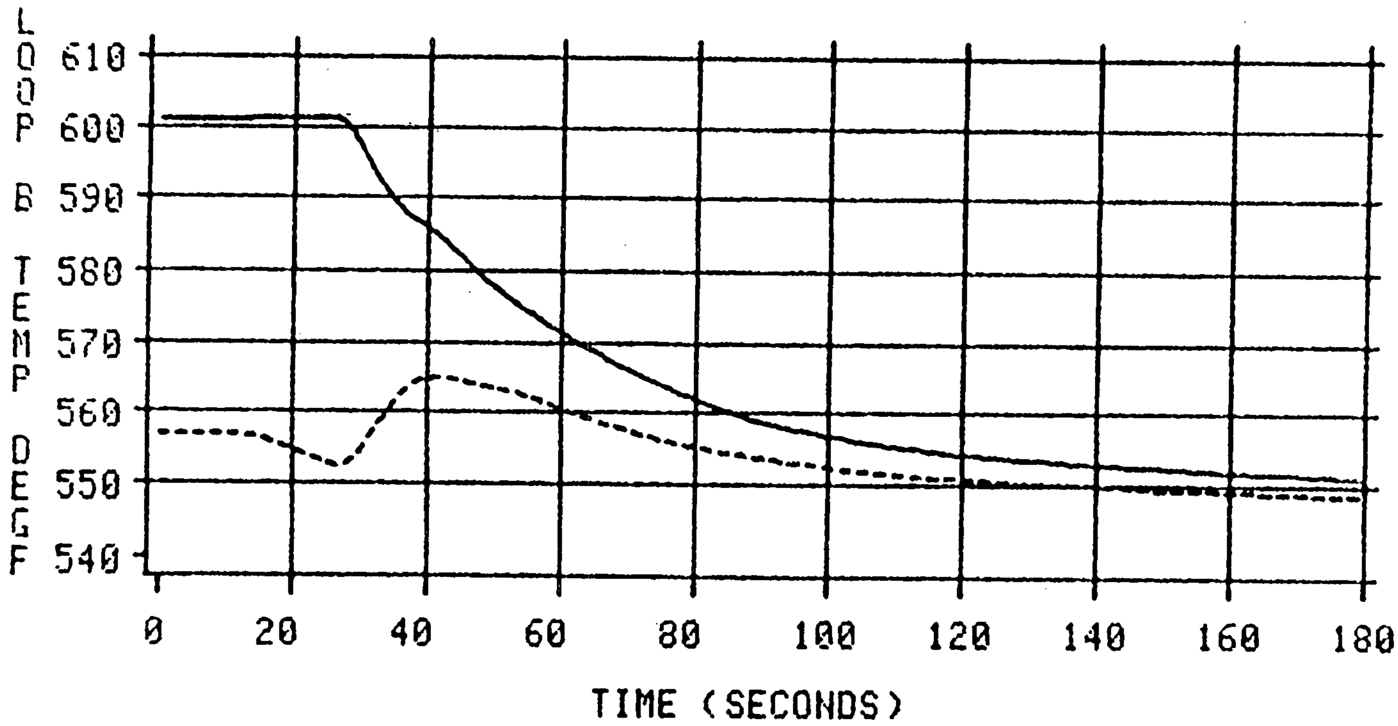


Figure 4.6.1-11

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

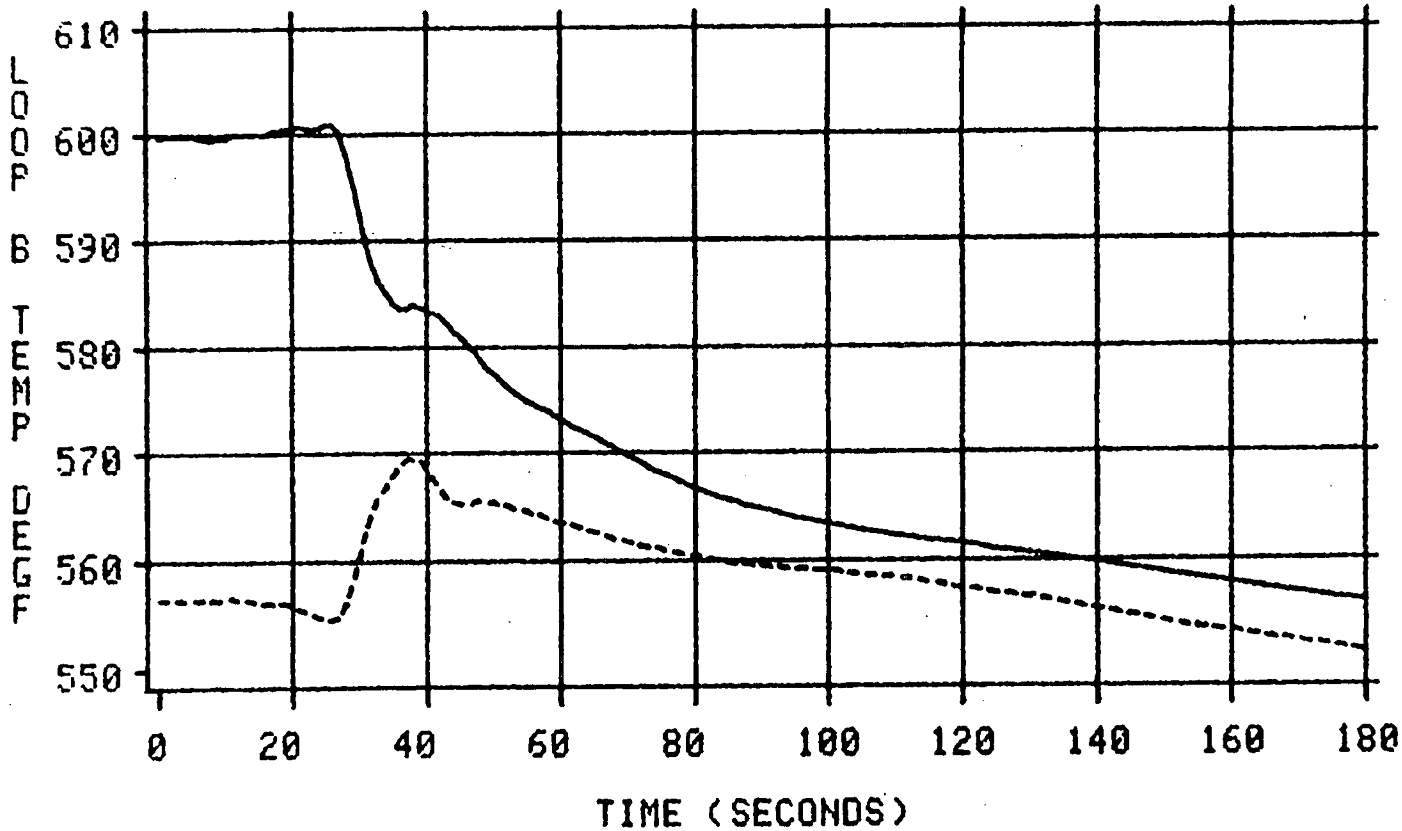


SOLID LINE = T HOT DASHED LINE = T COLD

RETRAN

Figure 4.6.1-12

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION



SOLID LINE = T HOT DASHED LINE = T COLD

PLANT DATA

Figure 4.6.1-13

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

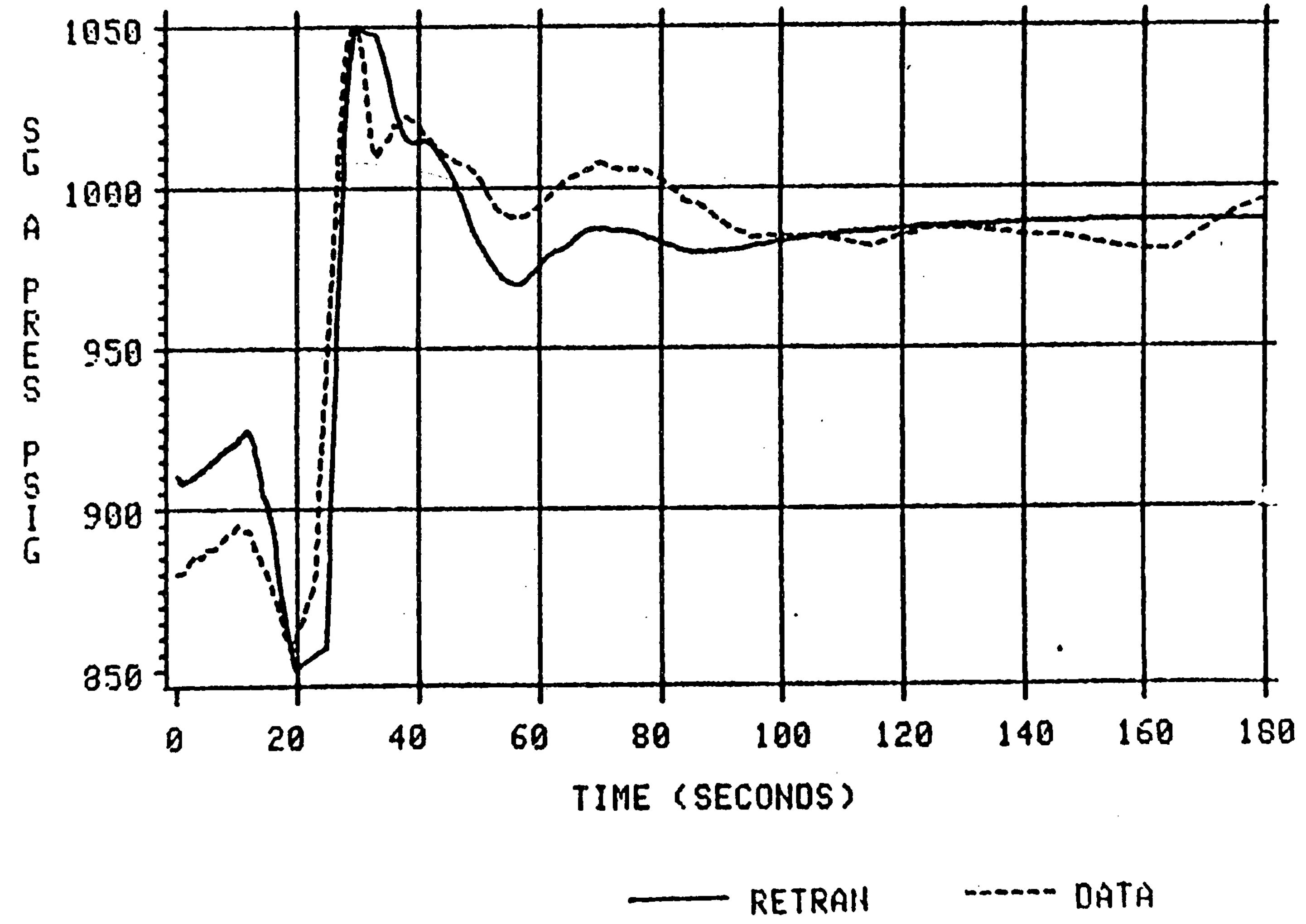


Figure 4.6.1-14

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

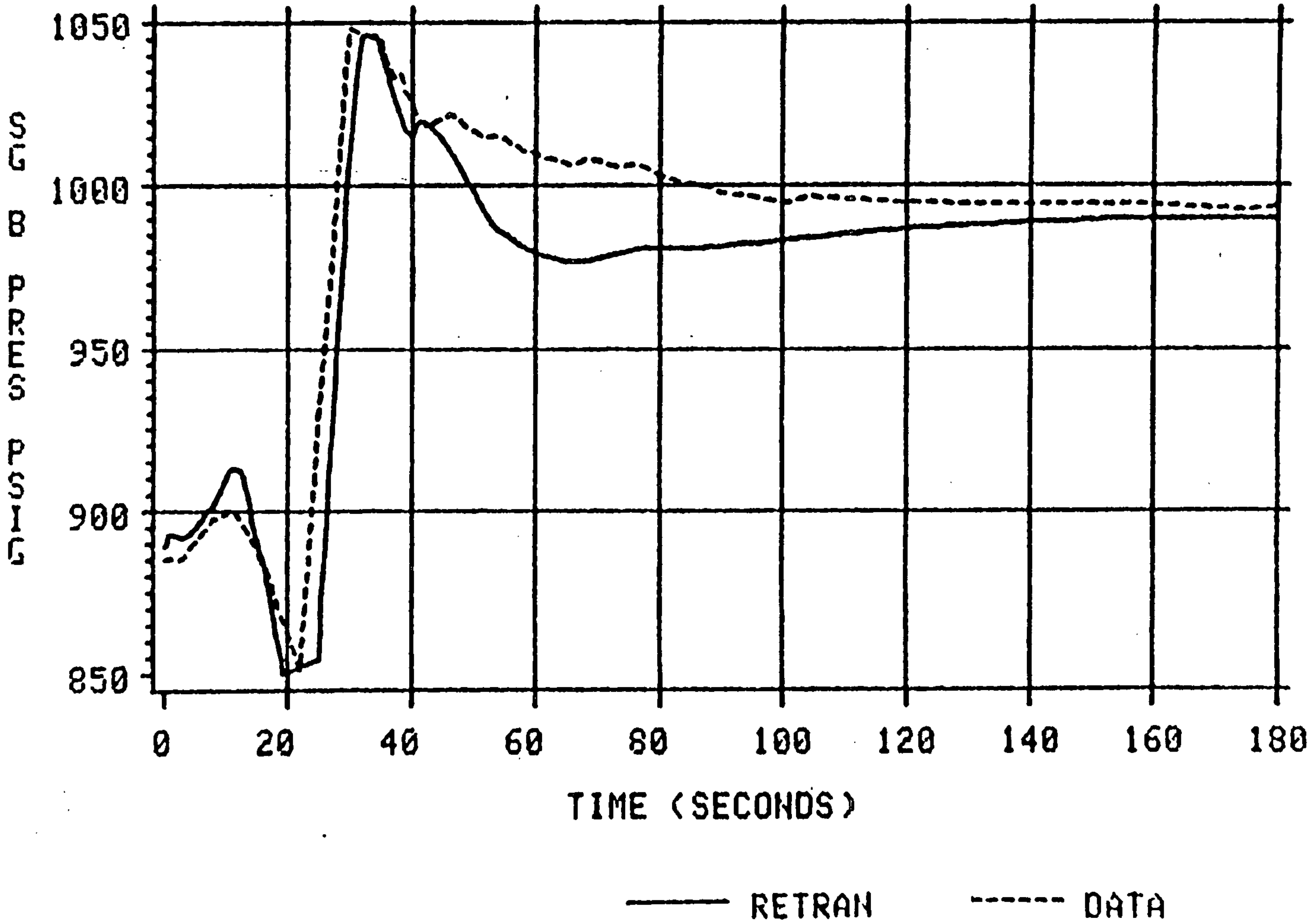


Figure 4.6.1-15

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

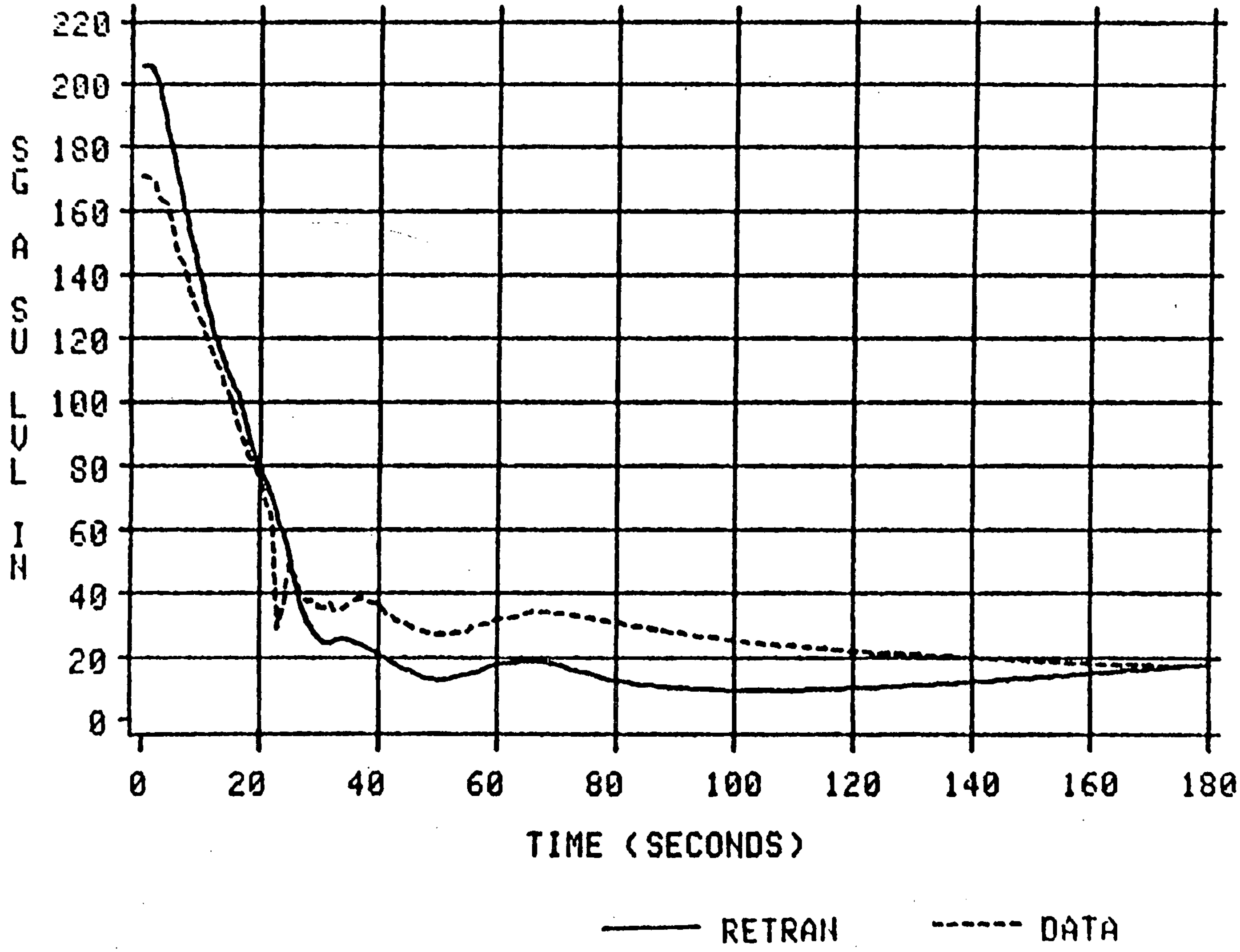


Figure 4.6.1-16

ONS3 7/23/85 TRIP FROM 3 RCP OPERATION

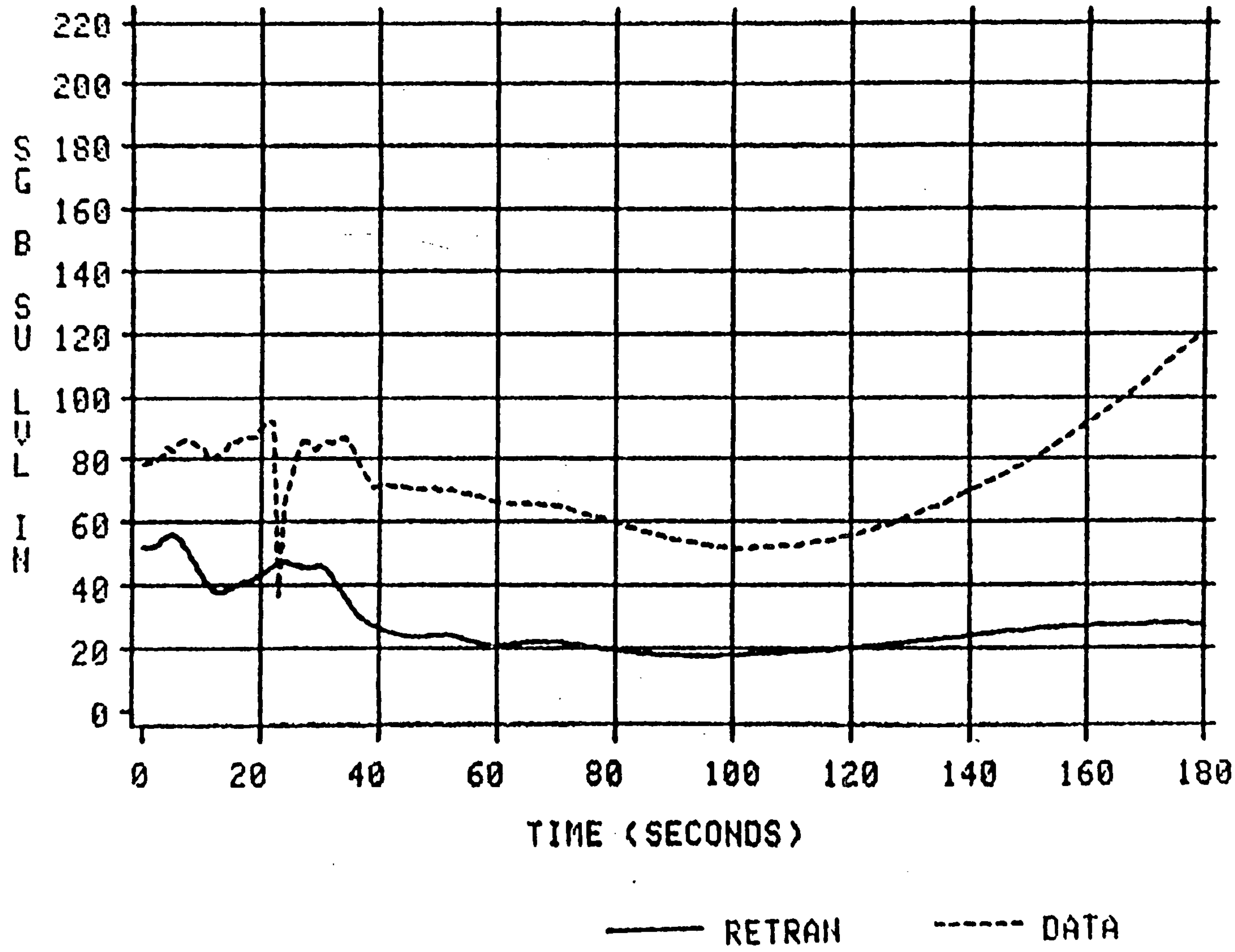


Figure 4.6.1-17

5.0 McGUIRE/CATAWBA RETRAN BENCHMARK ANALYSES

The eight plant transients selected for benchmarking the McGuire/Catawba RETRAN model include a broad spectrum of initial conditions, initiating events, and transient evolutions. A large set of plant transient monitor data is recorded, typically at a one second frequency, during a transient. The simulation is conducted by first initializing the RETRAN model as close as possible to the plant initial conditions. Next, boundary conditions such as actuation of interfacing pumps and valves and operator actions are identified and modeled. In some instances a data void or an atypical plant response, due for example to a spurious valve opening, may require assuming a boundary condition. The simulation is then performed for a duration that includes the plant parameter responses of interest. The results of the simulation are then compared to the plant data for a set of parameters that characterize the overall plant response. The end result provides an assessment of the capability of the McGuire/Catawba RETRAN model and the RETRAN-02 code to simulate certain thermal-hydraulic phenomena and the category of transients typical of the benchmarked event.

5.1 Loss of Secondary Heat Transfer

5.1.1 McGuire Nuclear Station - Unit 2
Loss of Main Feedwater from 30% Power
June 10, 1983

Transient Description

McGuire Unit 2 was operating at 30% full power when main feedwater was inadvertently isolated. Primary temperature and pressure quickly began to rise due to the loss of feedwater, and after approximately 65 seconds, the turbine control valves spuriously closed, running the unit back to about 70 MWe. The operator then opened the control valves, and turbine load was restored at approximately 90 seconds. The unit then tripped on low-low SG level at 152 seconds. The AFW pumps started on low-low SG level, except for one motor-driven pump which was started manually. Pressurizer pressure and level reached maximum values of 2274 psig and 47%, respectively, while the post-trip minimum

values were 2083 psig and 23%. At approximately 400 seconds primary temperature was stable at 552°F (5°F below the no-load target) and at approximately 500 seconds steam line pressure was also stable at approximately 1030 psig (62 psi below the no-load target). Pressurizer pressure was restored to its initial value at approximately 900 seconds.

Discussion of Important Phenomena

Several important phenomena occurred during the transient which challenged the capability of RETRAN and the McGuire/Catawba RETRAN model to accurately simulate the plant response. These phenomena include primary-to-secondary heat transfer, main steam relief, steam generator level response, non-equilibrium pressurizer behavior, and the effect of pressurizer spray. These phenomena will be important, each to a varying degree for most of the simulations discussed in this section of the report. Therefore, they will only be discussed in great detail in this first benchmark analysis.

Secondary pressure control has a major impact on plant transient response since primary-to-secondary heat transfer is mainly determined by steam generator saturation temperature. This is due to the constraint that the tube bundle is always covered during power operation, so that the heat transfer area is fixed. Following reactor trip the tube bundle may become partially uncovered, however the reduction in reactor power more than offsets the reduction in heat transfer area. Primary-to-secondary heat transfer is also directly impacted by a reduction in feedwater flow. This is particularly significant due to a [ ] Post-trip secondary pressure control is accomplished by the Steam Dump System, the main steam line PORVs, and the main steam code safety relief valves. Typically only the steam dump to condenser valves are required, but the other steam relief capabilities are demanded as required. The Steam Dump System modulates to reduce RCS T-ave to the no-load setpoint of 557°F following reactor trip.

Accurate simulation of the steam generator inventory distribution and the indicated level response are also important since low steam generator level is often the cause of reactor trip. Steam generator level is sensitive to mismatches in steam and feed flows, and also to pressure disturbances due to

the shrink and swell effect. Steam generator boundary conditions and both the static and dynamic effects on the pressure difference type level instrumentation affect the rate of level change.

Changes in primary-to-secondary heat transfer feed back on the primary system as an expansion or contraction in RCS volume as indicated by pressurizer level. RCS pressure responds to changes in pressurizer level as the pressurizer steam volume is compressed or expanded. Accurate simulation of pressurizer phenomena is important since these phenomena determine the RCS pressure response. Non-equilibrium effects accompanying the compression of the steam bubble during the pressurizer refilling phase are the most important of these. The efficiency of the pressurizer spray in desuperheating/condensing the steam bubble has a great effect on the RCS pressure response. Heat transfer between the liquid and vapor regions at the interface can be important, as can heat transfer to the pressurizer vessel. The importance of these phenomena can vary significantly, and is transient specific.

Model Description and Boundary Conditions

The one-loop McGuire Unit 2 RETRAN model was utilized for this analysis since the plant response among the four loops was essentially symmetrical.

Several modifications to the base model were necessary to simulate the primary and secondary pressure response. The closure of the turbine control valves, combined with the response of the Steam Dump System, resulted in an erratic steam pressure response prior to reactor trip. In order to simulate the transient accurately, it was necessary to construct a RETRAN control system which controls the position of the control valves, and hence steam flow, in order to match pre-trip steam line pressure data. Secondly, since the Condenser Dump System is designed to control steam flow to stabilize primary temperature at the no-load temperature of 557°, and since plant data shows that the temperature dropped several degrees below this value (post-trip), it was necessary to develop a control system similar to the one mentioned above to match the post-trip steam line pressure response. Thirdly, the plant pressurizer pressure shows an unexpected pressure response due to atypical

pressurizer spray operation. Therefore, a control system was developed which regulates spray flow to achieve an accurate pressure response during the short duration (approximately 65 seconds) of spray actuation.

The initial conditions were matched to plant data as shown in the following table. RCS flow was chosen in order to match plant ΔT.

Initial Conditions

	Model	Plant
Power Level	29.7% (1012.4 MWt)	29.7% (1012.4 MWt)
RCS Pressure	2238 psig	2238 psig
PZR Level	36.4%	36.5%
T-ave	566.6°F	566.6°F (ave)
ΔT	18.8°F	19.1°F (ave)
Steam Line Pressure	1050 psig	1050 psig (ave)
SG Level	48.0%	47.8% (ave)
MFW Temperature	344°F	344°F (ave)
MFW Flow	4.0×10^6 lbm/hr	4.2×10^6 lbm/hr

The problem boundary conditions include cycle-specific post trip delayed neutron power and decay heat, MFW flow, and AFW flow. As stated above, secondary pressure is also controlled as a boundary condition, as well as pre-trip pressurizer spray valve position. Normalized reactor power is input as described in Section 4.1.1. MFW and AFW flow versus time was obtained from plant transient monitor data. Charging and letdown flows are assumed to have little effect on the transient and are not modeled.

Simulation Results

The simulation begins with MFW isolation and continues for 900 seconds. The simulation is terminated when most plant parameters have stabilized and the phenomena of interest have occurred. The sequence of events is given in Table 5.1.1 and the comparisons of RETRAN predictions and plant data are shown in Figures 5.1.1-1 through 5.1.1-7.

The comparison of the predicted reactor power to plant data is shown in Figure 5.1.1-1. Prior to reactor trip, there is a slight drop in power due to moderator feedback associated with the increase in RCS temperature. The moderator feedback was not modeled, however, the deviation between predicted power and plant data is small (less than 2%). The difference in the predicted trip time (160 seconds) and actual trip time (152 seconds) is due to a slight deviation between predicted SG level and plant data, which will be discussed later.

The pressurizer pressure comparison is shown in Figure 5.1.1-2. The reduction in heat transfer associated with the loss of feedwater causes RCS temperature and pressure to rise quickly. At 2260 psig, pressurizer pressure is moderated by spray actuation. The spike and subsequent decrease in pressure to approximately 2200 psig is due to changes in turbine control valve position. The pressure then increases again until a few seconds before reactor trip when it drops slightly due to a reduction in steam pressure and T-ave. The RETRAN results trend all of these pressure variations well with a slight underprediction at approximately 100 seconds. The post-trip predicted pressure also trends the data well, although it is offset lower than the plant data.

The pressurizer level comparison is shown in Figure 5.1.1-3. The predicted level is in quite good agreement with plant data - typically within 3%. The increase in the level data near the end of the transient is most likely due to charging which was neglected in the simulation.

RCS T-ave and ΔT comparisons are shown in Figures 5.1.1-4 and 5.1.1-5. The predicted temperatures are very similar to the plant data throughout the duration of the simulation, with maximum deviations no greater than approximately $3^{\circ}F$.

As discussed in the modeling section, it was necessary to match steam line pressure to plant data, as shown in Figure 5.1.1-6. The unusual pre-trip pressure response results in erratic SG levels in both the predicted level and plant data, as shown in Figure 5.1.1-7. The downward spike in plant data at

152 seconds is due to the level in one SG reaching the low-low level trip setpoint of 12%. This trips the reactor 8 seconds before the predicted trip time. Both the predicted level and the plant data are below 3% for the rest of the simulation.

Table 5.1-1

McGuire Nuclear Station Unit 2
Loss of Main Feedwater
June 10, 1983

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
Feedwater isolation*	0	0
PZR spray on	**	12
Turbine control valves closed*	65	64
Steam line PORVs open	69	69
Maximum RCS pressure	72	74
Steam line PORVs closed	**	75
PZR spray off	**	75
All PZR heaters on	**	87
PZR backup heaters off	**	135
Reactor trip on low-low SG level	152	160
Turbine trip	152	160
AFW actuated	153	161
Condenser dump banks 1 and 2 open*	**	161
PZR backup heaters on	**	165
Condenser dump bank 2 closed*	**	169
End of simulation	N/A	900

Notes: Single asterisk designates boundary conditions
Double asterisks indicate plant data not available

MNS-2 LOSS OF MAIN FEEDWATER

6/10/83 EVENT

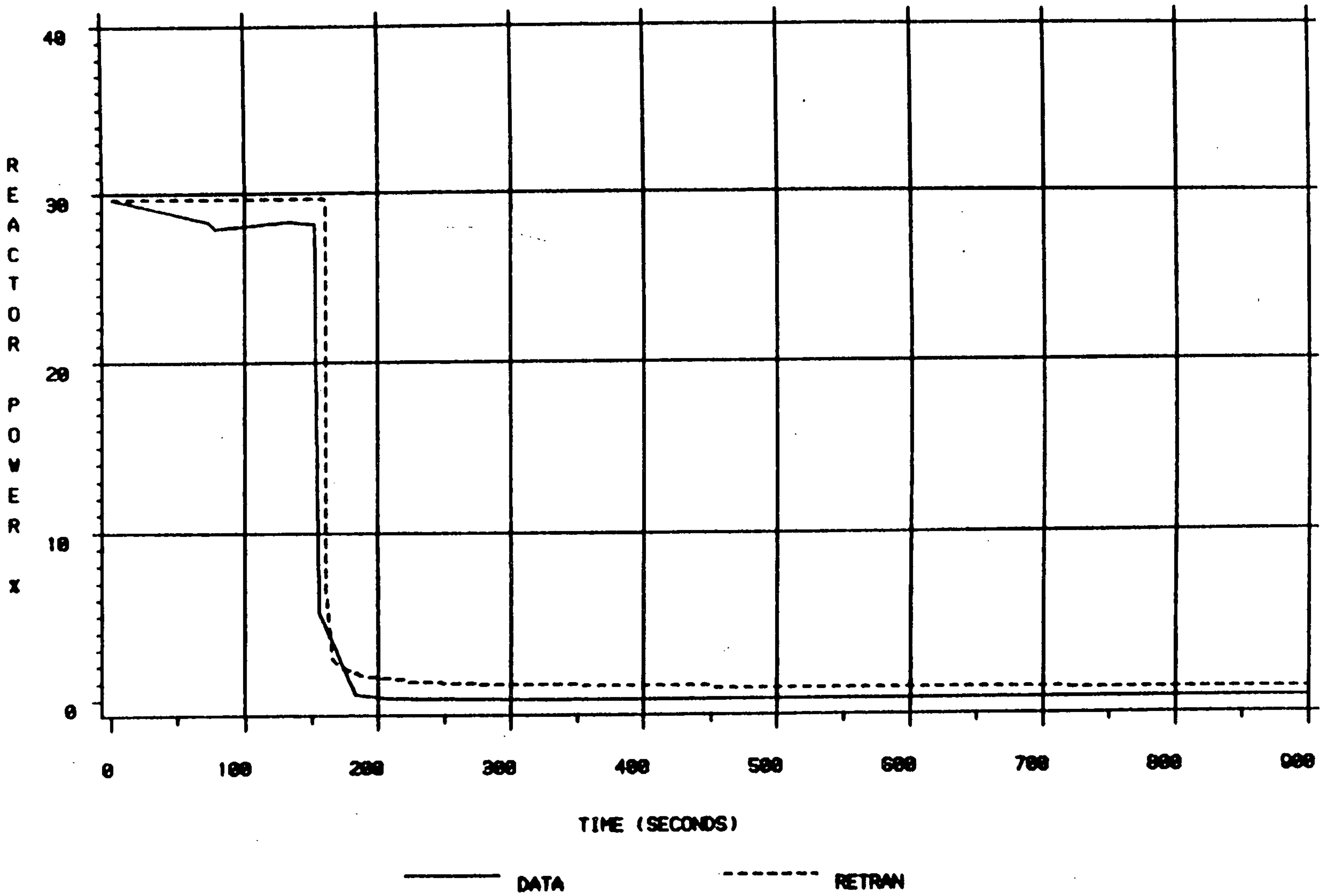


Figure 5.1.1-1

MNS-2 LOSS OF MAIN FEEDWATER

6/10/83 EVENT

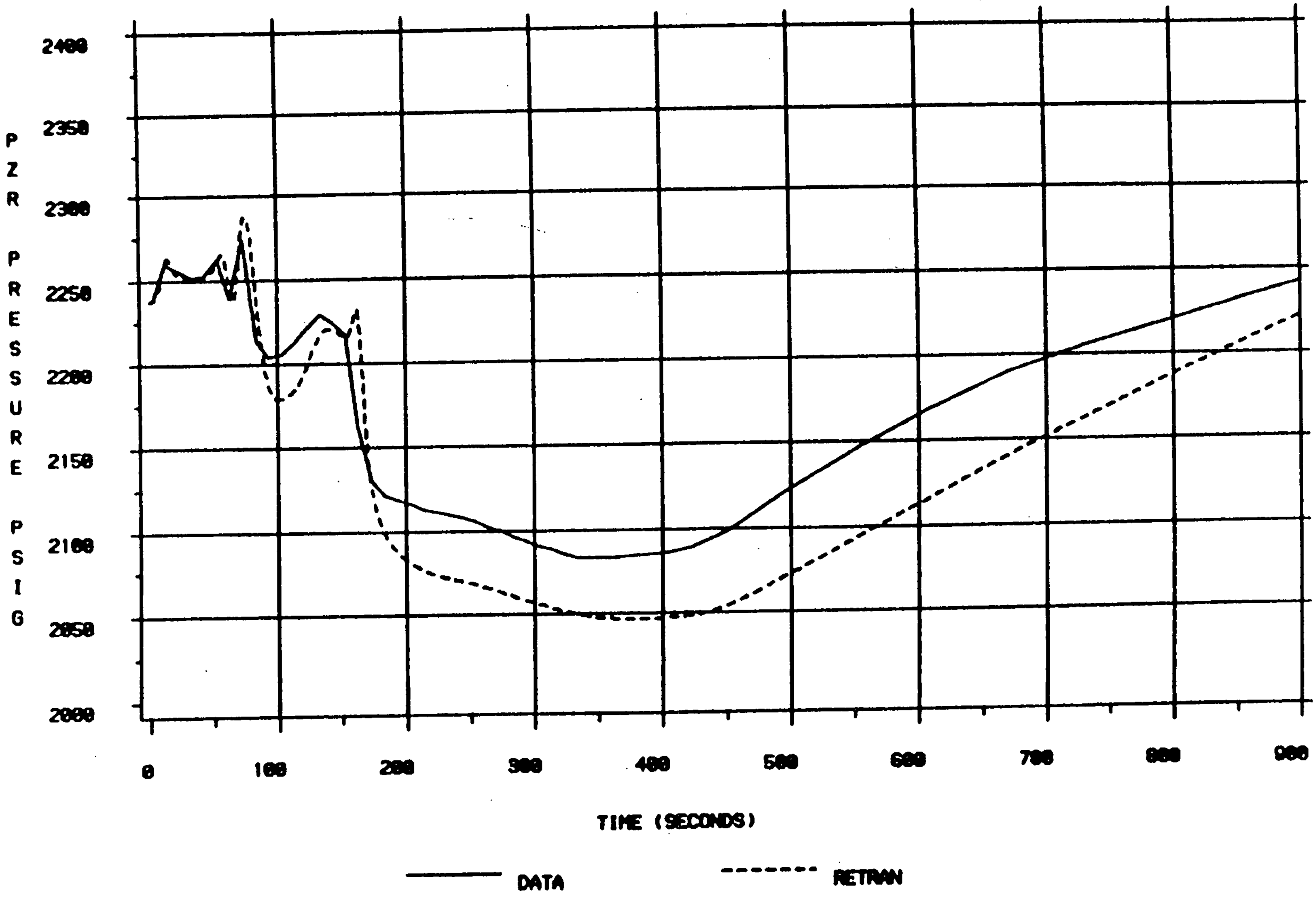


Figure 5.1.1-2

MNS-2 LOSS OF MAIN FEEDWATER

6/10/83 EVENT

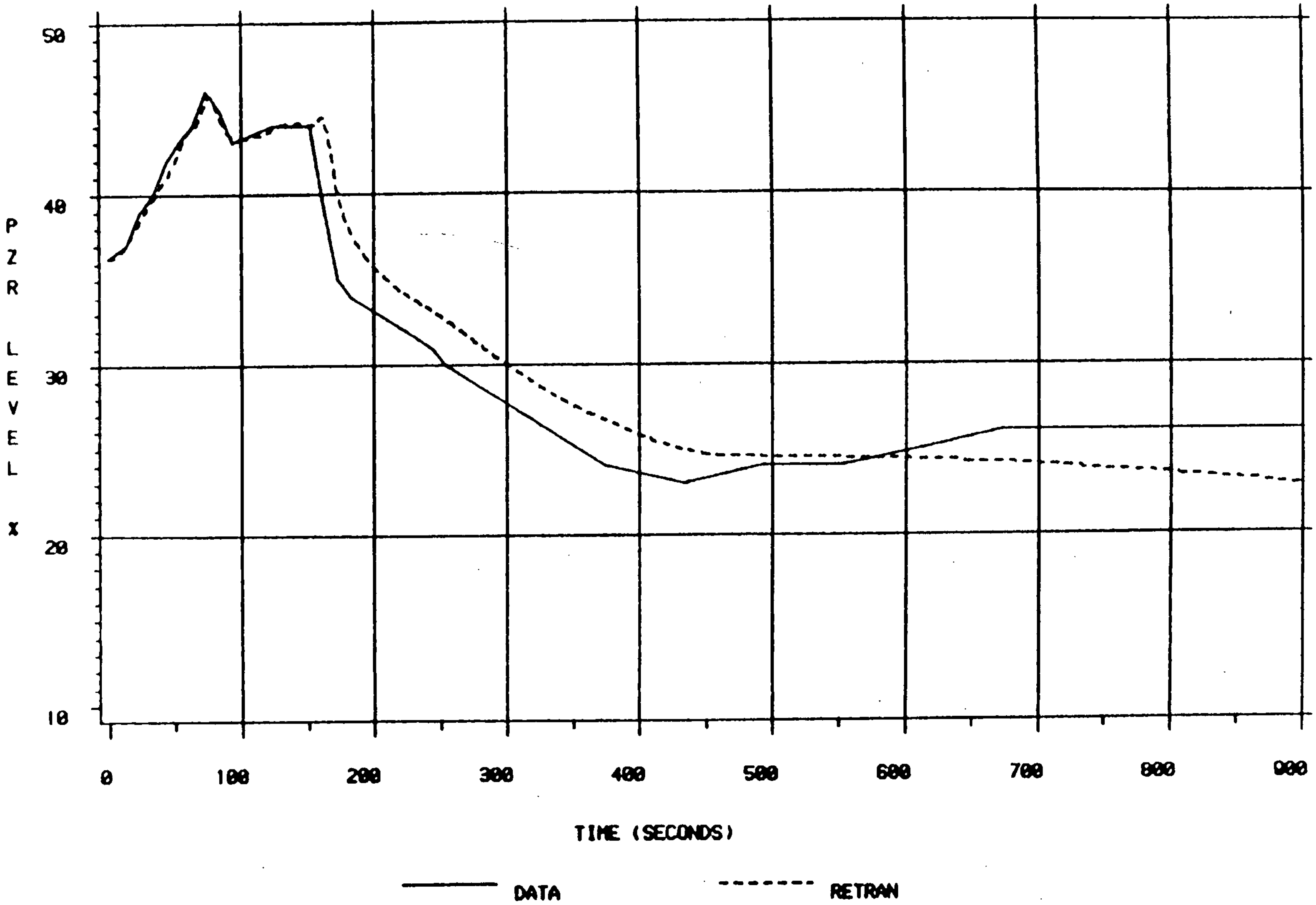


Figure 5.1.1-3

MNS-2 LOSS OF MAIN FEEDWATER

6/10/83 EVENT

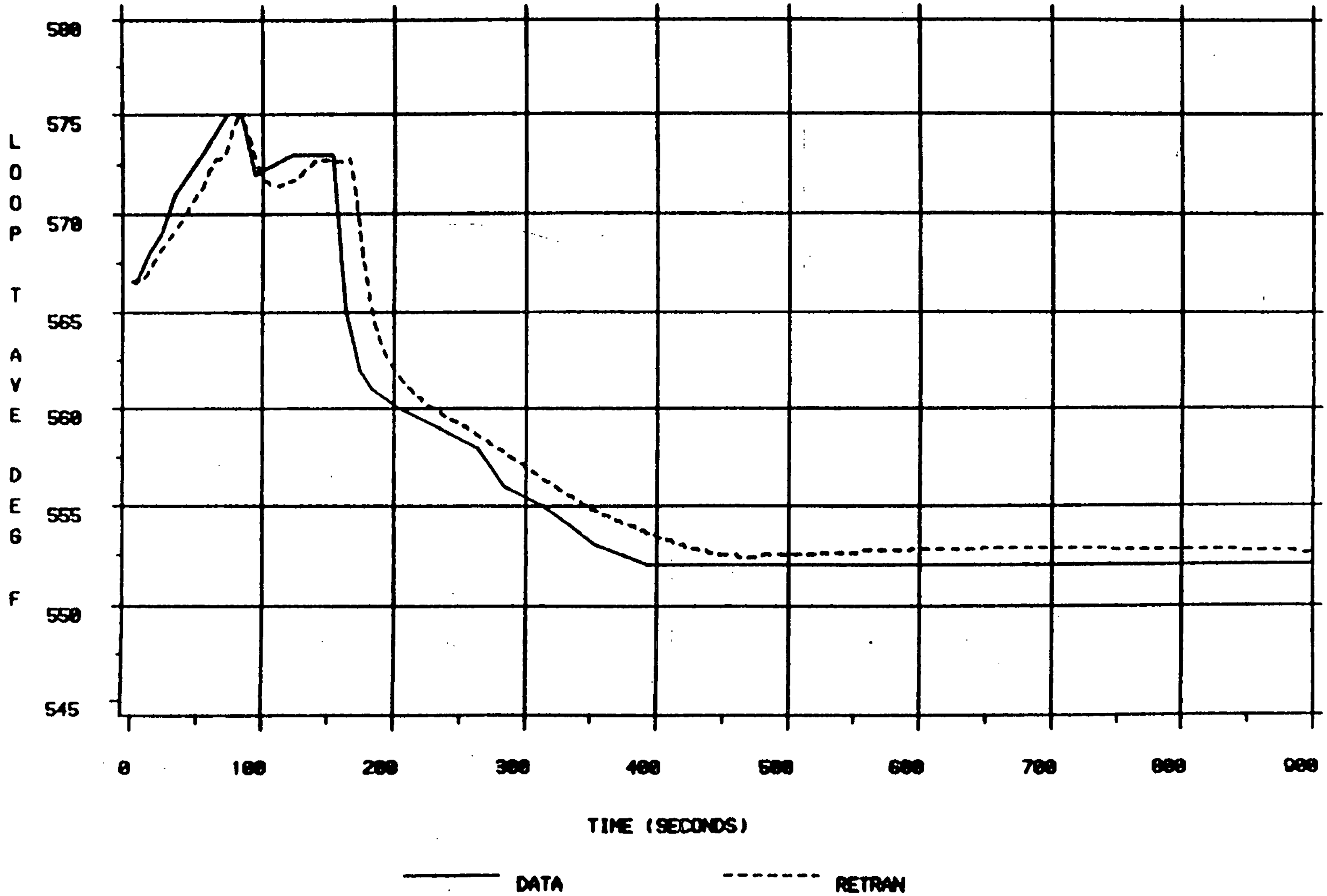


Figure 5.1.1-4

MNS-2 LOSS OF MAIN FEEDWATER

6/18/83 EVENT

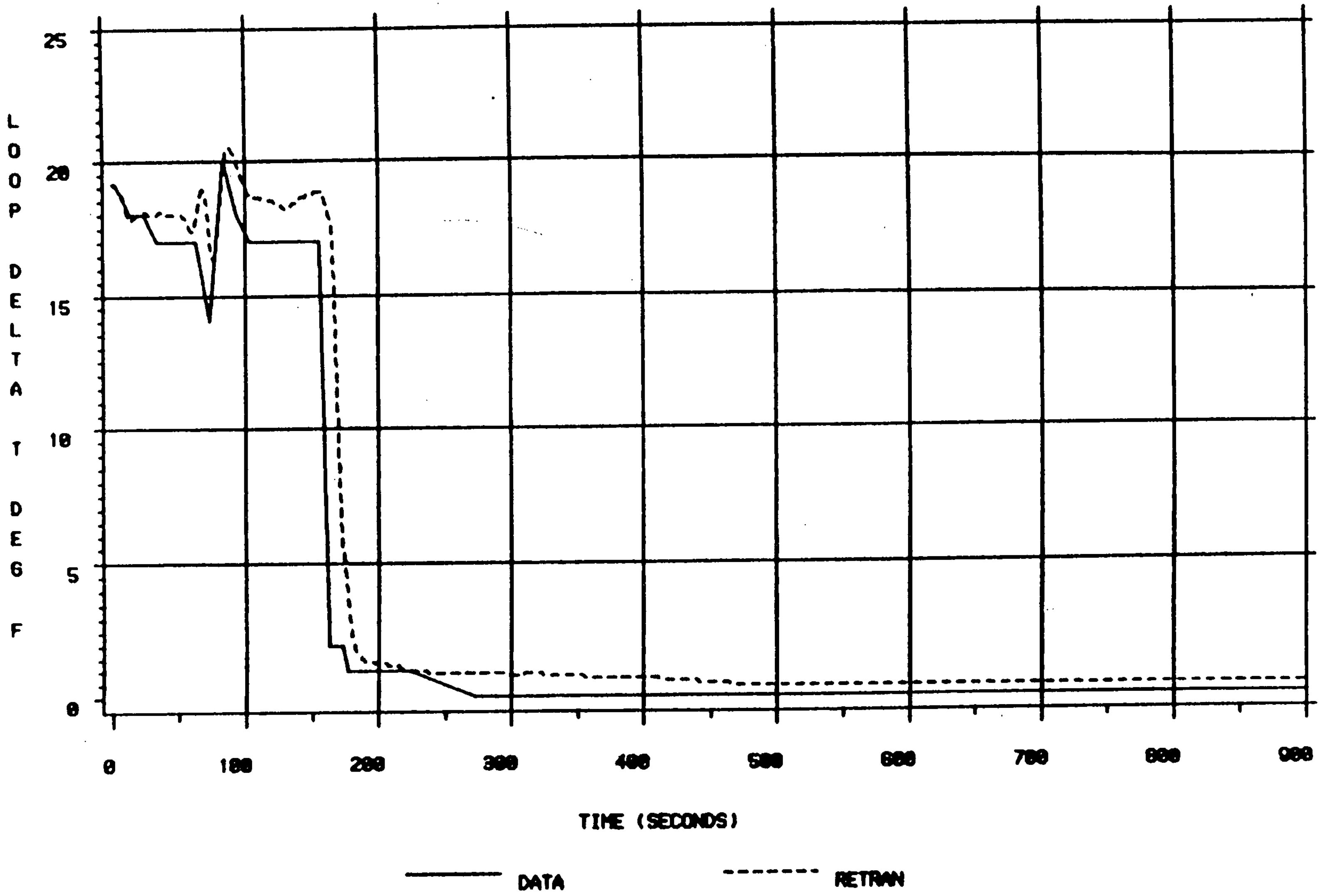


Figure 5.1.1-5

MNS-2 LOSS OF MAIN FEEDWATER

6/10/83 EVENT

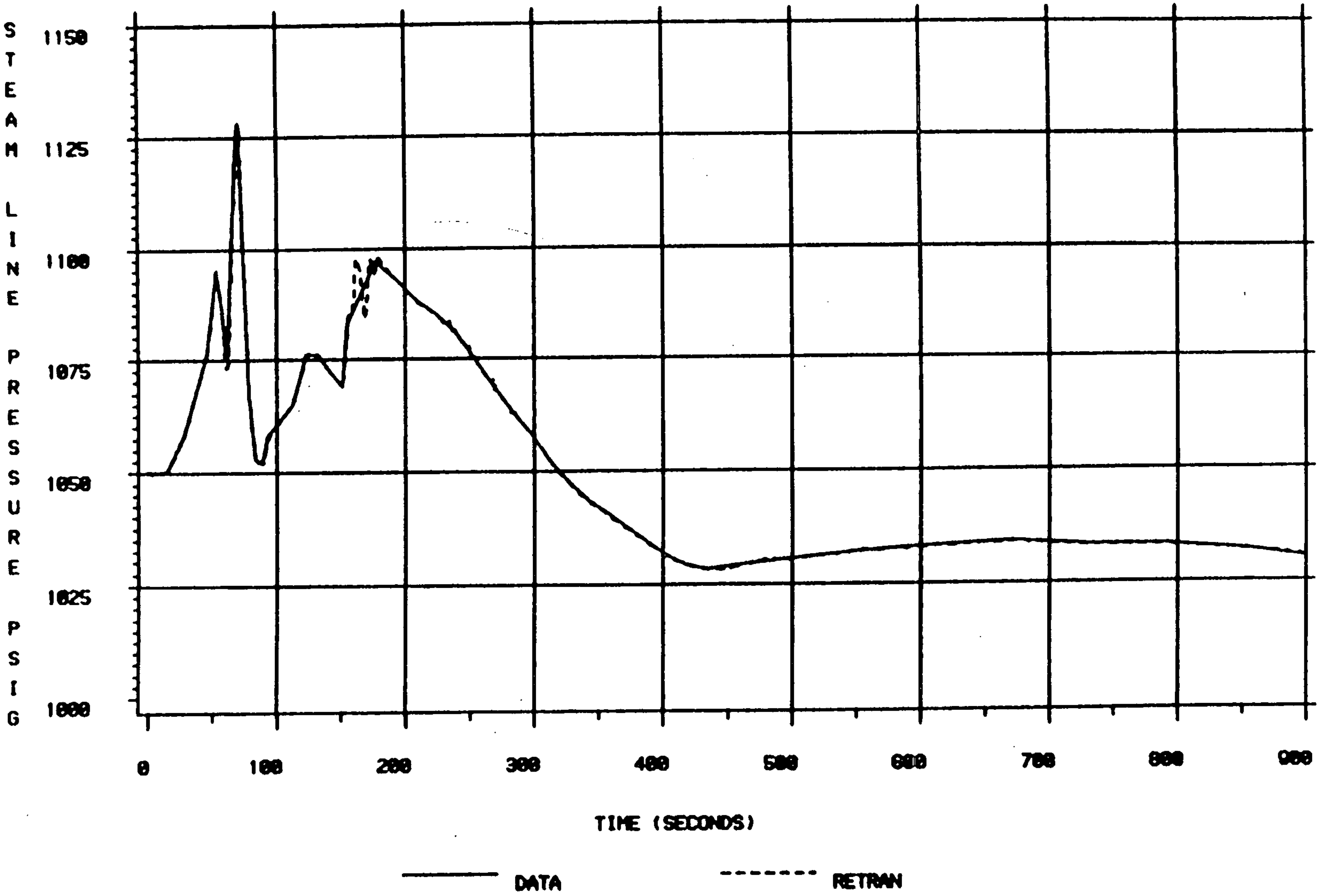


Figure 5.1.1-6

MNS-2 LOSS OF MAIN FEEDWATER

6/10/83 EVENT

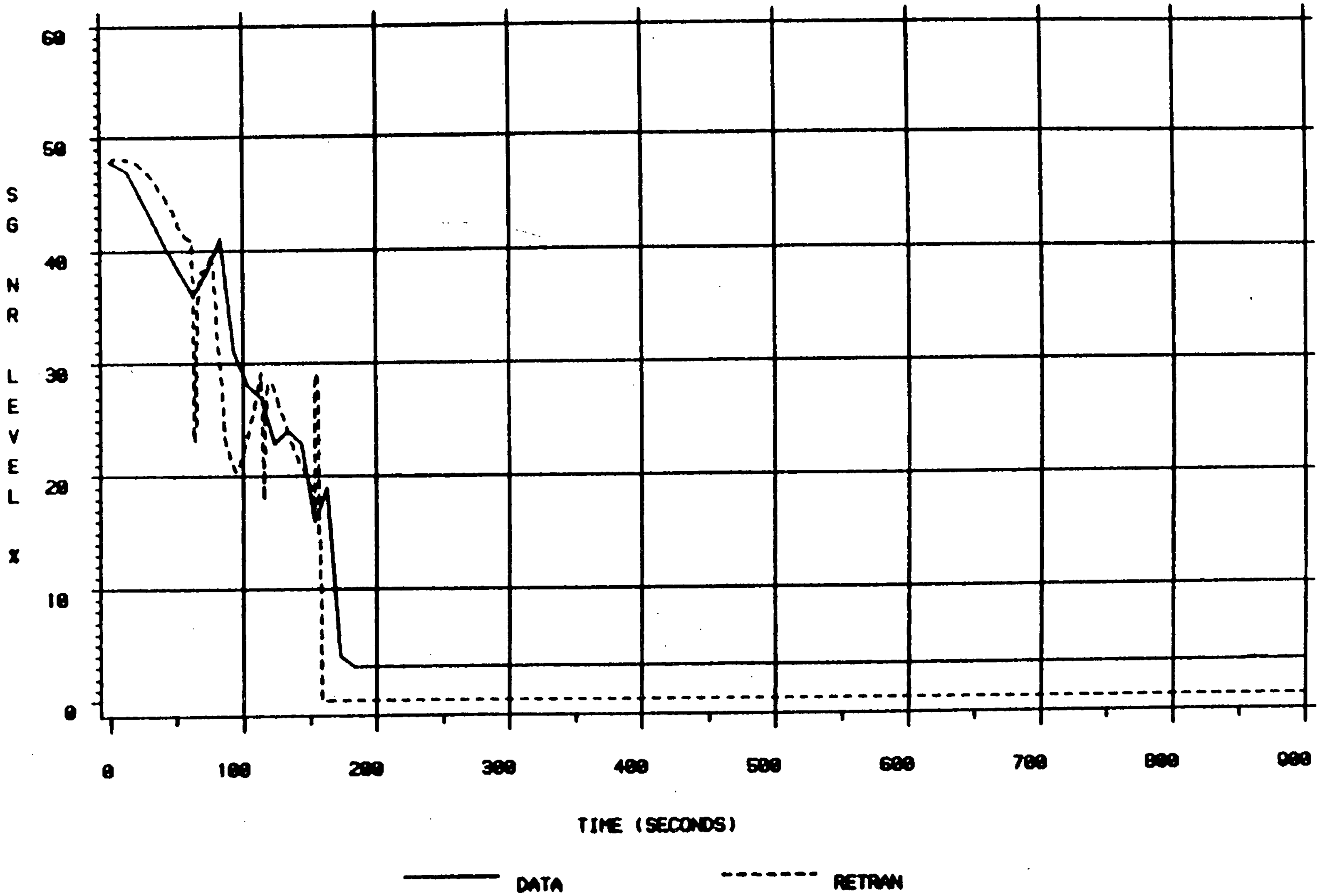


Figure 5.1.1-7

5.1.2 McGuire Nuclear Station Unit 2
Loss of Main Feedwater to One Steam Generator
June 24, 1985

Transient Description

McGuire Unit 2 was operating at 100% when CF-28, the MFW isolation valve to the lower nozzle on SG "C", failed closed. Level began to decrease due to the mismatch between steam flow and feed flow. The reactor tripped on low-low narrow range level in SG "C". The low-low level signal started both motor-driven AFW pumps. Flow from both pumps was throttled by the operators to maintain flow in the unaffected SGs near the no-load setpoint and to recover level in SG "C". MFW flow was isolated as designed on low RCS average temperature coincident with reactor trip. Pressurizer pressure and level dropped due to the post-trip coolant contraction. Level stabilized near the no-load setpoint while pressure was recovered by the pressurizer heaters. Minimum values reached were 23.5% and 1987 psig. The condenser dump valves and steam line PORVs controlled secondary pressure after reactor trip, stabilizing it at approximately 1070 psig. Narrow range level was eventually recovered in SG "C", reaching the no-load setpoint approximately 45 minutes post trip, after decreasing to a minimum of approximately 20% wide range.

Discussion of Important Phenomena

Aside from the general stabilization response common to most reactor trips, the transient exhibited several responses characteristic to an asymmetric loss of heat sink. First, the narrow range level in the affected steam generator dropped due to the mismatch of steam and feed flows, ultimately causing a reactor trip at 39 seconds at a setpoint of 40%. Careful modeling of both the static and dynamic effects on pressure difference type level instrumentation is necessary to accurately predict the rate of level decrease and the time at which reactor trip occurs. The decrease in feedwater flow to the affected steam generator caused an increase in the preheater temperature. This reduced the primary-to-secondary temperature difference results in a small primary

side ΔT decrease through SG "C". This caused RCS average temperature in loop "C" to increase, and ΔT in loop "C" to decrease, with respect to their steady-state pre-trip values.

Model Description

The plant response during this event showed definite asymmetry in loop "C" with respect to the loops to which MFW flow was not isolated prematurely. Therefore a two-loop McGuire Unit 2 model was used for the analysis. This model is very similar to the McGuire Unit 1 model but has unit-specific primary loop flow and loss coefficient modeling. The RCS flow specified in the simulation was chosen to match ΔT. To account for differences in recorded lift setpoints, the four steam line PORVs were modeled as separate junctions. The plant initial conditions were matched as follows:

Initial Conditions

	Model	Plant
Power Level	100% (3411 MWt)	100% (3411 MWt)
PZR Pressure	2235 psig	2235 psig
PZR Level	59.2%	59.2%
T-ave	588.1°F	588.1°F (ave)
ΔT	56.0°F	56.1°F (ave)
Steam Line Pressure	1011 psig	1011 psig (ave)
SG Level	66.3%	66.3% (ave)
MFW Temperature	439.4°F	439.7°F (ave)
MFW Flow	15.1×10^6 lbm/hr	15.1×10^6 lbm/hr

The problem boundary conditions used are cycle-specific post-trip delayed neutron power and decay heat, MFW flow, and AFW flow. Normalized reactor power is input as described in Section 4.1.1. MFW and AFW flow vs. time information was input from transient monitor data. Charging and letdown flows were deemed to have little effect on the transient and are not modeled.

Simulation Results

The simulation begins with a steady-state condition a few seconds before SG "C" MFW flow perturbations start and continues for 15 minutes. The simulation is terminated when pressurizer pressure has recovered to its pre-trip value, the other parameters having previously stabilized. The sequence of events is given in Table 5.1.2-1, and the results of the simulation are compared to the plant data in Figures 5.1.2-1 through 5.1.2-10.

The pressurizer pressure response (Figure 5.1.2-1) shows the prediction increasing slightly above the data during the coolant expansion prior to reactor trip. [ ] The RETRAN prediction is slightly lower on reactor trip due to an undershoot in steam line pressure. The repressurization rates trend closely until approximately 250 second when the plant data begins to decrease. This decrease is due to the reopening of SV-19, the loop A steam line PORV, at 1082 psig. This spurious actuation was not modeled in the simulation. The remaining discrepancy between the RETRAN prediction and the plant data is possibly due to an uncertainty about the number of pressurizer heaters in operation during the transient. Prior to reactor trip, heater groups A, B, and D were in manual control, but no record was kept of whether they were on or off. Typically, heaters are placed in manual control so that they can be energized to compensate for spray flow used to equalize the pressurizer and RCS boron concentrations. Depending on the spray flow, one, two, or three heater groups may be necessary to keep from depressurizing. Since the simulation models all heater groups as being on, it is postulated that the slower repressurization in the data may be due to one or more heater groups being in manual control and off.

The pressurizer level response (Figure 5.1.2-2) trends the data closely until the second opening of SV-19, discussed above. The deviation caused by this drop in the data is maintained through the remainder of the simulation.

The steam line pressure responses (Figures 5.1.2-3 and 4) exhibit the same general shape, peaking sharply at turbine trip and steam dump opening and settling out to $\sim$ 1070 psig. RETRAN underpredicts the initial peak and the

initial minimum by ~ 10-15 psig. The observed reseat setpoints of the steam line PORVs were approximately 30 psi below the nominal value. The sharpness of the steam line pressure decrease in the prediction with respect to the data suggests that the operators may have changed the condenser dump valve control mode, from RCS average temperature control to steam header pressure control, sometime prior to steam line PORV closure. This manual action is part of the normal reactor trip response, is not recorded, and cannot be simulated accurately with respect to time of occurrence. With the dump valves in pressure control mode, they would close to smooth the steam pressure transient as the PORVs remained open below their nominal reseat setpoint. The other obvious difference between the predictions and data is the already discussed reopening of SV-19, which was caused by the dump valve closure.

SG NR level (Figures 5.1.2-5 and 6) predictions and data trend closely before reactor trip and during the sharp level drop immediately after trip. The spiking in the level predictions at approximately 80 seconds is associated with the steam pressure decrease caused by closure of two of the four steam line PORVs.

The RCS average temperature response (Figures 5.1.2-7 and 8) shows close agreement between predictions and data. The slight perturbation in the data around 300 seconds is caused by the spurious opening and closing of SV-19. RETRAN correctly predicts the pre-trip rise in loop "C" temperature due to the increase in preheater temperature after feedwater isolation.

The RCS ΔT (Figures 5.1.2-9 and 10) prediction agrees closely with the data. The loop "C" graph shows the decrease in ΔT due to the increase in cold leg temperature discussed above.

Table 5.1.2-1

McGuire Nuclear Station Unit 2

Partial Loss of Main Feedwater

June 24, 1985

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
SG "C" feedwater isolated	0	0
Rx trip on SG "C" low-low level	39	44
Condenser dump banks #1 and #2 open	43	44
SV-13 begins to open	43	49
SV-1 begins to open	49	50
SV-19 begins to open (first time)	49	*
Condenser dump bank #2 begins to close	49	53
SV-13 fully open	49	57
SV-1 fully open	55	58
Condenser dump bank #2 fully closed	52-64	58
Condenser dump bank #1 begins to close	55	63
Low T-ave MFW isolation signal	64	67
SV-19 fully open (first time)	64	*
Condenser dump bank #1 fully closed	67-82	**
SV-1 begins to close	76	73
SV-13 begins to close	100	73
SV-1 fully closed	108	81
SV-13 fully closed	108	81
SV-19 begins to close (first time)	126	*
SV-19 fully closed (first time)	132	*
Three condenser dump bank #1 valves begin to open	141-157	**
SV-19 begins to open (second time)	239	*
SV-19 fully open (second time)	254	*
Three condenser dump bank #1 valves reclose	268-311	**
SV-19 begins to close (second time)	336	*
SV-19 fully closed (second time)	342	*
End of simulation	N/A	900

Note: * SV-19 did not open in the simulation.

SV-1, 3, and 19 are the PORVs in steam lines "D", "B", and "A"

** Condenser dump bank #1 valves never fully close in the simulation

MNS-2 PARTIAL LOSS OF MAIN FEEDWATER

6/24/85 EVENT

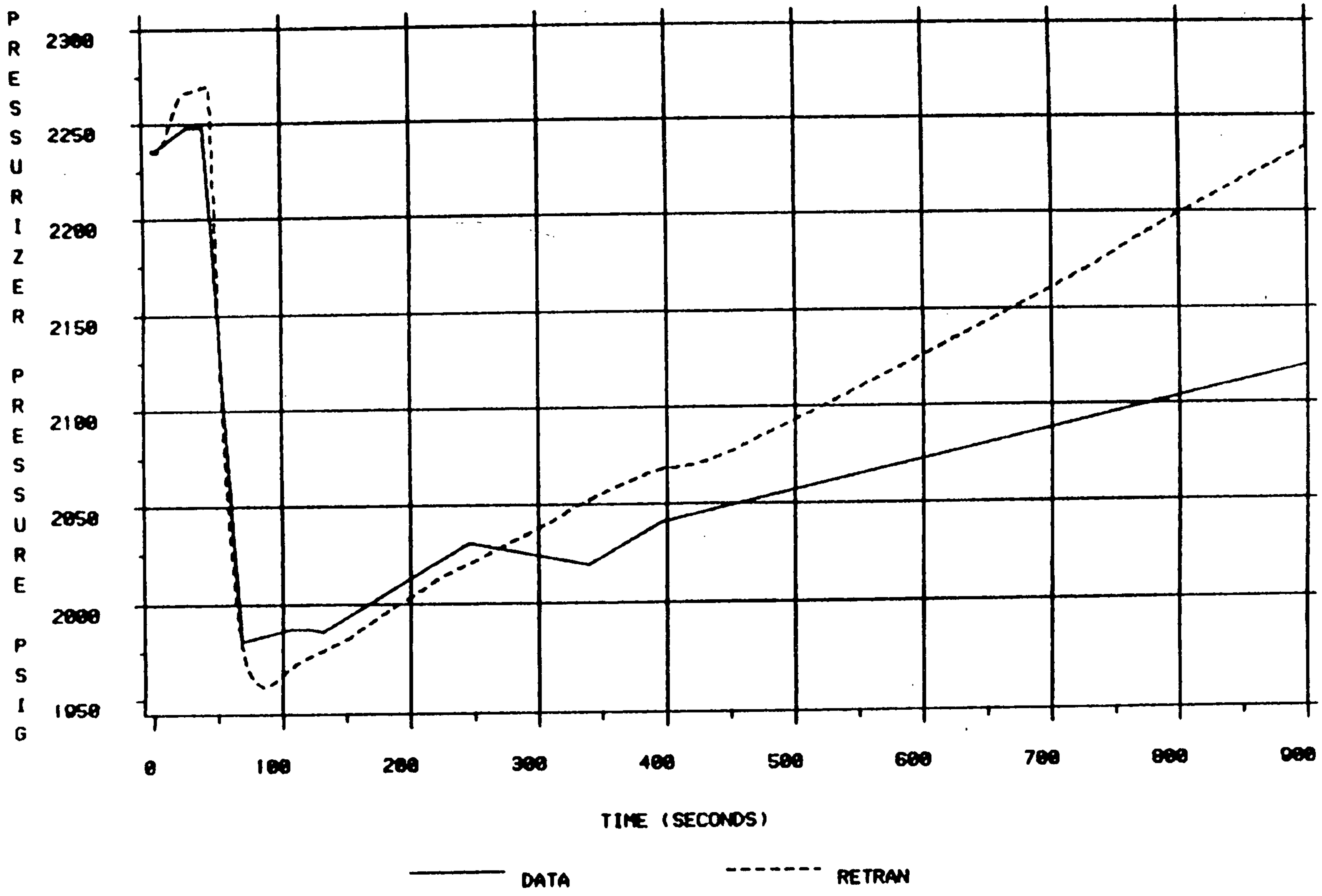


Figure 5.1.2-1

MNS-2 PARTIAL LOSS OF MAIN FEEDWATER

6/24/85 EVENT

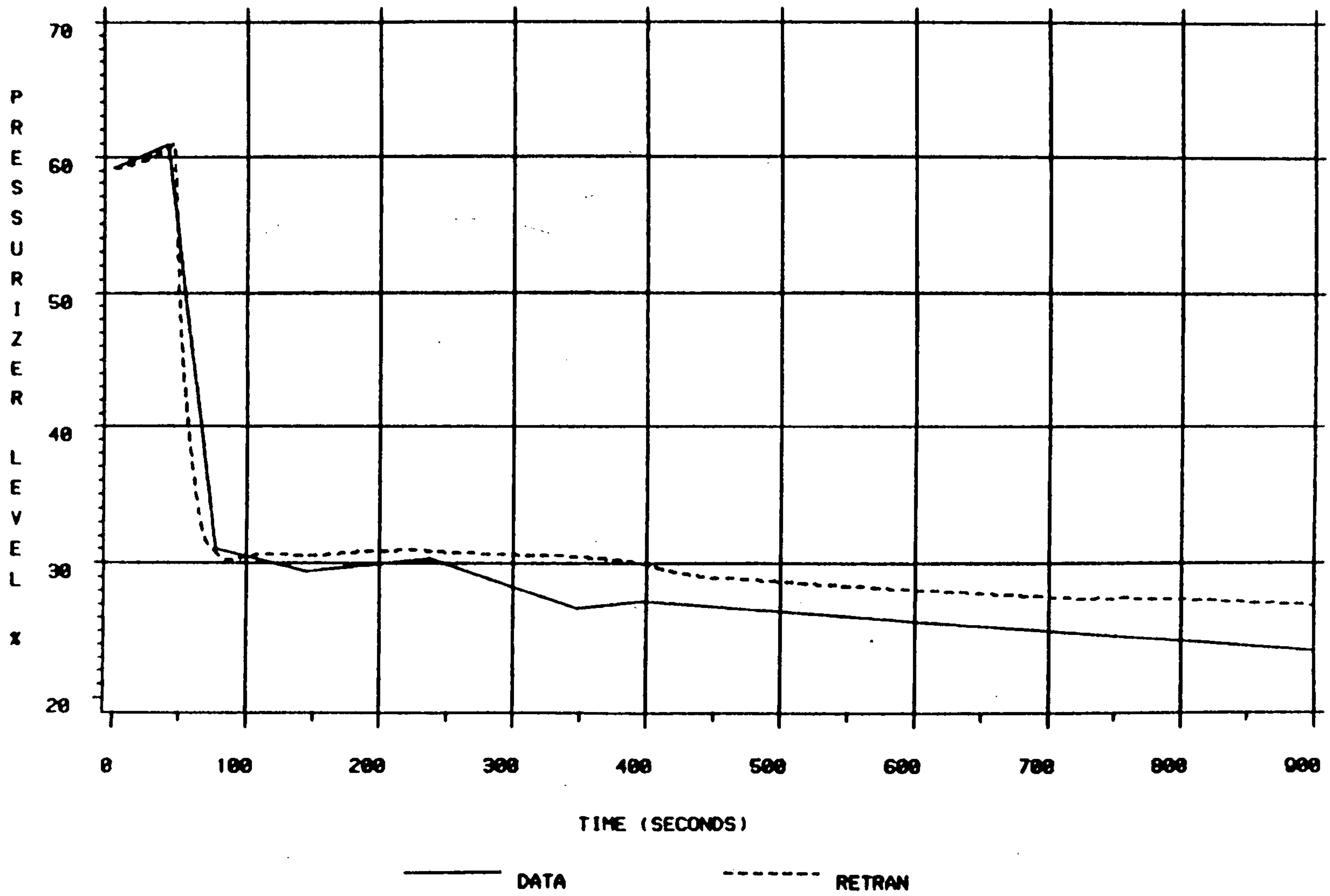


Figure 5.1.2-2

MNS-2 PARTIAL LOSS OF MAIN FEEDWATER

6/24/85 EVENT

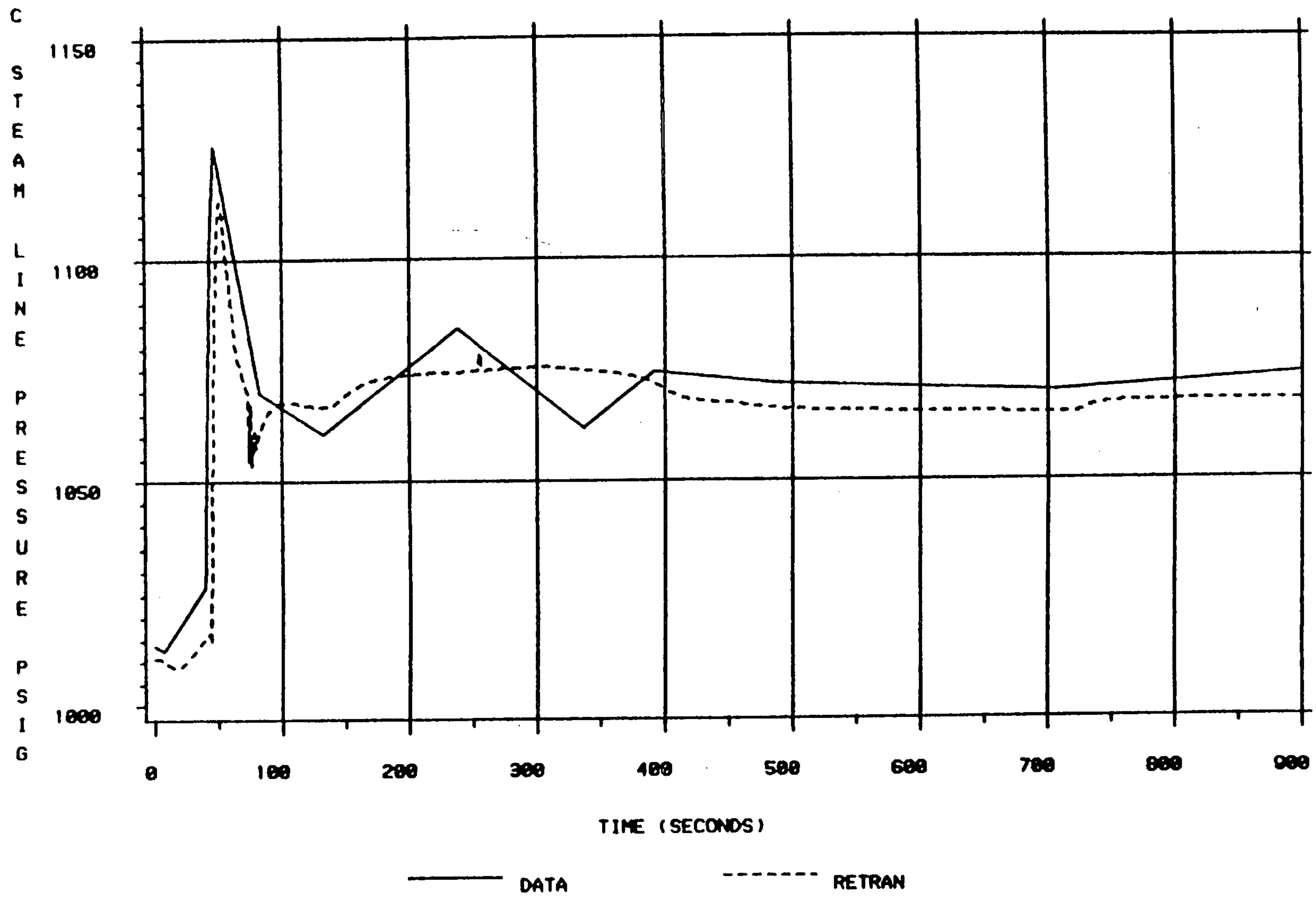


Figure 5.1.2-3

MNS-2 PARTIAL LOSS OF MAIN FEEDWATER

6/24/85 EVENT

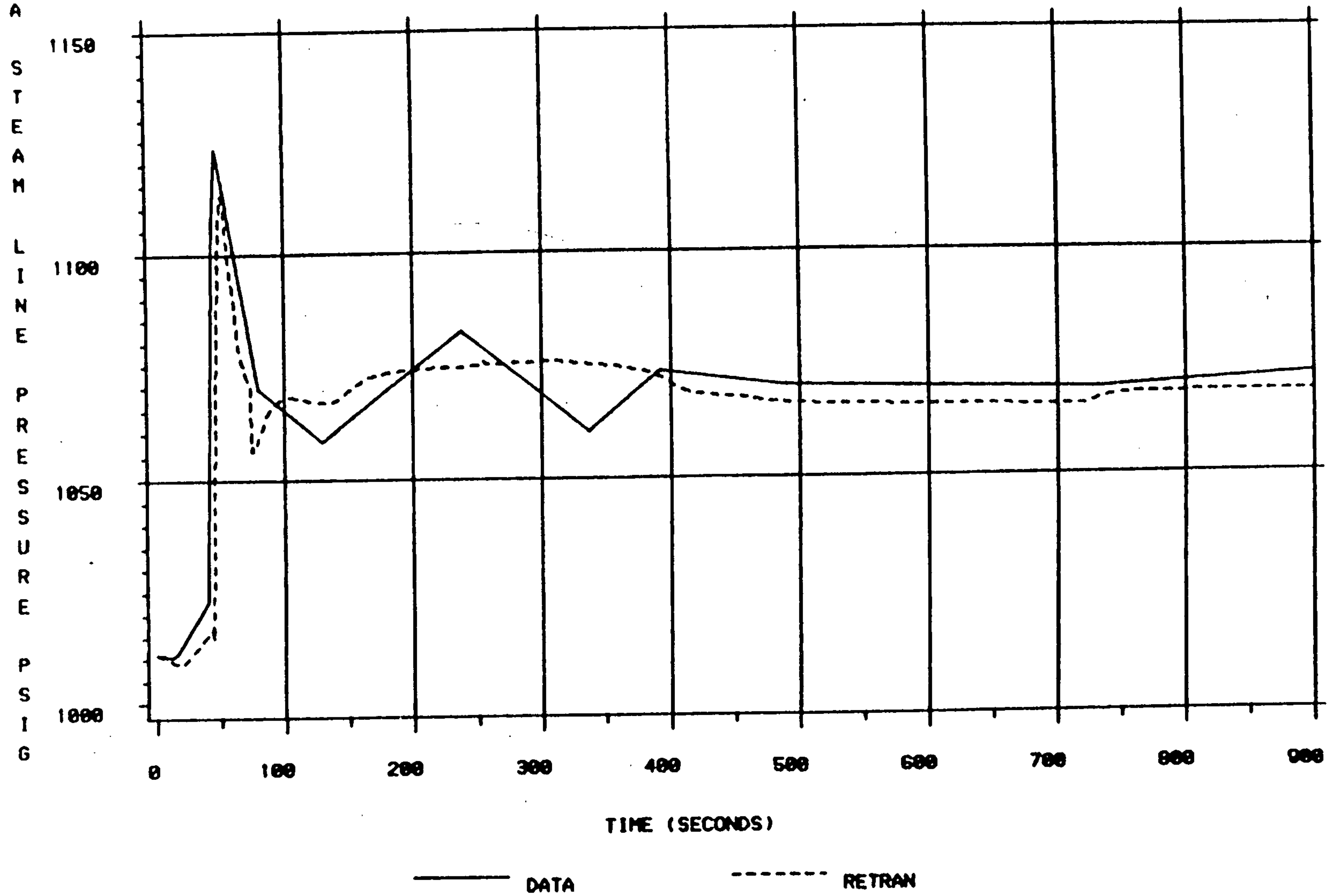


Figure 5.1.2-4

MNS-2 PARTIAL LOSS OF MAIN FEEDWATER

6/24/85 EVENT

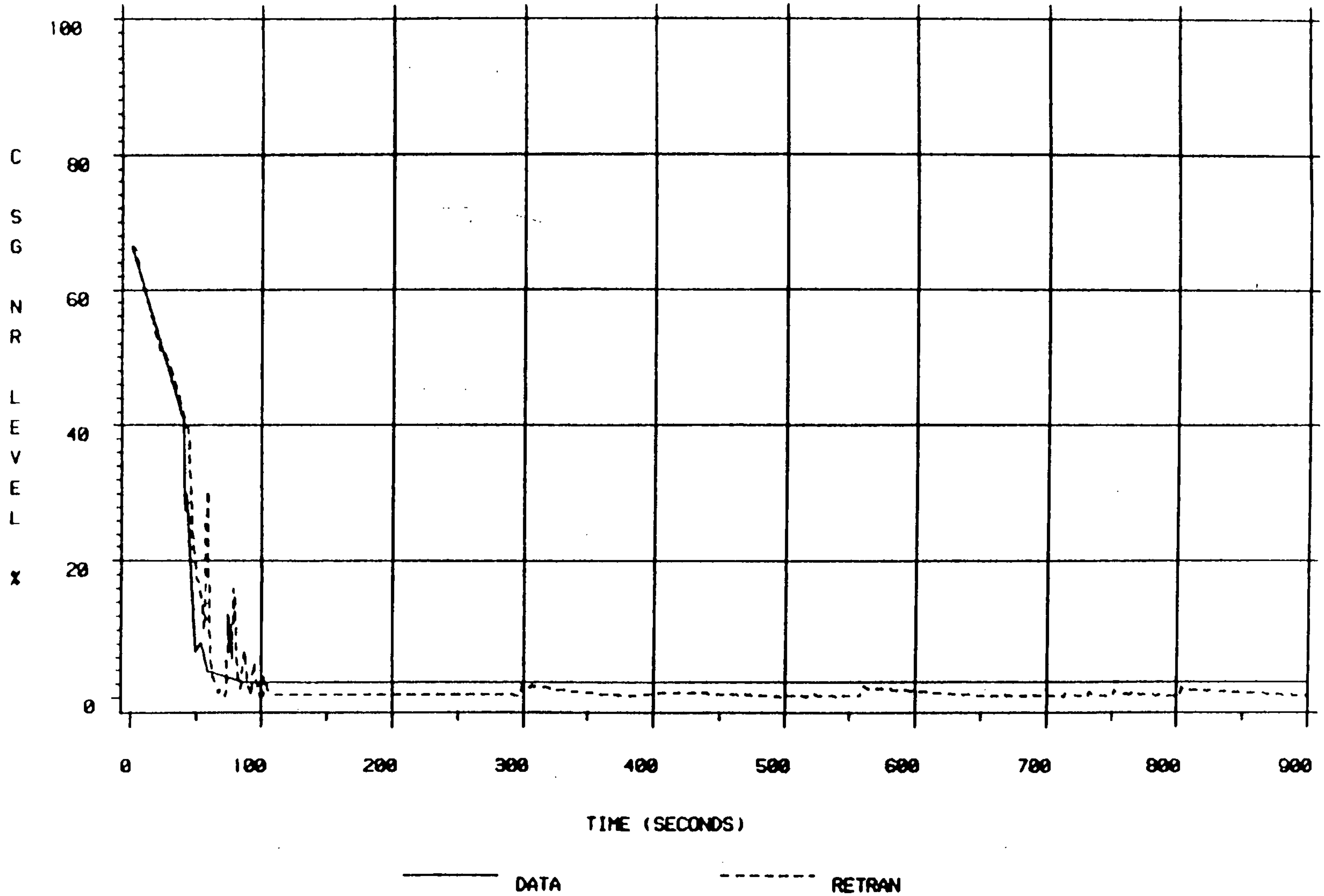


Figure 5.1.2-5

MNS-2 PARTIAL LOSS OF MAIN FEEDWATER

6/24/85 EVENT

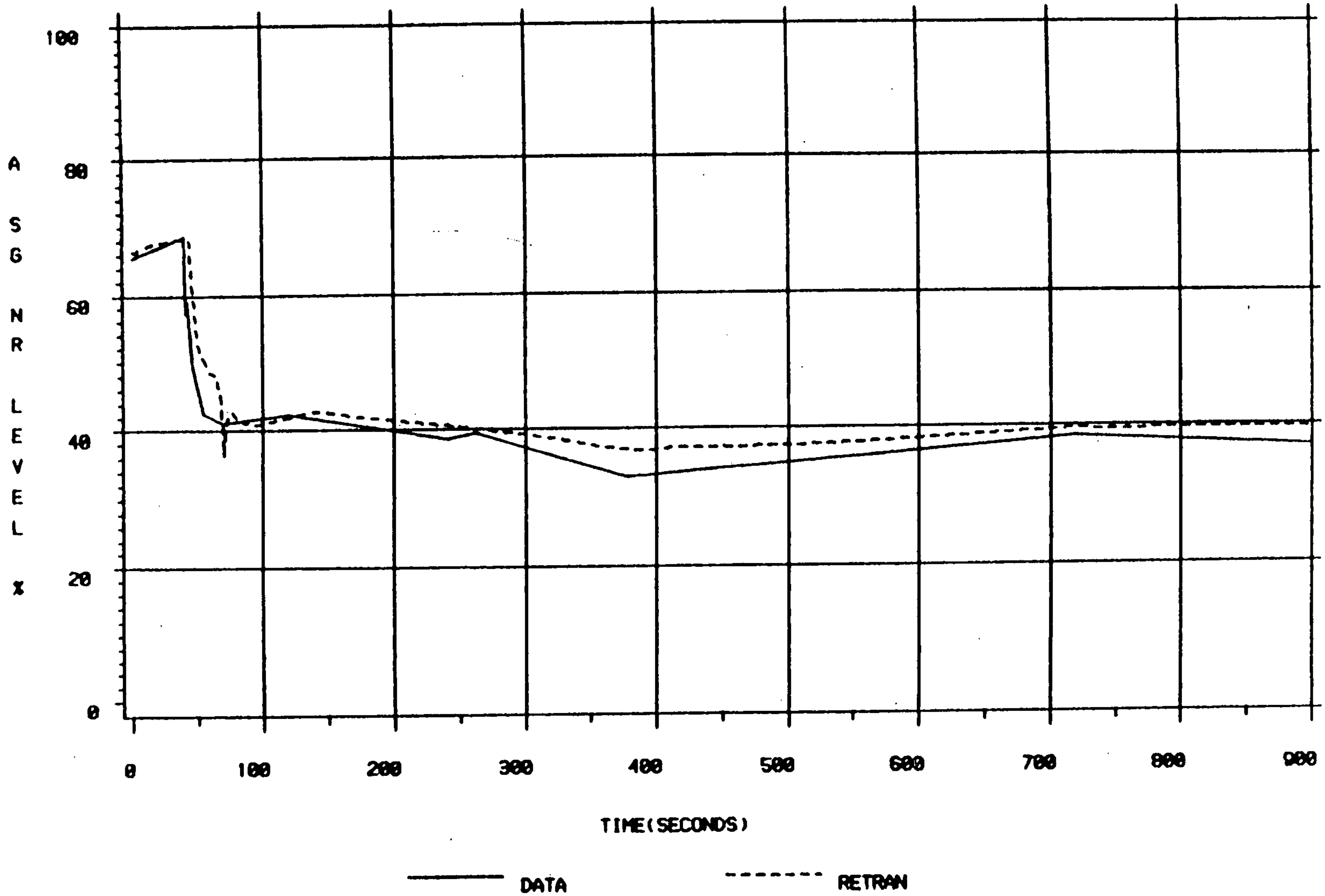


Figure 5.1.2-6

MNS-2 PARTIAL LOSS OF MAIN FEEDWATER

6/24/85 EVENT

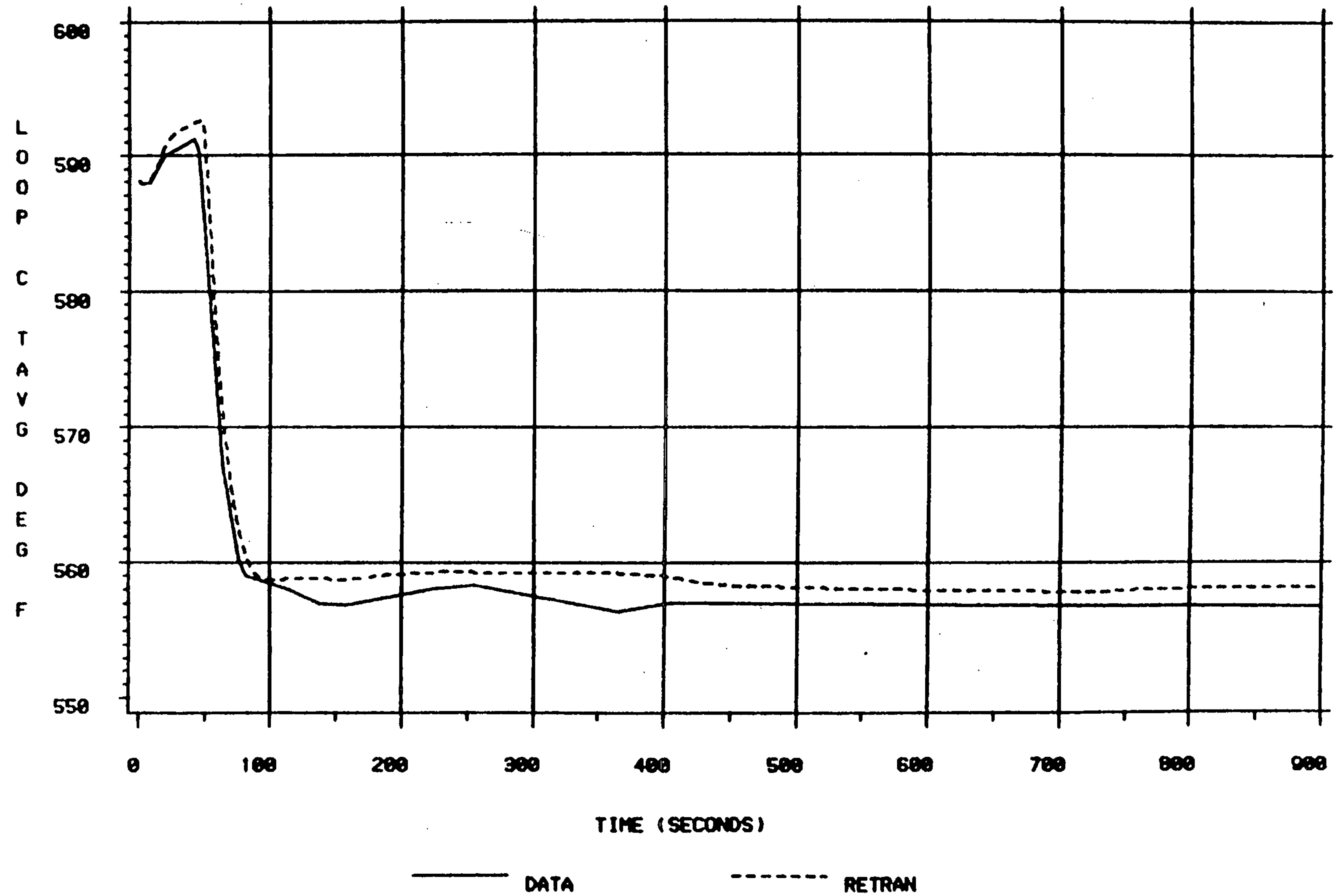


Figure 5.1.2-7

MNS-2 PARTIAL LOSS OF MAIN FEEDWATER

6/24/85 EVENT

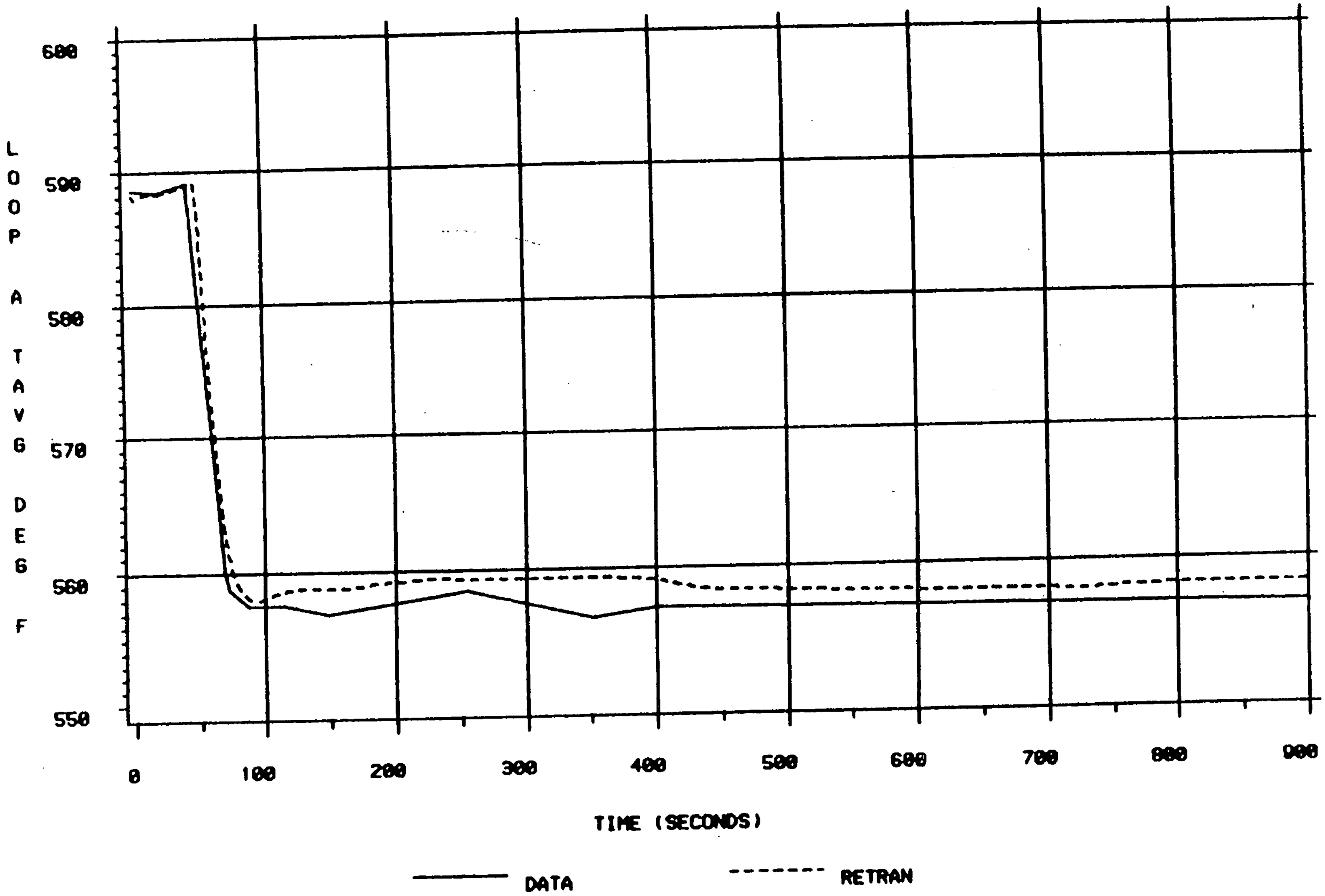


Figure 5.1.2-8

MNS-2 PARTIAL LOSS OF MAIN FEEDWATER

6/24/85 EVENT

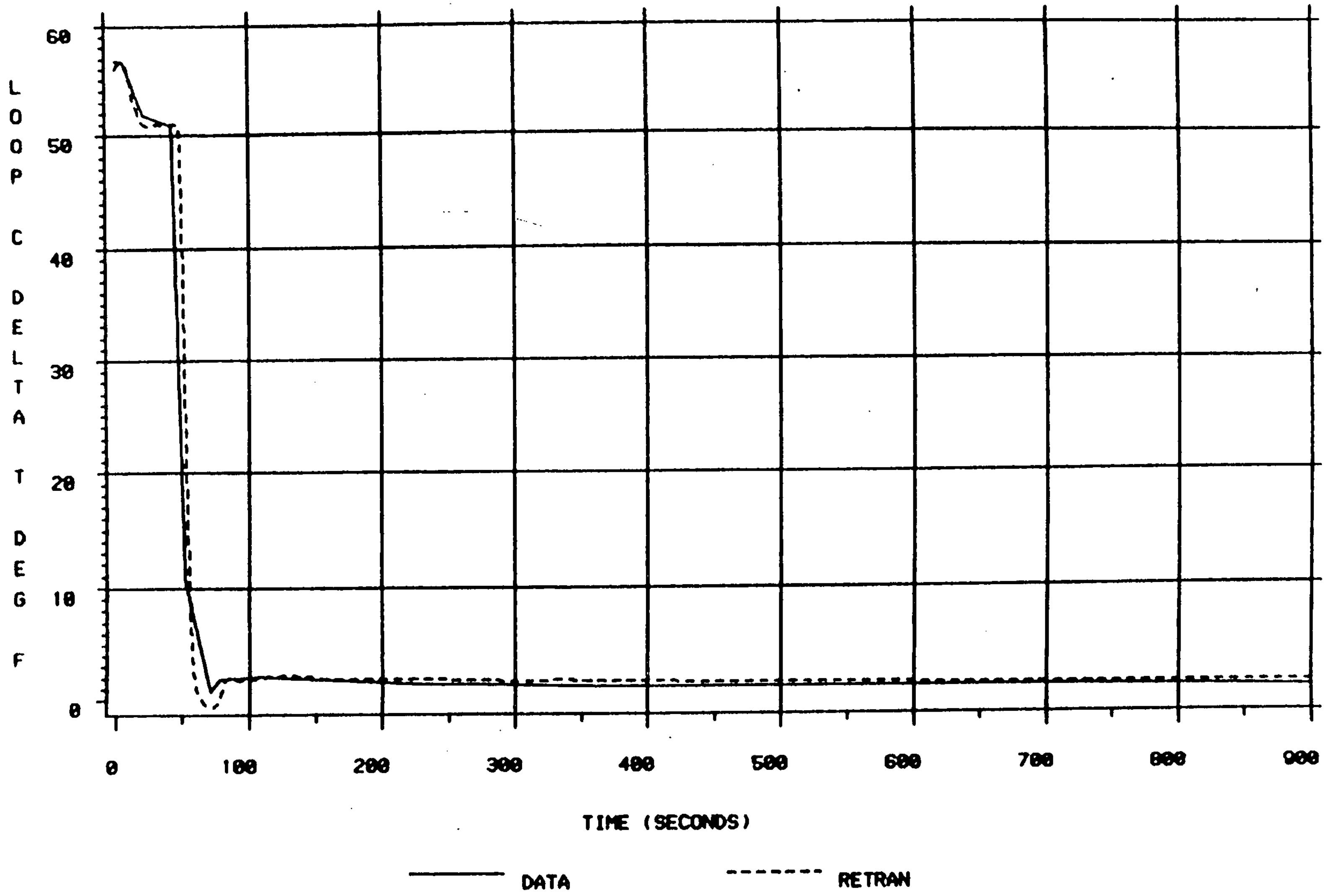


Figure 5.1.2-9

MNS-2 PARTIAL LOSS OF MAIN FEEDWATER

6/24/85 EVENT

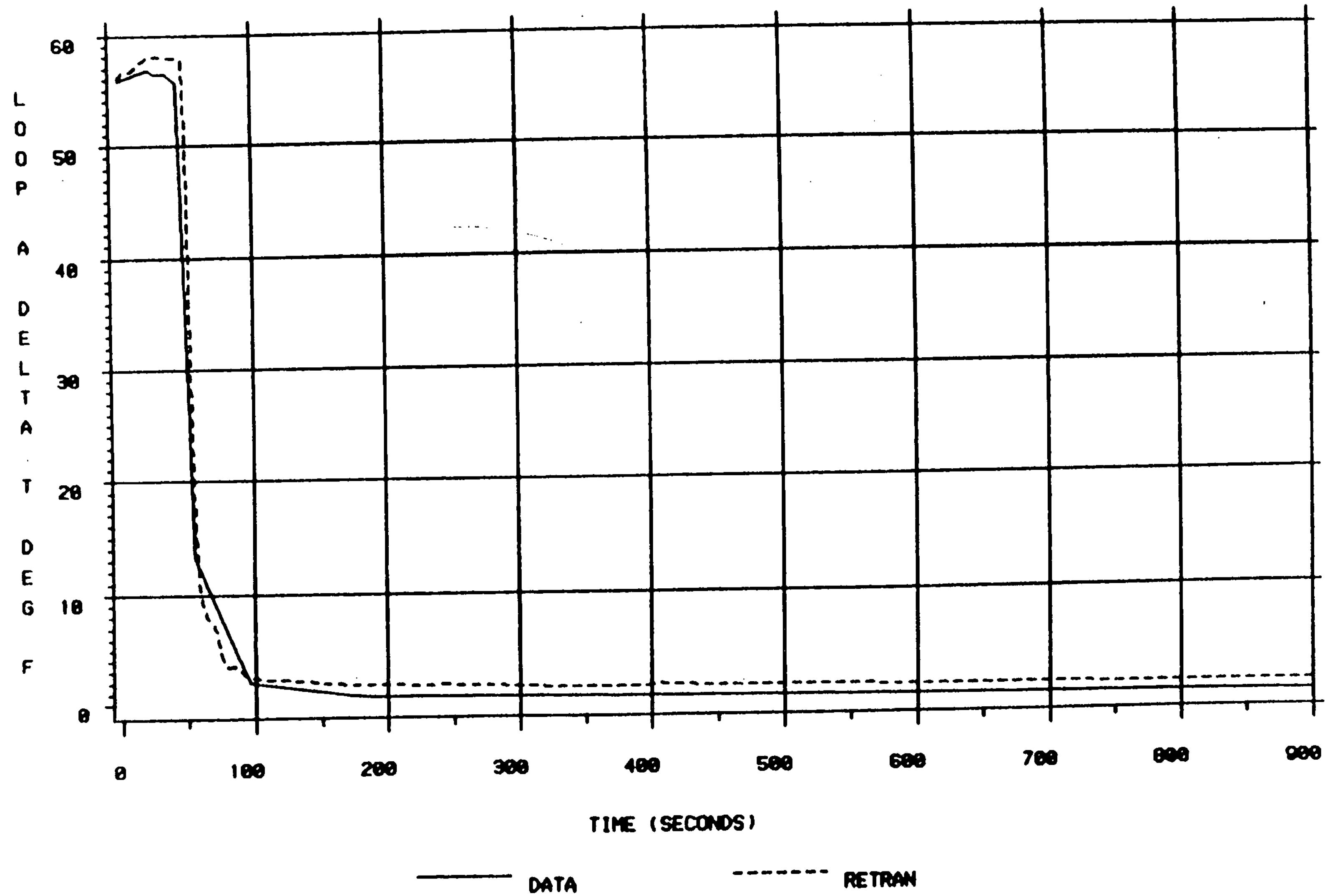


Figure 5.1.2-10

5.2 Excessive Secondary Heat Transfer

5.2.1 Catawba Nuclear Station - Unit 2
Steam Line PORV Failures
June 27, 1986

Transient Description

Catawba Unit 2 was operating at a stable condition of 24% full power when the unit was manually tripped per the Loss of Control Room test procedure. Control of the unit was then manually transferred to the auxiliary shutdown panel (ASP). The transfer of control to the ASP resulted in several valves automatically repositioning. During this time, the steam generator MSIVs closed, pressurizer heater banks A and B turned off, and the B MFW pump turbine tripped. Both motor-driven and the turbine-driven AFW pumps were automatically started on low-low level in all four SGs. Although the primary system temperature was gradually decreasing, pressurizer level fell rapidly due to a large difference between makeup and letdown resulting from the realignment of several flow control valves. Pressurizer level decreased from approximately 25% to 18% in the first five minutes post-trip. AFW flow recovered SG levels to 23% from a low of 13%.

The operators at the ASP are required to verify that the steam line PORV controllers are set such that they will not immediately open when the controlling breakers are energized. However, the PORV controllers had been modified and the controls not clearly labeled. The operators, unaware of the changes to the controller, increased valve demand while attempting to increase the lift setpoint above the actual steam line pressure. When the control breakers were energized approximately 270 seconds post trip, all four steam line PORVs opened and remained open until control was transferred back to the control room approximately six minutes later. The PORV openings resulted in a rapid depressurization of the secondary with an accompanying cooldown of the primary system. Pressurizer pressure and level went offscale low (1700 psig and 0%) approximately two minutes later. As primary and secondary pressure

decreased, safety injection signals were generated first on low-pressurizer pressure (1845 psig) and then on low steam line pressure (725 psig). However, safety injection actuation did not occur until control of the unit was transferred back to the control room. During the cooldown, the pressurizer emptied and RCS subcooling was temporarily lost.

Approximately eleven minutes after the manually initiated reactor trip, control was transferred back to the control room. Safety injection actuated and the steam line PORVs automatically closed on transfer back to the control room. Safety injection flow was sufficient to recover RCS pressure to approximately 1230 psig and pressurizer level to 33% five and a half minutes later.

Discussion of Important Phenomena

The transient being analyzed challenged the capability of RETRAN and the McGuire/Catawba RETRAN model to accurately simulate the plant response. The phenomena of interest in the simulation include excessive primary-to-secondary heat transfer, main steam relief, and primary system voiding.

The primary-to-secondary heat transfer rate controls the degree of overcooling and depressurization which may occur in the primary system. The ability to accurately model main steam relief and excessive heat transfer from the primary system is important in modeling primary system shrinkage, loss of subcooling, and void formation and elimination.

Model Description and Boundary Conditions

The plant response during the transient showed little asymmetry between loops so the one-loop Catawba Unit 2 RETRAN model was used for the analysis. The parameters used as initial conditions were matched, where possible, to the plant data. The McGuire RETRAN base model was modified to represent the important differences between McGuire Unit 1 and Catawba Unit 2. The RCS flow specified in the simulation was chosen in order to match plant ΔT. The initial conditions were matched to plant data as shown in the following table.

Initial Conditions

	Model	Plant
Power Level	24% (819 MWt)	24% (819 MWt)
PZR Pressure	2235 psig	2235 psig
PZR Level	29.0%	29.0%
T-ave	560.4°F	560.4°F
ΔT	14.9°F	14.9°F
Steam Line Pressure	1027 psig	1027 psig
SG Level	49.6%	49.6%
MFW Flow	3.1×10^6 lbm/hr	N/A
MFW Temperature	320.0°F	320.0°F

The problem boundary conditions include cycle specific post-trip delayed neutron power and decay heat, AFW flow, auxiliary steam loads, charging and letdown flows, and safety injection flow. The pressurizer heater banks were individually modeled to accurately reflect their status during the simulation. Control of the MSIVs was on elapsed time to simulate closure upon control being transferred to the ASP. The steam line PORVs were also controlled on elapsed time to simulate their modulation on transfer of control. The steam line PORV

[ ]

The charging and letdown flows were based on plant transient monitor data, and were modeled individually, as opposed to a net difference, in order to better simulate their impact on pressurizer level and RCS average temperature.

The safety injection flows used in the simulation represent best estimate flows determined by RETRAN simulation of the ECCS pumps and associated piping. Safety injection flow from the two HHSI pumps and the two IHSI pumps was controlled on elapsed time to accurately simulate their start and stop times during the transient.

Simulation Results

The simulation begins with the manual reactor trip required by the Loss of Control Room test procedure and continues for 20 minutes. The simulation is terminated at the point where pressurizer level and system pressure have stabilized and most plant parameters have returned to stable conditions. At the end of the simulation, pressurizer pressure and T-ave have not returned to their nominal post-trip values due to the severity of the primary system cooldown. The sequence of events is given in Table 5.2.1-1, and the results of the simulation are compared to the plant data in Figures 5.2.1-1 through 5.2.1-9.

The pressurizer pressure response, as shown in Figure 5.2.1-1, indicates that the initial RETRAN predicted pressure response trends very closely to the plant data until pressurizer pressure indication goes offscale low at 1700 psig. Upon opening the steam line PORVs, pressurizer pressure decreases at a rate equivalent to the plant response. The low pressurizer pressure safety injection signal is generated at similar times with RETRAN leading the plant response by 20 seconds. Both RETRAN and plant pressure indications go offscale low at nearly equivalent times as shown in Figure 5.2.1-1. The wide range RCS pressure prediction closely trends the plant response throughout the entire simulation as shown in Figure 5.2.1-2. A minimum system pressure of 710 psig occurs at approximately 678 seconds. Safety injection flow is sufficient to recover and maintain system pressure to approximately 1230 psig throughout the remainder of the simulation.

The pressurizer level response as shown in Figure 5.2.1-3 is very similar to the pressure response. Predicted level does not initially fall to the level indicated by the plant data. Low pressurizer level alarm and level off-scale low occur at times equivalent to the plant response. The RETRAN level recovery occurs approximately 60 seconds sooner than the plant. This is attributed to a slightly larger RETRAN safety injection flow than that indicated by the plant data as shown in Figure 5.2.1-9.

The reactor coolant system temperature response closely matches plant data. T-ave, like pressurizer pressure and level, does not decrease as rapidly in the first seconds post-trip as the plant data indicates. The predicted T-ave matches the plant trend from approximately 60 seconds after reactor trip until the steam line PORVs open. RETRAN and plant T-ave indications go offscale low (530°F) together as shown in Figure 5.2.1-4. Wide range hot leg and cold leg temperature indications, Figures 5.2.1-5 and 5.2.1-6, trend closely with the plant data throughout the entire simulation. The minimum RCS temperature of 475°F occurs 1200 seconds post-trip as shown in Figure 5.2.1-6.

The steam line pressure response is presented in Figure 5.2.1-7. Pressure increases approximately 20 psi above the plant data after reactor trip and remains slightly higher for approximately four and one-half minutes post-trip. The effect of the higher secondary side pressure is reflected in the RETRAN pressurizer pressure and level and primary system temperature having values slightly higher than the plant data during this time period. Upon opening the steam line PORVs, RETRAN pressure decreases at a rate equivalent to the plant data. A low steam line pressure SI signal is safety generated at a time equivalent to the plant response as shown in Table 5.2.1-1. RETRAN pressure increases slightly above the indicated plant condition and remains elevated from the time the PORVs close until the end of the simulation.

SG level response is shown in Figure 5.2.1-8. Level quickly falls below the low-low level setpoint upon reactor trip, resulting in the actuation of all three AFW pumps. RETRAN underpredicts the level during the first four minutes post-trip. The RETRAN level trends with the plant data during the time interval in which the steam line PORVs are open. Upon PORV closure, both RETRAN and plant level indications go offscale low. However, the plant data indicates a quicker level recovery than RETRAN beginning at 720 seconds, [

]

Table 5.2.1-1

Catawba Nuclear Station Unit 2
Steam Line PORV Failures
June 27, 1986

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
Manual reactor trip	0	0
PZR heater banks A and D on	11	8
AFW actuation on low-low SG level	18	25
MSIV closure and PZR heater bank A off on transfer of control of ASP*	38	38
PZR heater bank B off on transfer of control to ASP*	48	48
Steam line PORVs open*	288	288
PZR heater banks C and D off on level < 17.2%	302	305
T-avg offscale low (530°F)	413	415
Low PZR pressure (1845 psig) safety injection signal generated	445	425
PZR pressure offscale low (1700 psig)	485	473
Low steam line pressure (725 psig) safety injection signal generated	**	485
Safety injection actuation on transfer of control to control room*	655	655
Minimum RCS pressure	655	675
Steam line PORVs close on transfer of control to control room*	671	671
PZR level on-scale (>0%)	790	726
Safety injection manually terminated*	995	995
End of simulation	N/A	1200

Note: Single asterisk designate boundary conditions
Double asterisks indicate plant data unavailable

CNS-2 STEAM LINE PORV FAILURE

6/27/86 EVENT

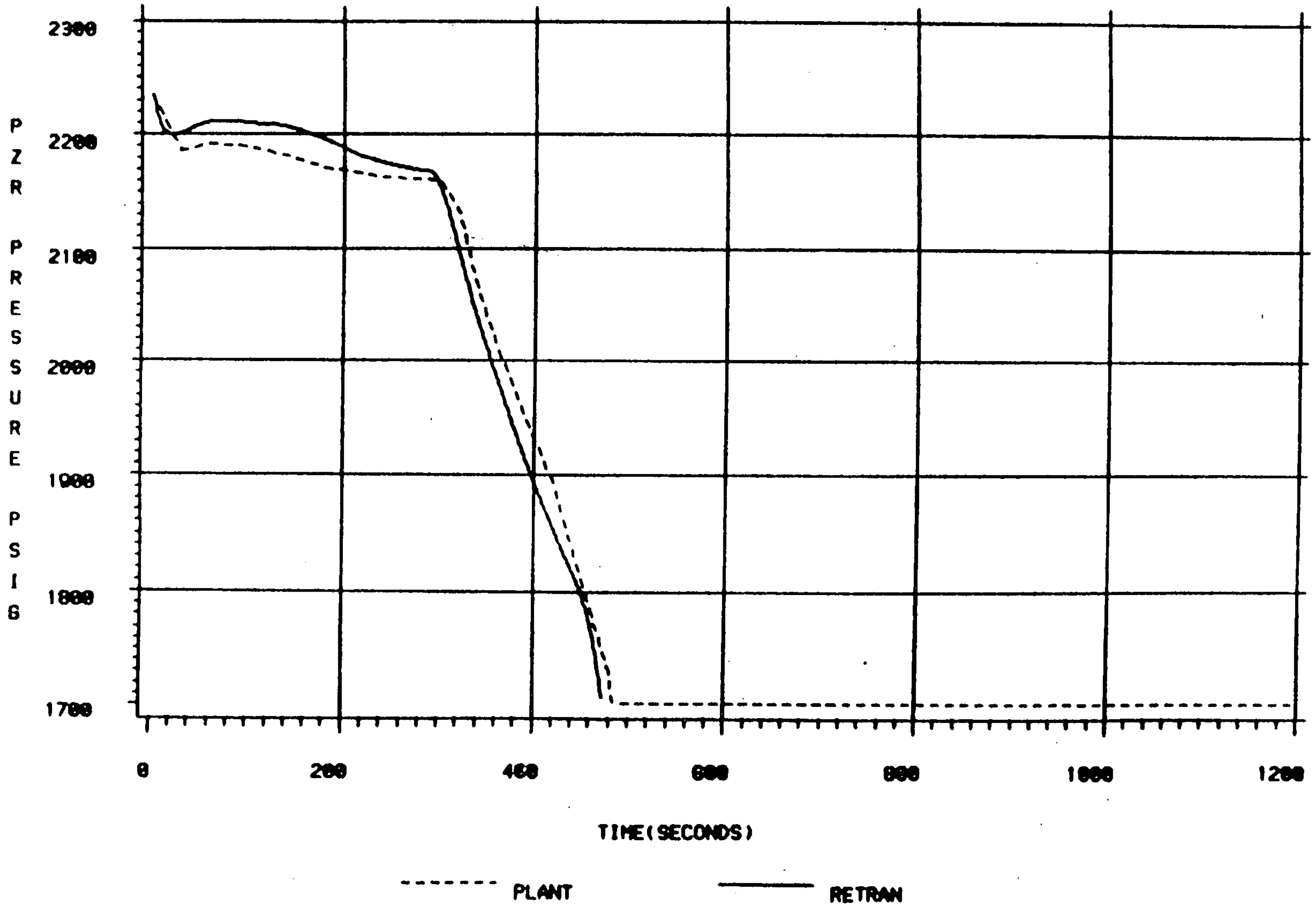


Figure 5.2.1-1

CNS-2 STEAM LINE PORV FAILURE

6/27/86 EVENT

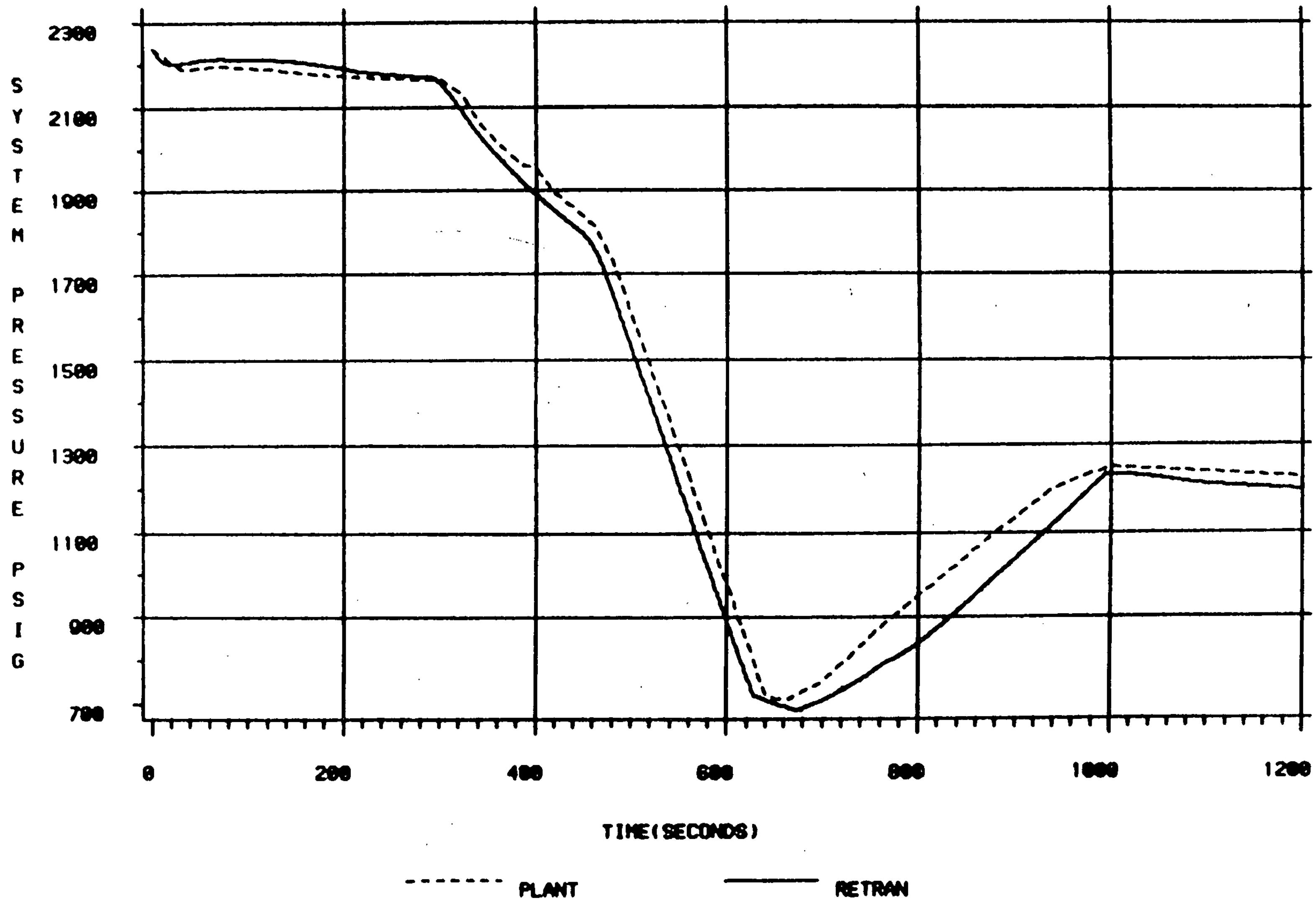


Figure 5.2.1-2

CNS-2 STEAM LINE PORV FAILURE

6/27/86 EVENT

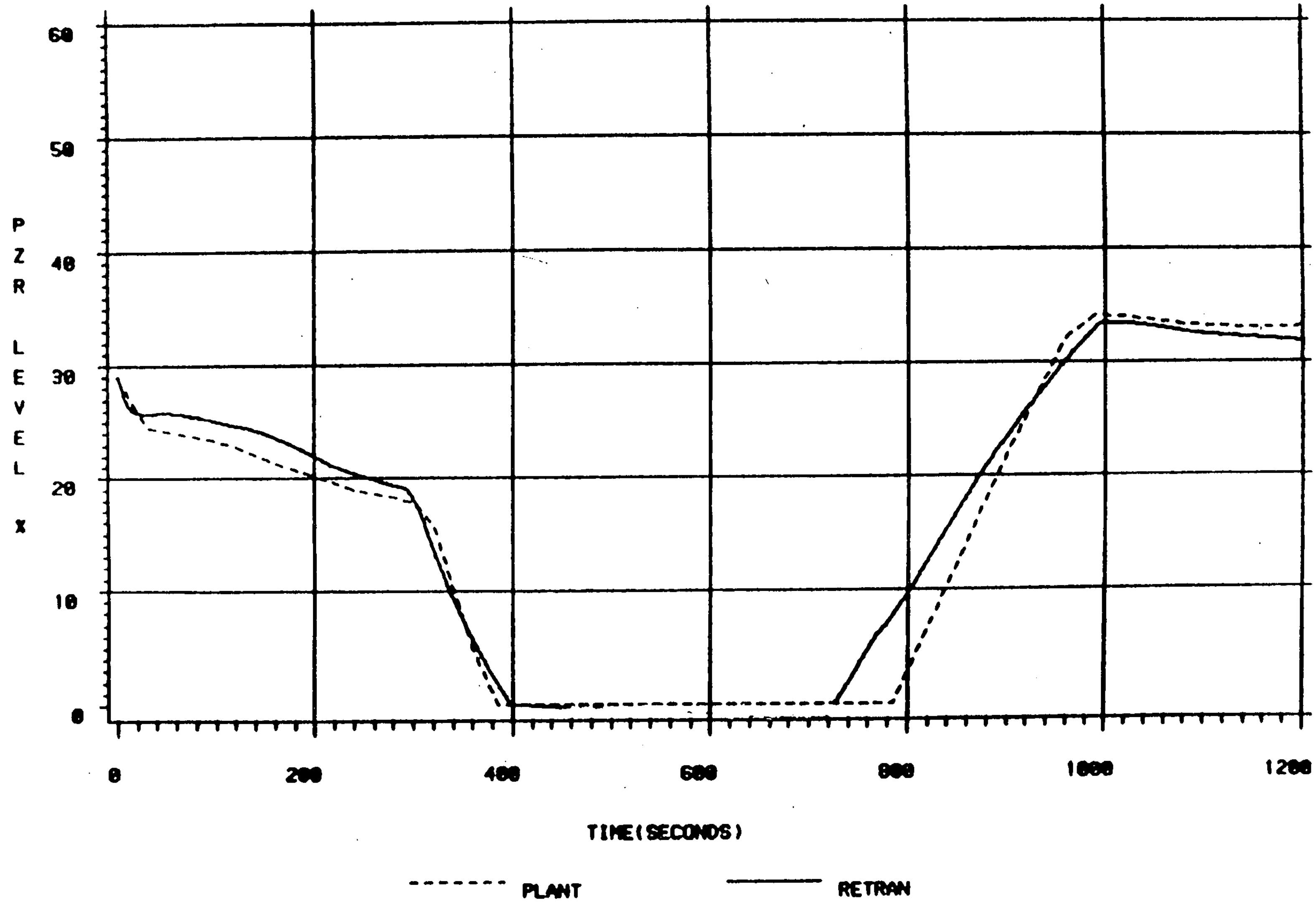


Figure 5.2.1-3

CNS-2 STEAM LINE PORV FAILURE

6/27/86 EVENT

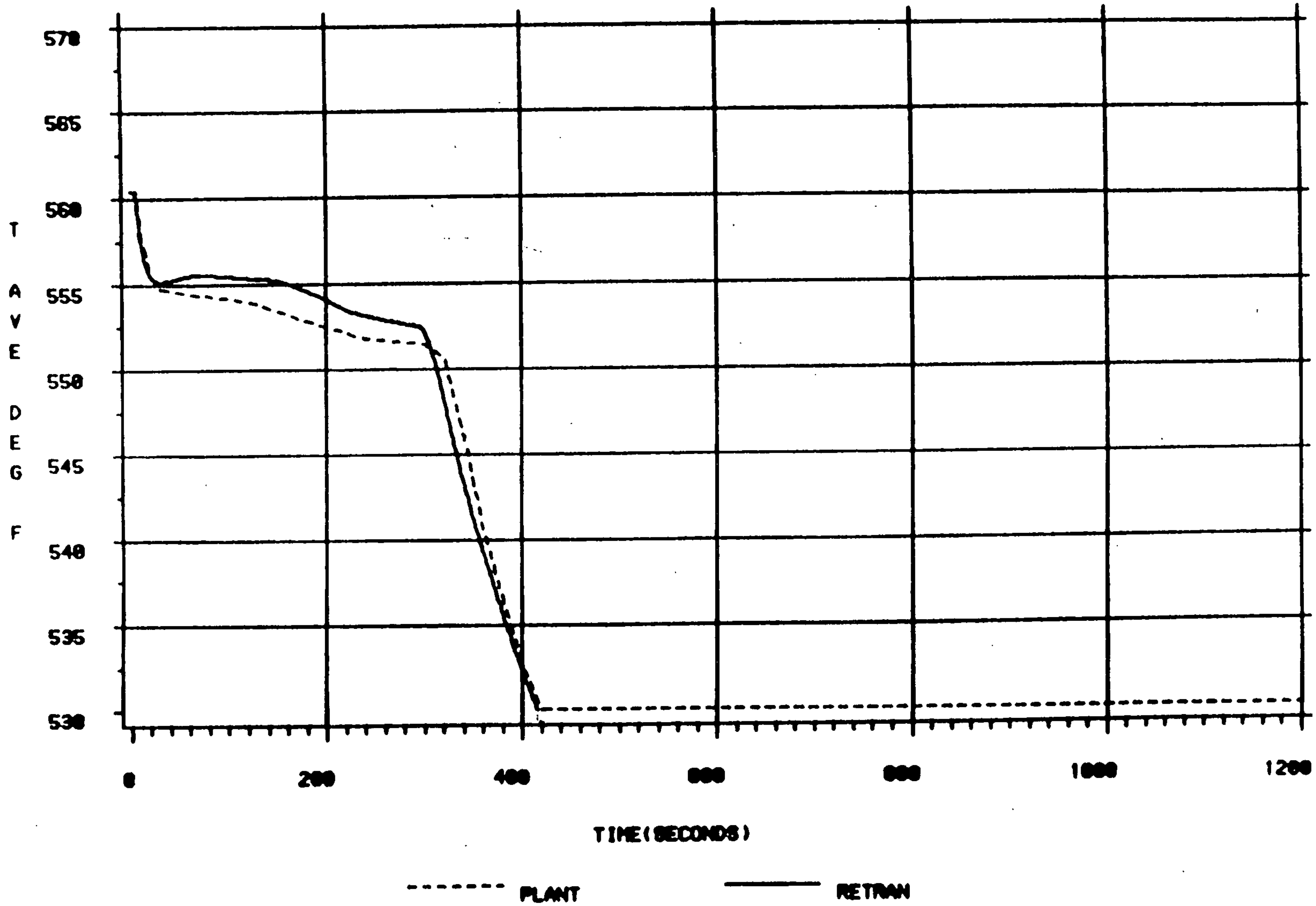


Figure 5.2.1-4

CNS-2 STEAM LINE PORV FAILURE

6/27/86 EVENT

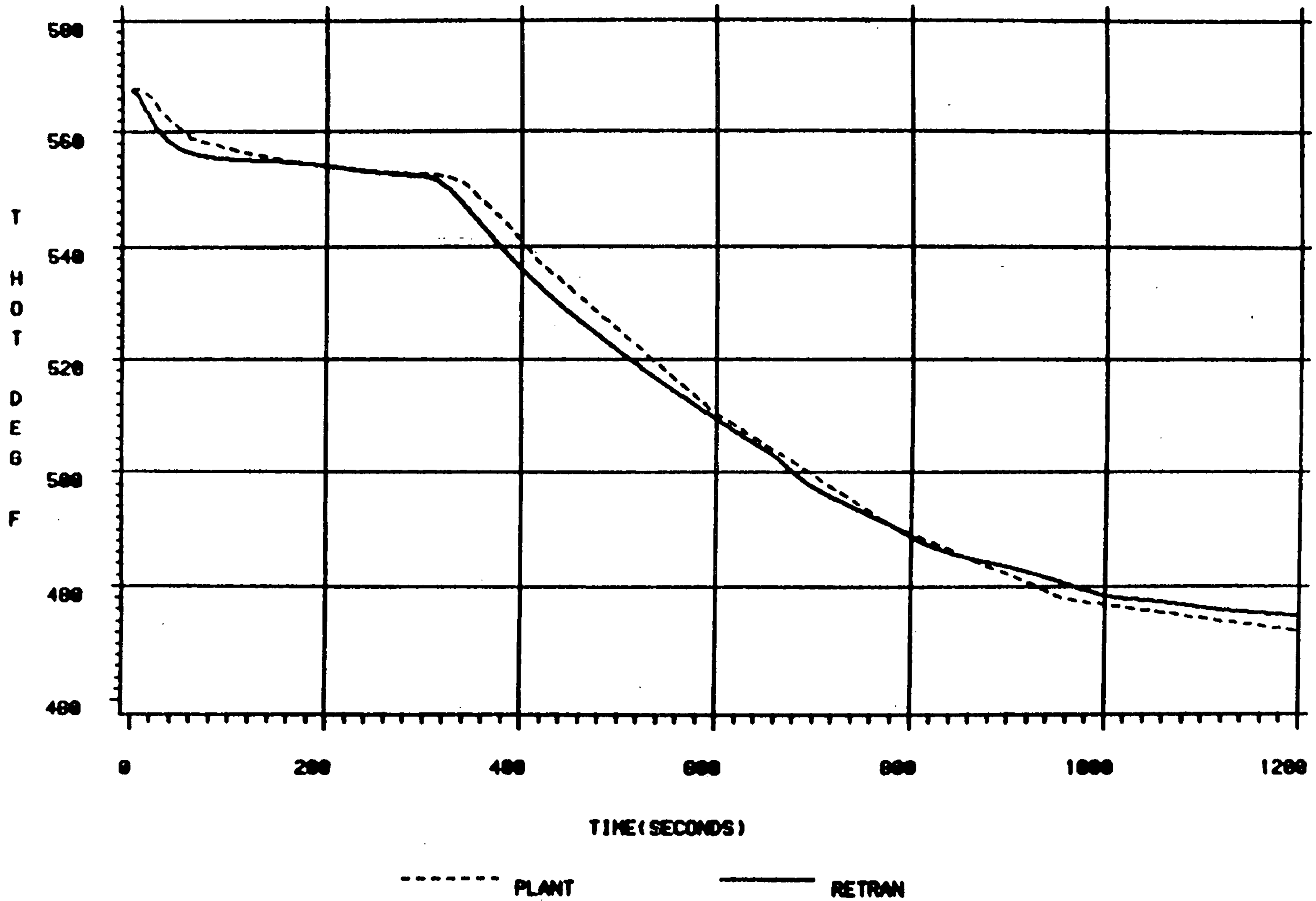


Figure 5.2.1-5

CNS-2 STEAM LINE PORV FAILURE

6/27/86 EVENT

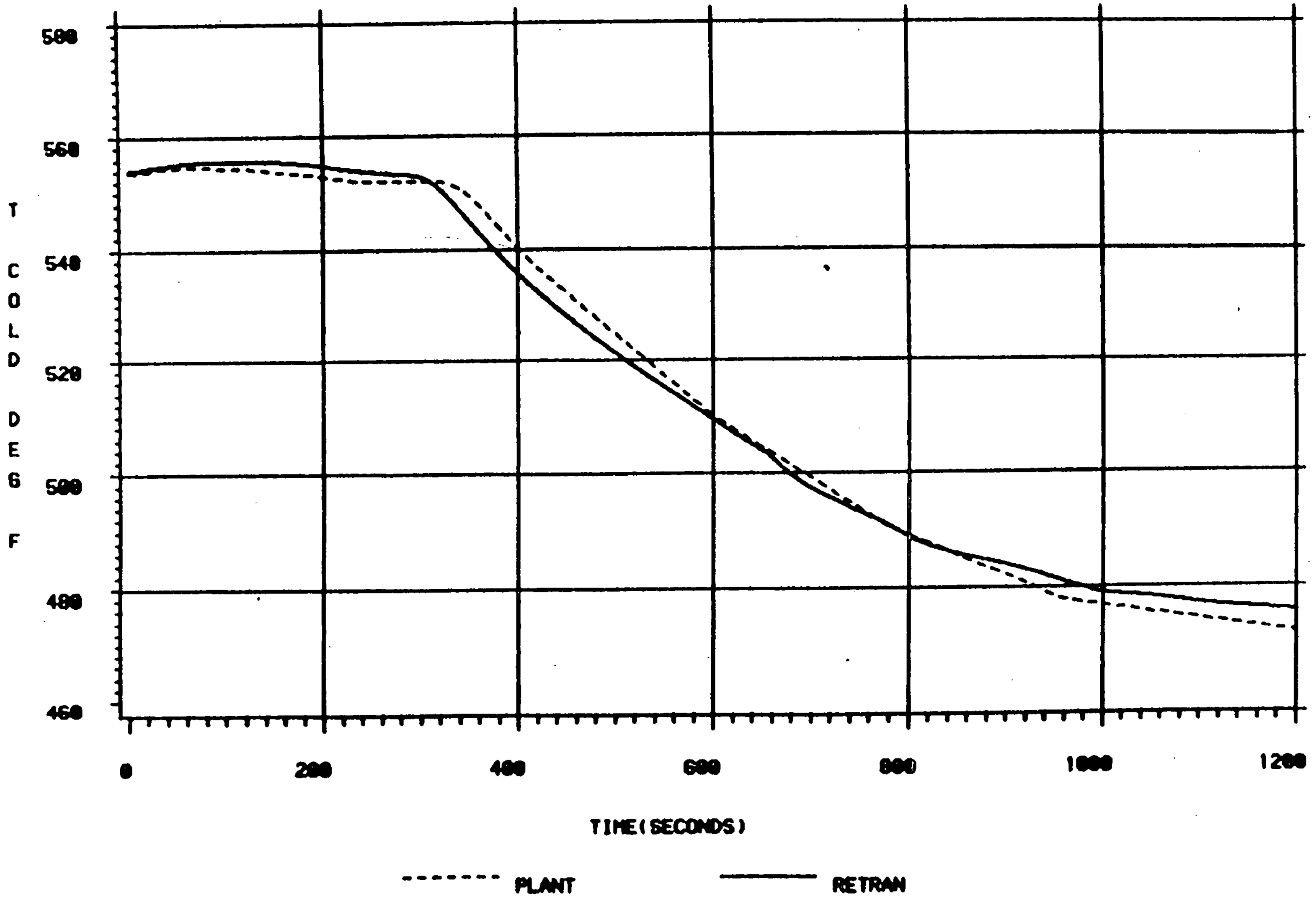


Figure 5.2.1-6

CNS-2 STEAM LINE PORV FAILURE

6/27/86 EVENT

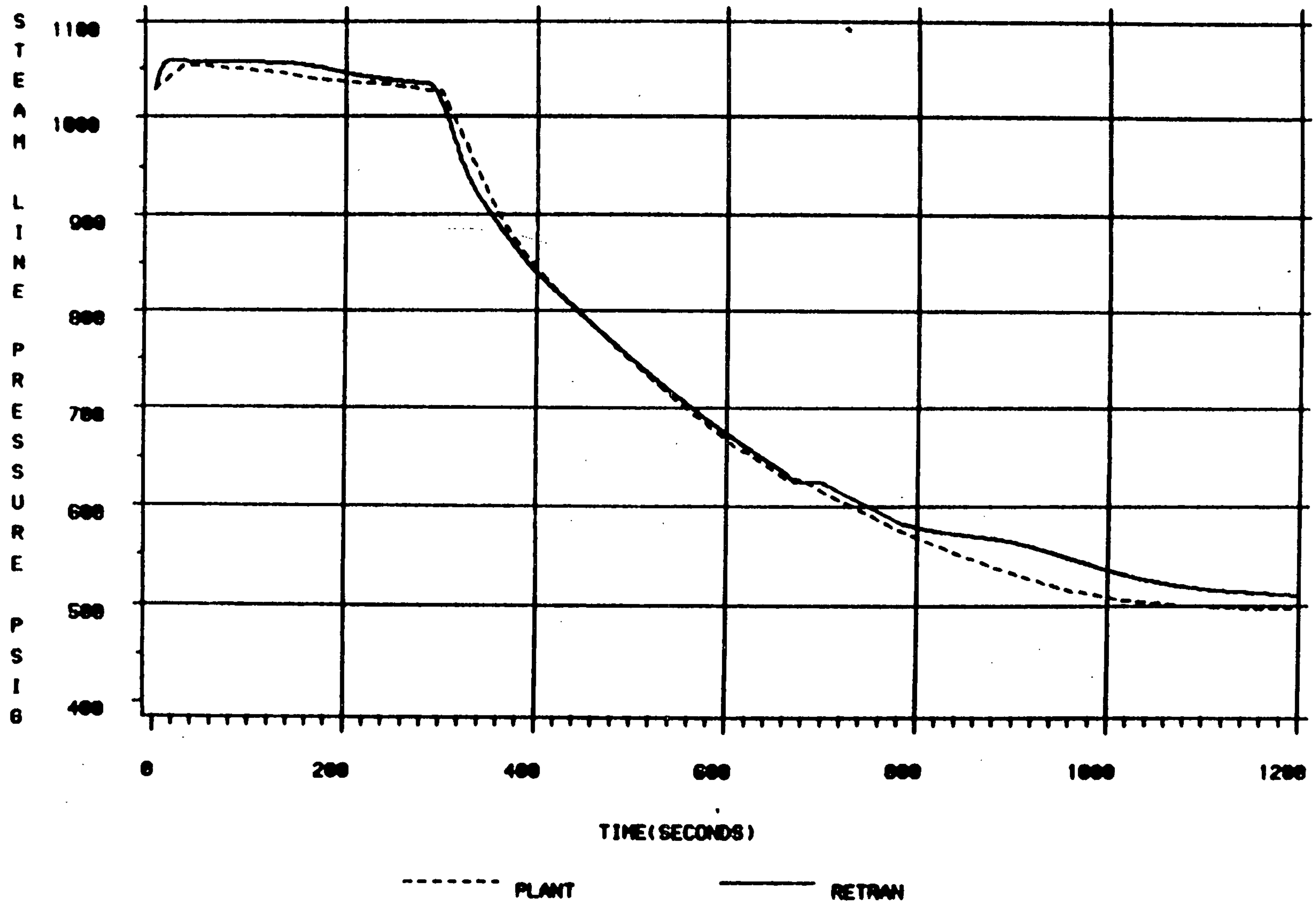


Figure 5.2.1-7

CNS-2 STEAM LINE PORV FAILURE

6/27/88 EVENT

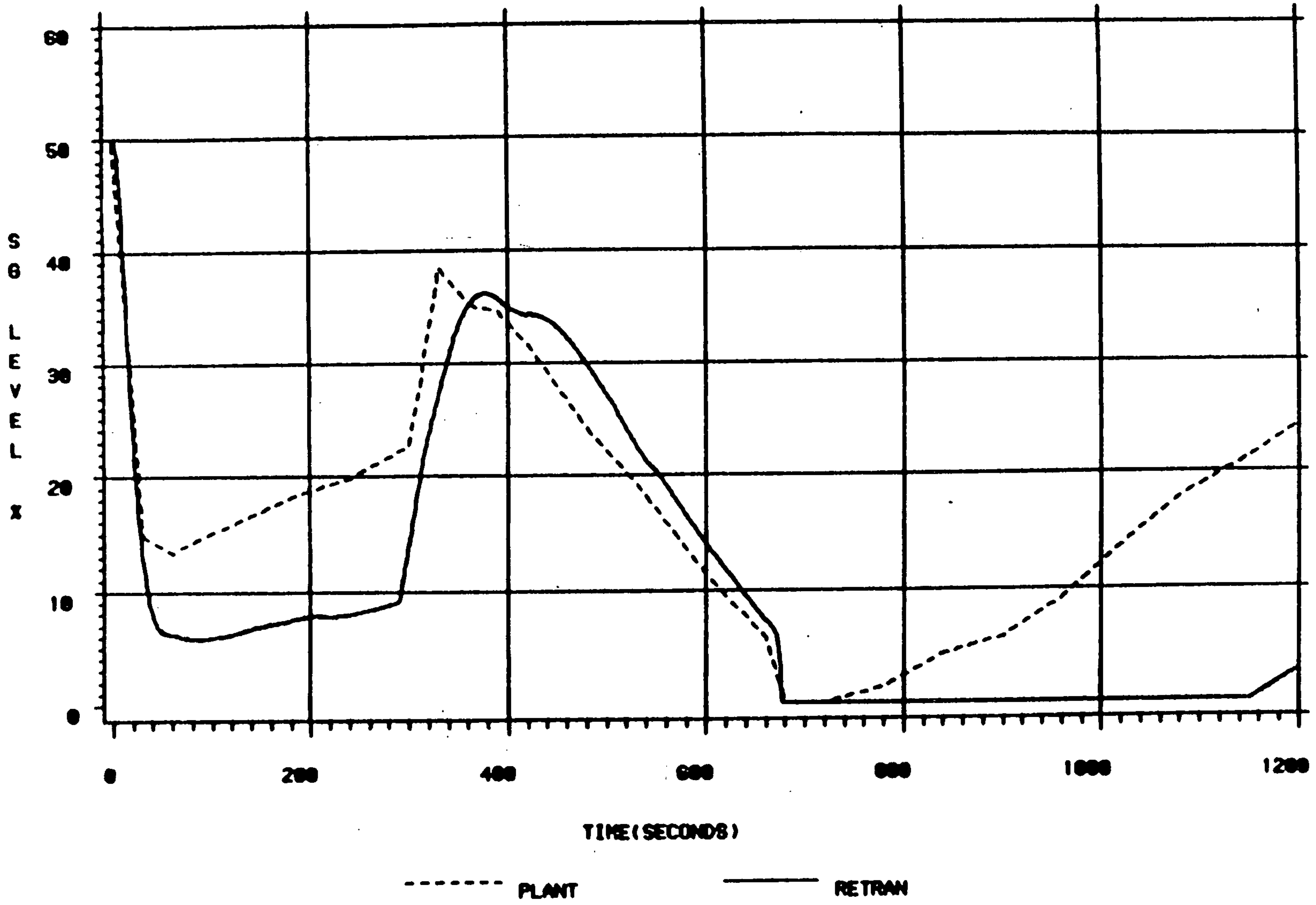


Figure 5.2.1-8

CNS-2 STEAM LINE PORV FAILURE

8/27/86 EVENT

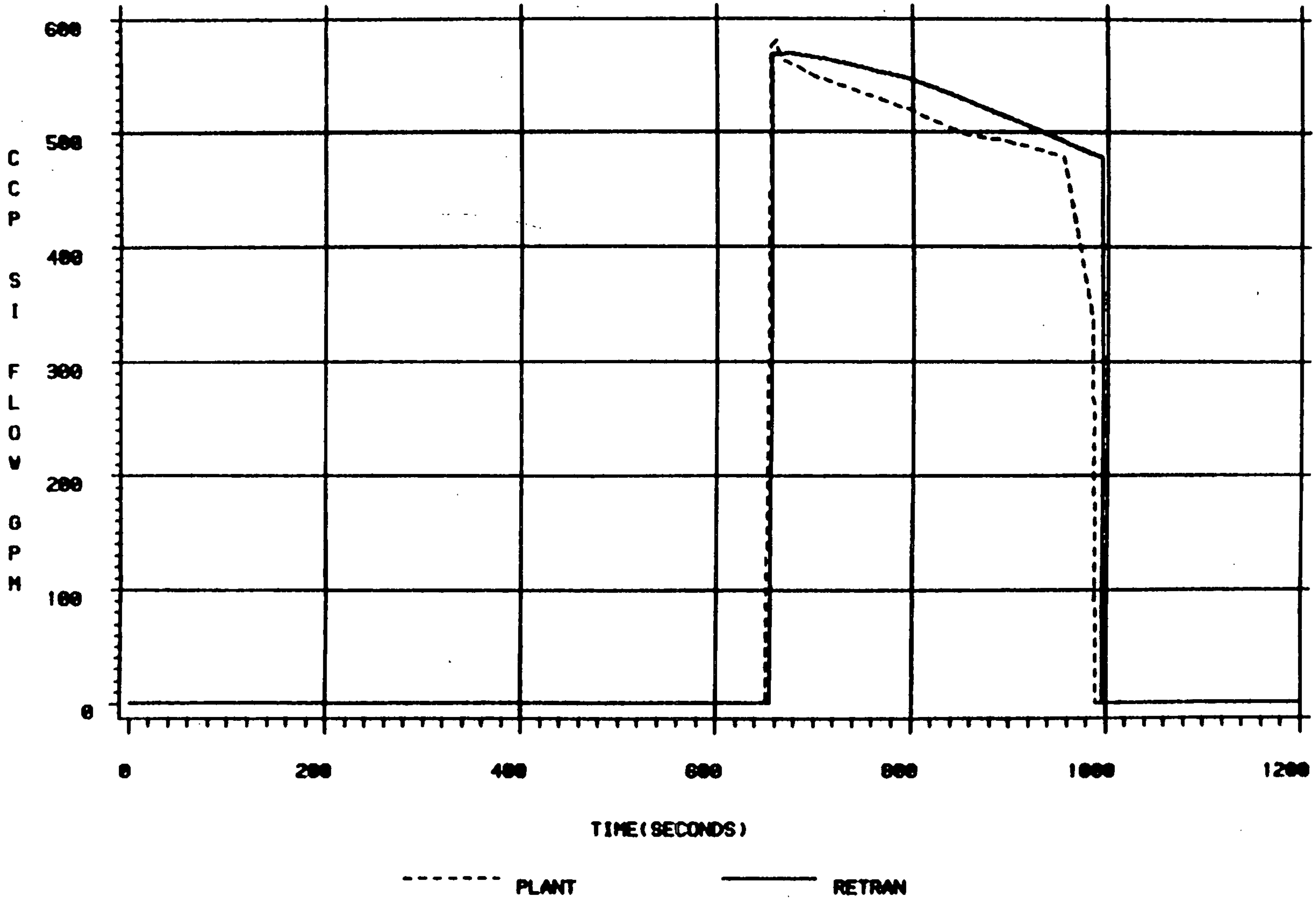


Figure 5.2.1-9

5.3 Loss of Forced Circulation

5.3.1 McGuire and Catawba Nuclear Stations Reactor Coolant Pump Flow Coastdown Tests

Transient Description

The pre-critical startup testing at each McGuire and Catawba unit included a number of RCP flow coastdown tests. These tests are conducted to confirm that the flow coastdown characteristics will not result in unacceptable DNBRs for the limiting FSAR transients. The tests are performed under isothermal conditions at approximately 555°F and 2250 psig with the reactor subcritical. Tests were initated with both four and three pumps in operation, and then either one pump or all pumps were simultaneously tripped. The notation "X/Y" is used to describe a test with "X" pumps tripped from a "Y" pumps operating initial condition. At both McGuire units 4/4, 1/4, 3/3, and 1/3 tests were conducted. At Catawba only the 4/4 and 1/4 tests were conducted. For all tests data were documented for a period of 10 seconds.

Discussion of Important Phenomena

The rate that the RCP coasts down is determined primarily by the size of the pump flywheel and the modeling of the pump frictional torque. With one or more pumps remaining in operation during the coastdown (i.e. 1/4, 1/3 tests), the dynamic interaction between the pumps comes into play as the operating pumps deliver a higher flowrate consistent with the pump head/flow characteristic curve. Parameters of interest are the decrease rate of the loop flow in the coasting down loop and of the core flow, and the increase rate of loop flow in an active loop.

Model Description and Boundary Conditions

Due to the isothermal nature of the flow coastdown tests, the RETRAN model used in these benchmarks has been simplified and consists solely of the primary loop with all thermal modeling deleted. A one-loop model is used for the 4/4 coastdown benchmarks, and a three-loop model is used for the 1/4, 3/3, and 1/3

benchmarks. In order to show consistency between the models, the 4/4 coastdown was modeled with the four, three and two loop models. Unit specific models were developed to determine if the minor differences between units impacted the coastdown response as predicted by RETRAN. The differences between Catawba Unit 2 RCPs and those in the other three units are explicitly accounted for. The inital coolant temperatures during the tests varied from 555°F to 558°F, and are matched in the simulations. Initial four-pump flowrates are also unit specific. Initial three-pump loop flowrates agreed well with the available data.

Simulation Results

The comparisons of the predicted pump coastdown flowrates and the plant test data are given in Figures 5.3.1-1 through 5.3.1-11. It is evident that in some of the plant test data the data is not very smooth at low flowrates. This is due to the data acquisition system which did not have high resolution and has a larger uncertainty at low flow rates. An analysis of the Catawba Unit 1 4/4 test was undertaken first since the test data was available for 24 seconds. The results of these runs are shown in Figure 5.3.1-1. The curve labeled "OLD-PUMP" is the prediction of the original RCP model. It is evident that RETRAN predicts a slower flow coastdown than the data. Based on this result, the RETRAN pump model was [ ] The result of the revised pump model is labeled "NEW-PUMP". The revised model closely matches the plant data. The revised pump model is used in all subsequent pump coastdown analyses presented, and will be used in all future MNS/CNS RETRAN model applications. Figure 5.3.1-2 shows that RETRAN predicts identical results for a 4/4 coastdown regardless of whether the primary loops are lumped into one, two, or three loops. Figure 5.3.1-3 shows predicted flow coastdowns for the 4/4 tests for all four units. The results indicate that the unit-specific modeling, including the different RCP modeling for Catawba 2, has only a very small impact on the coastdown. Based on this result, the remaining flow coastdown analyses were only performed using models of McGuire 1 and Catawba 2. McGuire 2 and Catawba 1 are essentially identical to the McGuire 1 model with respect to primary loop design. The comparison of the predicted 4/4 coastdowns to the plant test data are shown in Figures 5.3.1-4 and 5.3.1-5. RETRAN accurately predicts the coastdowns, with a maximum deviation of approxi-

mately 2% of initial flow. The comparison can also be interpreted as the RETRAN prediction leading or lagging the data by approximately 0.5 seconds at 10 seconds. Figure 5.3.1-1 shows that beyond 10 seconds the maximum deviation increases to only 3% of initial flow at 24 seconds, or that RETRAN leads the data by about 3 seconds at 24 seconds.

The comparisons between the predicted and measured flow coastdowns for the 1/4 tests are given in Figures 5.3.1-6 through 5.3.1-8. In each figure the prediction of either the flow in the loop with the tripped pump or of the core flow compares well with the plant test data. No data exists for the core flow during the Catawba 2 test. A maximum deviation of 5% in loop flow and 2.5% in core flow occurs, even with the obvious uncertainty in the test data at low flows. The comparison to 3/3 tests conducted at McGuire Units 1 & 2 is shown in Figure 5.3.1-9. Again, the agreement with the test data is very good, with a maximum deviation of 2% of the initial flow. The 1/3 test comparisons shown in Figures 5.3.1-10 and 5.3.1-11 have an interesting result. RETRAN predicts loop and core flowrates that are very nearly the average of the higher McGuire 1 results and the lower McGuire 2 results. A maximum deviation of approximately 3% is indicated.

The revised RCP model, which was revised in order to agree with the Catawba Unit 1 4/4 flow coastdown test data, has been shown to consistently and accurately simulate the plant test data for the various tests. Future applications with the revised model are therefore appropriate.

CNS-1 – 4/4 PUMP COASTDOWN

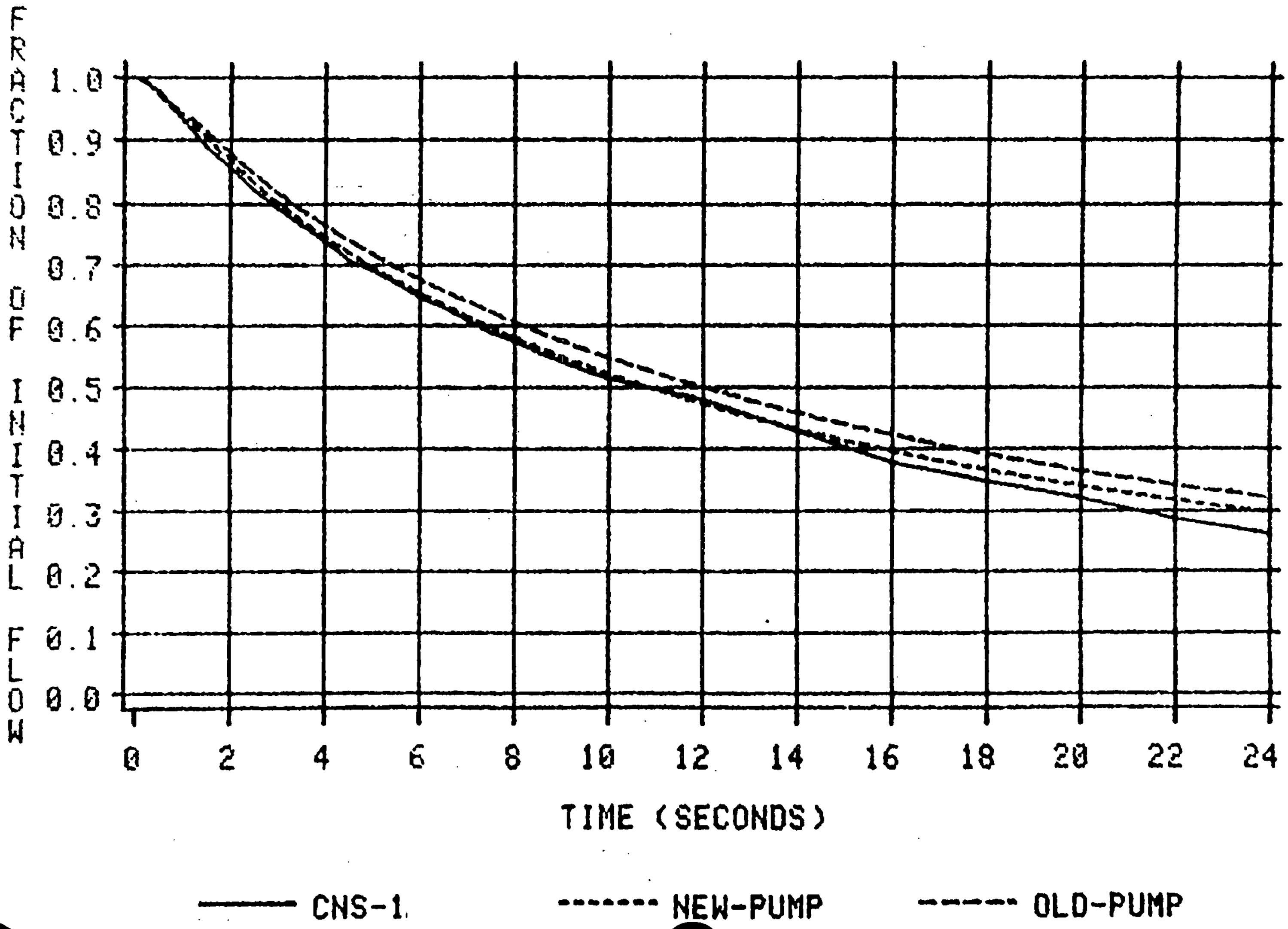


Figure 5.3.1-1

MNS-1 - 4/4 PUMP COASTDOWN

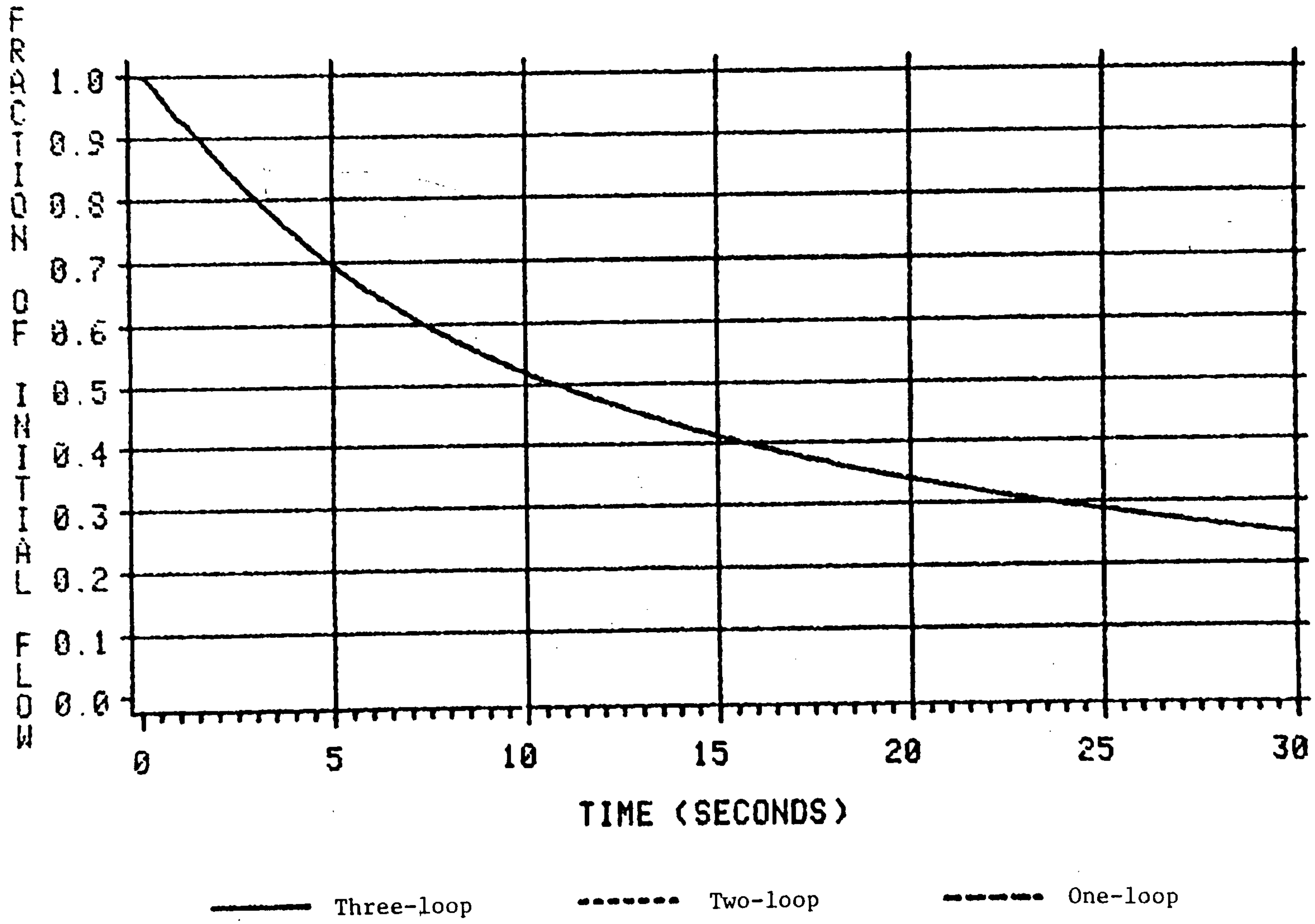


Figure 5.3.1-2

MNS/CNS – 4/4 PUMP COASTDOWN

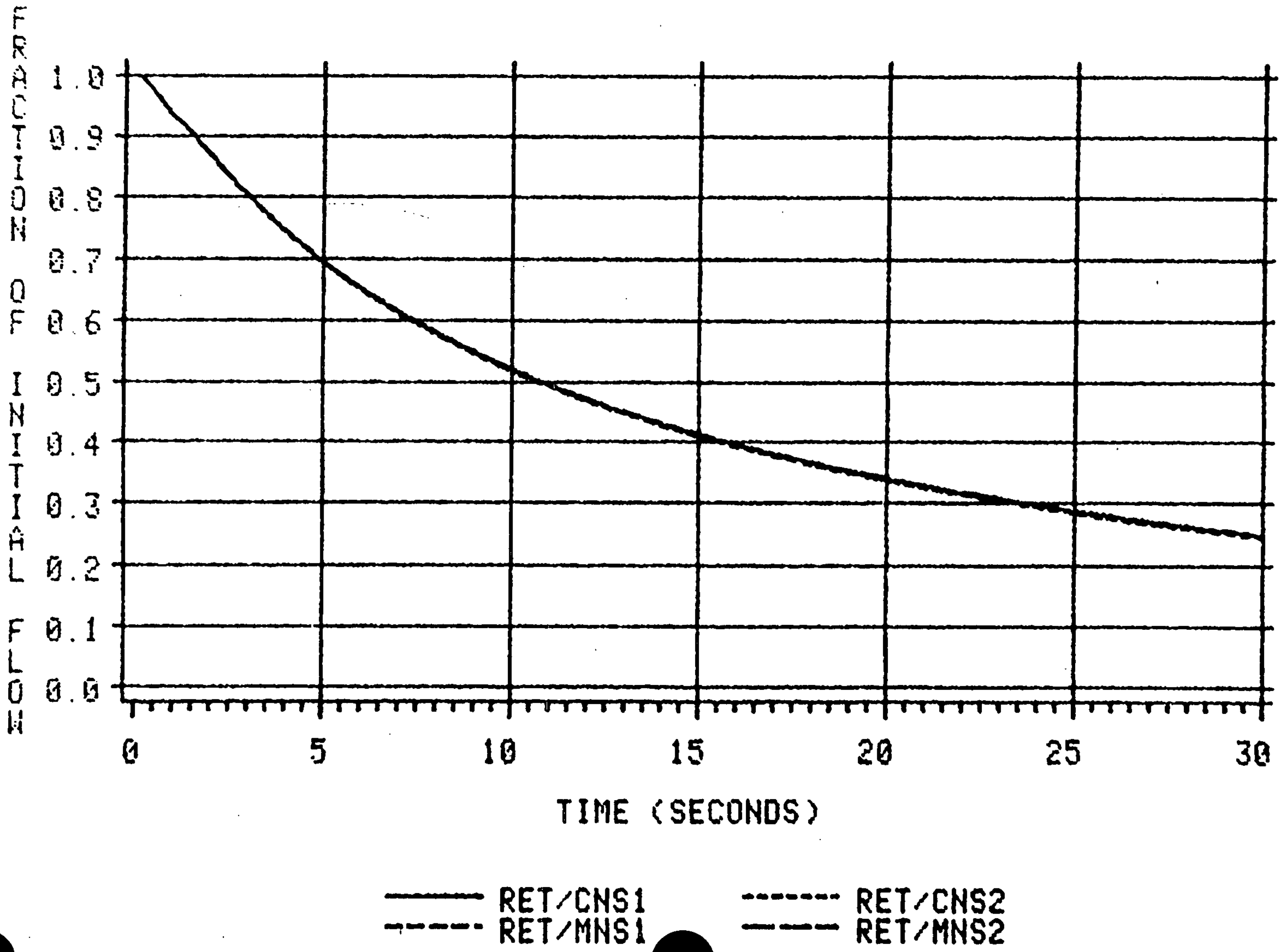


Figure 5.3.1-3

MNS-1&2 / CNS-1 - 4/4 PUMP COASTDOWN

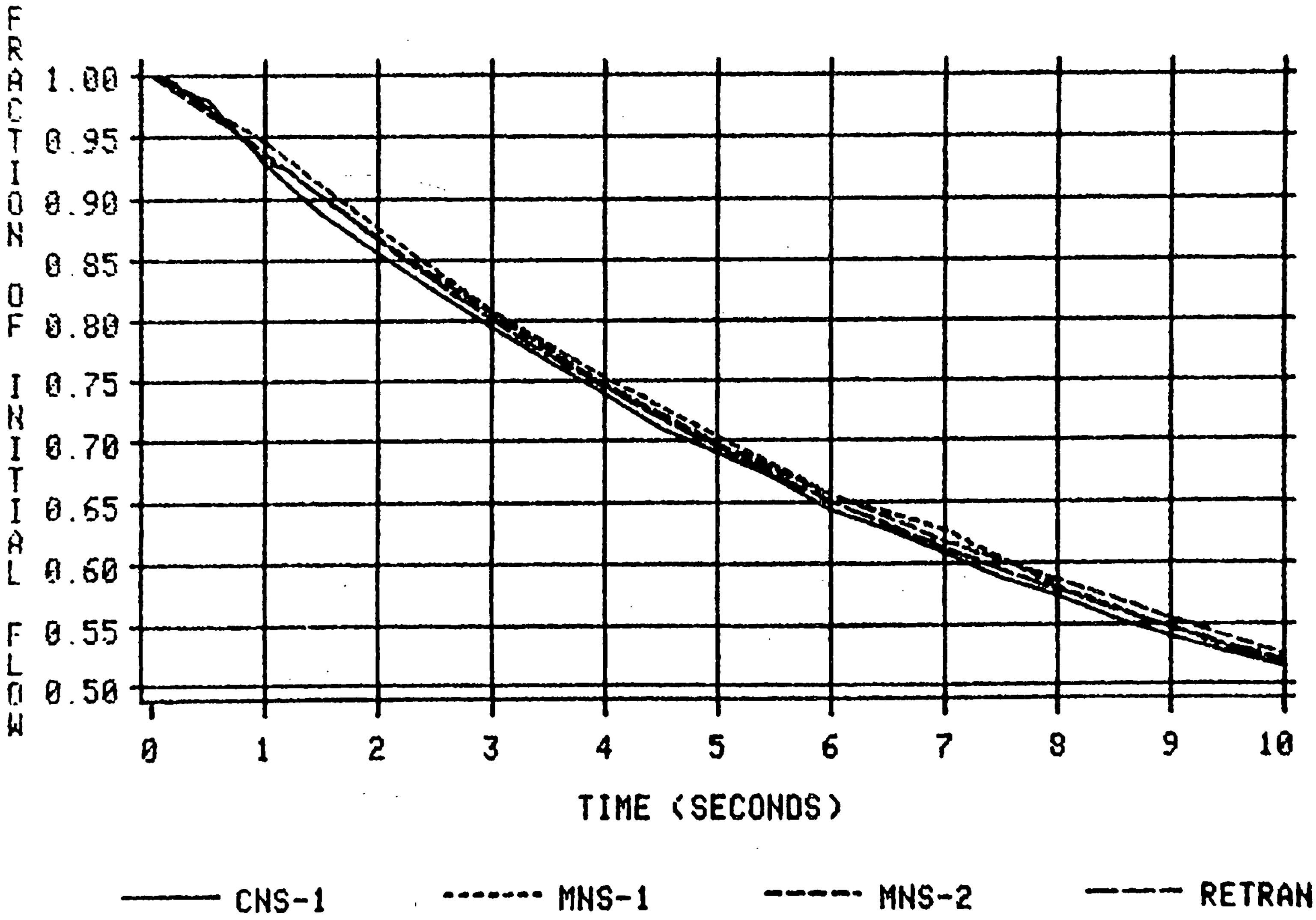


Figure 5.3.1-4

CNS-2 - 4/4 PUMP COASTDOWN

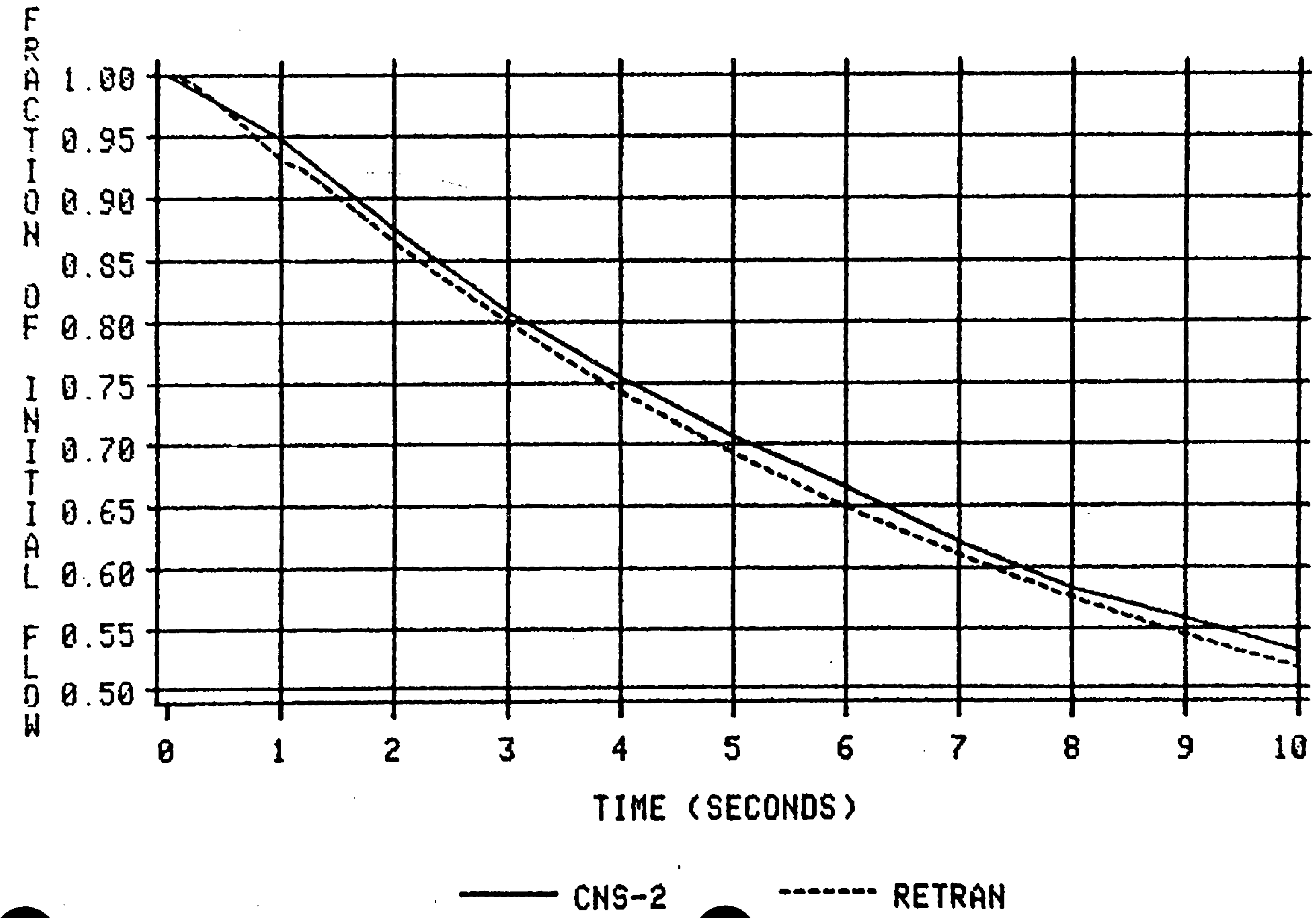
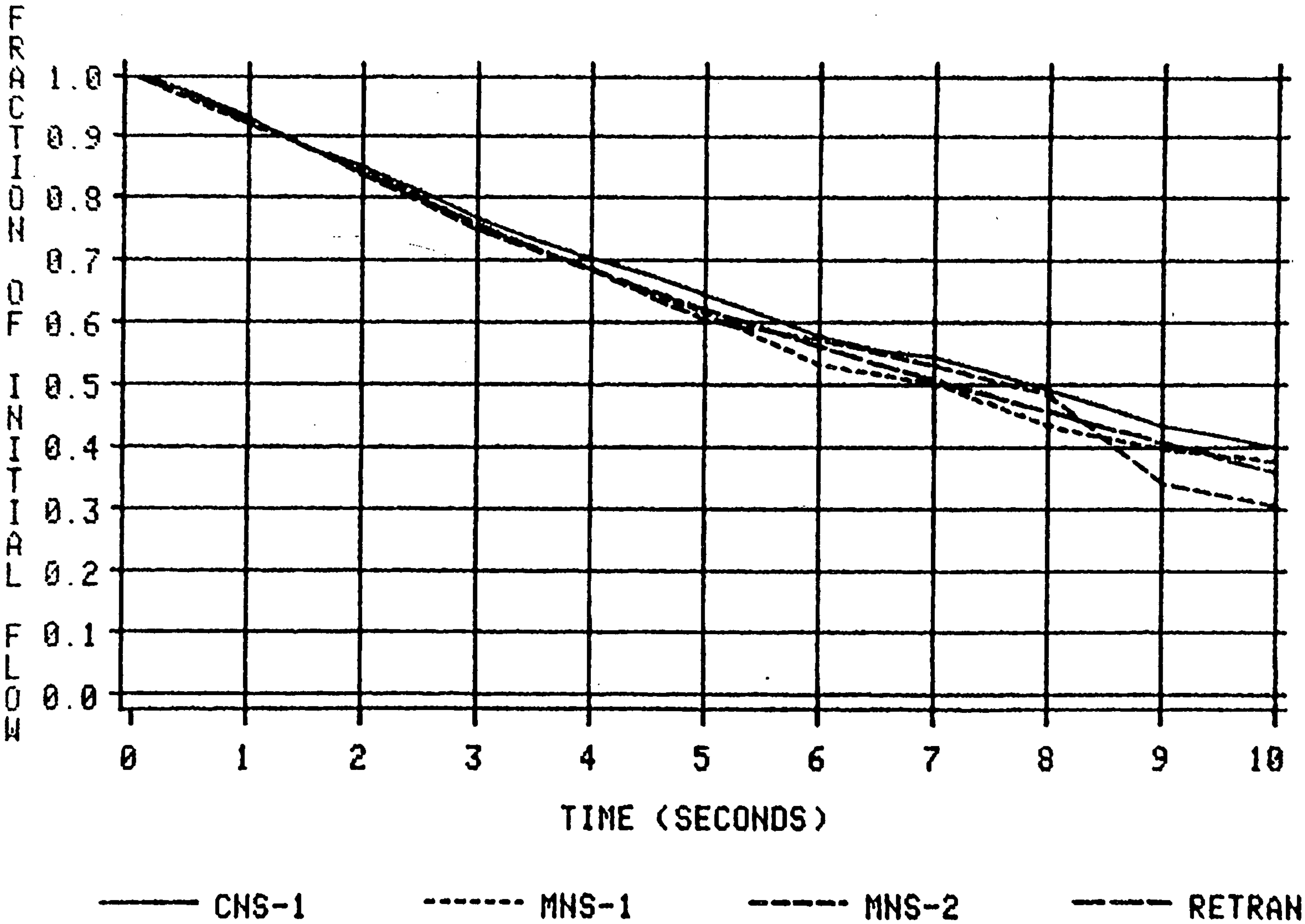


Figure 5.3.1-5

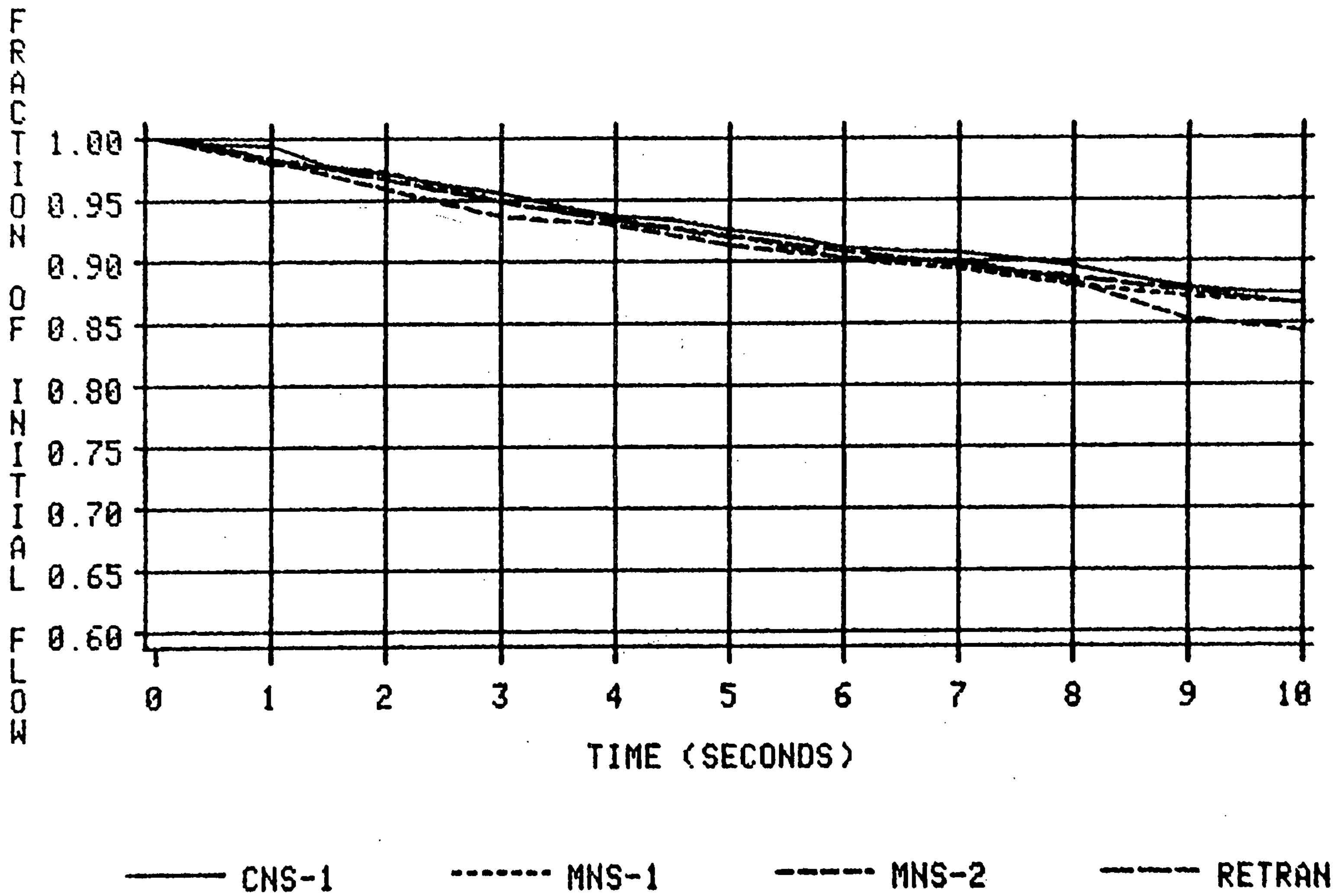
MNS-1&2 / CNS-1 - 1/4 PUMP COASTDOWN



FLOW IN LOOP WITH TRIPPED PUMP

Figure 5.3.1-6

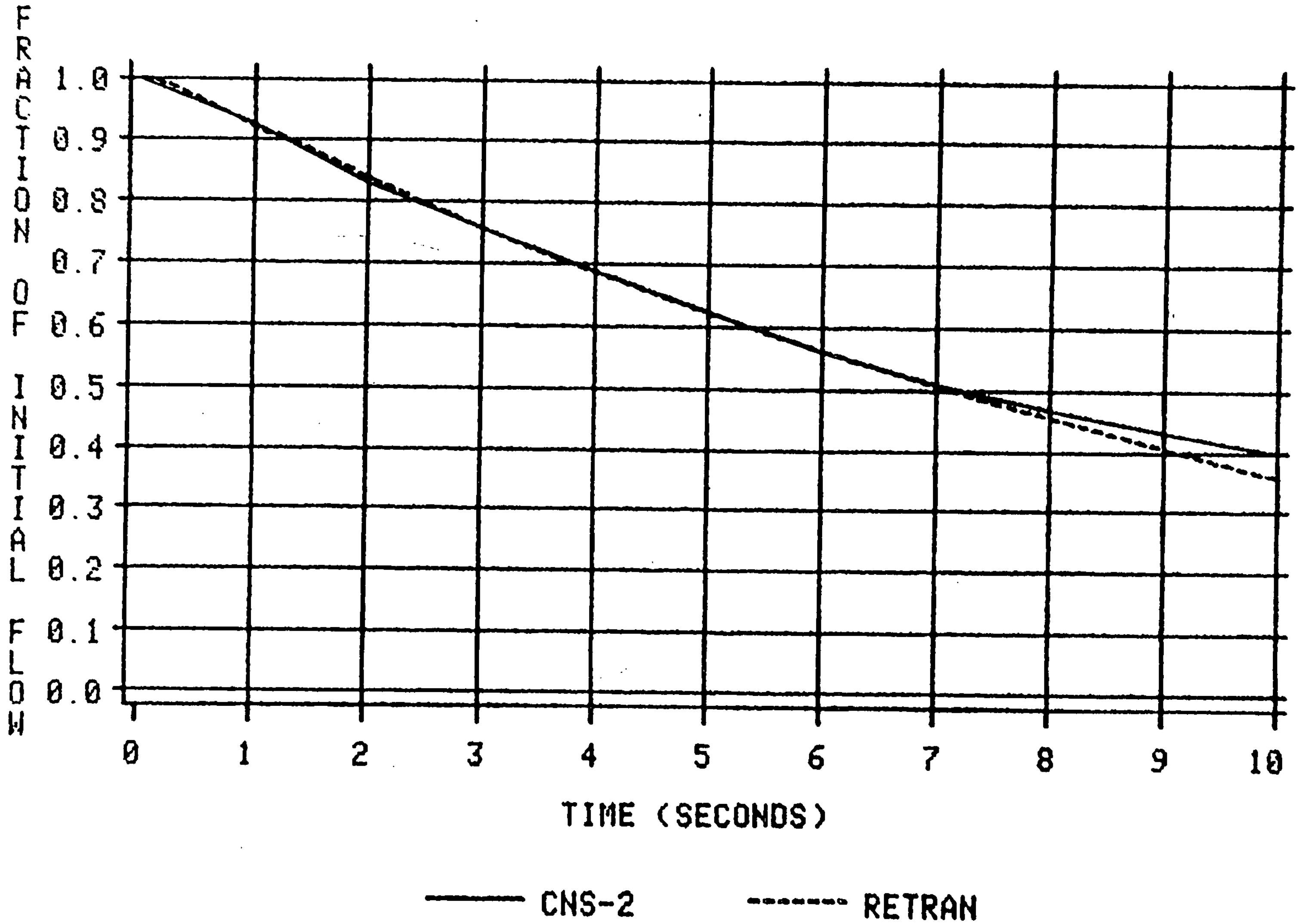
MNS-1&2 / CNS-1 - 1/4 PUMP COASTDOWN



CORE FLOW

Figure 5.3.1-7

CNS-2 – 1/4 PUMP COASTDOWN



FLOW IN LOOP WITH TRIPPED PUMP

Figure 5.3.1-8

5-56

MNS UNITS 1 & 2 – 3/3 PUMP COASTDOWN

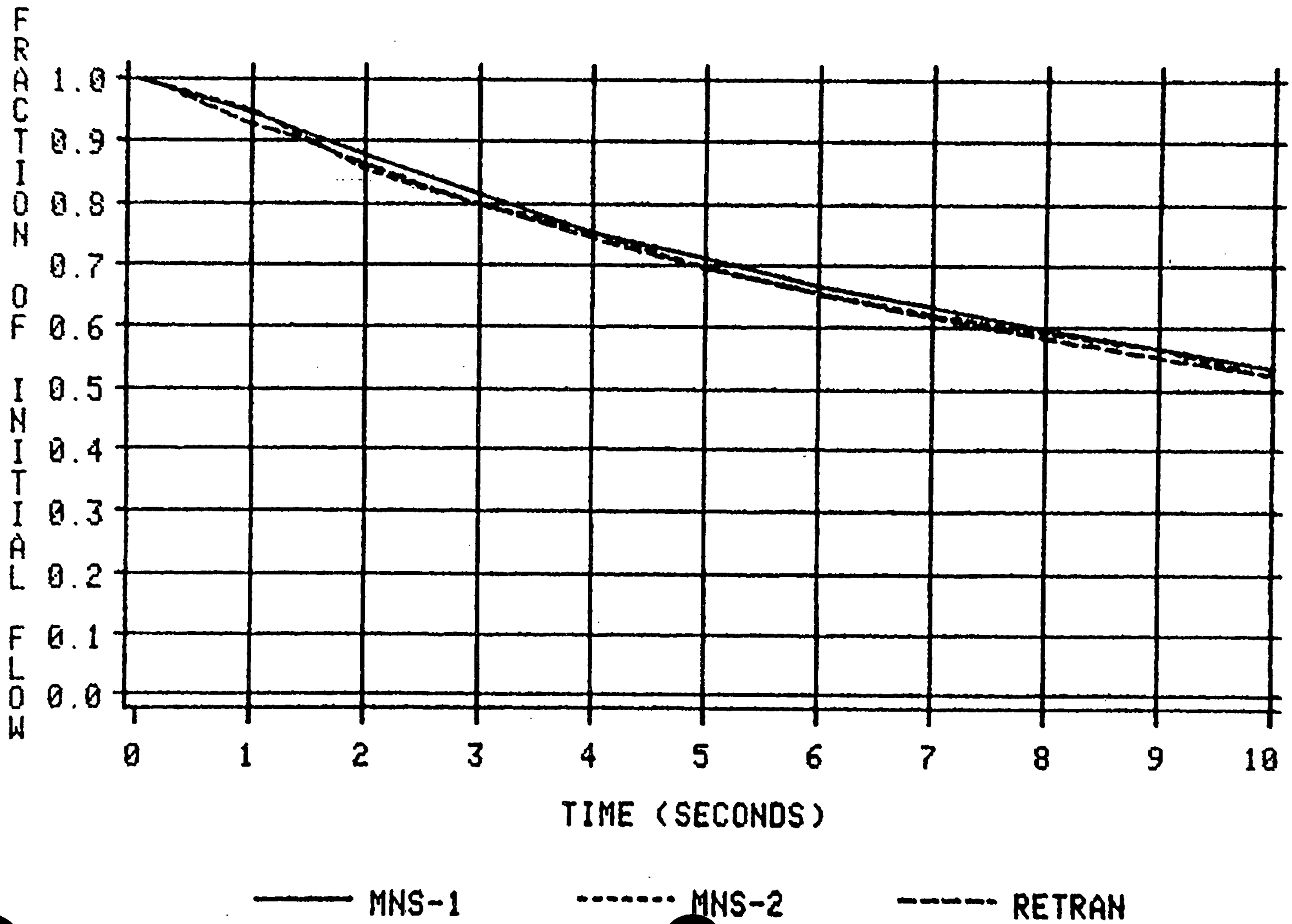
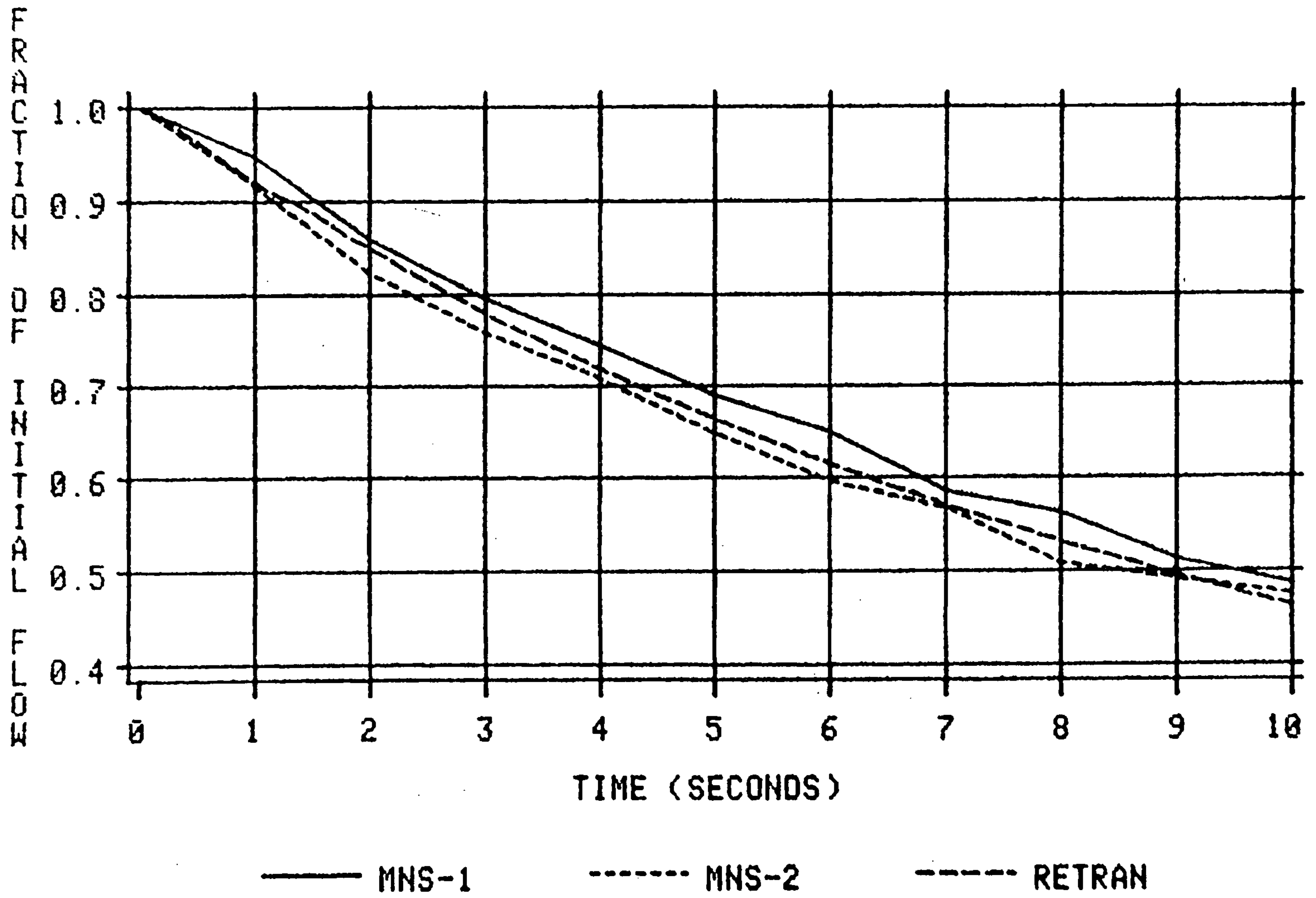


Figure 5.3.1-9

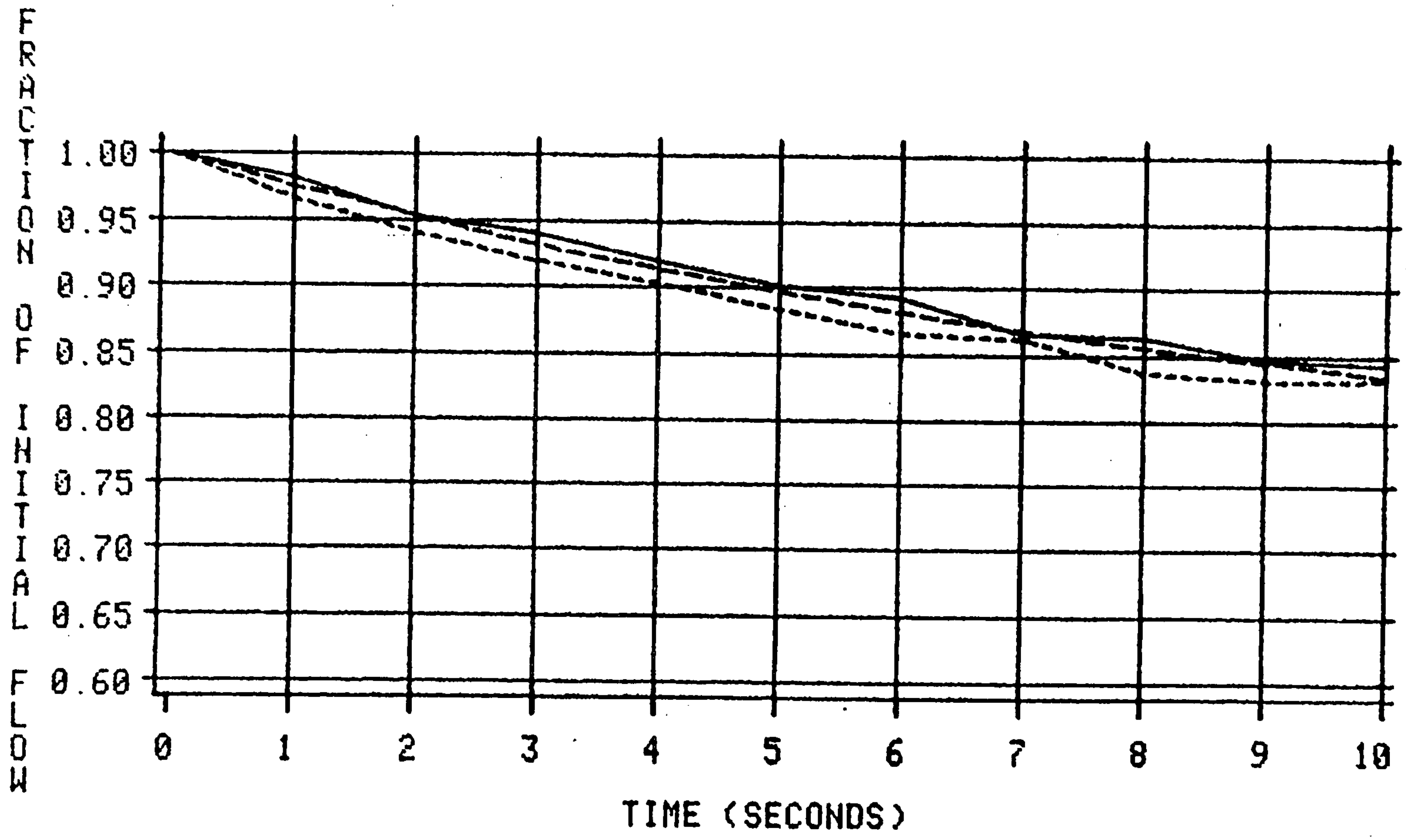
MNS UNITS 1 & 2 – 1/3 PUMP COASTDOWN



FLOW IN LOOP WITH TRIPPED PUMP

Figure 5.3.1-10

MNS UNITS 1 & 2 – 1/3 PUMP COASTDOWN



——— MNS-1 ------- MNS-2 ----- RETRAN

CORE FLOW

Figure 5.3.1-11

5.3.2 McGuire and Catawba Nuclear Stations Natural Circulation Testing

Transient Description

Two types of natural circulation testing that are useful for benchmarks were conducted during the initial startup testing at McGuire Unit 1 and Catawba Unit 1. At both units steady-state natural circulation tests were conducted with the unit at approximately 1% or 3% full power. The pertinent test result is the ΔT between hot leg and cold leg temperatures. It should be pointed out that there exists some degree of uncertainty in the true core power during such tests, and therefore the 1% and 3% power values are very approximate. Steady-state natural circulation is simulated by maintaining the reactor power stable at plateaus of 5%, 3%, 2%, 1%, and 0.5% full power, and allowing loop flowrates and loop ΔTs to stabilize.

The second type of testing was conducted only at McGuire Unit 1 and was performed to evaluate the plant response to isolating two SGs in sequence after achieving a stable natural circulation condition with the reactor critical at approximately 1% power. SGs were isolated by closing the MSIV, isolating feedwater, and isolating blowdown. The transition from all four SGs steaming to three, and to two, demonstrated the capability to remove decay heat in a natural circulation mode with only two SGs steaming.

A RETRAN simulation of this test enables a comparison of the resulting loop ΔTs and the repressurization rate of the SGs following isolation. The natural circulation flowrates predicted by RETRAN, for which test data are unavailable, are also presented.

Discussion of Important Phenomena

The steady-state natural circulation flowrate results from a balance between the driving head due to the difference in density between the hot leg and the cold leg in combination with the elevation difference between the thermal centers, and loop frictional losses. The balance changes as reactor power changes, and also changes as the number of SGs that are steaming changes. A

key phenomenon is the elevation of the thermal center in the SG, which is determined by the distribution of primary-to-secondary heat transfer. Another important phenomenon is the loop frictional loss at the low loop flowrates characteristic of natural circulation.

SG isolation results in a situation where the isolated SG can function as a heat sink only as long as the hot leg temperature exceeds the SG saturation temperature. Since no energy is being extracted from the SG (with the exception of leakage past the isolation valves and losses to ambient) the SG temperature will asymptotically approach the hot leg temperature, and the SG pressure will correspondingly increase. Following SG isolation, the natural circulation flowrate should decrease as the ΔT in that loop decreases. For a constant reactor power level the ΔT and loop flowrates in actively steaming loops should increase when other loops are isolated. This occurs since more energy must be transferred in the non-isolated loops, which requires a higher ΔT, and a higher ΔT causes higher natural circulation flow.

Model Description and Boundary Conditions

The steady-state natural circulation simulations use the one-loop McGuire Unit 1 RETRAN model since there is no loop asymmetry. Starting from an initialization at full power, the reactor and the reactor coolant pumps are tripped. The reactor power is then maintained at power plateaus of 5%, 3%, 2%, 1%, and 0.5% full power, and natural circulation conditions are allowed to stabilize. Steam header pressure is controlled at 1055 psig to maintain T-cold at 553°F, which is typical of plant test conditions. SG level is controlled at 38% with AFW.

The natural circulation with SG isolation test simulations require a three-loop McGuire Unit 1 RETRAN model. The two loops that are sequentially isolated are modeled as separate loops, with the remaining loops lumped. The test initial conditions were approximately 1% power with T-ave at 515°F and an initial ΔT of 20°F. The SG in loop 1 was isolated and the simulation was run for 1800 seconds. This is referred to as the "1/4 steam generators isolated" case. A second simulation isolated the SG in loop 2 1200 seconds after the loop 1 SG was isolated. This is referred to as the "2/4 steam generators isolated" case.

This simulation was then continued for an additional 1800 seconds. In both simulations steam header pressure was controlled to maintain T-cold at 515°F. AFW was also controlled to maintain SG level at 38% in active SGs.

Simulation Results

The predicted steady-state natural circulation ΔT vs. reactor power is shown in Figure 5.3.2-1. Also shown are four plant test data points. Although the available data are limited, the trend of increasing ΔT with power is consistent, and the magnitude also compares well considering the aforementioned uncertainty in test data power level. Figure 5.3.2-2 shows the corresponding predicted relationship between loop flow and power level.

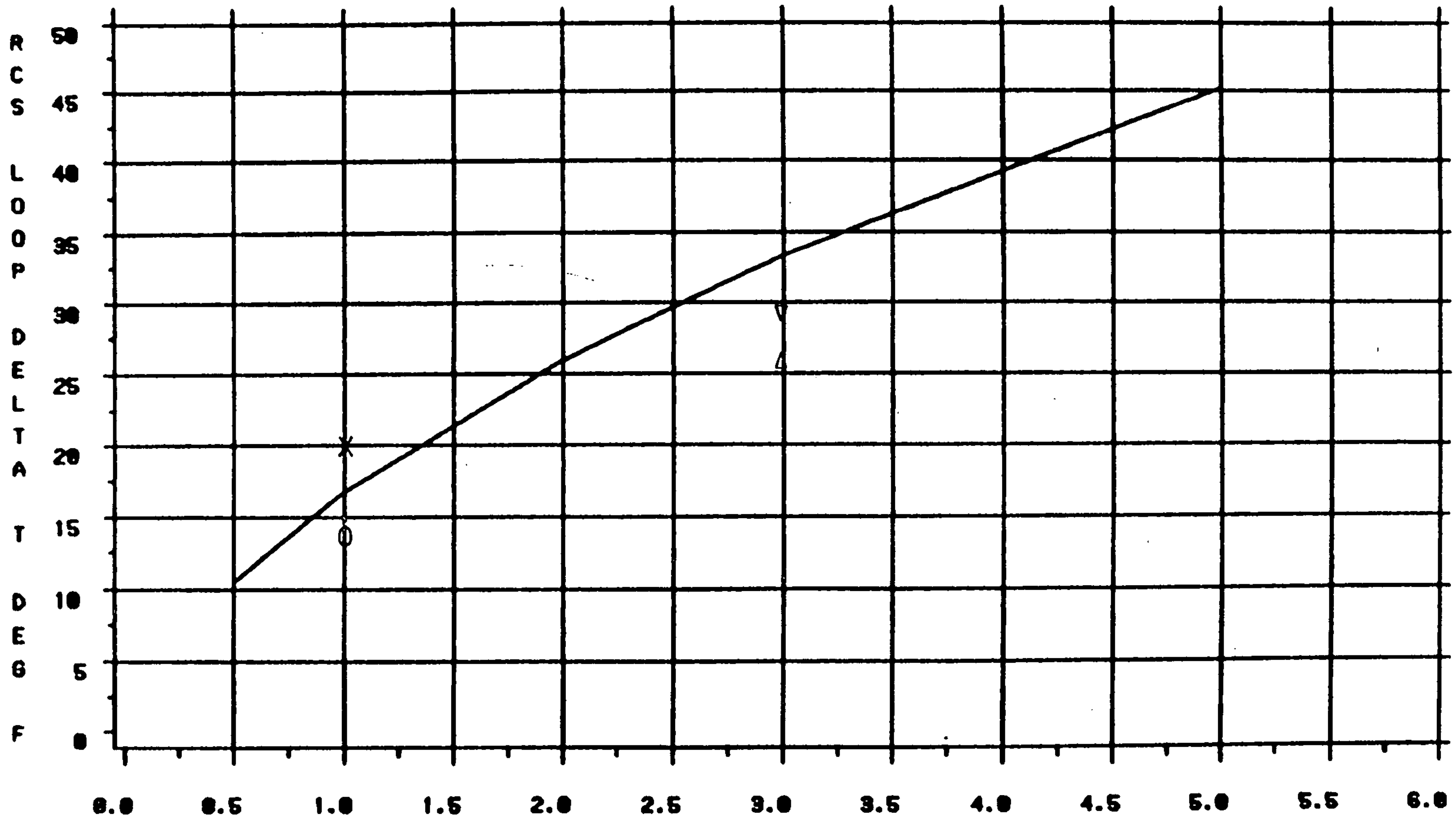
The comparisons of the 1/4 steam generators isolated case are shown in Figures 5.3.2-3 through 5.3.2-12. Figures 5.3.2-3 and 5.3.2-4 show the loop ΔT plant data and simulation results, respectively. The plant data starts with a ΔT of 20°F, and after 1800 seconds the active loop ΔT has increased to 22.5°F and the isolated loop has decreased to 8°F. In the simulation the ΔT starts at 22°F and after 1800 seconds the active loop has increased to 27°F and the isolated loop has decreased to 3°F. Figure 5.3.2-5 shows the comparison of the rate of decrease in the isolated loop ΔT. Figure 5.3.2-6 shows the comparison of the rate of increase in the active loop ΔT. Figures 5.3.2-7 and 5.3.2-8 show SG pressure data and predictions, respectively. In the plant data the isolated SG pressure increases by 100 psi in 1800 seconds, whereas RETRAN predicts a pressure increase of 200 psi. A comparison of the rates of pressure increase in the isolated SG is given in Figure 5.3.2-9.

The comparisons of ΔT and isolated SG pressure responses are consistent in that RETRAN predicts a more rapid loss of heat sink. The source of this difference can be one or a combination of many causes, such as the assumed RETRAN power level being too high, the plant SG not being well isolated, or the RETRAN heat transfer being too high following isolation. Figure 5.3.2-10 shows the asymptotic approach to loss of heat sink (loss of ΔT) as predicted by RETRAN. Figure 5.3.2-11 shows the increase in ΔT in the active loops. Figure 5.3.2-12 shows the corresponding changes in the active loop natural circulation flowrates following isolation.

The comparisons of the 2/4 steam generators isolated case are shown in Figures 5.3.2-13 through 5.3.2-23. Figures 5.3.2-13 and 5.3.2-14 show the loop ΔT plant data and the simulation results, respectively. The plant ΔT data for the second isolated SG decreases from 19°F to 13°F in 1800 seconds. The ΔT in the two active loops increases from 21°F to 23.5°F. In the simulation the ΔT in the second isolated SG decreases from 26.5°F to 4°F in 1800 seconds. The ΔT in the two active loops is predicted to increase from 26.5°F to 34°F. Figures 5.3.2-15 through 5.3.2-17 show the ΔT comparisons between RETRAN and plant data in each loop. In each figure it is evident that the trend is similar but the rates of change and the magnitudes are much greater in RETRAN. Figures 5.3.2-18 and 5.3.2-19 show the steam generator pressure data and predictions, respectively. In the plant the second isolated steam generator pressure increased by 70 psi in 1800 seconds, whereas RETRAN predicts a pressure increase of 230 psi.

The above discussion regarding the potential causes of the differences between plant data and predictions in the 1/4 test remain valid for the 2/4 test. The predicted loop ΔT responses following isolation of the second SG are shown in Figures 5.3.2-20 through 5.3.2-22. The characteristic asymptotic approach to loss of heat sink in the isolated SGs is evident, as is the increased ΔT in the active loop. Figure 5.3.2-23 shows the corresponding changes in the loop natural circulation flowrates. In both the 1/4 and the 2/4 cases the important phenomena are predicted, with only the rate of change and the magnitudes differing from the available plant data.

MNS/CNS STEADY-STATE NATURAL CIRCULATION

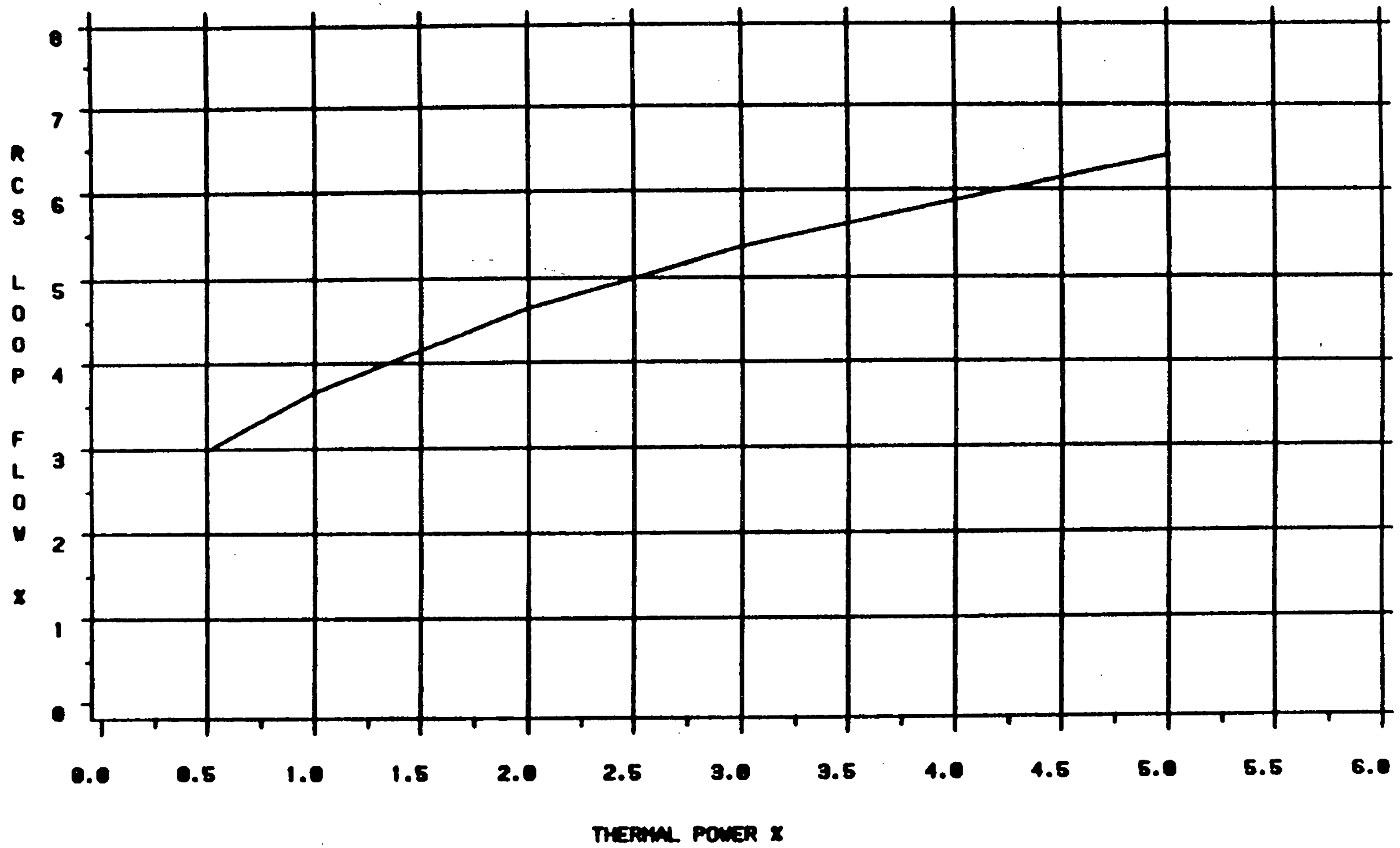


O - MNS-1 8/30/81
X - MNS-1 9/1/81
Δ - MNS-1 8/28/81
∇ - CNS-1 1/19/85

NATURAL CIRCULATION DELTA-T VS. POWER
CURVE IS RETRAN PREDICTED

Figure 5.3.2-1

MNS/CNS STEADY-STATE NATURAL CIRCULATION

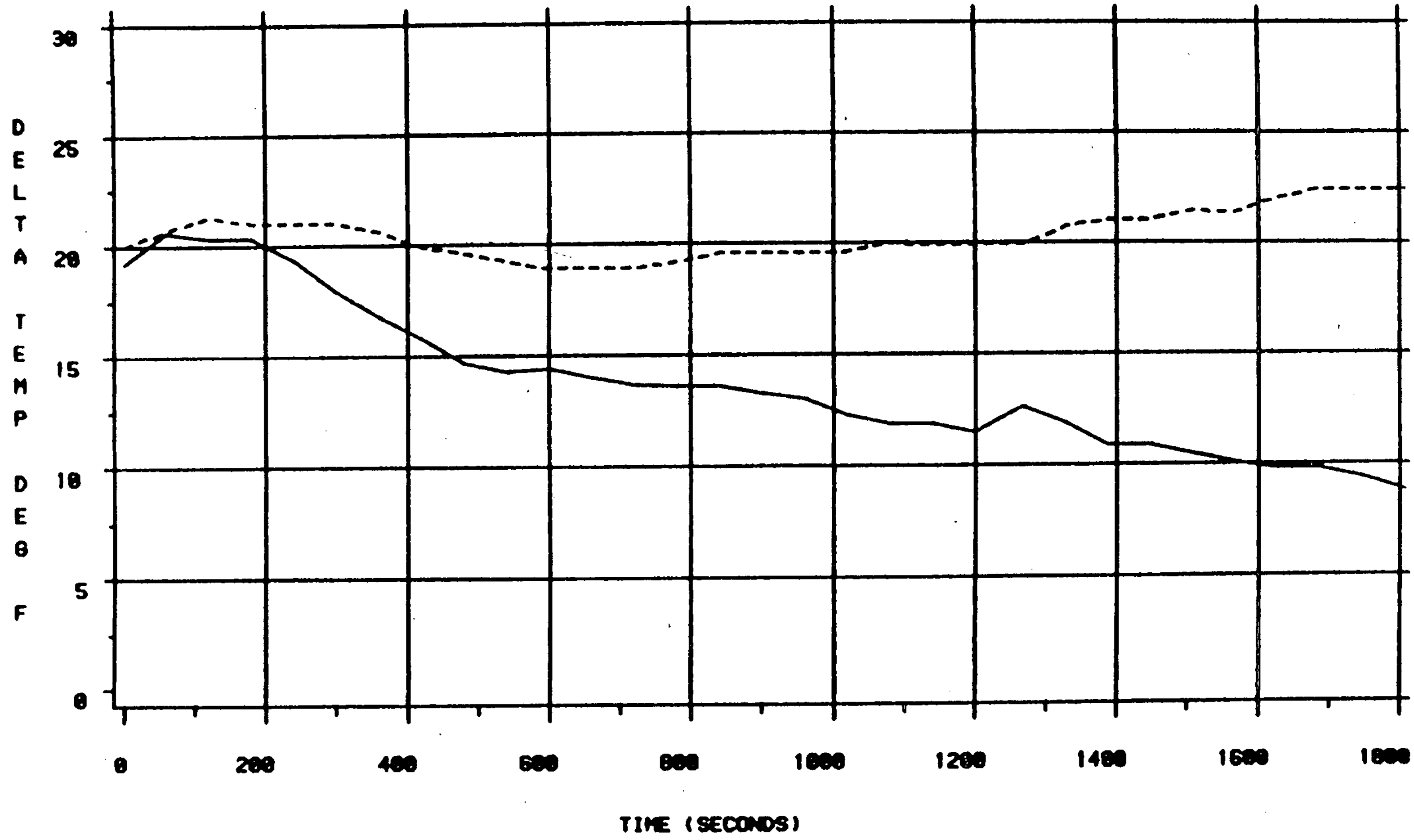


NATURAL CIRCULATION FLOW VS. POWER
CURVE IS RETRAN PREDICTED

Figure 5.3.2-2

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

1/4 STEAM GENERATORS ISOLATED

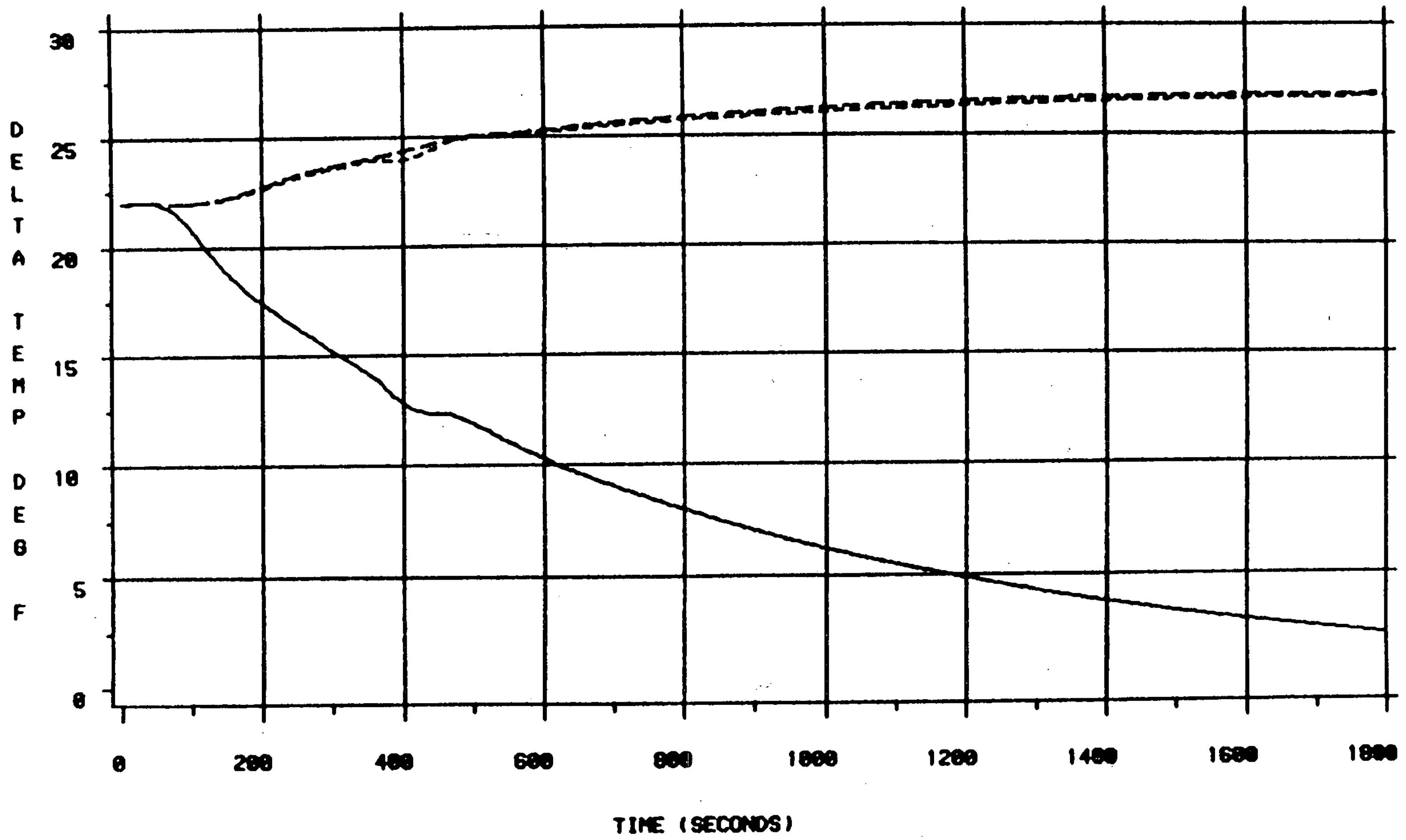


ISOLATED & ACTIVE LOOPS DELTA-T
PLANT DATA

Figure 5.3.2-3

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

1/4 STEAM GENERATORS ISOLATED

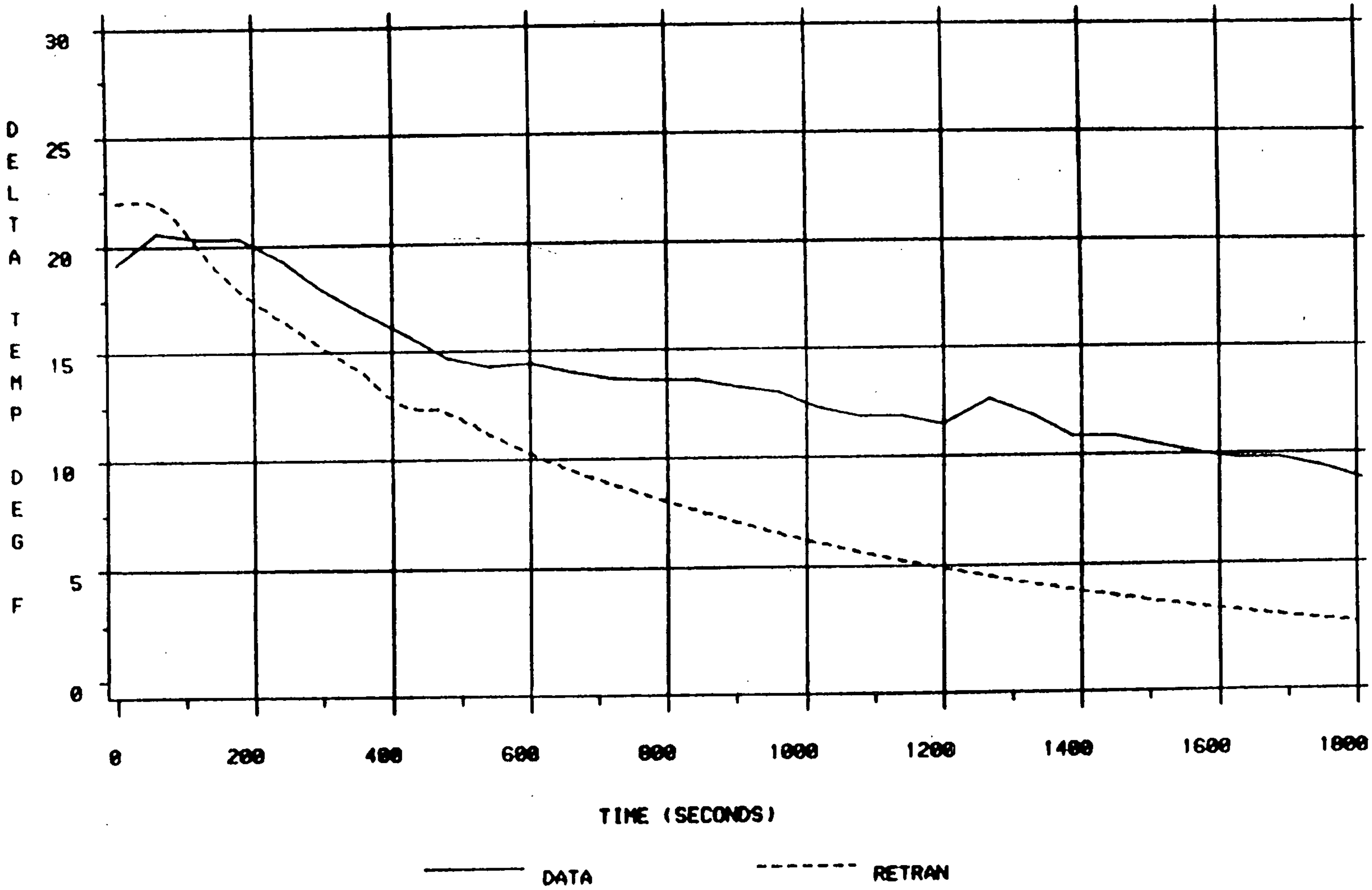


ISOLATED & ACTIVE LOOPS DELTA-T
RETRAN PREDICTION

Figure 5.3.2-4

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

1/4 STEAM GENERATORS ISOLATED

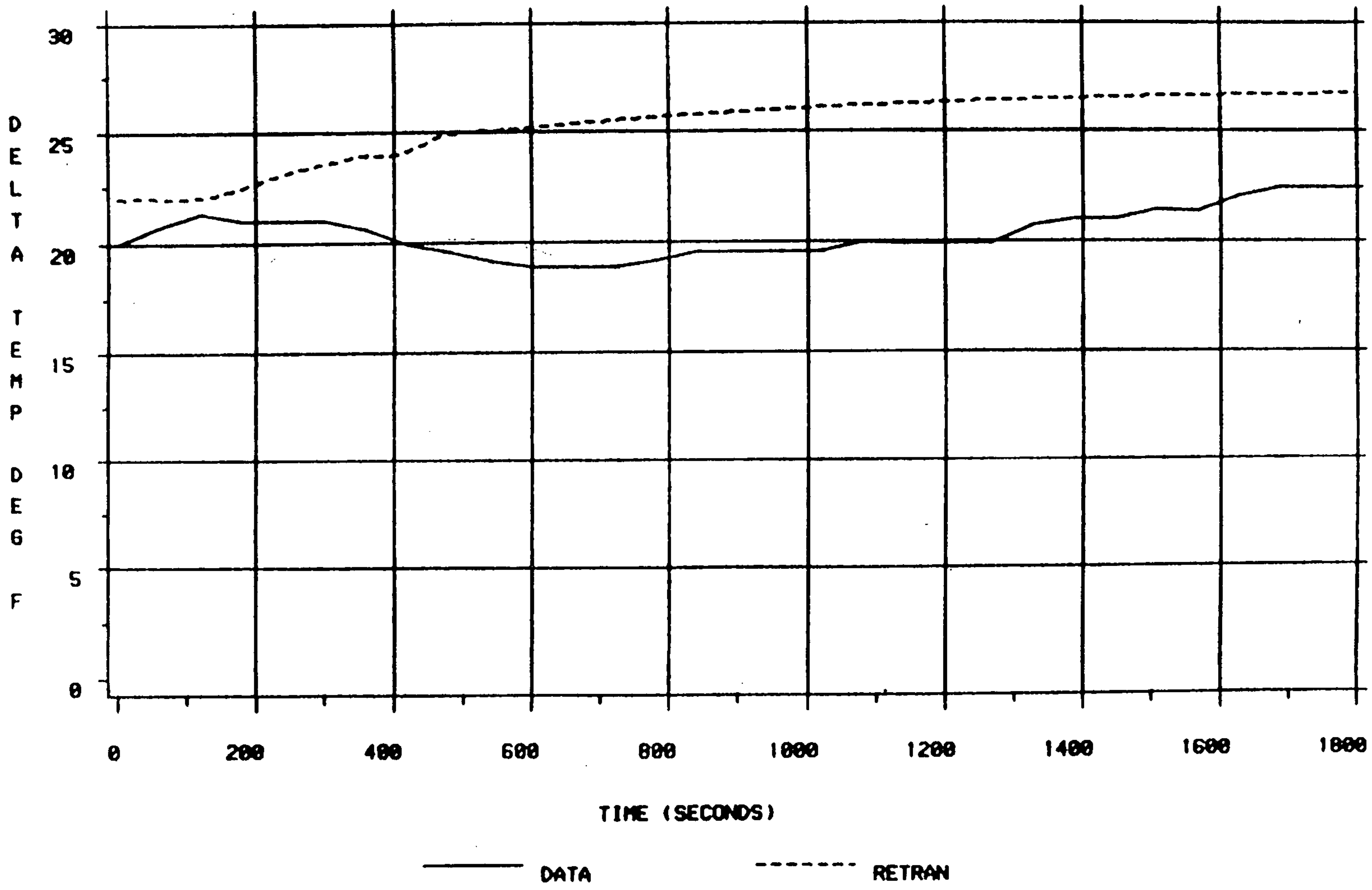


DELTA-T IN THE ISOLATED LOOP

Figure 5.3.2-5

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

1/4 STEAM GENERATORS ISOLATED



DELTA-T IN THE ACTIVE LOOPS

Figure 5.3.2-6

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

1/4 STEAM GENERATORS ISOLATED

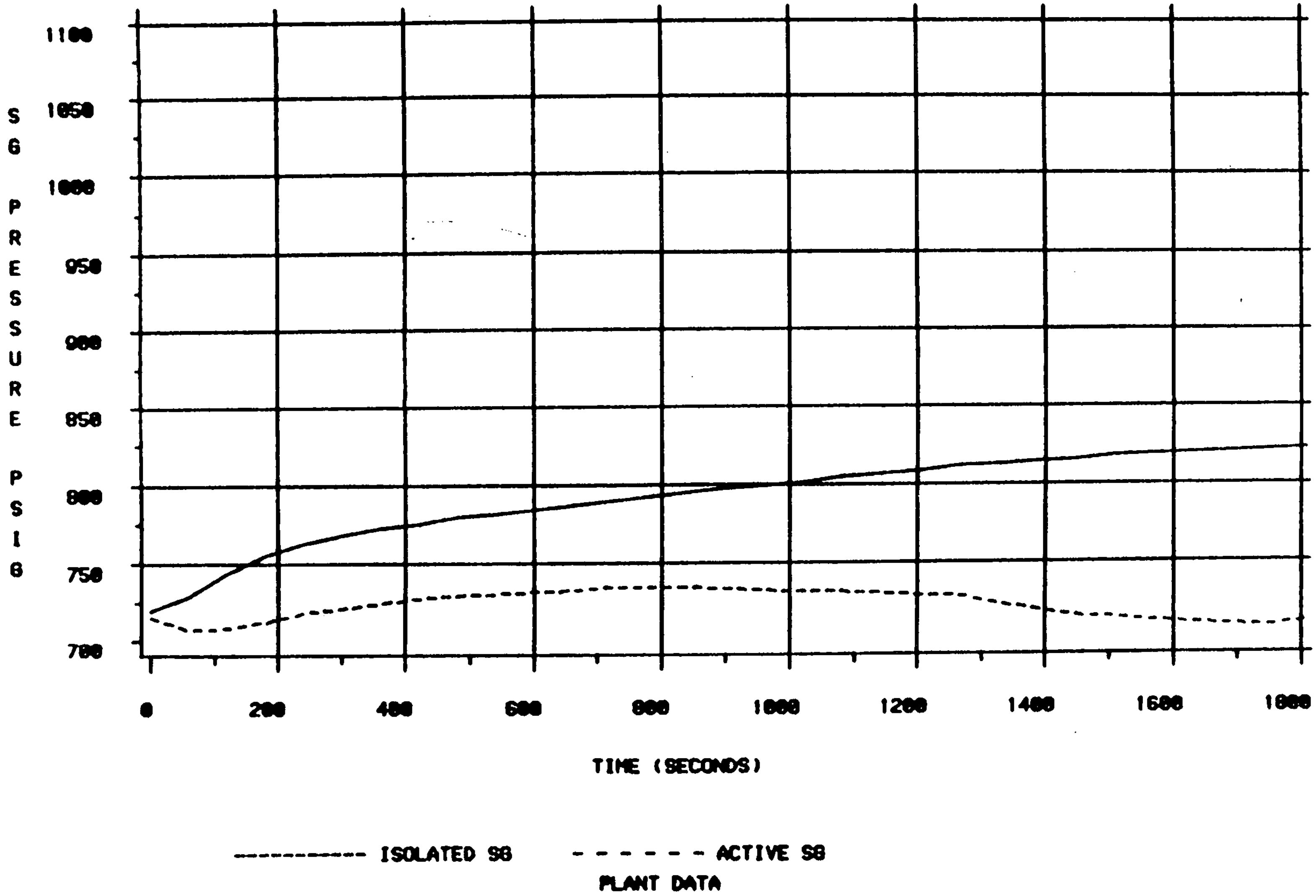


Figure 5.3.2-7

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

1/4 STEAM GENERATORS ISOLATED

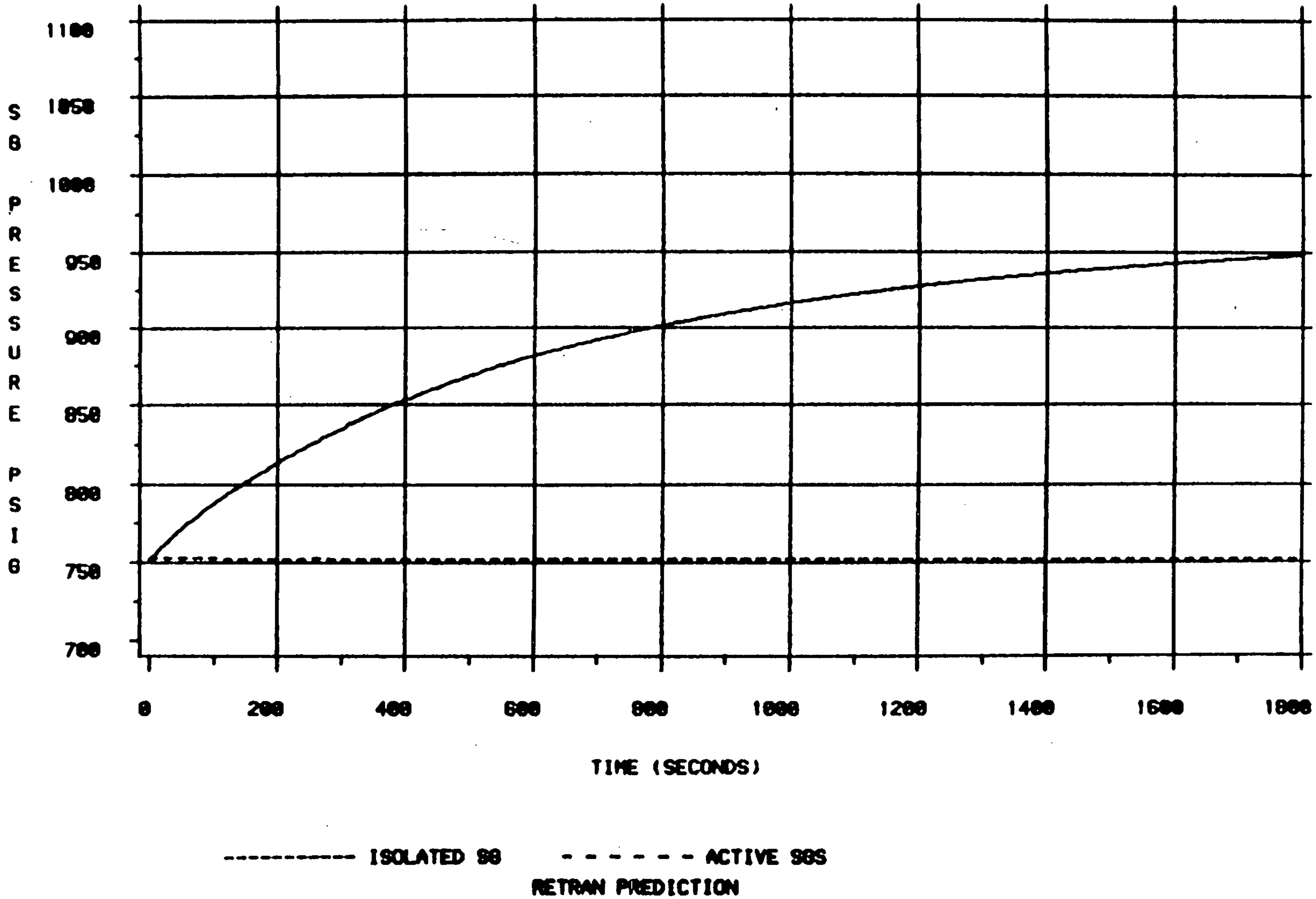


Figure 5.3.2-8

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

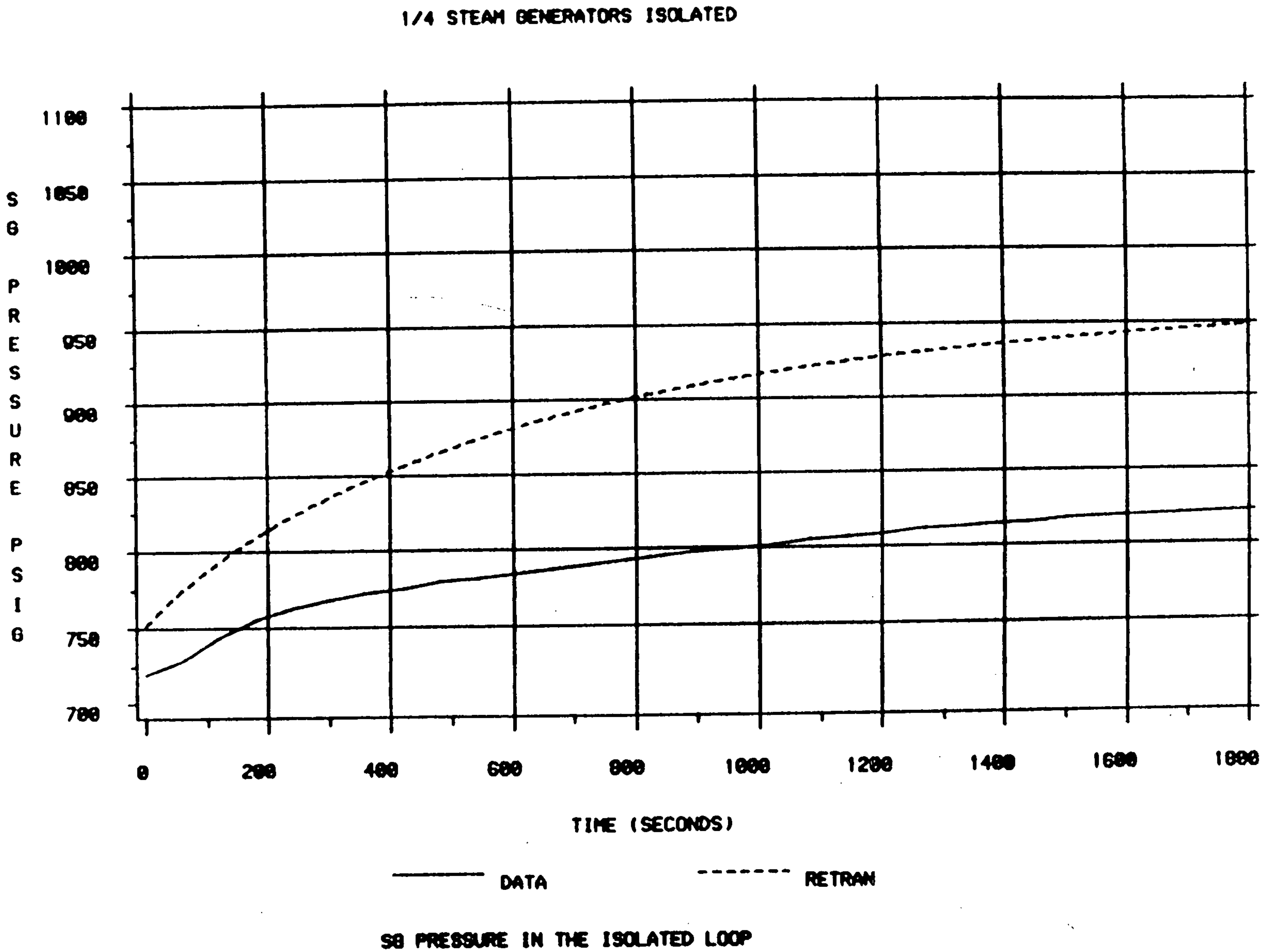
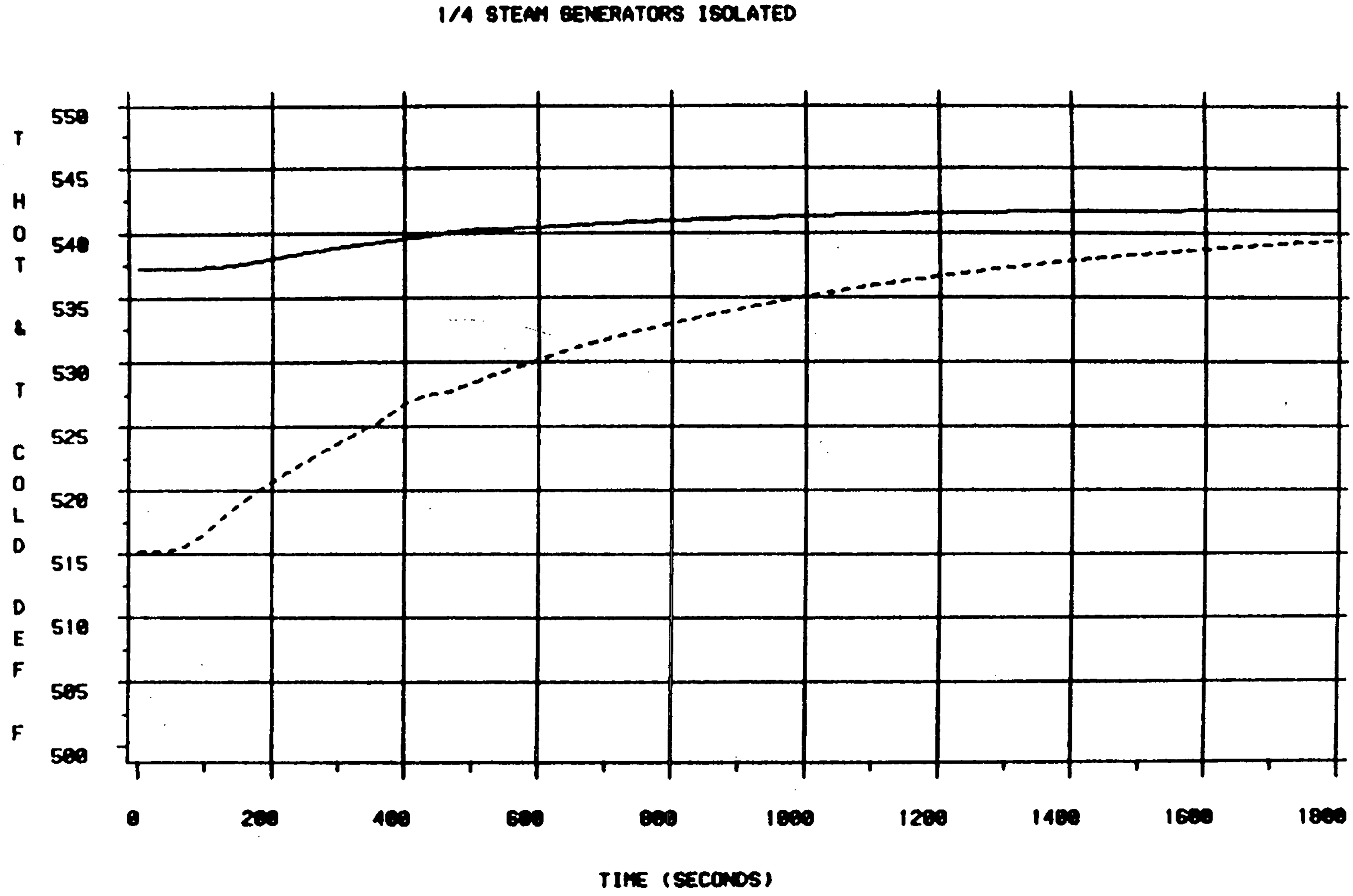


Figure 5.3.2-9

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

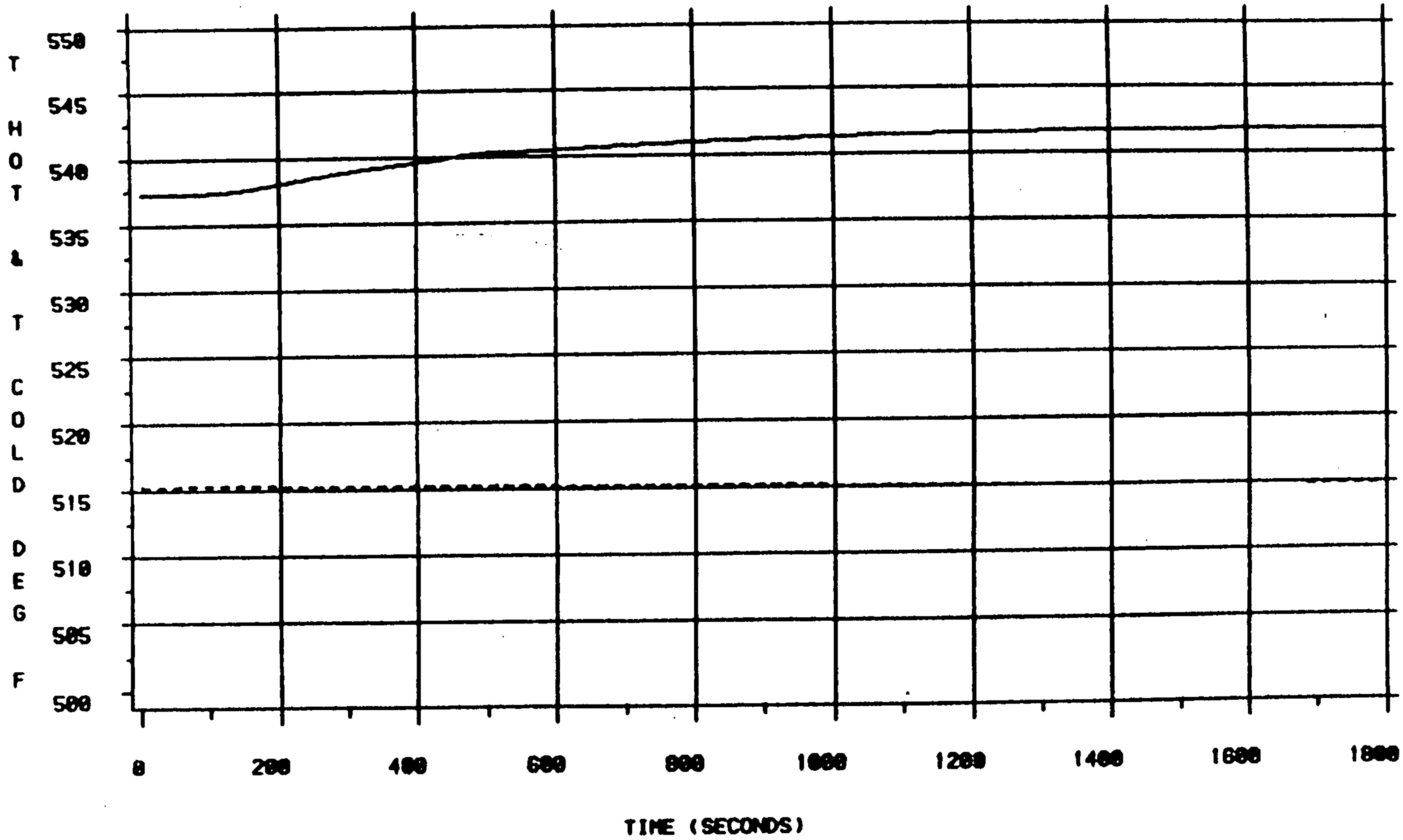


T-HOT & T-COLD IN THE ISOLATED LOOP
RETRAN PREDICTION

Figure 5.3.2-10

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

1/4 STEAM GENERATORS ISOLATED



T-HOT & T-COLD IN THE ACTIVE LOOPS
RETRAN PREDICTION

Figure 5.3.2-11

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

1/4 STEAM GENERATORS ISOLATED

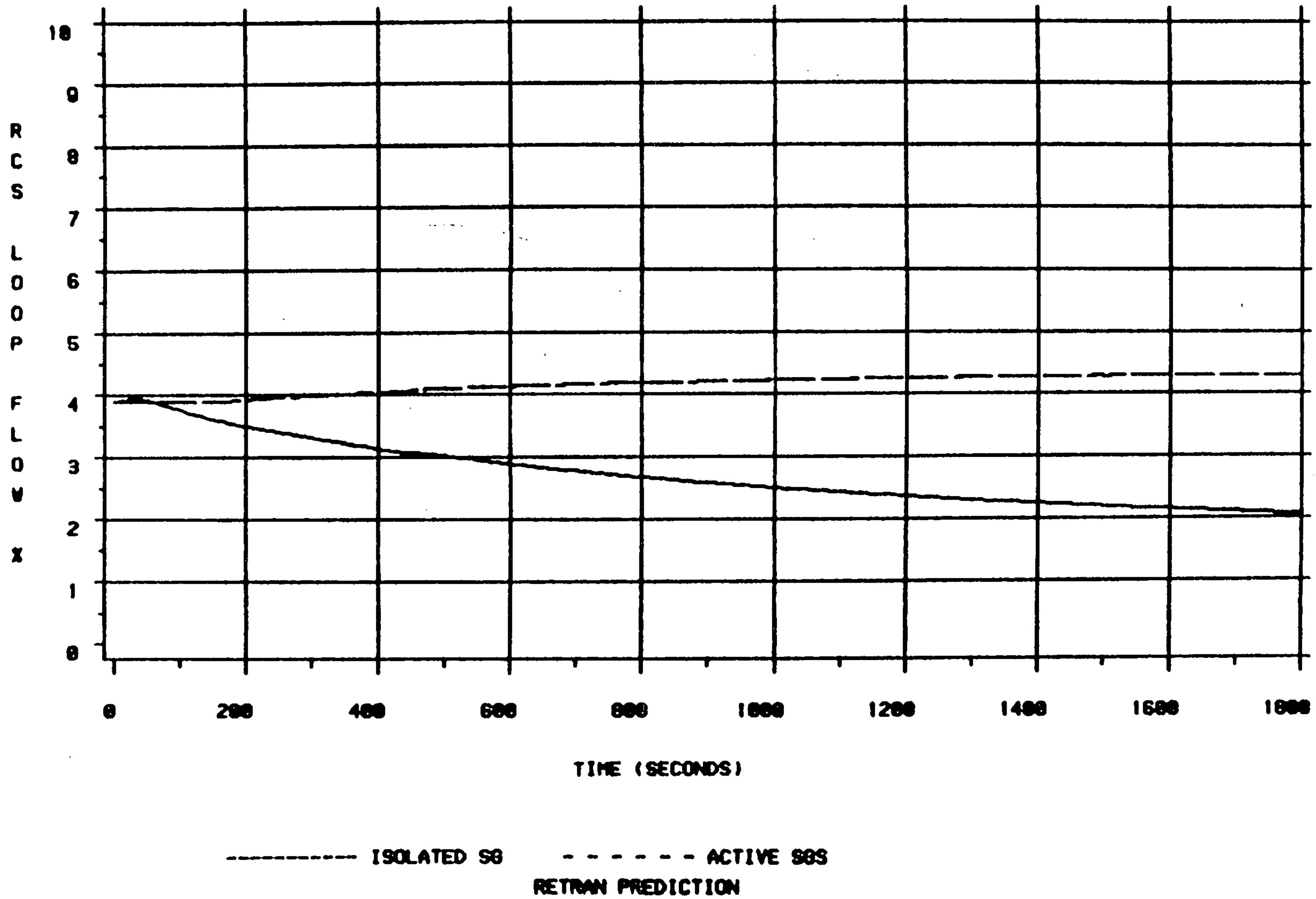


Figure 5.3.2-12

MNS−1 NATURAL CIRCULATION W/ SG ISOLATION

2/4 STEAM GENERATORS ISOLATED

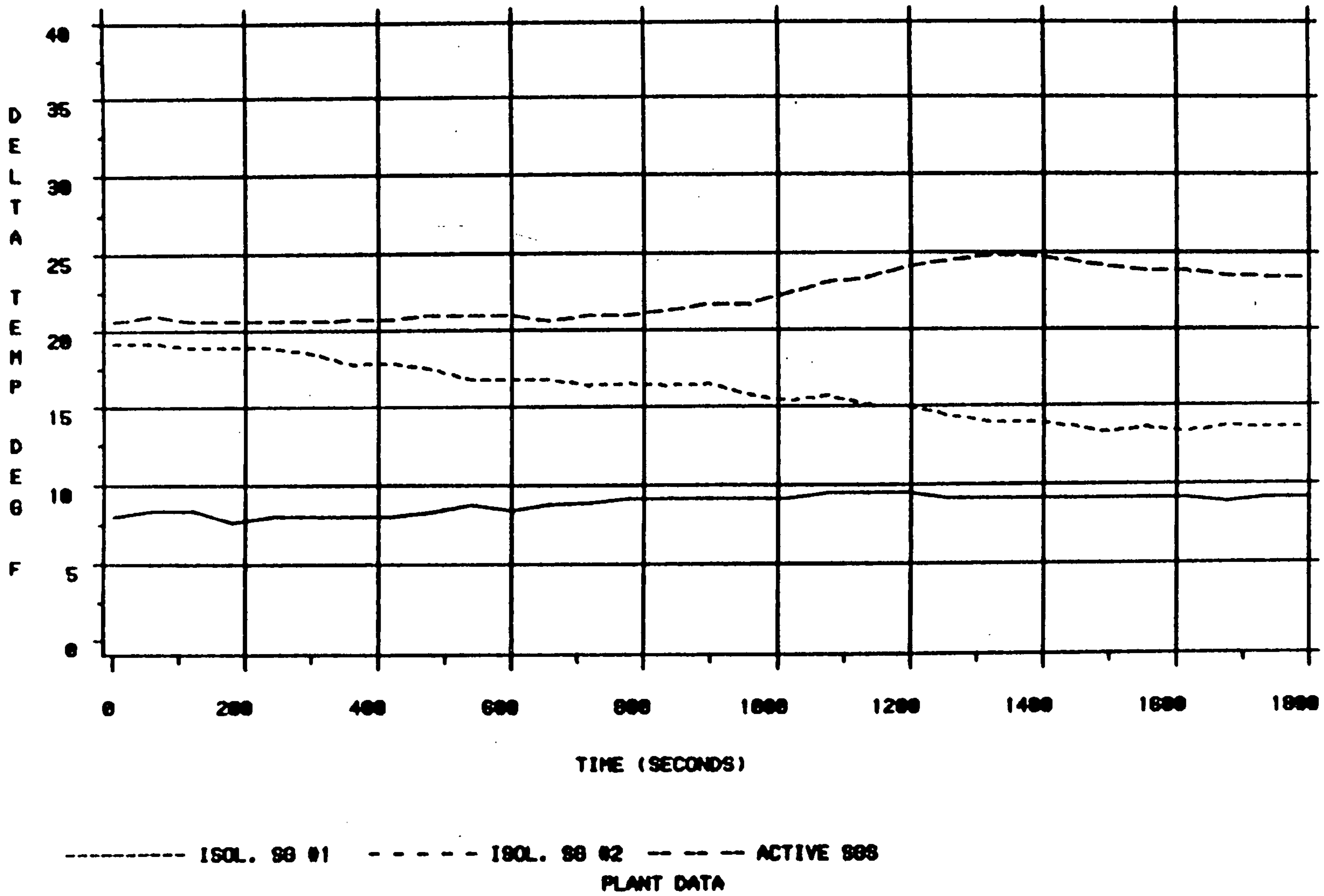


Figure 5.3.2-13

MNS−1 NATURAL CIRCULATION W/ SG ISOLATION

2/4 STEAM GENERATORS ISOLATED

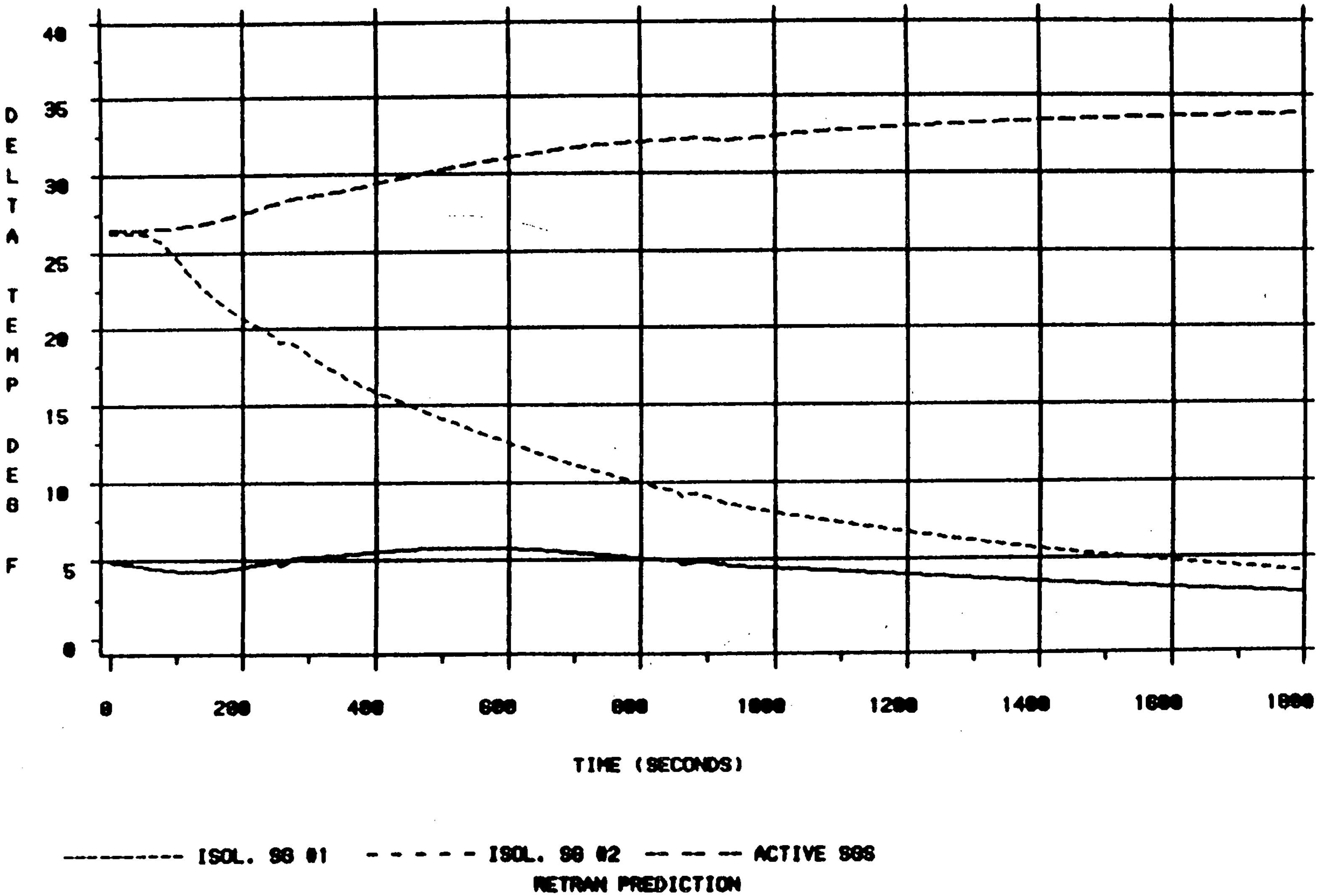
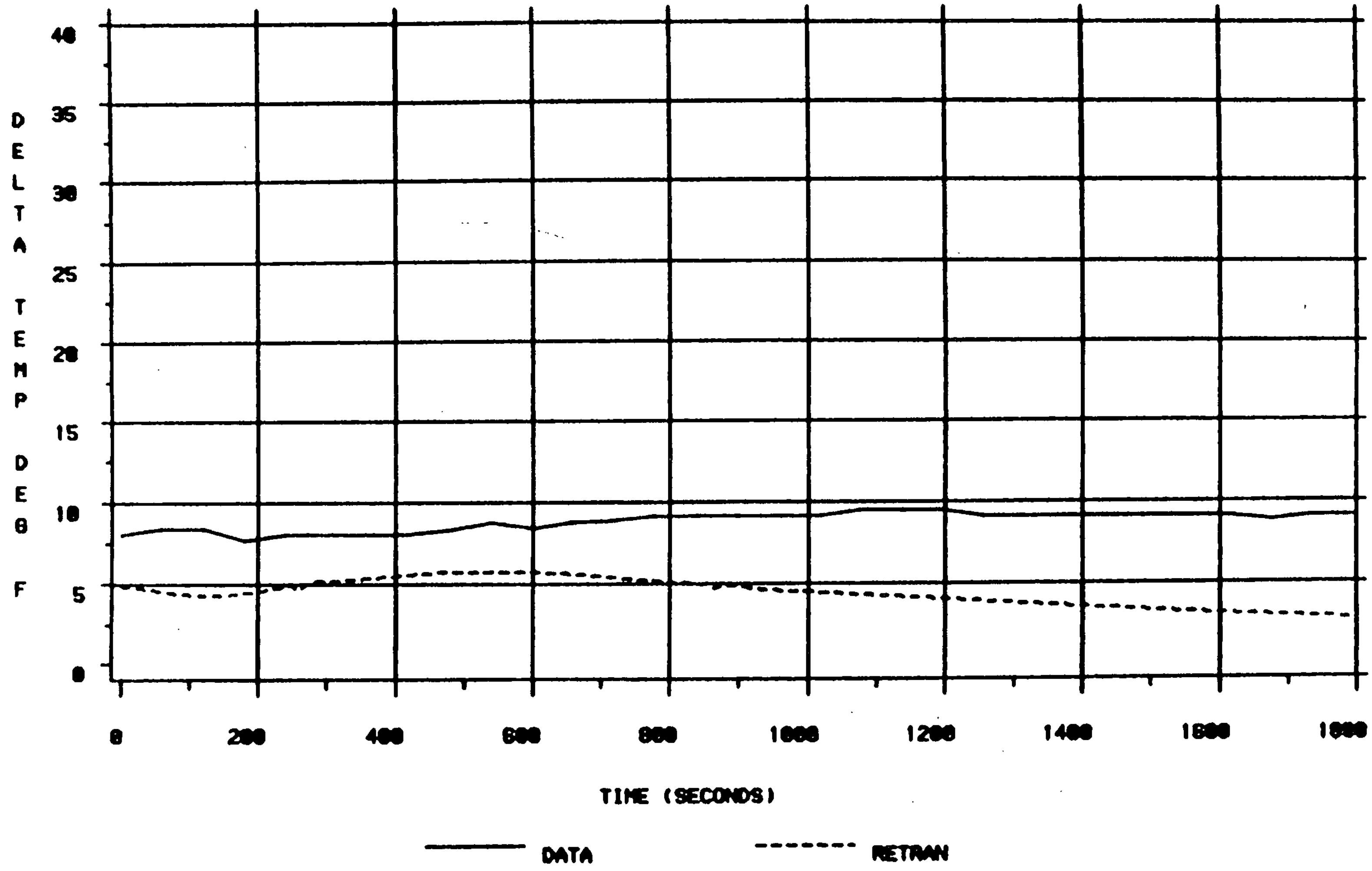


Figure 5.3.2-14

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

2/4 STEAM GENERATORS ISOLATED

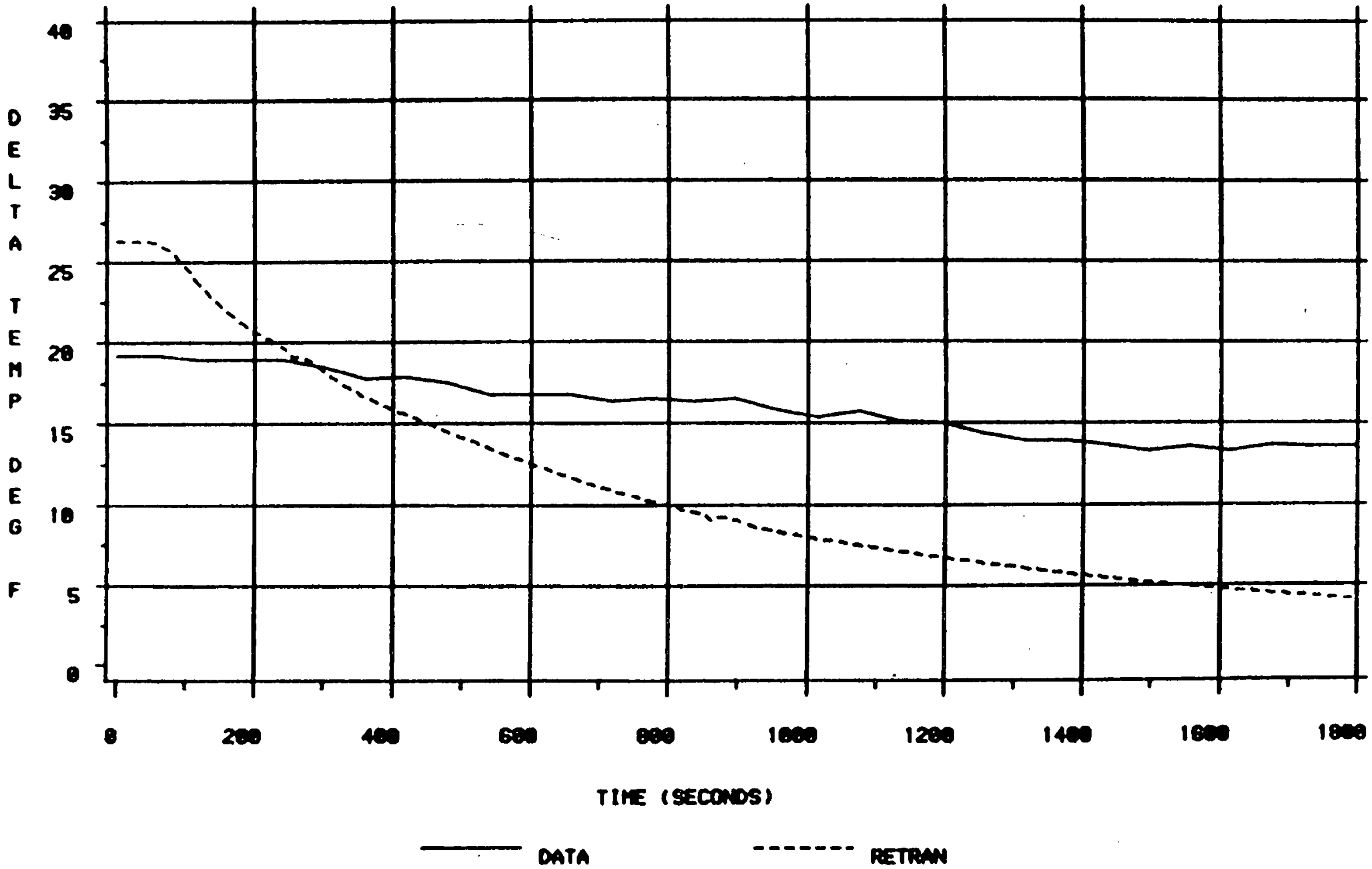


DELTA-T IN THE PREVIOUSLY ISOLATED LOOP

Figure 5.3.2-15

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

2/4 STEAM GENERATORS ISOLATED

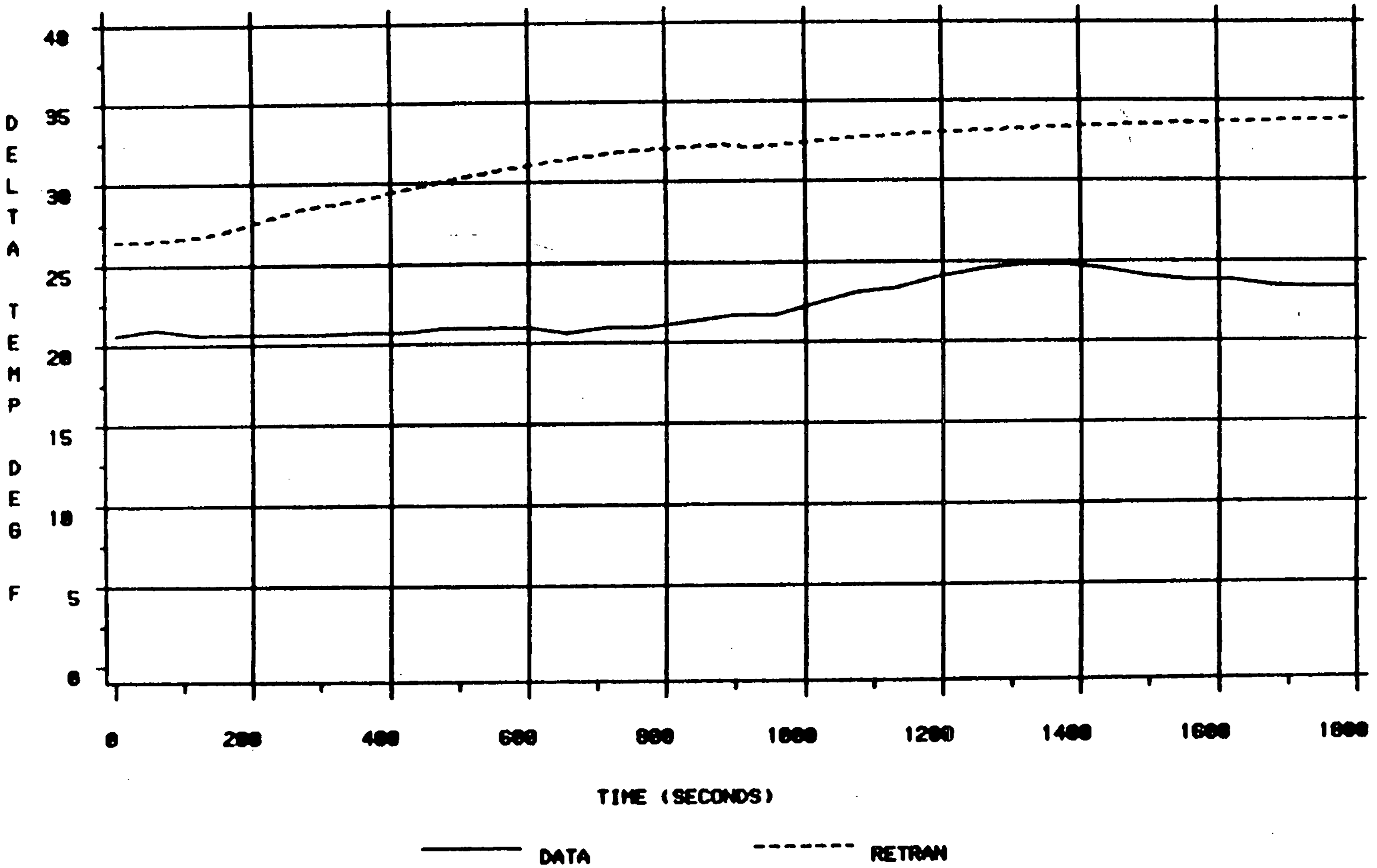


DELTA-T IN THE SECOND ISOLATED LOOP

Figure 5.3.2-16

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

2/4 STEAM GENERATORS ISOLATED



DELTA-T IN THE ACTIVE LOOPS

Figure 5.3.2-17

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

2/4 STEAM GENERATORS ISOLATED

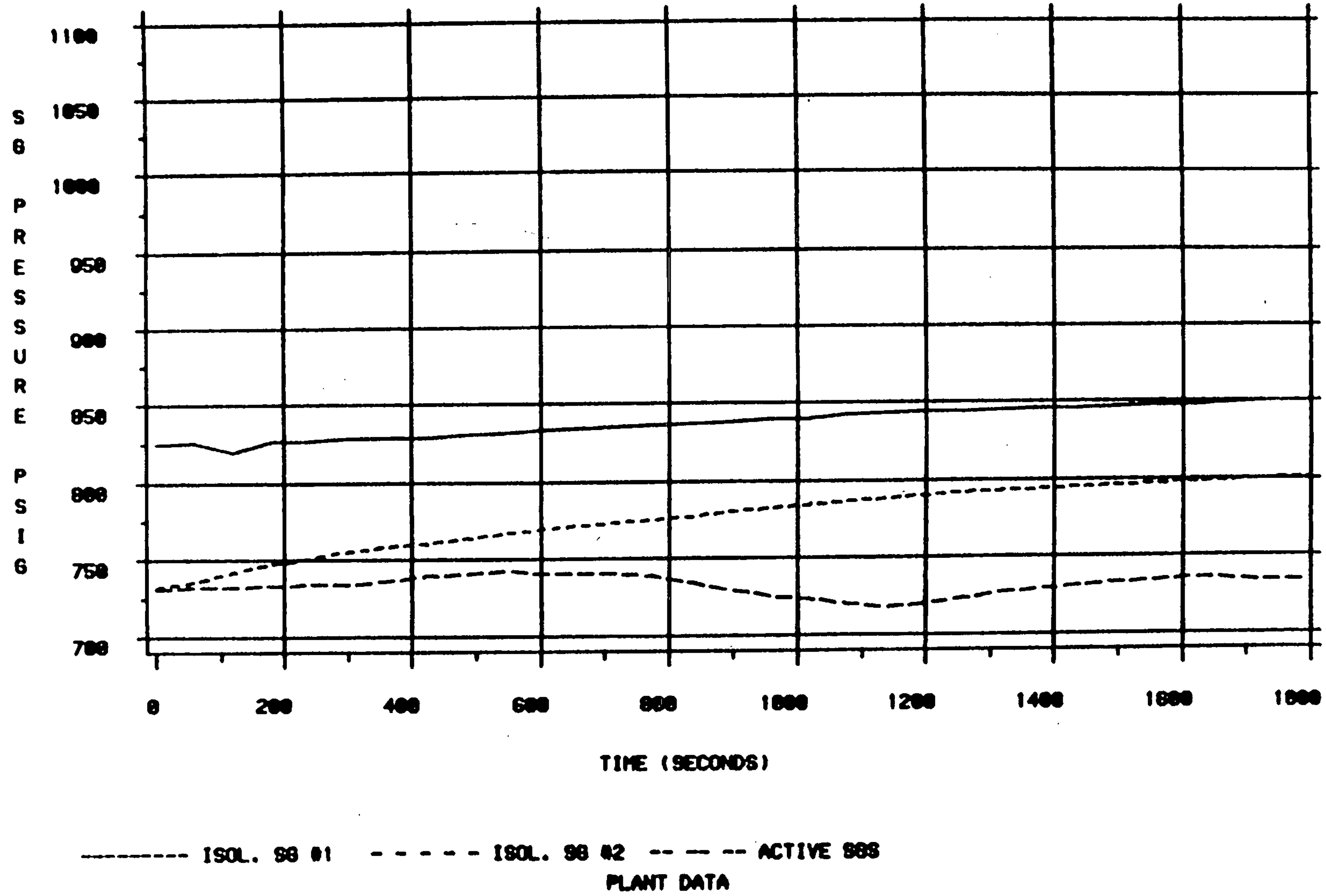


Figure 5.3.2-18

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

2/4 STEAM GENERATORS ISOLATED

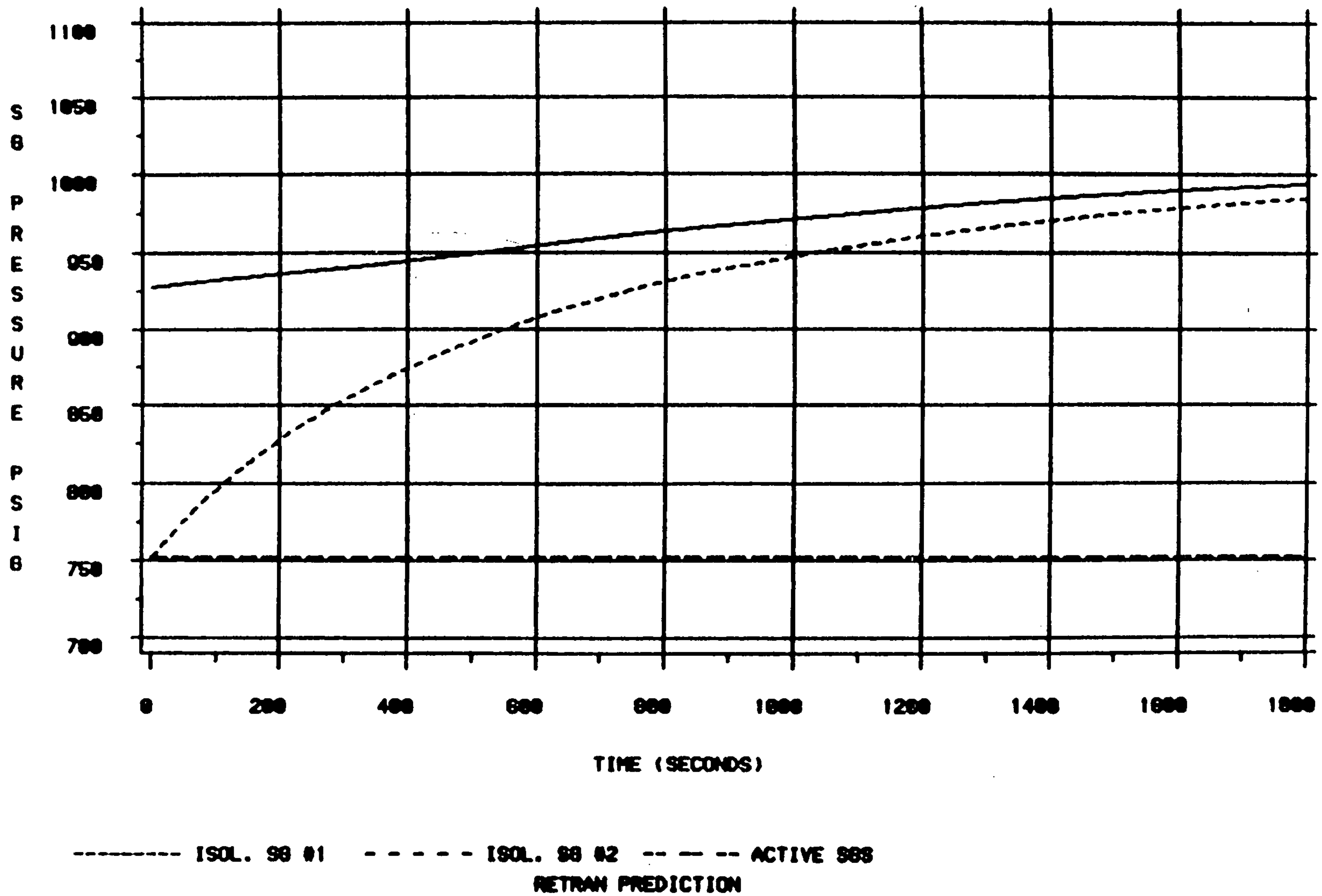
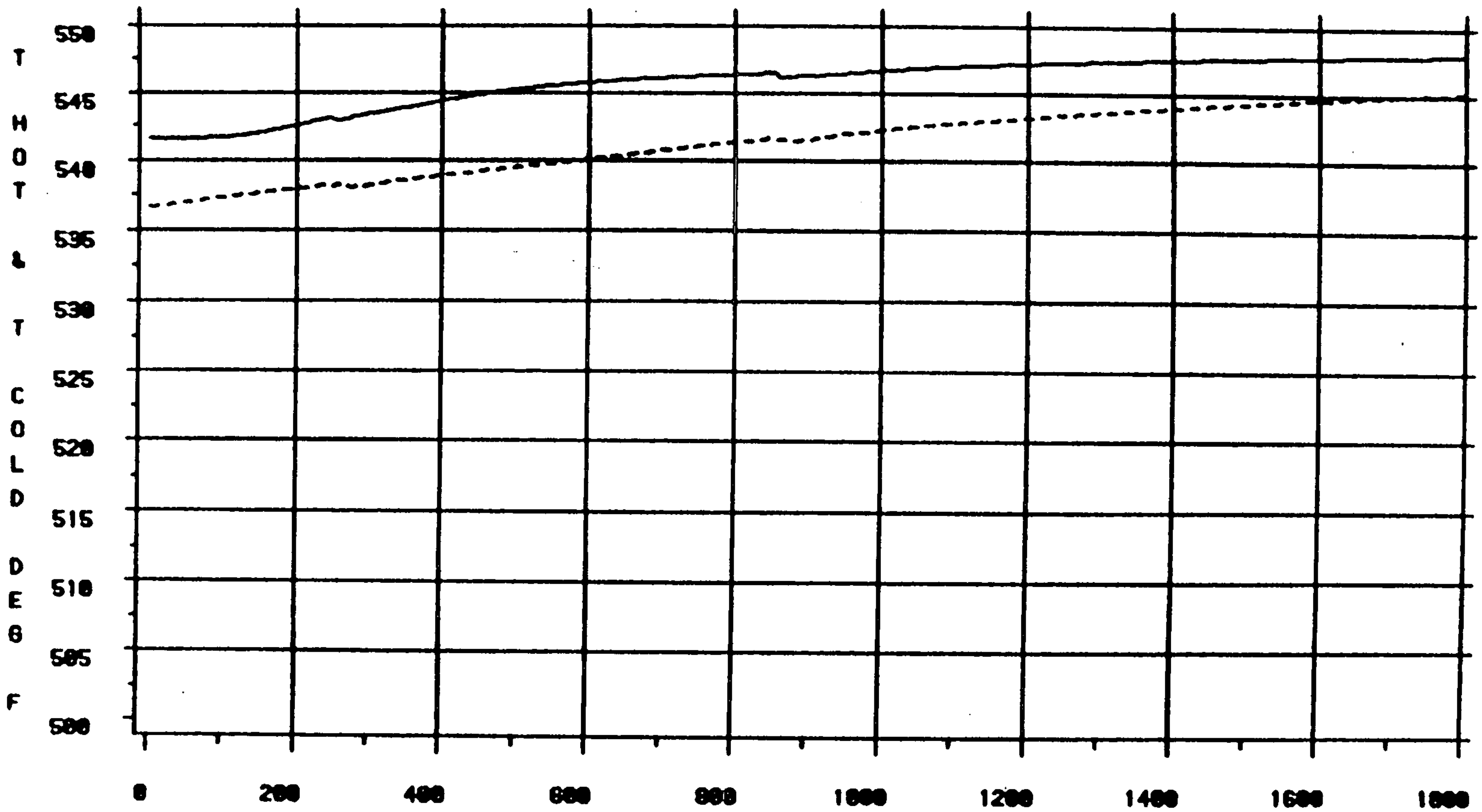


Figure 5.3.2-19

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

2/4 STEAM GENERATORS ISOLATED

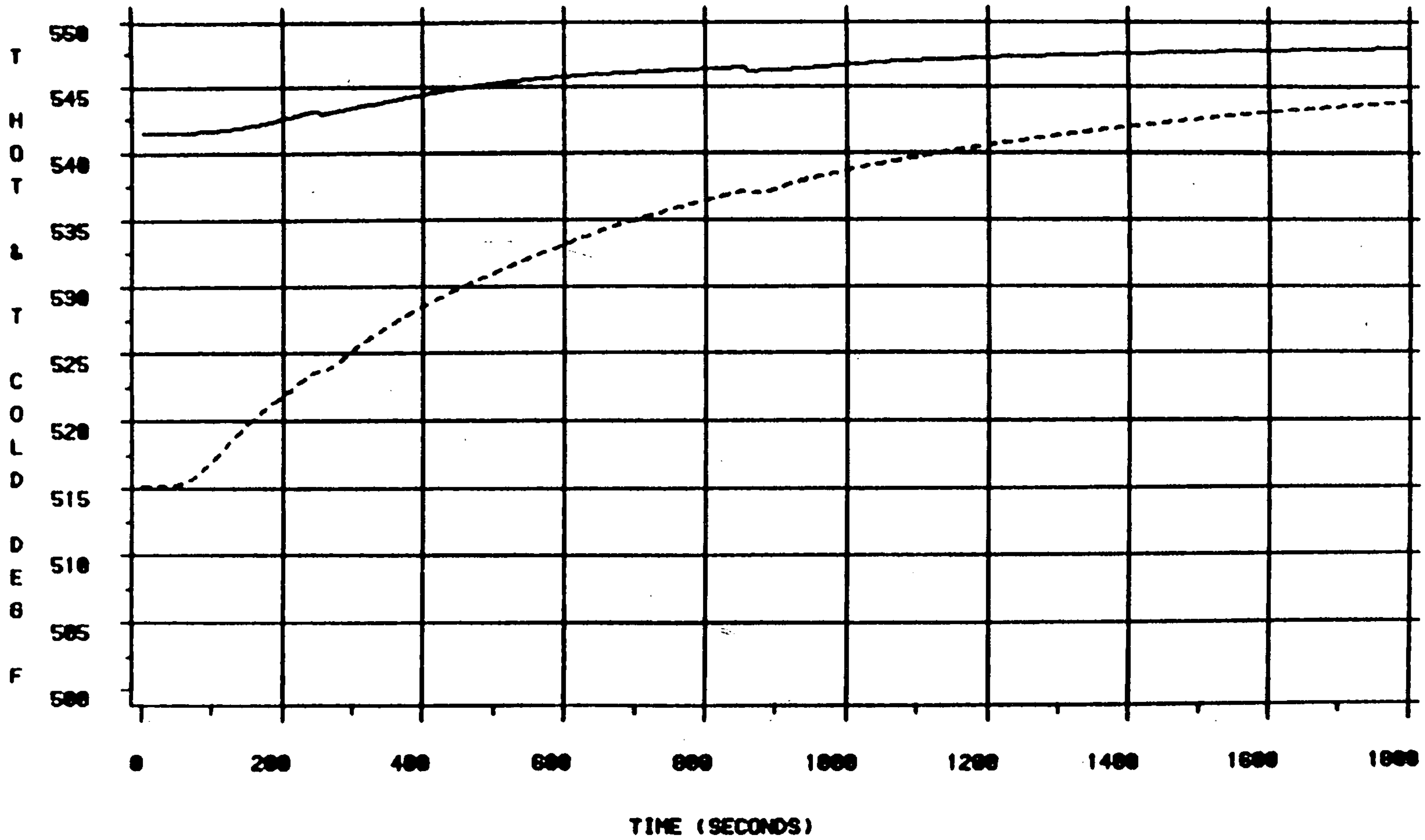


T-HOT & T-COLD IN THE PREVIOUSLY ISOLATED LOOP
RETRAN PREDICTION

Figure 5.3.2-20

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

2/4 STEAM GENERATORS ISOLATED

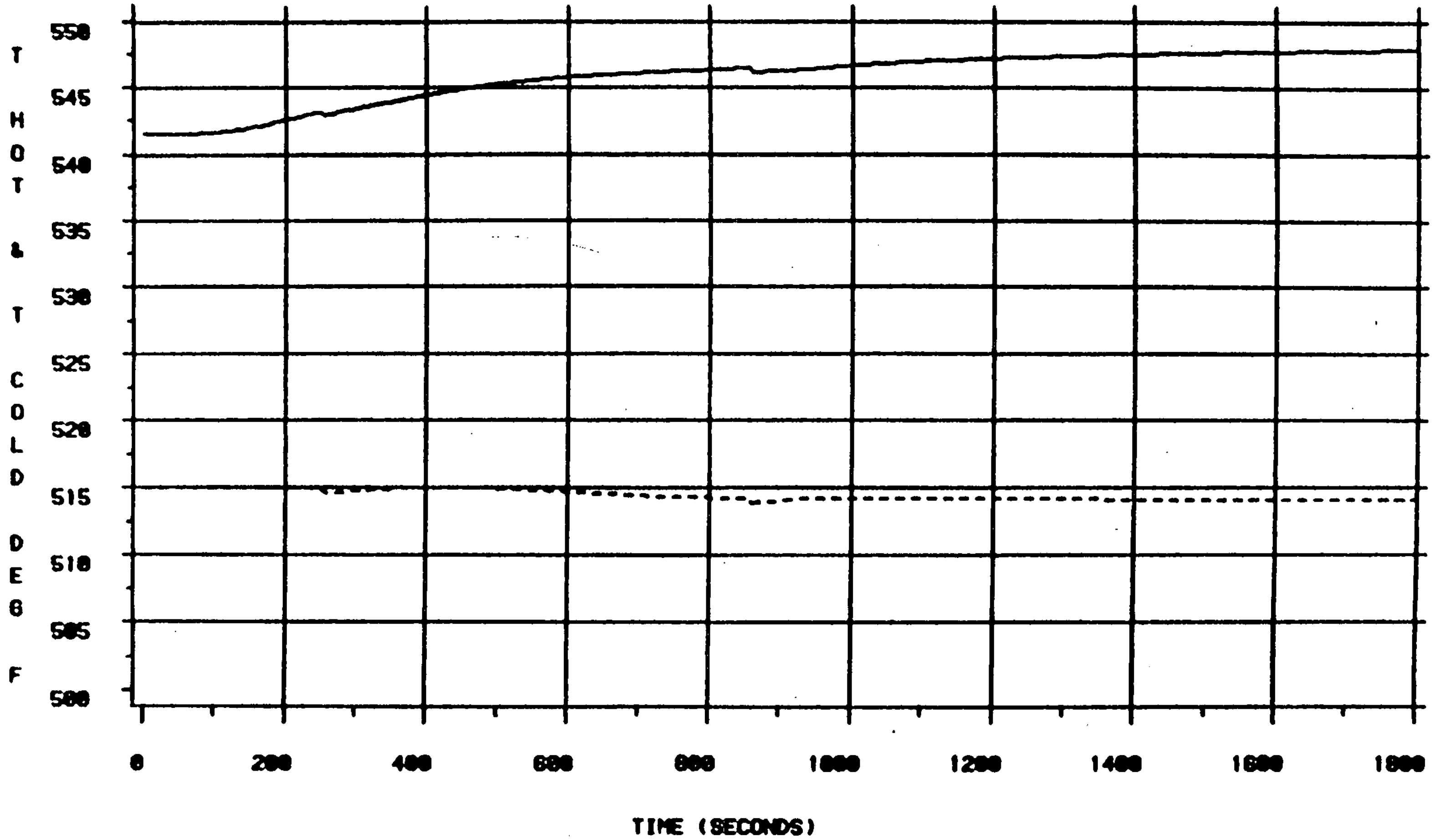


T-HOT & T-COLD IN THE SECOND ISOLATED LOOP
RETRAN PREDICTION

Figure 5.3.2-21

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

2/4 STEAM GENERATORS ISOLATED



T-HOT & T-COLD IN THE ACTIVE LOOPS
RETRAN PREDICTION

Figure 5.3.2-22

MNS-1 NATURAL CIRCULATION W/ SG ISOLATION

2/4 STEAM GENERATORS ISOLATED

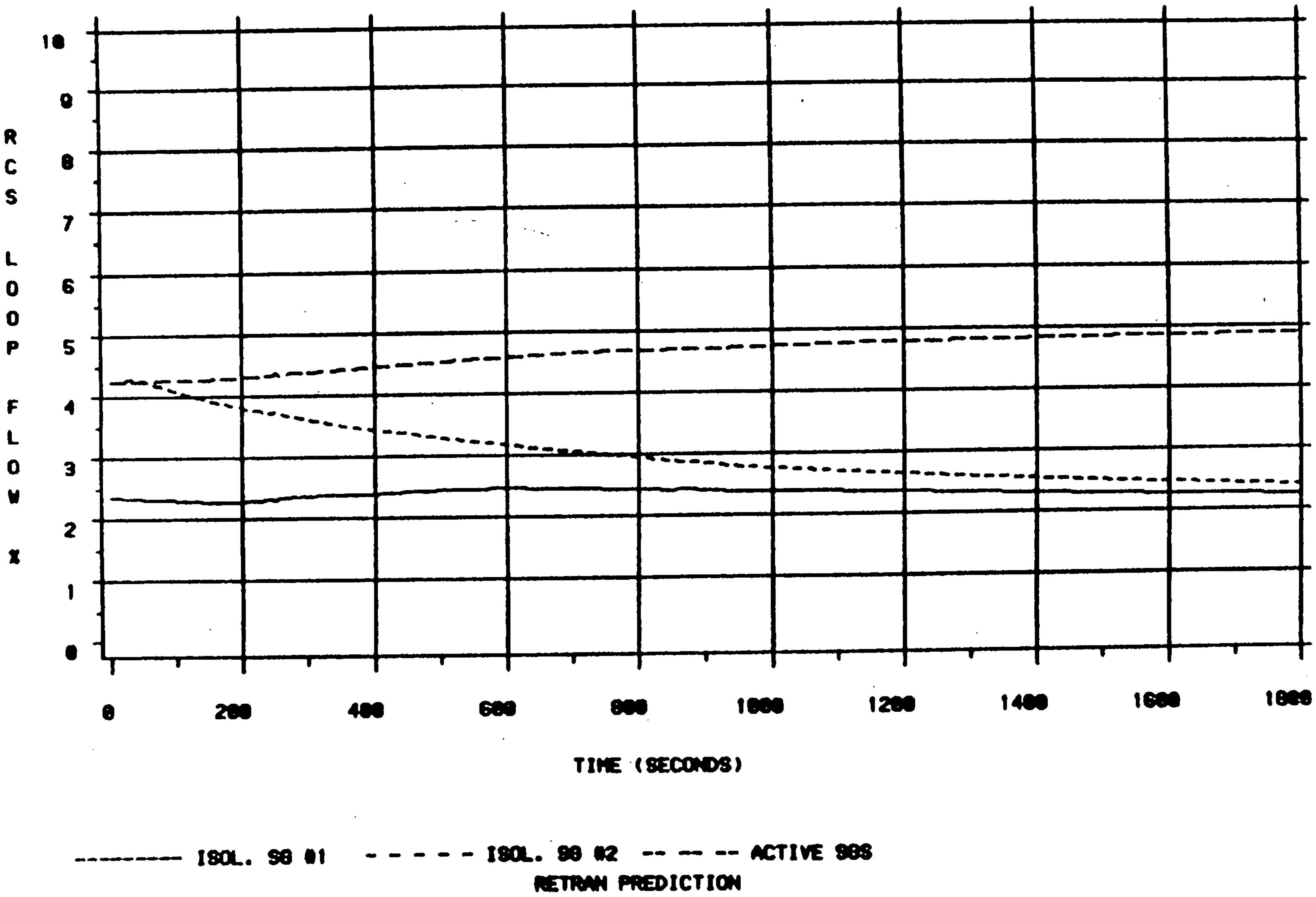


Figure 5.3.2-23

5.3.3 McGuire Nuclear Station - Unit 1 Reactor Coolant Pump Trip at 89% Power June 6, 1984

Transient Description

McGuire Unit 1 was operating at 89% full power when the RCP "C" bus feeder breaker opened. The reactor tripped almost immediately on low reactor coolant flow in loop C since reactor power was greater than 48% full power. All control stations except rod control were in automatic at the time of the event. Pressurizer pressure and level decreased post-trip due to the loss of heat source and continued feedwater addition to the SGs. Charging and letdown continued after the trip with the net difference between the two at approximately 13 gpm. Both banks of condenser dump valves initially opened post-trip to cool the unit down to the no-load temperature of 557°F. One condenser dump valve stuck open post-trip. Upon reactor trip, steam line pressure increased sharply resulting in the lifting of two of the four steam line PORVs. Flow in the affected loop decreased with RCP coastdown and then reversed due to the driving force of the remaining three RCPs. MFW was isolated on low reactor coolant average temperature of 564°F. AFW was initiated on low-low level in all four SGs.

Pressurizer pressure reached a minimum value of 1976 psig approximately 145 seconds post trip. Pressurizer level reached a minimum level of 24% at 220 seconds post-trip. T-ave was stabilized at 550°F approximately three minutes post-trip.

Discussion of Important Phenomena

The phenomenon of interest in this simulation is the effect of a RCP coastdown during a trip from a high power level. Reactor trip on low flow in one loop occurs immediately after a single RCP trip. Reverse flow in the affected loop is quickly established due to the net driving force of the three remaining RCPs. After flow reversal, the hot leg temperature decreases as the cooler fluid from the steam generator tube bundle flows back through the hot leg. T-ave in the remaining loops is unaffected by the flow reversal.

Model Description and Boundary Conditions

The two-loop McGuire Unit 1 RETRAN model was used for the analysis due to the asymmetric nature of the pump trip. RCS flow was specified in the simulation in order to match ΔT. The parameters used as initial conditions were matched to the plant data as follows:

Initial Conditions

	Model	Plant
Power Level	89% (3036 MWt)	89% (3036 MWt)
PZR Pressure	2228.0 psig	2228.0 psig
PZR Level	59.4%	59.4%
T-ave	560.4°F	560.4°F
ΔT	52.1°F	52.1°F
Steam Line Pressure	1036 psig	1036 psig
SG Level	64.4%	64.4 % (ave)
MFW Flow	1.33×10^6 lbm/hr	1.34×10^6 lbm/hr
MFW Temperature	429.5°F	429.5°F

The problem boundary conditions used included cycle specific post-trip delayed neutron power and decay heat, MFW, and AFW flow. Transient monitor steam dump valve performance data was insufficient in providing a full understanding of the valves operation. One condenser dump valve was noted to have stuck open during the transient and was modeled as such. The use of RETRAN best estimate steam dump bank performance resulted in secondary pressures much lower than those indicated by plant data. With the unavailability of complete plant valve position data and the discrepancy in results between RETRAN using the best estimate steam dump performance and the plant data, steam line pressure data was input as a boundary condition during the simulation in order to better match the actual plant performance.

Simulation Results

The simulation begins with the single RCP trip and continues for three minutes. The simulation is terminated after all major plant parameters have returned to nominal post-trip conditions. The sequence of events is given in Table 5.3.3-1. The results of the simulation are compared to the plant data in Figures 5.3.3-1 through 5.3.3-13.

The pressurizer pressure response is shown in Figure 5.3.3-1. The comparison indicates good agreement between RETRAN and the actual plant response. From approximately 20-50 seconds, RETRAN slightly underpredicts the plant pressurizer pressure. RETRAN and plant pressure trend together during the remainder of the simulation, with RETRAN slightly underpredicting pressure at the end of the simulation.

The pressurizer level response, like pressurizer pressure, indicates a similar trend with the plant data as shown in Figure 5.3.3-2. RETRAN pressurizer level trends closely with the plant data immediately after the reactor trip. From approximately 10-40 seconds, RETRAN underpredicts pressurizer level. RETRAN and plant level compare well throughout the remainder of the simulation.

The reactor coolant average temperature response for the unaffected loop is presented in Figure 5.3.3-3. Under normal operating conditions, bypass flow from the hot and cold legs is diverted through their respective RTD manifolds and back into the pump suction piping. The net pressure differences between hot leg and pump suction piping and cold leg and pump suction piping provide the necessary driving force required for the RTD Bypass System to work. The low flow and stagnant flow conditions existing in the affected loop after pump trip yield invalid RTD indications, and therefore the affected loop average temperature results are not presented. T-ave in the unaffected loop is relatively unaffected by the flow coastdown and reversal. The RETRAN prediction trends very closely with the plant data in the unaffected loop throughout the simulation.

The wide range hot leg temperature response for the affected and unaffected loops are presented in Figures 5.3.3-4 and 5.3.3-5, respectively. The RETRAN predictions closely match the plant data throughout the entire simulation. The wide range cold leg temperature response for the affected and unaffected loops are shown in Figures 5.3.3-6 and 5.3.3-7, respectively. During the initial 40 seconds of the simulation, the RETRAN temperatures are a few degrees less than the plant data. The trend then reverses and RETRAN predicts a slightly higher cold leg temperature throughout the remainder of the simulation.

The steam line pressure response for the affected and unaffected loop are shown in Figures 5.3.3-8 and 5.3.3.-9, respectively. Steam line pressure immediately increases post-trip due to the turbine trip and loss of steam load. The plant response resulted in the lifting of two of the four steam line PORVs. The pressure trends of both the affected and unaffected loops are nearly identical. Steam line pressure in the affected loop was controlled to match the plant data boundary condition. The use of the steam pressure boundary condition was necessary due to the unavailability of steam dump system operational data for the transient. The control system utilized varied the steam dump valve positions in order to match steam line pressure data.

The SG level comparisons for the affected and unaffected loops are shown in Figures 5.3.3-10 and 5.3.3-11, respectively. The RETRAN levels remain above the plant data during the first 40 seconds post-trip as the steam line pressure increases. The level prediction in the affected loop remains below the plant response throughout most of the simulation. The level prediction in the unaffected loop stabilizes early and trends with the plant data throughout the simulation.

The effects of the RCP trip on the flow in the affected and unaffected loops are presented in Figures 5.3.3-12 and 5.3.3-13, respectively. As shown in Figure 5.3.3-12, the RETRAN RCP coasts down in a time nearly equivalent to the plant data. Flow reversal is established approximately 20 seconds after the pump trip and stabilizes at approximately 28% of its pre-trip value. Reverse flow indication from the plant data is not available due to flow instrumen-

tation limitations. The subsequent increase in loop flow in the unaffected loop is shown in Figure 5.3.3-13. Flow in the unaffected loop stabilizes at approximately 107% of its pre-trip flow.

Table 5.3.3-1

McGuire Nuclear Station Unit 1
Reactor Coolant Pump Trip at 89% Full Power
June 6, 1984

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
Reactor coolant pump trip	0	0
Reactor trip and turbine trip	1	1
Auxiliary feedwater actuation on low-low steam generator levels		
Affected loop flow stagnation and reversal	16	20
Steam line PORVs open	28	**
Steam line PORVs close	54	**
End of simulation	N/A	180

Note: Two asterisks indicate that steam line PORV operation was not modeled due to assuming a steam line pressure boundary condition.

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT

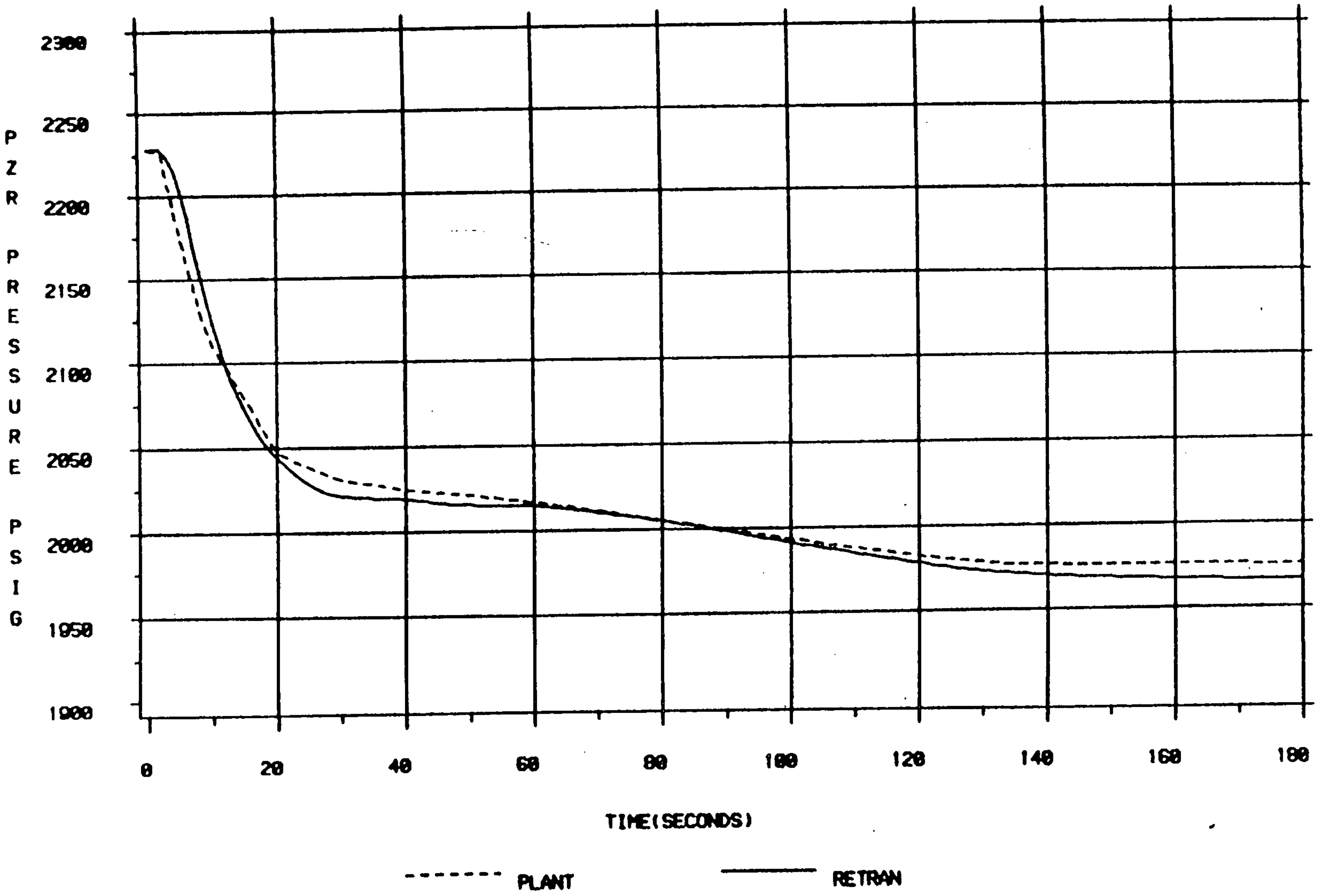


Figure 5.3.3-1

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT

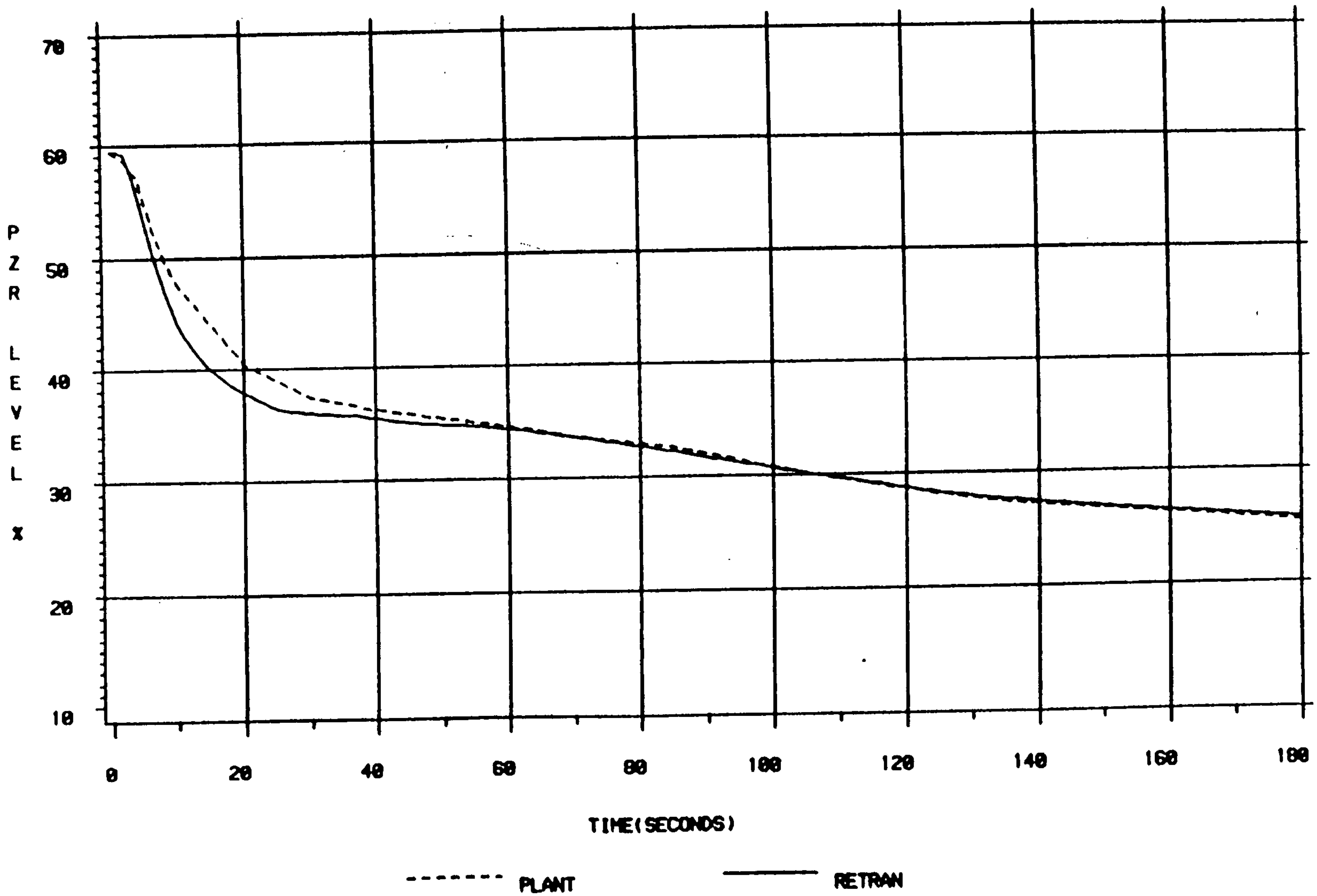
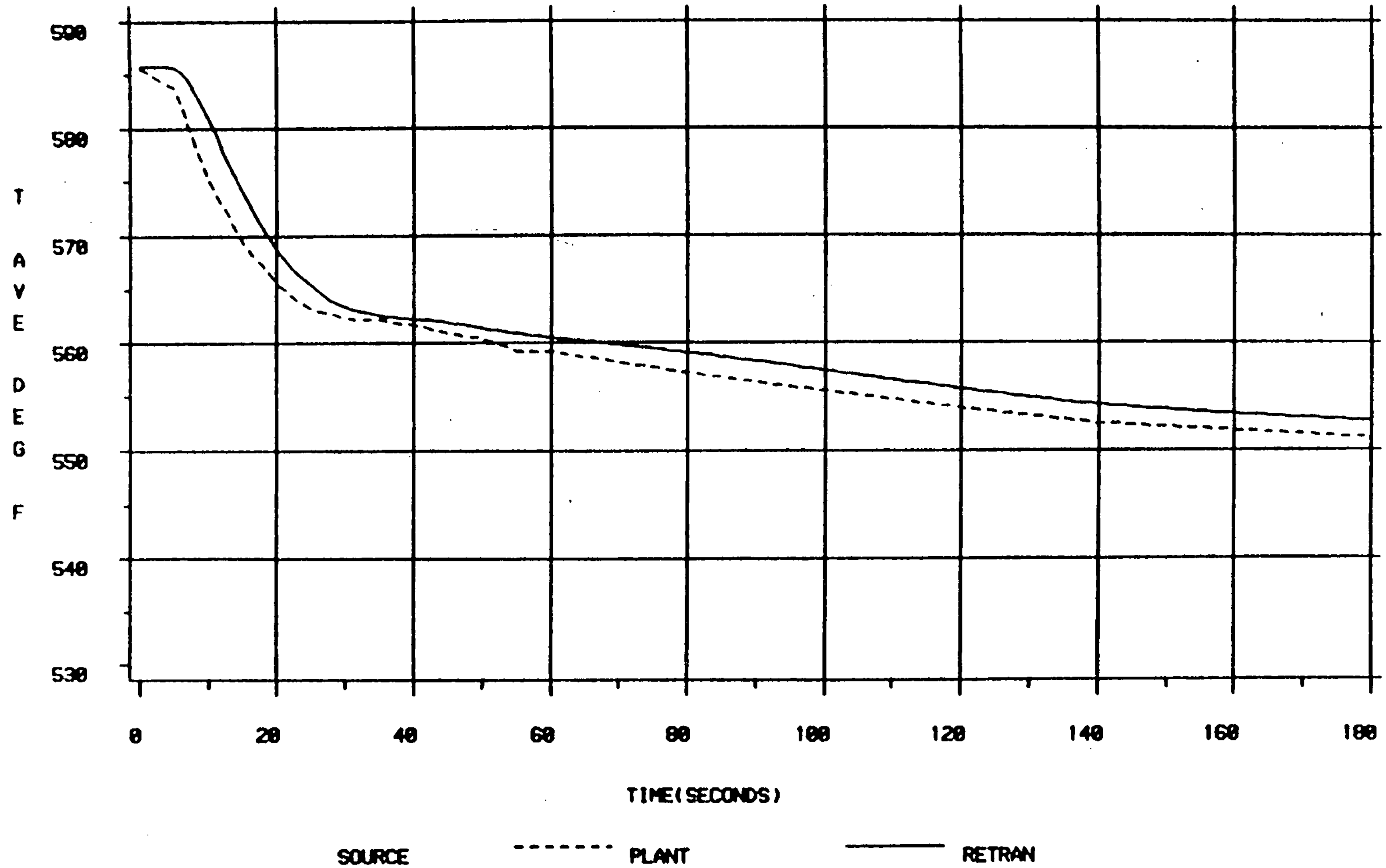


Figure 5.3.3-2

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT

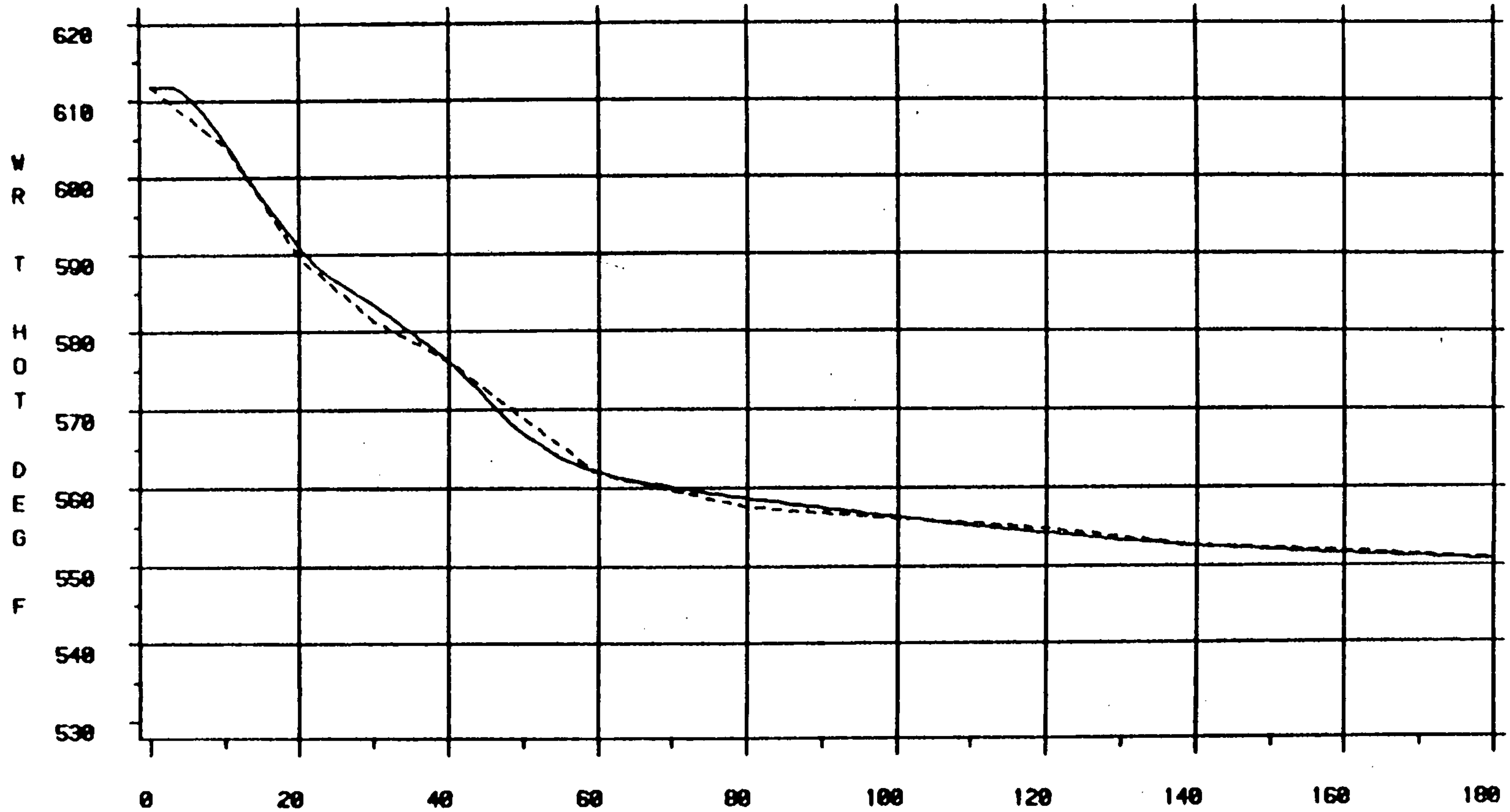


LOOP WITH PUMP ON

Figure 5.3.3-3

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT



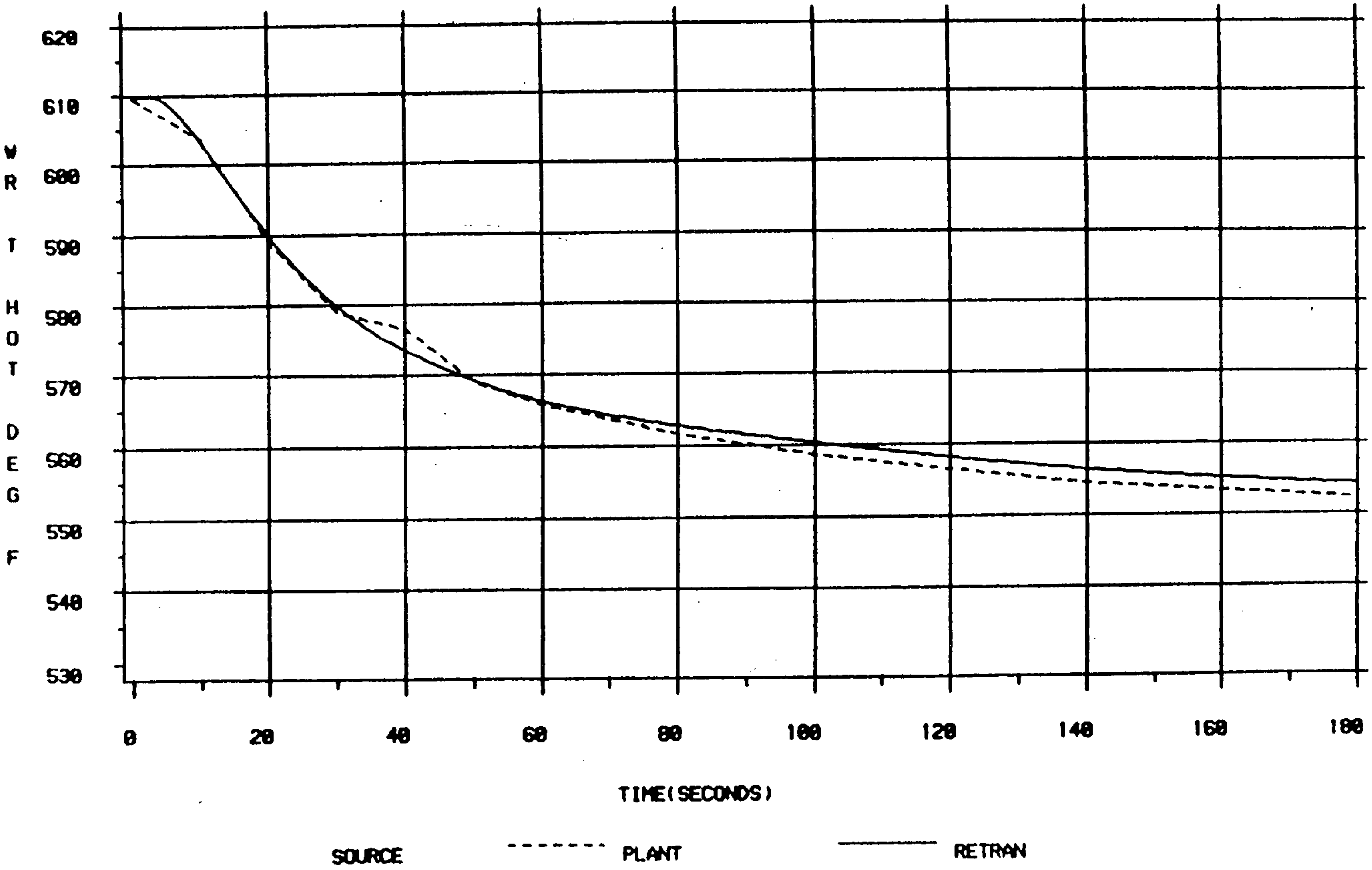
SOURCE - - - - - - PLANT ———— RETRAN

LOOP WITH PUMP TRIPPED

Figure 5.3.3-4

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT

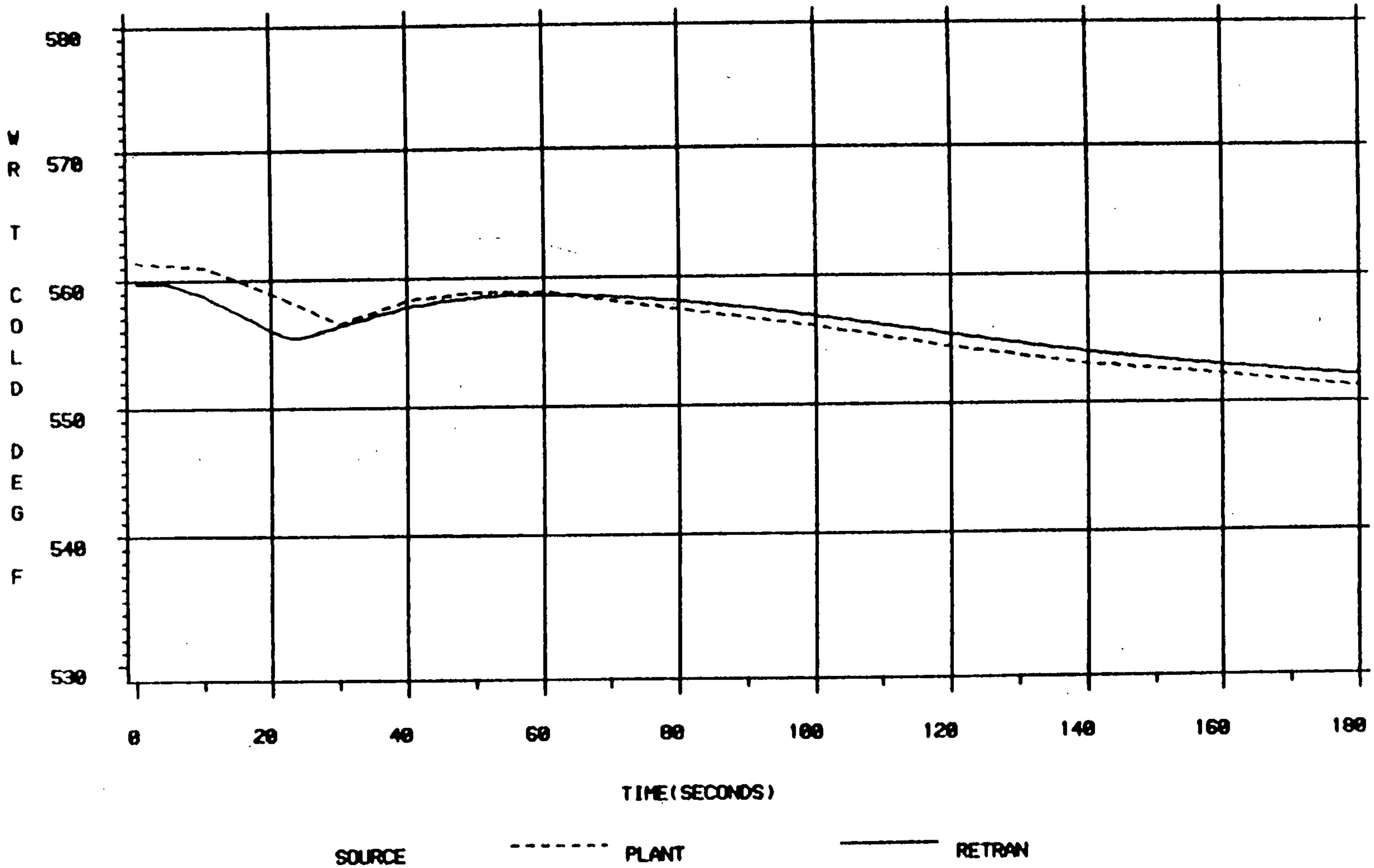


LOOP WITH PUMP ON

Figure 5.3.3-5

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT



LOOP WITH PUMP TRIPPED

Figure 5.3.3-6

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT

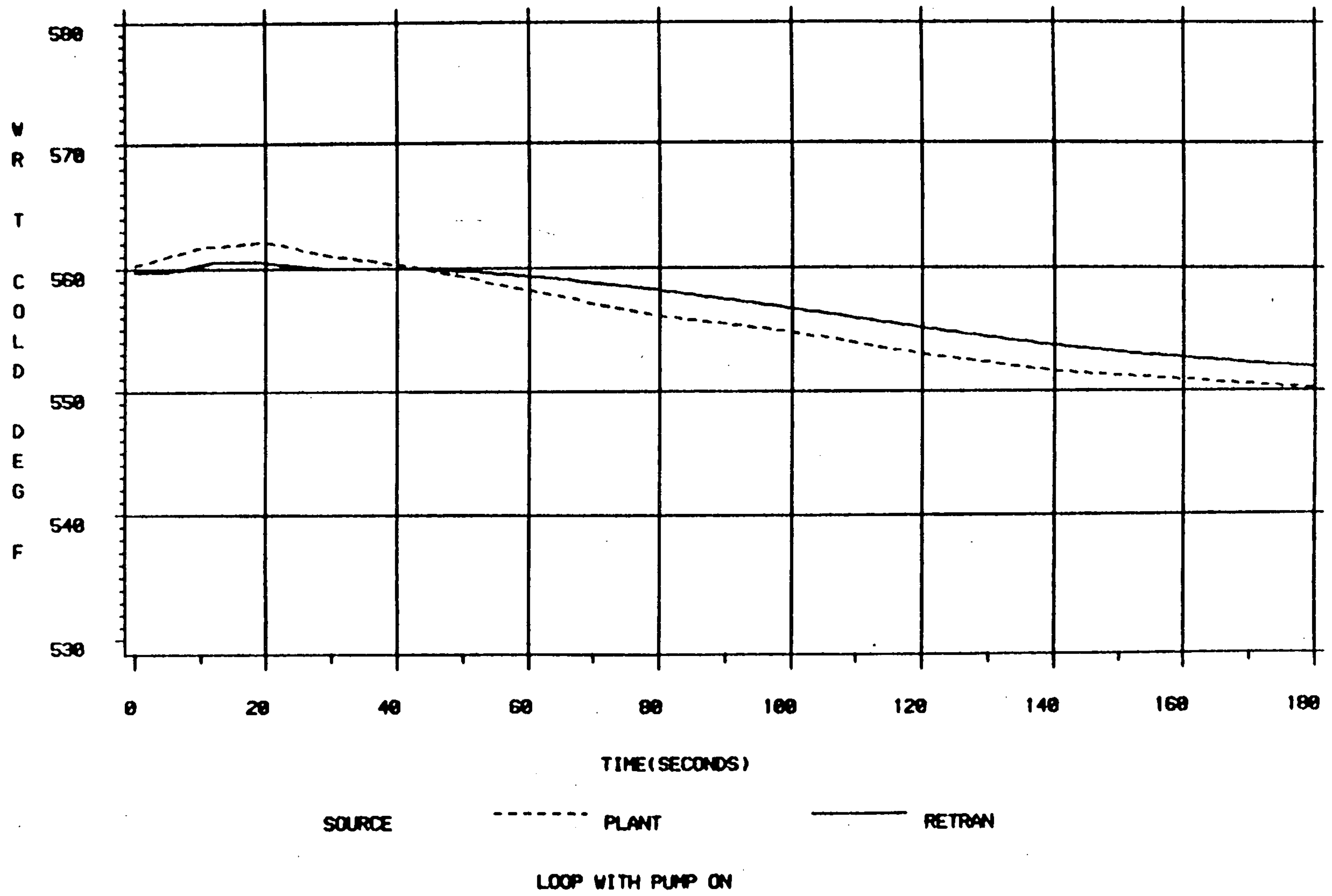


Figure 5.3.3-7

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT

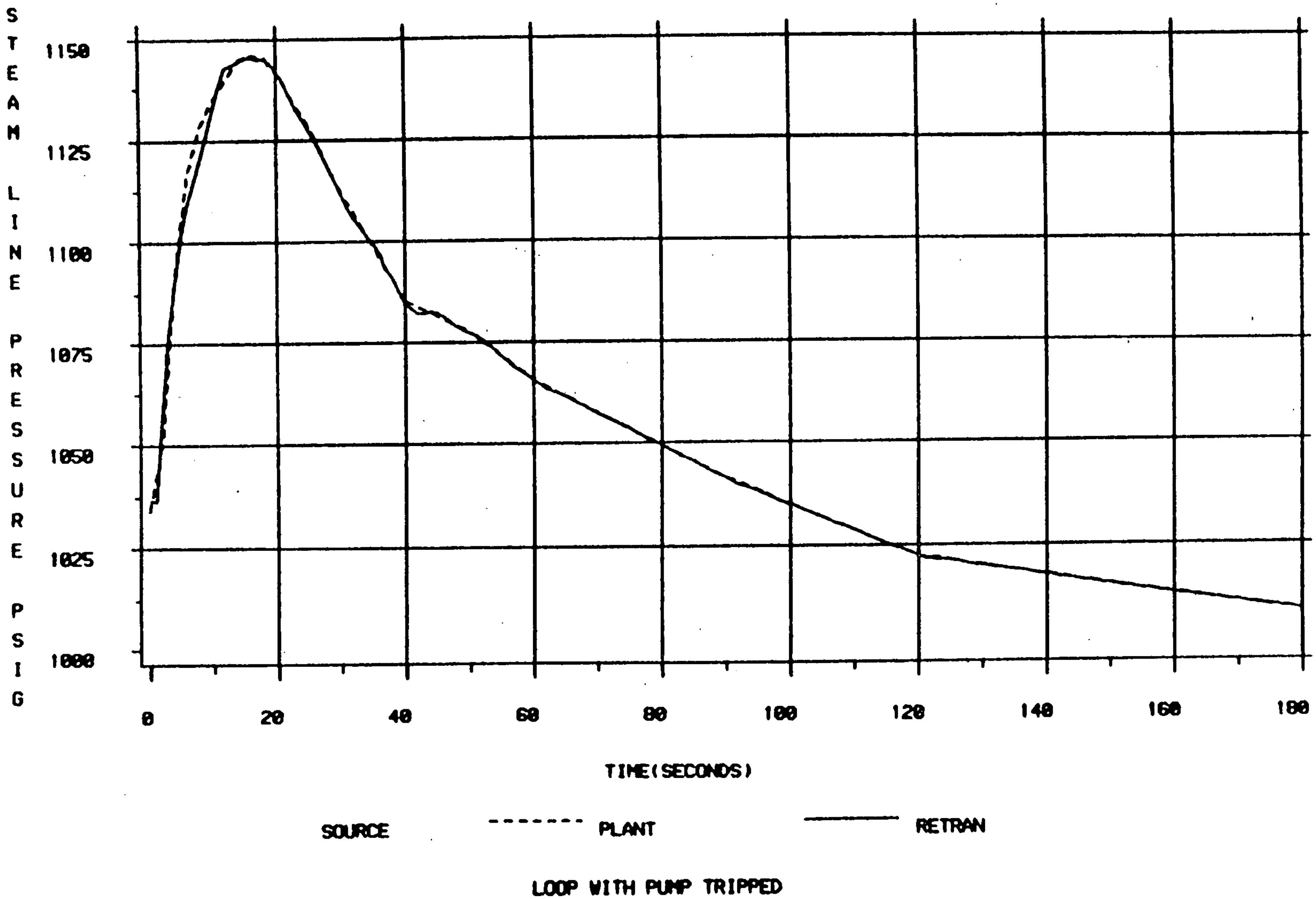
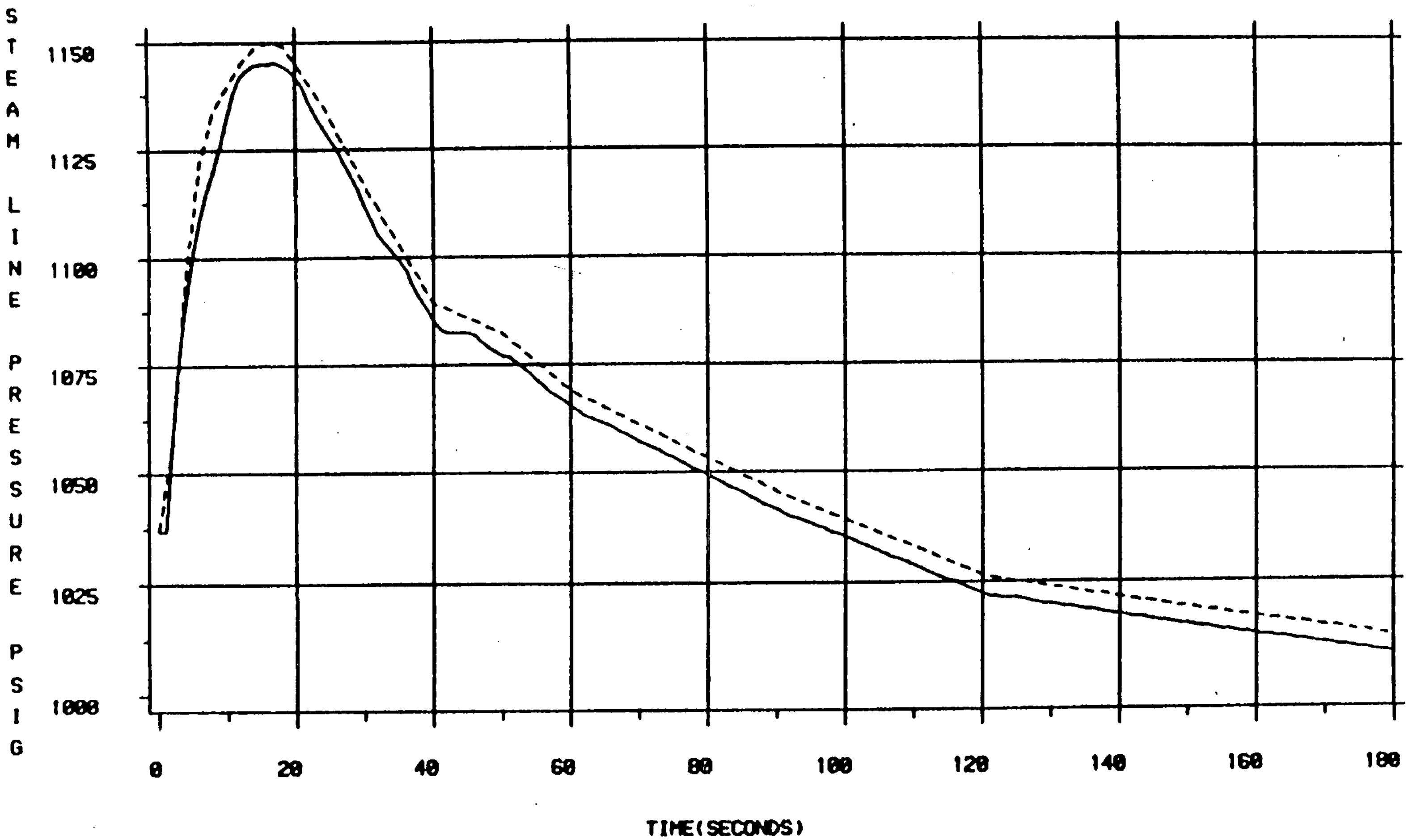


Figure 5.3.3-8

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT



SOURCE ------- PLANT ——— RETRAN

LOOP WITH PUMP ON

Figure 5.3.3-9

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT

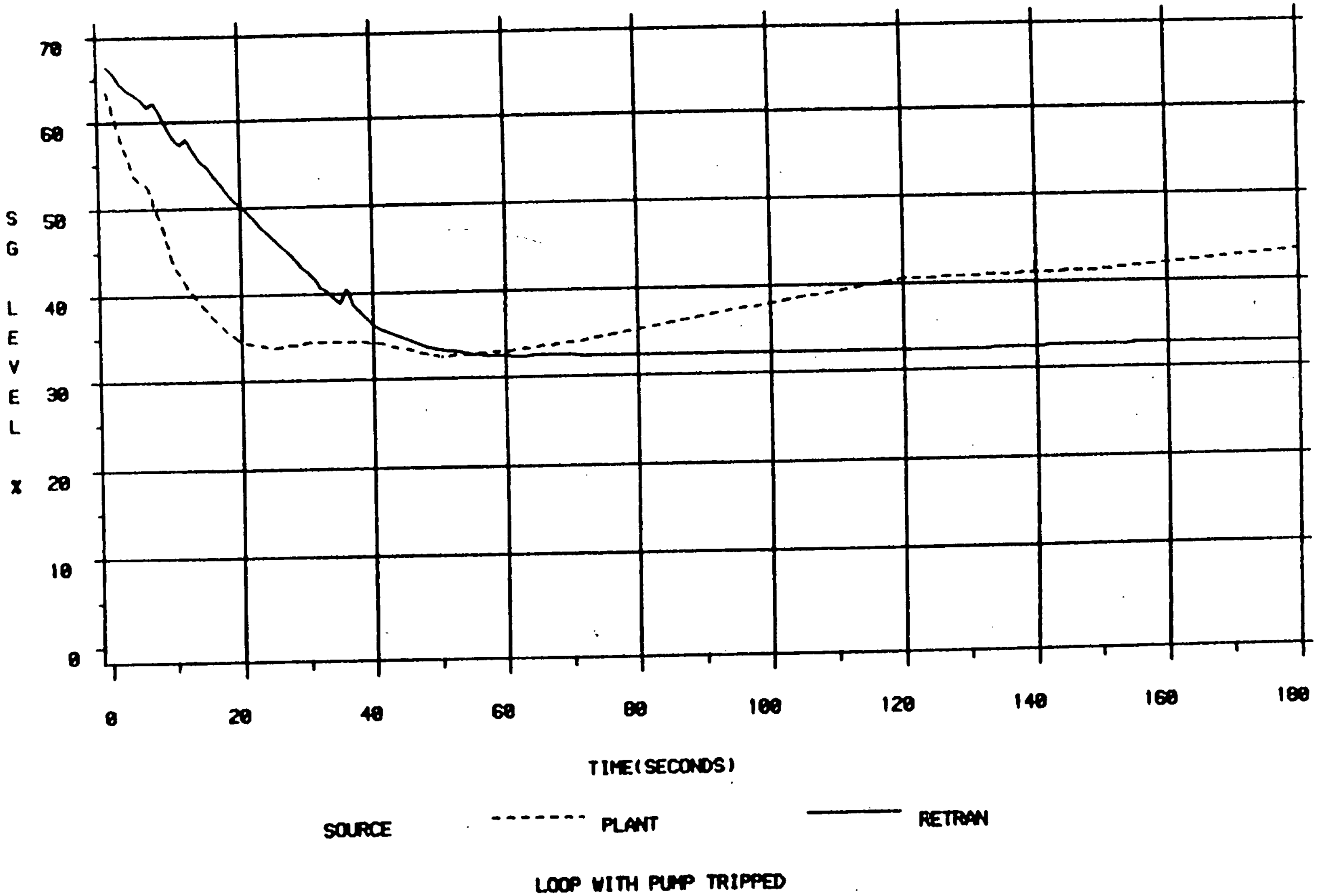
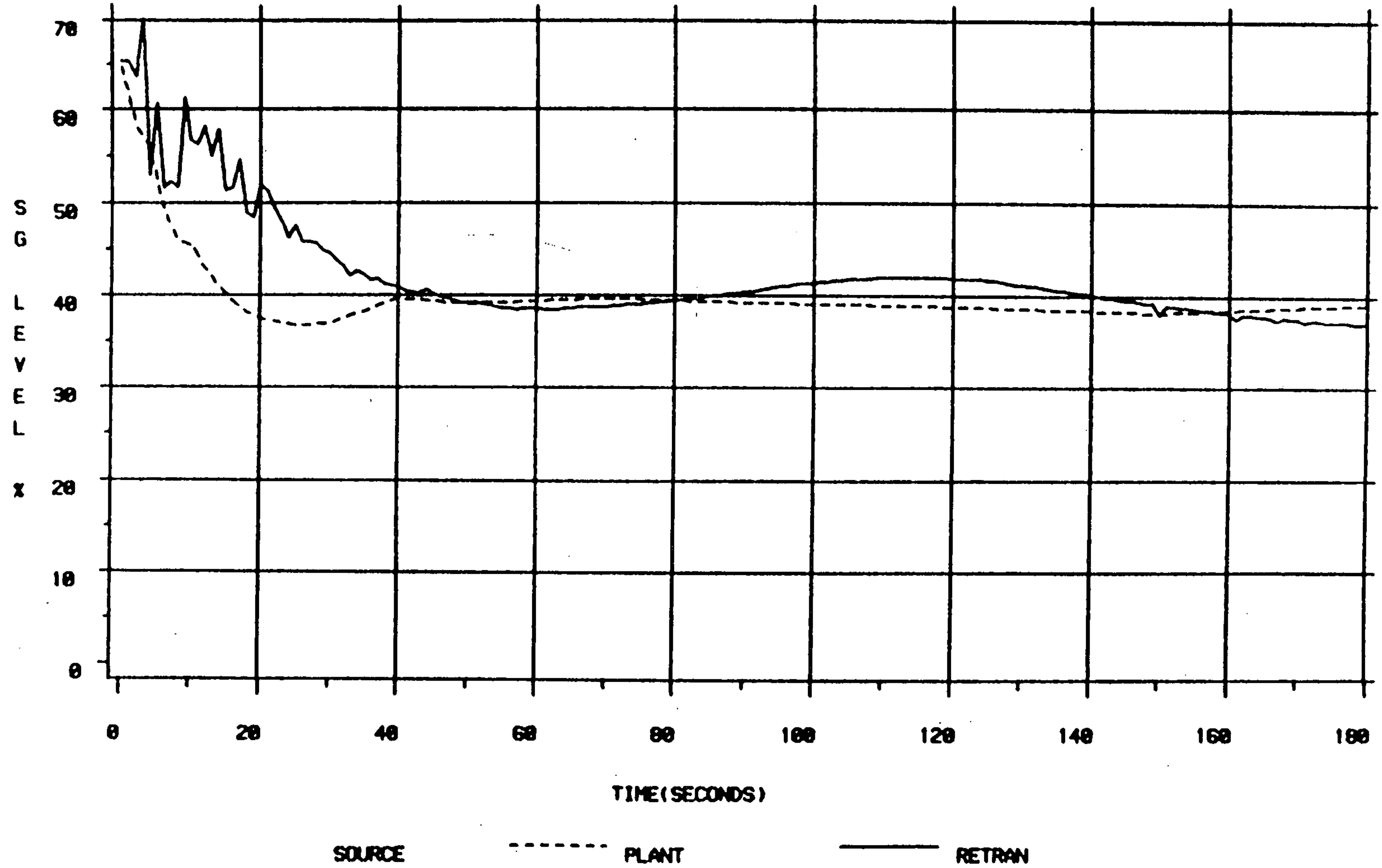


Figure 5.3.3-10

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT

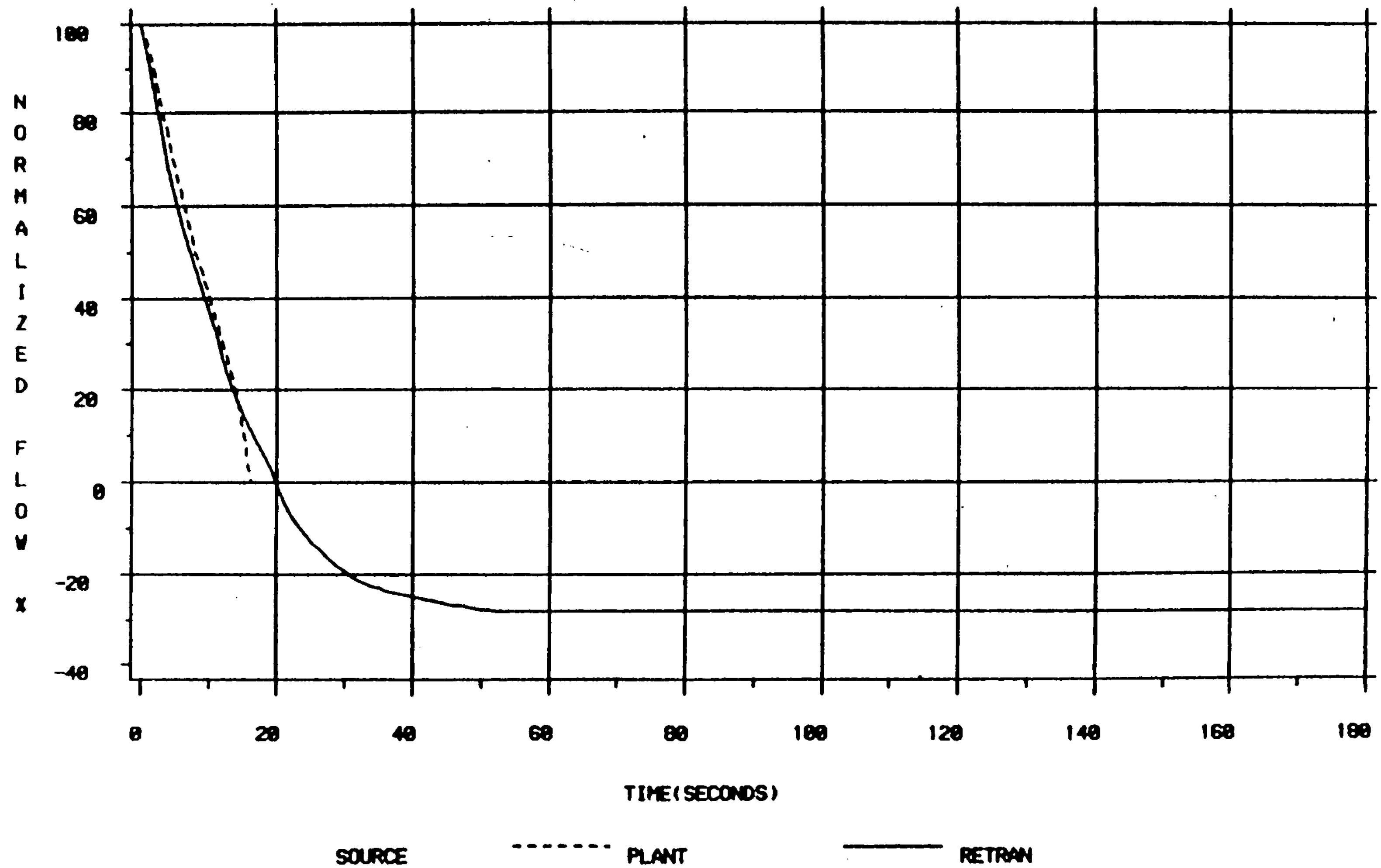


LOOP WITH PUMP ON

Figure 5.3.3-11

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT

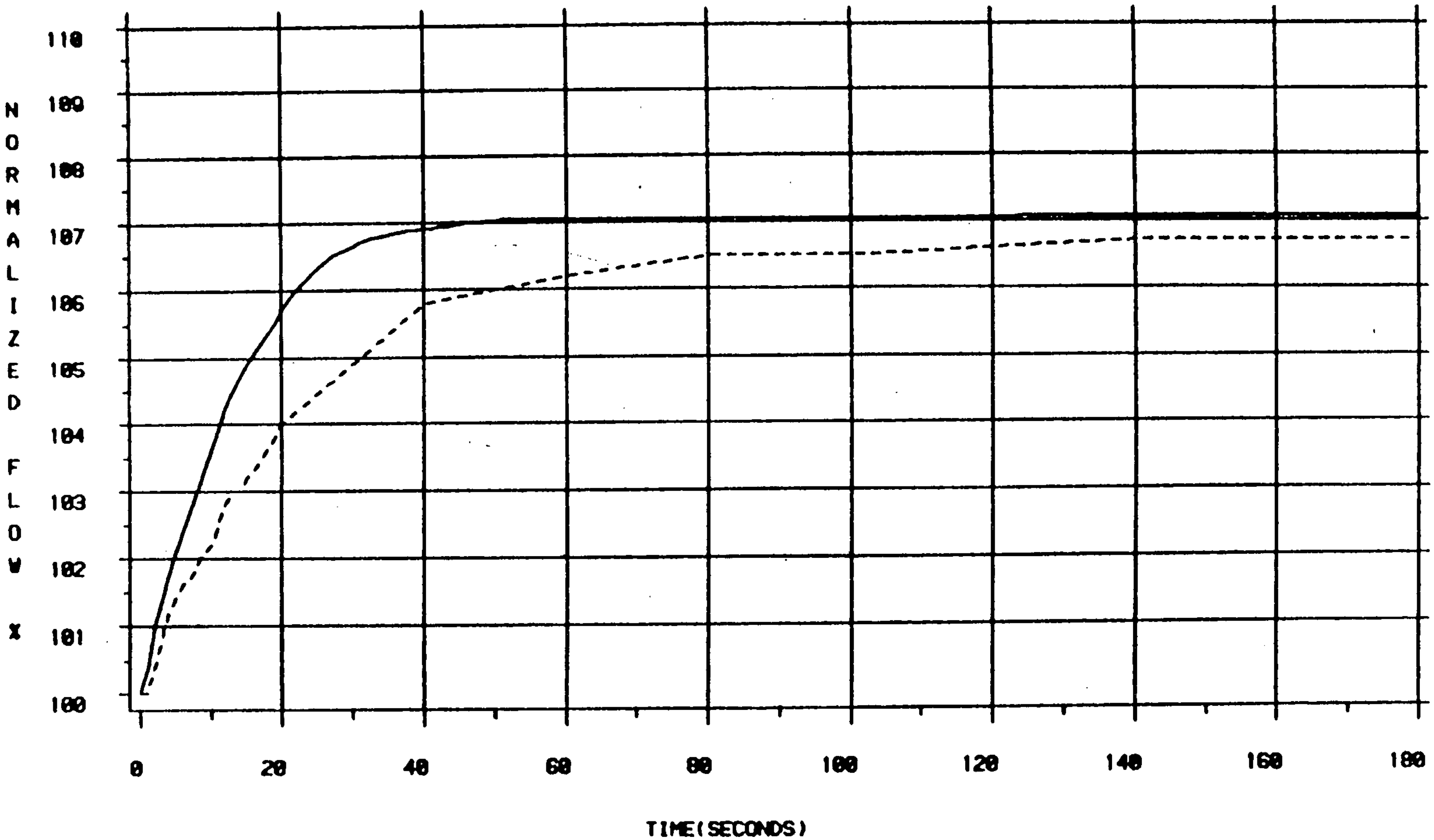


LOOP WITH TRIPPED PUMP

Figure 5.3.3-12

MNS-1 REACTOR COOLANT PUMP TRIP

6/6/84 EVENT



SOURCE ------ PLANT ——— RETRAN

LOOP WITH PUMP ON

Figure 5.3.3-13

5.3.4 McGuire Nuclear Station - Unit 1
Loss of Offsite Power
August 21, 1984

Transient Description

McGuire Unit 1 was operating at 100% full power when the reactor tripped on a spurious high power range flux rate. The RCPs tripped on underfrequency at 24 seconds following reactor trip. At approximately 48 seconds the switchyard computer opened essentially all breakers connecting the unit to normal power supplies. The emergency diesels started due to the blackout condition and assumed essential loads. All three AFW pumps also started. The unit entered a natural circulation mode and cooled down to approximately 518°F cold leg temperature at 1200 seconds. Stable natural circulation conditions developed as indicated by a constant ΔT. The excessive cooldown was due to continuously decreasing steam header pressure.

Discussion of Important Phenomena

The important phenomena that occurred during this transient are related to the transition from forced circulation cooling to natural circulation. Following RCP coastdown, a balance develops between the natural circulation driving head and loop frictional losses at the reduced flow condition. The distribution of heat transfer in the SGs determines the elevation of the thermal center and the driving force for natural circulation. Reactor vessel flow distributions change due to the absence of pump head and the development of buoyancy driven flow. The coupling between the primary and secondary during the cooldown phase of the transient is also a phenomenon of interest.

Model Description and Boundary Conditions

The plant responses during the transient showed little asymmetry between loops so a one-loop RETRAN model was used for the analysis. The RCS flow specified in the simulation was chosen in order to match ΔT. The parameters used as initial conditions were matched, where possible, to the plant data.

Initial Conditions

	Model	Plant
Power Level	100% (3411 MWt)	100% (3411 MWt)
Pressurizer Pressure	2229 psig	2229 psig (ave)
Pressurizer Level	60.8%	60.8%
T-ave	587.3°F	587.3°F
ΔT	56.8°F	56.8°F
Steam Line Pressure	1008 psig	1008 psig (ave)
SG Level	66.7% NR	66.7% NR (ave)
MFW Flow	15.1×10^6 lbm/hr	15.1×10^6 lbm/hr
MFW Temperature	437.6°F	437.6°F (ave)

The McGuire RETRAN model was constructed to McGuire Unit 1 dimensions and therefore required few changes to accurately simulate the McGuire Unit 1 transient. The major change was to the steam dump system. The steam dump system in the base RETRAN model uses narrow range primary coolant temperatures as a basis for control. These indications are sensed in the RTD bypass manifold and are invalid when forced flow is lost. Since it is unclear how steam dump was being controlled, and since the steam line pressure data indicates that substantial depressurization occurred, the simulation controls steam line pressure to match the plant pressure data.

The problem boundary conditions used are cycle specific post-trip delayed neutron power and decay heat, MFW, AFW, and charging and letdown flows. The pressurizer heater banks were modeled to reflect their status as recorded on plant transient data.

Simulation Results

The simulation begins with the reactor trip caused by a voltage spike and continues for 1200 seconds. The long term trends of key plant parameters have been established by that time. The sequence of events is given in Table 5.3.4-1. The comparison of RETRAN predictions to plant data are given in Figures 5.3.4-1 through 5.3.4-10.

Plant steam line pressure data used as a boundary condition to control the Steam Dump System are shown in Figure 5.3.4-1. The SG level comparison is shown in Figure 5.3.4-2. It is apparent that the RETRAN model predicts the plant level data very well when using the plant AFW flow data.

Pressurizer pressure, shown in Figure 5.3.4-3, tracked the trend of the plant data following the development of an offset of 100-150 psig (plant data higher) at about 200 seconds. The cause of this offset can be understood by examining the comparisons of pressurizer level and RCS temperature predictions and data. The pressurizer level prediction trends the plant data following the development of an offset of about 10%. This indication implies that the total system volume is somewhat low after natural circulation is established. The source of this volume discrepancy is apparent when the ΔT (Figure 5.3.4-5), T-hot (Figure 5.3.4-6), T-cold (Figure 5.3.4-7), and upper head temperature (Figure 5.3.4-8) comparisons are evaluated. T-cold predictions are very similar to plant data as expected due to matching the steam line pressure data. However, the T-hot and ΔT data both have a 10°F offset, which is consistent with the volume discrepancy observed in the pressurizer level figure. This offset occurs when loop ΔT stabilizes during natural circulation. The loop ΔT predicted by RETRAN is smaller and stabilizes sooner than the actual plant data for this transient. Therefore, RETRAN also predicts a lower T-hot. In addition, the reactor vessel upper head temperature predicted by RETRAN does not increase as much as plant data. Nevertheless, the transition to natural circulation and the cooldown response are predicted well.

Figure 5.3.4-8 shows a comparison of the prediction of the reactor vessel upper head temperature to an indication from one of five thermocouples installed in the McGuire Unit 1 vessel. McGuire 1 is a T-cold upper head plant, which explains the initial temperature of 555°F. Both the plant data and RETRAN prediction show an increase and then a decrease in the upper head temperature following the establishment of natural circulation. The trends match well, with the data exceeding the RETRAN predicted temperature by approximately 8-10 °F at the peak temperature, before closely agreeing at 1200 seconds. This prediction confirms that the reactor vessel upper head modeling is very adequate for vessel flow patterns during the transition to natural circulation. Normalized reactor coolant flow is shown in Figures 5.3.4-9 and 5.3.4-10. The

flow reduction due to the pump coastdown is similar to the plant response. It should be pointed out that plant data is essentially meaningless once flow has decreased to less than approximately 20% of initial flow due to instrumentation limitations. RETRAN predicts a relatively stable natural circulation flow of about 5% of the initial flow, with the expected slow decrease due to diminishing decay heat.

Table 5.3.4-1

McGuire Nuclear Station Unit 1

Loss of Offsite Power

August 21, 1984

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
Reactor/turbine trip	0	0
PZR heaters on*	1	1
RCPs trip*	24	24
PZR heaters off*	48	48
AFW initiates*	48	48
End of simulation	N/A	1200

Note: Asterisks designate boundary conditions

MNS 1 LOSS OF OFFSITE POWER

8/21/84 EVENT

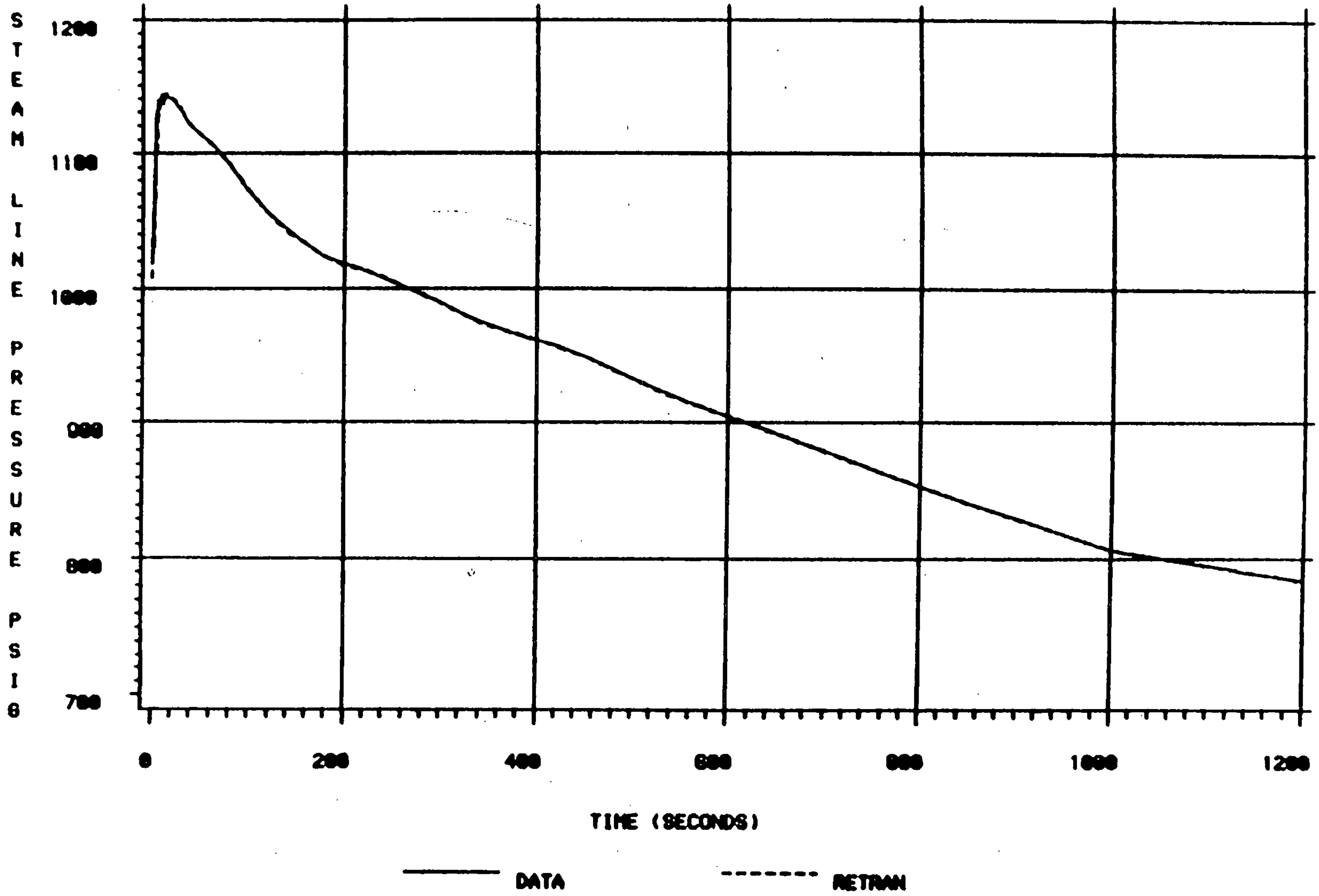


Figure 5.3.4-1

MNS 1 LOSS OF OFFSITE POWER

8/21/84 EVENT

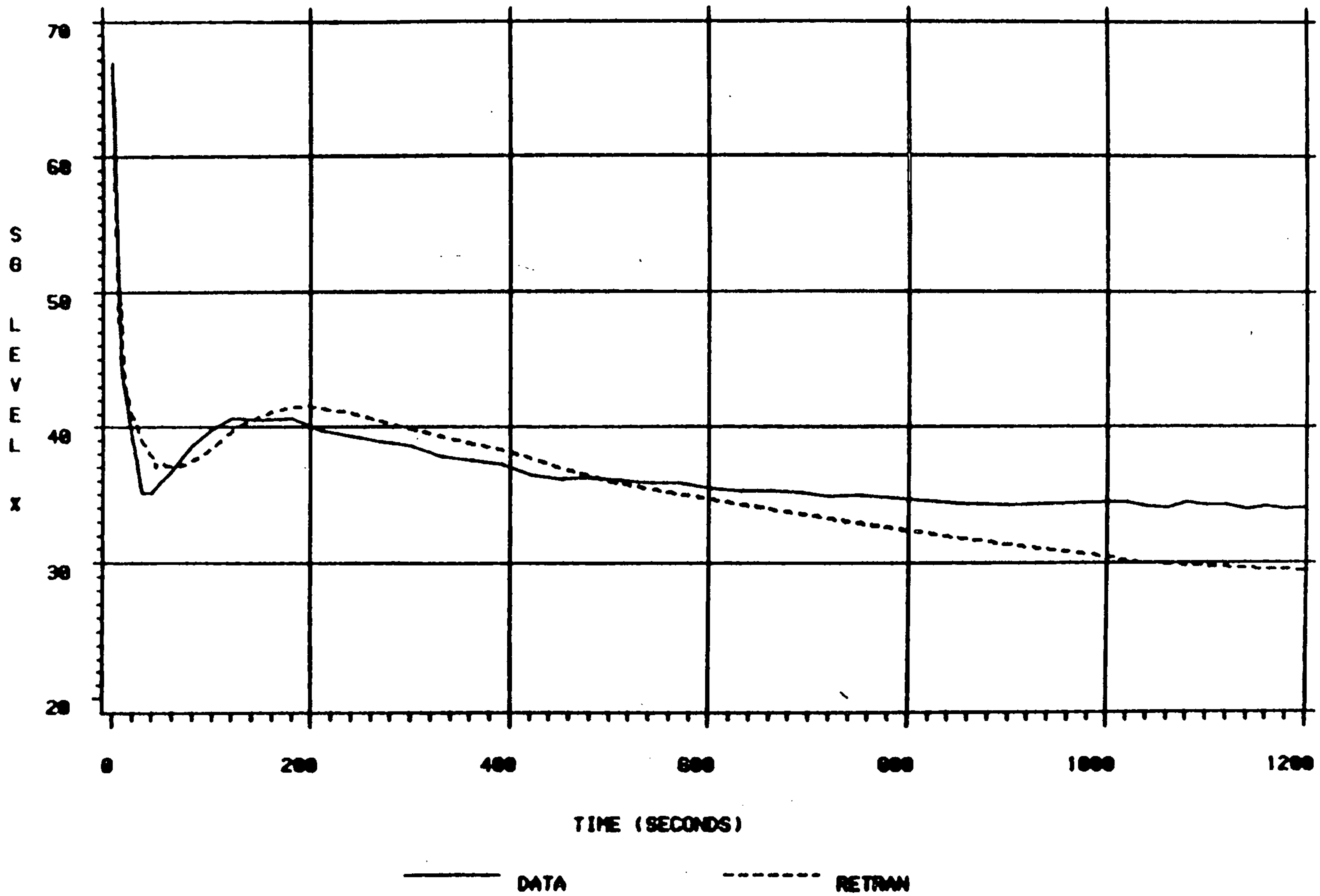


Figure 5.3.4-2

MNS 1 LOSS OF OFFSITE POWER

8/21/84 EVENT

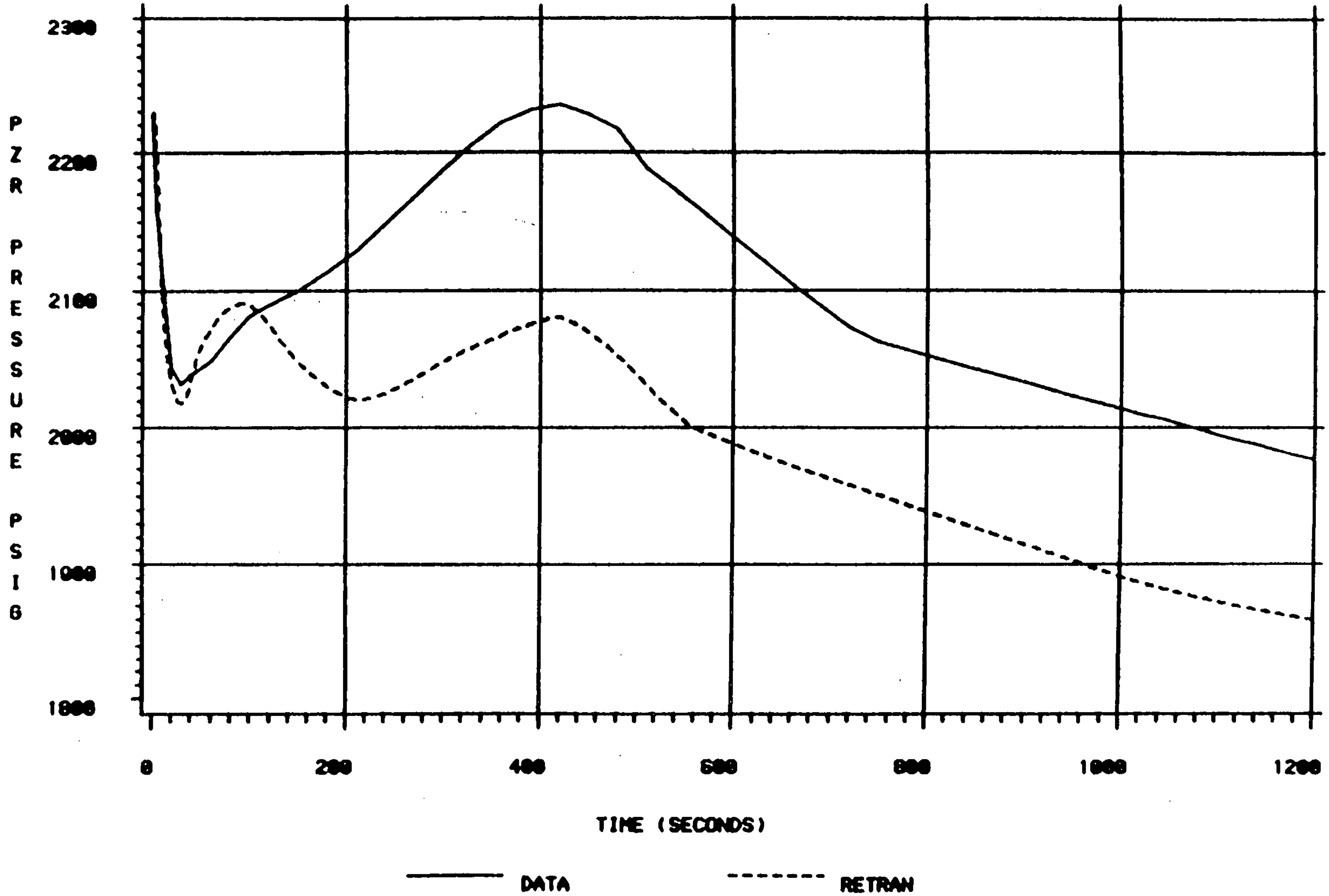


Figure 5.3.4-3

MNS 1 LOSS OF OFFSITE POWER

8/21/84 EVENT

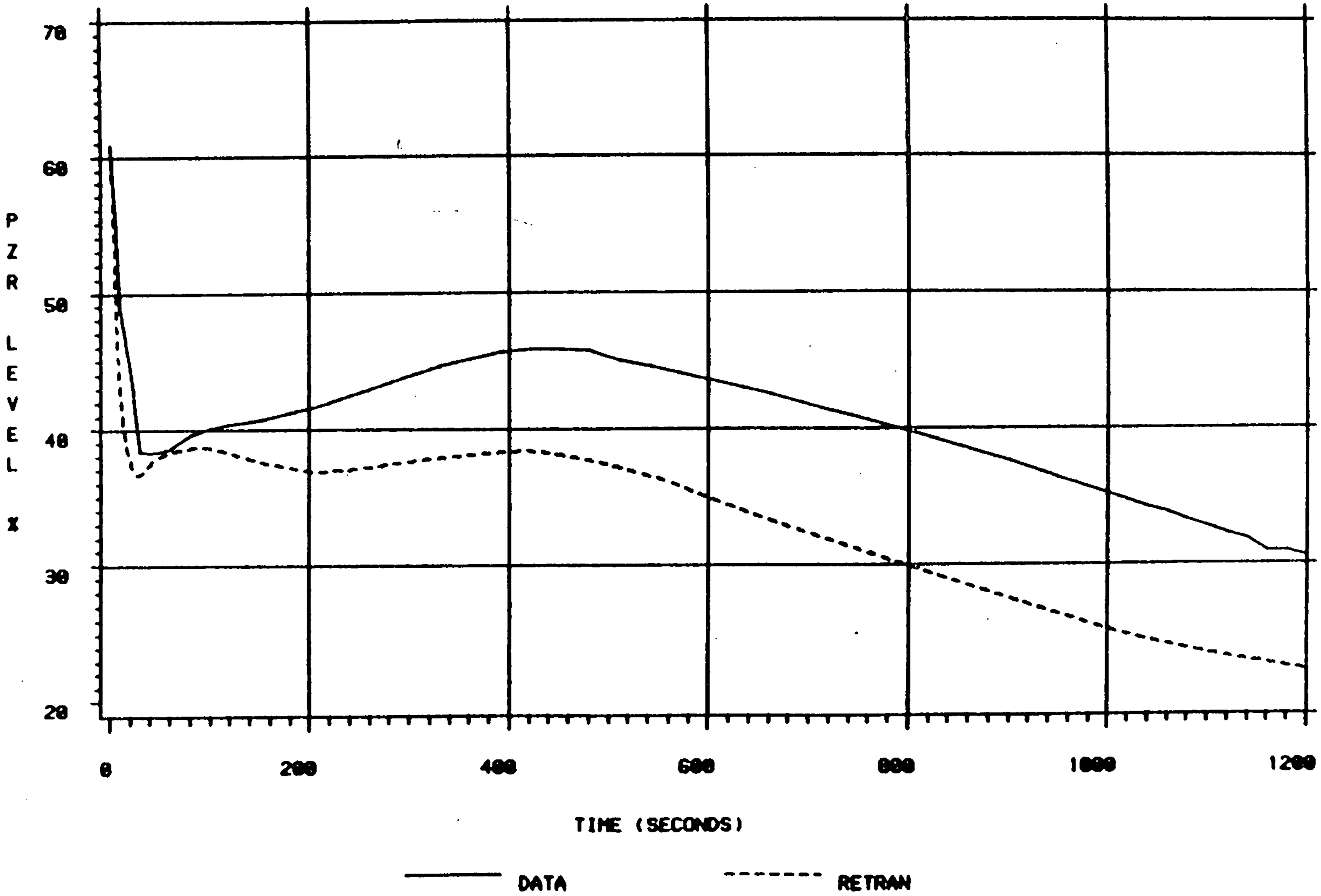


Figure 5.3.4-4

MNS 1 LOSS OF OFFSITE POWER

8/21/84 EVENT

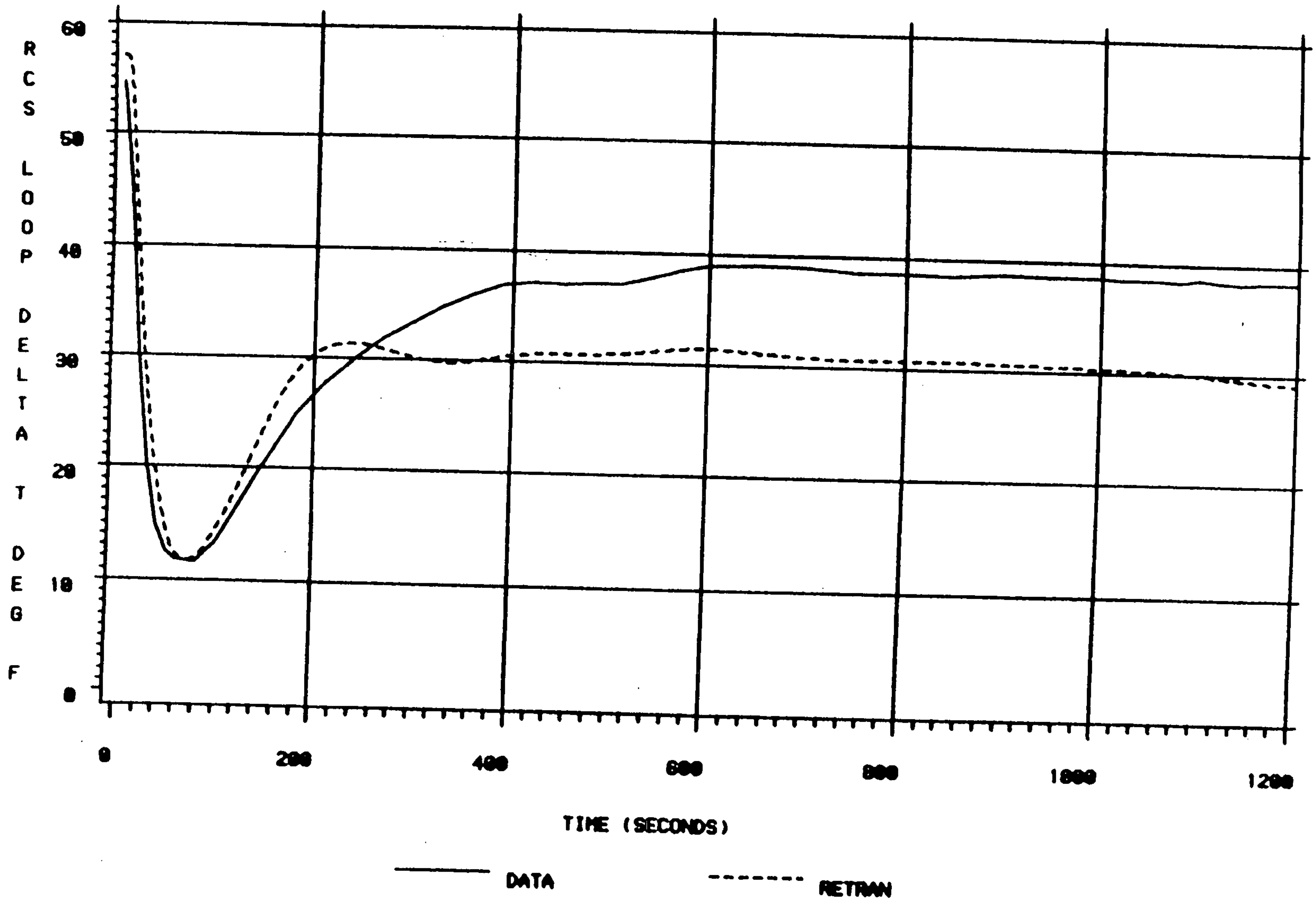


Figure 5.3.4-5

MNS 1 LOSS OF OFFSITE POWER

8/21/84 EVENT

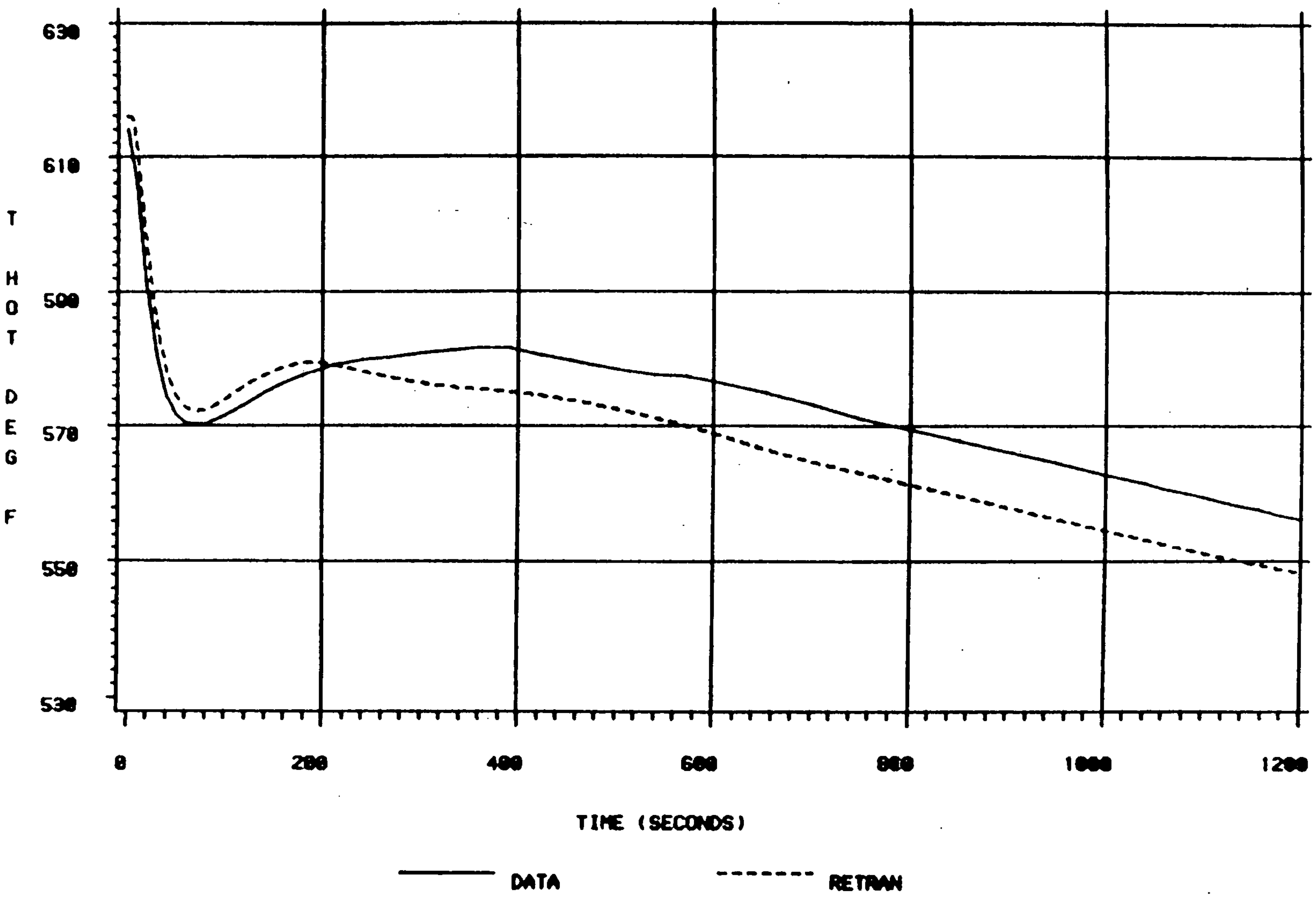


Figure 5.3.4-6

MNS 1 LOSS OF OFFSITE POWER

8/21/84 EVENT

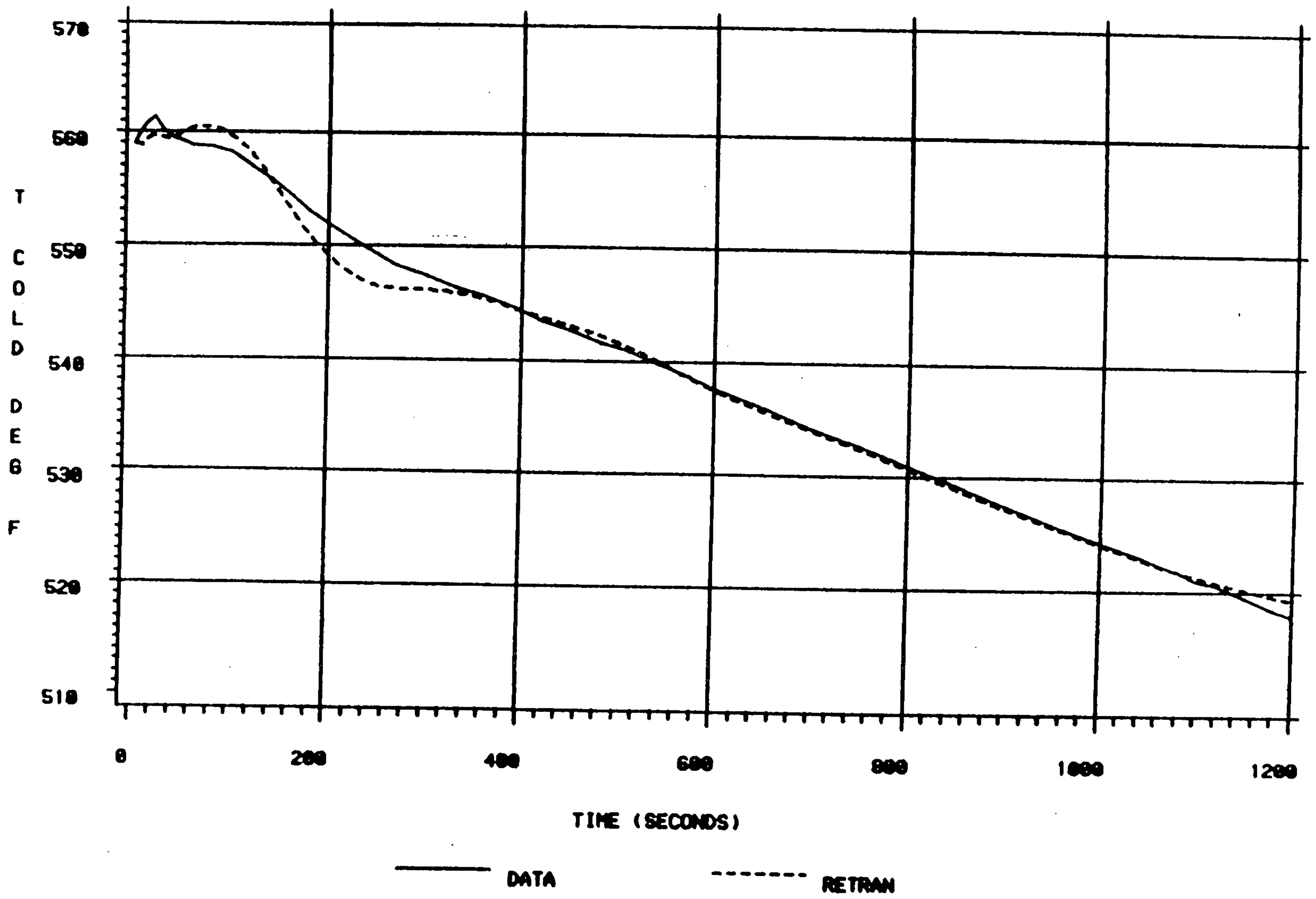


Figure 5.3.4-7

MNS-1 LOSS OF OFFSITE POWER

8/21/84 EVENT

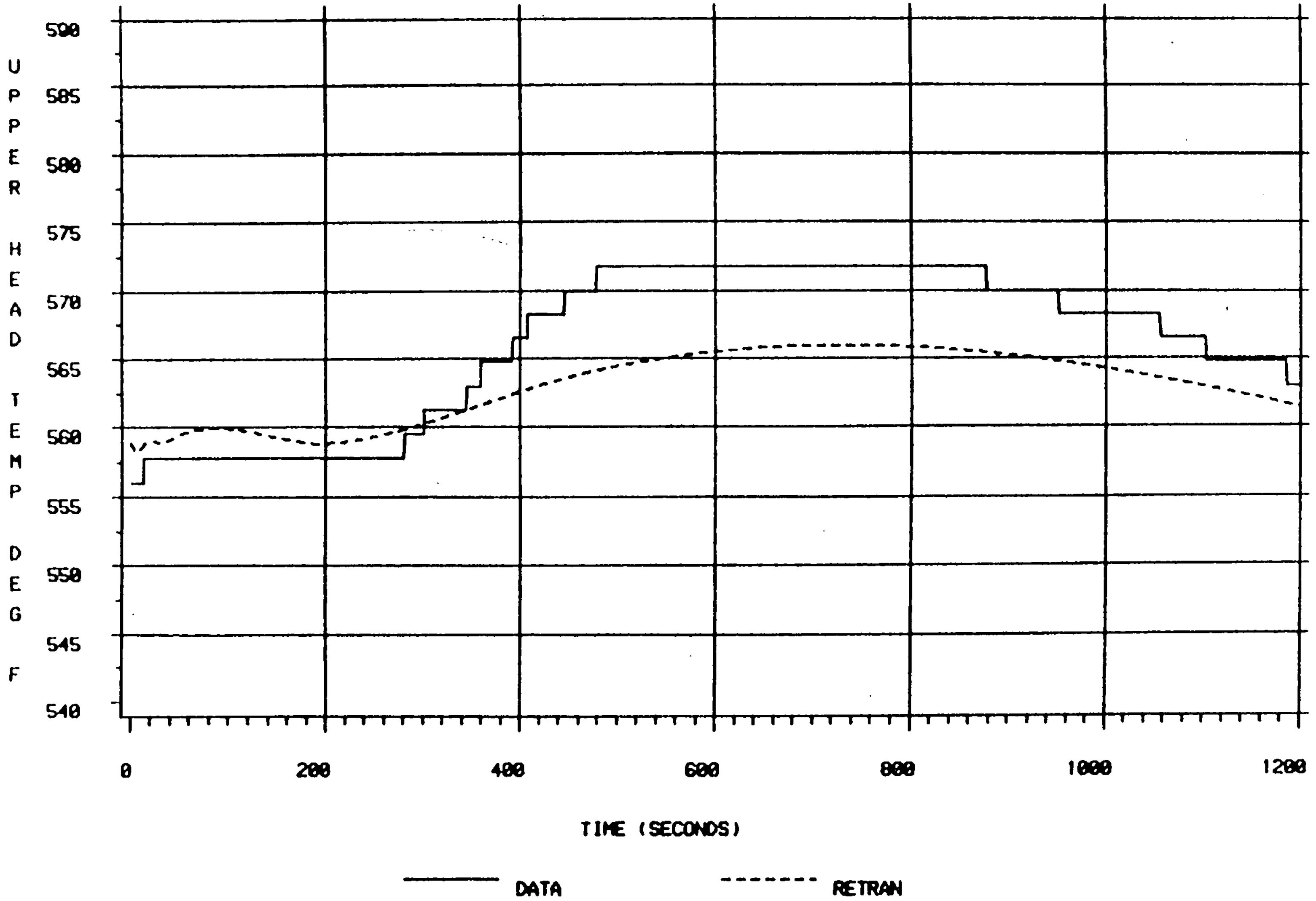


Figure 5.3.4-8

MNS 1 LOSS OF OFFSITE POWER

8/21/84 EVENT

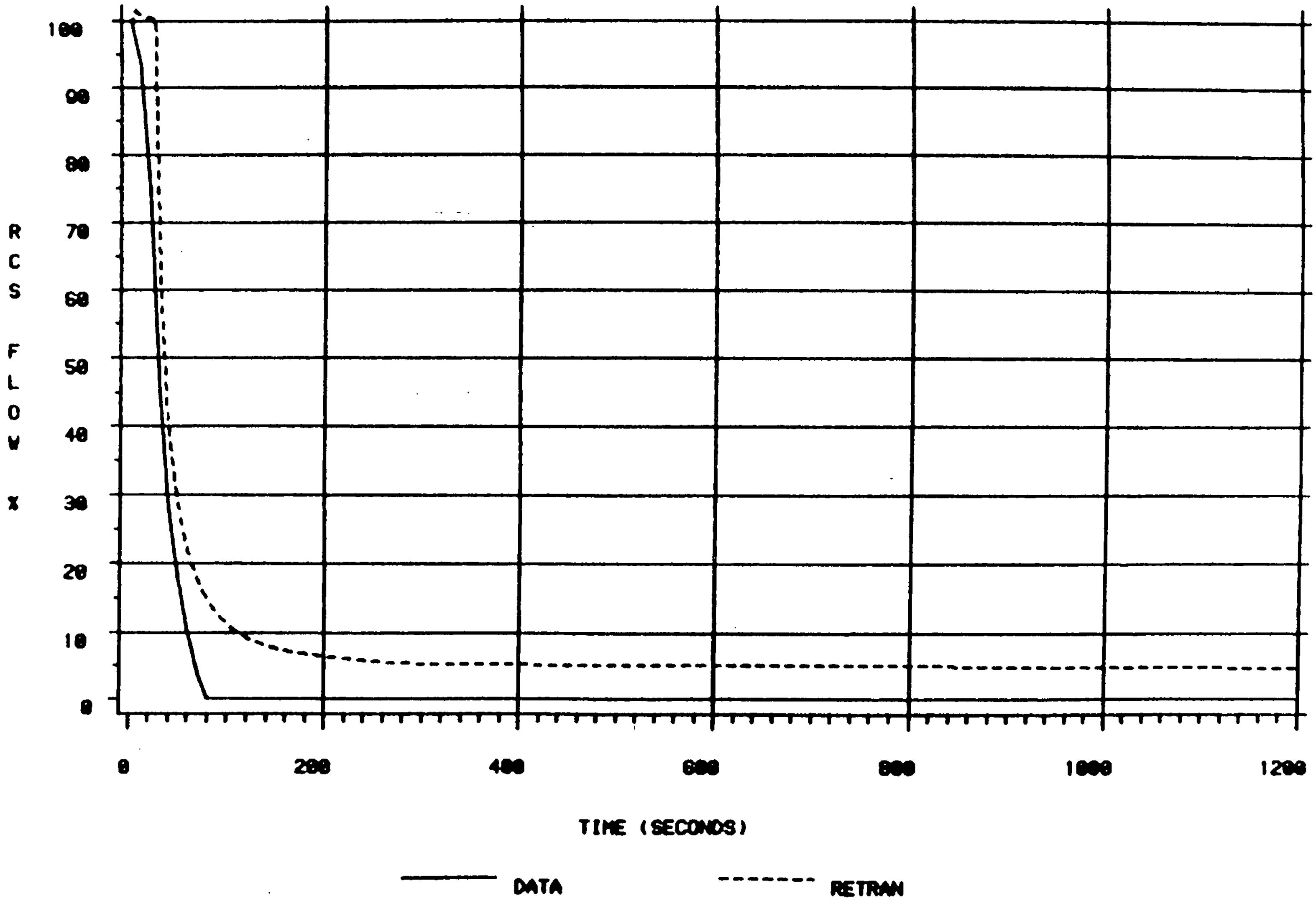


Figure 5.3.4-9

MNS 1 LOSS OF OFFSITE POWER

8/21/84 EVENT

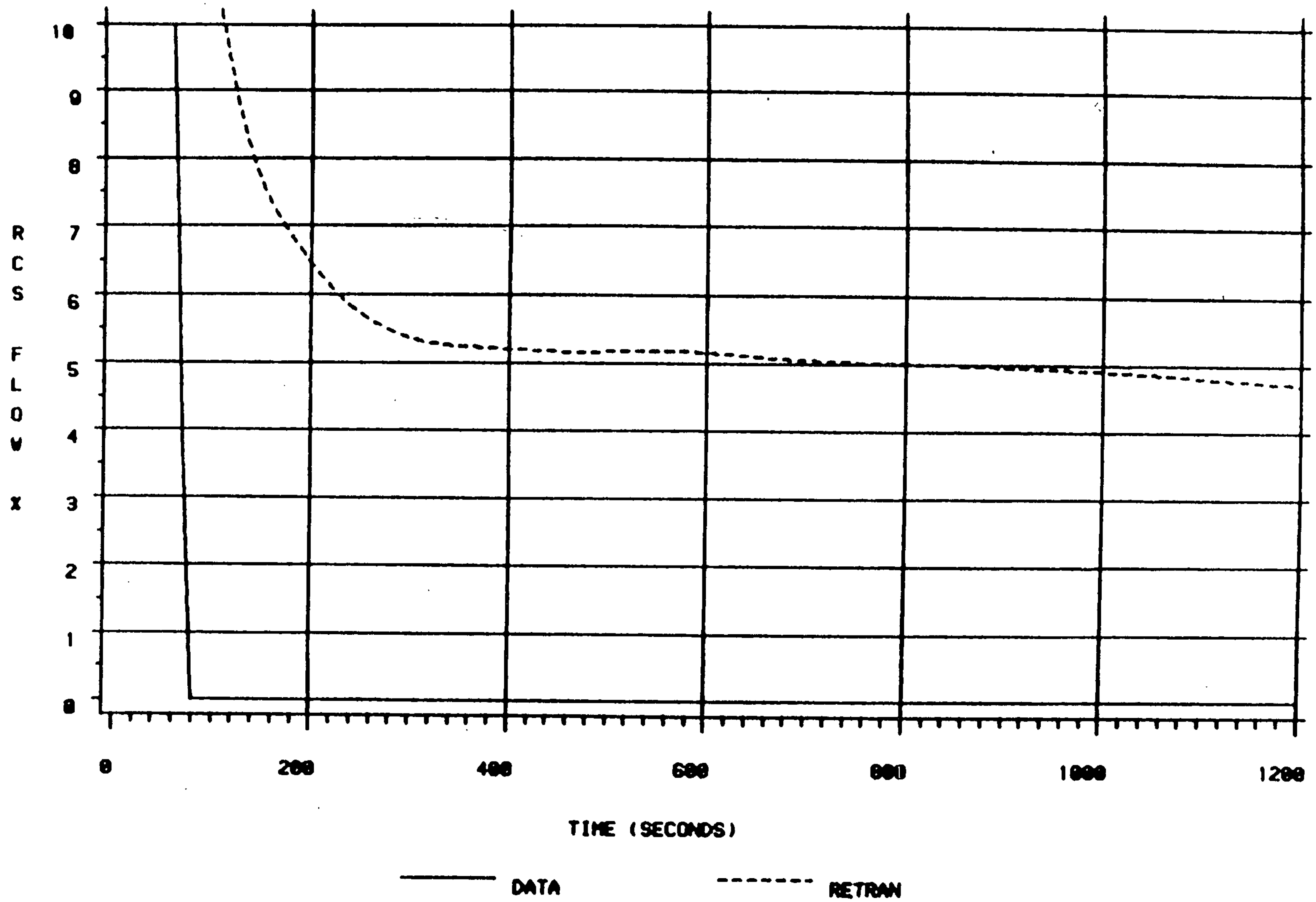


Figure 5.3.4-10

5.4 Operational Transients Without Reactor Trip

5.4.1 Catawba Nuclear Station - Unit 1
Turbine Trip Test at 68% Power
March 27, 1985

Transient Description

A turbine trip was manually initiated at Catawba Unit 1 with the unit at 68% full power to demonstrate the effectiveness of plant control systems to stabilize the plant without tripping the reactor. Upon closure of the turbine stop valves, a transitional mismatch between the reactor heat generation and secondary heat sink occurred, causing the RCS temperature and pressure to rise. The Rod Control System automatically inserted rods to reduce reactor power and the Condenser Dump and Atmospheric Dump Systems relieved steam. RCS temperature and pressure dropped, and the pressurizer heaters were actuated to restore RCS pressure.

The maximum pressurizer pressure and level were 2326 psig and 57% respectively, while the minimum values were 2124 psig and 33%. The pressurizer PORVs and safety valves were not challenged, nor were the steam line safety valves. The rods were placed in manual control at approximately 230 seconds, and the power was stabilized at approximately 18%. The pressurizer heaters restored primary pressure and SG level was stabilized at approximately 40%. Pressurizer pressure control was transferred to manual at an unknown time during the transient, resulting in a pressure overshoot to 2270 psig at 900 seconds.

Discussion of Important Phenomena

Of primary importance in this transient are the actions of the Rod Control System in reducing core power and the Steam Dump System in reducing primary temperature and pressure. Also of importance is the control of pressurizer pressure. Pressurizer spray is initiated early in the transient during the initial RCS pressurization. Shortly thereafer, during primary depressurization, the pressurizer heaters were actuated to restore primary pressure.

Detailed modeling of the pressurizer pressure controller and the controller and the control systems mentioned above, including operator actions which affect these systems, is therefore necessary to achieve accurate results.

Model Description and Boundary Conditions

The one-loop Catawba Unit 1 RETRAN Model was utilized for this analysis since the plant response among the four loops was essentially symmetrical. It was necessary in this analysis to model the Rod Control System, the load rejection controller, and the atmospheric steam dump valves.

The RCS flow specified in the simulation was chosen to match plant ΔT. The initial conditions were matched to plant data as shown in the following table:

Initial Conditions

	Model	Plant
Power Level	66.5% (2268.3 MWt)	66.5% (2268.3 MWt)
PZR Pressure	2226 psig	2226 psig
PZR Level	48.4%	48.4%
T-ave	578.6°F	578.6°F (ave)
ΔT	40.3°F	40.3°F (ave)
Steam Line Pressure	1034 psig	1034 psig (ave)
SG Level	58%	57% (ave)
MFW Flow	9.6×10^6 lbm/hr	10.3×10^6 lbm/hr
MFW Temperature	400°F	400°F (ave)

The problem boundary conditions include MFW flow and the reference T-ave (T-ref) as a function of time. When the simulated reactor power matched the actual power data following stabilization, the simulated control rod position was held constant to represent the transition to manual rod control. Charging and letdown flows are assumed to have little effect on the transient and are not modeled. Also, since plant data indicates that the pressurizer backup

heaters did not deenergize, these heaters were left energized in the simulation. Finally, the Bank 4 atmospheric dump valves were blocked closed until 13 seconds in the simulation to match the actual opening time.

Simulation Results

The simulation begins with the manual turbine trip and continues for 900 seconds. The simulation is terminated when most plant parameters have stabilized and the phenomena of interest have occurred. The sequence of events is given in Table 5.4-1 and the comparisons of RETRAN predictions and plant data are shown in Figures 5.4.1-1 through 5.4.1-7.

The comparison of the predicted reactor power to the plant data is shown in Figure 5.4.1-1. The reactor runback rate compares well until a deviation occurs at 90 seconds. This deviation is caused by a difference in the times at which the rod insertion speed slows due to a decrease in the power mismatch signal input to the Rod Control System. The consistent slopes of the power trends indicate that the reactivity insertion rates compare well.

The pressurizer pressure and level comparisons are shown in Figures 5.4.1-2 and 5.4.1-3. An initial insurge and pressurization accompanies the reduction in secondary heat sink following turbine trip. Subsequently, the repressurization due to pressurizer heaters occurs. The pressure prediction and level prediction generally trend the data well. RCS T-ave and ΔT comparisons are shown in Figures 5.4.1.-4 and 5.4.1-5. The predicted temperatures are very similar to the plant data throughout the duration of the simulation, with maximum deviations no greater than approximately $3^{o}F$. Insights into these deviations can be obtained from the steam line pressure comparisons.

The steam line pressure data, shown in Figure 5.4.1-6, indicates that several atypical events occurred following turbine trip. One of the Bank 2 condenser dump valves (SB-24) unexpectedly closed 13 seconds into the transient, thereby maintaining the pressure above the predicted pressure for the first 125 seconds of the transient. An additional discrepancy occurs at 190 seconds when the pressure increases due to the premature closure, and subsequent cycling, of

another one of the Bank 2 valves (SB-6). Neither of these events were simulated.

The SG level comparison is shown in Figure 5.4.1-7. Since MFW flow data is used in the simulation, this figure provides a good indication of the RETRAN SG level model. The level trend is predicted very well throughout the duration of the simulation. Some differences are to be expected due to the effect of SG pressure differences between the prediction and data.

Table 5.4-1

Catawba Nuclear Station Unit 1

Turbine Trip Test

March 27, 1985

Sequence of Events

Event Description	Time (sec) Plant	RETRAN
Turbine trips	0	0
MFW runback initiated*	1	1
PZR spray on	6	4
Condenser dump banks 1-3 open	6	3
Control rod insertion begins/reactor runback initated	**	1
Atmospheric dump bank 4 opens*	13	13
SB-24 (one of three valves in condenser dump bank 2) closed	13	-
Maximum RCS pressure	14	15
Atmospheric dump bank 5 opens	17	16
Maximum PZR Level	36	29
PZR spray off	42	30
PZR control heaters on	**	48
PZR backup heaters on	74	52
Atmospheric dump bank 5 closed	74	35
Atmospheric dump bank 4 closed	103	114
Condenser dump bank 3 closed	131	227
SB-6 (one of three valves in condenser dump bank 2) closes, then cycles	227	-
Control rod insertion stops	230	280
SB-15 (one of three valves in condenser dump bank 2) closed	503	-
PZR control heaters off	**	688
End of simulation	N/A	900

Note: Single asterisk designates boundary conditions
Double asterisks indicate plant data not available

CNS-1 TURBINE TRIP TEST

3/27/85 EVENT

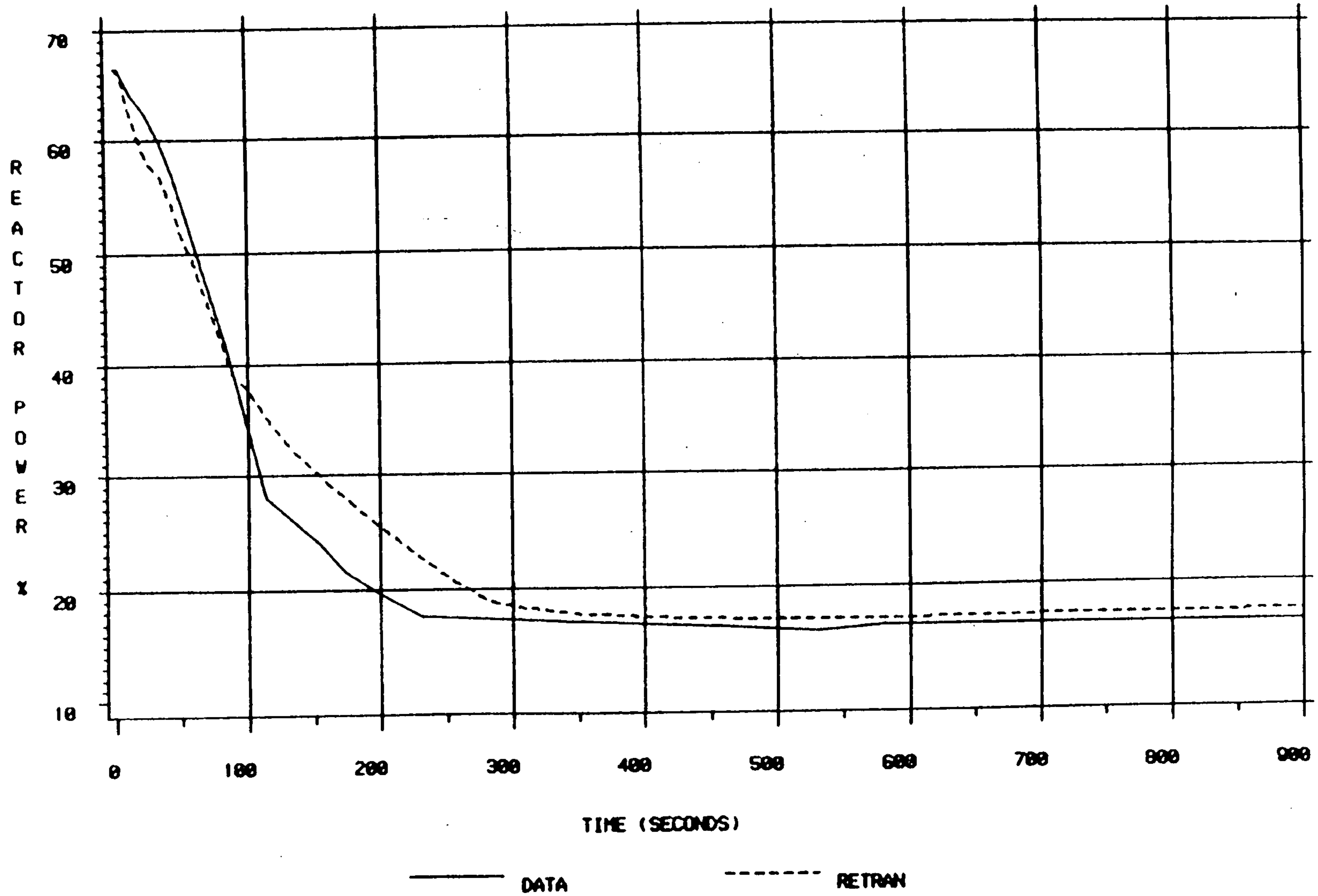


Figure 5.4.1-1

CNS-1 TURBINE TRIP TEST

3/27/85 EVENT

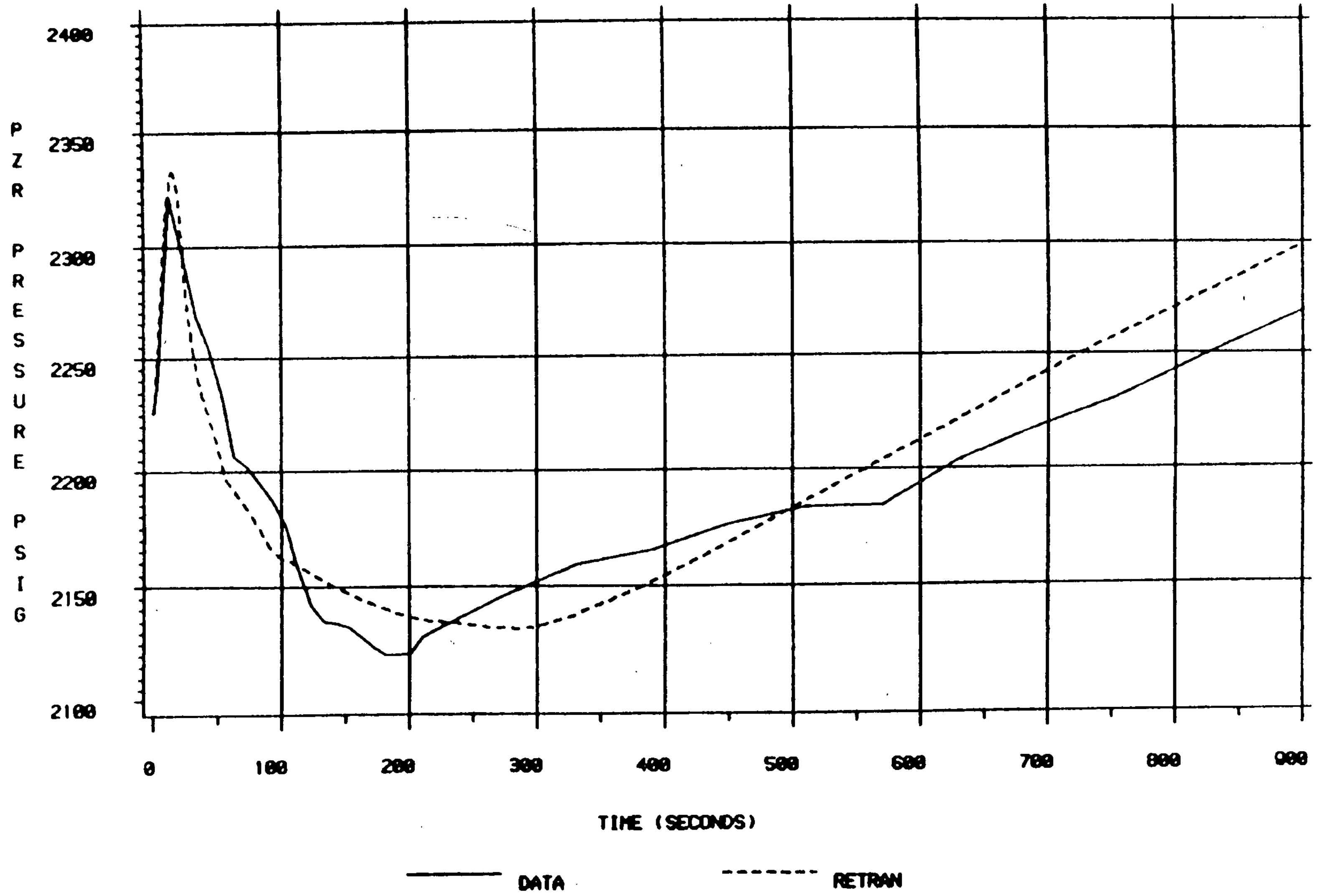
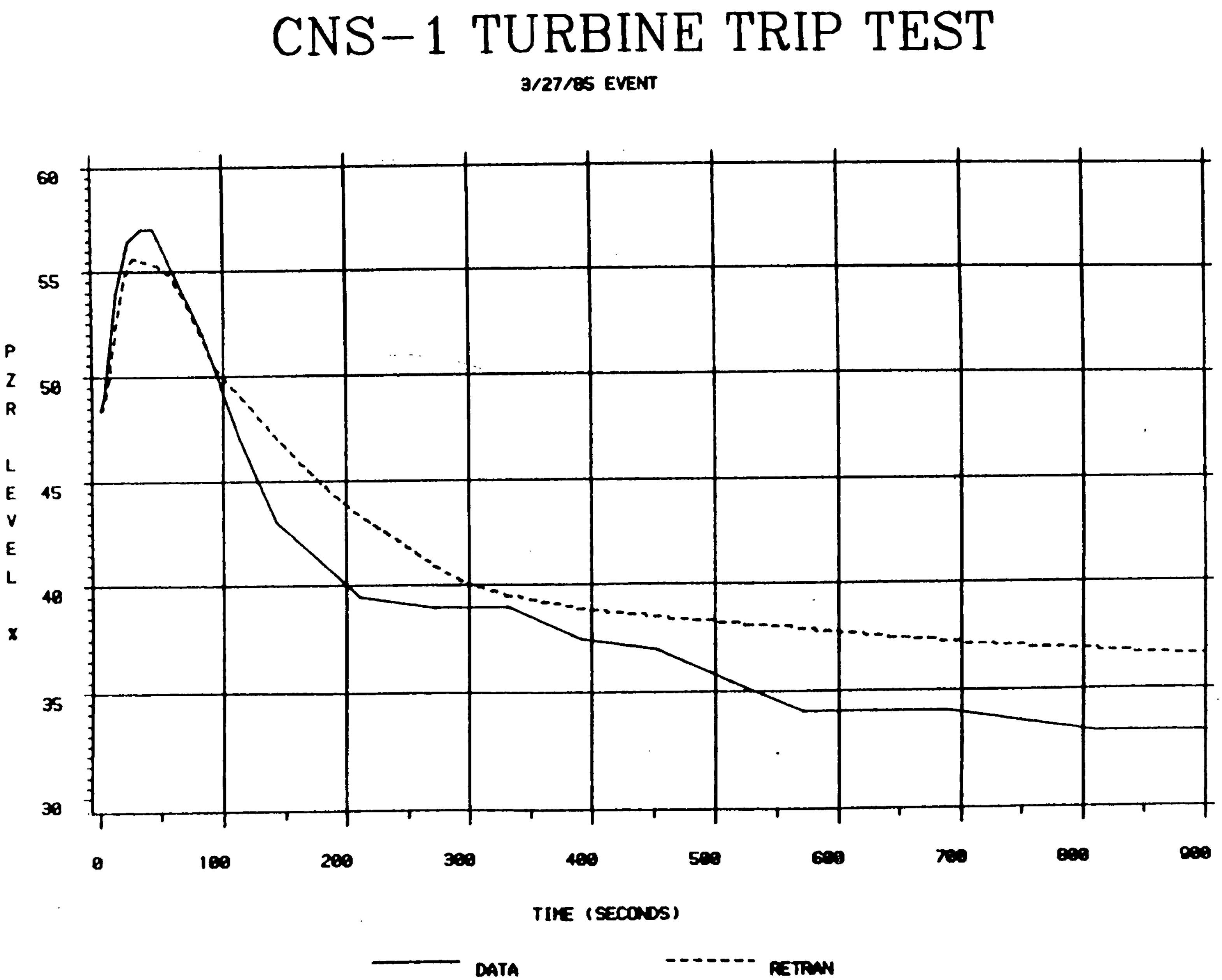


Figure 5.4.1-2



CNS-1 TURBINE TRIP TEST
3/27/85 EVENT
PZR LEVEL %
60
55
50
45
40
35
30
0
100
200
300
400
500
600
700
800
900
TIME (SECONDS)
DATA
RETRAN

Figure 5.4.1-3

CNS-1 TURBINE TRIP TEST

3/27/85 EVENT

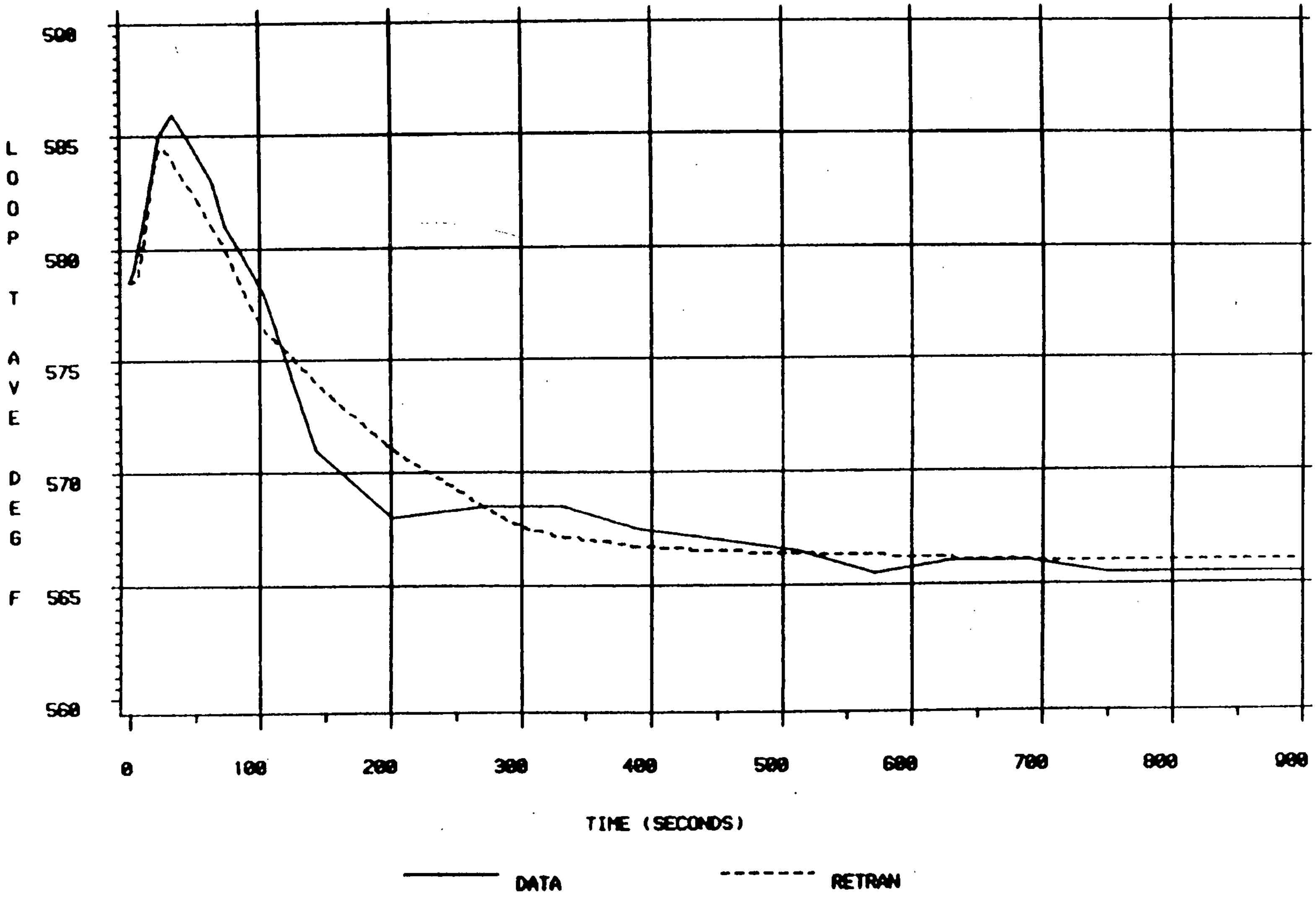


Figure 5.4.1-4

CNS-1 TURBINE TRIP TEST

3/27/85 EVENT

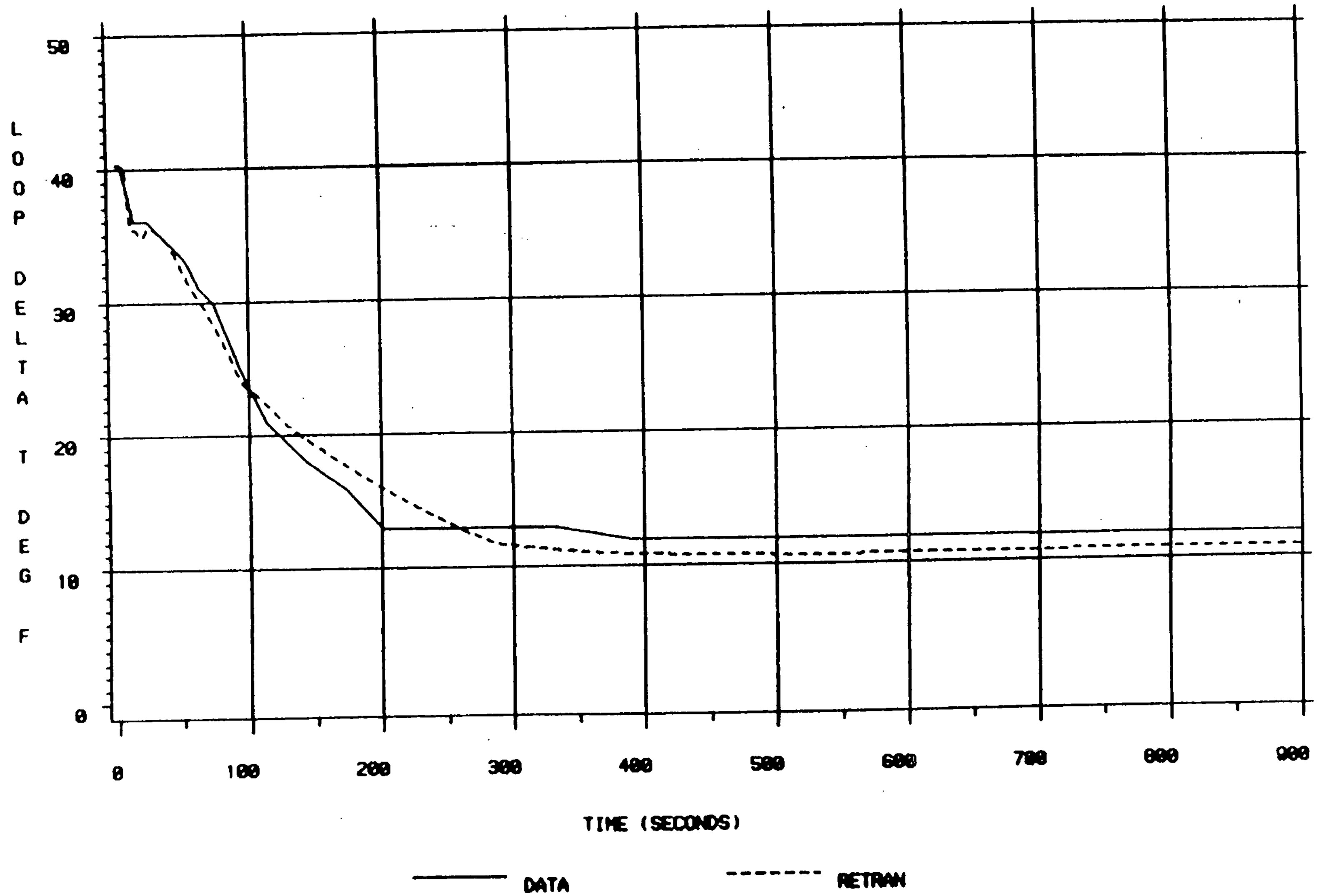


Figure 5.4.1-5

CNS-1 TURBINE TRIP TEST

3/27/85 EVENT

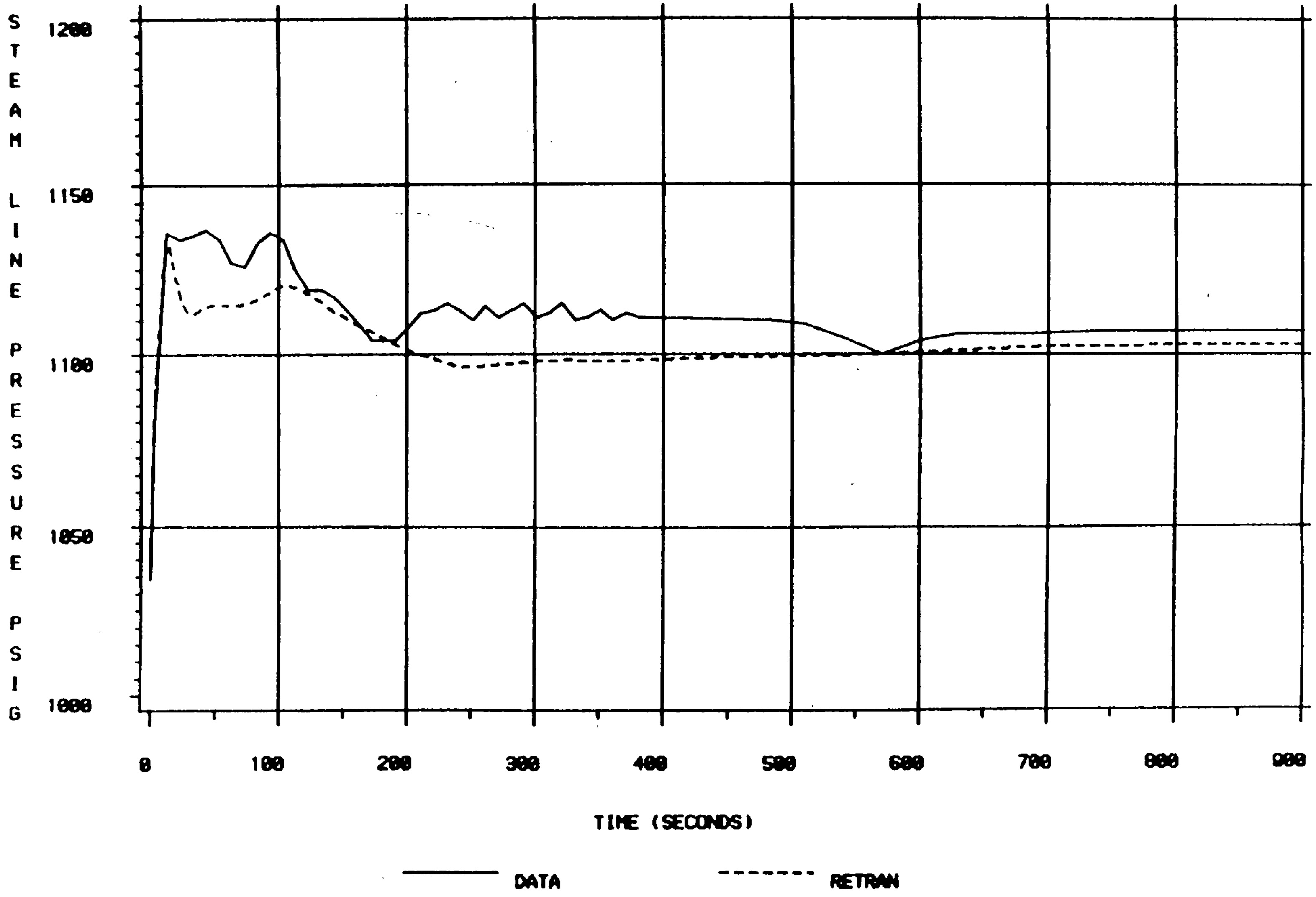


Figure 5.4.1-6

CNS-1 TURBINE TRIP TEST

3/27/85 EVENT

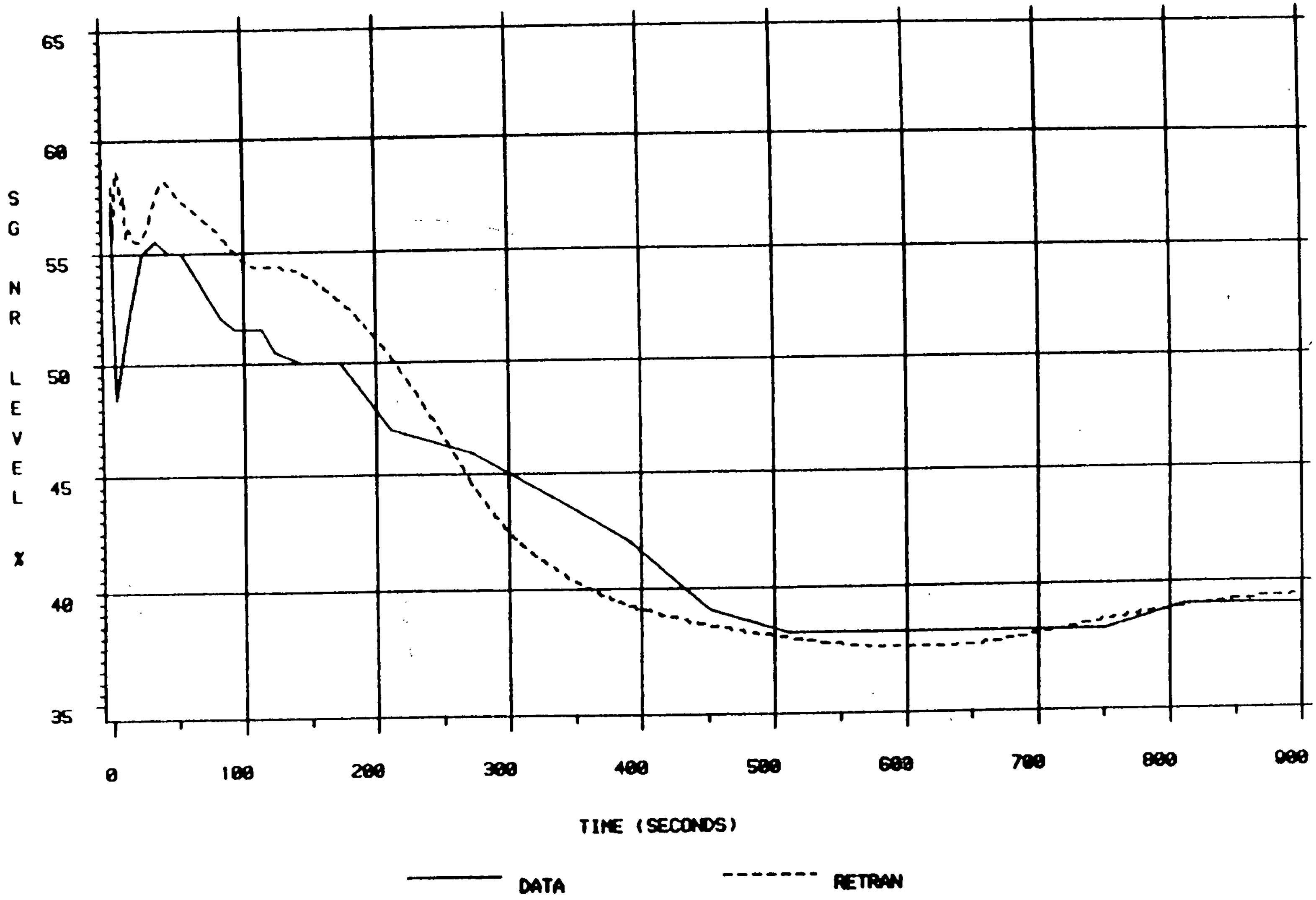


Figure 5.4.1-7

6.0 SUMMARY

The contents of this report focus on demonstrating analytical capability in the area of safety analysis, and the validation of transient thermal-hydraulic models. Detailed plant and core simulation models have been developed using the RETRAN-02 and VIPRE-01 codes. The level of detail used in the RETRAN plant models obviates the need for extensive nodalization sensitivity studies for the intended applications. The adequacy of the VIPRE core model and nodalization has been demonstrated by sensitivity studies. Both RETRAN and VIPRE have proven to have the required capabilities and necessary flexibility for a wide range of simulation needs.

Validation of the Oconee and McGuire/Catawba RETRAN models has been achieved by benchmarking to a spectrum of plant transient events. Station operating histories were reviewed to obtain transient data characterized by differing initiating events and subsequent phenomena, with emphasis on the more severe events. It should be noted that no benchmark analyses were withheld from the report due to the quality of the comparison between the simulation and the plant data. It is evident that the agreement between the RETRAN predictions and plant data varies from reasonable to excellent. Key thermal-hydraulic phenomena are typically predicted accurately with respect to data trends, and in most cases also with respect to quantitative values. RETRAN is particularly capable of simulating the coupling between primary and secondary and the effects of interfacing systems in an integrated and consistent manner. The benchmark analyses have been presented with discussions on the approach used by the analyst and identification of any unknown or atypical aspect of the plant transient which required an assumption or special treatment. A complete set of pertinent results have been plotted for each benchmark in order to show an overall comparison of the RETRAN prediction to data.

The nine transients selected for validating the Oconee RETRAN model encompass a broad range of thermal-hydraulic phenomena. The events initiated at both full and partial power, with one event initiating from a three-pump initial condition. Asymmetric loop conditions, both pre- and post-trip, are included. Primary flow distributions during a wide range of partial-pump

operating conditions and during natural circulation are also included. The most extensively benchmarked phenonema are those associated with disturbances in primary-to-secondary heat transfer. Transients resulting in both steam generator dryout and overfill are simulated and show steam generator level indication comparisons. The steam generator response to excessive steaming and subsequent overcooling is included. The reactor response to both slow and step reactivity insertions in included. The only phenomena for which plant data are unavailable are those associated with a loss of primary coolant. These phenomena are represented to some extent by the RCS inventory shrinkage caused by overcooling in several of the transients.

The eight transient events selected for validating the McGuire/Catawba RETRAN model also cover a wide range of thermal-hydraulic phenomena. The events initiate at both full and partial power, and also at 1-3% power under natural circulation conditions. The dynamic response of the reactor to control rod insertion is included. Asymmetric conditions with up to three-out-of-four loops with different secondary boundary conditions are included. A transition to natural circulation is included as well as primary flow distributions with various combinations of operating pumps. Of particular interest are the phenomena resulting from changes in feedwater flow and loss of steam generator pressure control. The impact of a reduction in feedwater on heat transfer, including heat transfer in the preheater, is benchmarked. Modeling of steam generator inventory indication and distribution, important due to the approach to trip setpoints, is validated. An absence of loss of coolant data is compensated for by data from a rapid overcooling event that caused the pressurizer to empty.

Validation of a VIPRE core thermal-hydraulic model is performed with a code-to-code comparison with COBRA-IIIC/MIT for the Oconee model. Additional VIPRE validation analyses have been separately documented in other Duke Power reports. Axial and radial nodalization sensitivity studies demonstrate the acceptability of model detail. Nearly identical consistency is shown between the local thermal-hydraulic conditions and DNBR values predicted by the two codes when similar correlations and modeling detail are maintained. VIPRE modeling assumptions to be utilized in future applications are discussed.

The results of development and analysis activities summarized in this report constitute the Duke Power Company response to Generic Letter 83-11. The current status of analytical model validation and technical capabilities in the areas of transient system and core thermal-hydraulic analysis has been presented. Analytical model development is viewed as an ongoing program. Benefitting from the excellent flexibility of the RETRAN and VIPRE codes, the models detailed in this report will continue to be enhanced as additional modeling improvements occur, and as further experience and data are obtained.

DPC-NE-3000-PA and -A
Revision 1

List of Changes/Errata to DPC-NE-3000-PA and -A

The following is the complete list of changes made in the conversion of DPC-NE-3000-PA and -A (August 1994) to DPC-NE-3000-PA and -A (December 1997). The significant methodology changes have been reviewed and approved by the NRC. None of the other minor changes are considered to be significant methodology changes, and therefore do not require NRC review.

List of changes from Revision 0 to External Revision 1 and Internal Revision1a

1. The title pages were revised to Revision 1 and were dated December 1997.

2. The proprietary text and figures were blanked out in the non-proprietary version

3. The Revision 1 SER dated 12/27/95 was included at the front

4. The Duke cover letter dated 8/9/94 (submitting Revision 1 related to replacement steam generators), and the letter dated 9/12/95 (responses to the NRC RIA letter dated 9/6/95) were included at the back (proprietary or non-proprietary)

5. The NRC letter dated 9/6/95 (RIA on Revision 1), and SERs dated 11/7/96 and 2/20/97 (approving use of the BWU-Z CHF correlation) were included at the back.

6. The revisions in the attachments to the 8/9/94 Duke letter (proprietary and non-proprietary) were inserted into the report.

7. p. iii: Added Section 2.1.5.4, Steam Line Break Detection and Mitigation Circuitry, to the Table of Contents. This station modification has been reviewed by the NRC.

8. Deleted existing footer revision labels. The entire document will be Revision 1 via the cover letter only.

9. p. 1-1-5, Section 1.6: Updated and simplified the discussion of the quality assurance documents and processes. Deleted "Design Engineering Department". Deleted references to superceded quality assurance documents and details from those documents. Deleted reference to the deleted workplace procedure for updating base models. Deleted reference to the superceded PR-101 procedure. Deleted the statement that calculations are subject to approval by management (they are approved by supervision).

10. p. 2-4, Section 2.1.2.4: Deleted the discussion of operation with two RCPs for power levels up to 50%. This operating mode is no longer permitted by technical specifications.

List of Changes/Errata to DPC-NE-3000-PA and -A

11. p. 2-20, Section 2.1.5.3: Revised the EFW actuation signals to delete the start on low MFW pump discharge pressure, and to add the start on low SG level. These changes reflect the current plant design.

12. p. 2-20, Section 2.1.5.4: Added a new section to describe the Steam Line Break Detection and Mitigation Circuitry.

13. p. 2-22, Section 2.1.6: Typo, replaced "hydraulic" with "hydraulically"

14. p. 2-36, Section 2.2.1.1, Control Rod Guide Assemblies: A sentence is added to clarify that the flow enters from the lower upper plenum in the model, due to modeling limitations. This is not a model change, only a clarification.

15. p. 2-36, Section 2.2.1.4: Deleted the statement about no structural conductors in the pressurizer. This statement should have been previously deleted.

16. p. 2-55, Section 2.2.7.5: Revised to state that a change has been made to enable use of the condensation heat transfer correlation with the forced convection heat transfer map. This is a change in the access to the RETRAN heat transfer package, and is not considered a change in the methodology.

17. p. 2-73, Section 2.3.3.1, Critical Heat Flux Correlation: Delete the MacBeth and Bowring CHF correlations as possible future correlations, since they will not be used.

18. p. 2-73, Section 2.3.3.2: A paragraph was added to state how the conservative factors are applied when the statistical core design methodology is used. A reference to the DPC-NE-2005-PA topical report "Thermal-Hydraulic Statistical Core Design Methodology", February 1995, is added.

19. p. 2-74, Section 2.3.3.2: The hot channel factor description is revised to delete the local heat flux factor since it is no longer used. This was previously submitted to the NRC as part of a reload submittal and is consistent with the current FCF methodology. The value of the power factor hot channel factor was revised to the current value of 1.0132.

20. p. 2-75 & -76, Section 2.3.3.4: RCS flow is 105.5% (non-SCD) or 107.5% (SCD), and core bypass flow ranges from 5% (low) to 7% (high). Also added statements that these values are typical.

21. p. 2-78, Section 2.3.4: The axial fuel lengths are no longer identified as a difference between the steady-state and transient methodologies since they are no longer different.

22. p. 2-84, Table 2.3-1: The active fuel length is revised to 142.29 in.

23. p. 2-100, Section 2.4: Reference 2-13, "Thermal-Hydraulic Statistical Core Design Methodology," DPC-NE-2005-PA, February 1995, is added.

24. p. 3-10, Section 3.1.3.3: The setpoints for the steam line safety valves are updated to reflect the current plant setpoints.

25. p. 3-18, Section 3.1.5.2: Safety injection actuation on low steam line pressure has been removed. This was reviewed by the NRC as part of a technical specification revision.

26. p. 3-21 and 3-24, Section 3.1.6.1: Revisions to reflect SG replacement at McGuire and Catawba Unit 1 are described.

27. p. 3-24, Section 3.1.6.2: The Catawba AFW active runout protection function has been deleted to reflect the current plant design.

28. p. 3-26, Section 3.1.6.4: The historical and current RCS average temperatures were clarified

29. p. 3-39, Section 3.2.1.1: The downcomer volume description was revised to reflect the barrel-baffle upflow modification at McGuire.

30. p. 3-40, Section 3.2.1.4: Deleted the statement about no structural conductors in the pressurizer. This statement should have been previously deleted.

31. p. 3-41, Section 3.2.2.2: Revisions to reflect SG replacement at McGuire and Catawba Unit 1.

32. p. 3-47, Section 3.2.4.2: Deleted the statement concerning safety injection on low steam line pressure. This circuit has been removed from the plant.

33. p. 3-66, Table 3.2-1: The lower core barrel (Conductor 5) is now modeled as a two-sided conductor between Volumes 1 and 6 due to the upflow modification.

34. p. 3-66, Table 3.2-1: The pressurizer spray conductor material is revised to stainless steel to correct an error.

35. p. 3-68, Table 3.2-1: The riser walls (Conductor 158) are now modeled as a single-sided conductor connected to Volume 156 only. This is a minor model change.

36. p. 3-74, Section 3.3.3.1: Added a reference to Reference 3-14 for the BWCMV SCD and SCD limit value.

37. p. 3-74, Section 3.3.3.1, Critical Heat Flux Correlation: Add BWU-Z CHF correlation and related discussions of minimum DNBR limits and statistical core design. Added Reference 3-11, "The BWU Critical Heat Flux Correlations," BAW-10199P, BWFC, November 1994. Added Reference 3-12, which is the NRC BWU-Z SER letter dated November 7, 1996, H. N. Berkow. Added Reference 3-13, which is the NRC BWU-Z SER letter dated February 20, 1997, P. S. Tam to M. S. Tuckman. Added Reference 3-14, "Thermal-Hydraulic Statistical Core Design Methodology," DPC-NE-2005-PA, February 1995

38. p. 3-75, Section 3.3.3.2: Replaced "DCHF-1" with "BWU-Z".

List of Changes/Errata to DPC-NE-3000-PA and -A

39. p. 3-77, Section 3.3.3.4: RCS flow is given as 382,000 gpm. This value can change with technical specification revisions.

40. p. 3-80, Section 3.3.4: Deleted RCS flow as a difference between steady-state and transient VIPRE models, since these values can change with technical specification revisions.

41. p. 3-74 and -75, Section 3.3.3.1, Critical Heat Flux Correlation: Delete the DCHF-1, MacBeth, and Bowring CHF correlations as possible future correlations, since they will not be used.

42. p. 3-77, Section 3.3.3.5: The 382,000 gpm flowrate has been described as an example of the technical specification flowrate.

43. p. 3-77, Section 3.3.3.5: A three-pump flowrate of 72.8% has been inserted.

44. p. 3-94, Section 3.4: Delete Reference 3-11 (DCHF-1) and add a new Reference 3-11, "The BWU Critical Heat Flux Correlations," BAW-10199P, BWFC, November 1994.

45. p. 3-94, Section 3.4: Add a new Reference 3-12, NRC SER letter dated November 7, 1996, H. N. Berkow (NRC) to M. S. Tuckman. This reference approved the use of BWU-Z.

46. p. 3-94, Section 3.4: Add a new Reference 3-13, NRC SER letter dated February 20, 1997, P. S. Tam (NRC) to M. S. Tuckman. This reference approved the use of BWU-Z.

47. p. 3-94, Section 3.4: Reference 3-14, "Thermal-Hydraulic Statistical Core Design Methodology," DPC-NE-2005-PA, February 1995, is added.

DPC-NE-3000-A
Revision 1

List of Attached Docketed Correspondence

1. 9/29/87 original submittal letter, H. B. Tucker to NRC
2. 4/3/89 letter proposing Revision 1, H. B. Tucker to NRC
3. 5/11/89 letter submitting Revision 1, H. B. Tucker to NRC (Revision 1 changes attached to this letter have been incorporated)
4. 6/15/89 letter responding to questions on ONS RETRAN, H. B. Tucker to NRC (Revision 6/15/89 changes attached to this letter have been incorporated)
5. 8/9/89 letter responding to questions on ONS SG heat transfer modeling, H. B. Tucker to NRC
6. 9/13/89 letter responding to questions on MNS/CNS RETRAN, H. B. Tucker to NRC (Revision 9/13/89 changes attached to this letter have been incorporated)
7. 2/20/90 letter responding to questions on VIPRE and submitting Revision 2, H. B. Tucker to NRC (Revision 2 changes attached to this letter have been incoroporated)
8. 8/3/90 letter responding to two questions on VIPRE, H. B. Tucker to NRC
9. 8/29/91 letter responding to restrictions on the methodology, M. S. Tuckman to NRC
10. 11/5/91 letter responding to questions on MNS/CNS SG modeling, H. B. Tucker to NRC
11. 3/11/92 letter responding to questions on ONS SG modeling, H. B. Tucker to NRC
12. 10/5/93 letter responding to questions on ONS RETRAN modeling, M. S. Tuckman to NRC
13. 8/9/94 letter submitting changes related to MNS/CNS replacement steam generators, M. S. Tuckman to NRC (Revision 1 changes attached to this letter have been incorporated)
14. 9/6/95 NRC RIA letter related to Revision 1, R. E. Martin to M. S. Tuckman
15. 9/12/95 letter responding to 9/6/95 RIA letter, M. S. Tuckman to NRC

List of Attached Docketed Correspondence (cont.)

16. 11/7/96 NRC SER approving the use of the BWU-Z CHF correlation, H. N. Berkow to M. S. Tuckman

17. 2/20/97 NRC SER approving the use of the BWU-Z CHF correlation, P. S. Tam to M. S. Tuckman

DUKE POWER COMPANY
P.O. BOX 33189
CHARLOTTE, N.C. 28242

HAL B. TUCKER
VICE PRESIDENT
NUCLEAR PRODUCTION

TELEPHONE
(704) 373-4531

September 29, 1987

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -289
McGuire Nuclear Station
Docket Nos. 50-369, -370
Catawba Nuclear Station
Docket Nos. 50-413, -414
Thermal-Hydraulic Transient
Analysis Methodology, DPC-NE-3000;
Response to Generic Letter 83-11

Gentlemen:

On February 8, 1983, Generic Letter 83-11, "Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions", was issued. The Duke Power Company response to this generic letter is submitted with the enclosed proprietary topical report DPC-NE-3000, "Thermal-Hydraulic Transient Analysis Methodology". Twenty-three copies are provided for your review. This report describes the development of thermal-hydraulic simulation models of the Oconee, McGuire, and Catawba Nuclear Stations using the RETRAN-02 and VIPRE-01 codes. These codes have received Safety Evaluation Reports following NRC review. The RETRAN plant simulation models have been extensively benchmarked against a broad spectrum of plant transient and test data. The VIPRE core thermal-hydraulic model for Oconee has been validated by comparison to the COBRA-IIIC/MIT code. The report also includes two examples of FSAR Chapter 15 analyses.

The objective of the report is to demonstrate the abilities of Duke Power Company to perform non-LOCA thermal-hydraulic transient analyses. These capabilities are intended for application toward the resolution of a wide range of safety and regulatory concerns. DPC-NE-3000 will be referenced as meeting the intent of Generic Letter 83-11.

In accordance with 10CFR 2.790, Duke Power Company requests that this report be considered proprietary. Information supporting this request is included in the attached affidavit. A non-proprietary version will be submitted following receipt of the Safety Evaluation Report.

Pursuant to 10CFR 170.12 an application fee check in the amount of $150.00 is enclosed.

Very truly yours,

Hal B. Tucker/ymn

Hal B. Tucker

SAG/89/jgc

Attachment

xc: Dr. J. Nelson Grace, Regional Administrator
U.S. Nuclear Regulatory Commission - Region II
101 Marietta Street, Suite 2900
Atlanta, Georgia 30323

Dr. K.N. Jabbour, Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Ms. Helen Pastis, Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Mr. Darl Hood, Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Mr. P.K. Van Doorn
NRC Resident Inspector
Catawba Nuclear Station

Mr. W.T. Orders
NRC Resident Inspector
McGuire Nuclear Station

Mr. J.C. Bryant
NRC Resident Inspector
Oconee Nuclear Station

AFFIDAVIT OF RICHARD B. PRIORY

1. I am Vice President, Design Engineering Department of Duke Power Company ("Duke") and as such have the responsibility of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing or rule-making proceedings, and am authorized to apply for its withholding on behalf of Duke.

2. I am making this affidavit in conformance with the provisions of 10 CFR §2.790 of the regulations of the Nuclear Regulatory Commission ("NRC") and in conjunction with Duke's application for withholding which accompanies this affidavit.

3. I have knowledge of the criteria used by Duke in designating information as proprietary or confidential.

4. Pursuant to the provisions of paragraph (b) (4) of 10 CFR §2.790, the following is furnished for consideration by the NRC in determining whether the information sought to be withheld from public disclosure should be withheld.

   (i) The information sought to be withheld from public disclosure is owned by Duke and has been held in confidence by Duke and its consultants.

   (ii) The information is of a type that would customarily be held in confidence by Duke. The information consists of analysis methodology details, analysis results, supporting data, and aspects of development programs, relative to a method of analysis that provides a competitive advantage to Duke.

      (a) The use of the information by a competitor would greatly reduce its expenditure in qualifying similar methodologies.

      (b) It reveals aspects of a methodology with potential commercial value to Duke Power.

   (iii) The information was transmitted to the NRC in confidence and and under the provisions of 10 CFR §2.790, it is to be received in confidence by the NRC.

   (iv) The information sought to be protected is not available in public sources to the best of our knowledge and belief.

RBPriory

Richard B. Priory

(continued)

(v) The proprietary information sought to be withheld in this submittal is that which is marked in the proprietary version of the report DPC-NE-3000, Thermal-Hydraulic Transient Analysis Methodology, and omitted from the non-proprietary version.

This information enables Duke to:

(a) Respond to Generic Letter 83-11, "Licensee Qualifiction for Performing Safety Analyses in support of Licensing Actions."

(b) Respond to NRC requests for information regarding the transient response of Babcock & Wilcox and Westinghouse pressurized water reactors.

(c) Support license amendment and Technical Specification revision requests for Babcock & Wilcox and Westinghouse pressurized water reactors.

(d) Perform safety reviews per 10 CFR 50.59.

(e) Enhance operation of and training programs related to nuclear power plants.

(vi) The proprietary information sought to be withheld from public disclosure has substantial commercial value to Duke.

(a) It allows Duke to reduce vendor and consultant expenses associated with supporting the operation and licensing of nuclear power plants.

(b) Duke intends to sell the information to nuclear utilities, vendors and consultants for the purpose of supporting the operation and licensing of nuclear power plants.

(c) The subject information could only be duplicated by competitors at similar expense to that incurred by Duke.

5. Public disclosure of this information is likely to cause harm to the position of Duke because it would allow competitors in the nuclear industry to benefit from the results of a significant development program without requiring a commensurate expense or allowing Duke to recoup a portion of its expenditures or benefit from the sale of the information.

RBPriory

Richard B. Priory

(continued)

AFFIDAVIT OF RICHARD B. PRIORY (Page 3)

Richard B. Priory, being duly sworn, on his oath deposes and says that he is the person who subscribed his name to the foregoing statement, and that the matters and facts set forth in the statement are true.

RBPriory

Richard B. Priory

Sworn to and subscribed before me this 29th day of September, 1987. Witness my hand and official seal.

Sue C. Sherrill

Notary Public

My commission expires September 20, 1989

Duke Power Company
P.O. Box 33198
Charlotte, N.C. 28242

DUKE POWER

April 3, 1989

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

Subject: McGuire Nuclear Station
Docket Numbers 50-369, and -370
Catawba Nuclear Station
Docket Numbers 50-413 and -414
Topical Report DPC-NE-3000,
"Thermal-Hydraulic Transient Analysis Methodology"

By letter dated September 29, 1987, I submitted for NRC review the topical report DPC-NE-3000, "Thermal-Hydraulic Transient Analysis Methodology." This report was submitted in response to Generic Letter 83-11, "Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions." During an initial telecon on March 16, 1989, and during followup discussions, the reviewer raised several questions regarding the content of this report and how it interfaced with other Duke topical reports currently under NRC review. The purpose of this letter is to respond to these questions and to outline a proposed revision to DPC-NE-3000.

The reviewer has correctly identified apparent inconsistencies in the area of Oconee core thermal-hydraulic model development using the VIPRE-01 code. The steady-state core reload design VIPRE-01 models are detailed in the Duke topical report DPC-NE-2003, which is currently under NRC review. The causes for the apparent inconsistencies are twofold. First, an evolution in modeling has occurred since the September 1987 submittal of DPC-NE-3000. The second cause is that the DNBR calculations associated with FSAR Chapter 15 transient analyses, which are the focus of DPC-NE-3000, require different and more flexible models than are required for steady-state core reload design. Duke proposes to submit a revised Section 2.3 of DPC-NE-3000 which converges technically with DPC-NE-2003, and focuses on modeling differences and the bases for those differences. This should provide sufficient clarification and improve the review process.

The reviewer stated that Section 6.0 of DPC-NE-3000 would not be reviewed, since it was considered to be beyond the scope of Generic Letter 83-11. It was agreed that this section could be either deleted or included in the final version at Duke's discretion. This section and all references to it will be deleted in the final version.

We request that a new Section 3.3 entitled "McGuire/Catawba VIPRE Model" be reviewed as part of the proposed revision. This section will have the same purpose as the existing Section 2.3, except that it will be applicable to the Duke Westinghouse units. This new Section 3.3 will similarly focus on the differences in modeling and the associated bases when compared to the Duke topical DPC-NE-2004. However, no validation results will be submitted with the new Section 3.3, and therefore it will be brief. Duke VIPRE validation for McGuire and Catawba has been submitted in DPC-NE-2004.

As discussed on March 16, 1989, we intend to submit the revisions to DPC-NE-3000 in approximately 30 days. Feedback on the proposed revision is requested in order to ensure that the concerns that have been raised will be addressed in the revision to DPC-NE-3000. You may call Scott Gewehr (704/373-7581) or Gregg Swindlehurst (704/373-5176) with your comments.

Very truly yours,

Hal B. Tucker

Hal B. Tucker

SAG/159/td

cc: Mr. Darl Hood
Office of Nuclear Reactor Reg.
U. S. Nuclear Regulatory Comm.
Washington, DC 20555

Mr. K. Jabbour
Office of Nuclear Reactor Reg.
U. S. Nuclear Regulatory Comm.
Washington, DC 20555

Mr. W. T. Orders
Senior Resident Inspector
Catawba Nuclear Station

Mr. P. K. VanDoorn
Senior Resident Inspector
McGuire Nuclear Station

Duke Power Company
P.O. Box 33198
Charlotte, N.C. 28242

DUKE POWER

May 11, 1989

U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Document Control Desk

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
McGuire Nuclear Station
Docket Nos. 50-369, -370
Catawba Nuclear Station
Docket Nos. 50-413, -414
Topical Report DPC-NE-3000
"Thermal-Hydraulic Transient Analysis Methodology"

By letter dated April 3, 1989, Duke Power Company proposed a revision to topical report DPC-NE-3000, to respond to NRC questions regarding the content to the report and how it interfaced with other Duke topical reports. During subsequent discussions the Staff agreed to the proposed scope of the revision. Consistent with this approach, please find attached for your review Revision 1 to DPC-NE-3000.

Revision 1 consists of four parts. The first part is a replacement Section 2.3, "Oconee VIPRE Model," which has been revised in response to the Staff's comments. Section 2.3.4 provides details regarding the differences between the transient core thermal-hydraulic models and the steady-state models submitted in DPC-NE-2003. The second part is a new section, Section 3.3, "McGuire/Catawba VIPRE Model. This section is similar to Section 2.3, and includes a Section 3.3.4 that similarly describes the modeling differences when compared to DPC-NE-2004. The third part is a deletion of Section 6.0, which was in response to a Staff question. The fourth part of Revision 1 is an update of the frontal matter (Table of Contents, etc.), Section 1.0, and Section 7.0 (now Section 6.0) to agree with the above technical changes.

In accordance with 10 CFR 2.790, Duke Power Company requests that Revision 1 to DPC-NE-3000 be considered proprietary. Information supporting this request was included in the affidavit which accompanied the original submittal of DPC-NE-3000, dated September 29, 1987.

Document Control Desk
May 11, 1989
Page Two

If we may be of further assistance in your review, please call Scott Gewehr (704/373-7581) or Gregg Swindlehurst (704/373-5176).

Very truly yours,

Hal B. Tucker

Hal B. Tucker

SAG/165/td

Attachment

cc: W/Attachment
Darl S. Hood
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, DC 20555

Kahtan Jabbour
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, DC 20555

Don Katze (2)
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, DC 20555

W/O Attachment
Stewart D. Ebneter, Regional Administrator
U. S. Nuclear Regulatory Commission - Region II
101 Marietta Street, NW - Suite 2900
Atlanta, GA 30323

DUKE POWER COMPANY
P.O. BOX 33189
CHARLOTTE, N.C. 28242

HAL B. TUCKER
VICE PRESIDENT
NUCLEAR PRODUCTION

TELEPHONE
(704) 373-4531

June 15, 1989

U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Attention: Document Control Desk

Subject: Oconee Nuclear Station
Docket Numbers 50-269, -270, and -287
McGuire Nuclear Station
Docket Numbers 50-369 and -370
Catawba Nuclear Station
Docket 50-413 and -414
Response to Questions On
DPC-NE-3000

By letter dated April 7, 1989, the NRC forwarded a set of questions relating to the Oconee sections of topical report DPC-NE-3000, "Thermal Hydraulic Transient Analysis Methodology".

In accordance with 10 CFR 2.790, Duke Power Company requests that the responses to these questions relating to DPC-NE-3000 be considered proprietary. Information supporting this request was included in the affidavit which accompanied the original submittal of DPC-NE-3000, dated September 29, 1987.

If we can be of further assistance in your review, please call Scott Gewehr at (704) 373-7581 or Gregg Swindlehurst at (704) 373-5176.

Very truly yours,

Hal B. Tucker

Hal B. Tucker

SAG169/lcs

Attachment

Duke Power Responses to NRC Questions
Dated April 7, 1989 Regarding DPC-NE-3000

PROPRIETARY
DUKE POWER CO.

Question 1

The topical report does not refer to sensitivity studies as a part of the model qualification. Discuss how model sensitivity studies were used.

Response

The use of sensitivity studies as part of model qualification is addressed by focusing on model nodalization and overall model performance. The level of final nodalization detail resulted from five factors: 1) an awareness of the level of detail employed by B&W for a non-LOCA transient simulation; 2) the relatively coarser detail that is satisfactory when considering application of the code to mainly subcooled primary conditions as opposed to LOCA analysis; 3) early experience indicated a need for a high level of detail in the steam generator secondary in order to obtain a reasonable initialization and adequate simulation of operation at low steam generator inventories; 4) utilization of the transport delay model to achieve the effect of greater nodalization detail; and 5) poor model performance when coarser nodalization detail was attempted. Each of these factors was considered as follows.

The final nodalization is considered to be sufficiently detailed when compared to other current methodologies for simulating non-LOCA transients in PWRs. Much of the focus of highly detailed nodalizations originates from LOCA phenomena, such as highly voided conditions, phase separation, and non-equilibrium effects. These phenomena are generally not of concern for non-LOCA applications and therefore that level of detail is unnecessary. Coarser steam generator models, such as dividing the tube bundle and secondary into [ ] nodes, were determined to be inadequate primarily during initialization efforts (see response to Question 11). The [

] were inadequate. The final nodalization is very sufficient for all of these parameters. The level of detail in the reactor vessel is also considered to be very sufficient since [
] are represented. The level of detail used is essentially as much as can be considered reasonable when applying one-dimensional modeling. By using the transport delay model in the loop piping, the ability to track a temperature front without a great level of noding detail is possible. One area in which greater detail was initially employed was in the steam lines. This was attempted in order to provide greater resolution for the steam pressure spike that results following turbine trip. This investigation showed [ ] As evident in DPC-NE-3000, the number of loops and cold legs modeled in a particular simulation is selected purely on the degree of symmetry of the initial and boundary conditions of the transient.

Sensitivity studies were also used in determining which code options were selected. Again, most of these studies focused on the accuracy of the resulting initialization. As examples, the enthalpy transport model, the [ ] and the phase separation options (slip and bubble rise) were selected based on initialization sensitivity results. Transient simulation experience served as the basis for confirmation of the modeling of the reactor coolant pump and selection of the non-equilibrium pressurizer model. In all cases, the

standard for comparison was measured plant data. The justification for the integrated model is the transient benchmarking presented in the report. The nodalization detail and modeling options used have resulted in an optimal application of the RETRAN-02 code to a B&W plant.

PROPRIETARY
DUKE POWER CO.

Question 2

Section 2.2.6.4 states that of the two models, the bubble rise model is the method of modeling phase separation. Justify use of the model and the choice of particular bubble rise velocity in each volume where it is used.

Response

The bubble rise model is used for phase separation for specific applications in the Oconee model, as shown in the following table.

Application	Gradient	Separation Velocity (ft/sec)
[		]

The bubble rise model determines the enthalpy at junctions which exit a separated volume. Each specific application is discussed below.

Pressurizer:

The pressurizer is a large tank which is outside the primary Reactor Coolant System flow path. In most situations it is partially filled with water and exhibits a distinct liquid/vapor interface. Use of the bubble rise model allows correct prediction of liquid exiting the bottom of the volume through the surge line and steam exiting the top through the pressurizer PORV or safety relief valves (when the pressurizer is not water solid). The values used for gradient and separation velocity are [ ] Experience has shown that these values provide reasonable agreement with observed behavior. However, there are no specific experimental data which support these values.

Core flood tanks:

The core flood tanks are filled with water and a cover gas (nitrogen). Because the water in the core flood tanks is very subcooled, even at low pressures, there will be no vapor generation below the mixture level. Therefore the bubble rise parameters are unimportant. The [ ] are used for those parameters in the core flood tanks.

[ ]

PROPRIETARY
DUKE POWER CO.

Question 3

Section 2.2.6.5 states that the non-equilibrium (NE) volume option has been used only with the pressurizer volume.

a) Provide a list of events indicating when the NE option is used, and descriptions of alternative modeling when the option is not used.

b) How will NE effects be accounted for in the reactor pressure vessel upper head should it draw a void?

Response

The non-equilibrium pressurizer option is used for all of the benchmarks presented in DPC-NE-3000. An equilibrium pressurizer is used only for those applications for which a conservatively low RCS pressure prediction is desired. An example of such an application is a FSAR Chapter 15 loss of coolant flow analysis. For such an event the equilibrium pressurizer model predicts a lower RCS pressure, which is a conservative boundary condition for the associated DNBR calculation.

Non-equilibrium effects are not normally expected in the reactor vessel head, since it usually remains in a subcooled state. In some situations, however, voids may develop in the head volume. Duke has performed such analyses in the past by specifying the vessel head as a non-equilibrium volume for that particular application.

Question 4

Section 2.2.4.5 states that the reactor vessel vent valve delta p is a function of valve position and frictional loss coefficient and is based on test data. Does the test data provide information on flow vs delta p? If not justify the valve model.

Response

The vent valve loss coefficient vs. dP information is taken directly from Reference 1, Table 2-1. As a part of the qualification and licensing of the Babcock & Wilcox Nuclear Steam Supply System, extensive testing and analysis was performed on the vent valves. Part of this effort was a 1/12 scale model test program to determine the vent valve flow resistance. The tests involved flow and dP measurements over a range of Reynolds numbers from 2.8×10^4 to 1.5×10^5. This program is described in Reference 2, Appendix B.

References:

1) BAW-1628, Reactor Vessel Brittle Fracture Analyses During Small Break LOCA Events With Extended Loss of Feedwater, Babcock and Wilcox, December 1980.

2) BAW-10034, Multinode Analysis of B&W's 2568-MWt Nuclear Plants During A Loss-Of-Coolant Accident, Babcock and Wilcox, October 1971.

Question 5

Section 2.2.6.7 states that local conditions heat transfer is not normally used in the base model. Justify the choice of not using this model.

Response

Local conditions heat transfer may be applied to a stack of conductors connected to a separated (bubble rise) volume. Each potential application of local conditions heat transfer is discussed below.

Pressurizer:

Modeling conductors in the pressurizer is desirable in that it would allow a representation of steam condensation on the pressurizer wall during an insurge. In early versions of RETRAN it was not possible to model heat conductors connected to a non-equilibrium volume. This capability was added to RETRAN02/MOD003. However, the RETRAN condensation correlation was inappropriate in that it was based on condensation on a bank of tubes rather than on a flat surface. Also, the coding did not account for mass transfer, i.e. taking mass out of the steam phase and adding it to the liquid phase due to the condensation heat transfer that was predicted. Therefore it was not considered worthwhile to model the pressurizer wall with conductors. This shortcoming of the model was corrected in MOD005 of the code. The model has been evaluated and conductors with the local conditions option will be added to the pressurizer. However, most of the Oconee benchmark analyses presented in DPC-NE-3000 were performed with MOD003, and as such do not contain local conditions conductors in the pressurizer. The exception to this is the loss of main feedwater benchmark reanalysis (4.1.1) which was performed in response to Questions 14-16.

Core flood tanks:

It is difficult to conceive of an instance in which heat transfer from conductors in the core flood tanks would have any impact on the plant transient response. Possibly during a very slow CFT discharge into the primary, heat transfer from the tank walls to the expanding (and thus cooling) nitrogen gas might have a slight but noticeable impact on the tank pressure. However, the RETRAN heat transfer correlations are not appropriate for such an application. Therefore no CFT conductors are modeled.

[ ]

PROPRIETARY
DUKE POWER CO.

Each potential application of local conditions heat transfer in the Oconee base model has been reviewed. In most cases the local conditions model was not used because it would provide no significant benefit in return for the additional modeling detail. In the case of the pressurizer wall conductors, the model was not used due to code limitations which existed at the time of the benchmark analyses. Based on the model corrections and enhancements in the latest versions of RETRAN, passive heat conductors in the pressurizer using the local conditions heat transfer option have been evaluated and will be implemented for future best estimate analyses.

Question 6

Section 2.2.7.5 states that the forced convection map is most often used for transient analyses. Justify its use in the steam generator secondary, in light of apparent differences between measured and computed data of the benchmark analyses.

Response

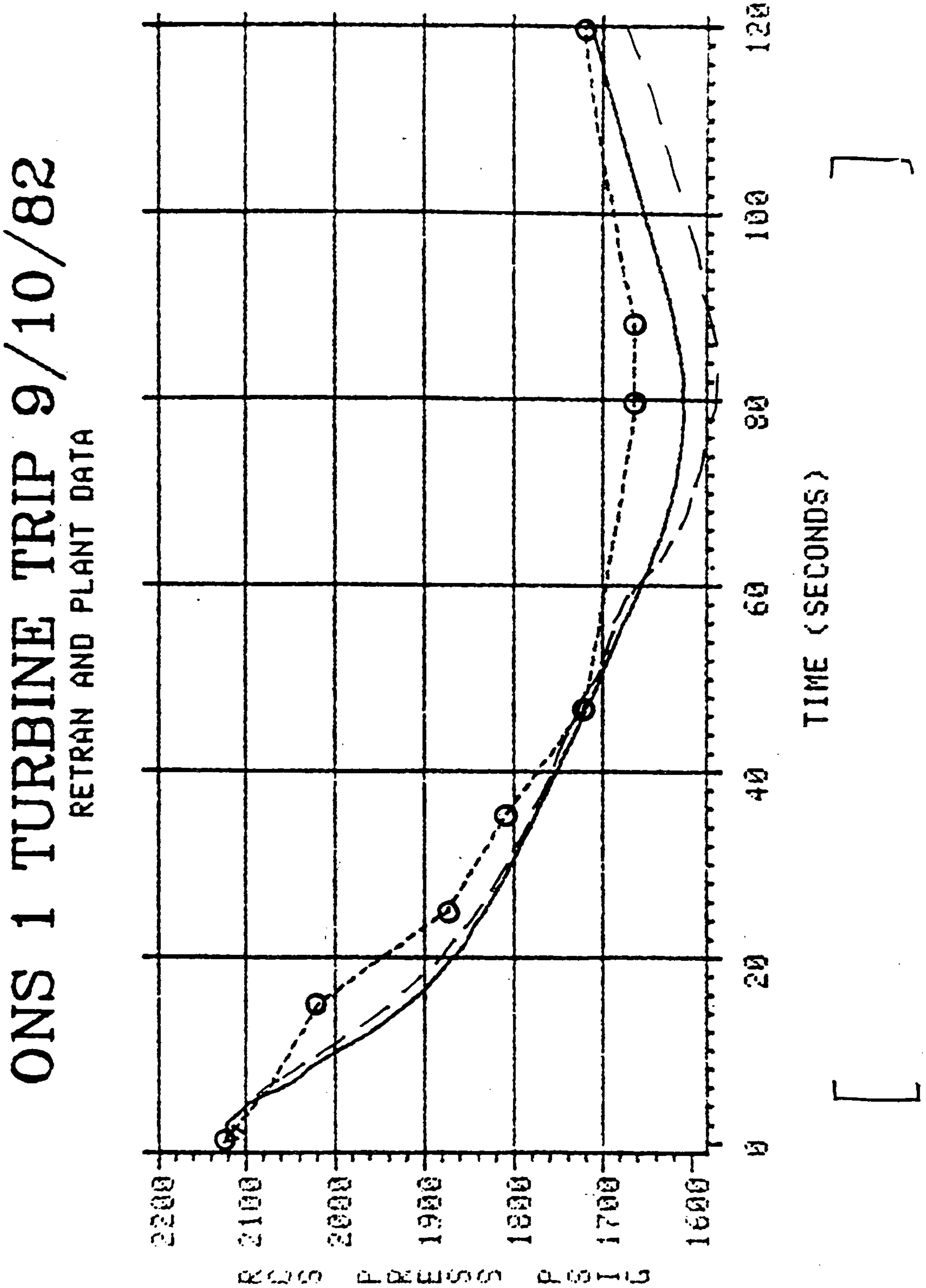
The combined heat transfer map contains an additional set of correlations which are used for low flow conditions. If the combined map is used, the code uses free convection correlations to represent the heat transfer on the secondary side of the OTSG at 100% power. As a result, the combined map [ ] in this situation. [ ] are required to match nominal initial conditions with the [ ] option.

A sensitivity study was performed on the heat transfer map option in association with the turbine bypass valve failure following reactor trip benchmark (4.2.1). A comparison between RETRAN results using the two different heat transfer options is shown on the Figures 6-1 through 6-3. These figures indicate that the forced convection map produces better agreement with the data than the combined map option. It is evident that the combined map [ ] for this simulation.

In general, the benchmark results exhibit good heat transfer agreement using the forced convection heat transfer map. This agreement provides justification for the use of that option.

PROPRIETARY
DUKE POWER CO.

Figure 6-1



ONS 1 TURBINE TRIP 9/10/82

RETRAN AND PLANT DATA

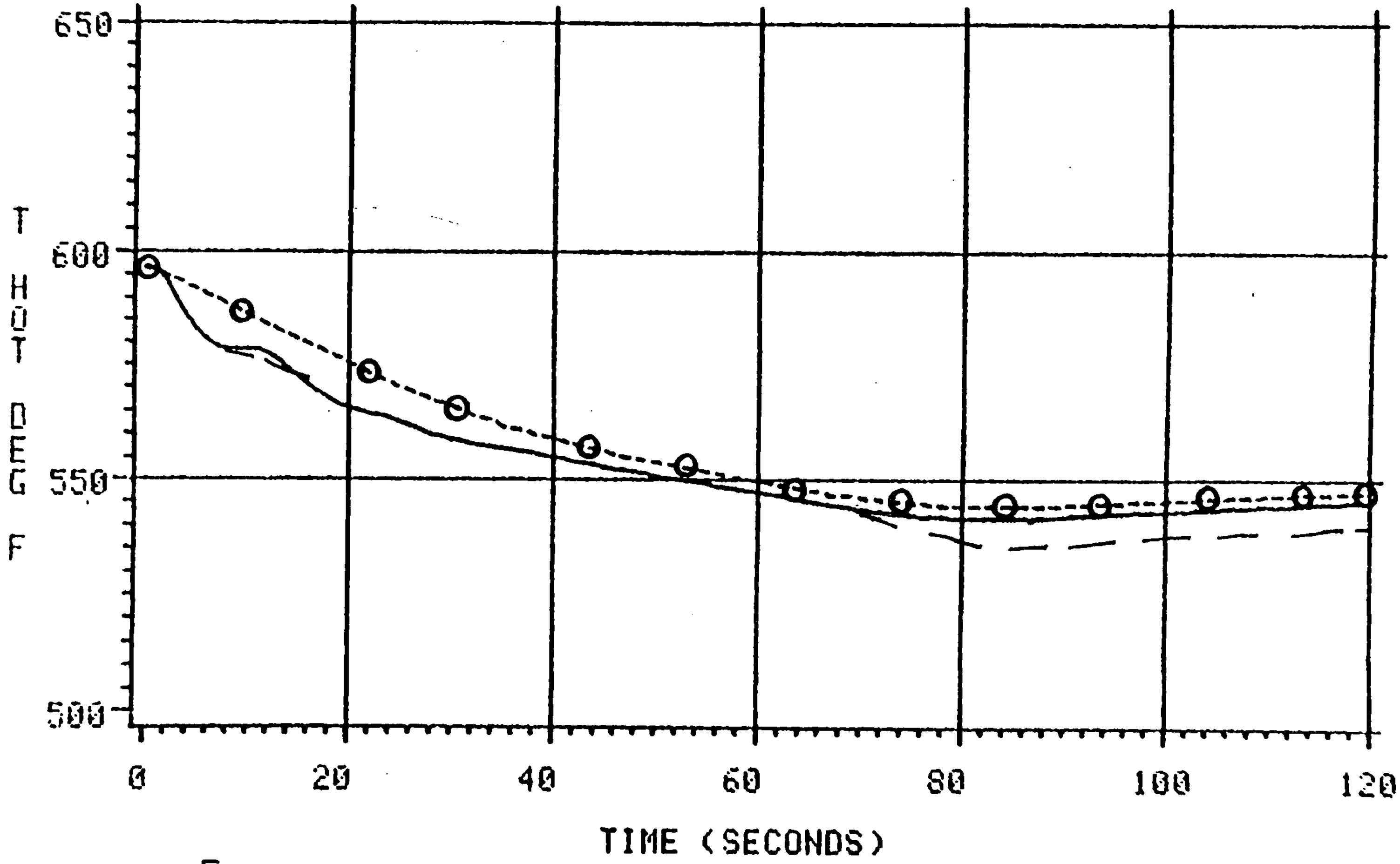


Figure 6-2

PROPRIETARY
DUKE POWER CO.

ONS 1 TURBINE TRIP 9/10/82
RETRAN AND PLANT DATA

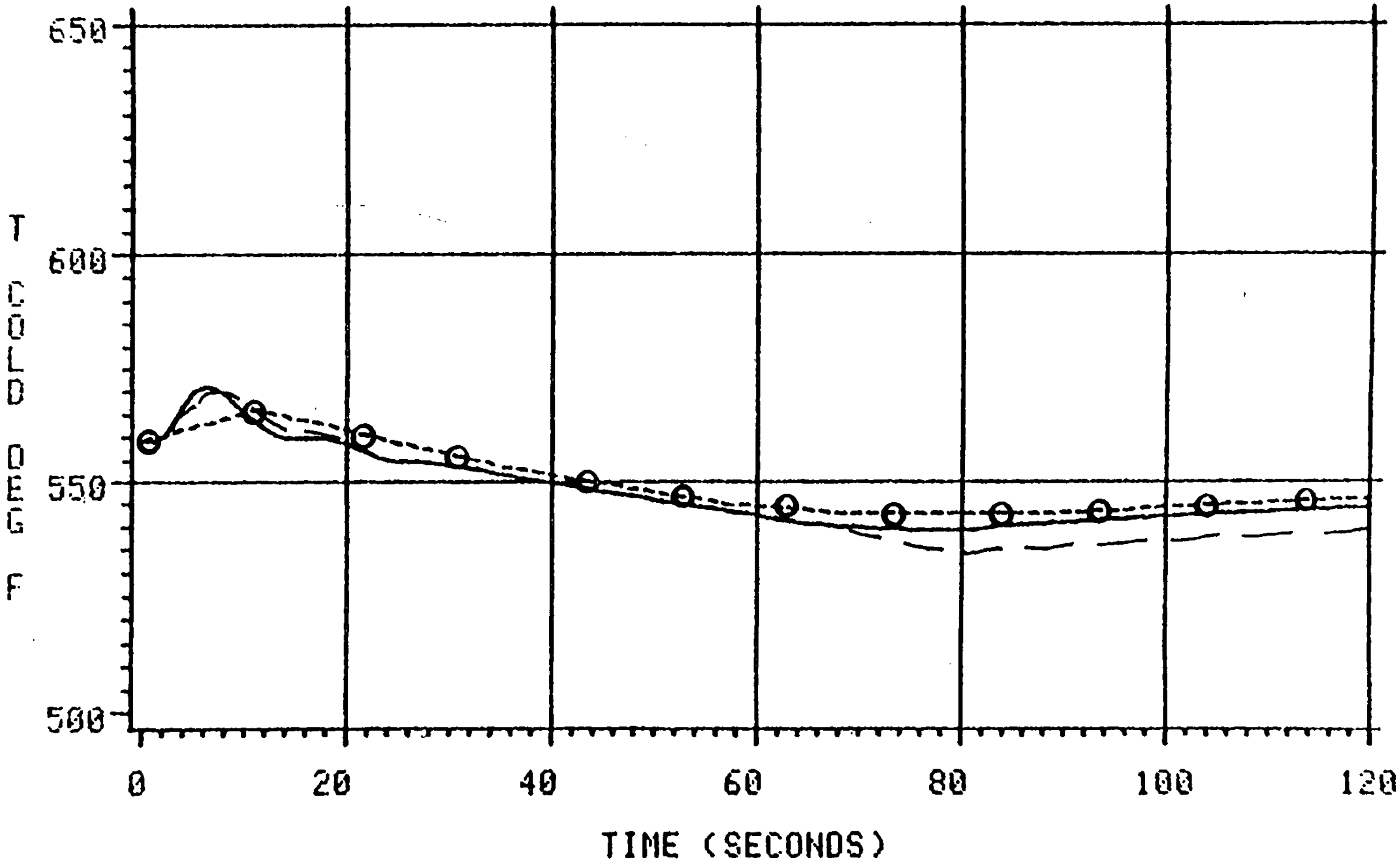


Figure 6-3

PROPRIETARY
DUKE POWER CO.

Question 7

Section 2.2.9 states that the pressurizer model does not mechanistically simulate heat transfer and this limitation can be compensated by careful modeling. Explain how this modeling is done.

Response

The statement that the non-equilibrium pressurizer model does not mechanistically simulate heat transfer refers primarily to the response of the model to a pressurizer insurge. The insurge results in the compression of the steam bubble. Along with the increase in pressure, the steam bubble will superheat due to the work associated with the compression process. Since the superheated steam temperature exceeds the temperature of the liquid and of the pressurizer vessel, heat transfer will occur. The rate of heat transfer will be governed by the respective temperature differences, the heat transfer areas, and the heat transfer coefficients. These factors are very dependent on the rate and duration of the insurge. While condensation on the vessel walls is relatively straightforward, the heat transfer process at the steam/liquid interface is complex. The liquid surface may be relatively quiescent, or it may be very turbulent when considering a large insurge or pressurizer spray operation.

RETRAN-02 MOD005 enables modeling of the heat transfer between the steam and the pressurizer vessel explicitly. Previous versions of RETRAN-02 lacked an accurate representation of this process. For this reason, the simulations presented in the report [ ] All versions of RETRAN-02 model heat transfer between the steam and liquid by using a user input constant heat transfer coefficient, the flow area of the pressurizer volume, and the temperature difference between the two phases. This approach is somewhat crude in that the heat transfer coefficient is not based on local fluid conditions. Also, the heat transfer area used does not account for turbulence at the phasic interface. An argument can also be made that temperature stratification in the liquid phase can be important, and it is not in the formulation.

Considering these model limitations, the model will overpredict the rate of pressurization following an insurge, provided that a small value of the heat transfer coefficient is input. This approach is perfectly acceptable if a conservative overprediction of the rate of pressurization can be accommodated. This approach is also generally acceptable if the simulation includes a substantial amount of pressurizer spray flow. If essentially no pressurization during an insurge is appropriate for a particular conservative simulation, then the pressurizer can be modeled as an equilibrium volume.

The use of careful modeling comes into play if a realistic rate of pressurization is desired. This technique simply involves the use of plant data showing the pressurization response to a given insurge event. Provided that plant data exists which is characterized by a pressurizer level transient that approximates the simulation of concern, the input interphase heat transfer coefficient can simply be adjusted until the rate of pressurization in the data is matched. This value of the interphase heat transfer coefficient can then be used in predictive simulations with similar pressurizer insurges.

Question 8

Section 4.2.2 provides a plant response during a significant asymmetric overfeed to the steam generators. Justify not using a split-core nodalization to model this benchmark event.

Response

A decision is made whether or not to use a split-core nodalization based on two considerations. One consideration is the occurrence of any asymmetry between the two loops as determined by reviewing the dynamic responses of the cold and hot leg temperatures. If the cold leg temperatures are very similar, then there is no need to split the core. If the cold leg temperatures are different but plant data shows that the hot leg temperatures are close, then again there is no need to split the core. This latter case is valid only for the reactor in a subcritical condition. In the Section 4.2.2 benchmark analysis the maximum difference between the cold leg temperatures is only 1.2°F. This alone justifies no need to use a split core nodalization. The small temperature difference between the loops for this event shows that an asymmetric overfeed of this magnitude does not result in an asymmetric primary loop response. The second consideration involves those transients for which there could be an asymmetric power distribution in the reactor. An example of this situation would be a steam line break transient. The reactor power could be substantially tilted and/or the hot leg temperatures can differ significantly in this situation, resulting from colder core inlet temperatures corresponding to the affected cold legs. An analysis with these asymmetric aspects would require a split-core nodalization.

Question 9

For each transient, justify the acceptance of mismatched initial conditions and discuss their impact on the transient.

Response

An effort was made to match the important initial conditions for each benchmark analysis. Experience has shown that the most important parameters are generally RCS pressure, pressurizer level, RCS temperature, and SG inventory. As has been noted, some initial conditions are not matched for each transient. The reasons for the discrepancies are discussed below.

Inherent uncertainties in the plant data make it impossible to match all parameters. For example, the RCS delta-T which is taken from the data will not be entirely consistent with the delta-T which can be inferred from the core power, reactor coolant pump power, and RCS flow rate.

The analyses were performed by taking a base deck and modifying it to match event-specific initial conditions and boundary conditions. In many cases the judgement was made that the conditions, although not perfectly matched, were close enough to proceed with the simulation. Otherwise, a great deal of effort may be spent for a negligible increase in accuracy. Experience gained with the code through informal sensitivity studies has revealed that the overall results are not significantly affected by minor variations in parameters such as primary system temperatures, RCS flow, SG level, or SG pressure.

A formal sensitivity study was performed for the SG overfeed following reactor trip benchmark (4.2.2). In Case 1, the initial conditions were matched as closely as possible, including asymmetric initial power removal fractions in the SGs. In Case 2, nominal base model initial conditions were generally used. A comparison of initial conditions is shown below.

Parameter	Case 1	Case 2	Data
Power Level (%)	100	100	100
RCS Pressure (psig)	2139	2139	2139
Pzr Level (inches)	228	228	228
T-hot Loop A (°F)	600.3	601.9	600.3
Loop B (°F)	600.3	601.9	601.2
T-cold Loop A (°F)	556.5	555.2	556.5
Loop B (°F)	554.0	555.2	556.7
SG A OR Level (%)	61	61	61
SG B OR Level (%)	68	68	68
SG A Pressure (psig)	910	910	898
SG B Pressure (psig)	910	910	895
MFW Temperature (°F)	454	460	454
RCS Flow (Mlbm/hr)	145	140	149
MFW A Flow (Mlbm/hr)	5.5	5.4	5.3
MFW B Flow (Mlbm/hr)	5.4	5.4	5.3

T-hot, T-cold, MFW temperature, and RCS flow were adjusted to match the data for Case 1 but left at nominal values for Case 2. However, the transient predictions showed no significant difference between the two

cases, as shown in Figures 9-1 through 9-10. Note: Case 1A is another sensitivity study which is unrelated to this response.

Generic aspects of matching initial conditions are discussed below.

Steam Generator Level:

Steam generator levels are the most notable area of discrepancies between initial plant data and model values. The dP measurements of SG level at Oconee reflect the frictional pressure drop between taps as well as the static head of water. At high power conditions the frictional dP is a substantial fraction of the total pressure drop. In addition, the Oconee once-through steam generators have exhibited fouling during their lifetime which has caused the indicated level to increase due to an increased frictional dP. While the full power SG operate range levels at initial startup were approximately 55%, the indicated levels had increased to more than 90% at full power operation due to fouling. A recent chemical cleaning operation has successfully reduced levels back to 55%.

For the majority of the Oconee benchmarks an initial SG level reflecting a clean condition was used. It was felt to be a more accurate approach to neglect the increased frictional dP component of the level signal, since that increase does not necessarily represent an increase in actual inventory. Therefore the initial SG levels do not generally match between the RETRAN model and the data. Exceptions to this are discussed later, under the specific transient.

Three more items should be noted pertaining to SG level. First, SG level is not a controlled parameter at B&W plants. The level varies with main feedwater flow as the Integrated Control System regulates overall primary-to-secondary heat transfer. Second is that, unlike most other plants, there are no reactor trip signals or EFW actuation signals generated based on any SG level indication. The only important setpoint which comes off of level is a trip of the MFW pumps on high operating range SG level. Thus the prediction of the absolute magnitude of the indicated SG level is not as important as it is for other pressurized water reactors. Third, informal studies have shown that the primary system response is not sensitive to variations in SG level such as those observed in the benchmark transients between the plant data and the RETRAN model.

Reactor Coolant System Flow:

Oconee Unit 1, with Westinghouse reactor coolant pumps, has lower Reactor Coolant System flow than Units 2 and 3, which have Bingham pumps. The Oconee base model is based on the Unit 1 thermal design flow, since that is conservative for DNB calculations. However, that flow rate is slightly low relative to typical Unit 1 values and even lower relative to Units 2 and 3. Again, experience has shown that these magnitudes of differences in primary flow rates do not significantly affect the accuracy of transient calculations. In most cases the judgement was made that the effort required to change the base model RCS flow rate was not justified by the negligible resulting increase in accuracy.

Reactor Coolant System Temperatures:

The previously discussed differences in RCS flow result in a difference between plant and model temperatures. In addition, slight asymmetries between loop conditions and instrument inaccuracies exist for the plant data. As with RCS flow, small variations in temperature do not significantly detract from the accuracy of the simulation. The usual approach for these benchmarks was to match the overall average RCS temperature or one of the loop temperatures. The resulting temperature distributions were sufficiently close to the initial data.

SG Pressure:

In general, nominal values are used for initial SG pressures. The plant controls main steam pressure (immediately upstream of the turbine) at 885 psig during power operation. The indicated SG pressure is determined by the main steam pressure and the frictional pressure drop between the SG pressure tap (actually located on the steam line immediately downstream of the SG) and the turbine inlet. The Oconee model uses a nominal 25 psi drop between the SG and the turbine at full power.

Rather than perturb the initialization, in most cases it was deemed to be adequate to accept a minor offset in initial SG pressure. This does not introduce large inaccuracies in heat transfer, because the saturation temperature changes by only 0.13°F per psi at normal operating pressure. Furthermore, the once-through SG heat transfer is more strongly affected by boiling length than pressure. The insensitivity of the overall plant response to this parameter has been observed in informal sensitivity studies. Of course, for licensing calculations in which peak secondary system pressure is a key parameter, more rigorous modeling and consideration of initial conditions would be necessary.

It should also be noted that the Oconee model takes the SG pressure indication from the uppermost node in the SG, as opposed to the steam line outside the SG. More extensive steam line nodalization would be required to obtain a pressure at the physical location of the tap, and this nodalization was not considered to be justified by a corresponding improvement in the overall accuracy of the simulations. As a result, the Oconee model generally has a higher initial pressure than the data, due in part to the fact that the frictional pressure drop leaving the generator is not accounted for by the model. After reactor trip the steam flow rate quickly decreases and the frictional pressure drop component is no longer important.

In the following section, the initial conditions of each Oconee benchmark transient are discussed in detail.

4.1.1 ONS 3 Loss of Main Feedwater:

Following review of this analysis for the response to Questions 14-16, it was decided that the calculation should be revised to more accurately model the boundary conditions of the benchmark transient. At the same time the initial conditions were matched more closely to the plant data. The revised Section 4.1 is attached to the response to Question 14, and the revised initial conditions are listed there. Those parameters which are in disagreement are discussed below.

T-hot and T-cold - See generic RCS temperature discussion above. T-ave is matched.

SG Pressure - See generic SG pressure discussion above.

SG level (OR) - See generic SG level discussion above.

SG level (SUR) - This parameter is closely matched.

4.2.1 ONS 1 TBV Failure Following Reactor Trip:

T-hot - See generic RCS temperature discussion.

SG levels - See generic SG level discussion.

RCS flow - For this transient, the RCS flow was increased to obtain better agreement with RCS temperatures. The resulting flow mismatch (3.5%) is not considered to be significant.

MFW flow - The 1% difference between plant and model MFW flow is within the inaccuracy of the flow instrument.

4.2.2 ONS 3 SG Overfeed Following Reactor Trip:

T-hot and T-cold - See generic RCS temperature discussion.

SG level - For this transient the levels were matched with the data for two reasons. First, a direct comparison of levels was desired during the overfeed, and second, the initial levels were relatively close to the clean generator level of 55%, indicating that extensive SG fouling had not occurred.

SG pressure - See generic SG pressure discussion.

RCS flow - See generic RCS flow discussion.

MFW flow - The 2.4% MFW flow discrepancy is considered to be insignificant.

4.2.3 ONS 3 Overcooling Following Loss of ICS Power:

T-hot and T-cold - See generic RCS temperature discussion.

RCS flow - See generic RCS flow discussion.

SG pressure - See generic SG pressure discussion.

SG level - Initial SG levels are matched for this transient in order to more easily compare the pre-trip change in this parameter. In addition, the relatively low initial levels indicated that extensive SG fouling had not occurred, making the level signal a relatively accurate representation of inventory.

MFW temperature - The nominal full power MFW temperature was used, so the model temperature was 6°F too high. This enthalpy difference is considered to be insignificant, compared to the

large enthalpy change which occurs when boiling and then superheating the feedwater.

4.3.1 ANO-1 Unit 1 Loss of Offsite Power:

T-hot and T-cold - See generic RCS temperature discussion.

SG level - See generic SG level discussion.

RCS flow - This parameter is matched well within the accuracy of typical flow instrumentation.

MFW flow - The 2% discrepancy in MFW flow can be partially or wholly attributed to instrument inaccuracy. The mismatch does not significantly affect the course of the transient.

4.3.2 ONS 1 Reactor Coolant Pump Coastdowns:

The model was initialized at the thermodynamic conditions and RCS flow rates corresponding to the tests.

4.3.3 Steady State Natural Circulation Comparisons:

This does not represent a direct comparison to any one event. Therefore, matching initial conditions is not relevant to this case.

4.4.1 ONS 1 Control Rod Group Drop:

T-hot and T-cold - See generic RCS temperature discussion.

SG pressure - See generic SG pressure discussion.

SG level - See generic SG level discussion.

RCS flow - The 1% discrepancy is within the accuracy of the indication.

MFW flow - The 1% discrepancy is within the accuracy of the indication.

4.5.1 ONS 1 MFW Pump Trip:

T-hot and T-cold - See generic RCS temperature discussion.

Main steam pressure - The same generic argument used for SG pressure applies to this 4 psig discrepancy in main steam pressure.

SG level - See generic SG level discussion.

RCS flow - The 1.4% discrepancy is within the accuracy of the indication.

MFW flow - The 1% discrepancy is within the accuracy of the indication.

4.5.2 ONS 1 Turbine Bypass Valve Failure:

Pressurizer level - A 1" offset is present in pressurizer level, which corresponds to a negligible 3 ft^3 pressurizer liquid deficit in the model.

T-hot and T-cold - See generic RCS temperature discussion.

SG level - See generic SG level discussion.

MFW flow - The 1% discrepancy is within the accuracy of the indication.

4.6.1 ONS 3 Reactor Trip From Three RCP Operation:

T-hot and T-cold - See generic RCS temperature discussion.

SG pressure - See SG pressure discussion above. Although there is a significant initial offset in SG A pressure, the model and the plant track very closely through the transient.

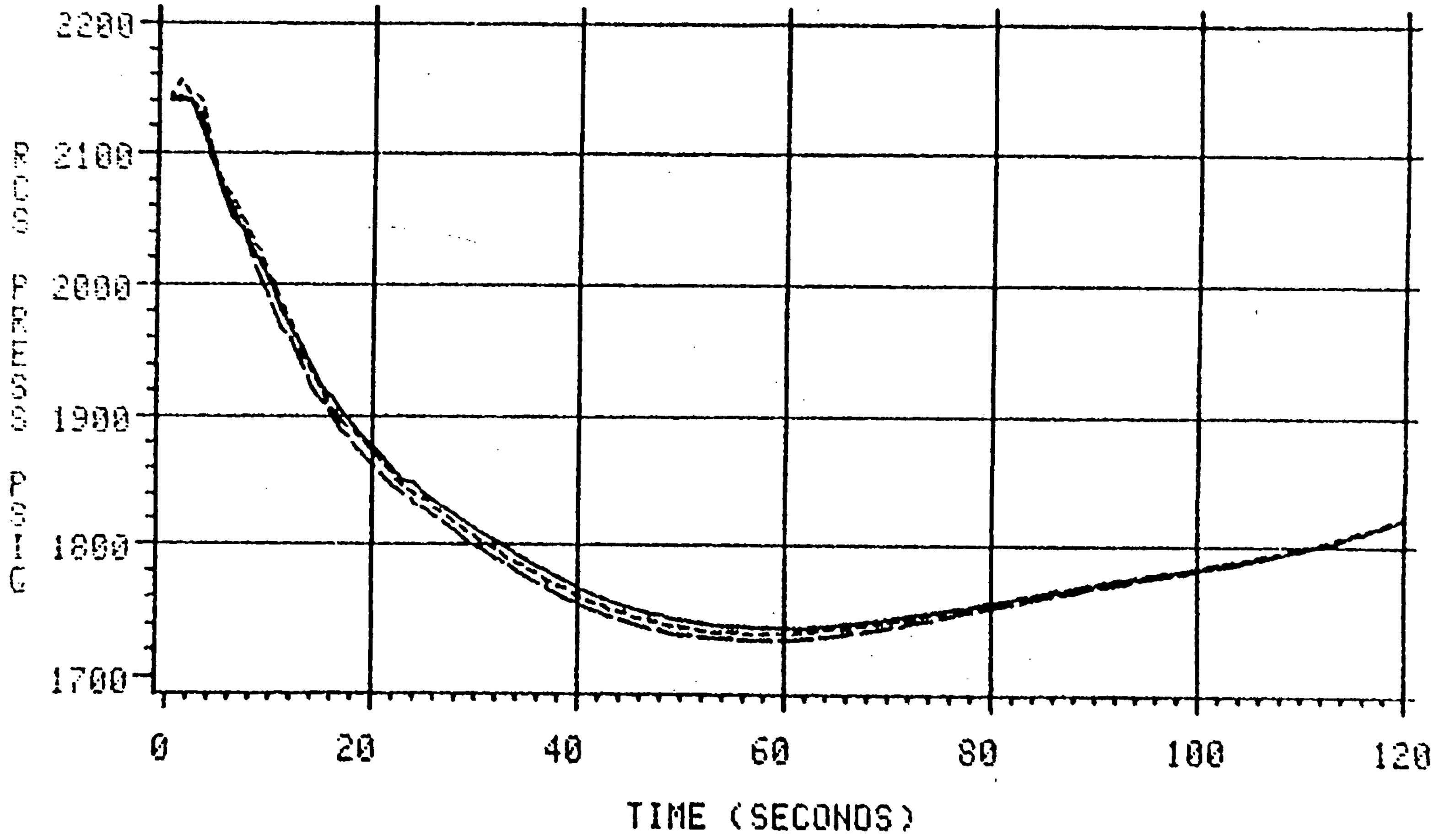
SG level - The initial RETRAN levels are matched to the data for this transient for two reasons. First, the event took place on Unit 3, which generally has had less fouled SGs than Units 1 and 2, so the levels should be representative of the actual inventory. Second, there was no available data on levels during three RCP operation with unfouled SGs, so the plant data was used.

MFW flow - There are discrepancies between the initial MFW flows in each loop, particularly in loop B. The total MFW flow is within 2%. Part of the discrepancies may be attributable to MFW flow indication error. Another part could be due to differences between the fraction of heat removal assumed in the respective SGs in the model at the beginning of the transient. However, the disagreement between the data and the model is not considered to be excessive.

In summary, for each benchmark analysis an effort was made to match the initial plant conditions which are considered most important for an accurate simulation. Other initial conditions were matched as much as was practicable. Several factors, such as accuracy and consistency of the data and mild asymmetries between loops, imposed limitations on the amount of agreement which was possible with the plant. However, the initial conditions were matched to the extent necessary to enable a comparison between the transient predictions of the code and the actual plant response.

ONS-3 TURBINE TRIP

3/14/80 EVENT

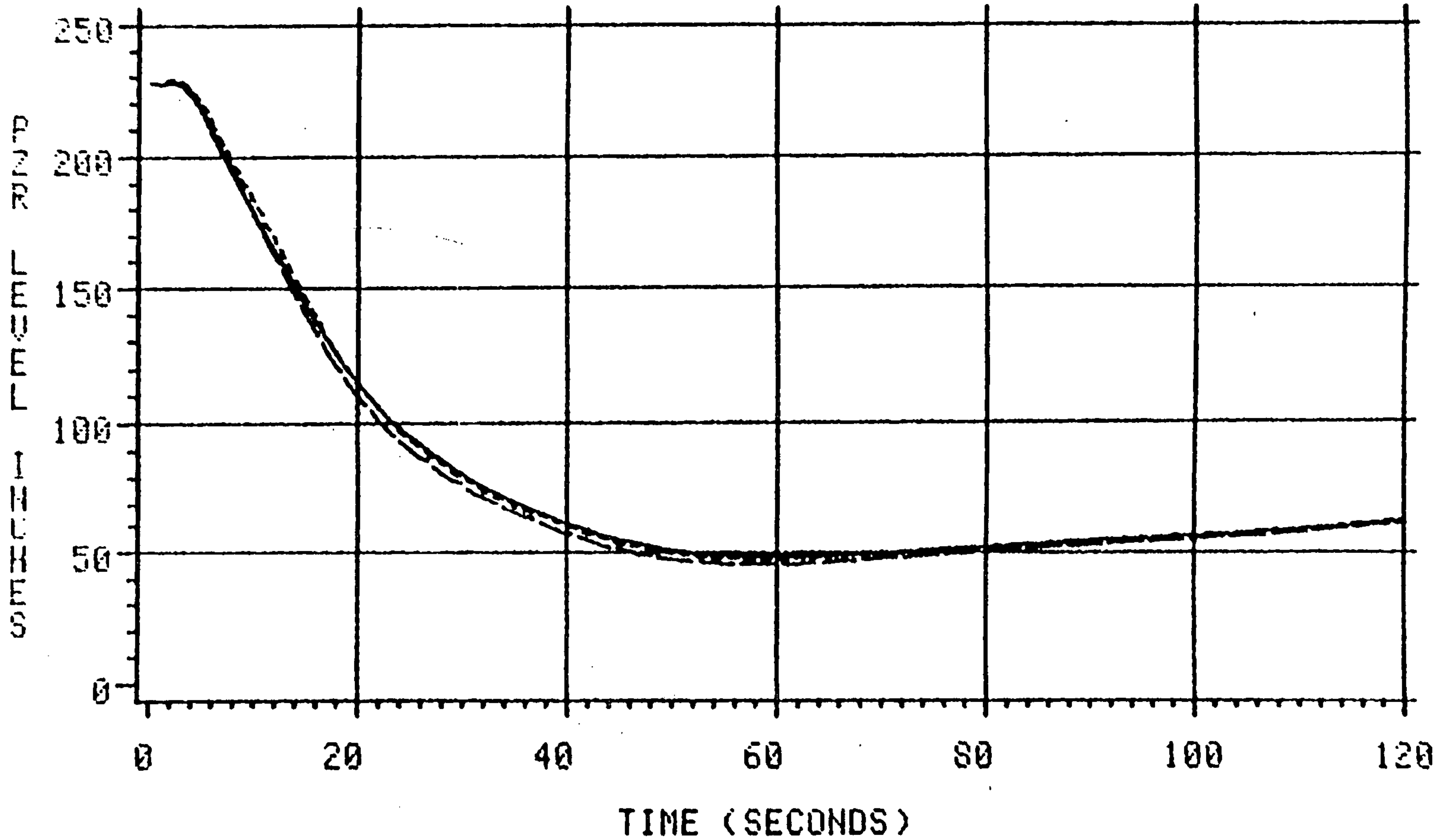


LEGEND: ——— CASE 1 ------CASE 1A — — —CASE 2

Figure 9-1

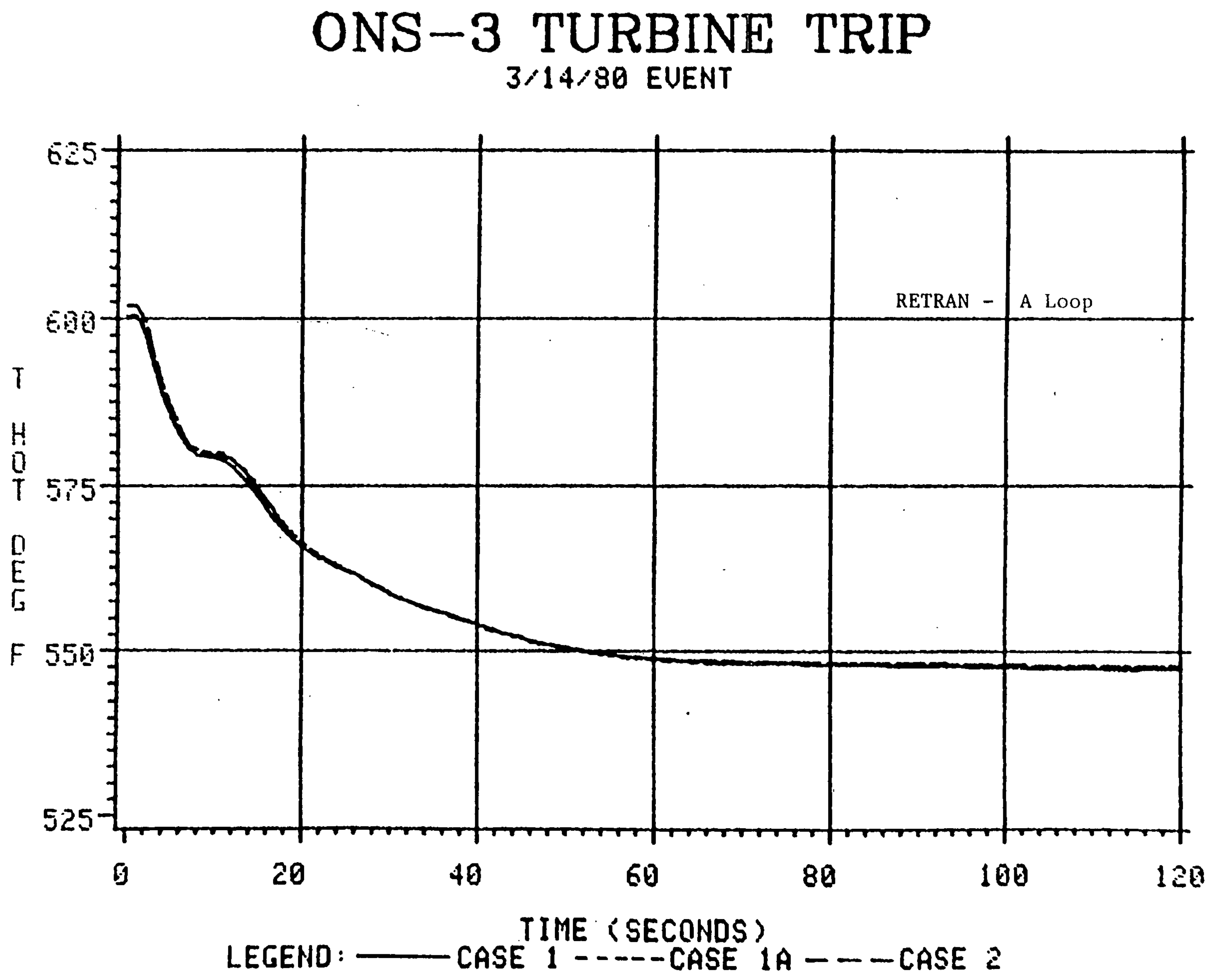
ONS-3 TURBINE TRIP

3/14/80 EVENT



LEGEND: ——— CASE 1 - - - - - - CASE 1A — — — CASE 2

Figure 9-2



ONS-3 TURBINE TRIP
3/14/80 EVENT
RETRAN - A Loop
T HOT DEG F
625
600
575
550
525
0
20
40
60
80
100
120
TIME (SECONDS)
LEGEND: CASE 1 CASE 1A CASE 2

Figure 9-3

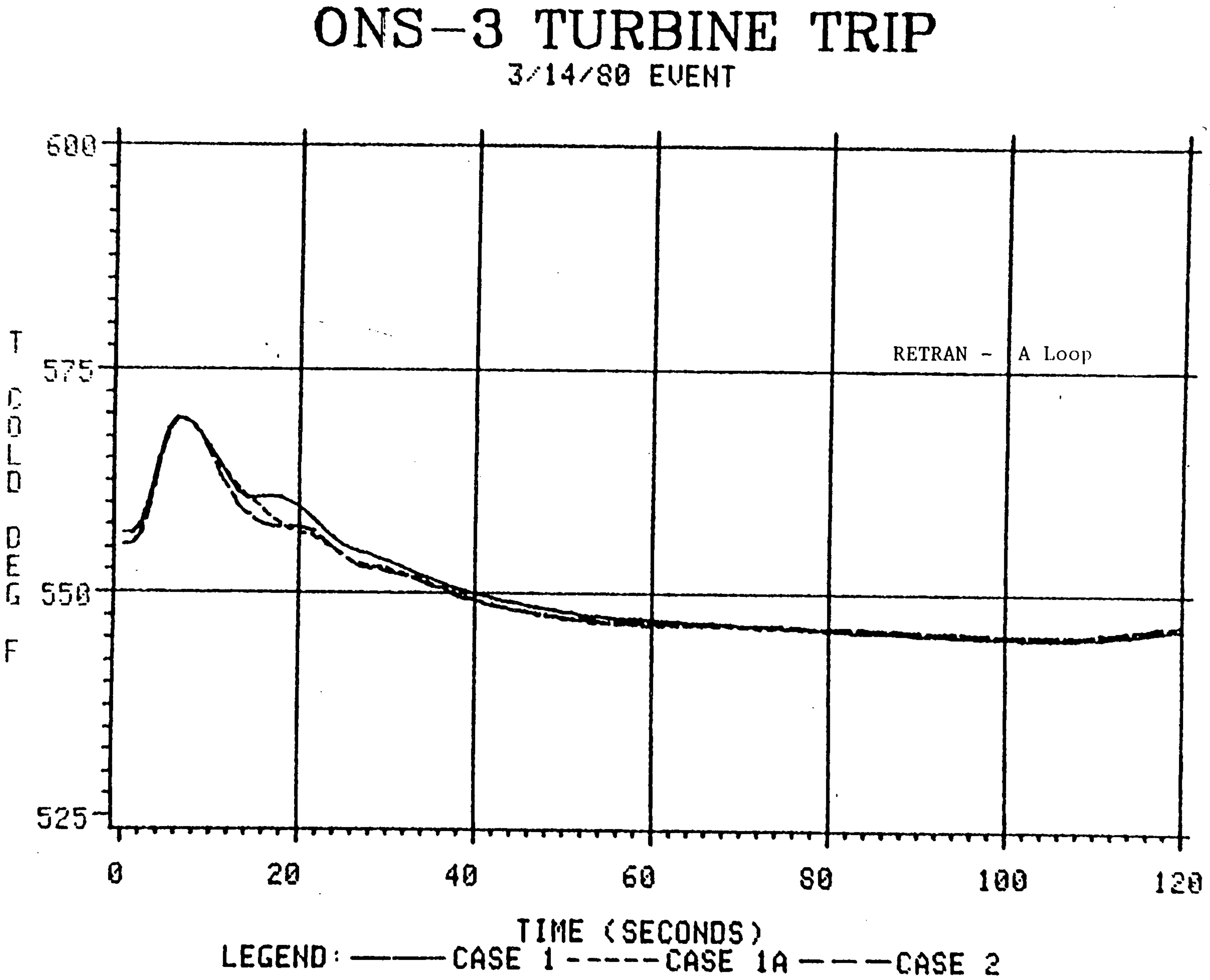

ONS-3 TURBINE TRIP
3/14/80 EVENT
RETRAN - A Loop
T COLD DEG F
600
575
550
525
0
20
40
60
80
100
120
TIME (SECONDS)
LEGEND: ——— CASE 1 ----- CASE 1A — — — CASE 2

Figure 9-4

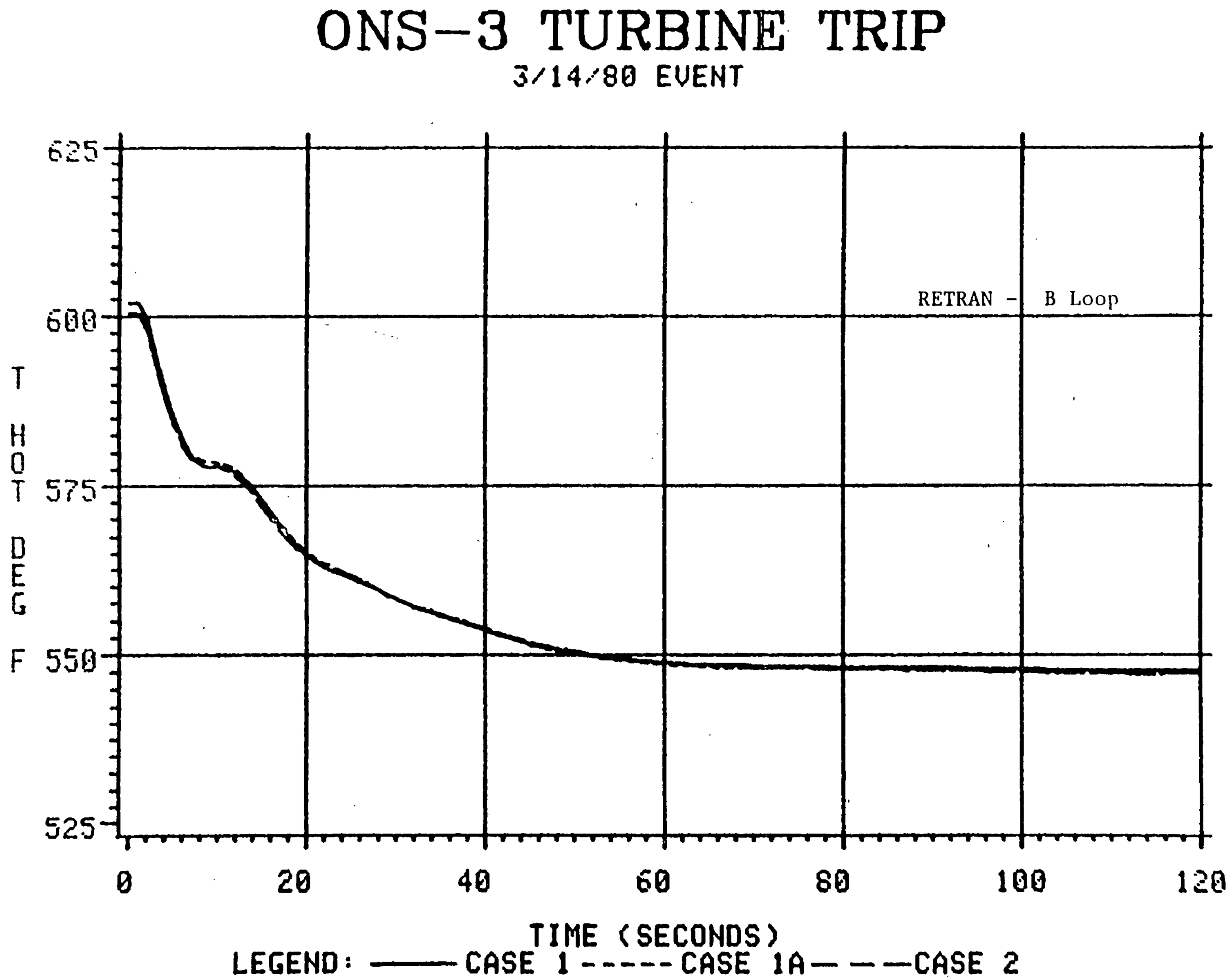

ONS-3 TURBINE TRIP
3/14/80 EVENT
625
600
575
550
525
T HOT DEG F
RETRAN - B Loop
0
20
40
60
80
100
120
TIME (SECONDS)
LEGEND: ——— CASE 1 - - - - - CASE 1A — — — CASE 2

Figure 9-5

ONS-3 TURBINE TRIP

3/14/80 EVENT

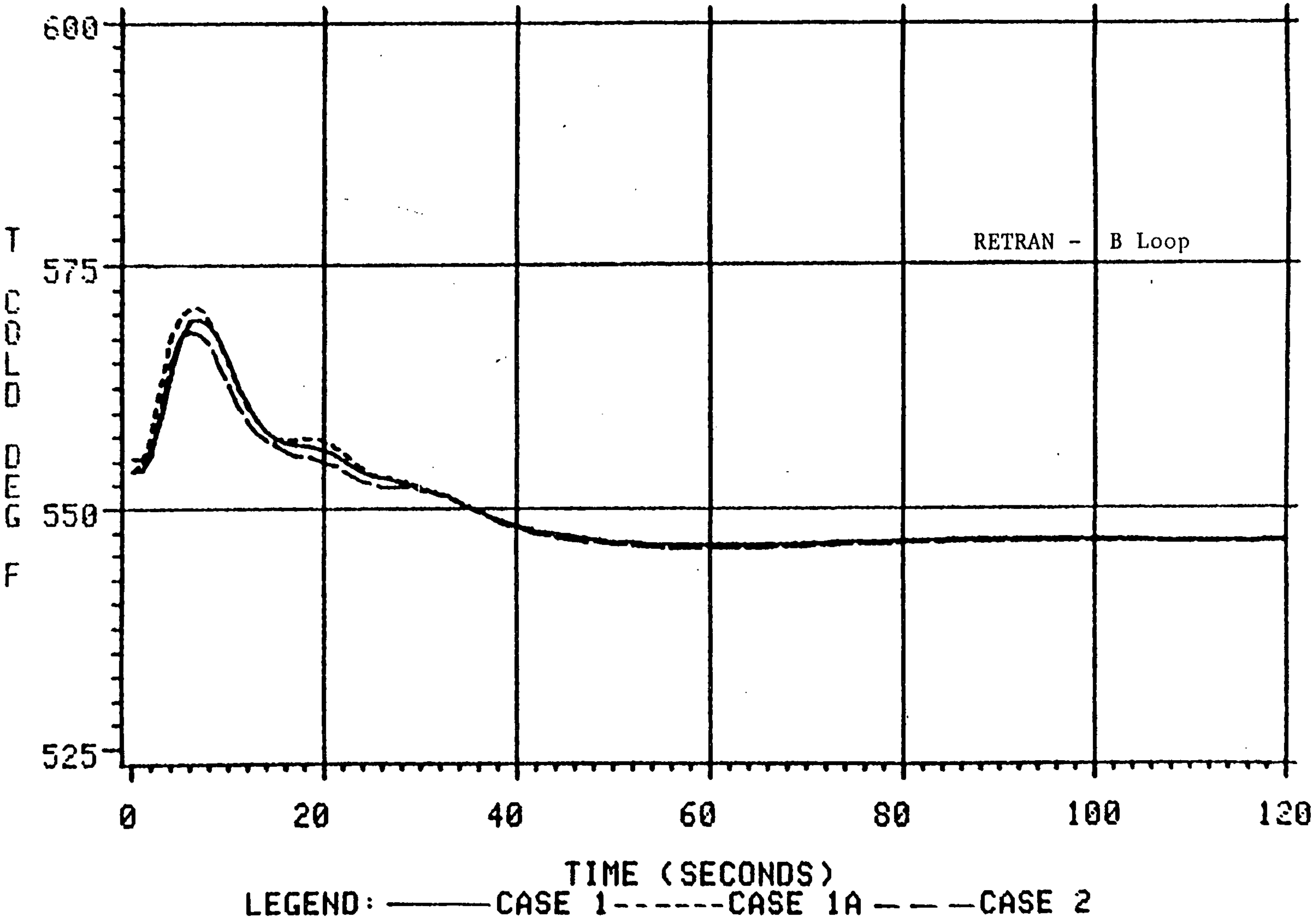


Figure 9-6

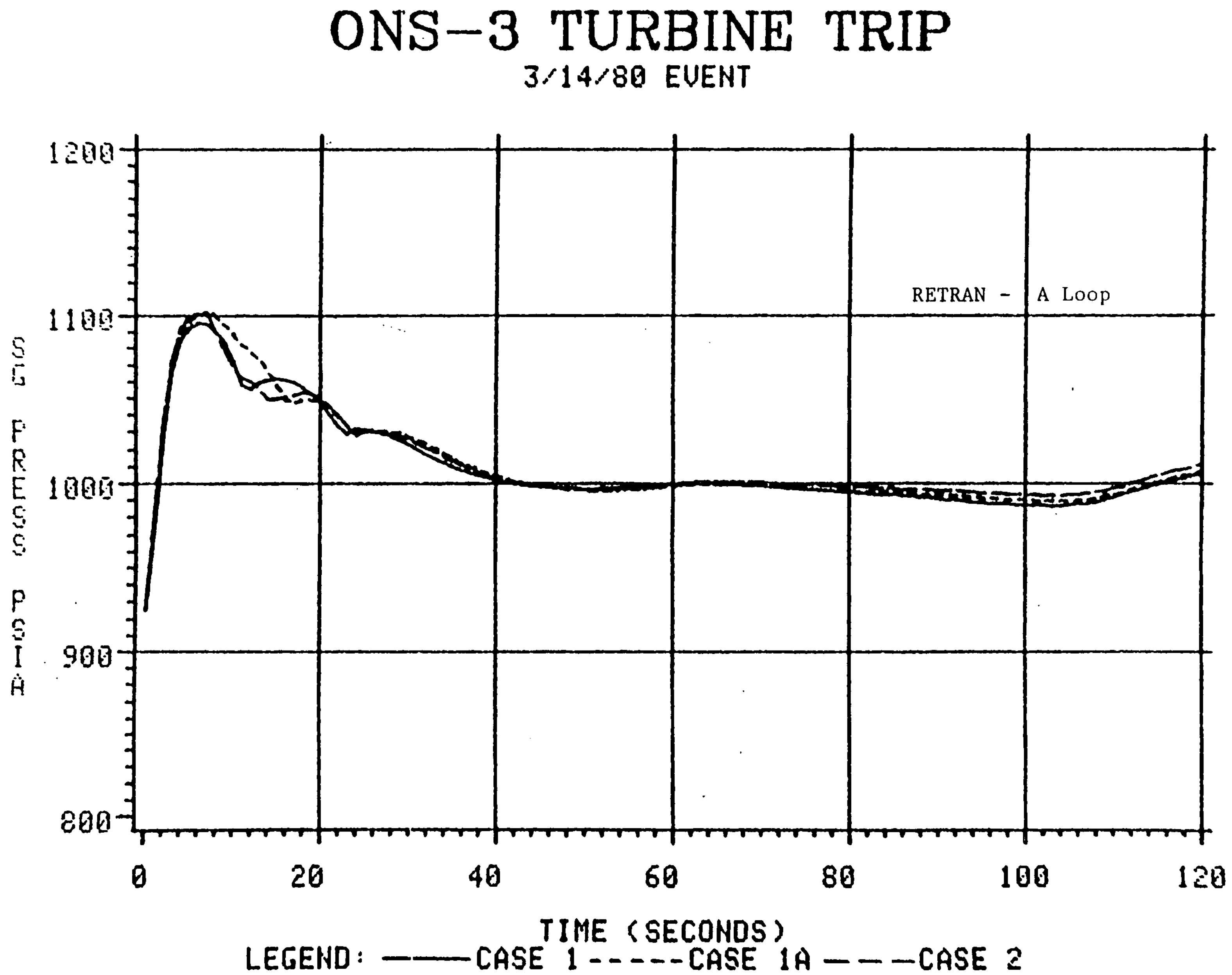

ONS-3 TURBINE TRIP
3/14/80 EVENT
RETRAN - A Loop
SG PRESS PSIA
1200
1100
1000
900
800
0
20
40
60
80
100
120
TIME (SECONDS)
LEGEND: ——CASE 1 -----CASE 1A — — —CASE 2

Figure 9-7

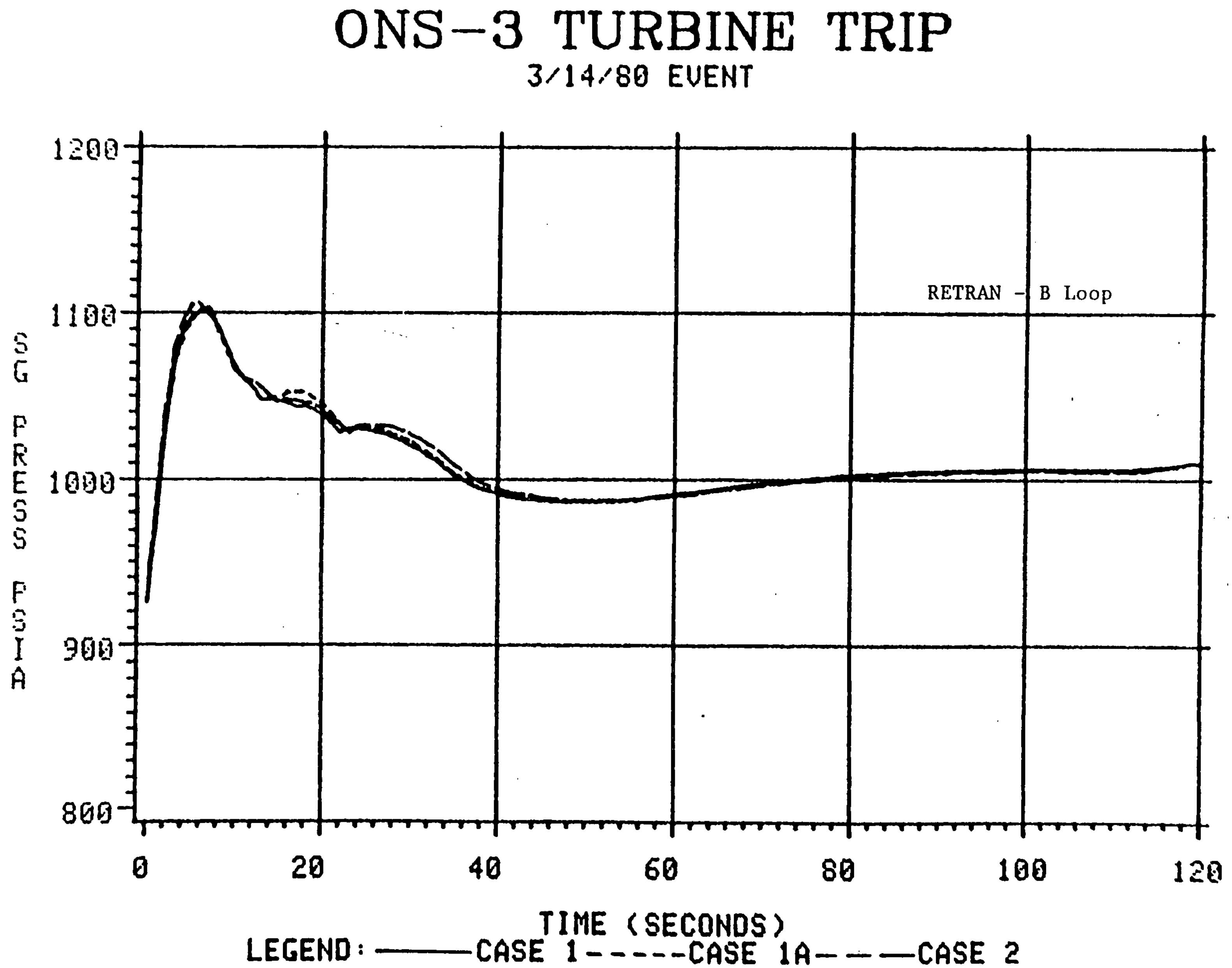
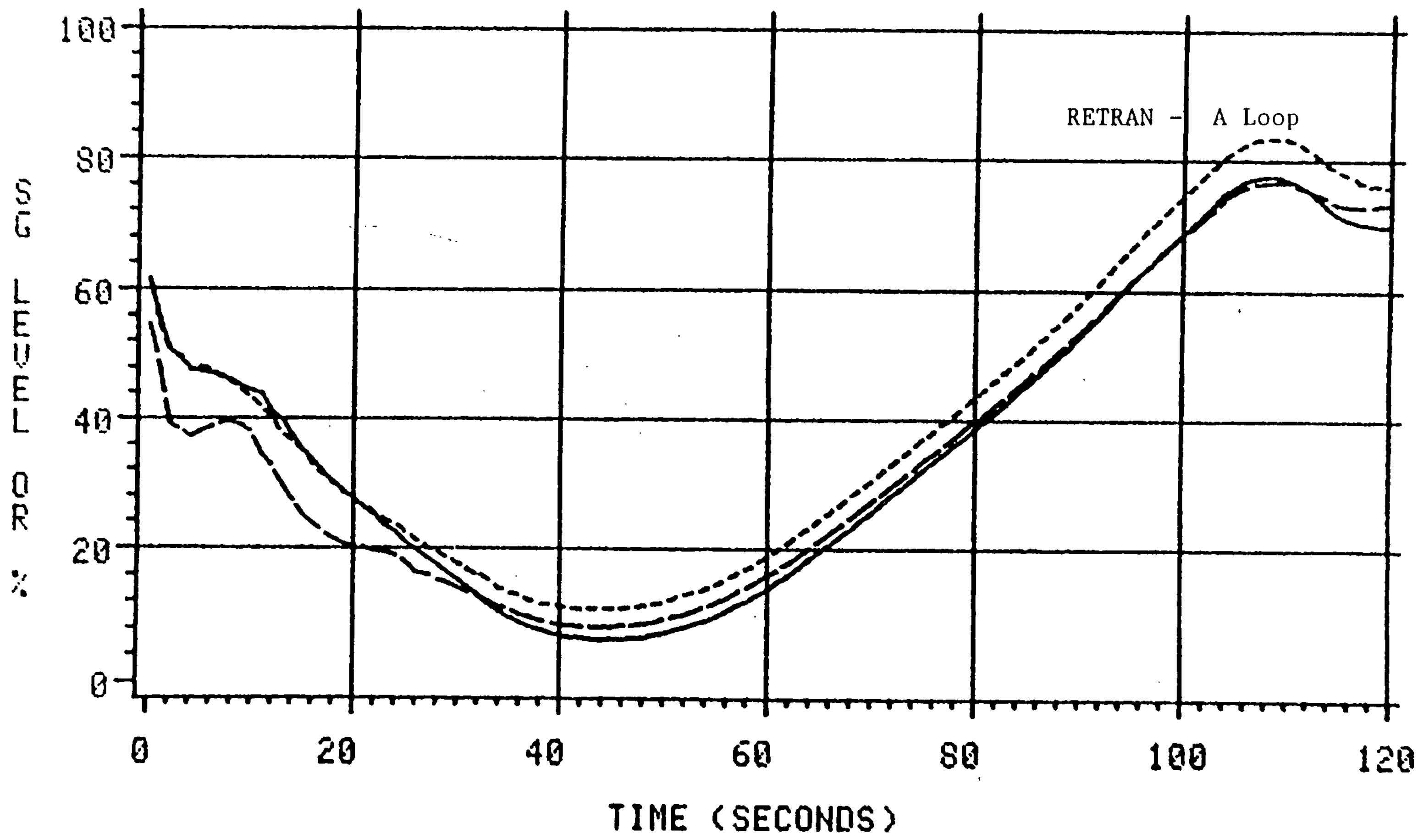

ONS-3 TURBINE TRIP
3/14/80 EVENT
1200
1100
1000
900
800
SG PRESS PSIA
RETRAN - B Loop
0
20
40
60
80
100
120
TIME (SECONDS)
LEGEND: ——CASE 1-----CASE 1A— — —CASE 2

Figure 9-8

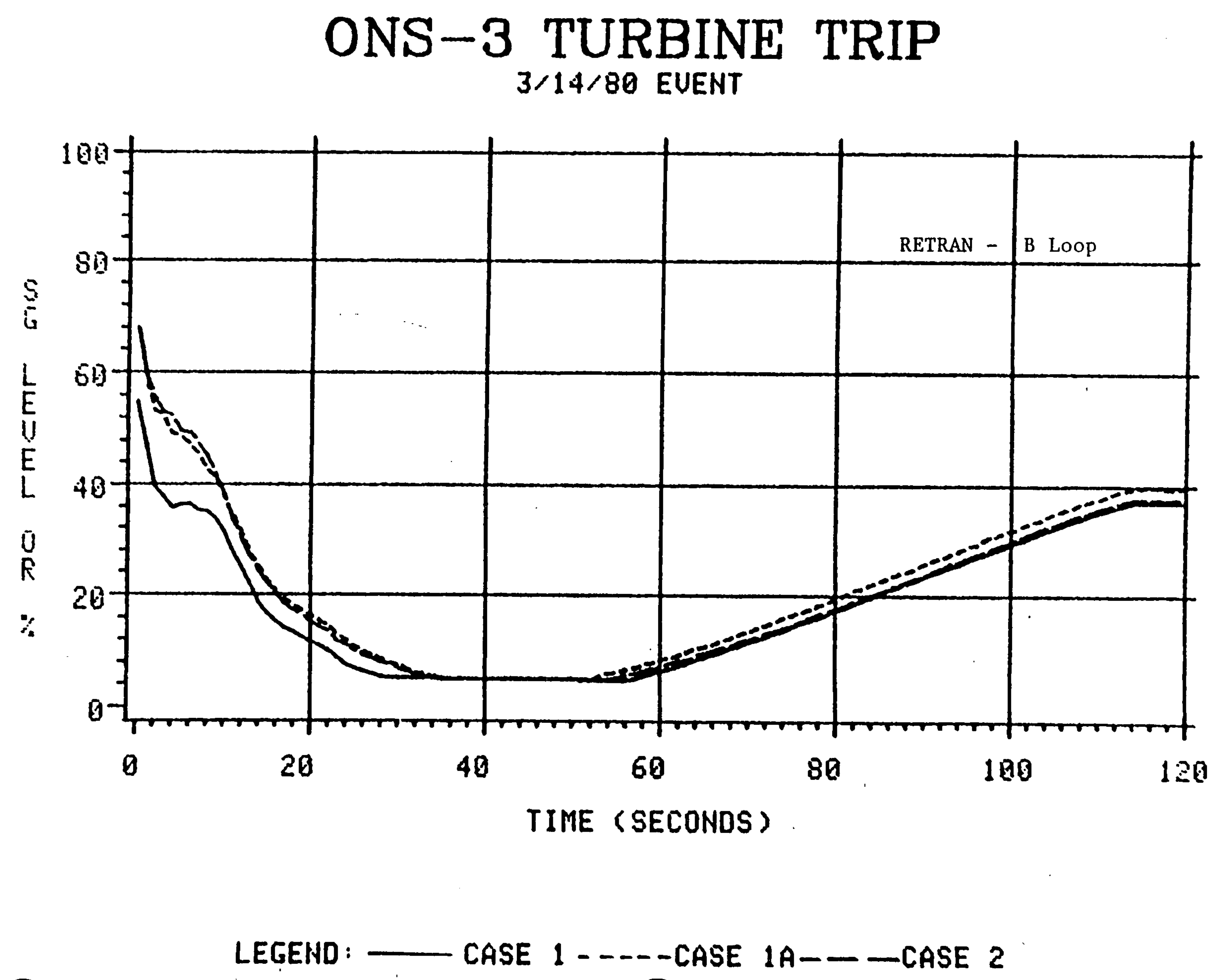
ONS-3 TURBINE TRIP

3/14/80 EVENT



LEGEND: ——— CASE 1 - - - - CASE 1A — — — CASE 2

Figure 9-9



ONS-3 TURBINE TRIP
3/14/80 EVENT
RETRAN - B Loop
SG LEVEL OR %
100
80
60
40
20
0
20
40
60
80
100
120
TIME (SECONDS)
LEGEND: CASE 1 CASE 1A CASE 2

Figure 9-10

Question 10

Section 2.1.4.2 states that the turbine control system maintains the turbine header pressure at the control setpoint. Explain why it is necessary to change the turbine bypass setpoint for each transient.

Response

The Turbine Control System (TCS) controls the main steam pressure (immediately upstream of the turbine) prior to turbine trip. In normal operation above 20% power, there is no flow through the Turbine Bypass System (TBS) - all steam flows to the turbine or to miscellaneous auxiliary steam loads. After turbine trip, the TBS controls SG pressure (measured immediately downstream of the steam generator), and the TCS is inactive, since the turbine stop valves are shut. The normal control setpoint for the TBS after reactor trip is 1010 psig, but this setpoint will drift somewhat during plant operation. The TBS setpoint used in the RETRAN model is typically adjusted to match the observed pressure control setpoint for a benchmark analysis. These alterations are always minor, and they have no impact on the initial conditions of the transient.

Question 11

Section 2.2.2.2 of the topical report states that eleven RETRAN volumes are used to simulate the shell side next to the SG tubes and are necessary to accurately model void distribution and effective area for primary-to-secondary heat transfer.

a) Demonstrate that using eleven volumes is adequately conservative by presenting results of any parametric studies using different nodalizations (both coarser and finer).

b) Provide comparisons of RETRAN computed steam generator void profile and SG mass inventory versus measured data at steady state and during transients (if available) and explain the difficulty in matching the initial SG levels in the benchmark analyses.

c) What data is available to justify the aspirator flow rate and energy addition to the incoming feedwater for steady state and transient cases?

Response

Parametric studies were performed using three different SG nodalizations: [ ] primary and secondary volumes in each generator, the base model with [ ] volumes in each generator, and [ ] primary and secondary volumes in each generator. The predicted full power steady-state primary and secondary temperature profiles are shown on Figure 11-1. The study indicates that both the [ ] and [ ] node models provide a reasonable prediction of the design temperature profiles, and that there is no significant difference between the two. The [ ] node model, on the other hand, does not agree well with the design data. This study provides justification for the nodalization which is used in the base model.

Data from a detailed three-dimensional Babcock and Wilcox SG design code is compared to the base model RETRAN full power initial SG mass in the following table. The design code has been benchmarked to test data from a full length scale model 19-tube once-through SG at the Alliance Research Center in Ohio.

	RETRAN	Design Code
Total SG mass (lbm)	[	]
SG tube region mass (lbm)		

Note: this data is for an unfouled SG at a power level corresponding to 2568 MW core power.

As can be seen, the initial RETRAN mass compares well to the design code result. SG mass data is unavailable during transients.

Concerning "difficulty in matching the initial SG levels in the benchmark analyses", the initial levels used for those analyses were deliberately chosen to reflect the best estimate of the initial SG mass in the presence of fouling. A more detailed discussion is given in the response to Question 9. For a licensing (as opposed to best estimate) calculation, bounding values for SG level are chosen in order to ensure

a conservative initial inventory.

The aspirator flow rate is varied to obtain the desired SG level indication. This approach is justified based on the agreement between the initial RETRAN SG mass at 55% OR level and the data from the SG design code. Furthermore, first of a kind test data from the Oconee startup in 1973 indicated that the SG downcomer is saturated for essentially its entire length. The aspirator flow is approximately that which is needed to raise the incoming MFW flow to a saturated liquid condition.

PROPRIETARY
DUKE POWER CO.

Figure 11-1

Question 12

Section 2.2.6.7 states that for long-running analyses in which an accurate simulation of full power conditions is not important the eleven steam generator secondary volumes may be replaced with one separated volume. Explain and justify the conditions under which one separated volume is used.

Response

Use of one separated volume, rather than the base model eleven volumes, in the steam generator secondary only occurs when there is no impact on the primary system response. This modeling approach is rarely used and can be best justified by an example. Consider that an extended simulation of the plant response to a loss of all feedwater scenario is to be performed. The objective of this particular simulation is to evaluate the plant conditions at 30 minutes into the event. For this scenario the steam generator secondary is important only in terms of the initial water inventory. This water inventory will boil off within a few minutes. Since the total amount of energy that this inventory can remove from the primary loop is fixed, and since it is unimportant to determine whether the inventory is boiled off in two minutes or five minutes, a simplified model that conserves the initial secondary water inventory is perfectly justifiable. In this manner the accuracy of the prediction of the primary response is not affected, and substantial computer cost savings are achieved.

Question 13

The sequence of events following a steam generator overfeed is described in Table 4.2.2-1 and illustrates the use of actuation times rather than actuation setpoints. Justify the use of actuation times rather than actuation setpoints.

Response

The only action based on time rather than setpoint in Table 4.2.2-1 is the MFW pump trip on high SG level. This approach was taken because the MFW flow boundary condition was taken from plant data, and the flow goes to zero immediately after MFW pump trip. It is evident that the code would have predicted a MFW pump trip approximately 10 seconds after the data if the same MFW flow had been extended. This approach allows for an appropriate comparison between the code and the data and is considered to be reasonable.

In general, actuations (except for operator actions) are based on setpoints, not elapsed time. The only other exception which was noted was the reactor trip during the simulation of the loss of ICS power at Oconee Unit 3 on November 10, 1979 (4.2.3). The RETRAN reactor power was based on the actual reactor trip time (55 seconds) rather than the predicted reactor trip time (42 seconds).

Question 14

For this event (loss of main feedwater), the initial conditions for simulated and measured level did not match. On page 4-5 it is stated that emergency feedwater (EFW) flow data was not available and its simulation was based on matching simulated level to plant level data.

a) Provide details of the control system which models EFW flow.

b) Explain the validity of the model in view of the initial mismatch in steam generator levels.

Response

Following a review of the loss of main feedwater benchmark calculation, it was discovered that some inaccuracies were present in the boundary conditions which were used, and therefore it was decided that a revised analysis would be performed. In addition to more accurate boundary conditions, improved modeling techniques were applied in several areas. These techniques have been developed since the loss of main feedwater benchmark was originally performed in 1985. The revised Section 4.1.1 is attached to this response, and will be included in the next revision to the report. The responses to Questions 14-16 are based on this revised analysis.

EFW is controlled to maintain SG level at the desired setpoint by a proportional plus integral controller which modulates a pneumatic control valve to vary flow. The maximum EFW flow at any point in time is a function of which EFW pumps are operating. The boundary conditions used for this simulation are listed below.

Time (sec)	Maximum EFW Flow (gpm) *	SG SUR Level Setpoint (inches)

During the first part of the transient, more than [ ] gpm was available from the turbine-driven and two motor-driven EFW pumps. EFW flow was automatically controlling at the normal setpoint of 25" on the extended startup range (XSUR). At 948 seconds all EFW flow was isolated by the operators. At 1310 seconds the operators reopened the EFW control valves and EFW flow to the SGs resumed. At this point the turbine-driven EFW pump had been tripped, so the maximum available flow decreased significantly. It is also apparent that the operators did not restore full EFW flow immediately. A maximum flow of [ ] gpm was assumed, and this proved to be adequate for maintaining SG level at the observed value. Following restoration of MFW, EFW flow was terminated.

PROPRIETARY
DUKE POWER CO.

For this transient a proportional plus integral control system was used for EFW to maintain the SG level at the level indicated by the plant data. This was necessary because no EFW flow data was available, and EFW was controlled manually during the latter portion of the transient. Thus SG level was a boundary condition for this analysis.

MFW was lost at the beginning of the transient, and restored at approximately 27 minutes. The SG levels increase following restoration of MFW. After restoration, MFW flow is controlled to match the observed SG level, as was done with EFW. A maximum flow of [ ] lbm/sec is assumed to be available. The boundary conditions used for the latter portion of the simulation are given below.

Time (sec)	Maximum MFW Flow (lbm/sec) *	SG SUR Level Setpoint (inches)
[		]

A proportional plus integral control system was used for MFW to maintain the SG level at the level indicated by the plant data. Thus SG level was a boundary condition for the analysis.

The EFW and MFW control systems are valid since they maintain the SG level at the value indicated by the data for the majority of the transient. The initial disagreement in levels (0-200 seconds) is due to the code predicting a more rapid inventory boiloff following reactor trip. The overall transient response shows good RCS temperature agreement between RETRAN and the plant, indicating a good overall prediction of SG heat transfer.

Question 15

Why are T-hot and T-cold consistently underpredicted (during the loss of main feedwater event)?

Response

The RETRAN code generally underpredicts hot and cold leg temperatures following reactor trip. The code tends to couple too closely between SG saturation temperature and the RCS temperature during low SG flow conditions. This is considered to be due, in large part, to an overprediction of boiling length or mixture level on the SG secondary side. This characteristic is caused by the lack of an unequal phase velocity model in the SG tube region. However, it is pointed out that the RCS temperature prediction is quite reasonable for this and most of the other benchmark transients.

Question 16

Explain why the pressurizer level is also underpredicted during the first 900 seconds (of the loss of main feedwater simulation), yet pressurizer pressure is cycling more frequently than the data, thus indicating faster pressurization.

Response

In the revised analysis (see Question 14 response) the rate of pressurizer level increase, which determines the pressurization rate, is greater than that in the plant data during the time of pressurizer spray operation. Therefore, the cycling frequency is consistent with the rate of pressurizer level increase. The number of spray cycles between 450 and 1300 seconds (11 predicted versus 8 actual) is considered to be very reasonable.

Another effect contributing to the discrepancy is that the RETRAN simulation does not account for interphase heat transfer between the vapor and liquid regions. It is generally considered that this phenomenon is especially important during spray operation, due to the increased turbulence at the vapor-liquid interface. However, the RETRAN interphase heat transfer model in the pressurizer is non-mechanistic, and it was not applied for this analysis (see Question 7 response).

Question 17

Explain the deviation of predicted steam generator level from the plant data (during the steam generator overfeed following reactor trip analysis) and correlate it to T-hot and T-cold data.

Response

The steam generator level prediction is not drastically different from the plant data for this event. It should be noted that 0% level on the operate range is not at the bottom of the generator, but more than 8 ft above the lower tubesheet.

Part of the SG level discrepancy may be explained by the fact that RETRAN slightly underpredicts the RCS temperature during the initial portion of the event. This would correspond to more boiloff in the SGs for the RETRAN analysis. Another possible explanation is uncertainty in MFW flow.

This magnitude of overfeed by MFW does not lead to a significant overcooling as long as there is no large depressurization of the steam generators. For this analysis, RCS T-hot and T-cold are predicted well. The deviation in SG level is not important as long as SG pressure is predicted accurately, as it is in this simulation.

PROPRIETARY
DUKE POWER CO.

Question 18

Reactor coolant system temperatures and pressurizer level are in good agreement. Explain the large difference in the reactor coolant system pressure at 50 seconds.

Response

Although the predicted pressurizer level appears to be in good agreement with the plant data, there is in fact a difference of 5-10 inches during the time frame of interest which contributes to the overprediction of RCS pressure. In addition, the interphase heat transfer coefficient selected for this transient was not the subject of a great deal of attention. As stated in the response to Question 7, this parameter can be selected to obtain practically any pressure response that is desired, within the bounds of no condensation and no superheating during the insurge. In the absence of a large interphase heat transfer coefficient, RETRAN tends to overpredict RCS pressure, as shown in this analysis. An additional factor in the comparison of the pressurizer level prediction to data is that the pressurizer level indication is [ ] Although this limitation is not a significant effect, as shown by generally good success in predicting the pressurizer level response in the benchmark analyses, an [ ] is now used in current applications.

Question 19

Explain the source(s) of the divergence between the predicted and measured data in Figures 4.3.2-3, 5, 9, 12, and 13.

Response

Five of the thirteen figures which show the comparisons between RETRAN predicted pump coastdown transients and plant data are identified as divergent. Of these five, Duke does not consider 4.3.2-3 and 4.3.2-5 to significantly deviate from the plant data. In Figure 4.3.2-3 the maximum deviation is only approximately 5%, and when considering that flow reverses in two cold legs and that there is a significant change in the operating point of the pumps in the other two cold legs, the comparison is satisfactory. In Figure 4.3.2-5, a maximum deviation of approximately 7% occurs in the phase of the coastdown where flow reverses in three loops. By 25 seconds the deviation has diminished. In Figures 4.3.2-9, 12, and 13, the plant data are suspect. The data are characterized by a lack of smoothness, as well as an unexplained stabilization at 13 seconds in Figure 4.3.2-13. The quality of these data has not been of concern since no plant operating limits depend on these particular flow coastdown configurations. Although these three comparisons do not add a great deal to the benchmarking effort, they were included for completeness. The overall agreement of the pump coastdown comparisons is very good when considering the two hot leg and four cold leg configuration of the plant, the range of coastdowns simulated, and the reasonableness of the RETRAN predictions in those cases where the data was lacking or suspect.

PROPRIETARY
DUKE POWER CO.

Question 19

Explain the source(s) of the divergence between the predicted and measured data in Figures 4.3.2-3, 5, 9, 12, and 13.

Response

The Oconee pump model utilizes the [ ] By using the [ ] with the actual pump characteristics such as moment of inertia, speed, torque, flow, and head, an approximation to the actual performance of the pump is achieved. Figures 4.3.2-3, 5, 9, and 13 refer to cases where reverse flow through the pump(s) occur. This places the operating regime of the pump(s) into a quadrant in which relatively little test data has been obtained, thus making discrepancies between actual and calculated pump performance more likely.

It should be pointed out that the pump coastdown cases which are cited are not limiting with respect to the plant operating limits. Duke Power does not perform transient analyses to determine operating limits with pump coastdown flow rates which are non-conservative with respect to plant data.

The plant data shown in Figure 4.3.2-12 is highly questionable. This data shows an uneven coastdown in flow, as well as only covering the first 12 seconds of the coastdown.

Question 20

Explain the deviation between the predicted and measured data as a function of steam generator level and mass inventory (during the steady state natural circulation comparison).

Response

The data points at 57 MW, 62.5 MW, and 80 MW are from a controlled test at a sister plant to Oconee. The data are in fairly good agreement with the RETRAN simulation at a 50% SG operating range level. The data point at 67 MW is from the same test, but with a SG level of 40%. The data indicates a drop of 0.83 Mlbm/hr (18.3%) from the interpolated value at 50% level when the level is decreased to 40%. RETRAN predicts a drop of 0.12 Mlbm/hr (2.4%) when going from 50% to 40% SG level at a power level of 67 MW. Thus it is evident that RETRAN is not as sensitive as the plant to changes in SG level during natural circulation.

The key parameter for natural circulation comparisons is the mixture level or boiling length in the SG. While the collapsed level is similar between the plant and the code at a given indication, the code tends to have a higher mixture level than the plant because there is no model for unequal phase velocities on the SG secondary side, i.e., no slip. This causes the code to predict a higher thermal center for heat removal in the SG and a correspondingly higher primary flow rate. However, the overall agreement is reasonable at nominal natural circulation conditions.

Question 21

The predicted reactor coolant system temperatures are lower than plant data. Explain why the predicted steam generator level and main steam pressure drift lower than plant data.

Response

The underprediction of RCS temperatures has been discussed previously (see response to Question 15) and is attributed to the fact that RETRAN tends to overpredict primary-to-secondary heat transfer. The overprediction of primary-to-secondary heat transfer partially explains why the RETRAN model underpredicts steam generator level. However, the major reason why steam generator level is underpredicted is uncertainty in the plant data. For the July 15, 1985 event, the plant data indicates an initial level of approximately 82% operate range. This level is indicative of a fouled steam generator.

Fouling in the steam generator affects the level indication in two ways. First, the increased frictional pressure drop between the level taps causes the indicated level to read higher than the actual level. Second, the fouling reduces the heat transfer coefficient in the steam generators. Thus, a larger heat transfer surface area (higher level) is necessary to remove the same energy. The relative magnitude of these two constituents is unknown. As is discussed in the response to Question 9, Duke has selected a nominal level of 55% operate range for most benchmarks. The above discussion reemphasizes the uncertainty associated with steam generator inventory in a fouled steam generator. Figure 4.5.1-6 of DPC-NE-3000 is intended to show that RETRAN predicts the same rate of change in steam generator level as is seen in the plant data. It should be noted that the plant data has been scaled to agree with the RETRAN level of 55% operate range at time zero. Thus, very little can be ascertained by comparing the magnitudes of the two levels.

The trends in main steam pressure between the RETRAN predictions and the plant data are reasonable. The RETRAN turbine control valve model appears to be a little more stable than the plant control system. The offset of approximately 10 psi between the RETRAN predictions and the plant data has a negligible impact on the transient response of the primary system. This offset may be due to different turbine control valve setpoints. The RETRAN model uses a turbine control valve setpoint of 885 psig. This is considered a nominal plant setpoint. However, it should be noted that the turbine control valve setpoint is manually adjustable. Thus, it is possible that the operator had increased the control setpoint to 895 psig prior to the event. At any rate, reducing the offset in main steam pressure would have a negligible impact on the steam generator heat transfer predicted by RETRAN.

Question 22

Explain the deviation in reactor coolant system pressure, pressurizer level, T-hot, T-cold, and steam generator levels (during the reactor trip from three reactor coolant pump operation analysis).

Response

The code underpredicts primary pressure, pressurizer level, and primary temperatures consistently following the reactor trip. This disagreement is attributed to an overprediction of SG heat transfer after reactor trip. The predicted cold leg temperature is much more tightly coupled to the SG saturation temperature during the RETRAN simulation. As a result, the RCS temperatures are generally 5°F lower than those observed at the plant. The lower temperatures lead to an overprediction of primary coolant shrinkage, and thus an excessive drop in pressurizer level and RCS pressure.

The SG B level is significantly underpredicted by the code throughout the transient. The initial offset is probably due to a low SG inventory in RETRAN. The later increase in level at the plant is real, but it is not reflected in the MFW flow data which was used as a boundary condition for the event. The MFW flow indication is sometimes questionable at low readings, and it is suspected that inaccuracies in this boundary condition are responsible for the lack of a level increase in RETRAN. At any rate, a more accurate prediction of SG level would require more initial SG inventory and more post-trip MFW flow, and this would only exacerbate the disagreement between the plant data and the predictions of the key primary system parameters.

It is evident that the post-trip code prediction is not very accurate for this event. Although trends are predicted correctly, the magnitudes are in significant disagreement with the data. The reasons for the extent of the disagreement are not known. However, it should be noted that the code generally predicts post-trip conditions well. This case could have been omitted from the report, but it was considered to be important to give as complete a comparison as possible between the code and the available data.

DUKE POWER COMPANY
P.O. BOX 33189
CHARLOTTE, N.C. 28242

HAL B. TUCKER
VICE PRESIDENT
NUCLEAR PRODUCTION

TELEPHONE
(704) 373-4531

August 9, 1989

Document Control Desk
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: Oconee Nuclear Station
Docket Numbers 50-269, -270, and -287
McGuire Nuclear Station
Docket Numbers 50-369 and -370
Catawba Nuclear Station
Docket Numbers 50-413 and -414
Additional Information On DPC-NE-3000,
"Thermal-Hydraulic Transient Analysis Methodology"

On July 18 and 19, 1989, the reviewers of the subject Topical Report and the authors had a telephone conversation regarding RETRAN once-through steam generator heat transfer modeling. The attached discussion serves to formalize and document the information exchanged during that telecon.

If there are any questions, please call Gregg Swindlehurst at (704) 373-5176 or Scott Gewehr at (704) 373-7581.

Very truly yours,

H. W. Hampton for

H. B. Tucker

SAG181/lcs

xc: Mr. D. S. Hood
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Mr. D. Katze
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Mr. L. A. Wiens
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dr. K. Jabbour
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Mr. S. D. Ebneter
Regional Administrator
U. S. Nuclear Regulatory Comm.
101 Marietta St., NW, Ste. 2900
Atlanta, Georgia 30323

Mr. W. T. Orders
NRC Resident Inspector
Catawba Nuclear Station

Mr. P. K. VanDoorn
Senior Resident Inspector
McGuire Nuclear Station

Mr. P. H. Skinner
NRC Resident Inspector
Oconee Nuclear Station

August 4, 1989

Duke Power Response to NRC Questions
Regarding Steam Generator Heat Transfer
Modeling with the RETRAN Code

On July 18 and 19, 1989 the NRC contractor, International Technical Services, asked several questions regarding the capability of the RETRAN code to simulate heat transfer on the secondary side of the B&W once-through steam generator. The following discussion is intended to respond to these questions by providing an overview of modeling, validation efforts, observed code/model limitations, and the approach for accommodating these limitations.

The Duke Power Oconee RETRAN model nodalizes the steam generator secondary tube bundle region with a vertical stack of homogeneous volumes. The steam generator downcomer is modeled as a separated bubble rise volume. The adequacy of the nodalization has been addressed by sensitivity studies which were submitted in response to a previous NRC question. The validation of the steam generator modeling, including secondary heat transfer, consists of both steady-state and transient comparisons to reference data. The steady-state comparisons include the axial variation of primary and secondary temperatures in the tube bundle region, and comparisons to steam generator secondary mass. Although the axial temperature profiles are not exactly matched in the RETRAN prediction, the boiling length and the general shape of the temperature profile at full power are reasonably well-predicted, and the amount of superheat at the exit matches plant data. The secondary mass inventory predicted by RETRAN is close to other code-predicted reference values, although no actual plant data exists. The capability of the RETRAN code to achieve an initialization that compares this well to the reference data is noteworthy, and is as good or better than similar codes.

Validation of the steam generator heat transfer modeling during transient conditions is based on the comparisons to plant transient data as described in Chapter 4 of DPC-NE-3000. The plant transients selected include a wide spectrum of heat transfer conditions and phenomena, including the following.

- The pressurization/depressurization cycle that occurs following a turbine trip, from several different pre-trip conditions [4.1.1, 4.2.1, 4.2.2, 4.2.3, 4.4.1, 4.6.1]
- Steam generator dryout due to loss of feedwater [4.1.1]
- Depressurization and overcooling due to excessive steaming following reactor trip [4.2.1]
- A severe overfeed following reactor trip [4.2.2]
- Steam generator depressurization and dryout due to excessive steaming, followed by a rapid overfill at low pressure [4.2.3]
- A transition to natural circulation [4.3.1]
- Steady-state natural circulation at various power levels [4.3.3]
- A power maneuver resulting from a decrease in feedwater flow [4.5.1]
- A power maneuver resulting from an increase in steaming rate [4.5.2]

By comparing the performance of the RETRAN model to a large set of data, it is possible to draw conclusions about the capability of the model to simulate the integrated response of the steam generator. Accurate simulation of steam generator pressure and level, the dominant parameters with respect to heat transfer, and the resulting cold leg temperatures, indicate the quality of the heat transfer prediction. As shown in Chapter 4 of DPC-NE-3000, RETRAN does compare reasonably well with the plant data over a wide range of transient conditions.

It is apparent from these benchmark analyses that the rapid secondary transient resulting from a turbine trip is a good test of the code/model. For this transient RETRAN predicts too much heat transfer due to the lack of an unequal phase velocity model and a consequent overprediction of the boiling length. This results in lower cold leg temperatures for a period of time immediately following the trip. Provided that the model is initialized with a correct inventory, and that the feedwater boundary condition is characterized appropriately, this overprediction of the heat transfer rate will be limited in duration and magnitude. As such there is only a limited impact on the simulation results. This can be confirmed by the predictions of pressurizer level, which indicate the net effect of primary coolant expansion or contraction due to changes in steam generator heat transfer. In all cases the comparisons between RETRAN predictions and plant transient data show that the pressurizer level trends are correctly simulated, and in most of the benchmarks the agreement is very good.

The capability of the code/model to predict natural circulation is also demonstrated in the validation analyses. The RETRAN simulations of a transition from forced to natural circulation, and several steady-state natural circulation data, indicate a small overprediction of the natural circulation flowrate. The transition to natural circulation is predicted very well. The difference in the steady-state comparison is a combination of several factors which affect the delicate balance between the loop density distribution, which is strongly influenced by the steam generator heat transfer profile, and loop frictional losses at low flow conditions. Uncertainty in the core power level is also a contributor. The integrated effect as predicted by the code/model is a very reasonable comparison with the plant data.

The benchmarks presented in Chapter 4 did not include any comparisons to scaled integral test facility data or to separate effects tests. The following summarizes the rationale for not including such validation work, and why the plant data which was used is sufficient. Scaled facility test data has typically focused on LOCA phenomena, for which plant-scale data is unavailable. As stated in DPC-NE-3000, the Oconee RETRAN model is not intended for simulating LOCAs. Another limitation of test facility data is that the impact of scaling on the validity of the data must be addressed. This can be very difficult if consideration is being given to modify the code or model based on the scaled data. Separate effects tests are mainly useful for qualifying particular aspects of a code, such as phase separation models or critical flow models. These data are therefore most useful in the code development process, or to serve as a basis for coding modifications. The validation of the Oconee RETRAN model has not identified a need to modify the RETRAN code. The perception that plant transient data is not of high enough quality for code/model validation is not supported by our experience. Provided that a large and broad database can be assembled, and provided that

generally good agreement is obtained without adjusting the code/model to correct significant mismatches between predictions and data, then plant data proves very sufficient. If the database was limited in scope and quantity, and if major code/model adjustments were necessary, then questions regarding the broader capabilities of the simulation model would be warranted. The overall agreement between RETRAN predictions and plant data varies from reasonable to excellent. The data trends are predicted, and although some differences in timing and magnitude do exist, no phenomena were missed. No tuning of the code and very limited adjustments to the model as detailed in DPC-NE-3000 resulted. Achieving this level of quality without good modeling of steam generator heat transfer would be impossible since the steam generator performance determines the response of most of the parameters of interest.

The validation efforts focused on the macroscopic integrated performance of the code and model by comparison to steady-state and transient plant data. Based on the validation results presented, it can be concluded that the Oconee RETRAN model has been thoroughly exercised, including modeling of steam generator heat transfer, and that it performs as well or better than other similar codes. This statement is valid in the context of the capability to simulate non-LOCA transients, which is the scope of DPC-NE-3000. The observed limitations discussed previously, regarding steam generator heat transfer modeling, can be accommodated in a conservative manner when reanalyzing an FSAR Chapter 15 transient. Many of the FSAR transients are unaffected by the observed limitations since these limitations occur primarily post-trip, and the pre-trip response is of interest in the FSAR. Nevertheless, the potential for the observed limitations to have an impact is recognized, and appropriate compensating assumptions will be incorporated as necessary to ensure a conservative reanalysis of FSAR transients.

DUKE POWER COMPANY
P.O. BOX 33189
CHARLOTTE, N.C. 28242

HAL B. TUCKER
VICE PRESIDENT
NUCLEAR PRODUCTION

TELEPHONE
(704) 373-4531

September 13, 1989

U. S. Nuclear Regulatory Commission
Washington, DC 20555

Attention: Document Control Desk

Subject: McGuire Nuclear Station
Docket Numbers 50-369 and -370
Catawba Nuclear Station
Docket Numbers 50-413 and -414
Oconee Nuclear Station
Docket Numbers 50-269, -270, and -289
Topical Report DPC-NE-3000;
Response to Request for Additional Information

By letter dated June 13, 1989, the NRC forwarded a set of questions relating to the McGuire and Catawba sections of topical report DPC-NE-3000. The responses to these questions are provided by Attachment 1 to this letter.

During a conference call on August 28, 1989, the reviewer of the report requested revisions to Section 4. These revisions are included as Attachment 2.

In accordance with 10 CFR 2.790, Duke Power Company requests that the responses to these questions relating to the DPC-NE-3000 be considered proprietary. Information supporting this request was included in the affidavit which accompanied the original submittal of DPC-NE-3000, dated September 29, 1987.

If we can be of further assistance in your review, please call Scott Gewehr at (704) 373-7581 or Gregg Swindlehurst at (704) 373-5176.

Very truly yours,

J.W. Hampton
for
Hal B. Tucker

SAG/187/td

Question 1a

Explain why the computed PZR pressure (Figure 5.1.1-2) is lower than the data, yet the computed PZR level (Figure 5.1.1-3) is higher than the data between 175 to 500 seconds.

Response

In general, the RETRAN predictions of pressurizer level and pressure are consistent, that is, any offset in the pressurizer level with respect to plant data results in a corresponding offset in the pressurizer pressure in the same direction. However, there is an inconsistency between the level and pressure in this simulation between 175 and 500 seconds. This is attributed to the possibility that the pressurizer backup heaters were not deenergized at the plant from 135 to 165 seconds as predicted by RETRAN, resulting in a low prediction of pressure. The trip summary report indicates that the pressurizer pressure controller was taken into manual control mode because "it did not work properly in auto." Because alarm typer data is not available for this transient, whether or not the backup heaters were deenergized cannot be ascertained. Nevertheless, the offset in pressure with respect to plant data between 175 and 500 seconds is small - typically within 40 psi.

The discrepancy between the predicted pressurizer level and the data during this period is partly due to the slight delay (8 seconds) in the predicted reactor trip time. Shifting the predicted level to the left by 8 seconds in Figure 5.1.1-3 would result in even better agreement with the plant data with a maximum duration of only approximately 2%.

Question 1b

Explain the crossover in measured and predicted PZR level indications (Figure 5.1.1-3) around 580 seconds.

Response

The increase in plant pressurizer level with respect to predicted level is attributed to makeup flow which was not accounted for in the simulation. It appears in Figure 5.1.1-3 that makeup was begun at approximately 425 seconds and continued until 675 seconds when the pressurizer no-load level of 25% was attained. Charging and letdown data are not available for this transient; however, it is highly probable that the level increase was due to makeup since the loop average temperature was constant at the time of the crossover. The 3% level increase during this period represents a pressurizer inventory increase of approximately 375 gallons. The net makeup rate required would therefore be 90 gpm, which is within the capability of the charging pumps. The charging pumps can supply a net makeup flow of approximately 100 gpm provided the 45 gpm letdown orifice is utilized.

Question 2a

Discuss how SG level was computed and measured.

Response

Steam generator level is measured by differential pressure instrumentation within the downcomer on the inner shell of the steam generator. The tap locations are shown in Figures 3.1-7 and 3.1-8. The differential pressure due to the weight of the column of fluid between the taps, vapor at 0% level and liquid at 100% level, is used as the basis for the level indications. The differential pressure due to a given fluid column is interpolated between these two endpoints to yield an indicated level. Steam generator level is computed in the McGuire/Catawba RETRAN model by [

]. As discussed in Section 3.2.4.1, [

]

Question 2b

Explain the sources of wide fluctuations produced for the SG narrow range level (Figure 5.1.1-7) in the range of 50 to 150 seconds and their relationship to steam line pressure.

Response

The RETRAN steam generator level indication is derived from the pressure difference between the level taps and is sensitive to shrink and swell effects due to changes in steam generator temperature and pressure. The level indication is also sensitive to [

]. Pressure disturbances resulting in level spikes may also be generated by other transient phenomena, such as abrupt changes in steam line pressure, steam flow and circulation ratio. Any number of these effects can strongly influence the level indication.

The loss of main feedwater transient particularly challenged the ability of RETRAN to accurately model the steam generator level indication because of the severity of the transient and the abrupt changes occurring in the steam generator boundary conditions. The rapid decrease in steam generator inventory due to the total loss of main feedwater, the rapid increase in steam line pressure at 65 seconds due to the turbine governor valves closing, the opening of the steam line PORVs, and the reactor trip all strongly influenced the level indication. Contributing to the complexity of interactions affecting the level indication is the possibility that the condenser dump valves opened at 50 and 70 seconds due to the large T-avg minus T-ref error signal generated as a result of the loss of main feedwater and the closure of the turbine governor valves. Plant data is not available to confirm that the load rejection controller opened the SB valves; however, this is evidenced by the pressure drops at 50 and 70 seconds.

The instability in the predicted steam generator level response between 50 and 150 seconds is attributed to these phenomena. However, most of the deviations are very short-lived, and the trending is close to the plant data. The prediction of the reactor trip on steam generator lo-lo level is within 8 seconds of the actual trip time.

Question 2c

Discuss and justify the accuracy of SG heat transfer modeling.

Response

Steam generator secondary heat transfer in the McGuire/Catawba RETRAN model is simulated with [ ] as shown in Figures 3.2-1 and 3.2-2. The [ ] option is used. For steady-state initialization at power, the secondary heat conductors are in RETRAN Mode [ ]. Within the heat transfer regime framework of RETRAN, these are the expected modes for power operation. After reactor trip, the preheater modes change in a predictable way. As main feedwater flow into the lower nozzle decreases, [ ]. As flow around the recirculation loop, and therefore mass flux within the generator, decreases, the [ ]. In general, the accuracy of the heat transfer modeling is shown by the agreement between predicted and measured values of reactor coolant system temperatures and steam generator levels, particularly for those transients where steam line pressure and feedwater flow are both matched. Matching steam line pressure and feedwater flow eliminates the dependence of the primary temperatures and secondary levels on these boundary conditions.

The [ ] model is used in the McGuire/Catawba RETRAN model as discussed in Section 3.2.6.4. The accuracy and adequacy of the phase separation modeling can be judged by comparison of model predictions with plant data for steam generator level indications and outlet flow quality. Such comparisons show that the model adequately predicts the separation of two-phase flow within the tube bundle into high quality outlet flow which enters the steam lines and low quality recirculation flow which enters the downcomer.

Question 3

Around 80 seconds, steam line pressure (Figures 5.1.2-3/4) sharply decreases and SG C shows rising level spikes (Figures 5.1.2-5). Explain why SG A (Figures 5.1.2-6) does not exhibit similar spikes.

Response

As discussed in the response to Question 2b. This steam generator level model is sometimes affected by shrink and swell effects and by [ ]. The spiking referred to in this

question is caused by such phenomena. The attached figure is from a reanalysis of this event with a slighty different core power boundary condition. As can be seen from a comparison of this figure and Figure 5.1.2-6, the difference between the two is the spiking in the subject time-frame. Since the attached figure showed a [

]

Question 4

Explain the sources of differences in predicted and measured SG levels in Figure 5.2.1-8.

Response

The underprediction of steam generator level from 50 to 300 seconds, and after the PORVs are closed (670 seconds), is attributed to low initial steam generator liquid mass and uncertainty in the auxiliary feedwater boundary condition. The model was initialized with a steam generator liquid mass approximately 5% low which contributed to the underprediction in level. There is also the possibility that the auxiliary feedwater flow might be low in the simulation. The only flow indication available for auxiliary feedwater during this transient is a wide range indication for the main feedwater bypass flow to the upper nozzle. This indication is not accurate for the relatively small AFW flow rates. Unrealistically low auxiliary feedwater flow rates would have contributed to the increasing difference in measured and predicted levels from 50 to 300 seconds and to the delay in bringing the narrow range level indication back on scale.

Question 5a

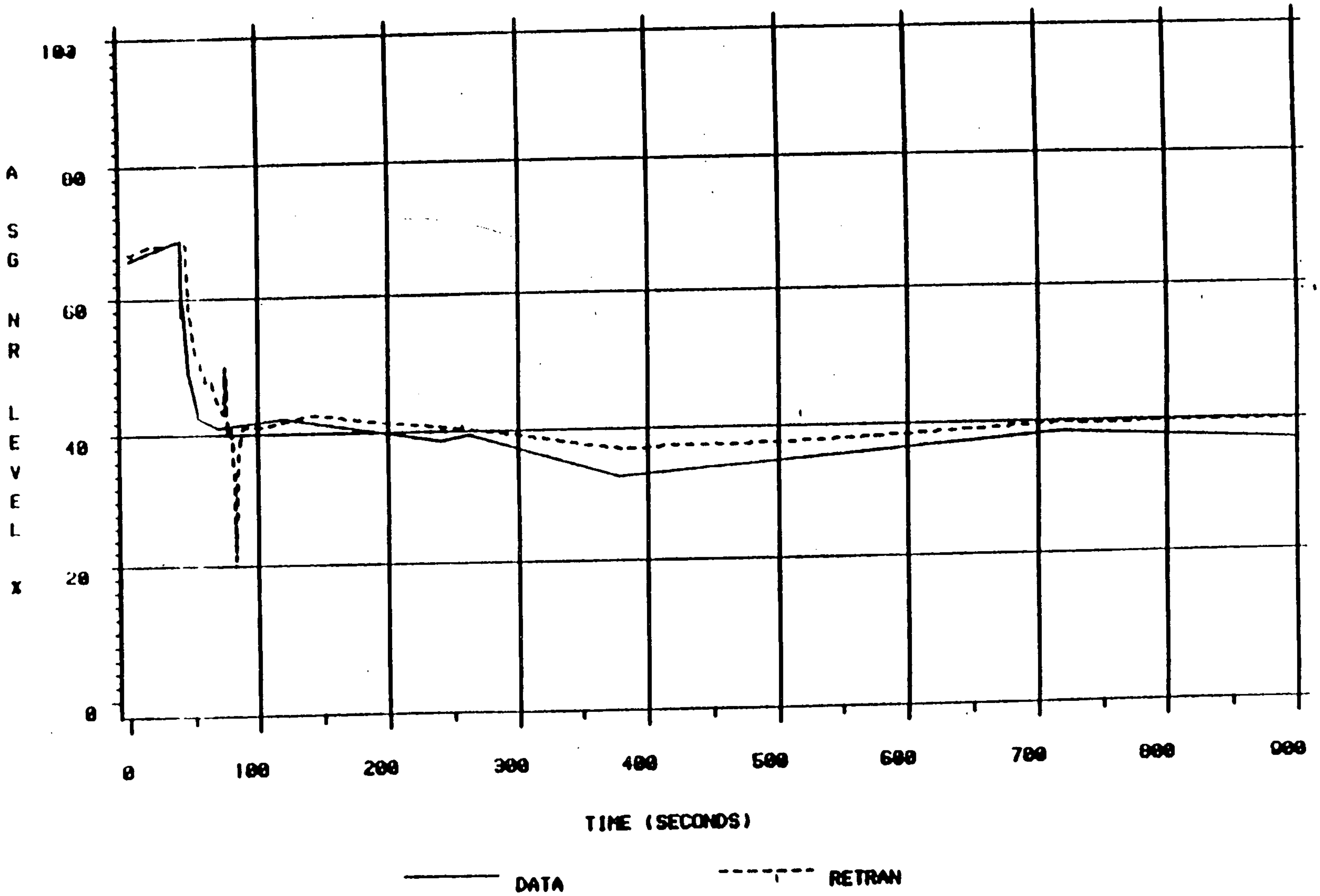
Figure 5.3.2-1 indicates a large difference in steady-state delta-T measurements at 1% power for McGuire on two different dates. Explain the difference, including the effect of power level uncertainties.

Response

As stated on p. 5-59, and as alluded to in the question, the difference in the delta-T measurements at 1% power is primarily the uncertainty in the power level. The magnitude of the uncertainty is impossible to quantify with the data that was logged during the natural circulation testing conducted at McGuire. The source of the uncertainty can be qualitatively explained by describing the test method. The tests are initiated from a forced circulation mode and are performed by simply tripping the reactor coolant pumps. Steam generator conditions are maintained stable at the initial conditions. The target power level of 1% or 3% is obtained by obtaining a delta-T across the reactor vessel during forced circulation which is a simple percentage of the full power delta-T of approximately 60°F. For a 3% power level there is some confidence that the uncertainty is not excessive. However, for a 1% power level, which corresponds to a delta-T of approximately 0.6°F, there is little

MNS-2 PARTIAL LOSS OF MAIN FEEDWATER

6/24/85 EVENT



(Question 3 Response)

confidence in the accuracy of the initial condition. As the reactor coolant pumps are tripped, the core average moderator temperature increases from an essentially isothermal condition to a delta-T of 15-20°F at 1% power. Due to the presence of a small negative temperature coefficient of reactivity, it is expected that reactor power will decrease. The reactor is allowed to reach a new steady-state without any compensating action, such as withdrawing control rods. In summary, there is both an initial condition power level uncertainty and an uncertainty due to the change in core average moderator temperature. The former is mainly valid for the 1% power initial condition, and the latter is valid for any low power level. The uncertainty cannot be quantified with the available data, but the trend predicted by RETRAN in Figure 5.3.2-1 is consistent with the data.

Question 5b

Explain why the delta-T at 3% power is overpredicted by approximately 20%.

The response to Question 5a described how the test method results in a decrease in power level due to the negative temperature coefficient of reactivity. This is the primary source of the 20% difference. If the power level had decreased to approximately 2.25% power as a result of this effect, which cannot be confirmed with the available plant data, then the RETRAN prediction would have matched the test data. There is also the potential that the loop hydraulic losses predicted by RETRAN at these low flow conditions include some uncertainty. The reasonable agreement between the simulation results and the data show that the RETRAN model is very sufficient.

Question 6

In Figures 5.3.2-5/6/13/14/16/17 the initial conditions are not matched. In addition, the delta-T is overpredicted in the active loops and underpredicted in the isolated loop(s). Explain and quantify the sources which contribute to these effects.

Response

Note: The following response assumes that Figure 5.3.2-14 referred to in the question was intended to be 5.3.2-15.

The initial conditions referred to in the question do not match since the only true initial conditions are at the beginning of the RETRAN analysis, which is 1% power with forced circulation. The time zero values in Figures 5.3.2-5 and 6 are a comparison of RETRAN predicted and plant data steady-state natural circulation delta-T at 1% power. The time zero values in Figure 5.3.2-13 are all plant data. The difference in the top two curves is due to a slight asymmetry between loops. The bottom curve represents the delta-T in the loop that was previously isolated. The time zero values in Figures 5.3.2-15, 16, and 17 do not agree because they are comparisons of the RETRAN predicted and plant data for a one-loop isolated natural circulation mode.

An evaluation of the delta-T comparisons has concluded that the differences between the predicted and measured values results from the true power level being less than the 1% analysis value. As discussed in the response to Question 5a, there are two possible sources of uncertainty. The decrease in power

level due to the negative temperature coefficient of reactivity, and the increase in core average moderator temperature when the reactor coolant pumps are tripped, are both applicable to this data. The delta-T in the active loop would be overpredicted because the assumed analysis power level of 1% is too high, and delta-T increases with power level under natural circulation conditions. The delta-T in the isolated loops would be underpredicted because the heat transfer to the isolated steam generator is too rapid, it pressurizes too quickly, the exiting cold leg temperature is too high, and the delta-T is too small. All of these trends exist in the comparisons of the predicted and test data. Other possible sources of the differences in delta-T are the decision not to model steam leaks and ambient cooling from isolated steam generators, and the aforementioned uncertainty in loop hydraulic losses at low flow conditions.

It is worth recognizing that this particular benchmark analysis is quite challenging when considering it requires a three-loop model and natural circulation driven loop flows. All of the observed trends are predicted, and consistent and plausible explanations exist for the differences in magnitude and timing.

Question 7

Measured flow data is not provided. Justify the accuracy of the predicted flow rates for McGuire and Catawba.

Response

The existing primary loop flow instrumentation at McGuire and Catawba cannot provide an indication of loop flow at natural circulation flow rates. No special instrumentation was installed during the natural circulation testing either. Flow values are calculated by a simple heat balance across the reactor vessel, using hot and cold leg temperatures and power level as inputs. A quantitative evaluation of natural circulation flows in a multiloop asymmetric configuration is not amenable to this simple calculational method. The hot and cold leg temperatures are quite accurate, while the power level is not very accurate as discussed in the responses to Questions 5 and 6. Due to absence of measured flow data, the higher accuracy of the temperature indications, and the fact that the temperature distribution in the loop is the driving force for natural circulation, the delta-T comparisons were judged to be the best parameter for illustration. It is essentially impossible to assess the accuracy of the predicted flow rates in any way other than by comparing to another code prediction.

Question 8a

On the basis of the RCP coastdown tests and model discussed in section 5.3.1 of the topical report discuss the adjustments made to the pump model to perform this transient.

Response

The reactor coolant pump model was adjusted in only one instance in order to better predict the plant data. As described on p. 5-46 of DPC-NE-3000, the pump [ ] to better match the observed pump coastdown transient data. This adjustment was not based on the Section 5.3.3

transient, but rather on the Section 5.3.1 pump coastdown test comparisons. The revised moment of inertia will be used in all future applications of the model. Another aspect of pump modeling which is important, but is not characterized as an adjustment, is the specification of the pump [

] will be used in all future applications of the model.

Question 8b

Demonstrate that the pump model accurately predicts the plant data in the RCP trip from 80% full power.

Response

As shown in Figure 5.3.3-12, the model accurately predicts the affected loop flow coastdown. The discrepancy occurring from 0 to 10% normalized flow is most likely due to the relatively large measurement uncertainty at low flow rates. The pump [ ] that was used results in close trending of the normalized flow in the unaffected loops. The flow in the unaffected loops stabilizes at approximately 107%, which matches the plant data. Also, loop temperatures are affected by the flow coastdown and reversal and are accurately predicted. In particular, the predicted affected loop WR T-cold indication (Figure 5.3.3-6) closely follows the slight temperature increase as reverse flow is established. The temperature then gradually decreases after 60 seconds to match the cold-leg temperature in the unaffected loops (Figure 5.3.3-7).

Question 9

Explain the cause(s) of the predicted SG level oscillation in Figure 5.3.3-11 and the large overprediction of the SG level in the first 40 seconds shown in Figures 5.3.3-10/11.

Response

As discussed in the response to Questions 2a and 2b, the RETRAN steam generator level indication is sensitive to many phenomena including shrink and swell effects due to changes in temperature and pressure, [ ], and abrupt changes in steam flow and steam line pressure. The level oscillations in Figure 5.3.3-11 are attributed to [ ] results in a response consistent with that of Figure 5.3.3-11, with an overprediction in level. It is noted that the deviation is short-lived and is of no consequence in this transient.

Question 10a

Explain why the primary pressure (Figure 5.3.4-3) was underpredicted by about 150 psi.

Response

Predicted pressurizer pressure and plant data trends compare well with the exception of the time frame between approximately 100-200 seconds. It is during this time period that the 150 psi difference occurs. A comparison of the predicted pressurizer level to plant data indicates an outsurge of 1.5% in the RETRAN prediction while plant data shows an insurge of 1.5%. This difference in pressurizer level indicates that the RETRAN-predicted average primary temperature is low. This is supported by a comparison of loop delta-T prediction and data. The loop delta-T data continues to increase to 400 seconds. The RETRAN prediction stabilizes at approximately 250 seconds, indicating that natural circulation is fully developed. A comparison of hot leg temperatures also shows the stabilization occurring. The major contributor to the 150 psi difference is evident in Figure 5.3.4-7. During the initial 100 seconds, the predicted cold leg temperature is higher than plant data. Between 100-200 seconds, the predicted cold leg temperature is lower and decreases faster than the data. The cold leg temperatures match at about 400 seconds and trend closely for the remainder of the transient.

Therefore, the 150 psi pressure difference occurs due to a small difference in the bulk coolant average temperature. The predicted stable natural circulation conditions maintain a delta-T of 8°F less than plant data. The pressure difference then remains stable as the trends of the RETRAN prediction exhibit the same response as the plant data. In summary, the 150 psi pressure difference develops because of a low prediction of pressurizer level, caused in turn by an overprediction of the rate at which cold leg temperature decreases. The reason for this overprediction is not known. The 150 psi difference remains because of an underprediction of loop delta-T. The reason for this underprediction is given in the response to Question 11a.

Question 10b

What were the PZR model and SG model contribution to this discrepancy?

Response

Comparisons of Figure 5.3.4-3 and Figure 5.3.4-4 support the conclusion that the pressurizer model does not contribute significantly to the 150 psi discrepancy. As Figure 5.3.4-3 illustrates, the pressurizer model predicts the pressure decrease upon reactor trip closely, with the slight overshoot being caused by the slight overprediction in the decrease of pressurizer level. Between 50 and 100 seconds, the predicted pressure increase is driven by a predicted insurge of 2% pressurizer level while an insurge of approximately 0.5% occurs in plant data. After 200 seconds, the trends of pressurizer pressure versus pressurizer level for both plant data and RETRAN predictions are comparable. Between 200 and 400 seconds a predicted insurge of 1.5% results in a pressure increase of 60 psi while plant data indicates an insurge of 4% and a pressure increase of 110 psi. The comparison of pressurizer pressure versus pressurizer level for both plant data and the

RETRAN predictions after 400 seconds shows good agreement. For a given change in pressurizer level the predicted pressure response is very reasonable.

The steam generator model contributes to the pressure response discrepancy in that the time-dependent bulk primary average temperature is not exactly matched in the RETRAN analysis (Refer to the response to Question 10a). It should be noted that the pressure discrepancy results from only a very minor difference in pressurizer level. When considering the magnitude of the transition from forced to natural circulation, the steam generator heat transfer prediction is very sufficient. The mismatch between the loop delta-T prediction and data is due to the underprediction of loop hydraulic losses at low loop flow conditions (Refer to the response to Questions 11a and 11b).

<u>Question 10c</u>

Discuss and justify the ability of the non-equilibrium PZR model to predict pressure during the insurge.

<u>Response</u>

The non-equilibrium pressurizer model used in this analysis [

]. This modeling approach was selected since the pressurizer insurge was not large, and the focus of this benchmark was the transition to natural circulation. As discussed in the response to Question 10b, the magnitude of the pressurization during the insurge was consistent with the magnitude of the insurge. For analyses in which the accuracy of the pressure response is a key result, [
] would be modeled.

<u>Question 11a</u>

Explain why the loop delta-T (Figure 5.3.4-5) after 250 seconds is underpredicted by about 20%.

<u>Response</u>

For this benchmark analysis, the predicted loop delta-T stabilizes at about 30°F whereas the plant data stabilizes at about 38°F. Since decay heat is slowly decreasing over the time frame of interest, and since the delta-T is essentially constant, it is evident that the natural circulation flowrate must also be slowly decreasing. A delicate balance exits between the loop density distribution, which drives natural circulation, and loop frictional losses at low flow conditions. Since the decay heat power level is known within a reasonably small band of uncertainty, and since the approximate 8°F difference between predicted and plant data is constant as decay heat decreases, it can be concluded that the difference is not due to power level uncertainty. Therefore, the difference must be due to an underprediction of loop frictional losses at low flow conditions.

PROPRIETARY
DUKE POWER CO.

Question 11b

How does the [underprediction of delta-T] affect the ability to accurately model natural circulation flows?

Response

The capability of the code/model to predict the transition from forced to natural circulation, steady state natural circulation, and the temperature transient in the reactor vessel upper head are all tested in this benchmark analysis. The transition is predicted very accurately as indicated by the comparison of the predicted and measured minimum temperatures at 80 seconds (Figure 5.3.4-5). The steady-state loop delta-T values differ by approximately 8°F. As discussed in the response to Question 11a, this is apparently due to a slight underprediction of the loop hydraulic losses at low flow conditions. Although the magnitude of the reactor vessel upper head temperature transient is smaller in the RETRAN prediction (Figure 5.3.4-8), the trend is predicted very well. This difference is caused by the underprediction in the delta-T across the core. The RETRAN model[

]

Question 12

Discuss the plotted measurement of plant flows and any corrections necessary from the full flow instrumentation correlation to the predictions at such low flow rates.

Response

As discussed in the response to Question 7, the existing primary loop flow instrumentation at McGuire cannot provide an indication of loop flow at natural circulation flowrates. As evident in Figure 5.3.4-9, the indication is essentially meaningless below approximately 20% of full flow. Unfortunately no valid direct indication of low loop flowrates exists. It is for this reason that the loop delta-T data is the key parameter for comparison. With the decay heat power level known with some reasonable degree of accuracy, and with accurate loop delta-T indications, the loop flow can be calculated and compared to the predicted value.

Question 13a

Explain how the power runback was simulated in the turbine trip test from 68% full power.

Response

The power runback was simulated by modeling the Rod Control System exactly as it exists at the plant, including all signal compensation. As discussed in Section 3.1.4.2, the Rod Control System is driven by two error signals, the sum of which is used to produce a rod demand signal. Inputs to the Rod Control System are auctioneered T-avg, nuclear power, and programmed reference temperature (T-ref). The first two signals are calculated by RETRAN. T-ref, which is proportional to the turbine impulse chamber pressure and turbine power are obtained from transient monitor data and are provided as a boundary

conditions. The output of the Rod Control System is input to a function generator to provide reactivity as a function of rod position. Reactivity versus röd position is calculated based on cycle-specific kinetics and rod worth data, and is also provided as a boundary condition.

Question 13b

Discuss why the predicted power (Figure 5.4.1-1) is higher from 100 seconds until the control rods were placed in manual control.

Response

The predicted power closely matches the plant data until a deviation occurs at approximately 90 seconds. At this time, the rate-lag compensated power mismatch signal has decayed such that it is no longer contributing to the total error signal to drive rods into the core. Therefore, only the auctioneered T-avg minus T-ref error signal is producing a rod insertion signal. The rate of change of rod insertion occurs approximately 30 seconds early because this error signal is reduced due to an underprediction in T-avg from 30 to 120 seconds as shown in Figure 5.4.1.4. In turn, the underprediction in T-avg during this period is caused by an underprediction in steamline pressure as shown in Figure 5.4.1-6. Alarm-typer data indicates that one of the Bank 2 condenser steam dump valves prematurely closed during this period, resulting in the underprediction in steam pressure. The atypical condenser dump valve closure was not modeled in the simulation.

Question 14a

Explain the inconsistent behaviors between predicted PZR pressure (Figure 5.4.1-2) and level (Figure 5.4.1-3) when compared to the data.

Response

Discrepancies in pressurizer pressure and level generally trend the discrepancies in T-avg (Figure 5.4.1-4) and can be attributed to under/overpredictions of this parameter. T-avg is driven by the actions of the Rod Control System in reducing reactor power and the load rejection controller in relieving steam. From 0-100 seconds, T-avg is slightly underpredicted due to an underprediction in steam pressure. The discrepancy in steam pressure is attributed to the unexpected closure of one of the Bank 2 condenser steam dump valves thereby maintaining the pressure above the predicted pressure during this period of time. From approximately 120 to 270 seconds, RETRAN overpredicts T-avg consistent with the overprediction in reactor power which is discussed in the response to Question 13a. Plant data then crosses above the predicted T-avg consistent with the increased steam pressure due to the premature closure and subsequent cycling of another one of the Bank 2 condenser dump valves. Neither of the valve anomalies are modeled. After 500 seconds, the T-avg prediction matches plant data. The overpredictions in pressurizer level and pressure after this time are attributed to a slight decrease in the plant Reactor Coolant System inventory due to the letdown flow exceeding the charging flow. Despite the effects of the condenser dump valve anomalies and the effects of charging and letdown, the predicted values of pressurizer pressure and level trend the data well with maximum deviations of only 30 psi and 4%, respectively.

Question 14b

Explain the inconsistent behaviors between predicted steamline pressure (Figure 5.4.1-6) and SG level (Figure 5.4.1-7) when compared to the data.

Response

As discussed in the response to Question 14a, the initial underprediction in steamline pressure is attributed to the premature closure of one of the Bank 2 condenser steam dump valves, and the underprediction from 200 to 575 seconds is attributed to the premature closure and subsequent cycling of another Bank 2 dump valve. This cycling is evident in the sawtooth pattern shown in Figure 5.4.1-6 from 200 to 400 seconds. The anomalous behavior of the condenser dump valves would have been accompanied by a reduction in steam flow, although accurate steam flow data is not available for comparison. The anomalous behavior of these valves was not modeled.

The steam generator level prediction after 125 seconds is consistent with the overprediction and subsequent underprediction of T-avg as shown in Figure 5.4.1-4. The cause of the steam generator level overprediction up to 125 seconds is difficult to establish; however, it appears to be the result of the low prediction of steam line pressure having a dominant effect on the level response during this period. It is noted that Figure 5.4.1-7 shows the narrow range level indication only from 35 to 65%, resulting in slight deviations appearing large. In general, the level prediction is very close to the plant data, typically within 4%.

February 20, 1990

U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Attention: Document Control Desk

Subject: McGuire Nuclear Station
Docket Numbers 50-369 and -370
Catawba Nuclear Station
Docket Numbers 50-413 and -414
Oconee Nuclear Station
Docket Numbers 50-269, -270, and -289
Topical Report DPC-NE-3000
Response to Request for Additional Information

By letter dated July 25, 1989, the NRC forwarded a set of questions relating to the VIPRE core thermal-hydraulic sections of topical report DPC-NE-3000. The responses to these questions are provided by Attachment 1 to this letter. Attachment 2 includes revised pages to DPC-NE-3000, which result from the responses to the questions in Attachment 1.

In accordance with 10CFR 2.790, Duke Power Company requests that the responses to these questions relating to the DPC-NE-3000 report be considered proprietary. Information supporting this request was included in the affidavit which accompanied the original submittal of DPC-NE-3000, dated September 29, 1987.

If we can be of further assistance in your review, please call Scott Gewehr at (704) 373-7581 or Gregg Swindlehurst at (704) 373-5176.

Very truly yours,

Hal B. Tucker

Hal B. Tucker

SAG210/lcs

Attachment 1

Response to NRC Questions
on DPC-NE-3000 Dated July 25, 1989

PROPRIETARY

DUKE POWER CO.

OCONEE/McGUIRE/CATAWBA APPLICATIONS

Question 1

Explain why the location of a hot subchannel depends on the critical heat flux CHF correlation used (pages 2-67 and 3-68 of Ref.1)? Which parameters in the correlations under consideration are affected by the location of a hot subchannel?

Response

The location of a hot subchannel can depend on the CHF correlation utilized because in some CHF correlations (such as the BAW2 and W3S correlations; Reference 1, Volume 1) there is a hydraulic diameter term; whereas in the other correlations [ ] Therefore, for a unit channel and a thimble channel with similar inlet boundary conditions and axial and radial power distributions, the BAW2 and W3S correlations would likely predict the MDNBR in the unit channel; [ ]

Question 2

Qualification of the coarse channel model in comparison to the fine channel model cannot be established by one set of steady-state conditions or by analysis of a single transient case. Provide comparative results by varying the steady-state and transient conditions, such as power, pressure, or flow conditions, over the range expected during for the events to be analyzed.

Response

Additional steady-state and transient cases are analyzed to show that in comparison with the fine channel models, the coarse channel model predicts conservative local fluid property and MDNBR values.

A. McGuire and Catawba Nuclear Stations (MNS/CNS)

1. Steady-state cases

Five cases are analyzed using the [ ] channel models. The first case represents the normal operating condition with nominal core power, core exit pressure, core inlet mass flux and core inlet temperature. Cases 2 to 5 simulate the conditions at which one of the boundary parameters is either at its safety analysis limit or at the value resulting in low MDNBR. Case 2 simulates the high core power condition. Case 3 simulates the low core exit pressure condition. Case 4 simulates the high core coolant inlet temperature condition, and Case 5 simulates the low flow condition. The BWCMV CHF correlation is used for the DNBR calculations. The boundary conditions are shown as follows.

Case	Core Power %	Core Exit Press. (psia)	Core Inlet Temp. (F)	Core Inlet Flowrate ($Mlbm/hr-ft^2$)
1	102	2305	561.4	2.4235
2	118	2305	561.4	2.4235
3	102	1900	561.4	2.4235
4	102	2305	600.0	2.4235
5	102	2305	561.4	1.8176

Table 1 shows the results of the above cases. Results show that the 14 channel model predicts equivalent or conservative local fluid properties and MDNBR values for all cases analyzed.

2. Transient cases

Four transients cases are analyzed using the [ ] channel models. In each case, only one boundary parameter is changed linearly from the normal operating value to the corresponding value described in Cases 2 to 5 of the steady-state analysis. The BWCMV CHF correlation is used for the DNBR calculations. The boundary conditions are shown below.

Case	Core Power %	Core Exit Press. (psia)	Core Inlet Temp. (F)	Core Inlet Flowrate ($Mlbm/hr-ft^2$)
1	changing from 102 to 118% in 4 sec.	2350	561.4	2.4235
2	102	changing from 2350 to 1900 in 4 sec.	561.4	2.4235
3	102	2350	changing from 561.4 to 600 F in 4 sec.	2.4235
4	102	2350	561.4	changing from 2.4235 to 1.8176 $Mlbm/hr-ft^2$ in 4 sec.

Tables 2 to 5 show the results of the transient cases. Results show that the [ ] channel model predicts equivalent or conservative local fluid properties and MDNBR values for all four transient cases.

3. Loss of flow transient

Utilizing the boundary conditions (Table 6) resulting from a

RETRAN system analysis for the loss of flow transient, the [ ] channel models are used to show that the [ ] channel models predicts equivalent or conservative local fluid properties and MDNBRs during the transient. The BWCMV CHF correlation is used for the DNBR calculation.

Table 7 shows the results of the loss of flow transient. Results show that the [ ] channel model predicts equivalent or conservative local fluid properties and MDNBR during the transient.

B. Oconee Nuclear Station (ONS)

1. Steady-state cases

Five cases are analyzed using the [ ] channel models. The first case represents the normal operating condition with nominal core power, core exit pressure, core inlet mass flux and core inlet temperature. Cases 2 to 5 simulate the conditions at which one of the boundary parameters is either at its safety analysis limit or at the value resulting in low MDNBR. Case 2 simulates the high core power condition. Case 3 simulates the low core exit pressure condition. Case 4 simulates the high core coolant inlet temperature condition, and Case 5 simulates the low flow condition. The BWC CHF correlation is used for the DNBR calculations. The boundary conditions are shown below.

Case	Core Power %	Core Exit Press. (psia)	Core Inlet Temp. (F)	Core Inlet Flowrate (Mlbm/hr-ft^2)
1	100	2170	579	2.5445
2	112	2170	579	2.5445
3	100	1815	579	2.5445
4	100	2170	600	2.5445
5	100	2170	579	1.9640

Table 8 shows the results of the above cases. Results show that the [ ] channel model predicts equivalent or conservative local fluid properties and MDNBR values for all cases analyzed.

2. Transient cases

Four transient cases are analyzed using the [ ] channel models. In each case, only one boundary parameter is changed linearly from the normal operating value to the corresponding value described in Cases 2 to 5 of the steady-state analysis. The BWC CHF correlation is used for the DNBR calculations. The boundary conditions are shown as follows:

Case	Core Power %	Core Exit Press. (psia)	Core Inlet Temp. (F)	Core Inlet Flowrate ($Mlbm/hr\text{-}ft^2$)
1	changing from 100 to 112% in 3 sec.	2170	579	2.5445
2	100	changing from 2170 to 1815 in 3 sec.	579	2.5445
3	100	2170	changing from 579 to 600 F in 3 sec.	2.5445
4	100	2170	579	changing from 2.5445 to 1.964 $Mlbm/hr\text{-}ft^2$ in 3 sec.

Tables 9 to 12 show the results of the transient cases. Results show that the[ ]channel model predicts the equivalent or conservative local fluid properties and MDNBR values for all four transient cases.

3. Loss of flow transient

Utilizing the boundary conditions (Table 13) resulting from a RETRAN system analysis for the loss of flow transient, the [ ]channel models are used to show that the[ ] channel model predicts the equivalent or conservative local fluid properties and MDNBRs during the transient. The BWC CHF correlation is used for the DNBR calculation.

Table 14 shows the results of the loss of flow transient. Results show that the[ ]channel model predicts equivalent or conservative local fluid properties and MDNBR during the transient.

Question 3

For asymmetrical transients, the report states that the coarse channel model may be modified. Provide more information on such modification and show that the use of the coarse model in that case would yield results that were either just as good or more conservative than those obtained using the fine channel model.

Response

Modeling of asymmetrical transients is beyond the scope of the VIPRE modeling discussed in DPC-NE-3000. Description and justification of those models will be covered in separate submittals. (for McGuire and Catawba, refer to DPC-NE-3001 (Reference 5)).

Question 4

Since the default value of the gap/centroid distance is recommended for subchannels having all the same dimensions (Ref. 2 Vol. 2 p. 2-11), what value of gap/centroid distance will be used for transient analysis for transition cores? Discuss in detail how the transient analysis of transition cores will be performed using VIPRE-01.

Response

A. MNS and CNS

In the transition core thermal-hydraulic analysis, the gap and centroid distance will be input for every channel to the model. The crossflow resistance coefficient, K_G, then is adjusted internally by the code for lumped channels based on the input gap and centroid distance. A sensitivity study using gaps based on the two different fuel rod sizes showed essentially no change in the hot channel coolant properties and MDNBR. A conservative steady-state transition core DNBR penalty will be determined and applied to the transient analysis as follows:

The overall pressure drop across the residual and new fuel assemblies will first be evaluated to determine which fuel assembly type results in less coolant flow. In general, flow will tend to be forced out of the fuel assembly type that has a higher overall pressure drop. Therefore, the fuel assembly type with the higher overall pressure drop will be the hot assembly. To obtain a conservative steady-state transition core MDNBR value, the transition core will contain the fuel assembly having the higher pressure drop as the hot assembly and an allowable maximum number of fuel assemblies (based on the reload design strategy) having less overall pressure drop. The gaps between the high pressure drop and low pressure drop assemblies will be input based on the high pressure drop fuel type dimensions. The resulting steady-state transition core MDNBR will be compared with that of a full core of replacement fuel to obtain a DNBR penalty factor. The steady-state transition core DNBR penalty is applied to the transient analysis by raising the MDNBR acceptance criterion. It should be noted that the MDNBR resulting from transients does not usually approach the DNBR limit. Therefore, the impact of any accumulated DNBR penalties such as a transition core penalty, is of relatively small significance. DNBR penalties are more significant in steady-state core thermal-hydraulic design since the design DNBR limit is a target value.

B. ONS

For an Oconee transition core, similar methodology to that described above will be utilized for the transition core calculation.

Question 5

Demonstrate that sensitivity analysis results would not be affected by changing from the RETRAN heat flux boundary condition to the VIPRE fuel pin conduction model (pages 2-74 and 3-76 for Ref.1).

Response

As stated in the report, Duke intends to use the RETRAN heat flux boundary condition resulting from the RETRAN fuel pin model, rather than use the VIPRE fuel pin model. This approach is preferred since the reactor dynamic response is modeled in RETRAN, and by using the RETRAN fuel pin model consistent thermal feedback modeling is maintained in the transient analysis. However, if a particular analysis requires, for example, detailed simulation of transient axial power shapes or cladding or fuel pellet temperatures, the VIPRE fuel pin model may be used with a RETRAN power boundary condition. This approach would be taken simply because VIPRE offers much greater modeling flexibility. The two approaches are evaluated on a case-by-case basis for each analysis and the optimum method is selected. With consistent geometry, material properties, and initial and boundary conditions, the RETRAN and VIPRE fuel pin models will yield comparable results. A sensitivity study was not performed in response to this question since a preferred approach exists for each transient based on the factors discussed above.

Question 6

For each intended plant application, identify and discuss the intended use of the three core models.

Response

The [ ] channel model will be used for all applications involving symmetric core power distributions. The more detailed models are only used for model verification purposes. Other models will be submitted separately for asymmetric power distribution analyses.

Question 7

Justify the use of the solution method for the full spectrum of transient analyses in the Final Safety Analysis Report (FSAR) for each plant application. If there is no intention to use the iterative solution method for all transient analyses, state those for which it is used, and state which solution method will be used for the others.

Response

VIPRE has three choices for the numerical solution. There is an iterative solution, a direct solution, and the RECIRC solution module. The three solution methods solve exactly the same energy, momentum, and continuity equations, but because they are different numerical methods the different solutions are best suited to solving different types of problems. The iterative and direct solutions are for problems with positive flow only. For most types of problems the direct solution requires less computation time and yields a slightly better solution than the iterative method. However, for very large problems, the iterative solution may be more efficient (Reference 1, Volume 5, Section 3.7.1). All three solution techniques are acceptable for licensing

calculations (Reference 7).

Neither the iterative nor the direct solution method can calculate flow reversals, and usually both have great difficulty converging with very low velocity buoyancy-dominated flow conditions or flows with severe disturbances. For problems of this type, the only recourse is the RECIRC solution module.

The energy and momentum equations in the direct and RECIRC methods are solved simultaneously at each axial level. The coefficient matrices can have a narrow bandwidth and therefore can be solved quite efficiently depending on the channel numbering system. The iterative solution does not need the full coefficient matrix, and the channel numbering system is not important. The bandwidth is twice the maximum difference between the indices of any two adjacent channels, plus one for the diagonal. The bandwidth, and therefore storage and also solution time, should be made as small as possible. Therefore, the iterative solution method may be required for large models.

A. <u>MNS and CNS</u>

The channel numbering method of the[ ]channel model results in a bandwidth that is within the allowable maximum bandwidth of the Duke VIPRE version. However, to avoid any convergence difficulties that the direct and iterative solution methods may have as described above, the RECIRC solution method will be used for all transient analyses for the[ ]channel models.

B. <u>ONS</u>

The channel numbering system of the[ ]channel model results in a large bandwidth that exceeds the allowable maximum bandwidth of the Duke VIPRE version. Thus, the model result comparisons in the DPC-NE-3000 report had to be performed utilizing the iterative solution. Consequently, the iterative solution will be used with all models for the Oconee FSAR application. Nevertheless, if the iterative solution fails to converge due the low velocity buoyancy-dominated flow condition or flows with severe disturbances, the recourse is to use the RECIRC solution method with the Oconee models.

<u>Question 8</u>

Show on a transient by transient basis for each plant application that Levy subcooled, Zuber-Findlay bulk void correlations and the Columbia/Electric Power Research Institute two-phase multiplier for two-phase flow will be applied within their ranges of applicability. Show in accordance with the VIPRE SER, that selecting these correlations results in a conservative MDNBR prediction.

<u>Response</u>

The pressure ranges of applicability for the Levy subcooled, Zuber-Findlay bulk void correlations and the Columbia/Electric Power Research Institute (EPRI) two-phase multiplier are shown as follows (Table 2-4, Vol. 2, Reference 1):

Correlation	Pressure (psia)
Levy	120-2000
Zuber-Findlay	600-2000
Columbia/EPRI	600-1300

The above data show that the models are correlated below the normal PWR operation pressure which is greater than 2000 psia. However, using the low pressure void correlations for high pressure analyses is conservative since in reality the liquid-to-vapor density moves closer to 1.0 as pressure increases resulting in smaller void fractions, a more homogeneous flow and smaller two-phase friction multipliers. Utilizing the[ ]channel model, a sensitivity study has been performed for different combinations of void models excluding the slip void models as follows.

Subcooled Void	Bulk Void	Two Phase Mult.
Levy	Zuber-Findlay	Columbia/EPRI
Levy	Armand	Columbia/EPRI
Levy	Smith	Columbia/EPRI
EPRI	EPRI	Columbia/EPRI
None	Homogeneous	Columbia/EPRI

The sensitivity study has been performed for the steady-state and transient boundary conditions described in Response 2. Results for the sensitivity study are shown in Table 15 for MNS and CNS and in Table 16 for ONS.

[ ]

Question 9

The VIPRE-01 code developer recommends the use of 2 to 3 inch nodes (Ref. 2, vol.4, p.7-3) in the region where MDNBR is expected to occur. Show that the noding selected is conservative and independent of the CHF correlations to be used in the transient analyses. Since Duke Power Company (DPC) intends to use different CHF correlations for transient analyses for the different plant applications, identify which CHF correlation was used in the parametric study summarized in Table 3.3-4 of the report and in other parametric studies in Chapter 3. Show that the sensitivity studies presented here would have the same results using other CHF correlations.

Response

As stated in Table 3.3-4 (as well as in Tables 3.3-2, 3.3-3) the BWCMV CHF correlation was used for the parametric studies in Chapter 3 of the report.

A. MNS and CNS

The[ ]channel core model with different active axial nodes is utilized for different transient cases described in Response 2. The[ ]inches/node, respectively) are analyzed with the BWCMV and DCHF1 CHF correlations.

Results of the analysis are shown in Tables 17 to 20 and are summarized below.

Case	MDNBR BWCMV 30N	40N	50N	DCHF1 30N	40N	50N
Power Trans.	[					]
Pressure Trans.						
T_{IN} Trans.						
Flow Trans.						

( ) - percent difference

$= [\qquad\qquad] \times 100\%$

[

] It is concluded that using [ ] axial nodes to perform the transient analysis is acceptable for both BWCMV and DCHF1 CHF correlations.

ONS

The [ ] channel core model with different active axial nodes is utilized for different transient cases described in Response 2. The [ ] active axial node cases [ ] inches/node, respectively) are analyzed with the BWC CHF correlation.

Results of the analysis are shown in Table 21 and are summarized below.

Case	MDNBR (BWC)
Power Trans.	[ ]
Pressure Trans.	
T_{IN} Trans.	
Flow Trans.	

[ ]

[ ] It is concluded that using [ ] axial nodes to perform the transient analysis is acceptable for the BWC CHF correlation.

OCONEE APPLICATIONS

Question 10.

The data in Table 2.3-1 of the report (Ref.1) are different from those in Table 3-1 of Reference 3. Provide an explanation of these differences, including those pertaining to the Mark B-type fuel assemblies, and address how they affect the VIPRE-01 analysis.

Response

The data in Table 2.3-1 of the report are the "hot" dimensions; whereas those in Table 3-1 of DPC-NE-2003 are the nominal dimensions. The "hot" dimensions are used for analyses in both DPC-NE-2003 and DPC-NE-3000 reports.

Question 11

Explain why the core model and the location of the hot assembly are not transient dependent.

Response

For symmetric transients, the core radial power distribution remains relatively proportional to the initial power distribution. Therefore, the highest powered fuel assembly at the initial condition remains the hot assembly, regardless of the transient. For asymmetric transients the location of the hot assembly can change. Different models not described in this report are designed to simulate responses of that type.

Question 12

How was it determined that use of a damping factor of 0.9 for axial flow instead of the default value of 1.0 is more conservative?

The damping factor of 0.9 for axial flow has been used instead of the default value (iterative method) of 1.0 for consistency with that of the RECIRC solution for which the default value is 0.9. Sensitivity studies have been performed using the [ ] channel model and the iterative method for damping factors of 0.9 and 1.0 for different transient cases described in Response 2. Table 22 shows the results. It shows that the damping factors of 0.9 and 1.0 yield identical results.

McGUIRE and CATAWBA APPLICATIONS

Question 13

On page 3-68 of Reference 1, it is stated that radial power distributions used originated from reload-typical power distributions. Explain why this type of power distribution is used for FSAR Chapter 15-type transients?

Response

The assembly and pin radial power distributions shown in Figure 3.3-2 and 3.3-3, respectively, are used for many of the FSAR Chapter 15-type transients because they are conservative. The assembly and pin radial power distributions were selected after studying a number of realistic power distributions. The assumed maximum assembly and pin radial power of [ ] are higher than those of the realistic power distributions. In Figure 3.3-2, a [ ] The pin radial power distribution shown in Figure 3.3-3 is also conservative because it is as [ ]

Question 14

Provide the source of the turbulent mixing coefficient used, and discuss how it was obtained.

Response

In subchannel crossflow codes such as VIPRE-01 the turbulent exchange between subchannels i and j is defined by

$$W'_{ij} = \beta S_{ij} G$$

where G is the average mass flux of the adjacent subchannels, S_{ij} is the width of the gap between subchannels i and j, and β is the turbulent mixing coefficient. The turbulent mixing coefficient has been determined by Nuclear Fuel Industries (NFI) for Inconel spacer grids that are nearly identical to Babcock and Wilcox's (B&W) Zircaloy Mark-BW grids. A mixing coefficient of [ ] was calculated based on tests measuring subchannel exit temperatures for a 5 x 5 array representative of 17 x 17 fuel geometry. Test were also run to obtain turbulence intensity data using a Laser Doppler Velocimeter (LDV). LDV data has also been obtained for the Mark-BW Zircaloy grids. The LDV data for both the Inconel and Zircaloy grids was reduced to obtain an assembly average turbulence intensity. The Zircaloy grid average turbulence intensity is approximately 10 percent greater than the Inconel grid turbulence intensity. From previous tests B&W found that the turbulent mixing coefficient is proportional to the turbulence intensity, thus the 17 x 17 Zircaloy grid turbulent mixing coefficient should be in the range of [ ] A conservative value of [ ] will be used for all McGuire/Catawba thermal-hydraulic analyses of Mark-BW fuel.

Question 15

Provide the spacer grid form loss coefficient used, and show that its use resulted in a conservative prediction of DNBR during a spectrum of transients to be analyzed.

Response

The spacer grid form loss coefficients used for the Mark-BW fuel type are listed below:

Axial Location*	Grid Type**	Unit Channel	Thimble Channel	Thimble ch. w/Ferrule

[ ]

Axial Location	Grid Type**	Instrument Channel	Peripheral Channel	Corner Channel

[ ]

* The axial locations given are from the bottom of the fuel rods to the center of each grid.

Overall Grid Form Loss Coefficients

** [ ]

Fuel assembly pressure drop data is taken by B&W for a wide range of flow, pressure, and temperatures values so that the spacer grid form loss coefficients can be calculated for reactor conditions. The pressure drop across the core can be expressed as the sum of the friction and form loss pressure drops. The friction pressure drop is the unrecoverable pressure drop due to the fluid flowing past the fuel rods (and the facility walls when test data is taken). The form loss pressure drop includes all of the pressure loss due to changes in flow area, in direction in flow, etc. The friction pressure drop is calculated and subtracted from the experimentally measured pressure drop. This leaves the form loss pressure drop which is divided by the dynamic head to yield the spacer grid form loss coefficients.

Individual subchannel form loss coefficients are calculated by B&W using

the grid loss evaluation program GRIL. The GRIL code is able to determine subchannel form loss coefficients analytically based on individual subchannel geometries and the experimentally determined overall grid loss coefficients. Subchannel geometries are defined in GRIL by inputting dimensions, drag areas, and drag coefficients for the different objects which obstruct flow in the individual subchannels. These objects include such things as hard stops, spring stops, and spacer grid webbing. GRIL calculates grid loss coefficients based on single-phase flow with coolant flow information being input in the form of average coolant density, average kinematic viscosity, and average Reynolds number. Flow velocity in the rod gap is calculated by boundary layer theory using a universal velocity profile which relates dimensionless velocity to all distance parameters for different flow regimes. Actual calculation of the subchannel loss coefficients in GRIL is an iterative process. For the first iteration, the channel flow velocities are assumed to be equal to the average velocity in the channel. Using the individual subchannel geometry and drag information, GRIL calculates individual subchannel loss coefficients, and overall grid loss coefficient, and new subchannel velocities. The iterative process continues until the calculated overall grid loss coefficient matches the experimental value. Comparisons made to laser doppler velocimeter (LDV) test results have shown that the subchannel velocity profiles calculated by GRIL agree well with experimental data.

Question 16

Show that the data used for the following are conservative, or provide references approving their use: (a) hot channel factor, (b) axial peaking factor, (c) radial peaking factor, (d) pin radial-local peaking factor.

Response

(a) The hot channel factor $F^E_{\Delta H}$ is the allowance on enthalpy rise to account for manufacturing tolerances. This factor allows for local variations in pellet density, diameter and enrichment, and fuel rod diameter. Combined statistically the net effect is a factor of 1.03 (Reference 6) which is applied to the hot channel enthalpy rise. This is a generic value conservatively determined by B&W.

(b) The reference axial power shape for the accidents for which DNB protection is required is a[ ] The reference axial power shape and radial power distribution are selected to yield DNBR margin in the Chapter 15 transients and peaking margin compared to cycle specific power distributions. The approach followed is to use a "design" power distribution for steady-state and transient core thermal-hydraulic analyses and then combinations of radial and axial peaking that provide equivalent DNB protection are determined. Operational Axial Flux Difference (AFD) limits are calculated based on Operational Maximum Allowable Peaking (MAP) limits which are determined for a complete range of axial peaks and locations of the axial peak (References 8 and 9) The Operational MAP limits are based on the complete loss of flow accident which is the most limiting DNB accident. Operation within the AFD limits ensures equivalent DNB protection to that calculated for a[ ] axial flux shape.

(c) The assembly radial peaking distritubtion was selected after

studying a number of realistic assembly power distributions. An assumed assembly radial peaking factor of [ ] is used for the transient analysis. The [ ] value is higher than any realistic core assembly peaking value and is also higher than the steady-state analysis value of [ ] (Reference 9). [power profile around the hot assembly is used in the 93 channel model as shown in Figure 3.3-2 to minimize the benefits of flow redistribution. A sensitivity study has shown that the MDNBR is very insensitive to peaking changes in the assemblies surrounding]

(d) The local peaking distribution was selected after studying a number of realistic pin power distributions. The assumed maximum pin radial power of [ ] is higher than any realistic core pin peaking value. The conservative power distribution shown in Figure 3.3-3 is [ ] As discussed above in part (b), the "design" power distribution is used to determine the limiting DNB transient and then MAP limits are calculated which provide equivalent DNB protection.

REFERENCES FOR THE QUESTIONS

1. Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000, Rev.1, May 1989

2. Letter from C. E. Rossi (USNRC) to J. A. Blaisdell (URGA), Acceptance for Referencing of Licensing Topical Report, EPRI NP-2511-CCM, "VIPRE-01: A Thermal-Hydraulic Analysis Code for Reactor Cores, Volumes 1, 2, 3, and 4, May 1, 1986.

3. Oconee Nuclear Station Core Thermal-Hydraulic Methodology Using VIPRE-01, DPC-NE-2003, August 1988.

REFERENCES FOR THE RESPONSES

1. VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM, Revision 2, EPRI, Volumes 1 to 5, July 1985.

2. BWC Correlation of Critical Heat Flux, BAW-10143P-A, April 1985.

3. BWCMV Correlation of Critical Heat Flux, BAW-10159B, May 1986.

4. DCHF-1 Correlation for Predicting Critical Heat Flux in Mixing Vane Grid Fuel Assemblies, DPC-NE-2000, September 1987.

5. Duke Power Company, McGuire Nuclear Station, Catawba Nuclear Station, Multidimensional Reactor Transients and Safety Analysis Physics Parameter Methodology, DPC-NE-3001-P, January 1990.

6. Mark-BW Hot Channel Factor, Babcock & Wilcox, 32-1172674-00, January 26, 1989.

7. Letter from C. E. Rossi (USNRC) to J. A. Blaisdel (URGA), Acceptance for Referencing of Licensing Topical Report, EPRI NP-2511-CCM, VIPRE-10: A Thermal-Hydraulic Analysis Code for Reactor Cores, Volumes 1, 2, 3, and 4, May 1, 1986.

8. DPC-NE-2001P, Nuclear Design Methodology for Core Operating Limits of Westinghouse Reactors, Duke Power Company, April 1988.

9. DPC-NE-2004, McGuire/Catawba Nuclear Stations Core Thermal-Hydraulic Methodology Using VIPRE-01, Duke Power Company, December 1988.

PROPRIETARY
DUKE POWER CO.

Table 1

McGuire and Catawba Nuclear Stations
Model Results Comparison for Steady-State Cases

Case 1 - Normal Operation

Model	MDNBR (BWCMV)	MDNBR at Axial Location (IN)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop Up to MDNBR (psi)

[ ]

Case 2 - High Power Condition

Model	MDNBR (BWCMV)	MDNBR at Axial Location (IN)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop Up to MDNBR (psi)

[ ]

Case 3 - Low Pressure Condition

Model	MDNBR (BWCMV)	MDNBR at Axial Location (IN)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop Up to MDNBR (psi)

[ ]

Case 4 - High Inlet Temperature Condition

Model	MDNBR (BWCMV)	MDNBR at Axial Location (IN)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop Up to MDNBR (psi)

[ ]

Case 5 - Low Inlet Flow Condition

Model	MDNBR (BWCMV)	MDNBR at Axial Location (IN)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop Up to MDNBR (psi)

[ ]

PROPRIETARY
DUKE POWER CO.

Table 2

McGuire and Catawba Nuclear Stations
Model Results Comparison
for the Power Transient Case

Time (sec)
0.0
0.8
1.6
2.4
3.2
4.0

Time (sec)
0.0
0.8
1.6
2.4
3.2
4.0

Time (sec)
0.0
0.8
1.6
2.4
3.2
4.0

Table 3

McGuire and Catawba Nuclear Stations
Model Results Comparison
for the Pressure Transient Case

Time (sec)	MDNBR (BWCMV)	MDNBR at Axial Location (in)
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

Time (sec)		
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

Time (sec)		
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

Table 4

McGuire and Catawba Nuclear Stations
Model Results Comparison
for the Inlet Temperature Transient Case

Time (sec)	MDNBR (BWCMV)	MDNBR at Axial Location (in)
0.00		
0.84		
1.68		
2.53		
3.37		
4.00		
Time (sec)		
0.00		
0.84		
1.68		
2.53		
3.37		
4.00		
Time (sec)		
0.00		
0.84		
1.68		
2.53		
3.37		
4.00		

Table 5

McGuire and Catawba Nuclear Stations
Model Results Comparison
for the Inlet Flow Transient Case

Time (sec)	MDNBR (BWCMV)	MDNBR at Axial Location (in)
0.0		
0.90		
1.78		
2.67		
3.56		
4.00		

Time (sec)		
0.00		
0.90		
1.78		
2.67		
3.56		
4.00		

Time (sec)		
0.00		
0.90		
1.78		
2.67		
3.56		
4.00		

PROPRIETARY
DUKE POWER CO.

Table 6

McGuire and Catawba Nuclear Stations
Loss of Flow Transient Boundary Conditions*

Time (sec)	Core Exit Pressure	Core Inlet Flow	Core Average Heat Flux	Core Inlet Temperature
0.00				
0.20				
0.40				
0.60				
0.80				
1.00				
1.20				
1.40				
1.60				
1.80				
2.00				
2.20				
2.40				
2.60				
2.80				
3.00				
3.20				
3.40				
3.60				
3.80				
4.00				
4.20				
4.40				
4.60				
4.80				
5.00				

* All values are normalized to the initial values

Initial values:

Table 7

Model Results Comparison
for the Loss of Flow Transient

Time (sec)	MDNBR (BWCMV)	MDNBR at Axial Location (in)
0.0		
0.44		
0.88		
1.32		
1.77		
2.21		
2.65		
3.09		
3.53		
3.68		
3.82		
3.97		
4.12		
4.27		
4.41		
4.56		
5.00		

Time (sec)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR
0.0		
0.44		
0.88		
1.32		
1.77		
2.21		
2.65		
3.09		
3.53		
3.68		
3.82		
3.97		
4.12		
4.27		
4.41		
4.56		
5.00		

PROPRIETARY
DUKE POWER CO.

Table 7 (Cont'd)

Time (sec)	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop up to MDNBR
0.00		
0.44		
0.88		
1.32		
1.77		
2.21		
2.65		
3.09		
3.53		
3.68		
3.82		
3.97		
4.12		
4.27		
4.41		
4.56		
5.00		

PROPRIETARY
DUKE POWER CO

Table 10

Oconee Nuclear Station
Model Results Comparison
For the Pressure Transient Case

Time	MDNBR (BWC)			Axial Location at MDNBR (in.)		
(sec.)	M1*	M2*	M3*	M1	M2	M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						

Time	Enthalpy at MDNBR (Btu/lbm)			Void Fraction at MDNBR		
(sec.)	M1	M2	M3	M1	M2	M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						

Time	Mass Flux at MDNBR ($Mlbm/hr-ft^2$)			Pressure Drop up to MDNBR Location (psi)		
(sec.)	M1	M2	M3	M1	M2	M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						

*Note: M1 = [ ] Channel Model, M2 = [ ] Channel Model,
M3 = [ ] Channel Model

Table 7 (Cont'd)

Time (sec)	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop up to MDNBR
0.00		
0.44		
0.88		
1.32		
1.77		
2.21		
2.65		
3.09		
3.53		
3.68		
3.82		
3.97		
4.12		
4.27		
4.41		
4.56		
5.00		

PROPRIETARY
DUKE POWER CO.

Table 8

Oconee Nuclear Station
Model Results Comparison for Steady-State Cases

Case 1 - Normal Operation

Model	MDNBR (BWC)	MDNBR at Axial Location (IN)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop Up to MDNBR (psi)

[ ]

Case 2 - High Power Condition

Model	MDNBR (BWC)	MDNBR at Axial Location (IN)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop Up to MDNBR (psi)

[ ]

Case 3 - Low pressure Condition

Model	MDNBR (BWC)	MDNBR at Axial Location (IN)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop Up to MDNBR (psi)

[ ]

Case 4 - High Inlet Temperature Condition

Model	MDNBR (BWC)	MDNBR at Axial Location (IN)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop Up to MDNBR (psi)

[ ]

Case 5 - Low Inlet Flow Condition

Model	MDNBR (BWC)	MDNBR at Axial Location (IN)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop Up to MDNBR (psi)

[ ]

PROPRIETARY
DUKE POWER CO.

Table 9

Oconee Nuclear Station
Model Results Comparison
For the Power Transient Case

Time	MDNBR (BWC)			Axial Location at MDNBR (in.)		
(sec.)	M1*	M2*	M3*	M1	M2	M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						

Time	Enthalpy at MDNBR (Btu/lbm)			Void Fraction at MDNBR		
(sec.)	M1	M2	M3	M1	M2	M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						

Time	Mass Flux at MDNBR ($Mlbm/hr-ft^2$)			Pressure Drop up to MDNBR Location (psi)		
(sec.)	M1	M2	M3	M1	M2	M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						

*Note: M1 =[ ]Channel Model, M2 =[ ]Channel Model,
M3 =[ ]Channel Model

PROPRIETARY
DUKE POWER CO

Table 10

Oconee Nuclear Station
Model Results Comparison
For the Pressure Transient Case

Time (sec.)	MDNBR (BWC) M1*	MDNBR (BWC) M2*	MDNBR (BWC) M3*	Axial Location at MDNBR (in.) M1	Axial Location at MDNBR (in.) M2	Axial Location at MDNBR (in.) M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						

Time (sec.)	Enthalpy at MDNBR (Btu/lbm) M1	Enthalpy at MDNBR (Btu/lbm) M2	Enthalpy at MDNBR (Btu/lbm) M3	Void Fraction at MDNBR M1	Void Fraction at MDNBR M2	Void Fraction at MDNBR M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						

Time (sec.)	Mass Flux at MDNBR ($Mlbm/hr\text{-}ft^2$) M1	Mass Flux at MDNBR ($Mlbm/hr\text{-}ft^2$) M2	Mass Flux at MDNBR ($Mlbm/hr\text{-}ft^2$) M3	Pressure Drop up to MDNBR Location (psi) M1	Pressure Drop up to MDNBR Location (psi) M2	Pressure Drop up to MDNBR Location (psi) M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						

*Note: M1 = [ ] Channel Model, M2 = [ ] Channel Model,
M3 = [ ] Channel Model

PROPRIETARY
DUKE POWER CO.

Table 11

Oconee Nuclear Station
Model Results Comparison
For the Inlet Temperature Transient Case

Time	MDNBR (BWC)			Axial Location at MDNBR (in.)		
(sec.)	M1*	M2*	M3*	M1	M2	M3
0.0						
0.514						
1.029						
1.543						
2.057						
2.571						
3.0						

Time	Enthalpy at MDNBR (Btu/lbm)			Void Fraction at MDNBR		
(sec.)	M1	M2	M3	M1	M2	M3
0.0						
0.514						
1.029						
1.543						
2.057						
2.571						
3.0						

Time	Mass Flux at MDNBR ($Mlbm/hr\text{-}ft^2$)			Pressure Drop up to MDNBR Location (psi)		
(sec.)	M1	M2	M3	M1	M2	M3
0.0						
0.514						
1.029						
1.545						
2.057						
2.517						
3.0						

MDNBR and thermal-hydraulic properties are given at selected time steps during the transient.

*Note: M1 =[ ]Channel Model, M2 =[ ]Channel Model,
M3 =[ ]Channel Model

PROPRIETARY
DUKE POWER CO.

Table 12

Oconee Nuclear Station
Model Results Comparison
For the Inlet Flow Transient Case

Time (sec.)	MDNBR (BWC) M1*	MDNBR (BWC) M2*	MDNBR (BWC) M3*	Axial Location at MDNBR (in.) M1	Axial Location at MDNBR (in.) M2	Axial Location at MDNBR (in.) M3
0.0	[					
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						]

Time (sec.)	Enthalpy at MDNBR (Btu/lbm) M1	Enthalpy at MDNBR (Btu/lbm) M2	Enthalpy at MDNBR (Btu/lbm) M3	Void Fraction at MDNBR M1	Void Fraction at MDNBR M2	Void Fraction at MDNBR M3
0.0	[					
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						]

Time (sec.)	Mass Flux at MDNBR ($Mlbm/hr-ft^2$) M1	Mass Flux at MDNBR ($Mlbm/hr-ft^2$) M2	Mass Flux at MDNBR ($Mlbm/hr-ft^2$) M3	Pressure Drop up to MDNBR Location (psi) M1	Pressure Drop up to MDNBR Location (psi) M2	Pressure Drop up to MDNBR Location (psi) M3
0.0	[					
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						]

*Note: M1 =[ ]Channel Model, M2 =[ ]Channel Model,
M3 =[ ]Channel Model

PROPRIETARY

DUKE POWER CO.

Table 13

Oconee Nuclear Station
Loss of Flow Transient Boundary Conditions*

Time (sec)	Core Exit Pressure	Core Inlet Flow	Core Average Heat Flux	Core Inlet Temperature
0.0				
0.2				
0.4				
0.6				
0.8				
1.0				
1.2				
1.4				
1.6				
1.8				
2.0				
2.2				
2.3				
2.4				
2.5				
2.6				
2.8				
3.0				

* All values are normalized to the initial values

Table 14

Oconee Nuclear Station
Model Results Comparison
For the Loss of Flow Transient

Time (sec.)	MDNBR (BWC) M1*	MDNBR (BWC) M2*	MDNBR (BWC) M3*	Axial Location at MDNBR (in.) M1	Axial Location at MDNBR (in.) M2	Axial Location at MDNBR (in.) M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.3						
3.0						

Time (sec.)	Enthalpy at MDNBR (Btu/lbm) M1	Enthalpy at MDNBR (Btu/lbm) M2	Enthalpy at MDNBR (Btu/lbm) M3	Void Fraction at MDNBR M1	Void Fraction at MDNBR M2	Void Fraction at MDNBR M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.3						
3.0						

Time (sec.)	Mass Flux at MDNBR ($Mlbm/hr\text{-}ft^2$) M1	Mass Flux at MDNBR ($Mlbm/hr\text{-}ft^2$) M2	Mass Flux at MDNBR ($Mlbm/hr\text{-}ft^2$) M3	Pressure Drop up to MDNBR Location (psi) M1	Pressure Drop up to MDNBR Location (psi) M2	Pressure Drop up to MDNBR Location (psi) M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.3						
3.0						

*Note: M1 = [ ] Channel Model, M2 = [ ] Channel Model,
M3 = [ ] Channel Model

PROPRIETARY
DUKE POWER CO.

Table 15

McGuire and Catawba Nuclear Stations
Subcooled and Bulk Void Models
Sensitivity Study Results Comparison

Power Transient

MDNBR (BWCMV)

Time (Sec.)	L-Z *	L-A *	L-S *	E-E *	HOMO*
0.0	[				]
4.0					

Pressure Transient

MDNBR (BWCMV)

Time (Sec.)	L-Z	L-A	L-S	E-E	HOMO
0.0	[				]
4.0					

Inlet Temperature Transient

MDNBR (BWCMV)

Time (Sec.)	L-Z	L-A	L-S	E-E	HOMO
0.0	[				]
4.0					

Inlet Flow Transient

MDNBR (BWCMV)

Time (Sec.)	L-Z	L-A	L-S	E-E	HOMO
0.0	[				]
4.0					

		Subcooled Void	Bulk Void
*	L-Z =	Levy	Zuber-Findlay
	L-A =	Levy	Armand
	L-S =	Levy	Smith
	E-E =	EPRI	EPRI
	Homo =	None	Homogeneous

PROPRIETARY
DUKE POWER CO

Table 16

Oconee Nuclear Station
Subcooled and Bulk Void Models
Sensitivity Study Results Comparison

Power Transient

MDNBR (BWC)

Time (Sec.)	L-Z *	L-A *	L-S *	E-E *	HOMO*
0.0	[				
3.0					]

Pressure Transient

MDNBR (BWC)

Time (Sec.)	L-Z	L-A	L-S	E-E	HOMO
0.0	[				
3.0					]

Inlet Temperature Transient

MDNBR (BWC)

Time (Sec.)	L-Z	L-A	L-S	E-E	HOMO
0.0	[				
3.0					]

Inlet Flow Transient

MDNBR (BWC)

Time (Sec.)	L-Z	L-A	L-S	E-E	HOMO
0.0	[				
3.0					]

		Subcooled Void	Bulk Void
*	L-Z =	Levy	Zuber-Findlay
	L-A =	Levy	Armand
	L-S =	Levy	Smith
	E-E =	EPRI	EPRI
	Homo =	None	Homogeneous

Table 17

McGuire and Catawba Nuclear Stations
Axial Node Size Sensitivity Study Results Comparison
Power Transient Case

BWCMV CHF Correlation

Time (sec)	MDNBR (BWCMV)	DNBR at Axial Location (in)
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

DCHF1 Correlation

Time (sec)	MDNBR (DCHF1)	DNBR at Axial Location (in)
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

BWCMV CHF Correlation

Time (sec)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

DCHF1 CHF Correlation

Time (sec)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

Table 17 (Cont'd)

BWCMV CHF Correlation

Time (sec)	Mass Flux at MDNBR ($Mlbm/hr\text{-}ft^2$)	Pressure Drop up to MDNBR
0.0	[	]
0.8		
1.6		
2.4		
3.2		
4.0		

DCHF1 CHF Correlation

Time (sec)	Mass Flux at MDNBR ($Mlbm/hr\text{-}ft^2$)	Pressure Drop up to MDNBR
0.0	[	]
0.8		
1.6		
2.4		
3.2		
4.0		

PROPRIETARY
DUKE POWER CO.

Table 18

McGuire and Catawba Nuclear Stations
Axial Node Size Sensitivity Study Results Comparison
Pressure Transient Case

BWCMV CHF Correlation

Time (sec)	MDNBR (BWCMV)	DNBR at Axial Location (in)
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

DCHF1 CHF Correlation

Time (sec)	MDNBR (DCHF1)	DNBR at Axial Location (in)
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

BWCMV CHF Correlation

Time (sec)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

DCHF1 CHF Correlation

Time (sec)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

PROPRIETARY
DUKE POWER CO.

Table 18 (Cont'd)

BWCMV CHF Correlation

Time (sec)	Mass Flux at MDNBR ($Mlbm/hr-ft^2$)	Pressure Drop up to MDNBR
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

DCHF1 CHF Correlation

Time (sec)	Mass Flux at MDNBR ($Mlbm/hr-ft^2$)	Pressure Drop up to MDNBR
0.0		
0.8		
1.6		
2.4		
3.2		
4.0		

Table 19

McGuire and Catawba Nuclear Stations
Axial Node Size Sensitivity Study Results Comparison
Inlet Temperature Transient Case

BWCMV CHF Correlation

Time (sec)	MDNBR (BWCMV)	DNBR at Axial Location (in)
0.00		
0.84		
1.68		
2.53		
3.37		
4.00		

DCHF1 CHF Correlation

Time (sec)	MDNBR (DCHF1)	DNBR at Axial Location (in)
0.00		
0.84		
1.68		
2.53		
3.37		
4.00		

BWCMV CHF Correlation

Time (sec)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR
0.0		
0.84		
1.68		
2.53		
3.37		
4.00		

DCHF1 CHF Correlation

Time (sec)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR
0.0		
0.84		
1.68		
2.53		
3.37		
4.00		

PROPRIETARY
DUKE POWER CO.

Table 19 (Cont'd)

BWCMV CHF Correlation

Time (sec)	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop up to MDNBR
0.0		
0.84		
1.68		
2.53		
3.37		
4.00		

DCHF1 CHF Correlation

Time (sec)	Mass Flux at MDNBR (Mlbm/hr-ft^2)	Pressure Drop up to MDNBR
0.00		
0.84		
1.68		
2.53		
3.37		
4.00		

PROPRIETARY
DUKE POWER CO.

Table 20

McGuire and Catawba Nuclear Stations
Axial Node Size Sensitivity Study Results Comparison
Inlet Flow Transient Case

BWCMV CHF Correlation

Time (sec)	MDNBR (BWCMV)	DNBR at Axial Location (in)
0.00		
0.89		
1.78		
2.67		
3.56		
4.00		

DCHF1 CHF Correlation

Time (sec)	MDNBR (DCHF1)	DNBR at Axial Location (in)
0.00		
0.89		
1.78		
2.67		
3.56		
4.00		

BWCMV CHF Correlation

Time (sec)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR
0.0		
0.89		
1.78		
2.67		
3.56		
4.00		

DCHF1 CHF Correlation

Time (sec)	Enthalpy at MDNBR (Btu/lbm)	Void Fraction at MDNBR
0.00		
0.89		
1.78		
2.67		
3.56		
4.00		

PROPRIETARY
DUKE POWER CO.

Table 20 (Cont'd)

BWCMV CHF Correlation

Time (sec)	Mass Flux at MDNBR ($Mlbm/hr\text{-}ft^2$)	Pressure Drop up to MDNBR
0.0		
0.89		
1.78		
2.67		
3.56		
4.00		

DCHF1 CHF Correlation

Time (sec)	Mass Flux at MDNBR ($Mlbm/hr\text{-}ft^2$)	Pressure Drop up to MDNBR
0.00		
0.89		
1.78		
2.67		
3.56		
4.00		

Table 21

Oconee Nuclear Station
Axial Node Size Sensitivity Study
Results Comparison

Power Transient Case

Time	MDNBR (BWC)			Axial Location at MDNBR (in.)		
(sec.)	M1*	M2*	M3*	M1	M2	M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						

Pressure Transient Case

Time	MDNBR (BWC)			Axial Location at MDNBR (in.)		
(sec.)	M1*	M2*	M3*	M1	M2	M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						

* M1 - [ ] Node Model
M2 - [ ] Node Model
M3 - [ ] Node Model

Table 21 (Cont'd)

Inlet Temperature Transient Case

	MDNBR (BWC)			Axial Location at MDNBR (in.)		
Time (sec.)	M1*	M2*	M3*	M1	M2	M3
0.0						
0.514						
1.029						
1.543						
2.057						
2.571						
3.0						

Inlet Flow Transient Case

	MDNBR (BWC)			Axial Location at MDNBR (in.)		
Time (sec.)	M1*	M2*	M3*	M1	M2	M3
0.0						
0.5						
1.0						
1.5						
2.0						
2.5						
3.0						

Table 22

Oconee Nuclear Station
Solution Axial Damping Factor Sensitivity

Power Transient Case

Time (sec.)	MDNBR (BWC) M1*	MDNBR (BWC) M2*	Axial Location at MDNBR (in.) M1	Axial Location at MDNBR (in.) M2
0.0				
0.5				
1.0				
1.5				
2.0				
2.5				
3.0				

Pressure Transient Case

Time (sec.)	MDNBR (BWC) M1*	MDNBR (BWC) M2*	Axial Location at MDNBR (in.) M1	Axial Location at MDNBR (in.) M2
0.0				
0.5				
1.0				
1.5				
2.0				
2.5				
3.0				

* M1 - 0.9 Damping Factor
M2 - 1.0 Damping Factor

PROPRIETARY
DUKE POWER CO.

Table 22 (Cont'd)

Inlet Temperature Transient Case

Time (sec.)	MDNBR (BWC) M1*	MDNBR (BWC) M2*	Axial Location at MDNBR (in.) M1	Axial Location at MDNBR (in.) M2
0.0				
0.514				
1.029				
1.543				
2.057				
2.571				
3.0				

Inlet Flow Transient Case

Time (sec.)	MDNBR (BWC) M1*	MDNBR (BWC) M2*	Axial Location at MDNBR (in.) M1	Axial Location at MDNBR (in.) M2
0.0				
0.5				
1.0				
1.5				
2.0				
2.5				
3.0				

* M1 - 0.9 Damping Factor
  M2 - 1.0 Damping Factor

Duke Power Company
P.O. Box 33198
Charlotte, N.C. 28242

Hal B Tucker
Vice President
Nuclear Production
(704)373-4531

DUKE POWER

August 3, 1990

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Subject: Catawba Nuclear Station
Docket Numbers 50-413 and -414
McGuire Nuclear Station
Docket Numbers 50-369 and -370
Oconee Nuclear Station
Docket Numbers 50-269, -270 and -287
Topical Report DPC-NE-3000

Attached are formal responses to two questions from ITS (the NRC contractor who is reviewing the subject Topical Report). These questions were discussed in a telephone conversation between Heidi Kormoria of ITS and Gregg Swindlehurst of Duke.

If you require additional information, please call Scott Gewehr at (704) 373-7581.

Very truly yours,

Hal B. Tucker

Hal B. Tucker

SAG/255/lcs

Attachment
Additional Information Concerning
Duke Power Topical Report DPC-NE-3000

1. It is Duke's intention to use the VIPRE core thermal-hydraulic models developed and described in DPC-NE-3000 to perform the core thermal-hydraulic analysis for the FSAR Chapter 15 transients resulting in symmetrical core conditions.

2. For McGuire/Catawba Nuclear Stations, a flow reduction factor of 0.95 will be applied to the hot assembly flowrate to simulate the inlet flow maldistribution during 2-pump operation as in 4-pump operation. The inlet flow maldistribution does not significantly impact the enthalpy rise and MDNBR in the hot channel due to crossflow effects. Studies have shown that when the flow reduction factor is applied to the hot channel, the hot channel flowrate recovers to the value for a uniform inlet flow distribution at approximately 30% of the core height. Since DNBR is typically of concern at or above the middle of the core, there is essentially no impact resulting from the assumed flow reduction factor.

DUKE POWER

August 29, 1991

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555

Subject: McGuire Nuclear Station
Docket Numbers 50-369 and -370
Catawba Nuclear Station
Docket Numbers 50-413 and -414
Oconee Nuclear Station
Docket Numbers 50-269, -270, and -287
Supplemental Information to Assist in Review of
Topical Reports DPC-NE-3000 and DPC-NE-2004

References: 1) DPC-NE-3000, "Thermal-Hydraulic Transient Analysis Methodology," July, 1987
2) DPC-NE-2004, "Core Thermal-Hydraulic Methodology Using VIPRE-01," December, 1988

References 1 and 2 provide, in part, the basis for the Technical Specification changes required to support the startup of McGuire Unit 1 Cycle 8. These topical reports are currently under NRC staff review. During the review, items have been identified which require clarification to assure that appropriate limitations and restrictions on the methodologies are observed. Accordingly, Attachment 1 contains a list of transients which use Statistical Core Design, and Attachment 2 is a compilation of commitments which apply to References 1 and 2.

Please note that Attachment 2 of this supplement contains information which is proprietary to Duke Power Company. Therefore, we request that this report be withheld from public disclosure, in accordance with 10 CFR2.790. Affidavits documenting the proprietary nature of the information in References 1 and 2 were provided with the original submittals, dated January 9, 1989 (DPC-NE-2004) and September 27, 1987 (DPC-NE-3000).

Also please note that approval of these Topical Reports is needed for startup of McGuire Unit 1 Cycle 8 following its upcoming refueling outage. The outage is scheduled to begin in late September, 1991. Cycle 8 is expected to start up in late November or early December.

If there are any questions, please call Scott Gewehr at (704) 373-7581.

Very truly yours,

M. S. Tuckman

M. S. Tuckman
cvr/sag

cc: Mr. T. A. Reed, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 9H3, OWFN
Washington, D. C. 20555

Mr. R.E. Martin, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 9H3, OWFN
Washington, D. C. 20555

Mr. S. D. Ebneter, Regional Administrator
U.S. Nuclear Regulatory Commission - Region II
101 Marietta Street, NW - Suite 2900
Atlanta, Georgia 30323

Mr. P. K. Van Doorn
Senior Resident Inspector
McGuire Nuclear Station

Mr. R. C. Jones
Reactor Systems Branch
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Mr. W. T. Orders
NRC Resident Inspector
Catawba Nuclear Station

DPC-NE-3000 NRC Restrictions and Limitations (VIPRE)

The evaluation of the methodology in this report is subject to the approval of DPC-NE-2004. The applicable restrictions in the application of this topical report are listed below:

(1) Determination of acceptability is based upon review of selection of models/correlations for symmetric transients only. For asymmetric transients, DPC intends to use other models not described in this submittal. Therefore, DPC submits for review, a full description, explanation and justification of its asymmetric models.

(2) Studies presented for McGuire/Catawba plants in this report are performed using design data for the Mark-BW fuel assembly. Although the approach described in this report is acceptable, its applicability to analysis of transition cores must be justified.

(3) Restrictions and user guidelines cited in the VIPRE-01 SER with respect to the CHF correlation and the time step size remain unchanged. DPC must provide discussion of conformity to these guidelines.

(4) Since the use of the BWCMV CHF correlation with the VIPRE-01 computer code has not been approved, before it is used in future analysis, DPC must submit its justification for NRC review and approval.

(5) Whenever DPC intends to use other CHF correlations, power distribution, fuel pin conduction model or any other input parameters and default options which were not part of the original review of the VIPRE-01 code, DPC must submit its justification for NRC review and approval.

(6) Core bypass flow must be determined and justified on cycle-by-cycle bases.

Response

(1) It is DPC's intention to use the VIPRE core thermal-hydraulic models developed in DPC-NE-3000 to perform the core thermal-hydraulic analysis for the FSAR Chapter 15 transients resulting in symmetrical core conditions. For transients resulting in asymmetric core conditions (rod ejection and steamline break transients), asymmetric models are utilized. DPC has submitted DPC-NE-3001 which documents the full description, explanation, and justification of the asymmetric models for NRC to review.

(2) In response to the NRC questions on DPC-NE-3000, dated July 25, 1989, DPC stated that for the transition core, a steady-state transition core DNBR penalty will be applied to the transient analysis by raising the MDNBR acceptance criterion. This transition core DNBR penalty is described above for DPC-NE-2004, Item 2.

(3) DPC will abide by the restrictions and user guidelines cited in the VIPRE-01 SER (Page 28) with respect to the CHF correlation. As stated on

Page 29 of the VIPRE-01 SER, if a profile fit subcooled boiling model (such as Levy and EPRI models) which was developed based on steady state data is used in a boiling transient, care should be taken in the time step size used for transient analysis to avoid a Courant number less than 1. DPC will also abide by this condition.

(4) DPC has submitted the justification of the use of the BWCMV CHF correlation with the VIPRE-01 computer code in DPC-NE-2004 for NRC review and approval.

(5) Whenever DPC intends to use other CHF correlations, power distributions, fuel pin conduction model or any other input parameters and default options which were not part of the original review of the DPC-NE-3000, DPC will submit its justification for NRC review and approval. DPC has already demonstrated this commitment in the report DPC-NE-3001. Details for transients not discussed in DPC-NE-3001 are provided in DPC-NE-3002.

(6) The core bypass flow will be determined on a cycle-by-cycle basis. However, a conservative bounding core bypass flow value will be used for the core thermal-hydraulic analysis. Additional details are provided above for DPC-NE-2004, Item 6.

DPC-NE-3000 NRC Retrictions and Limitations (RETRAN)

DPC's RETRAN models for the Oconee and McGuire/Catawba nuclear power plants are generally acceptable; however, each licensing analysis must be reviewed to assure that it contains adequate conservatisms to produce conservative results, and in particular DPC must demonstrate that:

(1) its steam generator secondary side modeling (particularly for Oconee) produces conservative results for each such licensing transient;
(2) its nodalization for the balance of plant is conservative;
(3) its selection of RETRAN internal models and correlations is conservative; and
(4) its RETRAN control systems are accurate and conservative.

Response

(1) With regard to McGuire (and Catawba), steam generator secondary-side modeling is as described and benchmarked in DPC-NE-3000. Conservatism is obtained by selecting conservative inputs and modeling for initial conditions (SG level, pressure, mass), boundary conditions (MFW, AFW, main turbine, steam relief), setpoints including allowances for errors, and not taking credit for non-safety equipment. These modeling aspects are selected for each transient based on experience or by determining the appropriate direction for the conservative allowance (high/low, max/min) to be applied by explicit analysis (sensitivity analyses). The level of attention paid to modeling details ensures a conservative overall result. Details for each FSAR Chapter 15 transient for McGuire and Catawba are presented in DPC-NE-3001 and DPC-NE-3002.

(2) This response interprets "balance of plant" to encompass auxiliary systems beyond the NSSS. The important balance of plant systems that are typically involved in FSAR transients includes main feedwater, auxiliary feedwater, main steam, steam dump, and ECCS. The interactions of these systems with the NSSS, including the impact of operator action, are typically modeled as boundary conditions such as flow vs. time or pressure. Often the RETRAN trip logic and control system models are used to accurately and conservatively represent the dynamic behavior that occurs during a specific transient. The level of detail presented in DPC-NE-3001, DPC-NE-3002, and FSAR Chapter 15 depends on the importance to the transient response. DPC-NE-3001 and DPC-NE-3002 describe how the balance of the plant is conservatively modeled for each transient.

(3) The selection of RETRAN internal models and correlations is as described in DPC-NE-3000 unless specifically described in DPC-NE-3001 or DPC-NE-3002. These correlations and models have been demonstrated in DPC-NE-3000 to be appropriate for simulating transients at McGuire and Catawba. Conservatism is introduced into each analysis on a case-by-case basis by selection of initial and boundary conditions as described in DPC-NE-3001 and DPC-NE-3002.

(4) Accuracy with regard to RETRAN control systems is ensured by the great level of modeling control provided by the RETRAN control models options, and by the same attention to detail and quality assurance that is part of safety-related work. Modeling compromises are rarely encountered, such that the exact control system response can be obtained. Any modeling limitation can be offset by appropriate conservative allowances. Furthermore, control system response is only credited if it serves to negatively impact the transient. Each transient is individually evaluated with respect to control system modeling. Details for each transient are provided in DPC-NE-3001 and DPC-NE-3002.

<u>References</u>

DPC-NE-2004: McGuire and Catawba Nuclear Stations, Core Thermal-Hydraulic Methodology Using VIPRE-01, December 1988.

DPC-NE-3000: Oconee, McGuire, and Catawba Nuclear Stations, Thermal-Hydraulic Transient Analysis Methodology, Revision 2, February 1990.

DPC-NE-3001: McGuire and Catawba Nuclear Stations, Multidimensional Reactor Transients and Safety Analysis Physics Parameters Methodology, Revision 1, June 1991.

DPC-NE-3002: McGuire and Catawba Nuclear Stations, FSAR Chapter 15 System Transient Analysis Methodology, August 1991.

DUKE POWER

November 5,1991

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555

Subject: McGuire Nuclear Station
Docket Numbers 50-369 and -370
Catawba Nuclear Station
Docket Numbers 50-413 and -414
Oconee Nuclear Station
Docket Numbers 50-269, -270, and -287
Final Response to Questions Regarding the Topical Reports Associated with the M1C8 Reload Package

References:
1) Letter, H. B. Tucker to NRC, January 9, 1989. (DPC-NE-2004 submittal)
2) Letter, H. B. Tucker to NRC, September 29, 1987. (DPC-NE-3000 submittal)
3) Letter, H. B. Tucker to NRC, January 29, 1990. (DPC-NE-3001 submittal)
4) Letter, M. S. Tuckman to NRC, September 25, 1991. (Reaffirmation of Proprietary Affidavit for DPC-NE-2004)
5) Letter, M. S. Tuckman to NRC, September 25, 1991. (Reaffirmation of Proprietary Affidavit for DPC-NE-3000)

On October 7 and 8, 1991, representatives of Duke Power met with NRC Staff and contract reviewers to discuss outstanding issues associated with three Topical Reports (References 1, 2, and 3), which are currently undergoing review. At this meeting, and during various telephone conference calls subsequent to the meeting, questions were identified which required additional information or clarification. Attached are formal responses to each of the questions. The attached information should resolve all outstanding issues related to the review of Topical Reports DPC-NE-2004, -3001, and -3000.

Please note that some of the information is identified as

proprietary, and should be withheld from public disclosure pursuant to 10 CFR2.790. Affidavits attesting to the proprietary nature of the information have been provided (References 3, 4, and 5).

Also, please note that while aspects of the referenced Topical Reports may be applicable to all three of Duke's nuclear stations, approval of the Reports is required for McGuire Unit 1 Cycle 8; currently scheduled for startup in early December, 1991.

If there are any questions, please call Scott Gewehr at (704) 373-7581.

Very truly yours,

H. B. Tucker

cc: Mr. T. A. Reed, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

Mr. R. E. Martin, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

Mr. L. A. Wiens, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN

Mr. S. D. Ebneter, Regional Administrator
U.S. Nuclear Regulatory Commission - Region II
101 Marietta Street, NW - Suite 2900
Atlanta, Georgia 30323

ATTACHMENTS

Attachment 1: A discussion of the adequacy of the McGuire/Catawba steam generator modeling in DPC-NE-3000 with respect to conservative prediction of primary-to-secondary heat transfer for transients which involve U-tube uncovery.

Attachment 2: Responses to informal questions on DPC-NE-3002, as understood by Duke Power, regarding issues that were not adequately addressed at the meeting, that were requested by the NRC to be formally docketed, or that arose in subsequent telephone conversations.

Attachment 3: Responses to informal questions on Chapter 15 markups, as understood by Duke Power, regarding issues that were not adequately addressed at the meeting, that were requested by the NRC to be formally docketed, or that arose in subsequent telephone conversations.

Attachment 4: A response to an additional question on DPC-NE-2004.

Attachment 5: A set of markups to DPC-NE-3001; due to questions asked at the meeting, and other corrections.

Attachment 6: A set of markups to DPC-NE-3002; due to questions asked at the meeting, and other corrections.

Attachment 1

McGuire/Catawba RETRAN Model
Impact of Steam Generator Tube Bundle Uncovery on Heat Transfer

The McGuire/Catawba RETRAN model described in DPC-NE-3000 models the steam generator secondary with [ ] volumes. A question has been raised regarding the validity of this model for situations where the secondary inventory decreases and the tube bundle becomes uncovered. In this situation the heat transfer in the uncovered portion of the tube bundle would significantly degrade. The following describes analytical studies which have been performed to assess the validity of the RETRAN model in this situation.

During power operation the McGuire/Catawba steam generators maintain a significant recirculation flow in the tube bundle region. Saturated liquid is separated in the swirl vane separators and flows downward in the downcomer annulus where it enters the tube bundle at the bottom. Feedwater is mainly delivered to the preheater, where it is preheated before entering the remainder of the tube bundle. Due to heat transfer from the tubes, the water is boiled as it flows upward in the tube bundle. The void fraction increases with elevation, but a two-phase mixture is present during recirculation. In this mode of operation the RETRAN model [ ] of the tube bundle region.

If the steam generator inventory decreases due to a loss of feedwater, the reactor will trip on low-low steam generator level. Recirculation flow continues provided that a significant steaming rate exists, and that the steam generator inventory is not significantly depleted. With sustained loss of inventory, recirculation will eventually stop and the tube bundle will uncover. When this occurs the tube bundle region will have a more defined mixture level, above which the void fraction is unity. Heat transfer below the mixture level remains effective, but above the mixture level where convection to steam exists, it is degraded. Depending on the heat load some depth of tube bundle coverage is necessary to maintain an adequate heat sink.

[ ]

PROPRIETARY
DUKE POWER CO.

By comparing the results of the [ ] and tube bundle uncovery can be assessed. The FSAR Chapter 15 loss of main feedwater event is analyzed since it results in the greatest depletion of steam generator inventory, and therefore will be the most impacted by tube bundle uncovery. The two models were initialized and the loss of feedwater transients were analyzed to obtain a meaningful comparison. The post-trip phase of the analysis is of interest since it includes the period of tube bundle uncovery.

[Refer to pp. 167-182 of the 10/7&8/91 meeting handout. This handout was formally submitted to the NRC Document Control Desk by letter dated October 16, 1991.]

The [ ] LOFW analysis results are shown on pp. 167-177. The integral effect of SG heat transfer is best illustrated by T-cold on p. 173. Following the reactor trip, T-cold rem ery stable at 570°F. This indicates that the [ ] the actual heat transfer has significantly decreased immediately after reactor trip, as is expected.

The [ ] LOFW analysis results are shown on pp. 178-182. The integral effect of SG heat transfer, represented by T-cold, is shown on p. 181. T-cold [ ] are transferring significant energy. The effect of tube bundle uncovery on heat transfer is characterized by these results. The results of the [ ] model demonstrates that the steam generator inventory is sufficient to remove decay heat for the loss of main feedwater transient.

Based on the comparison of the predictions of these two models, it can be concluded that the [ ] model adequately predicts the FSAR loss of main feedwater transient. Since this transient is the limiting event with regard to tube bundle uncovery, it can also be concluded that the [ ] model is appropriate for all loss of heat sink events (FSAR 15.2).

DUKE POWER

March 11, 1992

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D. C. 20555

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
McGuire Nuclear Station
Docket Nos. 50-369, -370
Catawba Nuclear Station
Docket Nos. 50-413, -414
Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000

Reference: November 15, 1991 letter from T. A. Reed (NRC) to H. B. Tucker (DPC), Safety Evaluation on Topical Report DPC-NE-3000, "Thermal-Hydraulic Transient Analysis Methodology" (TACs 73765/73766/73767/73768)

In response to Generic Letter 83-11, Duke Power Company submitted the topical report DPC-NE-3000, "Thermal-Hydraulic Transient Analysis Methodology," to the NRC in September of 1987. This report describes the development of thermal-hydraulic simulation models of the Oconee, McGuire, and Catawba Nuclear Stations using the RETRAN-02 and VIPRE-01 computer codes. The objective of the report is to demonstrate the abilities of Duke Power Company to perform non-LOCA thermal-hydraulic transient analyses.

The referenced letter issued the Safety Evaluation Report (SER) for DPC-NE-3000. The SER approved the use of the VIPRE-01 computer code models for Oconee, McGuire, and Catawba Nuclear Stations and the RETRAN-02 computer code models for McGuire and Catawba Nuclear Stations. However, the SER stated that "the RETRAN-02 models for Oconee have not been shown to be adequate for best estimate nor licensing calculations, and are therefore not approved for either of these applications."

On January 14, 1992, Duke Power Company met with the NRC and the contracted technical reviewers of DPC-NE-3000, International Technical Services, Incorporated (ITS), to resolve the technical issues associated with the Oconee RETRAN-02 model. During this meeting, Duke Power Company presented additional technical

information justifying the adequacy of the Oconee RETRAN-02 model. Attachment 1 provides responses to questions raised by the NRC and ITS during this meeting. The handouts from the meeting are included as Attachment 2.

Duke Power Company believes that the additional information submitted by this letter resolves the remaining technical issues associated with the Oconee RETRAN-02 model. Thus, Duke Power Company requests that a supplement to the DPC-NE-3000 SER be issued approving the Oconee RETRAN-02 model.

In accordance with 10 CFR 2.790, Duke Power Company also requests that the attached information relating to DPC-NE-3000 be considered proprietary. Information supporting this request was included in the affidavit which accompanied the original submittal of DPC-NE-3000, dated September 29, 1987, and reaffirmed by letter and affidavit dated September 20, 1991.

If we can be of further assistance in your review please call Scott Gewehr at (704) 373-7581 or Gregg Swindlehurst at (704) 373-5176.

Very truly yours,

Hal B. Tucker

H. B. Tucker

QA3000/sag

PROPRIETARY
DUKE POWER CO.

ATTACHMENT 1

The main concern of the NRC and ITS is the ability of the Oconee RETRAN model to predict the primary and secondary side performance of the once through steam generator (OTSG). Thus, the January 14, 1992 Duke Power Company (DPC) presentation focused on the OTSG model. During the January 14, 1992 meeting, the NRC and ITS asked several questions regarding the Oconee RETRAN model. The objective of this attachment is to document the DPC responses to these questions. Paraphrased versions of the questions are given along with the DPC responses.

1) The benchmarks in DPC-NE-3000 indicate that the Oconee RETRAN model overpredicts primary-to-secondary heat transfer following reactor trip. How will this overprediction of heat transfer be accounted for in the FSAR safety analyses?

In most of the benchmark transients, the Oconee RETRAN model consistently overpredicts primary-to-secondary heat transfer immediately following a reactor trip. This is seen as an underprediction of T-hot, T-cold, RCS pressure, pressurizer level, and a more rapid steam generator level decrease when compared to plant data. The reason the Oconee RETRAN model overpredicts the post-trip primary-to-secondary heat transfer is that the model tends to couple the primary system and secondary system too closely during low flow steam generator conditions. This tight coupling is due to an overprediction of the boiling length on the secondary side as the steam generators boil down to their post-trip setpoints. The overprediction of the boiling length is [ ]

Even so, the results of the benchmark work have shown that this anomalous behavior in the steam generators during the time they are boiling down to their post-trip setpoints has little impact on the overall transient response predicted by the model. It should be noted that the benchmark results indicate that the Oconee RETRAN model accurately predicts primary-to-secondary heat transfer prior to reactor trip. For example, in the November 10, 1979 overcooling following a loss of Integrated Control System (ICS) power benchmark (see Section 4.2.2 of DPC-NE-3000), a reactor trip did not occur until 55 seconds into the event. During this 55 second time period, a reactor runback was occurring due to the loss of a main feedwater pump. The plant data indicates that T-cold increased by about 11°F during this time period. During the same time period, RETRAN predicted an increase in T-cold of about 15°F. It should be noted that the RETRAN T-cold prediction was not adjusted to account for the approximately 5 second time constant associated with the cold leg RTDs. If this time constant were included in the model, the RETRAN prediction of the cold leg temperature response would be very close to the plant data. Thus, DPC believes that the Oconee RETRAN model accurately predicts primary-to-secondary heat transfer prior to reactor trip.

The overprediction of post-trip heat transfer must be accounted for when performing FSAR Chapter 15 safety analyses. For overcooling transients, such as a steam line break

accident, this effect will be conservative since the initial rate of overcooling will increase. For rapid transients, such as a loss of RCS flow or rod ejection accident, the acceptance criteria are challenged during the first few seconds of the accident. Since these transients are very short in duration, the prediction of steam generator heat transfer will essentially have no impact on the results.

An overprediction of primary-to-secondary heat transfer can have a non-conservative impact on some overheating events, such as a loss of main feedwater (LOMFW) event. During this event, the acceptance criteria are not challenged within a few seconds of reactor trip. For these overheating events, the overprediction of post-trip primary-to-secondary heat transfer must be addressed by conservative modeling assumptions. The primary concern during a LOMFW event is that the loss of secondary-side cooling does not lead to a water-solid condition in the pressurizer. Water-solid conditions in the pressurizer will not be challenged until after the secondary side inventory has boiled down to the post-trip control setpoint. Although emergency feedwater (EFW) is actuated upon the loss of the main feedwater pumps, the control valves remain closed until the steam generator level decreases below the post-trip control setpoint. The fact that the Oconee RETRAN model boils down to the control setpoint earlier than is indicated by plant data could result in premature injection of EFW. An additional delay in the EFW start time could be incorporated in the analysis to ensure that the EFW boundary condition conservatively bounds the expected plant response. Thus, the total delivered EFW flow would be less than or equal to a case which accurately predicted the initial boil off rate in the steam generators.

In summary, the overprediction in post-trip heat transfer either is conservative, does not matter, or can be accommodated by conservative modeling.

2) Pages 28-43 of Attachment 2 present the results of a reactor trip transient analysis comparing the [ ] volume steam generator model described in DPC-NE-3000 to a [ ] volume steam generator model. Would one of the FSAR accident analyses result in a more severe secondary side transient response than in the transient used for the [ ] volume vs. [ ] volume steam generator sensitivity study?

The analysis of a reactor trip does result in a secondary side transient that is severe and comparable to those in the FSAR. The largest change in the secondary parameters, such as main feedwater flow, steam generator level, and steam generator pressure, occurs following a reactor trip. Main feedwater is isolated until approximately 150 inches of secondary inventory are boiled off. At this time, the control valves open to maintain steam generator level at the post-trip control setpoint. Steam generator pressure is normally at about 910 psig during full power operation. An increase of as much as 200 psi occurs after reactor trip as the main steam safety valves lift and reseat to control steam generator pressure. The magnitude of the changes seen in the secondary side parameters is approximately the same in the FSAR analyses. For those FSAR accidents in which a reactor trip does not occur immediately, the secondary response remains relatively stable as compared to the response following a reactor trip.

The only non-LOCA accident in Chapter 15 of the Oconee FSAR which would result in a more severe secondary-side response is the main steam line break transient. As was discussed at the January 14, 1992 meeting, DPC will use a [ ] for this accident. The revised model, described on page 27 of Attachment 2, will ensure a conservative prediction of the steam line break. The details of this model are beyond the scope of DPC-NE-3000.

3) Pages 13-14 of Attachment 2 compare the Oconee RETRAN model nodalization to nodalizations used by other organizations. Considering the differences in computer codes used by these organizations, what does this comparison illustrate?

DPC acknowledges that the computer codes listed in this comparison do differ in their fundamental models from the RETRAN02 code. The CRAFT2 and TRAP2 codes use a drift flux model to account for phase separation in the tube region of the steam generators. This model determines the drift velocity at the junction between two control volumes. A bubble rise model is applied to the control volume which contains the mixture level. The control volumes below the volume which contains the mixture level are essentially treated as HEM volumes. RELAP5 is a six equation, two fluid code, while the Oconee RETRAN model is [ ]

The comparison of the Oconee RETRAN model nodalization to nodalizations used by other organizations was included in the presentation for two reasons. First, the Oconee RETRAN model was originally developed based on geometry considerations, and to a lesser extent, the level of detail used by other organizations. Thus, this comparison does provide a historical perspective on the Oconee model development and does illustrate that the level of detail used in the Oconee model is comparable to the level of detail used by other organizations.

Secondly, for non-LOCA analyses, the comparison does illustrate that the Oconee RETRAN model of the reactor vessel is [ ] the models used by other organizations. For example, the TRAP2 code is primarily used for steam line break accident analyses. Little voiding, if any, occurs in the reactor vessel during this accident. Thus, differences in the computer code constitutive equations under single phase conditions are relatively minor during this accident. For this reason, it is reasonable to conclude that the level of detail in the Oconee RETRAN model of the reactor vessel [ ] used by other organizations.

4) Given the fact that steam generator fouling impacts inventory, how is the initial steam generator inventory for an analysis determined?

No plant data exists related to steam generator inventory. DPC relies on design predictions from B&W steam generator performance computer codes to define the

inventory at a given power level. These predictions are based on a clean steam generator. At full power, the B&W performance codes predict a total inventory of about [ ] lbs. Approximately [ ] pounds are in the tube region and [ ] pounds are in the downcomer.

The RETRAN code is initialized such that the feedwater flow rate, inlet temperature, steam generator pressure, and steam exit temperature agree with plant data. These parameters are critical in determining the inventory in the tube region. In order to achieve these conditions, a [ ] is necessary. This [ ] on the steam generator tubes. Using this approach, the full power initialization results in a tube region inventory of about [ ] pounds. During the initial operation of Oconee, and following chemical cleaning of the steam generators, the operate range level at full power was about 55%. Thus, to model a clean generator, the last step in the initialization process is to [ ] to achieve an operate level of 55%. The resultant downcomer inventory associated with this level is about [ ] pounds. Thus, the total full power steam generator inventory in the Oconee RETRAN model is in close agreement with the B&W design code predictions.

Steam generator fouling increases the pressure drop in the tube region. Thus, more inventory is required in the downcomer to offset this larger pressure drop. The Oconee FSAR steam line break analysis assumes a fouled inventory of 55,000 pounds. B&W determined this value by [ ] exits at the outlet of the steam generator. With these assumptions, the inventory is distributed with about [ ] pounds in the downcomer and 20,000 pounds in the tube region. Thus, it is theoretically possible for the inventory in the steam generator at full power to range from [ ] pounds.

For FSAR accident analyses, DPC would adjust the initial inventory to ensure a conservative prediction of primary-to-secondary heat transfer. For example, undercooling events from full power would use an inventory representative of a clean steam generator and overcooling accidents would use an inventory representative of a fouled steam generator.

5) Pages 45 - 57 of Attachment 2 provide the results of a steam line nodalization study. How does the difference in heat removal rates between approximately 5 and 25 seconds affect the primary system response?

Upon further review of this figure, DPC determined that there was an error in the plot. The plot on page 55 was determined by adding the heat removal rates of [ ] heat conductors that are in the model. This figure is corrected in Attachment 2 and indicates that very little difference actually exists in the heat removal rates over this time period. As was discussed in the meeting, differences in the predictions between the two models over the first 20 seconds are primarily due to slight timing differences in the opening of the main steam relief valves. These timing

differences are a direct result of slightly different pressure predictions in the steam lines associated with the two models. Following 20 seconds, the small offset in primary system parameters is due to the initial difference in steam generator inventory of about 1000 pounds.

6) Do the high steam velocities in the steam generator support the use of [ ] model?

The maximum average velocity of the saturated and superheated steam will be about 19.1 feet per second, at 100% full power. The average velocity of the steam increases from 1.4 feet per second at the bottom of the tube region to its maximum value in the superheat region. In the portion of the boiling region where the void fractions exceed 0.95, the force of the steam flow tends to accelerate the remaining water enough that the water velocities begin to approach the steam velocities. In this region [ ] where about two thirds of the heat transfer occurs, the mixture [ ] conditions.

The RETRAN-02 use of [ ] resulting in an overprediction of the heat transfer in this region. This is a localized effect and does not significantly impact the ability of the RETRAN code to predict global parameters at full power conditions. The [ ] does cause the RETRAN OTSG model to overpredict primary-to-secondary heat transfer following reactor trip. As was described in the response to Question 1, DPC will conservatively account for the overprediction of post-trip heat transfer in the FSAR accident analyses, as necessary.

7) How does the macro or integral OTSG validation approach verify that microscopic operating characteristics of the OTSG, such as the aspirator flow, are appropriately modeled?

No plant data exist which would allow one to validate certain microscopic aspects of steam generator performance. For example, no data exist regarding the transient aspirator flow rate, steam generator inventory, or secondary-side tube region void fraction profile. The following plant data are available to assess transient steam generator performance:

- Main feedwater flow rate
- Steam generator level
- Feedwater inlet temperature
- Steam generator pressure
- Steam exit temperature
- Primary side inlet temperature (T-hot)

- Primary side outlet temperature (T-cold)

The Oconee RETRAN OTSG model was validated by performing a number of benchmarks. The above plant data were compared to the code predictions to assess the adequacy of the model. For example, the aspirator is simply a 4 inch cylindrical gap between the downcomer and the tube region. The steam flow from the tube region into the downcomer preheats the feedwater to saturated conditions before it enters the tube region. This is known from downcomer temperature measurements and pressure drop data taken during the first of a kind (FOAK) testing on Oconee Unit 1. Thus, the inventory in the downcomer is a function of the aspirator flow rate and main feedwater flow rate. Steam generator operate range level also provides an indication of the inventory in the downcomer. Many of the transient benchmarks use main feedwater flow rate as a boundary condition. Thus, since the transient benchmarks demonstrate that the Oconee RETRAN model accurately predicts changes in operate range level, the model must be doing a reasonable job of predicting the transient flow rate through the aspirator port.

Similar arguments can be made regarding transient predictions of primary-to-secondary heat transfer and steam generator inventory. The primary-to-secondary heat transfer is a strong function of the tube region boiling length and the primary-to-secondary temperature difference. If, during a benchmark, the steam generator pressure response matches plant data, the differences in primary-to-secondary heat transfer can be attributed to differences between the actual and predicted boiling length response. A comparison of the predicted and actual steam generator level responses also enables one to judge the accuracy of the predicted boiling length and inventory response during a transient. Thus, although no plant data exist for the transient boiling length or inventory responses, an evaluation of the global steam generator plant data enables one to assess whether or not the model is accurately predicting the boiling length during a transient.

In addition, the Oconee RETRAN model simulates the downcomer with [ ] The adequacy of the downcomer model is verified by comparing the predicted level and inventory with available plant data and design data. The transient response of the downcomer inventory is assessed by comparing trends in the plant operate range level with the operate range level in Oconee RETRAN model. It should be noted that the operate range level in the Oconee RETRAN model is a Δp based level that is temperature compensated based on the algorithm used in the plant instrumentation. Thus, a comparison of the RETRAN operate level response to the plant operate range level response demonstrates that the downcomer model is adequate.

In summary, DPC believes that a comparison of plant data to code predictions is the most effective way to validate the steam generator model. The benchmarks in DPC-NE-3000 demonstrate that the Oconee RETRAN model is capable of modeling both steady-state and transient steam generator performance.

8) What are the heat transfer coefficients, modes, and rates in the tube region of the steam generator?

The feedwater flow is sprayed into the top of the steam generator downcomer at a temperature of about 460°F. Steam from the tube region is drawn through the aspirator port, which is also located near the top of the downcomer. The steam flow through the aspirator port preheats the feedwater to create a two phase mixture in the downcomer. The downcomer fluid enters the tube region through ports just above the lower tube sheet. Primary-to-secondary heat transfer boils off the inventory achieving about 55°F of superheat at the exit of the steam generator. For a full power initialization, the following secondary side heat transfer characteristics are predicted by the Oconee RETRAN model:

In addition, pages 23-24 of Attachment 2 provide primary and secondary temperature profiles in the OTSG.

9) How will control system modeling be performed for conservative FSAR safety analyses?

The control system models in the RETRAN-02 code allow one to accurately model the proportional plus integral type controllers typically used at Oconee Nuclear Station. In order to develop an accurate control system, DPC typically uses plant calibration procedures to establish the gains and biases. This approach results in a very accurate representation of the controllers used in the plant. For example, Figure 1 compares the Oconee RETRAN model of the Turbine Bypass System valve position demand to plant data. This comparison is not in DPC-NE-3000. The turbine bypass valves control steam generator pressure during a runback or post-trip. Valve position is controlled by the error between the indicated steam generator pressure and the setpoint. In this benchmark, steam generator pressure is used as a boundary condition for the model. The predicted valve position demand for this transient closely matches the valve position demand from the plant data. The accuracy of the Oconee RETRAN control systems is also supported by the plant benchmarks in DPC-NE-3000. Since control systems significantly impact the boundary conditions in a number of these benchmarks, the

agreement between RETRAN and the plant data would not be possible without accurate control system models.

The FSAR accident analyses will incorporate conservative assumptions regarding control system performance. Control systems are assumed to function only if their operation will make the transient more severe or if such operation is necessary for the transient to occur at all. No credit will be taken for control system operation which makes the transient less severe. Control systems are generally assumed to operate with nominal gains, setpoints, and time constants. Process parameter indications which are inputs to control systems are conservatively adjusted to account for instrument uncertainties. For example, increased attenuation of the neutron flux due to a decrease in the downcomer temperature is modeled during overcooling accidents. In summary, any FSAR analyses performed by DPC will conservatively account for control system performance. For a large majority of the FSAR accident analyses, the most conservative assumptions are for the control systems to be in manual and inactive.

10) Why is there an offset in the cold leg temperatures in the loss of main feedwater benchmark (see Section 4.1.1 of DPC-NE-3000)?

The plant data from this event showed a 3 to 4°F difference in cold leg temperatures throughout the transient. It is believed that this difference in cold leg temperature readings was due to the Loop A narrow range cold leg RTD being out of calibration. It should be noted that the cold leg RTDs do not feed into the Reactor Protective System at Oconee; they are only used by the ICS to control Tave. The belief that the RTD was out of calibration is supported by the fact that the plant data showed steam generator pressure, steam generator level, and feedwater flow in each loop to be nearly equal throughout the transient.

When the plant operates with a cold leg temperature difference (ΔTc) that is greater than zero, total feedwater flow is divided between the two loops such that one steam generator will receive more feedwater flow, thus increasing heat removal and lowering T-cold in that loop. Based on current plant operating data, the difference between feedwater flows to the two loops would be approximately 0.078E6 lbm/hr for each degree difference in cold leg temperatures. This would result in a predicted difference of about 0.265E6 lbm/hr for the ΔTc of 3.4°F seen before reactor trip in the benchmark data. However, the benchmark data shows a much smaller difference in feedwater flows between the loops of 0.077E6 lbm/hr. Thus, the feedwater flows in the benchmark data support the conclusion that the difference in cold leg temperatures was due to a calibration error in one of the RTDs.

In addition, an energy balance was performed using plant conditions before the reactor trip. For the given RCS flow rate and heat generation rate, the temperature difference across the core is predicted to be 44.3°F. The Loop B plant data showed a ΔT across the core of 44.5°F, whereas Loop A showed 47.4°F. Another energy balance was performed using plant conditions five minutes after reactor trip. Again, the Loop B temperature

difference across the core was in much better agreement with the predicted value than Loop A. Therefore, it is believed that the difference in cold leg temperatures seen in the benchmark data was due to a calibration error in the Loop A cold leg RTD.

11) Why is there a difference in the slope of the OTSG primary side axial temperature profile and what is the impact of this slope difference on the transient analyses?

Pages 23-24 of Attachment 2 compare RETRAN predictions of the primary and secondary axial temperature profile to design information in the OTSG functional specifications. The design data in the functional specifications is approximately 25 years old. Based on the questions asked during the meeting, DPC researched the availability of more recent steam generator performance data. Since no plant data exists regarding these axial temperature profiles, the only comparison that is possible is against the predictions of another design code. B&W has benchmarked its design code, VAGEN, to test data from the 19 tube steam generator at Alliance Research Center (ARC). The VAGEN code was developed in the 1970s and has replaced the design predictions used to develop the original plots in the OTSG functional specifications.

The ARC data and VAGEN code predict a boiling length of about [ ] feet versus the [ ] foot boiling length given in the functional specifications. Thus, the RETRAN boiling length of about [ ] feet is in reasonable agreement with the current vendor design predictions. Figure 2 compares the secondary side quality profile in RETRAN to the profile predicted by VAGEN. The [ ] in RETRAN do predict more heat transfer in the upper portion of the boiling region than is predicted by the VAGEN code. However, this difference does not significantly impact the predictive capabilities of the RETRAN code. The benchmarks indicate that, with the exception of overpredicting primary-to-secondary heat transfer post-trip, the RETRAN model accurately predicts the steam generator performance under steady-state and transient conditions. As was discussed in the response to Question 1, DPC will conservatively account for the post-trip overprediction of heat transfer for any FSAR accident analyses.

12) What is the impact of the pressurizer inter-region heat transfer coefficient on the pressurizer spray cycling in the loss of main feedwater benchmark (Section 4.1.1 of DPC-NE-3000)?

A non-equilibrium pressurizer is used for this analysis, with the pressurizer walls represented by [ ] passive heat conductors. Because the inter-region heat transfer coefficient [ ] RETRAN-02 will predict that the RCS [ ] than the plant during pressurizer insurges. However, the differences between the RETRAN-02 and plant RCS pressure responses are not solely due to [ ] An important consideration is the comparison of the pressurizer insurge rates as indicated by pressurizer level.

Pages 67 and 68 of Attachment 2 show that the RETRAN-02 prediction of pressurizer level and RCS pressure agree well with the plant data during the time of repressurization to the spray setpoint. However, after reaching the spray setpoint (at 450 seconds), RETRAN-02 predicts a faster spray cycling frequency than the plant data. Between 400 and 900 seconds, the RCS temperatures are fairly stable, letdown is isolated, and the HPI System is providing makeup flow to compensate for post-trip shrinkage of the RCS. The predicted RCS temperatures during this period are very close to the plant data, but the predicted pressurizer level is increasing about 55% faster than the rate of level increase shown in the plant data. Thus, it appears that the difference in the spray cycling frequency is primarily the result of the HPI makeup boundary condition. The actual HPI makeup flow rate was not retained in the post-trip plant data, so this boundary condition had to be estimated. The remaining difference between the predicted and actual rates of RCS pressure increase/spray frequency can be attributed to the [ ]

Letdown is reestablished at 948 seconds into the transient. After approximately 1000 seconds, the pressurizer level has increased above the 220 inch setpoint, and HPI makeup flow stops. The subsequent loss of EFW flow leads to a renewed heatup and pressurization of the RCS. During this time period, RETRAN-02 predicts that the spray will cycle about 30% more frequently than the plant response. Because the predicted RCS temperatures are close to the plant data, the difference in the spray frequency over this time period can be attributed primarily to the letdown flow rate boundary condition, as reflected in the pressurizer level response. The actual letdown flow rate was not retained in the post-trip plant data, so this boundary condition also had to be estimated.

In summary, uncertainty in the makeup and letdown boundary conditions appears to be a major factor in explaining the differences between the predicted and actual RCS pressure responses. It is believed that these boundary conditions have as much or more impact on the RCS pressure response [ ]

13) What is the uncertainty associated with the plant data in the steady-state natural circulation benchmarks in Section 4.3.3 of DPC-NE-3000?

The benchmark compares RETRAN-02 natural circulation flow predictions for symmetric, steady-state conditions to RCS flow estimates calculated from plant data obtained during natural circulation transients and tests at various B&W lowered-loop plants. The flow rates obtained from plant data should be recognized as approximate values, not as absolute points of reference. In each case, the natural circulation flow rate has been calculated from a measured or estimated core power level and a measured temperature difference between the RCS cold legs and hot legs. Both the power level and the calculated flow rate contain uncertainties introduced by plant instrumentation, calculation assumptions, and the degree to which the plant conditions approached true steady-state natural circulation conditions.

The calculated natural circulation flow rate is sensitive to uncertainties in the measured temperature difference across the core. Typically, the temperature difference is obtained from the hot leg and cold leg RTD readings. The measurement uncertainties of these RTDs, in particular, can have an appreciable impact on the calculated flow rate. Another source of potential error lies in differences between the water temperatures at the RTDs and at the core inlet and exit, caused by the water transit times between these locations. Finally, in some cases, anomalous cold leg RTD temperature data have been replaced with estimates of the steam generator secondary-side saturation temperatures. This approach does not account for the possibility that the primary water leaving the steam generator may be higher than the secondary-side saturation temperature, nor does it account for uncertainties in the estimated saturation temperature introduced by uncertainties in the measured steam generator pressure.

Uncertainties will also be present in the power level used to calculate the natural circulation flow rate. Data points incorporating NI power indications will potentially include bias errors introduced by differences in the downcomer water density from the water density at calibration conditions, as well as other hardware and calibration-induced uncertainties. Some of the plant data points have been derived from decay heat predictions that were conservatively low, which underpredicts the natural circulation flow rate.

The degree to which the plant approached symmetric, steady-state natural circulation conditions has an impact on the estimated natural circulation flow rate. A review of the three data points below 30 MW reveals that the plants were far from steady-state natural circulation conditions, with significant asymmetries in the steam generator conditions. Therefore, it is not surprising that the predicted RCS flows for these cases are not close to the RETRAN-02 predictions. The four plant data points with natural circulation rates above 3.0% design flow (48 MW, 57 MW, 62.5 MW, and 80 MW) were obtained from transients and tests that were close to true steady-state conditions. These data are in fairly good agreement with the RETRAN simulation at a steam generator level of 50% operate range, both in magnitude and trend.

A key parameter for natural circulation comparisons is the mixture level or boiling length in the steam generator, as reflected by the steam generator level indication. While the collapsed water level corresponding to a given steam generator level indication is similar for the plant and the code, RETRAN-02 tends to predict a higher mixture level than the plant. [ ] This causes the code to predict a higher thermal center for decay heat removal in the steam generator and a correspondingly higher primary flow rate. In addition, uncertainties introduced by the plant level instrumentation can impact the agreement between the code and plant data predictions. However, for the best four plant data points reflecting conditions near steady-state natural circulation, the overall agreement is reasonable.

The Oconee RETRAN-02 model used for the benchmark incorporates RCS loop form loss coefficients derived from full power primary system pressure distributions. It is

possible to adjust the loss coefficients so that the RETRAN-02 flow rate prediction matches that best of the plant data. DPC has chosen not to do this, given the fairly good agreement already evident in the benchmark. In addition, the above described uncertainties in the plant data prevent a precise estimation of the RCS natural circulation flow rate.

ONS3 11/14/88 TBV DEMAND BENCHMARK

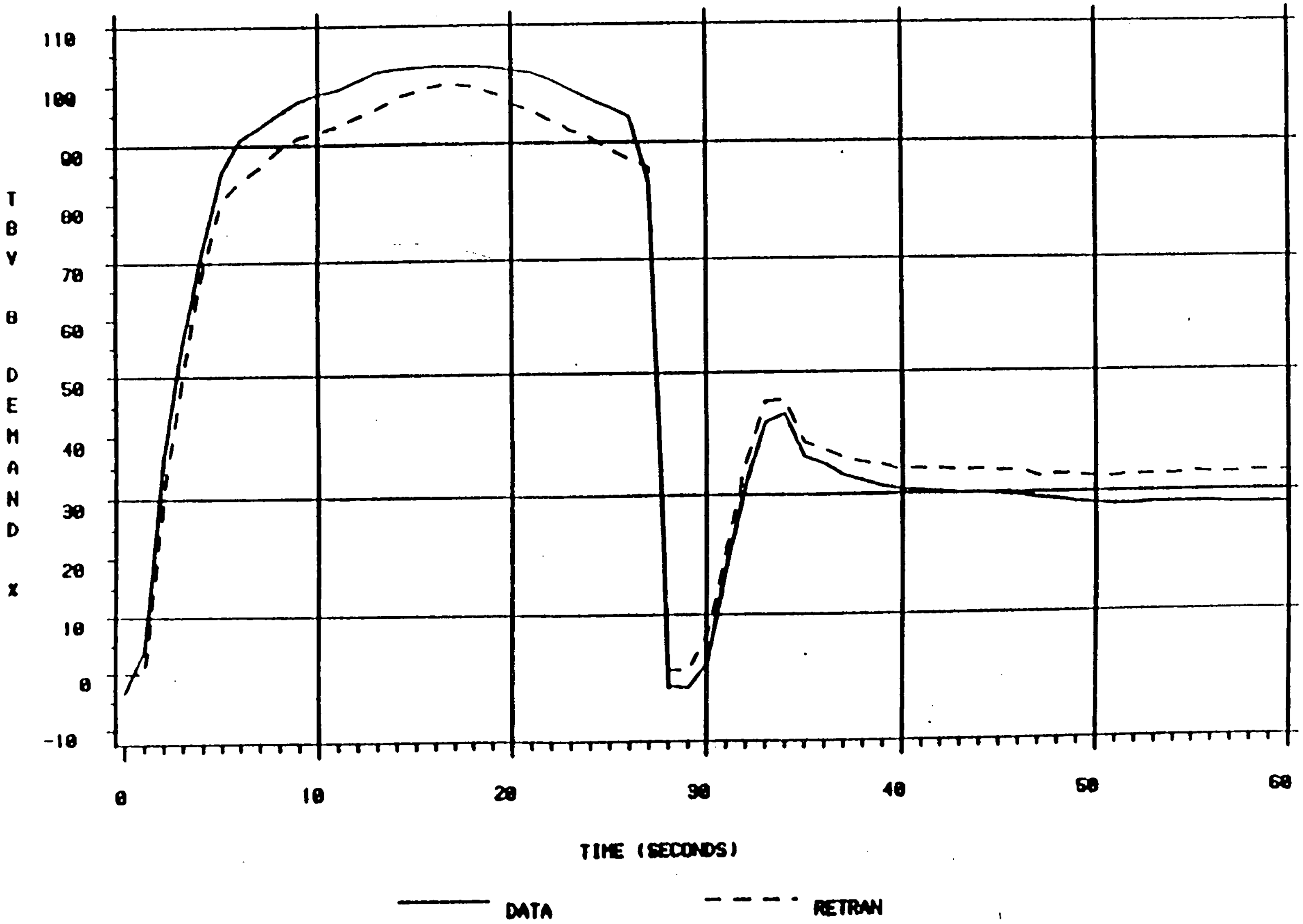
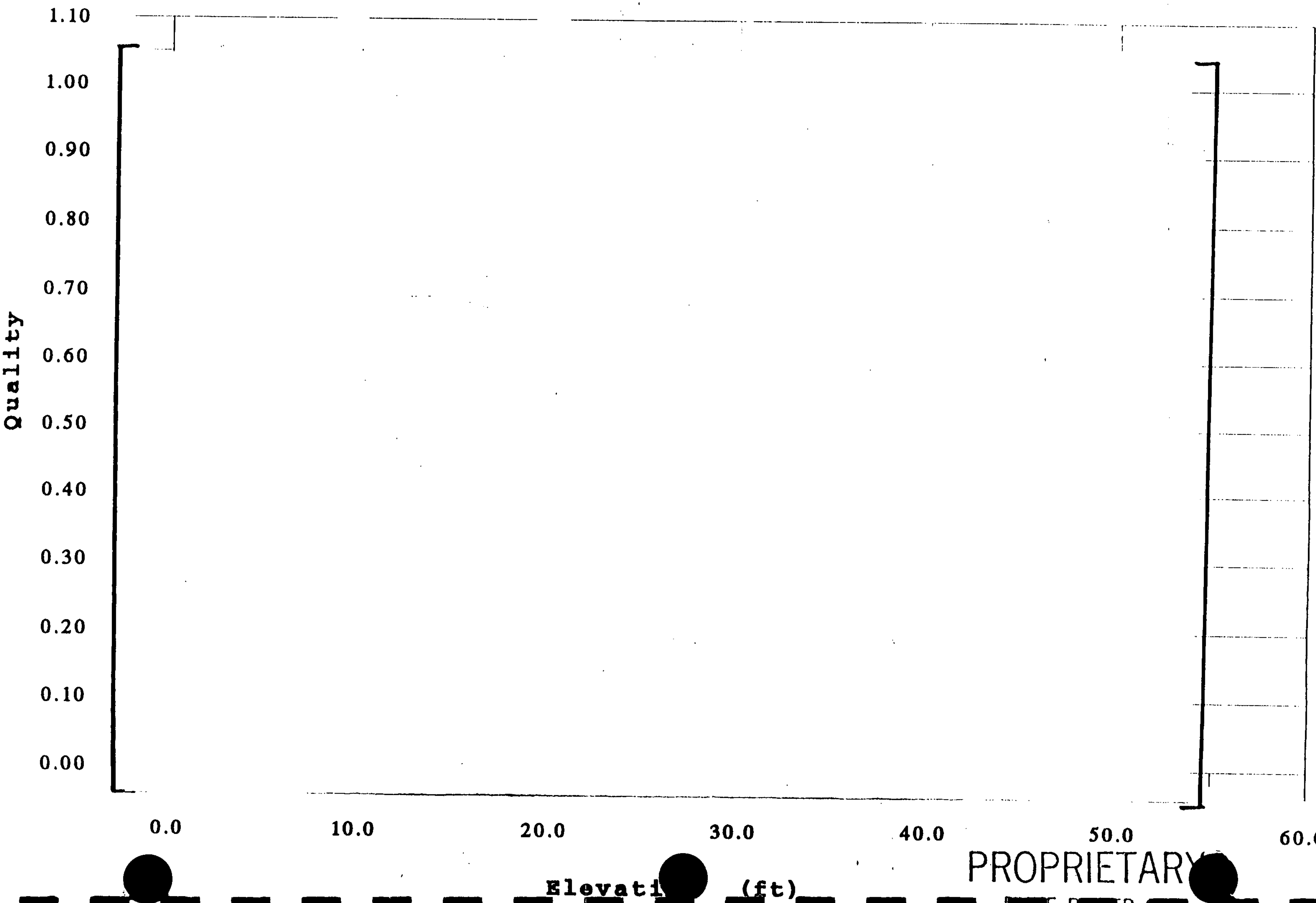


Figure 1

Figure 2 - RETRAN/VAGEN Quality Profile Comparison



PROPRIETARY

Duke Power Company
P.O. Box 1006
Charlotte, NC 28201-1006

M. S. TUCKMAN
Senior Vice President
Nuclear Generation
(704)382-2200 Office
(704)382-4360 Fax

DUKE POWER

October 5, 1993

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D. C. 20555

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
Thermal-Hydraulic Transient Analysis Methodology,
DPC-NE-3000

By letter dated March 11, 1992, Duke Power Company responded to a request for additional information to assist the NRC staff and their contractors with the ongoing review of Topical Report DPC-NE-3000, "Thermal-Hydraulic Transient Methodology." Attached please find supplemental responses to those provided in the March 11, 1992 letter.

Please note that these responses contain proprietary information, and should be protected from public disclosure. An affidavit which supports the proprietary nature of the information is included with the attachment.

If we can be of further assistance in your review please call Scott Gewehr at (704) 373-7581 or Gregg Swindlehurst at (704) 373-5176.

Very truly yours,

M. S. Tuckman

M. S. Tuckman

AFFIDAVIT OF M. S. TUCKMAN

1. I am Senior Vice President, Nuclear Generation Department, Duke Power Company ("Duke"), and as such have the responsibility of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear plant licensing, and am authorized to apply for its withholding on behalf of Duke.

2. I am making this affidavit in conformance with the provisions of 10 CFR 2.790 of the regulations of the Nuclear Regulatory Commission ("NRC") and in conjunction with Duke's application for withholding which accompanies this affidavit.

3. I have knowledge of the criteria used by Duke in designating information as proprietary or confidential.

4. Pursuant to the provisions of paragraph (b)(4) of 10 CFR 2.790, the following is furnished for consideration by the NRC in determining whether the information sought to be withheld from public disclosure should be withheld.

   (i) The information sought to be withheld from public disclosure is owned by Duke and has been held in confidence by Duke and its consultants.

   (ii) The information is of a type that would customarily be held in confidence by Duke. The information consists of analysis methodology details, analysis results, supporting data, and aspects of development programs, relative to a method of analysis that provides a competitive advantage to Duke.

   (iii) The information was transmitted to the NRC in confidence and under the provisions of 10 CFR 2.790, it is to be received in confidence by the NRC.

   (iv) The information sought to be protected is not available in public to the best of our knowledge and belief.

   (v) The proprietary information sought to be withheld in this submittal is that which is marked in the proprietary version of the report DPC-NE-3000, "Thermal -Hydraulic Transient Analysis Methodology" and supporting documentation, and omitted from the non-proprietary versions.

M. S. Tuckman

M. S. Tuckman

(continued)

This information enables Duke to:

(a) Respond to Generic Letter 83-11, "Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions."

(b) Respond to NRC requests for information regarding the transient response of Babcock & Wilcox and Westinghouse pressurized water reactors.

(c) Support license amendment and Technical Specification revision requests for Babcock & Wilcox and Westinghouse PWRs.

(d) Perform safety reviews per 10 CFR 50.59.

(e) Enhance operation of and training programs related to nuclear power plants.

(vi) The proprietary information sought to be withheld from public disclosure has substantial commercial value to Duke.

(a) It allows Duke to reduce vendor and consultant expenses associated with supporting the operation and licensing of nuclear power plants.

(b) Duke intends to sell the information to nuclear utilities, vendors, and consultants for the purpose of supporting the operation and licensing of nuclear power plants.

(c) The subject information could only be duplicated by competitors at similar expense to that incurred by Duke.

5. Public disclosure of this information is likely to cause harm to Duke because it would allow competitors in the nuclear industry to benefit from the results of a significant development program without requiring a commensurate expense or allowing Duke to recoup a portion of its expenditures or benefit from the sale of the information.

M. S. Tuckman

M. S. Tuckman

(continued)

AFFIDAVIT OF M. S. TUCKMAN (Page 3)

M. S. Tuckman, being duly sworn, on his oath deposes and says that he is the person who subscribed his name to the foregoing statement, and that the matters and facts set forth in the statement are true.

M. S. Tuckman

M. S. Tuckman

Sworn to and subscribed before me this 6TH day of October, 1993. Witness my hand and official seal.

Mary P. Nelms

Notary Public

My commission expires JAN 26, 1996.

Attachment

Supplemental Information Regarding the Prediction of Post-Trip Heat Transfer

In most of the benchmark transients, the Oconee RETRAN model overpredicts primary-to-secondary heat transfer immediately following a reactor trip. This is evident as a more rapid steam generator level decrease, when compared to plant data, which results in an underprediction of T-cold. T-hot is then underpredicted due to the T-cold trend, and consequently pressurizer level and RCS pressure are underpredicted. These trends are generally short-lived, and the predicted temperatures approach the plant data provided that the boundary conditions are consistent. The reason the Oconee RETRAN model overpredicts the post-trip primary-to-secondary heat transfer is that [

]

Even so, the results of the benchmark work have shown that this level behavior in the steam generators during the time they are boiling down to their post-trip setpoints has little impact on the overall transient response predicted by the model. It should be noted that the benchmark results indicate that the Oconee RETRAN model accurately predicts primary-to-secondary heat transfer prior to reactor trip. For example, in the November 10, 1979 overcooling following a loss of Integrated Control System (ICS) power benchmark (see Section 4.2.2 of DPC-NE-3000), a reactor trip did not occur until 55 seconds into the event. During this 55 second time period, a reactor runback was occurring due to the loss of a main feedwater pump. The plant data indicates that T-cold increased by about 11 ^{o}F during this time period. During the same time period, RETRAN predicted an increase in T-cold of about 15 ^{o}F. It should be noted that the RETRAN T-cold prediction was not adjusted to account for the approximately 5 second time constant associated with the cold leg RTDs. If this time constant were included in the model, the RETRAN prediction of the cold leg temperature response would be very close to the plant data. Thus, DPC believes that the Oconee RETRAN model accurately predicts primary-to-secondary heat transfer prior to reactor trip.

The overprediction of post-trip heat transfer must be accounted for when performing FSAR safety analyses. To demonstrate how this will be done, the relevant FSAR analyses are classified into four categories. These categories are shown below, with an explanation of how the overprediction of post-trip heat transfer will be handled for each:

Category 1

FSAR Section 15.2 - Startup Accident
FSAR Section 15.3 - Rod Withdrawal Accident
FSAR Section 15.4 - Moderator Dilution Accident
FSAR Section 15.5 - Cold Water Accident
FSAR Section 15.6 - Loss of Coolant Flow Accident
FSAR Section 15.7 - Control Rod Misalignment Accidents
FSAR Section 15.12 - Rod Ejection Accident

The acceptance criteria for these transients are challenged within seconds of the reactor trip, thus overprediction of post-trip steam generator heat transfer will essentially have no impact on the results.

Category 2

FSAR Section 15.13 - Steam Line Break
FSAR Section 10.4.7.1.7 - Feedwater Line Break

An overprediction of post-trip SG heat transfer will result in a conservatively higher initial rate of overcooling for a steam line break. For a feedwater line break downstream of the isolation check valve, a conservatively higher initial rate of overcooling will also occur, but will be bounded by the steam line break results. A break upstream of the check valve will result in a transient that will have the same response as a loss of main feedwater event (see Catagory 4).

Category 3

FSAR Section 15.9 - Steam Generator Tube Rupture

The acceptance criteria for the steam generator tube rupture accident are the dose limits specified in 10CFR100 over a 2-hour time period. The source term for the dose calculation during this time frame is related to the amount of steam generator inventory boiled off. The source term is not significantly affected by the exact timing of the rate of boiloff during the 2-hour period. The amount of inventory boiled off is determined by the integrated decay heat, reactor coolant pump heat, and RCS coolant and structural stored energy that is transferred from the primary coolant. Since the same amount of energy will be removed with or without a more rapid post-trip boil down time (i.e., EFW injection time) in the SGs, the total secondary inventory boiled off during the 2-hour time period will remain the same. Therefore, the offsite dose release will be no greater than that for a simulation which more accurately predicts the initial post-trip heat transfer.

Category 4

FSAR Section 10.4.7.1.1 - Loss of Main Feedwater (LOMFW)
FSAR Section 10.4.7.1.2 - LOMFW with Loss of Offsite AC Power
FSAR Section 10.4.7.1.3 - LOMFW with Loss of Onsite and Offsite AC Power
FSAR Section 15.8 - Loss of Electric Power Accidents

The acceptance criteria for these transients are that the minimum DNBR will not be less than the acceptance criterion for the correlation used and the system pressure will not exceed code limits. During these transients, the acceptance criteria may or may not be challenged. The overprediction of heat transfer evident in the RETRAN predictions cannot have any impact within a few seconds of reactor trip, if that is the time at which the acceptance criteria are approached. If the acceptance criteria are approached later on in time, there is the potential for the post-trip heat transfer to have an impact. In these transients a concern with regard to the primary side code pressure limit is that the loss of secondary-side cooling does not lead to a water-solid condition in the pressurizer due to RCS expansion. For the LOMFW event, water-solid conditions in the pressurizer will not be approached until after the secondary side inventory has boiled down to the post-trip control setpoint. Although emergency feedwater (EFW) is actuated upon the loss of the main feedwater pumps (or possibly on low steam generator level), the control valves remain closed until the steam generator level decreases below the post-trip control setpoint. Plant data has indicated that the Oconee RETRAN model prematurely injects EFW for this scenario since the SGs boil down more rapidly than expected to the control setpoint. To account for this in the analysis, an additional delay in the EFW start time is used. Transient monitor data was reviewed for LOMFW events at Oconee. This data indicated that the SGs took approximately 1 minute 40 seconds to boil down to their post-trip setpoints. This time, in conjunction with an EFW pump start time, an EFW header fill delay time, and an additional delay time added for conservatism combine for a total EFW delay time on the order of 3 minutes. This compensatory modeling will assure that the initiation of EFW flow conservatively bounds the expected plant response.

The loss of electric power events result in the reactor coolant pumps tripping off. This results in a SG post-trip setpoint of 242" (extended startup range) being required to promote natural circulation in the RCS. In controlling to this setpoint, the EFW control valves will immediately open to increase SG levels. The delay time associated with EFW injection will be based on the signal delay time, EFW pump start delay time, and the EFW header fill delay time. An overprediction of post-trip heat transfer has no effect on the results of these events since the total EFW inventory supplied to the SGs will be the same as a simulation which more accurately predicts the initial boiloff rate.

In summary, the overprediction in post-trip heat transfer either is conservative, does not matter, or will be accommodated by compensating modeling by using a conservative delay time for EFW injection. The acceptance criteria for the Category 1 events are challenged within seconds of the reactor trip, thus limiting any impact that post-trip SG heat transfer may have on them. The overcooling transients listed in Category 2 will result in a conservatively higher initial rate of overcooling due to an overprediction of post-trip SG heat transfer. The SGTR event (Category 3) will not be impacted by the SG post-trip boil down rate since this will not impact the source term used in the dose calculations. For the LOMFW In Category 4, compensating modeling based on an EFW delay time will be used to ensure that the initiation of EFW flow conservatively bounds the expected plant response. The Category 4 events in which the RCPs

are tripped off will not be impacted by a more rapid post-trip boil down time in the SGs since the EFW control valves open immediately to raise SG levels to their natural circulation setpoint. Based on these arguments, the overprediction of primary-to-secondary heat transfer following a reactor trip that is observed in the Oconee RETRAN model can be accounted for in a conservative manner for all FSAR analyses.

Supplemental Information Regarding Steam Line Break Modeling

In order to conservatively model the FSAR Chapter 15 steam line break transient the base model Oconee RETRAN nodalization requires modifications. These modifications are necessary due to the complex thermal-hydraulic and reactor kinetic responses that result from the severe overcooling caused by a steam line break. The modeling modifications consist of both fundamental nodalization differences and additional modeling to include more of the plant. In addition, modeling of the Integrated Control System as it relates to main feedwater pump and main feedwater valve control is also necessary for the steam line break analysis. These modifications and additions are as follows:

[ ]

Steam line break reanalyses identified that the injection of boron from the core flood tanks (nitrogen pressurized accumulators that inject into the reactor vessel downcomer) was an important mitigation function. Due to the fact that the two core flood tanks are at different elevations in the containment building,[ ]it was decided to model each individually. This approach is different than in the base RETRAN model where they are represented as a lumped single component

The steam line nodalization is revised to enable modeling of the break. The conventional approach is followed for modeling a double-ended break. This involves opening two valves, each representing the cross-sectional area of the main steam line at its largest diameter, and connecting them to a backpressure volume. This backpressure volume can represent either the atmosphere or the containment. The break junctions and their associated volumes are physically isolated from each other to ensure no hydraulic interaction.

The main feedwater piping is modeled in much greater detail for the steam line break. In the base RETRAN model, the feedwater piping is only modeled back to the main feedwater control valve. For the steam line break the condensate/feedwater piping is modeled all the way back to the condensate booster pumps. This modeling is necessary due to the importance of the feedwater boundary condition on the steam line break. As the steam generator depressurizes, the feedwater system pumps will dynamically respond to the pressure change, and flow will increase. Eventually, the steam generator pressure can decrease to below the saturation pressure for the feedwater in the feedwater piping. When this happens, the feedwater will flash and water will be forced into the steam generator. Since high feedwater flow conservatively maximizes the over-cooling for steam line break, the additional modeling is intended to ensure that these effects are all accounted for.

In addition to the more detailed modeling of the feedwater piping and pumps, the Integrated Control System interaction with the feedwater pumps and control valves is also modeled. This modeling is intended to ensure that the feedwater flow boundary condition is conservatively maximized. Analyses with and without the Integrated Control System are performed to determine the limiting case with respect to either automatic or manual control.

The base model steam generator secondary nodalization has been determined to be appropriate for simulating the steam line break. The two main considerations when evaluating the adequacy of the nodalization are in the areas of heat transfer and water carryover. The assumptions used in the steam line break analysis must conservatively maximize the primary-to-secondary heat transfer. Due to the high steam velocities, the blowdown of the steam generator will potentially result in carryover of some liquid with the break flow. This would be strongly influenced by the mass of water in the steam generator and the flowrate of feedwater into the steam generator. Since any water that is carried over will not be boiled and will therefore result in less heat transfer from the primary, it is non-conservative for liquid carryover to occur. As the feedwater flow boundary condition increases, however, liquid carryover must occur if the feedwater flowrate is greater than the boiloff rate. Also, for high feedwater flowrates which result in liquid carryover, the total heat transfer can be less due to less enthalpy rise per pound of feedwater even if the feedwater flowrate is greater. To identify the limiting case a range of feedwater flow boundary conditions were analyzed. The results of the analyses using the base model steam generator nodalization have determined that the limiting steam line break occurs with a feedwater flowrate that does not result in significant liquid carryover. At lower or higher feedwater flowrates the heat transfer is less, and the steam line break analysis results are less limiting. Consequently, the concerns regarding the adequacy of the base model nodalization for the steam line break analysis were resolved.

The above discussion identifies the changes in the Oconee RETRAN model that are necessary to perform a conservative analysis of the steam line break. The specific details regarding the analysis, such as initial and boundary conditions, are beyond the scope of DPC-NE-3000. These details will be submitted to the NRC in a subsequent topical report.

Figure 1

PROPRIETARY
DUKE POWER CO.

Supplemental Information Regarding Main Feedwater Modeling

The Main Feedwater System (MFW) is the normal source of feedwater supply to the steam generators (SG) during power operation and startup and shutdown. The Emergency Feedwater System (EFW) only actuates when MFW is lost. EFW actuates on MFW pump trip (as indicated by low MFW pump discharge pressure or low hydraulic oil pressure on both MFW pump turbines), or on low SG level at a setpoint of 21 inches on the startup range level instrument (a 21 inch setpoint is 27 inches above the tubesheet). MFW controls at 25 inches on the startup range level instrument at power levels up to approximately 15% of full power. Above 15% power the increase in feedwater flow results in the increase in SG level which is necessary to achieve the required heat transfer area. If the EFW pumps actuate, the EFW Control System will control at a 30 inch setpoint. Since this setpoint is higher than the MFW level control setpoint, the feedwater will be supplied by EFW and the MFW valves will remain closed.

Due to the large capacity of the MFW pumps, there is no question that the post-trip heat sink can be maintained. If the MFW pumps are operational it is necessary that offsite power has remained available. Therefore there are no delays associated with loading the feedwater source on the emergency power supply or filling the feedwater piping. For these reasons, the limiting FSAR analyses with respect to loss of heat sink transients all involve a loss of the MFW System, which results in actuation of the smaller capacity EFW System. Many of the FSAR transients assume the continuation of offsite power and focus on the transient response in areas other than the heat sink capability of the SGs. For these transients the pre- and post-trip feedwater supply is provided by the MFW System. Although the modeling of MFW, including SG level control, is included in these transients, it is unnecessary to employ the conservative modeling associated with the EFW System since the MFW System is significantly less important.

The plant transient benchmark analyses presented in Chapter 4 of DPC-NE-3000 include several that compare the post-trip SG level response predicted by RETRAN with plant data. Figure 4.2.1-6 shows the SG level response comparison for a typical reactor trip event for which the MFW flow boundary condition used in the analysis was the actual plant data. During the two minute duration of the simulation, the maximum level deviation is about 20 inches, or the time shift is no more than 20 seconds. The plant data is matched once the level control setpoint is reached at 90 seconds. It is worth noting that this event was also characterized by a loss of SG pressure control which further challenges the predictive capability of the code. Based on the resulting RCS temperature predictions, it can be concluded that the primary-to-secondary heat transfer during low level conditions and MFW flow is predicted well for this event.

Figure 4.4.1-8 is another example of a comparison of primary-to-secondary heat transfer during low SG level conditions and MFW flow. In this figure it is evident that the ICS has demanded a feedwater flowrate which resulted in the SG levels stabilizing well above the expected 25 inch setpoint. The RETRAN model predicts SG level to be approximately 15 inches less than the plant data at two minutes. The predicted cold leg temperatures (Figure 4.4.1-6) show that this higher than expected level has minimal impact on the primary-to-secondary heat transfer. This is expected since the post-trip heat transfer rate is mainly determined by SG pressure control (as long as the minimum SG level is maintained). It can be concluded that the RETRAN level prediction is very reasonable, and that the difference between the predicted level and plant data has no impact on the overall plant transient response. This supports the modeling of MFW and

SG level control in the FSAR analyses for those transients where the SG heat sink does not significantly impact the results.

The FSAR transients for which conservative modeling of the secondary heat sink is critical are the loss of main feedwater, the loss of offsite power, and the feedwater line break transients. Appropriate consideration of EFW actuation delays and SG level modeling must be included for these events.

Duke Power Company
P.O. Box 1006
Charlotte, NC 28201-1006

M. S. TUCKMAN
Senior Vice President
Nuclear Generation
(704)382-2200 Office
(704)382-4360 Fax

DUKE POWER

August 9, 1994

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D. C. 20555

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
McGuire Nuclear Station
Docket Nos. 50-369, -370
Catawba Nuclear Station
Docket Nos. 50-413, -414
Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000

Please find attached revisions to Topical Report DPC-NE-3000, Thermal-Hydraulic Transient Analysis Methodology. This Topical Report was approved for Catawba and McGuire on November 15, 1991; approval for Oconee is pending. The revisions reflect changes due to the replacement steam generators for McGuire and Catawba, corrections to typographical errors, and minor methodology changes. Attachment II contains a proprietary copy of the revisions, Attachment III contains a non-proprietary copy of the revisions.

In accordance with 10 CFR 2.790, Duke Power Company requests that the attached information relating to DPC-NE-3000 be considered proprietary. Information supporting this request is included in the affidavit which appears as Attachment I.

Duke Power is requesting review and approval of these changes by August 9, 1995 in order to support the steam generator replacement schedule for McGuire Unit 1. Revisions to the Topical Report pertaining to Oconee are submitted to update the report only, they are not required for the McGuire replacement.

If we can be of assistance in your review, please call Mary Hazeltine at (704) 382-6111.

Very truly yours,

M. S. Tuckman

M. S. Tuckman

cc: Mr. V. Nerses, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

Mr. L. A. Wiens, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

Mr. R. E. Martin, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

Mr. S. D. Ebneter, Regional Administrator
U.S. Nuclear Regulatory Commission - Region II
101 Marietta Street, NW - Suite 2900
Atlanta, Georgia 30323

Mr. G. F. Maxwell
Senior Resident Inspector
McGuire Nuclear Station

Mr. R. J. Freudenburger
Senior Resident Inspector
Catawba Nuclear Station

Mr. P. E. Harmon
Senior Resident Inspector
Oconee Nuclear Station

T. E. Collins, Acting Branch Chief
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 8 E23, OWFN
Washington, D. C. 20555

bxc: G. A. Copp
T. R. Niggel
G. B. Swindlehurst
C. F. Robinson
S. A. Gewehr
Z. L. Taylor
J. E. Snyder
CN/MC 1201.37-30
File: GS-801.01

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

September 6, 1995

Mr. M. S. Tuckman
Senior Vice President
Nuclear Generation
Duke Power Company
P. O. Box 1006
Charlotte, NC 28201

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION - DPC-NE-3000, THERMAL-HYDRAULIC TRANSIENT ANALYSIS METHODOLOGY - McGUIRE NUCLEAR STATION, UNITS 1 AND 2; AND CATAWBA NUCLEAR STATION, UNIT 1 (TAC NOS. M90143, M90144, AND M90145)

Dear Mr. Tuckman:

By letter dated August 9, 1994, you submitted for staff review and approval a report identified as Revision 3 of Topical Report DPC-NE-3000, "Thermal-Hydraulic Transient Analysis Methodology." Based on our review of your report conducted to date, the NRC staff has identified a need for additional information as indicated in the enclosure. Proprietary information in the enclosure was identified by your staff and documented by your letter dated April 9, 1994. The enclosure should be controlled and distribution limited to personnel with a "need to know." The enclosure is considered exempt from Public Disclosure in accordance with Title 10, Code of Federal Regulations, Part 2.790. However, a copy of this letter, with a non-proprietary version of the enclosure, will be placed in the NRC Public Document Room. Please provide a response within sixty (60) days of receipt of this letter to enable us to complete our review.

This requirement affects nine or fewer respondents, and therefore, it is not subject to the Office of Management and Budget review under P.L. 96-511.

Sincerely,

Robert E Martin

Robert E. Martin, Senior Project Manager
Project Directorate II-2
Directorate for Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket Nos. 50-369, 50-370,
and 50-413

Enclosure:
Request for Information
(Proprietary)

cc w/non-proprietary enclosure:
See next page

Document transmitted herewith contains sensitive unclassified information. When separated from enclosure, this document is decontrolled.

Duke Power Company

McGuire Nuclear Station
Catawba Nuclear Station

cc:
A. V. Carr, Esquire
Duke Power Company
422 South Church Street
Charlotte, North Carolina 28242-0001

County Manager of Mecklenburg County
720 East Fourth Street
Charlotte, North Carolina 28202

Mr. J. E. Snyder
Regulatory Compliance Manager
Duke Power Company
McGuire Nuclear Site
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

J. Michael McGarry, III, Esquire
Winston and Strawn
1400 L Street, NW.
Washington, DC 20005

Senior Resident Inspector
c/o U. S. Nuclear Regulatory Commission
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Mr. T. Richard Puryear
Nuclear Technical Services Manager
Westinghouse Electric Corporation
Carolinas District
2709 Water Ridge Parkway, Suite 430
Charlotte, North Carolina 28217

Dr. John M. Barry
Mecklenburg County
Department of Environmental Protection
700 N. Tryon Street
Charlotte, North Carolina 28202

Mr. Dayne H. Brown, Director
Department of Environmental, Health and Natural Resources
Division of Radiation Protection
P. O. Box 27687
Raleigh, North Carolina 27611-7687

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of Justice
P. O. Box 629
Raleigh, North Carolina 27602

Mr. G. A. Copp
Licensing - EC050
Duke Power Company
526 South Church Street
Charlotte, North Carolina 28242-0001

Regional Administrator, Region II
U.S. Nuclear Regulatory Commission
101 Marietta Street, NW. Suite 2900
Atlanta, Georgia 30323

Elaine Wathen
Lead REP Planner
Division of Emergency Management
116 West Jones Street
Raleigh, North Carolina 27603-1335

cc:
Mr. Z. L. Taylor
Regulatory Compliance Manager
Duke Power Company
4800 Concord Road
York, South Carolina 29745

North Carolina Municipal Power
Agency Number 1
1427 Meadowwood Boulevard
P. O. Box 29513
Raleigh, North Carolina 27626-0513

County Manager of York County
York County Courthouse
York, South Carolina 29745

Richard P. Wilson, Esquire
Assistant Attorney General
South Carolina Attorney General's
Office
P. O. Box 11549
Columbia, South Carolina 29211

Piedmont Municipal Power Agency
121 Village Drive
Greer, South Carolina 29651

Saluda River Electric
P. O. Box 929
Laurens, South Carolina 29360

Max Batavia, Chief
Bureau of Radiological Health
South Carolina Department of
Health and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201

North Carolina Electric Membership
Corporation
P. O. Box 27306
Raleigh, North Carolina 27611

Senior Resident Inspector
4830 Concord Road
York, South Carolina 29745

Mr. William R. McCollum
Site Vice President
Catawba Nuclear Station
Duke Power Company
4800 Concord Road
York, South Carolina 29745

Mr. T. C. McMeekin
Vice President, McGuire Site
Duke Power Company
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

NON-PROPRIETARY INFORMATION

REQUEST FOR ADDITIONAL INFORMATION

THERMAL-HYDRAULIC TRANSIENT

ANALYSIS METHODOLOGY

1. Justify the proposed use of the [ ] for material properties and the [ ] for the fuel gap conductivity by demonstrating that computations will result in conservative system predictions for all transients. (p.2-40)

2. Discuss the situations in which [ ] during steady-state initialization may not result in conservative prediction of the transient calculations and reconcile that result with the response to Question 1. (p.2-40)

3. In the previously submitted model with the original topical report, DPC observed that a large adjustment in the [ ] was necessary during the outsurge portion of any transient containing a strong outsurge. Discuss how this problem is addressed by the use of the revised PZR model which includes modeling of the surge line.

4. Demonstrate by reanalysis of transients/tests that the revised PZR model with heat conductors results in adequately conservative predictions. In addition, DPC should qualify its PZR water level prediction procedure.(p.2-42 & p.3-47)

5. Discuss modeling of phase separation including the selected BR velocity in the [ ] (p.2-49 & 51).

6. Provide thorough discussion and qualification of the revised SG model for feedring SGs including steady-state initialization and nodalization sensitivities, and demonstrate that the model produces an adequately conservative prediction of heat transfer. In addition, DPC should qualify the SG level calculator for the feedring SG against the data.

7. Discuss the source(s) of the significant reduction in trip setpoints for the load rejection controller for Catawba.

8. Clarify the new paragraph to be inserted in page 3-16 regarding the SG level control. Do both Catawba Units have the DFCS? Discuss how this system is simulated and qualified in the RETRAN analysis.

9. Discuss the source(s) and reasons for changes and impact on safety analysis in the following plant models, setpoints and values:

   a. HHSI pump characteristics
   b. IHSI pump characteristics
   c. LHSI pump characteristics
   d. Steam line pressure for SI signal & steam line isolation
   e. elimination of a RPS condition for reactor trip
   f. steam line safety valve opening setpoints
   g. HHSI and IHSI injection after 7 hours

10. Once the planned steam generator replacement takes place, what does DPC plan to do with respect to the aspects of the report addressing the old SGs for McGuire #1 and 2 and Catawba #1 which would no longer be applicable? Provide comparable benchmark analysis to be included in the topical report in support of the new steam generators.

11. Clarify Section 3.1.6.2. Which unit at Catawba does the revised AFW runout protection apply to and how is the other unit protected?

12. Discuss the impact of installation of feedring steam generators and its accompanying changes on transient analysis such as the MFW and AFW flow.

13. Discuss in detail how the general transport model is used to ismulate boron transport, including the nodalization of injection site, mixing coefficient, analysis for which this is credited, and demonstrate that the model produces conservative results.

14. Discuss the change in assumed steady-state pump head and flow for various transients (§ 2.2.6.2).

Duke Power Company
P.O. Box 1006
Charlotte, NC 28201-1006

I	ONS	MNS	CNS	NGO	Other
E	NRC	DOE	B&W	W	Other
Key Word:					

M. S. Tuckman
Senior Vice President
Nuclear Generation
(704)382-2200 Office
(704)382-4360 Fax

DUKE POWER

September 12, 1995

U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Document Control Desk

Subject: McGuire Nuclear Station
Docket Numbers 50-369 and -370
Catawba Nuclear Station
Docket Numbers 50-413 and -414
Oconee Nuclear Station
Docket Numbers 50-269, -270, and -287
Request for Additional Information Relative to DPC-NE-3000P, Revision 1;
Responses to Questions

By letters dated November 15, 1991 (for application to McGuire and Catawba Nuclear Stations) and August 8, 1994 (for application to Oconee Nuclear Station), the NRC transmitted safety evaluations for the subject Topical Report. By letter dated August 9, 1994, Duke Power Company submitted for NRC review Revision 1 to the approved Topical Report. The NRC staff issued a request for additional information (RAI) dated September 6, 1995. Responses to the questions contained in the RAI are presented in Attachment II.

Please note that the responses to several of the questions contain information that Duke considers proprietary. In accordance with 10CFR 2.790, Duke requests that this information be withheld from public disclosure. An affidavit which attests to the proprietary nature of this information is included as Attachment I. Attachment III contains a non-proprietary version of the responses.

If any additional information is needed, please call Scott Gewehr at (704) 382-7581.

Very truly yours,

M. S. Tuckman

M. S. Tuckman

cc (w/ Attachments):

Mr. V. Nerses, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

L. A. Weins
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

Mr. R. E. Martin, Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 14H25, OWFN
Washington, D. C. 20555

(w/o Attachments):

Mr. S. D. Ebneter, Regional Administrator
U.S. Nuclear Regulatory Commission - Region II
101 Marietta Street, NW - Suite 2900
Atlanta, Georgia 30323

Mr. G. F. Maxwell
Senior Resident Inspector
McGuire Nuclear Station

Mr. R. J. Freudenberger
Senior Resident Inspector
Catawba Nuclear Station

Mr. P. E. Harmon
Senior Resident Inspector
Oconee Nuclear Station

bxc: (w/o Attachments)
G. A. Copp

(w/ Attachments)
S. A. Gewehr
G. B. Swindlehurst
ELL

AFFIDAVIT OF M. S. TUCKMAN

1. I am Senior Vice President, Nuclear Generation Department, Duke Power Company ("Duke"), and as such have the responsibility of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear plant licensing, and am authorized to apply for its witholding on behalf of Duke.

2 I am making this affidavit in conformance with the provisions of 10 CFR 2.790 of the regulations of the Nuclear Regulatory Commission ("NRC") and in conjunction with Duke's application for withholding which accompanies this affidavit.

3. I have knowledge of the criteria used by Duke in designating information as proprietary or confidential.

4. Pursuant to the provisions of paragraph (b)(4) of 10 CFR 2.790, the following is furnished for consideration by the NRC in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned by Duke and and has been held in confidence by Duke and its consultants.

(ii) The information is of a type that would customarily be held in confidence by Duke. The information consists of analysis methodology details, analysis results, supporting data, and aspects of development programs, relative to a method of analysis that provides a competitive advantage to Duke.

(iii) The information was transmitted to the NRC in confidence and under the provisions of 10 CFR 2.790, it is to be received in confidence by the NRC.

(iv) The information sought to be protected is not available in public to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is marked in the proprietary version of the report DPC-NE-3000, "Thermal Hydraulic Transient Analysis Methodology" and supporting documentation, and omitted from the non-proprietary versions.

M. S. Tuckman

M. S. Tuckman

(continued)

This information enables Duke to:

(a) Respond to Generic Letter 83-11, "Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions."

(b) Respond to NRC requests for information regarding the transient response of Babcock & Wilcox and Westinghouse pressurized water reactors.

(c) Support license amendment and Technical Specification revision requests for Babcock & Wilcox and Westinghouse PWRs.

(d) Perform safety reviews per 10 CFR 50.59.

(e) Enhance operation of and training programs related to nuclear power plants.

(vi) The proprietary information sought to be withheld from public disclosure has substantial commercial value to Duke.

(a) It allows Duke to reduce vendor and consultant expenses associated with supporting the operation and licensing of nuclear power plants.

(b) Duke intends to sell the information to nuclear utilities, vendors, and consultants for the purpose of supporting the operation and licensing of nuclear power plants.

(c) The subject information could only be duplicated by competitors at similar expense to that incurred by Duke.

5. Public disclosure of this information is likely to cause harm to Duke because it would allow competitors in the nuclear industry to benefit from the results of a significant development program without requiring a commensurate expense or allowing Duke to recoup a portion of its expenditures or benefit from the sale of the information.

M. S. Tuckman

M. S. Tuckman

(continued)

M. S. Tuckman, being duly sworn, on his oath deposes and says that he is the person who subscribed his name to the foregoing statement, and that the matters and facts set forth in the statement are true.

M. S. Tuckman

M. S. Tuckman

Sworn to and subscribed before me this 12th day of September 1995. Witness my hand and official seal.

Linda Case Smith

Notary Public

My commission expires May 6, 2000

Attachment 3

Question 1

Justify the proposed use of the[ ]for material properties and the[ ]for the fuel gap conductivity by demonstrating that computations will result in conservative system predictions for all transients. (p. 2-40)

Response

This question concerns modeling which has not been revised. Conservative results are obtained as follows. The fuel gap[ ]in order to conservatively model both the stored energy in and heat transfer from the fuel rods to the reactor coolant, and fuel temperature feedback reactivity. This approach results in conservative fuel temperatures and power response, although the material properties of the fuel and cladding are[ ]The fuel temperature is the key modeling parameter, as noted in DPC-NE-3002.

Question 2

Discuss the situations in which[ ]during steady-state initialization may not result in conservative prediction of the transient calculations and reconcile that result with the response to Question 1. (p. 2-40)

Response

In order to obtain steady-state initialization, RETRAN adjusts the SG heat transfer area. If this adjustment is significant, then there will be an impact on the analysis results. To minimize this heat transfer area deviation,[ ]can be employed. This[ ]The heat transfer area reduction cannot be physically justified. Given a choice between these two, the [ ]is preferred. Overall performance of the Oconee RETRAN model has been demonstrated by validation to plant transient data. Adequate conservatism in the heat transfer between the primary and secondary systems is ensured through the assumptions made for the following parameters: Reactor Coolant System flow, steam generator tube plugging, and steam generator level.

Question 3

In the previously submitted model with the original topical report, DPC observed that a large adjustment in the[ ]was necessary during the outsurge portion of any transient containing a strong outsurge. Discuss how this problem is addressed by the use of the revised PZR model which includes modeling of the surge line.

Response

The previously submitted Oconee RETRAN model included modeling of the pressurizer surge line. The surge line metal as a heat conductor was not modeled. The adjustment in the[ ] is related to the solution of the conservation of momentum equation. The heat capacity of the surge line metal is related mainly to the solution of the conservation of energy equation. Therefore, this modeling change is not expected to impact the pressure response during an outsurge.

Question 4

Demonstrate by reanalysis of transients/tests that the revised PZR model with heat conductors results in adequately conservative predictions. In addition, DPC should qualify its PZR water level prediction procedure. (p. 2-42 & p. 3-47)

Response

The revised pressurizer model includes a more detailed treatment of the heat transfer to the pressurizer walls through the use of the[ ]This should be a improvement over the currently approved model in the predictive capabilities of the pressurizer model. As discussed in the DPC response to Question 5 from the NRC letter dated April 7, 1989, a loss of main feedwater at Oconee was actually analyzed employing the improved pressurizer model. The adequacy of the model is discussed in detail in §4.1.1 of the topical report.

The RETRAN pressurizer level control system exactly duplicates the temperature compensated level indication circuit in place at Oconee. The only method to truly validate the level prediction would require knowledge of the actual water level in the pressurizer vessel, which is not available. Discrepancies in the pressurizer level indication observed during plant transient benchmarks are not mainly due to level modeling inaccuracies, but rather are the result of deviations in the predicted reactor power level or primary to secondary heat transfer.

This revised model was benchmarked against plant data from a turbine trip from 37% power. This event is characterized by a reactor power decrease from 37% to 28% over 27 seconds. The pressurizer level response is shown in the attached Figure 4-1. RETRAN slightly overpredicts the pressurizer level during the first 15 seconds. After 15 seconds, RETRAN slightly underpredicts the pressurizer level. These deviations are the result of the integrated effects of the core power and primary-to-secondary heat transfer predictions versus plant data. The overall comparison of the pressurizer level prediction to data is reasonable.

Question 5

Discuss modeling of phase separation including the selected BR velocity in the[ ](p. 2-49 & 51)

Response

The values for the separation velocity and bubble gradient are the same as those used for the pressurizer volume[ ]and are typical of the RETRAN community. Past experience with the model has shown these values to perform adequately for this application. Particularly since the[ ] is essentially a dead-ended volume, the selection of the bubble rise parameters does not have a significant impact on the transient results. Modeling of a bubble rise volume instead of an HEM volume can have a significant impact on some transients. This model change addresses that limitation.

Question 6

Provide thorough discussion and qualification of the revised SG model for feedring SGs including steady-state initialization and nodalization sensitivities, and demonstrate that the model produces an adequately conservative prediction of heat transfer. In addition, DPC should qualify the SG level calculator for the feedring SG against the data.

Response

The secondary side nodalization for the feedring steam generator has essentially the same level of detail as the preheater-type steam generator model, which has been shown to be adequate. The only significant difference between the two models is that both the lower downcomer and tube bundle regions are [ ] in the feedring steam generator model.

In the absence of a preheater, it was no longer necessary to [ ] The feedring model employs [ ] in the preheater model to more accurately predict primary to secondary heat transfer. These secondary side nodes are coterminous with the primary side tube bundle nodes.

A sensitivity study was performed on the lower downcomer nodalization in an attempt to more closely match vendor data for steam generator level and liquid mass. Based on this sensitivity study, the final nodalization scheme includes [ ]

Obviously there is, as of yet, no plant data to benchmark the feedring steam generator model against. As mentioned above, a good correlation with the manufacturer's calculated data for steam generator level and liquid mass was achieved. The heat transfer prediction was validated based on a comparison of RETRAN results versus vendor data for primary system hot and cold leg temperatures given a specified RCS flow and steam line pressure. Also, the RETRAN feedring steam generator model produces a reasonable void profile over the height of the tube bundle volumes. Both the DPC RETRAN results and the vendor code predictions for the key modeling parameters are shown in the table below:

Parameter	DPC	Vendor
SG outlet pressure (psia)	1020	1020
T_{hot} (°F)	612.75	613.76
T_{cold} (°F)	555.66	556.36
SG Level (%)	65	65
SG Liquid Mass (lbm)	120,124	120,369

Question 7

Discuss the source(s) of the significant reduction in trip setpoints for the load rejection controller for Catawba.

Response

Subsequent to the submittal of the DPC-NE-3002 revision, another modification to the load rejection steam dump setpoints was discovered. The current values are as follows:

Bank	Setpoint (°F)
1	
2	
3	
4	
5	

This is essentially a plant operations issue, since no credit is taken for the non-safety load rejection steam dump controller in any of the Chapter 15 transient analyses. The load rejection controller setpoints have been fine tuned in order to provide better protection in the event of a major load rejection. As a result of the post-modification testing which is to follow the installation of the feedring steam generators, additional adjustments to these setpoints might be made. Revision of these setpoints in the topical report was intended only to keep the document current. Future setpoint changes will be similarly updated as the opportunity arises.

Question 8

Clarify the new paragraph to be inserted in page 3-16 regarding the SG level control. Do both Catawba Units have the DFCS? Discuss how this system is simulated and qualified in the RETRAN analysis.

Response

The original steam generator level control system was replaced by the Digital Feedwater Control System (DFCS) at both Catawba Units. A RETRAN model of the controller has been created, including actual plant values for the controller setpoints, gains and time constants. Prior to implementation in any RETRAN analyses, this model would be validated by benchmarking against plant data taken with the DFCS in place. Currently, however, the steam generator level control system is modeled indirectly as described in §3.2.4.4. This simplified method is used since its only impact on the transient results is in the avoidance of reactor protection and engineered safeguards actuations.

Question 9

Discuss the source(s) and reasons for changes and impact on safety analysis in the following plant models, setpoints and values:

a. HHSI pump characteristics
b. IHSI pump characteristics
c. LHSI pump characteristics

d. Steam line pressure for SI signal & steam line isolation
e. Elimination of a RPS condition for reactor trip
f. Steam line safety valve opening setpoints
g. HHSI and IHSI injection after 7 hours

Response

a, b, & c) Updated vendor information regarding the pump runout limitations on the HHSI and IHSI pumps necessitated modifications to the ECCS flow balancing procedure. These modifications yielded the revised shutoff pressures and runout flows. The values given are consistent with the revised Technical Specifications which were approved on December 15, 1993 for Catawba and July 29, 1994 for McGuire. Revised ECCS injection flow rates have been generated for use in both LOCA and non-LOCA safety analyses.

d) The modification to the low steam line pressure safety injection and steam line isolation Technical Specification setpoints was proposed in the McGuire 1 Cycle 8 reload submittal. The removal of the dynamic compensation of the steam line pressure signal, which accompanies the change in the low pressure setpoint, was intended to eliminate the spurious ESF actuation on minor (but rapid) pressure decreases in the secondary system. The revised steam line pressure setpoint is consistent with all licensing basis safety analyses. The NRC granted the Tech Spec change on November 27, 1991.

e) The removal of the negative flux rate trip from the Technical Specifications was proposed in the McGuire 1 Cycle 8 reload submittal. Based on the elimination of unnecessary reactor trips resulting from mild reactor power transients and the fact that no credit is taken for this trip in the accident analyses, the NRC granted the Tech Spec change on November 27, 1991.

f) The modification to the Bank 4 and 5 SMSV lift setpoints was necessitated by the turbine trip peak secondary pressure analysis. DPC is currently pursuing a change to the way the SMSV lift is modeled which has eliminated the need for these setpoint changes. Therefore, an amended submittal to the NRC will be made shortly.

g) Realignment of the safety injection flow to the hot legs is performed to preclude post-LOCA boron precipitation in the reactor core. Due to increased maximum boron concentrations in the injection water sources (Cold Leg Accumulators, Refueling Water Storage Tank, and the Ice Condenser), the hot leg recirculation switchover time has been changed from 15 to 7 hours.

Question 10

Once the planned steam generator replacement takes place, what does DPC plan to do with respect to the aspects of the report addressing the old SGs for McGuire #1 and 2 and Catawba #1 which would no longer be applicable? Provide comparable benchmark analysis to be included in the topical report in support of the new steam generators.

Response

DPC does not intend to remove any of the discussion or schematics referring to the split flow preheater steam generator designs that are currently in place at both McGuire units and Catawba Unit 1. This is but a small portion of the topical report which, for the most part,

discusses McGuire and Catawba generically. This discussion will remain valid for Catawba Unit 2.

As mentioned in the response to Question 6, prior to the installation of the feedring steam generators, there is no transient data available for benchmarking analysis. DPC feels that the differences between the preheater-type steam generators and the feedring steam generators are relatively minor and should not effect the ability of the RETRAN code to accurately predict transient behavior.

Question 11

Clarify Section 3.1.6.2. Which unit at Catawba does the revised AFW runout protection apply to and how is the other unit protected?

Response

The revised AFW runout protection applies to both Catawba units. The basis for the active runout protection which is to be removed is to ensure that a minimum flow requirement is met. This flow requirement is based on a vendor analysis which has been superseded and is no longer part of the DPC licensing basis.

Question 12

Discuss the impact of installation of feedring steam generators and its accompanying changes on transient analysis such as the MFW and AFW flow.

Response

The major design differences in the feedring steam generator with respect to the preheater design include the following: a) the main feedwater enters the annular downcomer of the steam generator through a feedring near the top of the tube bundle as opposed to entering a preheater region at the bottom of the tube bundle, b) the tube bundle itself is about 8 feet taller and contains approximately 2000 more tubes of a slightly smaller diameter, and c) the steam generator liquid mass is approximately 20,000 lbm greater at full power.

Two of the licensing basis analyses where the effects of these design changes are most evident are the feedwater system pipe break and steam generator tube rupture events. The impact of the feedring steam generators on the RETRAN transient analyses for these two events is discussed in the DPC responses to Questions 8 and 12 from the NRC Request for Additional Information regarding the DPC-NE-3002 revision.

Question 13

Discuss in detail how the general transport model is used to simulate boron transport, including the nodalization of injection site, mixing coefficient, analysis for which this is credited, and demonstrate that the model produces conservative results.

Response

This revision does not introduce any changes to the approved boron injection modeling methodology discussed in detail in §5.3.2.5 of DPC-NE-3001. Currently, the general transport model is used only in the steam line break and inadvertent opening of a steam generator relief

or safety valve analyses. The injection of the borated safety injection water is modeled at both the high and intermediate head safety injection nozzles. Fill junction boron concentration is determined by control system assuming a mixing coefficient of 1.0.

The conservatisms built into the boron injection modeling include: a conservatively long safety injection response time with no credit taken for flow delivery until the injection pumps have reached full speed, a conservatively high purge volume of unborated water (up to the Refueling Water Storage Tank isolation valves), and a conservatively low Refueling Water Storage Tank boron concentration which includes measurement uncertainties.

Question 14

Discuss the change in assumed steady-state pump head and flow for various transients (§ 2.2.6.2).

Response

The referenced change is editorial in nature. The reactor coolant pump flow rate given in the original topical report was a bounding low value. This is replaced by a best-estimate flow rate which is based on precision calorimetric plant data. A best-estimate value is consistent with the text of the section.

For Chapter 15 accident analyses, the RCS flow rate is adjusted to a bounding value in order to be conservative with respect to the specified acceptance criterion. The pump developed head is adjusted as necessary to be compatible with the desired flow rate assumption.

ONS3 11/14/88 TURBINE TRIP FROM 37% POWER

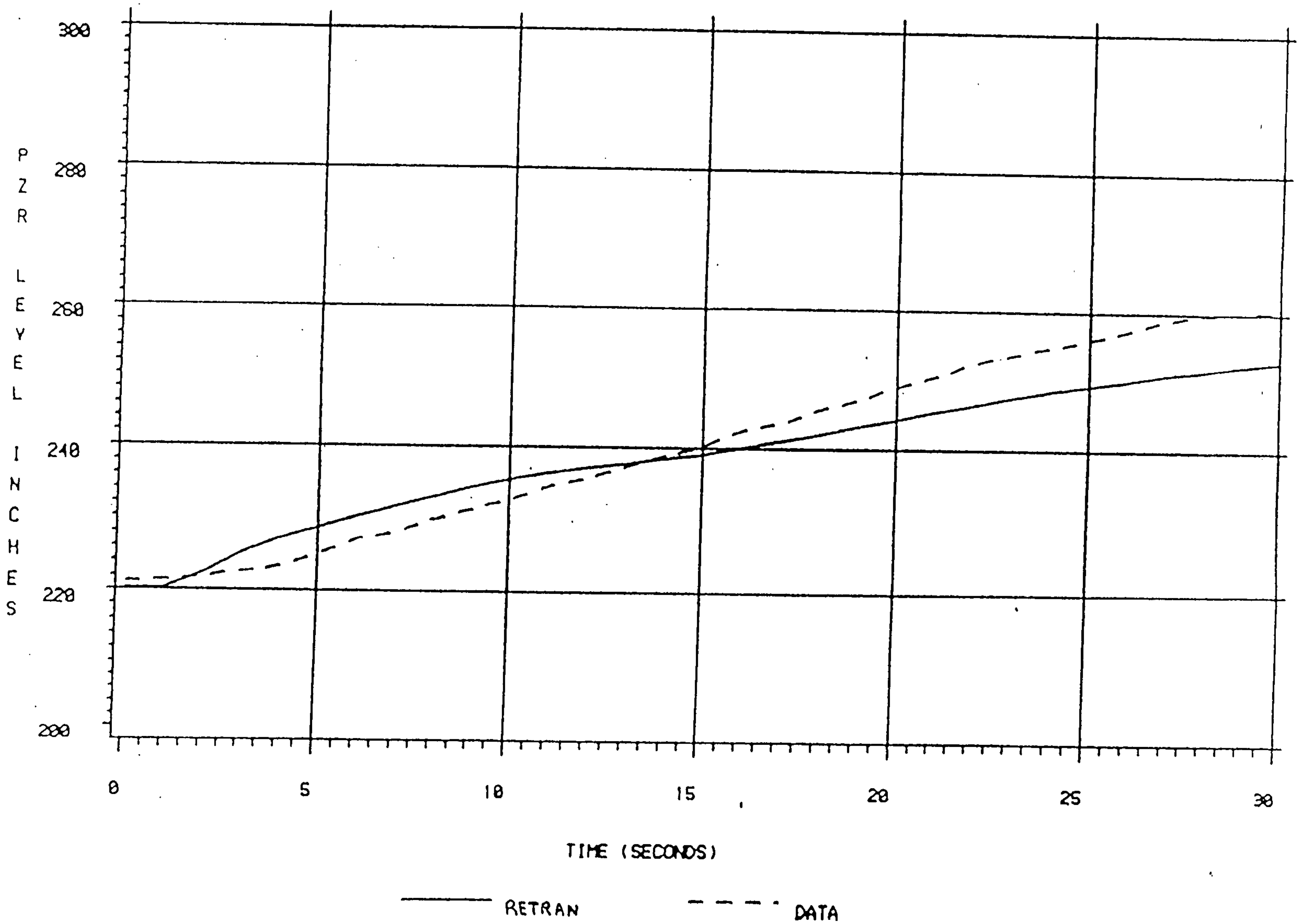


Figure 4-1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

November 7, 1996

RECEIVED
NOV 14 1996
REGULATORY COMPLIANCE

Mr. M. S. Tuckman
Senior Vice President
Nuclear Generation
Duke Power Company
P. O. Box 1006
Charlotte, NC 28201

SUBJECT: SAFETY EVALUATION ON THE USE OF THE BWU-Z CRITICAL HEAT FLUX CORRELATION FOR MCGUIRE NUCLEAR STATION, UNITS 1 AND 2; AND CATAWBA NUCLEAR STATION, UNITS 1 AND 2 (TAC NOS. M95267, M95268 AND M95333, M95334)

Dear Mr. Tuckman:

By letters dated October 13 and December 4, 1995, as supplemented by letters dated April 26 and September 5, 1996, Duke Power Company requested approval for applying the BWU-Z critical heat flux (CHF) correlation for analyses of the McGuire and Catawba reactor cores with Mark-BW 17x17 type fuel. The BWU-Z CHF correlation for the Mark-BW 17x17 type fuel is one of the three applications stated in Babcock and Wilcox Fuel Company's (BWFC's) (now Framatome Cogema Fuels) Topical Report BAW-10199P, "The BWU CHF Correlations." This topical report was reviewed and approved by the NRC by letter dated April 5, 1996.

Based on its review, the staff finds the proposed application of the BWU-Z CHF correlation for the McGuire and Catawba Mark-BW 17x17 type fuel acceptable. Our safety evaluation, which provides the results of the review, is enclosed.

Sincerely,

Herbert N. Berkow

Herbert N. Berkow, Director
Project Directorate II-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket Nos. 50-369, 50-370
50-413, and 50-414

Enclosure: Safety Evaluation

cc w/encl: See next page

cc:
Mr. Paul R. Newton
Legal Department (PB05E)
Duke Power Company
422 South Church Street
Charlotte, North Carolina 28242-0001

County Manager of Mecklenburg County
720 East Fourth Street
Charlotte, North Carolina 28202

Mr. J. E. Snyder
Regulatory Compliance Manager
Duke Power Company
McGuire Nuclear Site
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

J. Michael McGarry, III, Esquire
Winston and Strawn
1400 L Street, NW.
Washington, DC 20005

Senior Resident Inspector
c/o U. S. Nuclear Regulatory
Commission
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Mr. Peter R. Harden, IV
Account Sales Manager
Westinghouse Electric Corporation
Power Systems Field Sales
P. O. Box 7288
Charlotte, North Carolina 28241

Dr. John M. Barry
Mecklenburg County
Department of Environmental
Protection
700 N. Tryon Street
Charlotte, North Carolina 28202

Mr. Dayne H. Brown, Director
Division of Radiation Protection
North Carolina Department of
Environmental, Health and
Natural Resources
P. O. Box 27687
Raleigh, North Carolina 27611-7687

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of
Justice
P. O. Box 629
Raleigh, North Carolina 27602

Mr. G. A. Copp
Licensing - EC050
Duke Power Company
526 South Church Street
Charlotte, North Carolina 28242-0001

Regional Administrator, Region II
U.S. Nuclear Regulatory Commission
101 Marietta Street, NW. Suite 2900
Atlanta, Georgia 30323

Elaine Wathen
Lead REP Planner
Division of Emergency Management
116 West Jones Street
Raleigh, North Carolina 27603-1335

Mr. T. Richard Puryear
Owners Group (NCEMC)
Duke Power Company
4800 Concord Road
York, South Carolina 29745

Duke Power Company

McGuire Nuclear Station
Catawba Nuclear Station

cc:
Mr. M. S. Kitlan
Regulatory Compliance Manager
Duke Power Company
4800 Concord Road
York, South Carolina 29745

North Carolina Municipal Power
Agency Number 1
1427 Meadowwood Boulevard
P. O. Box 29513
Raleigh, North Carolina 27626-0513

County Manager of York County
York County Courthouse
York, South Carolina 29745

Richard P. Wilson, Esquire
Assistant Attorney General
South Carolina Attorney General's
Office
P. O. Box 11549
Columbia, South Carolina 29211

Piedmont Municipal Power Agency
121 Village Drive
Greer, South Carolina 29651

Saluda River Electric
P. O. Box 929
Laurens, South Carolina 29360

Max Batavia, Chief
Bureau of Radiological Health
South Carolina Department of
Health and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201

North Carolina Electric Membership
Corporation
P. O. Box 27306
Raleigh, North Carolina 27611

Senior Resident Inspector
4830 Concord Road
York, South Carolina 29745

Mr. William R. McCollum
Site Vice President
Catawba Nuclear Station
Duke Power Company
4800 Concord Road
York, South Carolina 29745

Mr. T. C. McMeekin
Vice President, McGuire Site
Duke Power Company
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

DUKE POWER COMPANY

MCGUIRE NUCLEAR STATION, UNITS 1 AND 2

DOCKET NOS. 50-369 AND 50-370

CATAWBA NUCLEAR STATION, UNITS 1 AND 2

DOCKET NOS. 50-413 AND 50-414

1.0 INTRODUCTION

By letters dated October 13, 1995 (Reference 1) and December 4, 1995 (Reference 2), as supplemented by letters dated April 26, 1996 (Reference 3) and September 5, 1996 (Reference 4), Duke Power Company (DPC or the licensee) requested the use of the BWU-Z critical heat flux (CHF) correlation for analyses of the McGuire and Catawba reactor cores, which consist of a full core of Mark-BW 17x17 type fuel assemblies.

2.0 DISCUSSION/EVALUATION

The licensee submitted Appendix C to DPC-NE-2005P-A to support plant-specific applications to the reload analyses for the McGuire and Catawba plants. Specifically, Appendix C contains the plant-specific data and limits with Mark-BW 17x17 type fuel using the BWU-Z form of the BWU CHF correlation, the VIPRE-01 thermal-hydraulic computer code (Reference 6), and Duke Power Company thermal-hydraulic (T-H) statistical core design (SCD) methodology (Reference 7). The licensee stated that the BWU-Z form of the BWU correlation used in the analyses for the McGuire and Catawba units is exactly the same as the correlation used in BAW-10199P (Reference 5).

In addition, the licensee used the approved method as described in Reference 7 regarding the statepoint propagation. In its calculation of the statistical limit, the licensee increased the number of cases from 3,000 to 5,000 per statepoint. The licensee stated that increasing the number of cases provided higher confidence of defining the bounding behavior and reducing the multipliers. The 5,000-case number was selected due to a balance between computer resources required for the calculation and the reduction in statistical uncertainty to determine a conservative Statistical Design Limit (SDL).

The maximum statepoint statistical value for departure from nucleate boiling ratio (DNBR) for the 5,000-case propagation is given in Table C-4 of Reference 3. This table also contains the values where case propagation is

less than the 5,000-case propagation. The 5,000-case value will be used in analyses with the BWU-Z form of the BWU CHF correlation for Mark-BW 17x17 type fuel at McGuire and Catawba.

The statistical design limit given in Table C-4 is applicable to this analysis only when all statepoint parameters fall within the McGuire/Catawba key parameter ranges given in Table C-5 of Reference 3.

DPC has also used the VIPRE-01 thermal-hydraulic computer code (Reference 6) to calculate the measured-to-predicted (M/P) CHF ratios with respect to mass velocity, pressure, or thermodynamic quality. The results show that the average M/P value and the data standard deviation are within 1% of the values reported in BWU CHF correlation (Reference 5).

A comparison between the BWU-Z ranges of applicability for Mark-BW 17x17 type fuel database given in Table 4-1 of Reference 5 and the parameter ranges provided in Table C-1 of Reference 3 shows a 0.01 difference in design limit DNBR using the LYNX and the VIPRE-01 code (1.19 design limit DNBR resulted from the LYNX code versus 1.18 design limit DNBR resulted from VIPRE-01 code). However, DPC will use the larger of the two non-statistical correlation limits.

The staff reviewed the submitals provided by DPC (Reference 1 through Reference 4), and found that the proposed use of BWU-Z CHF correlation is acceptable for use at the McGuire and Catawba plants. This conclusion is based on core analyses that (1) both plants have a full homogeneous core of Mark-BW 17 x 17 type fuel assemblies for upcoming reloads, (2) NRC-approved methodologies (T-H SCD, VIPRE-01, and BWU-Z CHF) are used, (3) the larger of the two correlation limits (VIPRE-01 or LYNX) will be used for non-SCD analyses, and (4) the conservative result from the 5,000-case propagation will be used for SCD analyses.

3.0 <u>CONCLUSION</u>

Based on the above discussions, the staff concludes that the proposed use of BWU-Z critical heat flux correlation for McGuire Nuclear Station, Units 1 and 2, and Catawba Nuclear Station, Units 1 and 2, acceptable.

4.0 <u>REFERENCES</u>

1. Letter from M. S. Tuckman to USNRC requesting review the use of the BWU-Z critical heat flux correlation, dated October 13, 1995.

2. Letter from M. S. Tuckman to USNRC discussing Duke Power Company intent to use of the BWU-Z critical heat flux correlation, dated December 4, 1995.

3. Letter from M. S. Tuckman to USNRC submitting the Appendix to DPC-NE-2005P-A, "McGuire/Catawba Plant Specific Data, Mark-BW Fuel BWU-Z Critical Heat Flux Correlation," dated April 26, 1996.

4. Letter from M. S. Tuckman to USNRC responding to the USNRC's Request for Additional Information regarding Appendix C to DPC-NE-2005P-A, dated September 5, 1996.

5. BAW-10199P, The BWU Critical Heat Flux Correlations, BWFC, November 1994 (Approved by letter from R. C. Jones to J. H. Taylor, dated April 5, 1996).

6. DPC-NE-2004P-A, Duke Power Company McGuire and Catawba Nuclear Stations Core Thermal-Hydraulic Methodology Using VIPRE-01, December 1991.

7. DPC-NE-2005P-A, Duke Power Company Thermal-Hydraulic Statistical Core Design Methodology, February 1995.

Principal Contributor: T. Huang

Date: November 7, 1996

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

February 20, 1997

Mr. M. S. Tuckman
Senior Vice President
Nuclear Generation
Duke Power Company
P. O. Box 1006
Charlotte, NC 28201

SUBJECT: CATAWBA AND MCGUIRE NUCLEAR STATIONS - USE OF THE BWU-Z CRITICAL HEAT FLUX CORRELATION IN LICENSING ANALYSES (TAC NOS. M97139, M97140, M97141, AND M97142)

Dear Mr. Tuckman:

In a letter of October 22, 1996, Duke Power Company requested approval to reference the BWU-Z critical heat flux (CHF) correlation included in the descriptions contained in the topical report BAW-10199P-A in licensing documentation describing the VIPRE code for its Catawba and McGuire Nuclear Stations, and incorporate that correlation in its VIPRE code for licensing analyses for those plants. We reviewed your submittal and find that the BWU-Z CHF correlation may be referenced and used as requested. Details of our review and conclusions are set forth in the enclosed safety evaluation (SE).

You also requested to add the statement "Other CHF correlations that have been reviewed and approved by the NRC may also be used to perform DNBR analyses," currently found in the approved topical report DPC-NE-3000, Revision 1, into topical reports DPC-NE-3001, DPC-NE-2004, and DPC-NE-2007. We conclude that apparently you have misconstrued the intent of approving the subject statement to stand in DPC-NE-3000, Revision 1. With your apparent interpretation, the wording is unacceptable for inclusion in the other reports, and is permitted to stand in DPC-NE-3000, Revision 1, only with the understanding as given in the attached SE.

If you have any questions regarding this review please contact me. This completes our effort on your submittal.

Sincerely,

Peter S. Tam

Peter S. Tam, Senior Project Manager
Project Directorate II-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket Nos. 50-369, 50-370, 50-413
and 50-414

Enclosure: Safety Evaluation

cc w/encl: See next page

cc:
Mr. Paul R. Newton
Legal Department (PB05E)
Duke Power Company
422 South Church Street
Charlotte, North Carolina 28242-0001

County Manager of Mecklenburg County
720 East Fourth Street
Charlotte, North Carolina 28202

Mr. J. E. Snyder
Regulatory Compliance Manager
Duke Power Company
McGuire Nuclear Site
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

J. Michael McGarry, III, Esquire
Winston and Strawn
1400 L Street, NW.
Washington, DC 20005

Senior Resident Inspector
c/o U. S. Nuclear Regulatory
Commission
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Mr. Peter R. Harden, IV
Account Sales Manager
Westinghouse Electric Corporation
Power Systems Field Sales
P. O. Box 7288
Charlotte, North Carolina 28241

Dr. John M. Barry
Mecklenburg County
Department of Environmental
Protection
700 N. Tryon Street
Charlotte, North Carolina 28202

Mr. Dayne H. Brown, Director
Division of Radiation Protection
North Carolina Department of
Environmental, Health and
Natural Resources
P. O. Box 27687
Raleigh, North Carolina 27611-7687

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of
Justice
P. O. Box 629
Raleigh, North Carolina 27602

Mr. G. A. Copp
Licensing - EC050
Duke Power Company
526 South Church Street
Charlotte, North Carolina 28242-0001

Regional Administrator, Region II
U.S. Nuclear Regulatory Commission
101 Marietta Street, NW. Suite 2900
Atlanta, Georgia 30323

Elaine Wathen
Lead REP Planner
Division of Emergency Management
116 West Jones Street
Raleigh, North Carolina 27603-1335

Mr. T. Richard Puryear
Owners Group (NCEMC)
Duke Power Company
4800 Concord Road
York, South Carolina 29745

Duke Power Company

McGuire Nuclear Station
Catawba Nuclear Station

cc:
Mr. M. S. Kitlan
Regulatory Compliance Manager
Duke Power Company
4800 Concord Road
York, South Carolina 29745

North Carolina Municipal Power
Agency Number 1
1427 Meadowwood Boulevard
P. O. Box 29513
Raleigh, North Carolina 27626-0513

County Manager of York County
York County Courthouse
York, South Carolina 29745

Richard P. Wilson, Esquire
Assistant Attorney General
South Carolina Attorney General's
Office
P. O. Box 11549
Columbia, South Carolina 29211

Piedmont Municipal Power Agency
121 Village Drive
Greer, South Carolina 29651

Saluda River Electric
P. O. Box 929
Laurens, South Carolina 29360

Max Batavia, Chief
Bureau of Radiological Health
South Carolina Department of
Health and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201

North Carolina Electric Membership
Corporation
P. O. Box 27306
Raleigh, North Carolina 27611

Senior Resident Inspector
4830 Concord Road
York, South Carolina 29745

Mr. William R. McCollum
Site Vice President
Catawba Nuclear Station
Duke Power Company
4800 Concord Road
York, South Carolina 29745

Mr. H. B. Barron
Vice President, McGuire Site
Duke Power Company
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO REFERENCE OF THE BWU-Z CRITICAL HEAT FLUX CORRELATION

IN LICENSING DOCUMENTATION AND USE IN LICENSING APPLICATIONS

DUKE POWER COMPANY

CATAWBA NUCLEAR STATION, UNITS 1 AND 2

MCGUIRE NUCLEAR STATION, UNITS 1 AND 2

DOCKET NOS. 50-413, 50-414, 50-369, AND 50-370

1.0 INTRODUCTION

In a letter of October 22, 1996, Duke Power Company (DPC), requested approval to reference the BWU-Z critical heat flux (CHF) correlation included in the descriptions contained in the topical report BAW-10199P-A, "The BWU Critical Heat Flux Correlations" (approved by letter, R. Jones to J. Taylor, April 5, 1996) in licensing documentation for its Catawba and McGuire Nuclear Stations, and incorporate that correlation in its licensing analytical models for those plants. DPC also requested to incorporate the statement "Other CHF correlations that have been reviewed and approved by the NRC may also be used to perform DNBR analyses," currently found in the approved DPC report DPC-NE-3000, Revision 1, into its reports DPC-NE-3001, DPC-NE-2004, and DPC-NE-2007.

2.0 EVALUATION

2.1 BWU-Z Applicability to Catawba and McGuire

In its review, the staff considered the acceptability of the BWU-Z CHF correlation for reference in Catawba and McGuire licensing documentation and use in Catawba and McGuire licensing analyses. The staff also referred to BAW-10199P-A and the staff's safety evaluation report (SER) of April 5, 1996, which discuss the BWU-Z correlation and its applicability considerations. From such review, the staff concludes that the BWU-Z correlation covers the ranges of thermal/hydraulic conditions expected in Catawba and McGuire licensing analyses and therefore is suitable for inclusion in versions of the VIPRE code approved for use in Catawba and McGuire licensing analyses. Therefore, the staff also concludes that BAW-10199P-A (August 1996) is acceptable for reference in Catawba and McGuire licensing documentation, including plant technical specifications and core operating limits reports (COLRs).

2.2 Topical Reports Wording Change

In its October 22, 1996, letter, DPC also requested to incorporate the statement "Other CHF correlations that have been reviewed and approved by the NRC may also be used to perform DNBR analyses," currently found in the approved DPC topical report DPC-NE-3000, Revision 1, into its reports DPC-NE-3001, DPC-NE-2004, and DPC-NE-2007. In the staff's reading of the request, it appears that the wording would permit DPC to reference and use other approved correlations in licensing analyses without prior NRC approval. Such reference and use would be contrary to the operating license and COLR change process, which requires that any change to a methodology referenced in plant technical specifications or COLR (e.g., VIPRE) be reviewed and approved by the staff for that reference prior to doing so. Therefore, the staff concludes that the proposed wording change is unacceptable. The staff's understanding of the wording is that it is to indicate which correlations might be candidates for technical specifications or COLR inclusion, with only an applicability review by the staff. It is only with this understanding that the staff previously approved the wording to stand in DPC-NE-3000, Revision 1.

3.0 CONCLUSIONS

The staff concludes that BAW-10199P-A (August 1996) is acceptable for reference in Catawba and McGuire licensing documentation, including plant technical specifications and COLRs, and for use in versions of the VIPRE code approved for use in Catawba and McGuire licensing analyses.

The staff does not approve the requested topical report wording changes.

Principal Contributor: Frank R. Orr

Date: February 20, 1997