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Docket Number 50-346

10 CFR 50.90

License Number NPF-3

Serial Number 3000

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United States Nuclear Regulatory Commission
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Washington, DC 20555-0001

Subject: Davis-Besse Nuclear Power Station
License Amendment Application to Revise Technical Specification 3/4.4.5, "Reactor Coolant System - Steam Generators," to Permit One-Time Extension of Steam Generator Tube Inservice Inspection Interval
(License Amendment Request No. 03-0019)

Ladies and Gentlemen:

Pursuant to 10 CFR 50.90, the following amendment is requested for the Davis-Besse Nuclear Power Station, Unit 1 (DBNPS). The proposed amendment would revise Technical Specification (TS) 3/4.4.5, "Reactor Coolant System - Steam Generators," to allow a one-time extension of the steam generator tube inservice inspection interval. This one-time interval extension would apply only to the first inservice inspection following completion of the extended thirteenth refueling outage (13RFO). A comprehensive inservice inspection of the steam generators was performed during 13RFO and was completed on March 9, 2002. Since February 16, 2002, the DBNPS has been in an extended shutdown. During this extended shutdown, the steam generators were in a condition in which active degradation would not be expected. The proposed change will allow delaying steam generator inservice inspection until a mid-cycle outage commencing on or before March 31, 2005. Enclosure 1 to this letter contains the technical basis for the proposed extension and the proposed no significant hazards consideration.

Approval of the proposed amendment is requested by February 8, 2004, to allow implementation of the amendment prior to the expiration of the TS surveillance interval on March 9, 2004. Once approved, the amendment shall be implemented within 30 days.

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The proposed changes have been reviewed by the DBNPS Station Review Board and Company Nuclear Review Board.

Should you have any questions or require additional information, please contact Mr. Kevin L. Ostrowski, Manager - Regulatory Affairs, at (419) 321-8450.

The statements contained in this submittal, including its associated enclosures and attachments, are true and correct to the best of my knowledge and belief. I declare under penalty of perjury that I am authorized by the FirstEnergy Nuclear Operating Company to make this request and the foregoing is true and correct.

Executed on: 12/16/03.

By:

Mark B. Bezilla, Vice President - Nuclear

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Enclosures

cc: Regional Administrator, NRC Region III
J. B. Hopkins, NRC/NRR Senior Project Manager
D. J. Shipley, Executive Director, Ohio Emergency Management Agency, State of Ohio (NRC Liaison)
C. S. Thomas, NRC Region III, DB-1 Senior Resident Inspector
Utility Radiological Safety Board

Docket Number 50-346
License Number NPF-3
Serial Number 3000
Enclosure 1

DAVIS-BESSE NUCLEAR POWER STATION
EVALUATION
FOR
LICENSE AMENDMENT REQUEST NUMBER 03-0019

(98 pages follow)

DAVIS-BESSE NUCLEAR POWER STATION
EVALUATION
FOR
LICENSE AMENDMENT REQUEST NUMBER 03-0019

Subject: License Amendment Application to Revise Technical Specification 3/4.4.5, "Reactor Coolant System - Steam Generators," to Permit One-Time Extension of Steam Generator Tube Inservice Inspection Interval

1.0 DESCRIPTION

This letter is a request to amend the Davis-Besse Nuclear Power Station, Unit Number 1 (DBNPS) Facility Operating License Number NPF-3.

The proposed change would revise the Operating License Technical Specification 3/4.4.5, "Reactor Coolant System - Steam Generators," to permit a one-time extension of the steam generator tube inservice inspection interval. The DBNPS thirteenth refueling outage (13RFO) commenced on February 16, 2002. Inservice inspection of the steam generators was performed during 13RFO and was completed on March 9, 2002 with the next inspection due March 9, 2004. Details of the inspection scope are provided in Section 3.0 of this application. Since February 16, 2002, the DBNPS has been in an extended shutdown. During this extended shutdown, no conditions existed that would require an assessment of active degradation mechanisms, crack growth rate progressions, or internal steam generator components. Additionally, no conditions were identified that would have an adverse effect on, or cause any type of known corrosion damage to the steam generators during the layup period. The proposed change will allow delaying steam generator inservice inspection until a mid-cycle outage commencing on or before March 31, 2005.

2.0 PROPOSED CHANGE

The proposed change affects TS 3/4.4.5 and is shown on the marked-up TS page in Attachment 1.

The proposed change would add a note to TS Surveillance Requirement (SR) 4.4.5.3.a. SR 4.4.5.3.a currently states:

> Inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If the results of two consecutive inspections for a given group of tubes following service under all volatile treatment (AVT) conditions fall into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval for that group may be extended to a maximum of 40 months.

The proposed change would add a double asterisked note to SR 4.4.5.3.a which states:

> An exception applies for the interval following the March 2002 inspection completed during the Thirteenth Refueling Outage. Under this exception, the next inservice inspection may be delayed until March 31, 2005.

In summary, the proposed change revises Technical Specification 3/4.4.5, "Reactor Coolant System - Steam Generators," to permit a one-time extension of the steam generator tube inservice inspection interval until March 31, 2005.

No associated change to the Technical Specification Bases is being made.

3.0 BACKGROUND

TS SR 4.4.5.3.a requires that inservice inspections of steam generator tubes be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. Per TS SR 4.4.5.3.d, the 25% surveillance interval extension provided in TS 4.0.2 does not apply to this requirement. Inservice inspection of the steam generators was performed during 13RFO, which commenced on February 16, 2002. A comprehensive inspection of the steam generators was completed on March 9, 2002. TS SR 4.4.5.3.a requires performance of the next inspection by March 9, 2004. Since February 16, 2002, the DBNPS has been in an extended shutdown. During this extended shutdown, the steam generators were in a condition in which active degradation of the steam generators would not be expected.

The DBNPS reactor coolant system (RCS) contains two steam generators. The steam generators are discussed in DBNPS Updated Safety Analysis Report (USAR) Section 5.5.2, "Steam Generators." The steam generators are vertical, straight tube, once through, counterflow, shell and tube heat exchangers with shell side boiling. The steam generators perform the following safety functions:

- Provide a pressure boundary between the reactor coolant and the secondary side fluid to confine fission products and activation products within the reactor coolant system.
- Provide heat transfer capability to remove the reactor coolant heat produced during normal power operations.
- Provide normal and auxiliary feedwater flow paths and heat transfer capability for both normal and emergency cooldown, and supply steam for the auxiliary feed pump turbines for emergency cooling.

Steam generator inspection activities are performed in accordance with the DBNPS Steam Generator Management Program. The DBNPS Steam Generator Management Program implements the guidance of NEI 97-06, "Steam Generator Program Guidelines." The most recent steam generator inservice inspection was completed on March 9, 2002. This inspection included:

1. Inspection of new re-rolls.
2. Inspection of all in-service tubes and sleeves by a bobbin coil.
3. Inspection of 62 percent of the sleeve roll expansions by a plus point coil.
4. Inspection of 57 percent of the tube upper roll expansions by a plus point and pancake coil.
5. Inspection of all of the non-stress-relieved tube roll expansions–factory re-rolls by a plus point and pancake coil.
6. Inspection of 60 percent of the hot leg roll plugs by a plus point coil.
7. Inspection of the tubes bordering the sleeve region by a plus point and pancake coil.
8. Inspection of all of the flaw-like indications reported from bobbin by a plus point and pancake coil.
9. Inspection of the dent indications, including all those located above the 14th tube support plate and a 60 percent sample of the remaining population by a plus point and pancake coil.

10. Inspection of 500 tubes at the sludge pile region of the lower tubesheet in each steam generator by a plus point and pancake coil.
11. Inspection of plugged tubes per the Three Mile Island (TMI) severance tube event.
12. Inspection of all welded tube plugs by qualified VT-1.

Results of this inspection have been provided to the NRC in letters dated March 22, 2002 (Serial Number 2771), April 25, 2002 (Serial Number 2768), March 31, 2003 (Serial Number 2944), and November 3, 2003 (Serial Number 2989).

Currently, the Davis-Besse steam generators have been in service for approximately 15.8 EFPY and have 562 (3.6%) plugged tubes in steam generator 2-A and 161 (1.0%) plugged tubes in steam generator 1-B leaving a total of 30191 tubes in service.

4.0 TECHNICAL ANALYSIS

The surveillance requirements for inspection of the steam generator tubes ensure that the structural integrity of this portion of the RCS will be maintained. Inservice inspection of steam generator tubing is essential in order to monitor the condition of the tubes for evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

Two assessments have been performed to assure the acceptable operation of the DBNPS steam generators for a period of up to 1.4 effective full power years (EFPY) following the end of the thirteenth refueling outage. The first assessment is documented in Framatome-ANP Document 51-5033009-03, "DB-1 Steam Generator Shut Down/Lay Up Chemistry Assessment - 2003." This detailed assessment is included as Attachment 4 to this application. This assessment evaluated the layup and storage conditions of the steam generators during the extended shutdown from February 16, 2002 through December 1, 2003. This assessment concluded that no conditions existed that would require an assessment of active degradation mechanisms, crack growth rate progressions, or internal steam generator components. Additionally, no conditions were identified that would have an adverse effect on, or cause any type of known corrosion damage to the steam generators during the layup period. It is projected that there will be no degradation of the steam generator materials prior to plant restart provided current satisfactory storage and layup conditions are maintained. Prior to operation beyond the original surveillance interval (i.e., March 9, 2004), the DBNPS staff will assure that the steam generator layup and storage conditions subsequent to the time period assessed in Framatome-ANP Document 51-5033009-03 were consistent with the conclusions of that assessment.

The second assessment is documented in Framatome-ANP Document 51-5034594-02, "A Steam Generator Tubing Operational Assessment for Davis Besse." This assessment is included as Attachment 5 to this application. An operational assessment for a full cycle length (approximately 1.85 EFPY) had been completed following the inspections performed in 2002. Framatome-ANP Document 51-5034594-02 updated the full cycle operational assessment for a mid-cycle outage at approximately 1.4 EFPY. This assessment concluded that projected structural margins are greater for 1.4 EFPY of operation than they are for a full cycle of operation. The projected number of indications remain the same for wear and decrease by about 20% for other degradation mechanisms for 1.4 EFPY of operation. In addition, projected accident leakage following a steam line break remains at nominal projected values.

The proposed amendment would allow operation on the DBNPS steam generators until their next inspection during a mid-cycle outage commencing on or before March 31, 2005. This will include no more than 1.4 EFPY of operation. During a full cycle, approximately 1.85 EFPY of operation is expected. Since the layup and storage conditions of the steam generators during the extended outage have been evaluated and determined to not adversely affect the steam generators, and since the operational assessment for the mid-cycle outage has shown substantial margin for any unexpected degradation that may have occurred, the proposed one time exception to the steam generator inspection interval is acceptable.

5.0 REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration

Technical Specification Surveillance Requirement 4.4.5.3 requires performance of steam generator tube inspections at an interval not more than 24 calendar months. The proposed amendment would provide for a one-time extension of the steam generator tube inservice inspection interval. The proposed change would allow the first steam generator inspection following the thirteenth refueling outage to be delayed until no later than March 31, 2005.

An evaluation has been performed to determine whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The steam generator tubes perform both an accident prevention and an accident mitigation function. Steam generator tube integrity is necessary to prevent the loss of reactor coolant system inventory to the secondary system and to provide a barrier to fission product release to the environment. The layup and storage conditions of the steam generator during the extended outage have been assessed and determined to not adversely affect steam generator conditions. An operational assessment of the steam generators for approximately 1.4 effective full power year has been performed to assure acceptable structural integrity during the extended surveillance interval. The operational assessment for the steam generators has determined that primary-to-secondary leakage following a steam line break, which is the limiting event (other than a tube rupture), would continue to be acceptable. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   The proposed change does not introduce any new or different failure mechanism for the steam generators. Steam generator tube integrity will be maintained as previously analyzed following postulated events. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No.

   The layup and storage conditions of the steam generator during the extended outage have been assessed and determined to not adversely affect steam generator condition. The operational assessment for the mid-cycle outage has shown that structural margins are greater at approximately 1.4 EFPY then they would be at the end of a typical full cycle of operation. Accident induced leakage is projected to be the same for the surveillance interval extension period as it would be for a full cycle of operation. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, it is concluded that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements/Criteria

Inspection requirements for the DBNPS steam generator are specified, in part, in USAR Section 3D.1.10, "Criterion 14 - Reactor Coolant Pressure Boundary." USAR Section 3D.1.10 states, in part:

> The reactor coolant pressure boundary has been designed, fabricated, erected, and tested to ensure an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

The steam generator tubes form part of the reactor coolant system pressure boundary. The proposed amendment does not affect any design, fabrication, or erection requirements. The technical analyses provided in Section 4.0 of this application and the referenced attachments demonstrate that the one-time surveillance interval extension will not adversely affect steam generator operation. The one-time modification to steam generator test (i.e, inservice inspection) requirements will not adversely affect the probability of abnormal leakage, of rapidly propagating failure, or of gross rupture.

USAR Section 3D.1.26, "Criterion 30 - Quality of Reactor Coolant Pressure Boundary," states, in part:

> Components which are part of the reactor coolant pressure boundary are designed, fabricated, erected, and tested to the highest quality standards practical. Means are provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

The proposed change does not alter the quality standards to which the steam generators are tested. The test methods used during the thirteenth refueling outage and the test methods planned to be used during the mid-cycle outage will be consistent with the DBNPS Technical Specifications and industry guidance.

USAR Section 3D.1.28, "Criterion 32 - Inspection of Reactor Coolant Pressure Boundary," states, in part:

> Components that are part of the reactor coolant pressure boundary are designed to permit (1) periodic inspection and testing of important areas and features to assess their structural and leaktight integrity, and (2) an appropriate material surveillance program for the reactor pressure vessel.

The proposed change does not alter the design of the steam generators regarding the ability to perform periodic inspection and testing.

The DBNPS Technical Specification requirements for inservice inspection of the steam generator tubes are based on a modification of Regulatory Guide (RG) 1.83, Revision 1, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes." The proposed change provides for a one-time extended inspection interval beyond the 24 calendar months specified in the RG. However, as addressed by the technical analysis provided in Section 4.0 of this application, the one-time exception to the RG inspection interval is acceptable.

10 CFR 50.55a, "Codes and Standards," requires the inservice examination of components in compliance with the requirements of the latest edition and addenda of the American Society of Mechanical Engineers Boiler and Pressure Vessel (ASME) Code incorporated by reference into 10 CFR 50.55a twelve months prior

to the start of the 120-month inspection interval. The current Third Ten Year Interval Inservice Inspection Program is based on ASME Code Section XI of the 1995 Edition with the 1996 Addenda, as modified by 10 CFR 50.55a.
10 CFR 50.55a(b)(2)(iii) states:

> Steam generator tubing (modifies Article IWB- 2000). If the technical specifications of a nuclear power plant include surveillance requirements for steam generators different than those in Article IWB- 2000, the inservice inspection program for steam generator tubing is governed by the requirements in the technical specifications.

Accordingly, the steam generator tube inspections are governed by the DBNPS Technical Specifications, including the frequency of inspection, which is addressed by this proposed change.

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

7.0 REFERENCES

1. DBNPS Operating License NPF-3, Appendix A Technical Specifications through Amendment 260.

2. DBNPS Updated Safety Analysis Report through Revision 23.

3. Framatome Document 51-5033009-03, "DB-1 Steam Generator Shut Down/Lay Up Chemistry Assessment - 2003," dated December 10, 2003.

4. Framatome Document 51-5034594-02, "A Steam Generator Tubing Operational Assessment for Davis Besse," dated December 9, 2003.

5. NEI 97-06, *Steam Generator Program Guidelines,* Revision 1, dated January 2001.

6. Regulatory Guide (RG) 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," Revision 1, dated July 1975.

7. Letter from FENOC to the NRC dated March 22, 2002, "Davis-Besse Nuclear Power Station Technical Specification 4.4.5.5a Report of Steam Generator Tube Plugging," DBNPS Serial Number 2771, ADAMS Accession No. ML020850568.

8. Letter from FENOC to the NRC dated April 25, 2002, "Davis-Besse Nuclear Power Station License Condition 2.C(7) Report for the Thirteenth Refueling Outage," DBNPS Serial Number 2768, ADAMS Accession No. ML021210583.

9. Letter from FENOC to the NRC dated March 31, 2003, "Technical Specifications 4.4.5.5.b and 6.9.1.5.b: Report of Steam Generator Tube Inservice Inspection Results," DBNPS Serial Number 2944, ADAMS Accession No. ML030930374.

10. Letter from FENOC to the NRC dated November 3, 2003, "Request for Additional Information Regarding the 2002 Steam Generator Tube Inspections (TAC No. MB9541)," DBNPS Serial Number 2989, ADAMS Accession No. ML033100370.

8.0 ATTACHMENTS

1. Proposed Mark-Up of Technical Specification Pages
2. Proposed Retyped Technical Specification Page
3. Technical Specification Bases Pages
4. Framatome Document 51-5033009-03
5. Framatome Document 51-5034594-02

LAR 03-0019
Attachment 1

**PROPOSED MARK-UP
OF
TECHNICAL SPECIFICATION PAGES**

(11 pages follow)

INFORMATION ONLY

REACTOR COOLANT SYSTEM

STEAM GENERATORS

LIMITING CONDITION FOR OPERATION

3.4.5 Each Steam Generator shall be OPERABLE with a minimum water level of 18 inches and the maximum specified below as applicable:

MODES 1 and 2:

a. The acceptable operating region of Figure 3.4-5.

MODE 3*:

b. 50 inches Startup Range with the SFRCS Low Pressure Trip bypassed and one or both Main Feedwater Pump(s) capable of supplying Feedwater to any Steam Generator.

c. 96 percent Operate Range with:

1. The SFRCS Low Pressure Trip active.

   Or

2. The SFRCS Low Pressure Trip bypassed and both Main Feedwater Pumps incapable of supplying Feedwater to the Steam Generators.

MODE 4:

d. 625 inches Full Range Level

APPLICABILITY: MODES 1, 2, 3, and 4, as above.

ACTION:

a. With one or more steam generators inoperable due to steam generator tube imperfections, restore the inoperable generator(s) to OPERABLE status prior to increasing T_{avg} above 200°F.

b. With one or more steam generators inoperable due to the water level being outside the limits, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the next 30 hours.

*Establish adequate SHUTDOWN MARGIN to ensure the reactor will stay subcritical during a MODE 3 Main Steam Line Break.

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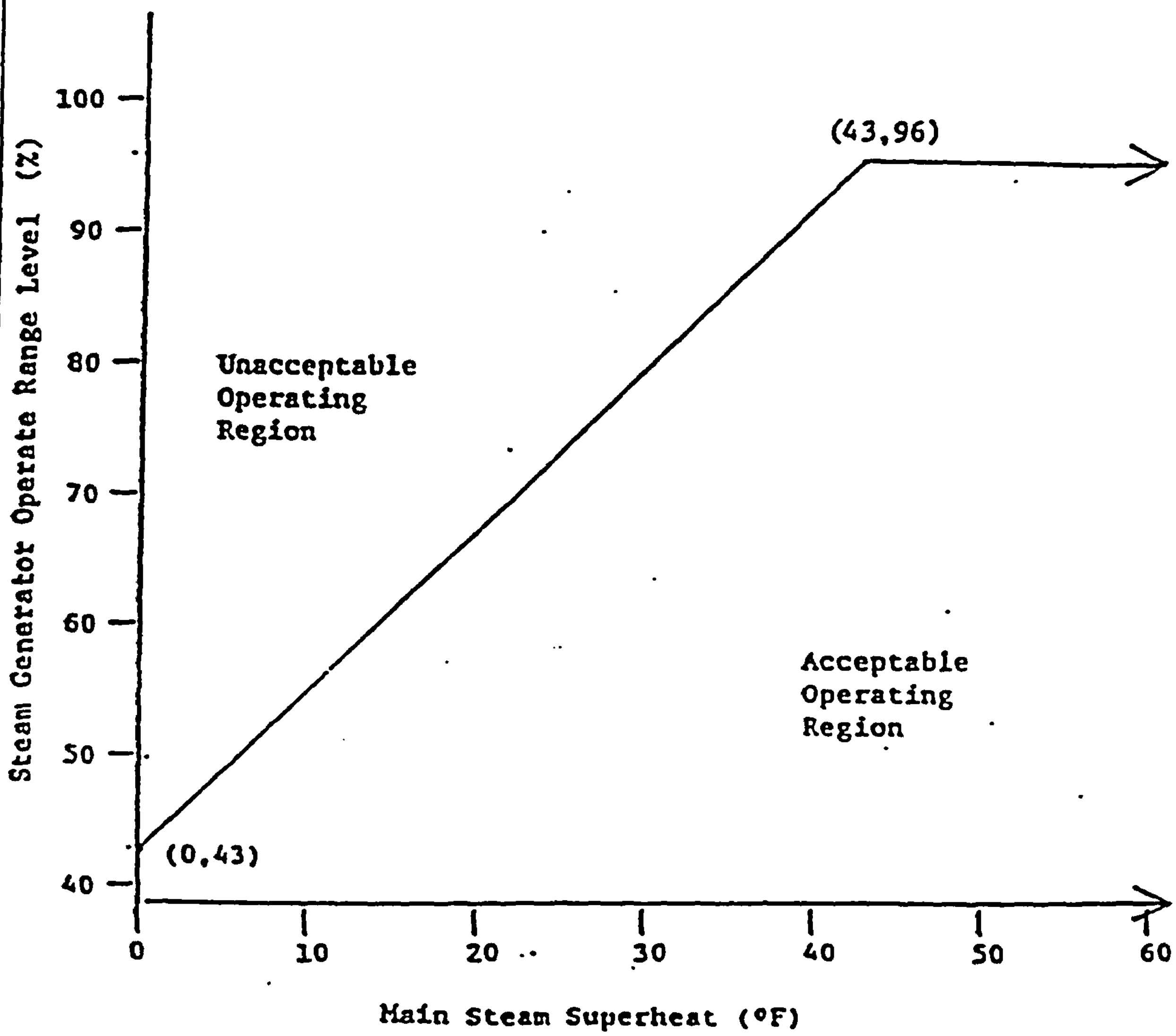
Figure 3.4-5
Maximum Allowable Steam Generator Level
in MODES 1 and 2



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STEAM GENERATORS

SURVEILLANCE REQUIREMENTS

4.4.5.0 Each steam generator shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program and the requirements of Specification 4.0.5.

4.4.5.1 Steam Generator Sample Selection and Inspection - Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 4-4.1.

4.4.5.2 Steam Generator Tube Sample Selection and Inspection - The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 4.4-2. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 4.4.5.3 and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 4.4.5.4. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators; the tubes selected for these inspections shall be selected on a random basis except:

a. The first sample inspection during each inservice inspection of each steam generator shall include:

   1. All tubes or tube sleeves that previously had detectable wall penetrations (> 20%) that have not been plugged or repaired by repair roll or sleeving in the affected area. (Tubes repaired by sleeving or repair roll remain available for random selection).

   2. At least 50% of the tubes inspected shall be in those areas where experience has indicated potential problems.

3. A tube inspection (pursuant to Specification 4.4.5.4.a.9.) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

b. Tubes in the following groups may be excluded from the first random sample if all tubes in a group in both steam generators are inspected. No credit will be taken for these tubes in meeting minimum sample size requirements.

   1. Group A-1: Tubes within one, two or three rows of the open inspection lane.

   2. Group A-2: Tubes having a drilled opening in the 15th support plate.

   3. Group A-3: Tubes included in the rectangle bounded by rows 62 and 90 and by tubes 58 and 76, excluding tubes included in Group A-1.*

c. The tubes selected as the second and third samples (if required by Table 4.4-2) during each inservice inspection may be subjected to less than a full tube inspection provided:

   1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.

   2. The inspections include those portions of the tubes where imperfections were previously found.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

* Tubes in Group A-3 shall not be excluded after completion of the fifth refueling outage.

Notes: (1) In all inspections, previously degraded tubes must exhibit significant (> 10%) further wall penetrations to be included in the above percentage calculations.

(2) Where special inspections are performed pursuant to 4.4.5.2.b, defective or degraded tubes found as a result of the inspection shall be included in determining the Inspection Results Category for that special inspection but need not be included in determining the Inspection Results Category for the general steam generator inspection.

4.4.5.3 Inspection Frequencies - The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. Inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months** after the previous inspection. If the results of two consecutive inspections for a given group* of tubes following service under all volatile treatment (AVT) conditions fall into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval for that group may be extended to a maximum of 40 months.

b. If the results of the inservice inspection of a steam generator performed in accordance with Table 4.4-2 at 40 month intervals for a given group* of tubes fall in Category C-3, subsequent inservice inspections shall be performed at intervals of not less than 10 nor more than 20 calendar months after the previous inspection. The increase in inspection frequency shall apply until a subsequent inspection meets the conditions specified in 4.4.5.3a and the interval can be extended to 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 4.4-2 during the shutdown subsequent to any of the following conditions:

1. Primary-to-secondary tube leaks (not including leaks originating from tube-to tube sheet welds) in excess of the limits of Specification 3.4.6.2.

   If the leak is determined to be from a repair roll joint, rather than selecting a random sample, inspect 100% of the repair roll joints in the affected steam generator. If the results of this inspection fall into the C-3 category, perform additional inspections of the new roll areas in the unaffected steam generator.

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*A group of tubes means:

(a) All tubes inspected pursuant to 4.4.5.2.b, or

(b) All tubes in a steam generator less those inspected pursuant to 4.4.5.2.b.

** An exception applies for the interval following the March 2002 inspection completed during the Thirteenth Refueling Outage. Under this exception, the next inservice inspection may be delayed until March 31, 2005.

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SURVEILLANCE REQUIREMENTS (Continued)

2. A seismic occurrence greater than the Operating Basis Earthquake.

3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

4. A main steam line or feedwater line break.

d. The provisions of Specification 4.0.2 are not applicable.

4.4.5.4 Acceptance Criteria

a. As used in this Specification:

1. Tubing or Tube means that portion of the tube or tube sleeve which forms the primary system to secondary system boundary.

2. Imperfection means an exception to the dimensions, finish or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal tube wall thickness, if detectable, may be considered as imperfections.

3. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either inside or outside of a tube.

4. Degraded Tube means a tube containing imperfections $\geq$ 20% of the nominal wall thickness caused by degradation that has not been repaired by repair roll or sleeving in the affected area.

5. % Degradation means the percentage of the tube wall thickness affected or removed by degradation.

6. Defect means an imperfection of such severity that it exceeds the repair limit. A defective tube is a tube containing a defect that has not been repaired by repair roll or sleeving in the affected area or a sleeved tube that has a defect in the sleeve.

7. Repair Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging or repaired by repair roll or sleeving in the affected area because it may become unserviceable prior to the next inspection and is equal to 40% of the nominal tube wall thickness. The process described in Topical Report BAW-2120P will be used for sleeving.

(Continued) 7. The repair roll process used is described in the Topical Report BAW-2303P, Revision 4. The new roll area must be free of degradation in order for the repair to be considered acceptable.

8. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 4.4.5.3.c, above.

9. Tube Inspection means an inspection of the steam generator tube from the point of entry completely to the point of exit. The previously existing tube and tube roll, outboard of the new roll area in the tube sheet, can be excluded from future periodic inspection requirements because it is no longer part of the pressure boundary once the repair roll is installed.

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10. Preservice Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed prior to initial POWER OPERATION using the equipment and techniques expected to be used during subsequent inservice inspections.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug or repair by repair roll or sleeving in the affected areas all tubes exceeding the repair limit and all tubes containing through-wall cracks) required by Table 4.4-2.

4.4.5.5 Reports

a. Following each inservice inspection of steam generator tubes, the number of tubes plugged in each steam generator shall be reported to the Commission within 15 days.

b. The complete results of the steam generator tube inservice inspection shall be submitted on an annual basis in a report for the period in which this inspection was completed. This report shall include:

1. Number and extent of tubes inspected.

2. Location and percent of wall-thickness penetration for each indication of an imperfection.

3. Identification of tubes plugged, sleeved or repair rolled.

c. Results of steam generator tube inspections which fall into Category C-3 and require notification of the Commission shall be reported prior to resumption of plant operation. This report shall provide a description of investigations conducted to determine cause of the tube degradation and corrective measures taken to prevent recurrence.

4.4.5.6 The steam generator shall be demonstrated OPERABLE by verifying steam generator level to be within limits at least once per 12 hours.

4.4.5.7 When steam generator tube inspection is performed as per Section 4.4.5.2, an additional but totally separate inspection shall be performed on special interest peripheral tubes in the vicinity of the secured internal auxiliary feedwater header. This testing shall only be required on the steam generator selected for inspection, and the test shall require inspection only between

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the upper tube sheet and the 15th tube support plate. The tubes selected for inspection shall represent the entire circumference of the steam generator and shall total at least 150 peripheral tubes.

4.4.5.8 Visual inspections of the secured internal auxiliary feedwater header, header to shroud attachment welds, and the external header thermal sleeves shall be performed on each steam generator through the auxiliary feedwater injection penetrations.

These inspections of the secured internal auxiliary feedwater header, header to shroud attachment welds, and the external header thermal sleeves shall be performed during the third period of each ten-year Inservice Inspection Interval (ISI).

4.4.5.9 When steam generator tube inspection is performed as per Section 4.4.5.2, an additional but totally separate inspection shall be performed on special interest tubes that have been repaired by the repair roll process. This inspection shall be performed on 100% of the tubes that have been repaired by the repair roll process. The inspection shall be limited to the repair roll joint and the roll transitions of the repair roll. Defective or degraded tubes found in the repair roll region as a result of the inspection need not be included in determining the Inspection Results Category for the general steam generator inspection.

TABLE 4.4-1

MINIMUM NUMBER OF STEAM GENERATORS TO BE INSPECTED DURING INSERVICE INSPECTION

Preservice Inspection	No			Yes		
No. of Steam Generators per Unit	Two	Three	Four	Two	Three	Four
First Inservice Inspection	All			One	Two	Two
Second & Subsequent Inservice Inspections	One[1]			One[1]	One[2]	One[3]

<u>Table Notation:</u>

1. The inservice inspection may be limited to one steam generator on a rotating schedule encompassing 3 N % of the tubes (where N is the number of steam generators in the plant) if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. Note that under some circumstances, the operating conditions in one or more steam generators may be found to be more severe than those in other steam generators. Under such circumstances the sample sequence shall be modified to inspect the most severe conditions.

2. The other steam generator not inspected during the first inservice inspection shall be inspected. The third and subsequent inspections should follow the instructions described in 1 above.

3. Each of the other two steam generators not inspected during the first inservice inspections shall be inspected during the second and third inspections. The fourth and subsequent inspections shall follow the instructions described in 1 above.

TABLE 4.4-2
STEAM GENERATOR TUBE INSPECTION

1ST SAMPLE INSPECTION			2ND SAMPLE INSPECTION		3RD SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per S.G. (1)	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug or repair by repair rolling or sleeving defective tubes and inspect additional 2S tubes in this S.G.	C-1	None	N/A	N/A
			C-2	Plug or repair by repair rolling or sleeving defective tubes and inspect additional 4S tubes in this S.G.	C-1	None
					C-2	Plug or repair by repair rolling or sleeving defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N/A	N/A
	C-3	Inspect all tubes in this S.G., plug or repair by repair rolling or sleeving defective tubes and inspect 2S tubes in each other S.G. Report to the NRC prior to resumption of plant operation.	All other S.G.s are C-1	None	N/A	N/A
			Some S.G.s C-2 but no additional S.G. are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional S.G. is C-3	Inspect all tubes in each S.G. and plug or repair by repair rolling or sleeving defective tubes. Report to the NRC prior to resumption of plant operation.	N/A	N/A

(1) $S = 3\frac{N}{n}\%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

**PROPOSED RETYPED
TECHNICAL SPECIFICATION PAGE**

(1 page follows)

Notes: (1) In all inspections, previously degraded tubes must exhibit significant (> 10%) further wall penetrations to be included in the above percentage calculations.

(2) Where special inspections are performed pursuant to 4.4.5.2.b, defective or degraded tubes found as a result of the inspection shall be included in determining the Inspection Results Category for that special inspection but need not be included in determining the Inspection Results Category for the general steam generator inspection.

4.4.5.3 Inspection Frequencies - The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. Inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months** after the previous inspection. If the results of two consecutive inspections for a given group* of tubes following service under all volatile treatment (AVT) conditions fall into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval for that group may be extended to a maximum of 40 months.

b. If the results of the inservice inspection of a steam generator performed in accordance with Table 4.4-2 at 40 month intervals for a given group* of tubes fall in Category C-3, subsequent inservice inspections shall be performed at intervals of not less than 10 nor more than 20 calendar months after the previous inspection. The increase in inspection frequency shall apply until a subsequent inspection meets the conditions specified in 4.4.5.3a and the interval can be extended to 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 4.4-2 during the shutdown subsequent to any of the following conditions:

   1. Primary-to-secondary tube leaks (not including leaks originating from tube-to tube sheet welds) in excess of the limits of Specification 3.4.6.2.

      If the leak is determined to be from a repair roll joint, rather than selecting a random sample, inspect 100% of the repair roll joints in the affected steam generator. If the results of this inspection fall into the C-3 category, perform additional inspections of the new roll areas in the unaffected steam generator.

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*A group of tubes means:
(a) All tubes inspected pursuant to 4.4.5.2.b, or
(b) All tubes in a steam generator less those inspected pursuant to 4.4.5.2.b.

** An exception applies for the interval following the March 2002 inspection completed during the Thirteenth Refueling Outage. Under this exception, the next inservice inspection may be delayed until March 31, 2005.

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Attachment 3

TECHNICAL SPECIFICATION BASES PAGES

(3 pages follow)

Note: The Bases pages are provided for information only.

3/4.4.4 PRESSURIZER

A steam bubble in the pressurizer ensures that the RCS is not a hydraulically solid system and is capable of accommodating pressure surges during operation. The steam bubble also protects the pressurizer code safety valves and pilot operated relief valve against water relief.

The low level limit is based on providing enough water volume to prevent the low level interlock from de-energizing the pressurizer heaters during steady state operations. The high level limit is based on providing enough steam volume to prevent water relief through the pressurizer relief valves during the most challenging anticipated pressurizer insurge transient, which is a loss of feedwater. Since prevention of water relief is a goal for abnormal transient operation, rather than a Safety Limit, the value for high pressurizer level is nominal and is not adjusted for instrument error.

The ACTION statement provides 1 hour to restore pressurizer level prior to requiring shutdown. The 1-hour completion time is considered to be a reasonable time for restoring pressurizer level to within limits.

The pilot operated relief valve and steam bubble function to relieve RCS pressure during all design transients. Operation of the pilot operated relief valve minimizes the undesirable opening of the spring-loaded pressurizer code safety valves.

3/4.4.5 STEAM GENERATORS

The Surveillance Requirements for inspection of the steam generator tubes ensure that the structural integrity of this portion of the RCS will be maintained. The program for inservice inspection of steam generator tubes is based on a modification of Regulatory Guide 1.83, Revision 1. Inservice inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken. A process equivalent to the inspection method described in Topical Report BAW-2120P will be used for inservice inspection of steam generator tube sleeves. This inspection will provide ensurance of RCS integrity.

The plant is expected to be operated in a manner such that the secondary coolant will be maintained within those chemistry limits found to result in negligible corrosion of the steam generator tubes. If the secondary coolant chemistry is not maintained within these chemistry limits, localized corrosion may likely result in stress corrosion cracking. The extent of cracking during plant operation would be limited by the limitation of steam generator tube leakage between the primary coolant system and the secondary coolant system (primary-to-secondary leakage = 150 GPD through any one steam generator). Cracks having a primary-to-secondary leakage less than this limit during operation will have an adequate margin of safety to withstand the loads imposed during normal operation and by postulated accidents. Operating plants have demonstrated that primary-to-secondary leakage of 150 GPD can be detected by monitoring the secondary coolant. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged or repaired by repair rolling or sleeving in the affected areas.

Wastage-type defects are unlikely with proper chemistry treatment of the secondary coolant. However, even if a defect should develop in service, it will be found during scheduled inservice steam generator tube examinations. As described in Topical Report BAW-2120P, degradation as small as 20% through wall can be detected in all areas of a tube sleeve except for the roll expanded areas and the sleeve end, where the limit of detectability is 40% through wall. Tubes with imperfections exceeding the repair limit of 40% of the nominal wall thickness will be plugged or repaired by repair rolling or sleeving the affected areas. Davis-Besse will evaluate, and as appropriate implement, better testing methods which are developed and validated for commercial use so as to enable detection of degradation as small as 20% through wall without exception. Until such time as 20% penetration can be detected in the roll expanded areas and the sleeve end, inspection results will be compared to those obtained during the baseline sleeved tube inspection.

An additional repair method for degraded steam generator tubes consists of rerolling the tubes in the tubesheet to create a new roll area and pressure boundary for the tube. The repair roll process will ensure that the area of degradation will not serve as a pressure boundary, thus permitting the tube to remain in service. The degraded area of the tube can be excluded from future periodic inspection requirements because it is no longer part of the pressure boundary once the repair roll is installed in the tubesheet.

All tubes which have been repaired using the repair roll process will have the new roll area inspected during the inservice inspection. Defective or degraded tube indications found in the new roll area as a result of the inspection of the repair roll and any indications found in the originally rolled region of the rerolled tube need not be included in determining the Inspection Results Category for the general steam generator inspection.

The repair roll process will be performed as described in the Topical Report BAW-2303P, Revision 4. The new roll area must be free of degradation in order for the repair to be considered acceptable. After the new roll area is initially deemed acceptable, future degradation in the new roll area will be analyzed to determine if the tube is defective and needs to be removed from service. Leakage from repair rolls will be accounted for to ensure post-accident primary-to-secondary leakage will not exceed that assumed in the safety analyses.

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Whenever the results of any steam generator tubing inservice inspection fall into Category C-3, these results shall be reported to the Commission prior to resumption of plant operation. Such cases will be considered by the Commission on a case-by-case basis and may result in a requirement for analysis, laboratory examinations, tests, additional eddy-current inspection, and revision of the Technical Specifications, if necessary.

The steam generator water level limits are consistent with the initial assumptions in the USAR. While in MODE 3, examples of Main Feedwater Pumps that are incapable of supplying feedwater to the Steam Generators are tripped pumps or a manual valve closed in the discharge flowpath. The reactivity requirements to ensure adequate SHUTDOWN MARGIN are provided in plant operating procedures.

The steam generator minimum water level requirement is met by verifying the indicated steam generator level is greater than or equal to the value that corresponds to the required actual minimum level above the tubesheet.

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Attachment 4

FRAMATOME DOCUMENT 51-5033009-03

DB-1 Steam Generator Shut Down/Lay Up Chemistry Assessment - 2003

(50 pages follow)

FRAMATOME ANP

ENGINEERING INFORMATION RECORD

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Title DB-1 Steam Generator Shut Down/Lay Up Chemistry Assessment-2003

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Technical Manager Statement: Initials JW

Reviewer is Independent. L.S. Lamanna

Remarks:

Framatome ANP, Inc. initiated the Shutdown/Layup Chemistry Assessment Task (Task 3 of the Steam Generator Startup Review Project) to evaluate the layup and storage conditions in the OTSGs during the current plant shutdown. The shutdown period began on 2/16/02 @ 0255 with a turbine trip, and continued until plant heat-up in September 2003. The evaluation period was from 2/16/02 until 12/01/03, and included the Normal Operating Pressure Test (NOPT) period in addition to the periods when the plant was at ambient temperature. The objectives of Task 3 are to ensure that appropriate controls were in place during the extended outage to preclude any adverse effects on the OTSGs and to provide a technical basis to support a one time license change request to allow OTSG operation beyond the 24 month inspection interval. No conditions were identified that would have an adverse effect on, or cause any type of known corrosion damage to, the steam generators during the layup period including the NOPT. Further, no conditions were identified that would require an assessment of active degradation mechanisms, crack growth rate progressions, or internal steam generator components.

FENOC
ENGINEERING DOCUMENT REVIEW

1. ☒ WORK MAY PROCEED.
2. ☐ REVISE AND RESUBMIT. WORK MAY PROCEED SUBJECT TO INCORPORATION OF CHANGES INDICATED.
3. ☐ REVISE AND RESUBMIT. WORK MAY NOT PROCEED.
4. ☐ REVIEW NOT REQUIRED. WORK MAY PROCEED.

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BY: [signature] DATE: 12/11/03

Record of Revision

Date	Revision	Section	Description
09/15/03	00	All	Original Release
11/06/03	01	4.0	Add customer comments
11/14/03	02	4.4	Add customer comment
12/10/03	03	All	Update to 12/01/03

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1.0 INTRODUCTION

Framatome ANP, Inc. (FANP) initiated the Shutdown/Layup Chemistry Assessment Task (Task 3 of the Steam Generator Startup Review Project) to evaluate the layup and storage conditions in the OTSGs during the current plant shutdown. The shutdown period began on 2/16/02 @ 0255 with a turbine trip, and continued until plant heat-up in September 2003. The evaluation period was from 2/16/02 until 12/01/03, and included the Normal Operating Pressure Test (NOPT) period in addition to the periods when the plant was at ambient temperature. The objectives of Task 3 are to ensure that appropriate controls were in place during the extended outage to preclude any adverse effects on the OTSGs, and to provide a technical basis to support a one time license change request to allow OTSG operation beyond the 24 month inspection interval.

2.0 METHODOLOGY

Task 3 was implemented by working on-site with site chemistry personnel to compile the OTSG lay-up chemistry environment data during the time period of the extended outage. Data was obtained in the following areas:

- OTSG Water Sample Analyses Data
- RCS Chemistry and Conditions (OTSG 1° levels)
- Fill and Makeup Water Source Chemistry Data (DWST, HW)
- Record of OTSG opening to air/nitrogen blanket during openings
- OTSG Nitrogen Blanket Data
- Condensate/Steam and Feedwater storage data (startup chemistry effects)
- Procedures including Chemistry Layup Control, Shutdown Operations, Fill, Drain, and Layup, and Operational Chemistry Control Limits.

The data compiled was subsequently reviewed in Lynchburg by FANP to ensure appropriate controls were in place to preclude any adverse affects on SG tubing and internals.

3.0 STEAM GENERATOR EVENT TIME-LINE

The plant OPS logs were reviewed, and a steam generator event time-line was prepared. The main incidents of interest were the steam generator events associated with establishing appropriate layup conditions. The events time-line is presented in tabular form in Appendix A.

4.0 PLANT CHEMISTRY DATA

Plant chemistry data was obtained for the primary, secondary, and OTSG makeup water system for the shutdown period and reviewed.

4.1 PRIMARY CHEMISTRY

Corrosion experience with sensitized Alloy 600 OTSG tubing has identified reduced sulfur forms as contaminants of concern at storage and layup conditions. The analysis of sulfate in the RCS provides a good indication of the presence of sulfur forms. The RCS sulfate data for the shutdown period are shown in Figure 1. Note that after the typical sulfate spike associated with the shutdown (turbine trip), the sulfates were kept in control for the shutdown period. The normal RCS sulfate limits are <150 ppb when the temperature is below 250°F[1]. The sulfate during the shutdown period only slightly exceeded 100 ppb on two occasions. The RCS was drained, and nozzle dams were installed in the primary heads on 2/20/02 and removed on 3/14/02; installed again on 7/5/02, and removed on 3/13/03. During those time periods, the primary side of the steam generator would be completely drained and not subject to a corrosive environment. Between 3/14/02 and 7/5/02 and after 3/13/03, the primary side steam generators levels fluctuated from completely full when the RCS was pressurized to various levels as the refueling canal level changed. During these times, when a partial primary side level resulted, sulfate levels were low. No other RCS chemistry parameters or conditions are considered to be potentially detrimental to the OTSG tubing during the shutdown period.

4.1.1 NOPT

The plant operated above 250°F temperature during the period from September 13, 2003 to October 4, 2003 (Figure 21). The RCS chemistry requirements during these plant conditions are given in Table 7[1]. The plant chemistry data for this period are shown in Figure 1A. None of the control parameters were exceeded while the RCS temperature was above 250°F.

4.2 OTSG CHEMISTRY

Chemistry data was obtained for both OTSGs during the shutdown period (2/16/02 to 12/1/03 including the NOPT period) for the parameters listed below. The data for these parameters are shown in the indicated figures for OTSG 1 and 2, respectively.

- Chloride – Figures 2, 10
- Oxygen – Figures 3, 11
- Fluoride – Figures 4, 12
- Hydrazine – Figures 5, 13
- Sodium – Figures 6, 15
- Sulfate – Figures 7, 16
- Solution pH – Figures 8, 17
- Silica – Figures 9, 14

These data were compared to the plant operating limits for the shutdown period given in Table 1[2], and the EPRI guidelines given in Table 2[3]. Throughout the shutdown period, the chemistry was found to be within the limits of both the plant specifications[2] as well as the EPRI Guidelines[3]. A summary of the plant chemistry control for the layup water in the two steam generators during the shutdown period is given in Table 4, where it will be noted that the observed data is well within the limits defined in both the plant and EPRI control specifications. However, two spikes up to about 1 ppm were observed in the silica concentration in both OTSGs (Figures 9 and 14). The observed spikes occurred in January and in June-August, 2003. The cause of the spikes is unknown, but analytical error is one possibility. No materials degradation would result from these relatively low concentrations. Silica is not a control or diagnostic parameter in the EPRI Guidelines[3].

4.2.1 NOPT

The plant operated above 250°F temperature during the period from September 13, 2003 to October 4, 2003 (Figure 21). The secondary system chemistry control requirements during the NOPT are given in Tables 8 and 9[2], and are the same as for startup/hot standby. The OTSG and feedwater control parameters were all within the required limits (OTSG Chloride – Figures 2, 10, Sodium – Figures 6, 15, Sulfate – Figures 7, 16, and Feedwater (Figures 22 through 25).

4.3 OTSG FILL WATER

The source of the OTSG fill water is the demineralized water storage tank. The chemistry data for the demineralized water during the shutdown period is shown in Figures 18 and 19. The plant specifications for the demineralized water are given in Table 3[2]. It is noted that on several occasions, the fluoride, sodium, dissolved oxygen, and chloride exceeded the specifications in Table 3. As indicated in the OTSG Events Timeline (Appendix A), demineralized water was added on several occasions during the shutdown period. Additions occurred during the initial shutdown period of 2/16/02 – 2/20/02 for soaks and flushes; during refill following maintenance on 4/4/02 – 4/5/02; on 11/20/02 for level adjustment; and during the period 3/5/03-3/10/03 for filling after draining for maintenance. In all cases except on 11/20/02, the demineralized water was within the required quality specifications. Demineralized water was added on 11/20/02 during a small dissolved oxygen excursion when the dissolved oxygen concentration reached 200 ppb. Since this was a level adjustment addition, dilution of the fill water with the low oxygen water in the OTSGs would maintain the OTSG water at <100 ppb. Thus, no adverse effects of this addition would be expected.

4.4 NITROGEN BLANKETING

A nitrogen blanket is initiated and maintained on the steam generators to exclude air (oxygen) from entering and promoting corrosion reactions, and to facilitate draining of the OTSGs when necessary. Nitrogen may be added to produce a blanket pressure, or as a trickle feed when maintenance activities prevent a positive pressure blanket.[4] Appropriate safety precautions are taken to prevent accidents associated with nitrogen applications. As noted in the OTSG Events Timeline (Appendix A), nitrogen was added on numerous occasions. Based on these data, it is concluded that nitrogen was used appropriately to protect the OTSGs. However, it is apparent that not all the nitrogen addition events were recorded. For example, it is known from discussion with plant personnel that nitrogen was used during the fill, soak, and drains that occurred during the initial shutdown period. However, there were no nitrogen addition events during the fill, soak and drain evolutions recorded in the plant operator's logs, which provided the information for the generation of the Event Timeline (Appendix A).

On 9/1/03, while the assessment team was on site, the steam generators were drained to the condenser in preparation for an AFW pump test. At that time, nitrogen was not available to blanket the generators while draining, so it must be assumed that air was introduced. Subsequently, a nitrogen blanket was established on 9/5/03 until the OTSGs were placed under vacuum for Mode 3 entry on 9/11/03. This short exposure to air is not considered to have caused any corrosive damage. The OTSGs were placed back in full wet layup recirculation following the NOPT on 10/07/03.

4.5 CONDENSATE/STEAM AND FEEDWATER STORAGE

Storage of the condensate and feedwater system will have no effect on the layup conditions in the steam generators. However, in the interest of minimizing the ingress of contaminants, such as corrosion product iron oxide into the steam generators on startup, the control of storage conditions in the condensate and feedwater systems can have a significant contribution. Chemicals were reportedly added to the condensate on 2/17/2002 at 0330 at 0% power with the plant in Mode 3. Reported chemistry data is given in Table 5 show that the fluoride, chloride, sulfate and sodium were very low and that hydrazine was being added. Table 6 shows the condensate and feedwater conditions and activities during the shutdown.

5.0 DISCUSSION AND CONCLUSIONS

Working on-site with site chemistry personnel, the OTSG lay-up chemistry environment data was compiled for the time period of the extended outage beginning in February, 2002.

One addition of demineralized water was made to maintain level when the makeup water dissolved oxygen was greater than 100 ppb. Since at that time high hydrazine was present and low oxygen water was already in the OTSGs, oxygen control was not lost due to this addition.

The plant OPS logs provided a good method of determining the steam generator events time-line (Appendix A). However, better record keeping concerning the steam generator conditions would provide better documentation in support of adequate shutdown/layup control. For example, on several occasions layup recirculation was either stopped or started in consecutive steps without the opposite step recorded in sequence. The Steam

Generator lay-up status record keeping concern was captured in the DBNPS corrective action program.

Layup recirculation is an important part of maintaining a uniform layup chemical treatment. On two occasions, valve misalignments following steam generator filling resulted in some period of time without recirculation when it was thought to be operating. Fortunately, chemical addition occurred along with the demineralized water fill and provided adequate distribution of chemicals in the steam generators. Subsequent sampling and analyses confirmed layup chemical control.

Based on the review of steam generator layup chemistry control described and discussed above, it is concluded that no conditions existed that would require an assessment of active degradation mechanisms, crack growth rate progressions, or internal steam generator components. No conditions were identified that would have an adverse effect on, or cause any type of known corrosion damage to the steam generators during the layup period.

It is projected that there will be no degradation of the steam generator materials prior to plant restart provided current satisfactory storage and layup conditions are maintained. These assumed storage conditions will be confirmed following plant startup and any deviations and/or discrepancies will be evaluated as to their effect on steam generator materials.

6.0 REFERENCES

1. EPRI TR-105714-R5, PWR Primary Chemistry Guidelines, September 2003.

2. DB-CH-06900, Operational Chemistry Control Limits, R08, March 31, 2003.

3. EPRI TR-102134-R5, PWR Secondary Chemistry Guidelines, March, 2000.

4. DB-OP-06230, Steam Generator Secondary Side Fill, Drain and Layup, R04, April, 2003.

5. DB-OP-06903, Plant Shutdown and Cooldown, R08, August, 2003

6. DB-OP-06904, Shutdown Operations, R15, August, 2003.

7. E-mail, R. Edwards to M. Bell, 11/11/03, OTSG Nitrogen Blanket

TABLE 1: OTSG LAYUP WATER CONTROL PARAMETERS[2]	
PARAMETER	**SPECIFICATION**
Hydrazine	>75 ppm, <500 ppm
pH	≥9.8
Sodium	<1.0 ppm
Chloride	<1.0 ppm
Dissolved Oxygen	<100 ppb
Sulfate	<1.0 ppm

TABLE 2: OTSG LAYUP WATER CONTROL PARAMETERS[3]	
PARAMETER	**SPECIFICATION**
Hydrazine, ppm	75-500
pH	≥9.8
Sodium, ppb	<1000
Chloride, ppb	<1000
Dissolved Oxygen, ppb	<100
Sulfate, ppb	<1000

TABLE 3: DEMINERALIZED WATER SPECIFICATIONS [2]	
PARAMETER (CONTROL)	**SPECIFICATION**
Specific Conductivity, μS/cm	<0.3
Silica, ppb	<20
Sodium, ppb	<3
Chloride, ppb	<5
Fluoride, ppb	<5
Dissolved Oxygen, ppb	<100
Sulfate, ppb	<5
Total Organic Carbon, ppb	<100
Iron (Membrane), ppb	<10
PARAMETER (DIAGNOSTIC)	**TYPICAL VALUE**
Calcium, ppb	<40
Aluminum, ppb	<40
Magnesium, ppb	<40

TABLE 4: OTSG LAYUP WATER CHEMISTRY CONTROL					
PARAMETER	SPECIFICATION	VALUE			
		OTSG# 1		OTSG# 2	
		Max., Min. or Range	Average	Max., Min. or Range	Average
Hydrazine, ppm	75-500	67-176	116	68-136	97
pH	≥ 9.8	9.78	9.97	9.80	10.01
Sodium, ppb	<1000	312	159	445	229
Chloride, ppb	<1000	69	37	77	40
Dissolved Oxygen, ppb	<100	80	17	60	19
Sulfate, ppb	<1000	333	154	361	241

TABLE 5: FEEDWATER CHEMISTRY DATA DURING SHUTDOWN							
DATE	TIME	POWER/MODE	HYDRAZINE, ppb	FLUORIDE, ppb	CHLORIDE, ppb	SULFATE, ppb	SODIUM, ppb
2/10/02	00:15	100/1		<1		<1	
2/11/02	08:00	0/3	35				
2/13/02	00:40	0/3		<1	1.98	1.58	
	08:15	0/3		<1	2.50	1.53	
2/16/02	00:00	0/3	91				
	20:00	0/3	1008				
	20:45	0/3	540			2.47	
	22:05	0/3	606				29
2/17/02	00:05	0/3	946				45
	01:40	0/3	842				25
	03:35	0/3	16300				

TABLE 6: CONDENSATE/FEEDWATER SYSTEMS SHUTDOWN CONDITION	
DATE	CONDITION
3/12/02	Refilling condensate maintaining pH>9.6
4/14/02	Condensate pump s/d and condensate on mini-recirc
4/20/02	Condensate pump on
5/12/02	FW cleanup/DO removal
5/23/02	Condensate shutdown
6/1/02 - 6/5/03	Condensate drained
6/5/03	Fill condensate
6/7/03	Drain condensate to remove iron
6/9/03	Refill condensate
6/10/03	Condensate on recirculation
6/17/03	Condensate on mini recirculation
6/28/03	Condensate off mini recirculation
6/30/03	Drain deareartors for maintenance
7/5/03	Restart condensate pump and refill deareartors
7/15/03	FW cleanup and DO removal
7/20/03	Condensate layup with mini-recirculation

TABLE 7: RCS STARTUP/HOT STANDBY CONTROL PARAMETERS[1]	
PARAMETER	**Prior to >250°F and Criticality**
Chloride, ppb	<150
Sulfate, ppb	<150
Fluoride, ppb	<150
Oxygen, ppb	<100

TABLE 8: OTSG STARTUP/HOT STANDBY CONTROL PARAMETERS[2]	
PARAMETER	**INITIATE ACTION**
Sodium, ppb	>100
Chloride, ppb	>100
Sulfate, ppb	>100
Cation Conductivity, μS/cm	>2

TABLE 9: FEEDWATER STARTUP/HOT STANDBY CONTROL PARAMETERS[2]	
PARAMETER	**INITIATE ACTION**
SU Dissolved O_2, ppb	>100
Hydrazine, ppb	<8 x O_2, <50
SU Suspended Solids, ppb	>100
Hot SB Suspended Solids, ppb	>10

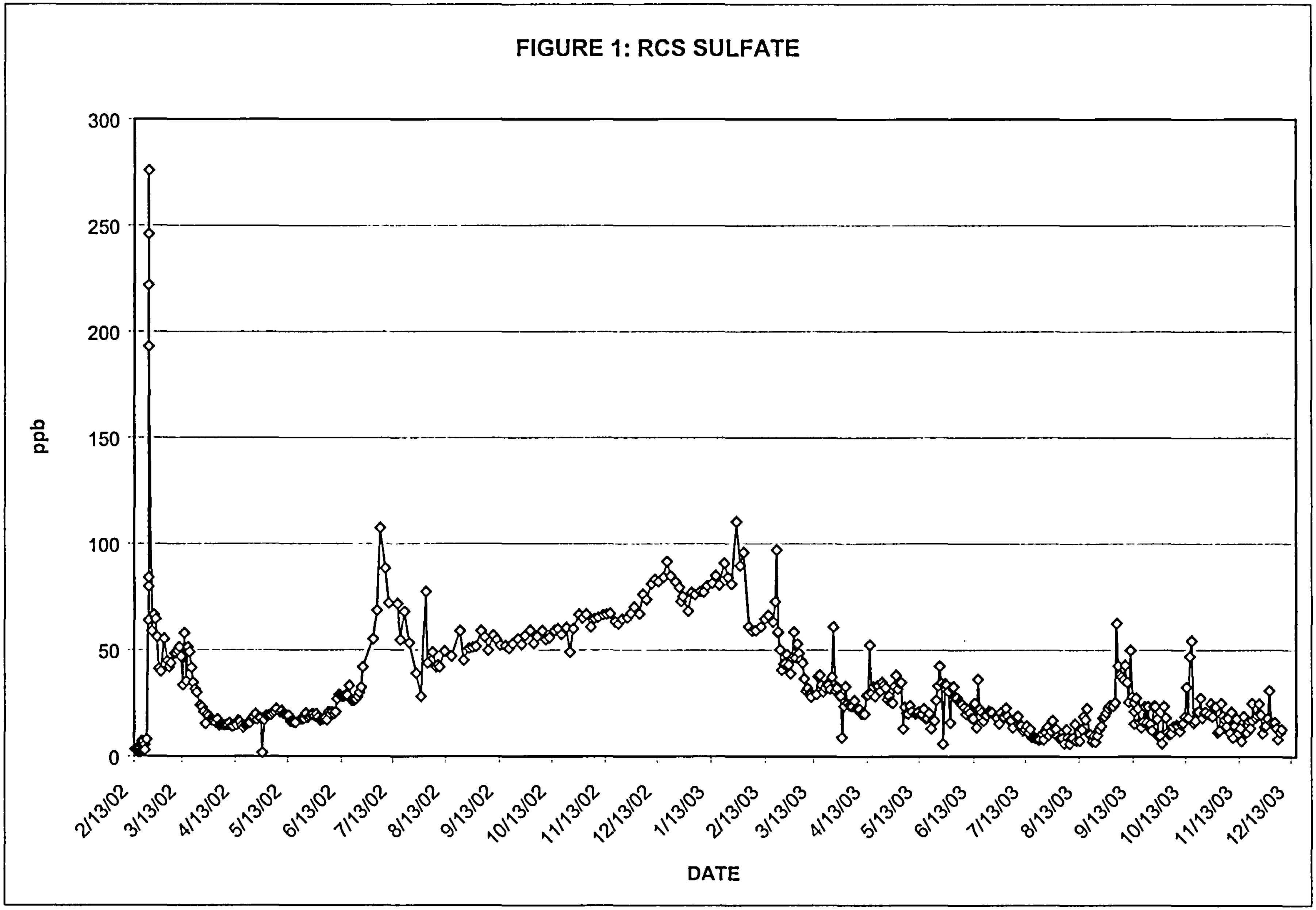


FIGURE 1: RCS SULFATE
ppb
300
250
200
150
100
50
0
2/13/02
3/13/02
4/13/02
5/13/02
6/13/02
7/13/02
8/13/02
9/13/02
10/13/02
11/13/02
12/13/02
1/13/03
2/13/03
3/13/03
4/13/03
5/13/03
6/13/03
7/13/03
8/13/03
9/13/03
10/13/03
11/13/03
12/13/03
DATE

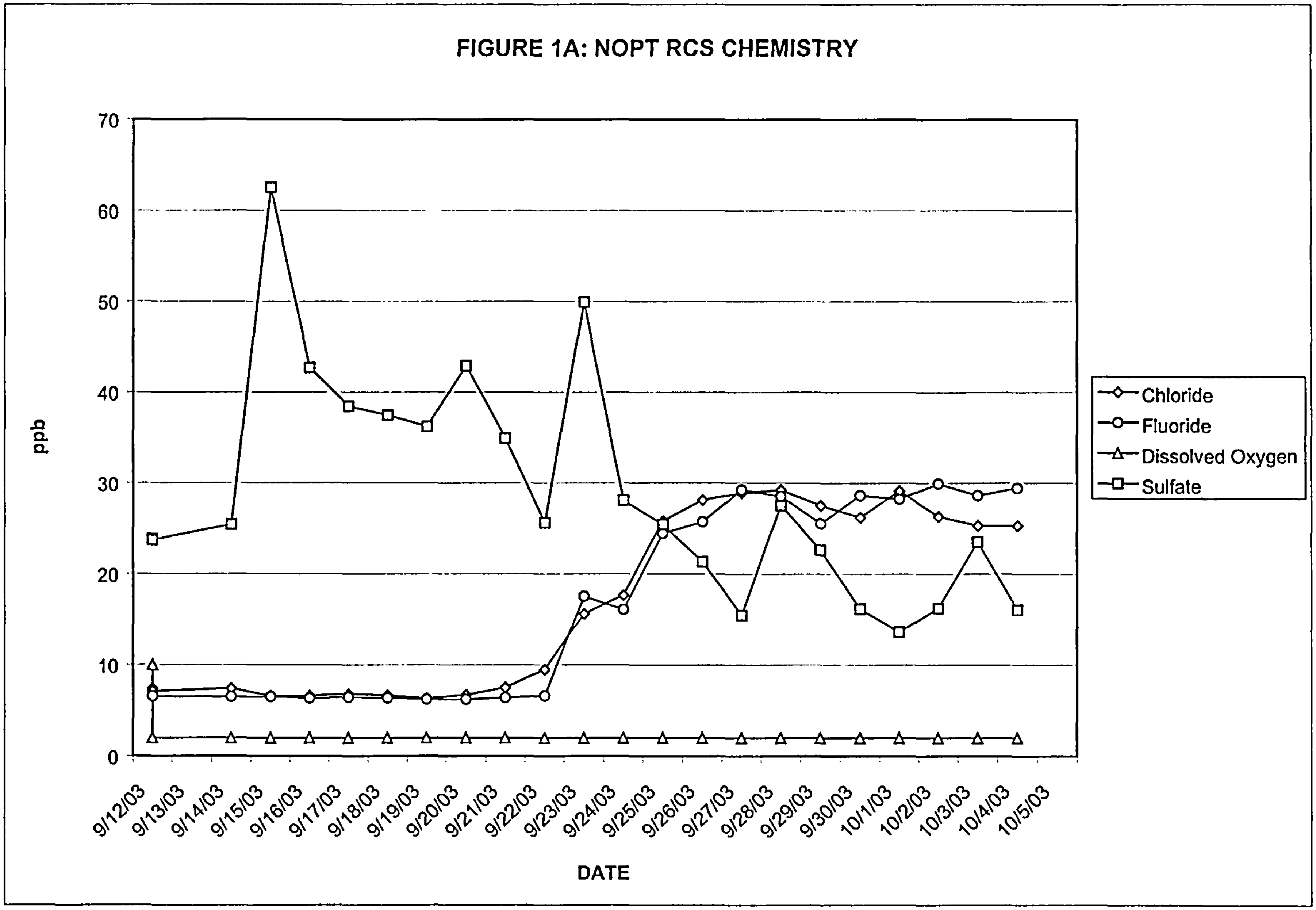


FIGURE 1A: NOPT RCS CHEMISTRY
70
60
50
40
30
20
10
0
ppb
9/12/03
9/13/03
9/14/03
9/15/03
9/16/03
9/17/03
9/18/03
9/19/03
9/20/03
9/21/03
9/22/03
9/23/03
9/24/03
9/25/03
9/26/03
9/27/03
9/28/03
9/29/03
9/30/03
10/1/03
10/2/03
10/3/03
10/4/03
10/5/03
DATE
Chloride
Fluoride
Dissolved Oxygen
Sulfate

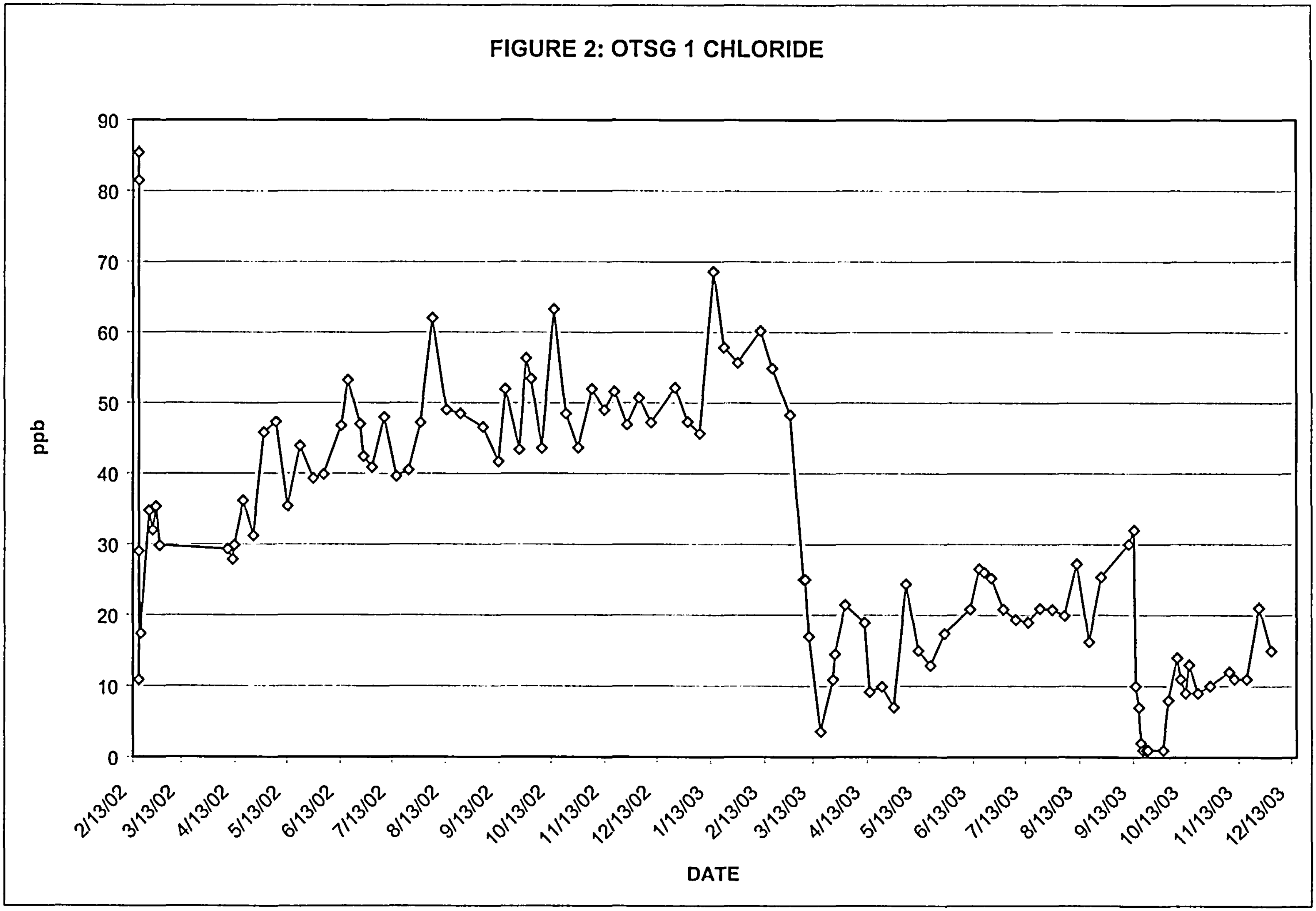


FIGURE 2: OTSG 1 CHLORIDE
ppb
90
80
70
60
50
40
30
20
10
0
2/13/02
3/13/02
4/13/02
5/13/02
6/13/02
7/13/02
8/13/02
9/13/02
10/13/02
11/13/02
12/13/02
1/13/03
2/13/03
3/13/03
4/13/03
5/13/03
6/13/03
7/13/03
8/13/03
9/13/03
10/13/03
11/13/03
12/13/03
DATE

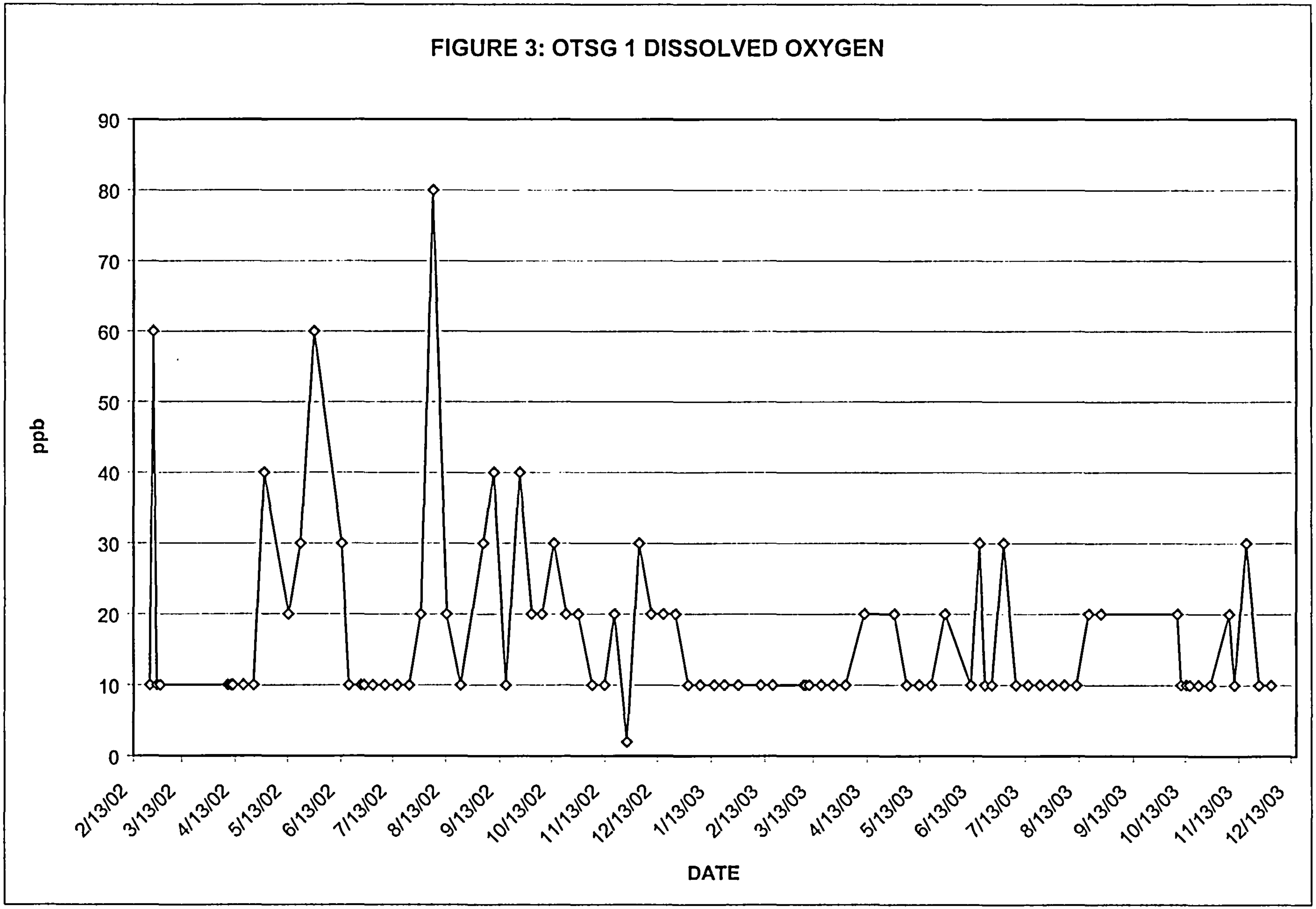


FIGURE 3: OTSG 1 DISSOLVED OXYGEN
ppb
90
80
70
60
50
40
30
20
10
0
2/13/02
3/13/02
4/13/02
5/13/02
6/13/02
7/13/02
8/13/02
9/13/02
10/13/02
11/13/02
12/13/02
1/13/03
2/13/03
3/13/03
4/13/03
5/13/03
6/13/03
7/13/03
8/13/03
9/13/03
10/13/03
11/13/03
12/13/03
DATE

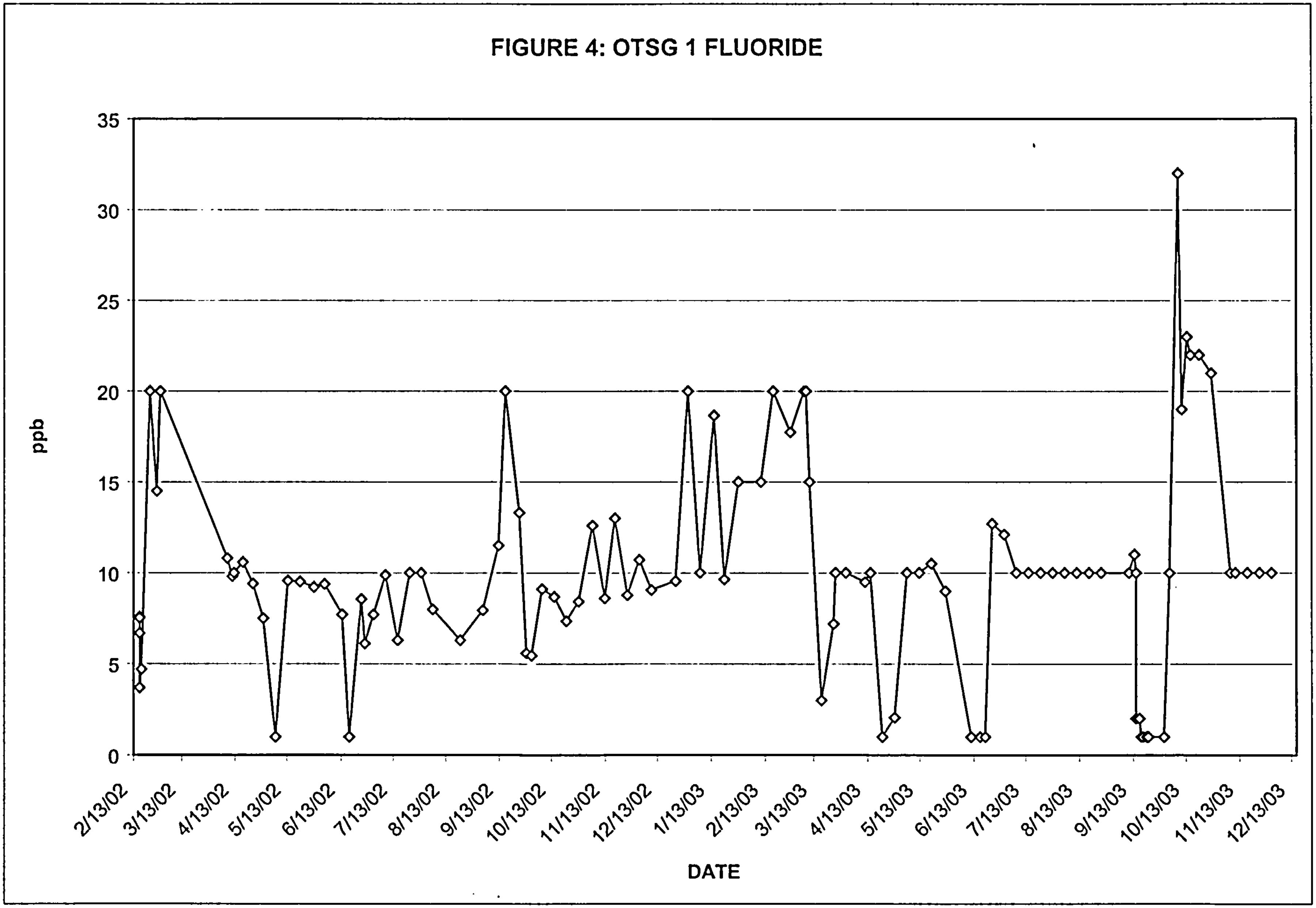


FIGURE 4: OTSG 1 FLUORIDE
35
30
25
20
15
10
5
0
ppb
2/13/02
3/13/02
4/13/02
5/13/02
6/13/02
7/13/02
8/13/02
9/13/02
10/13/02
11/13/02
12/13/02
1/13/03
2/13/03
3/13/03
4/13/03
5/13/03
6/13/03
7/13/03
8/13/03
9/13/03
10/13/03
11/13/03
12/13/03
DATE

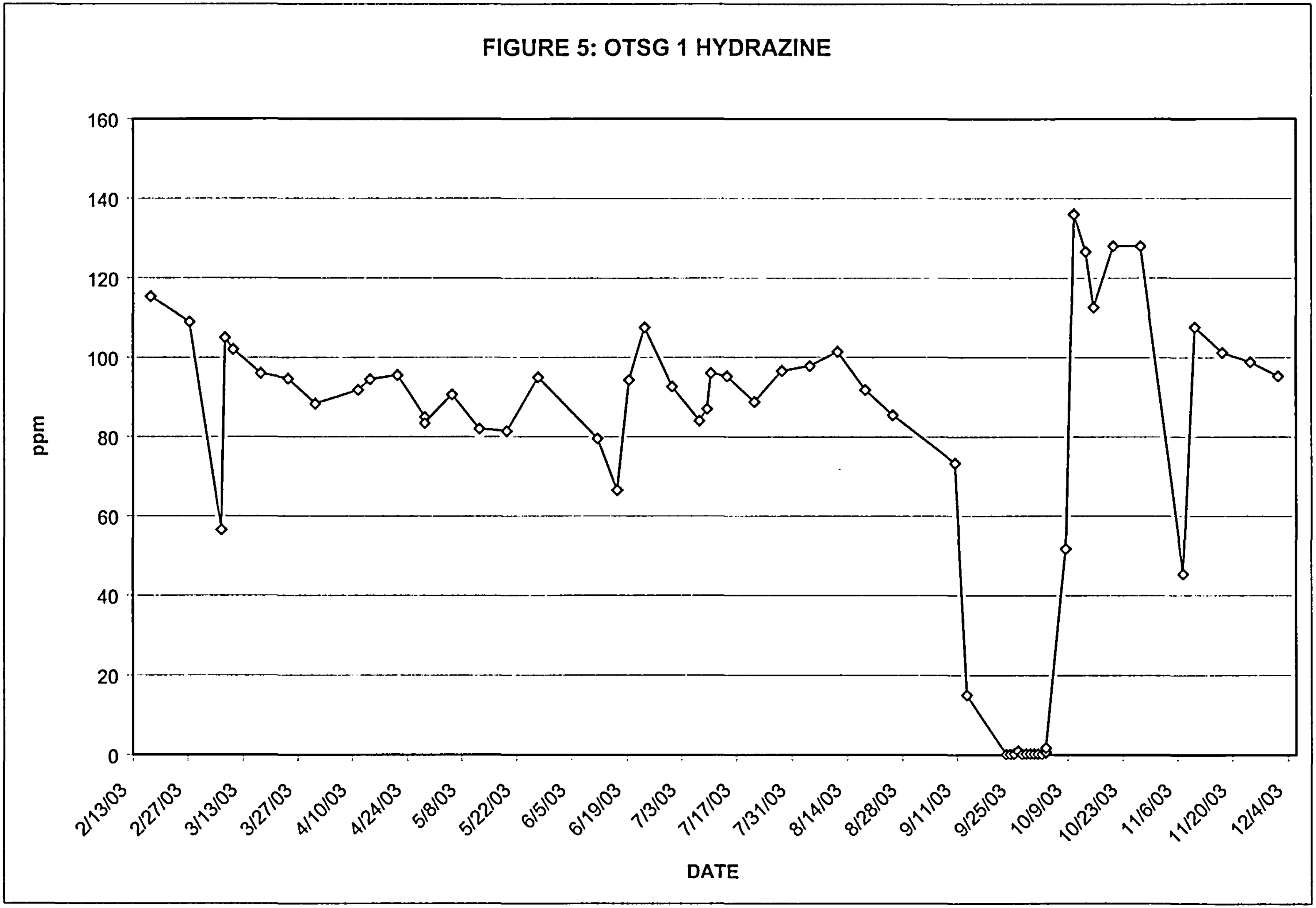


FIGURE 5: OTSG 1 HYDRAZINE
160
140
120
100
80
60
40
20
0
ppm
2/13/03
2/27/03
3/13/03
3/27/03
4/10/03
4/24/03
5/8/03
5/22/03
6/5/03
6/19/03
7/3/03
7/17/03
7/31/03
8/14/03
8/28/03
9/11/03
9/25/03
10/9/03
10/23/03
11/6/03
11/20/03
12/4/03
DATE

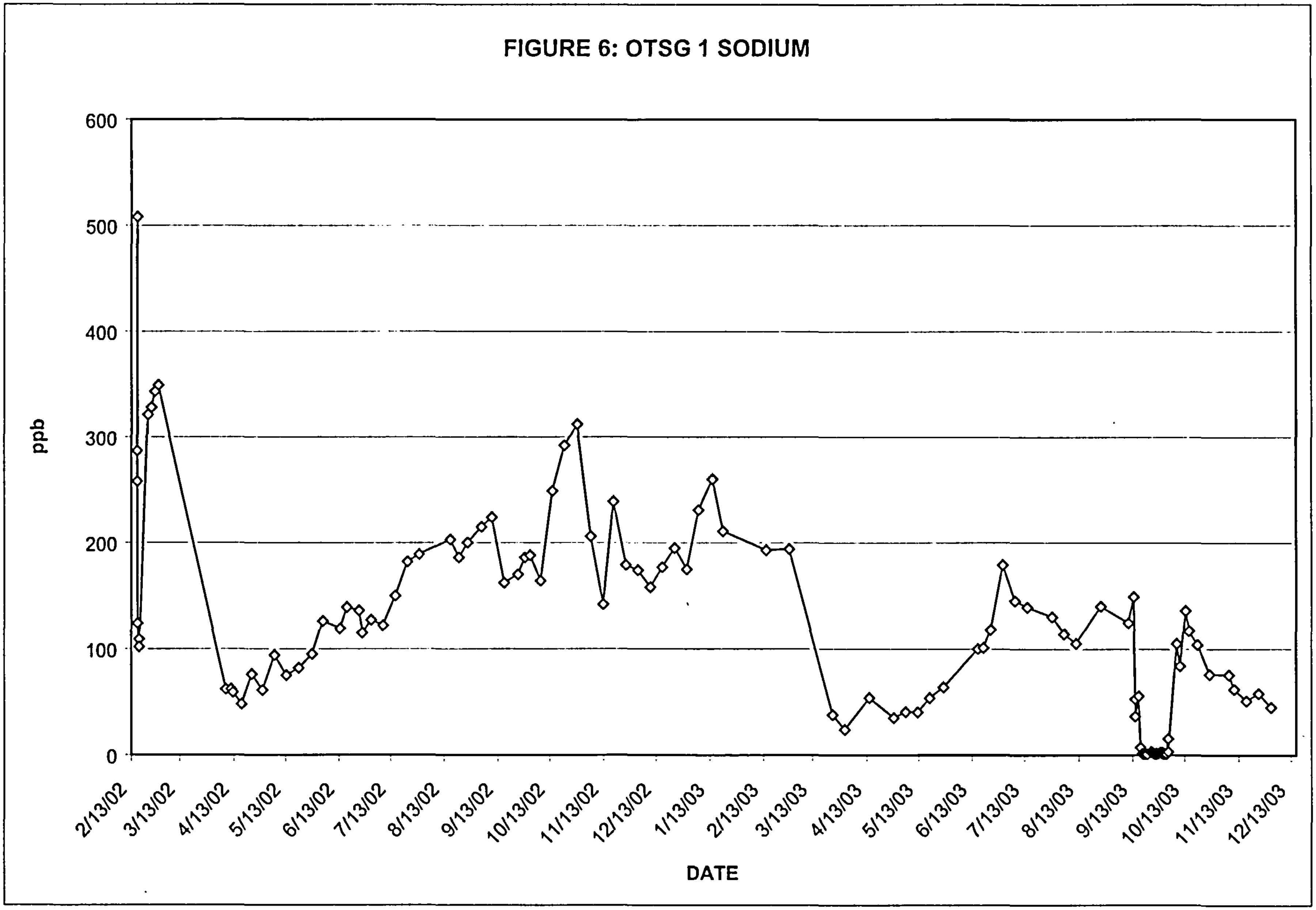


FIGURE 6: OTSG 1 SODIUM
ppb
600
500
400
300
200
100
0
2/13/02
3/13/02
4/13/02
5/13/02
6/13/02
7/13/02
8/13/02
9/13/02
10/13/02
11/13/02
12/13/02
1/13/03
2/13/03
3/13/03
4/13/03
5/13/03
6/13/03
7/13/03
8/13/03
9/13/03
10/13/03
11/13/03
12/13/03
DATE

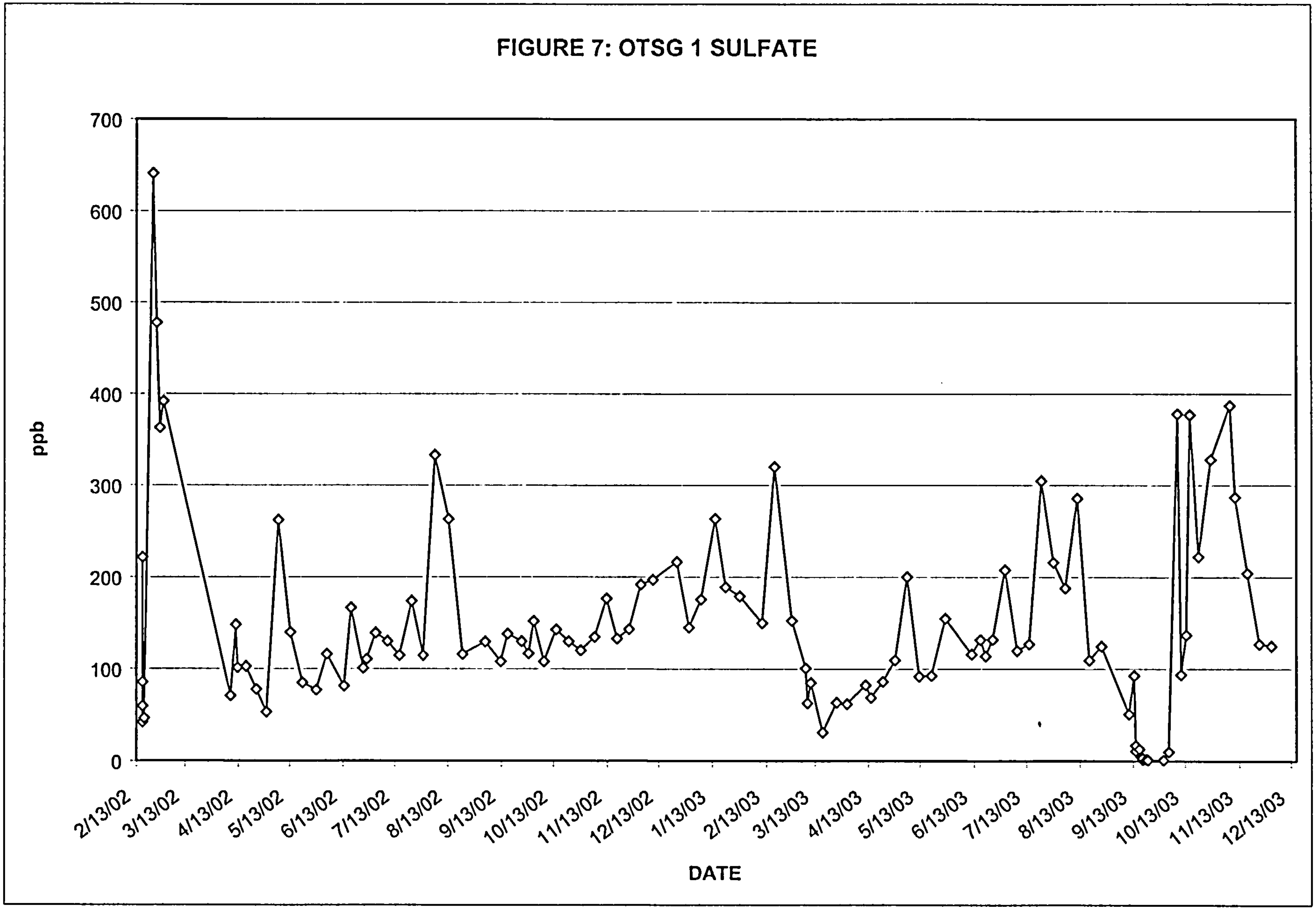


FIGURE 7: OTSG 1 SULFATE
700
600
500
400
300
200
100
0
ppb
2/13/02
3/13/02
4/13/02
5/13/02
6/13/02
7/13/02
8/13/02
9/13/02
10/13/02
11/13/02
12/13/02
1/13/03
2/13/03
3/13/03
4/13/03
5/13/03
6/13/03
7/13/03
8/13/03
9/13/03
10/13/03
11/13/03
12/13/03
DATE

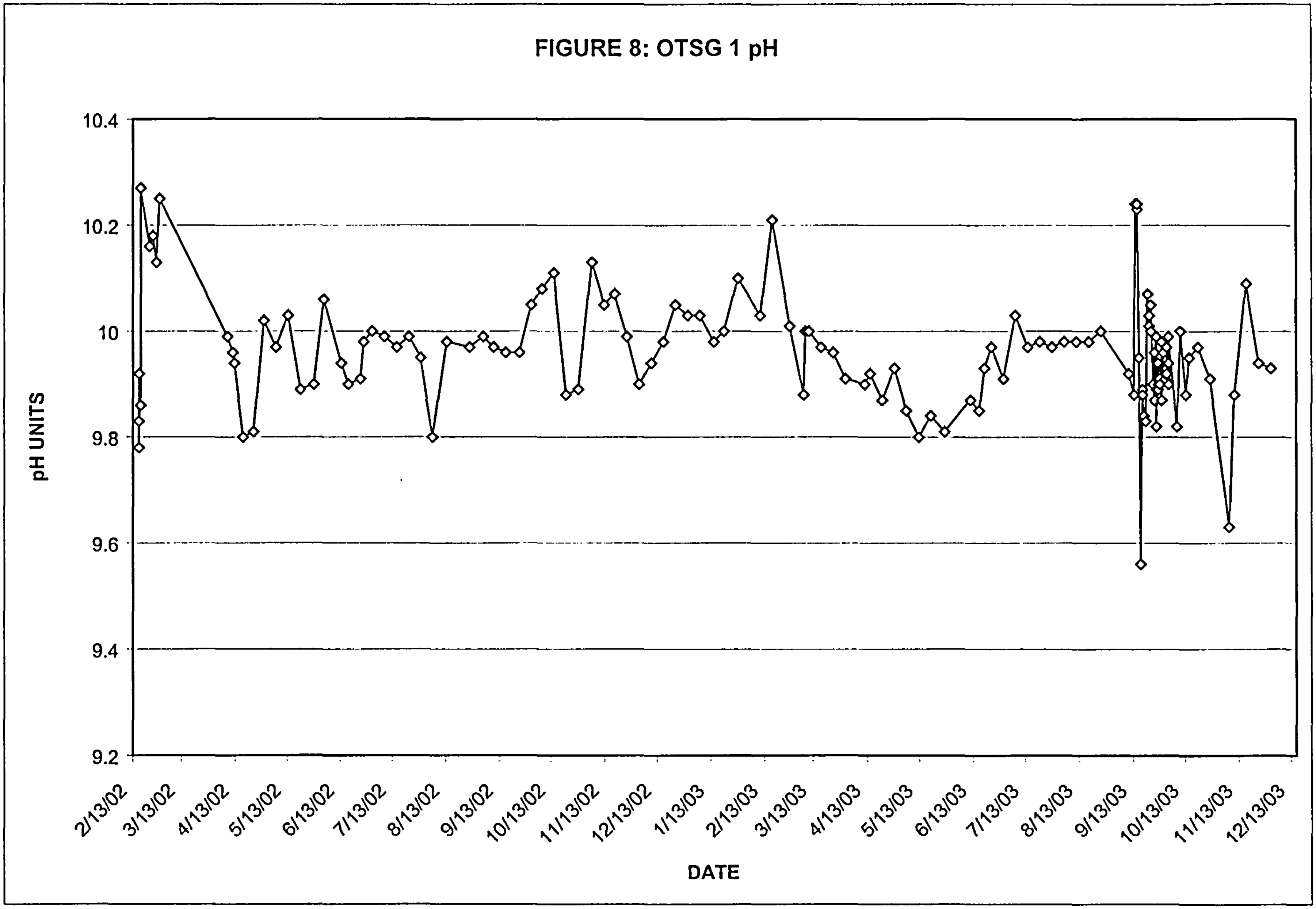
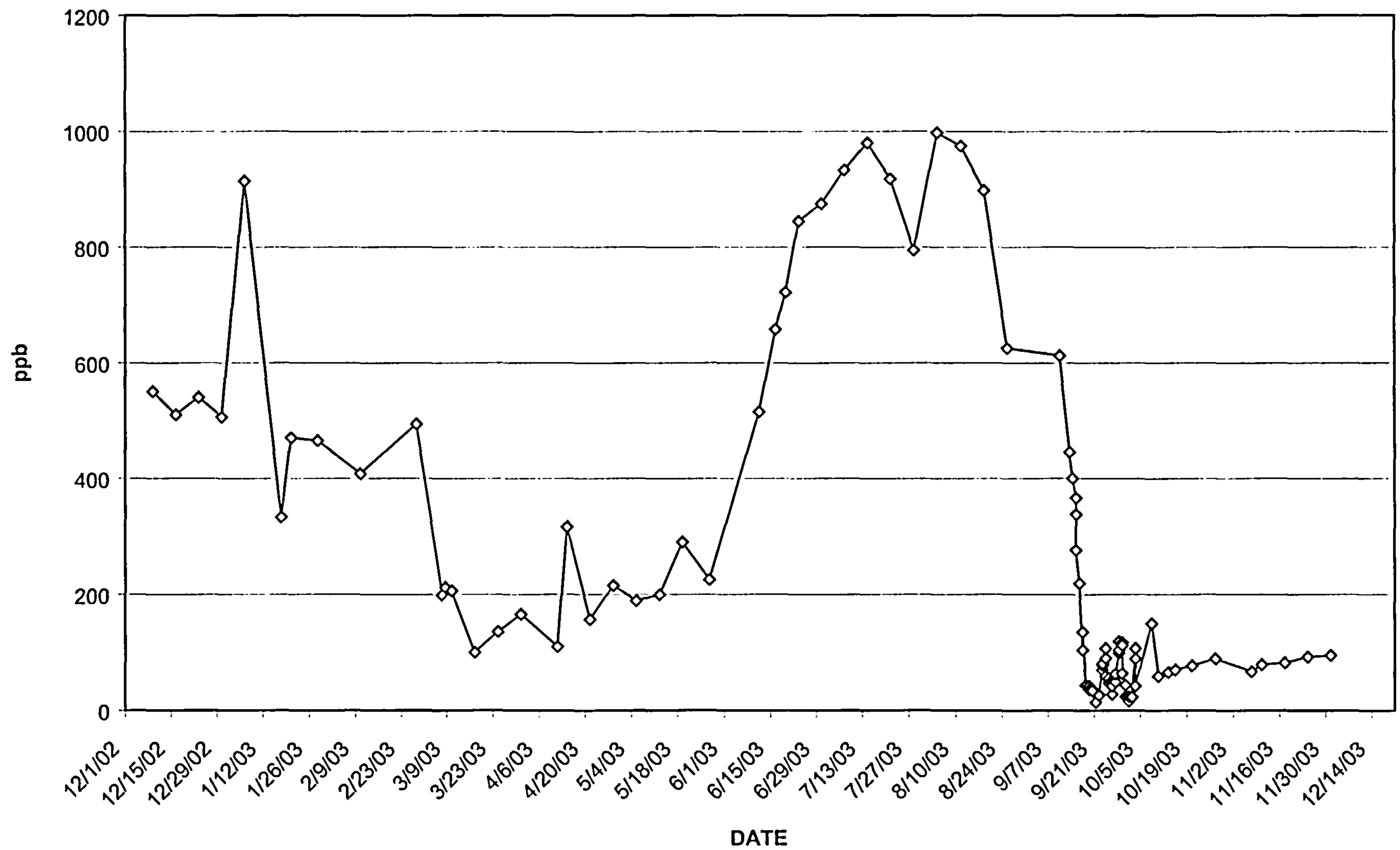


FIGURE 8: OTSG 1 pH
10.4
10.2
10
9.8
9.6
9.4
9.2
pH UNITS
2/13/02
3/13/02
4/13/02
5/13/02
6/13/02
7/13/02
8/13/02
9/13/02
10/13/02
11/13/02
12/13/02
1/13/03
2/13/03
3/13/03
4/13/03
5/13/03
6/13/03
7/13/03
8/13/03
9/13/03
10/13/03
11/13/03
12/13/03
DATE

FIGURE 9: OTSG 1 SILICA



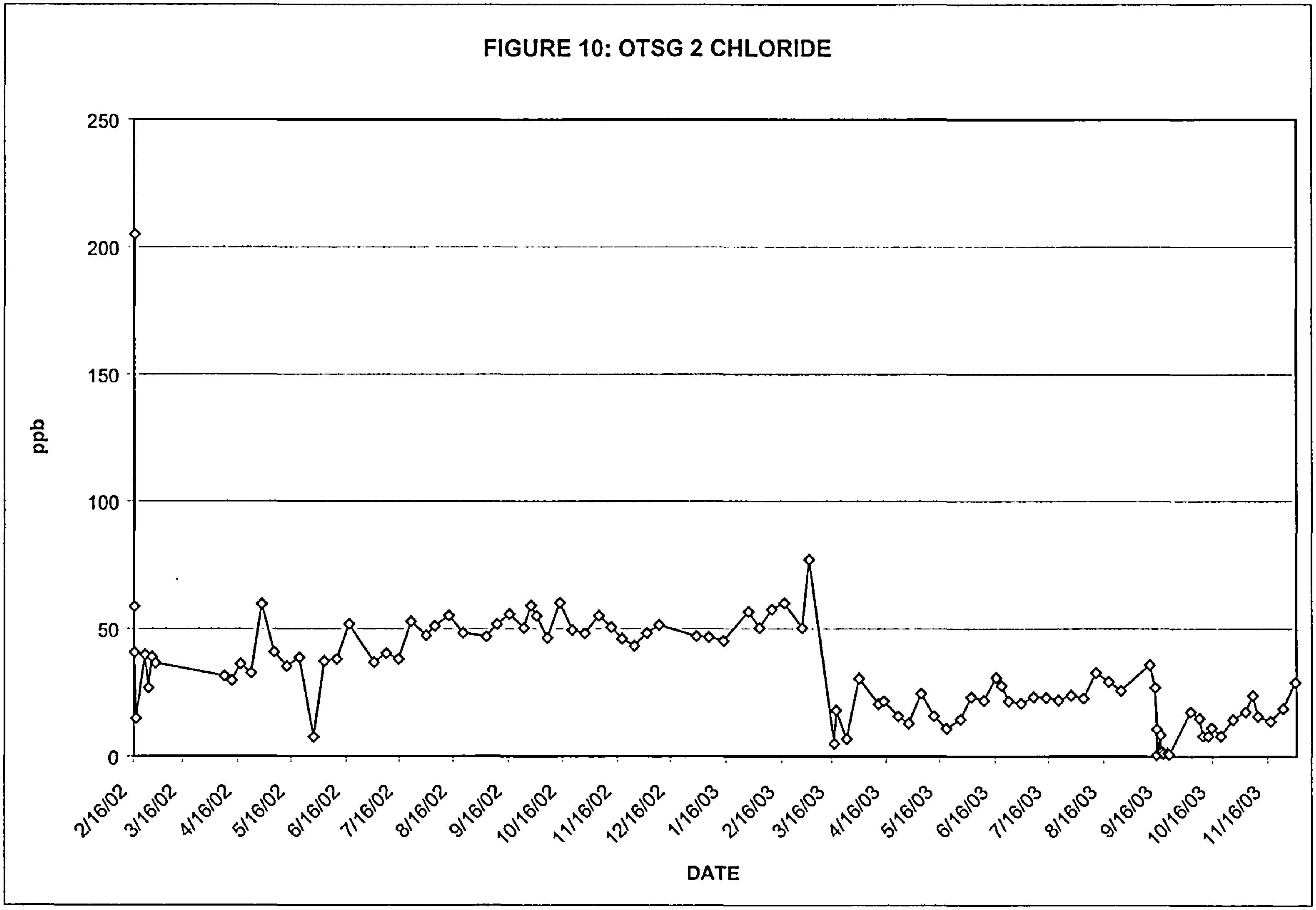


FIGURE 10: OTSG 2 CHLORIDE
250
200
150
100
50
0
ppb
2/16/02
3/16/02
4/16/02
5/16/02
6/16/02
7/16/02
8/16/02
9/16/02
10/16/02
11/16/02
12/16/02
1/16/03
2/16/03
3/16/03
4/16/03
5/16/03
6/16/03
7/16/03
8/16/03
9/16/03
10/16/03
11/16/03
DATE

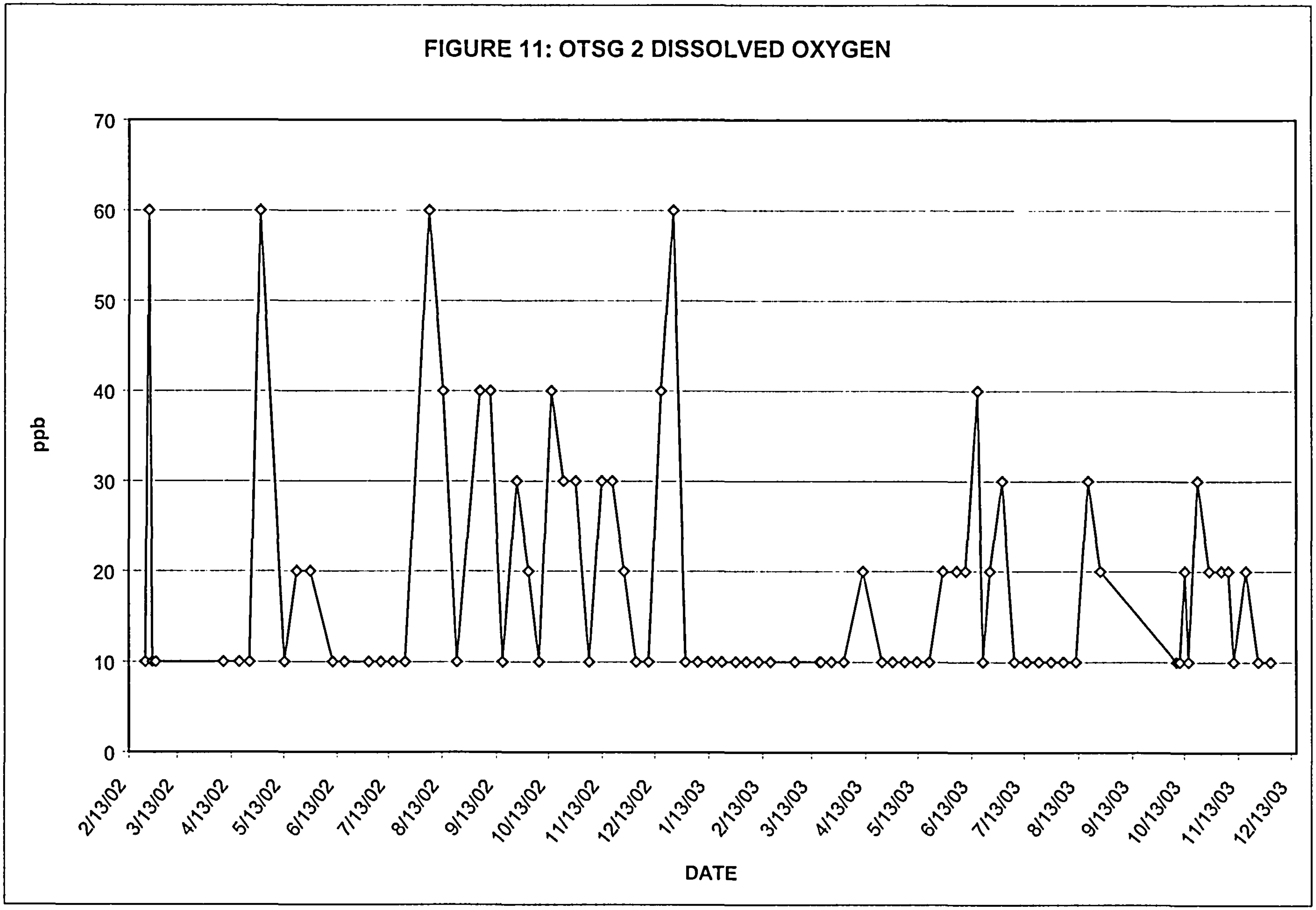


FIGURE 11: OTSG 2 DISSOLVED OXYGEN
ppb
0
10
20
30
40
50
60
70
2/13/02
3/13/02
4/13/02
5/13/02
6/13/02
7/13/02
8/13/02
9/13/02
10/13/02
11/13/02
12/13/02
1/13/03
2/13/03
3/13/03
4/13/03
5/13/03
6/13/03
7/13/03
8/13/03
9/13/03
10/13/03
11/13/03
12/13/03
DATE

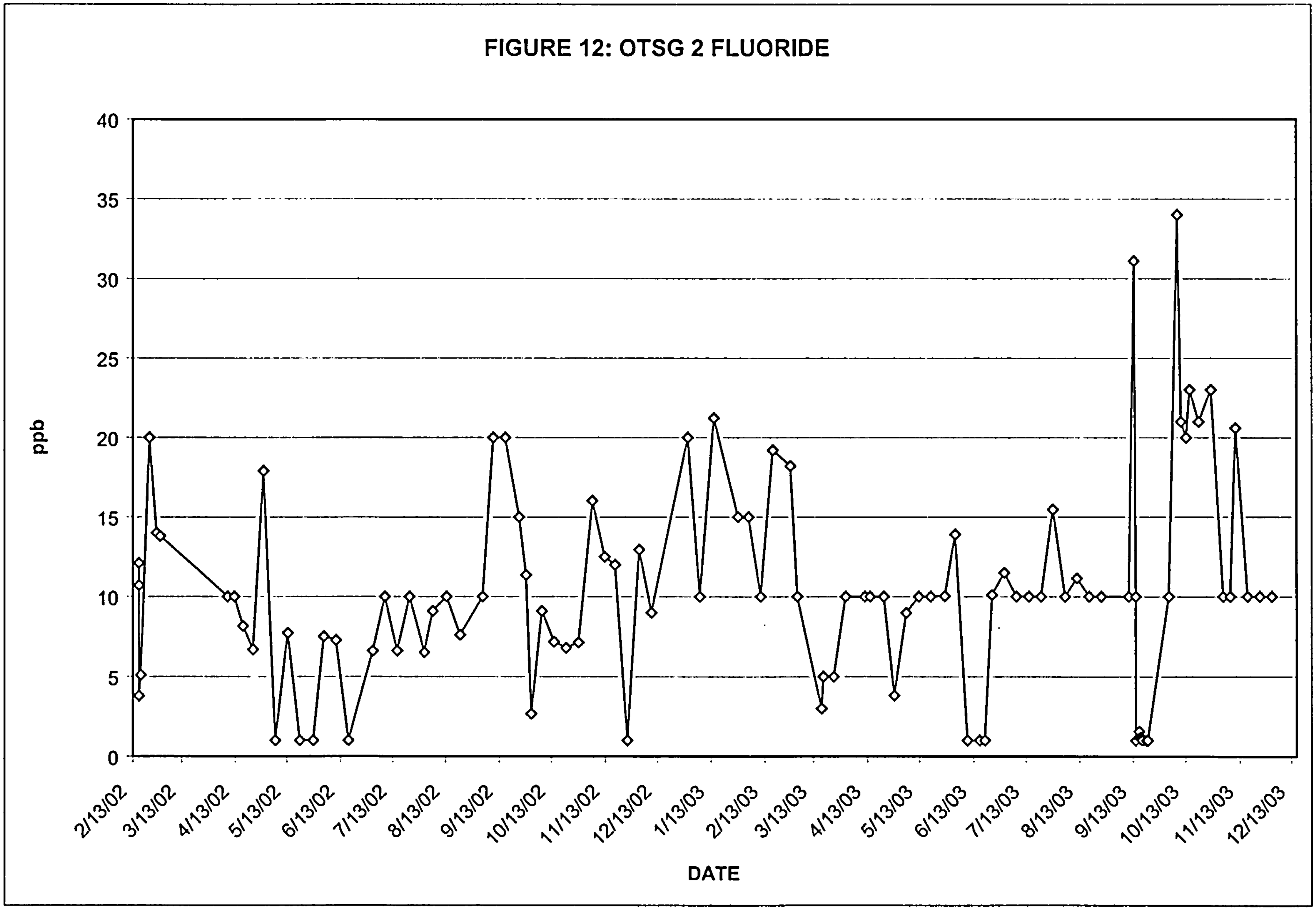


FIGURE 12: OTSG 2 FLUORIDE
ppb
0
5
10
15
20
25
30
35
40
2/13/02
3/13/02
4/13/02
5/13/02
6/13/02
7/13/02
8/13/02
9/13/02
10/13/02
11/13/02
12/13/02
1/13/03
2/13/03
3/13/03
4/13/03
5/13/03
6/13/03
7/13/03
8/13/03
9/13/03
10/13/03
11/13/03
12/13/03
DATE

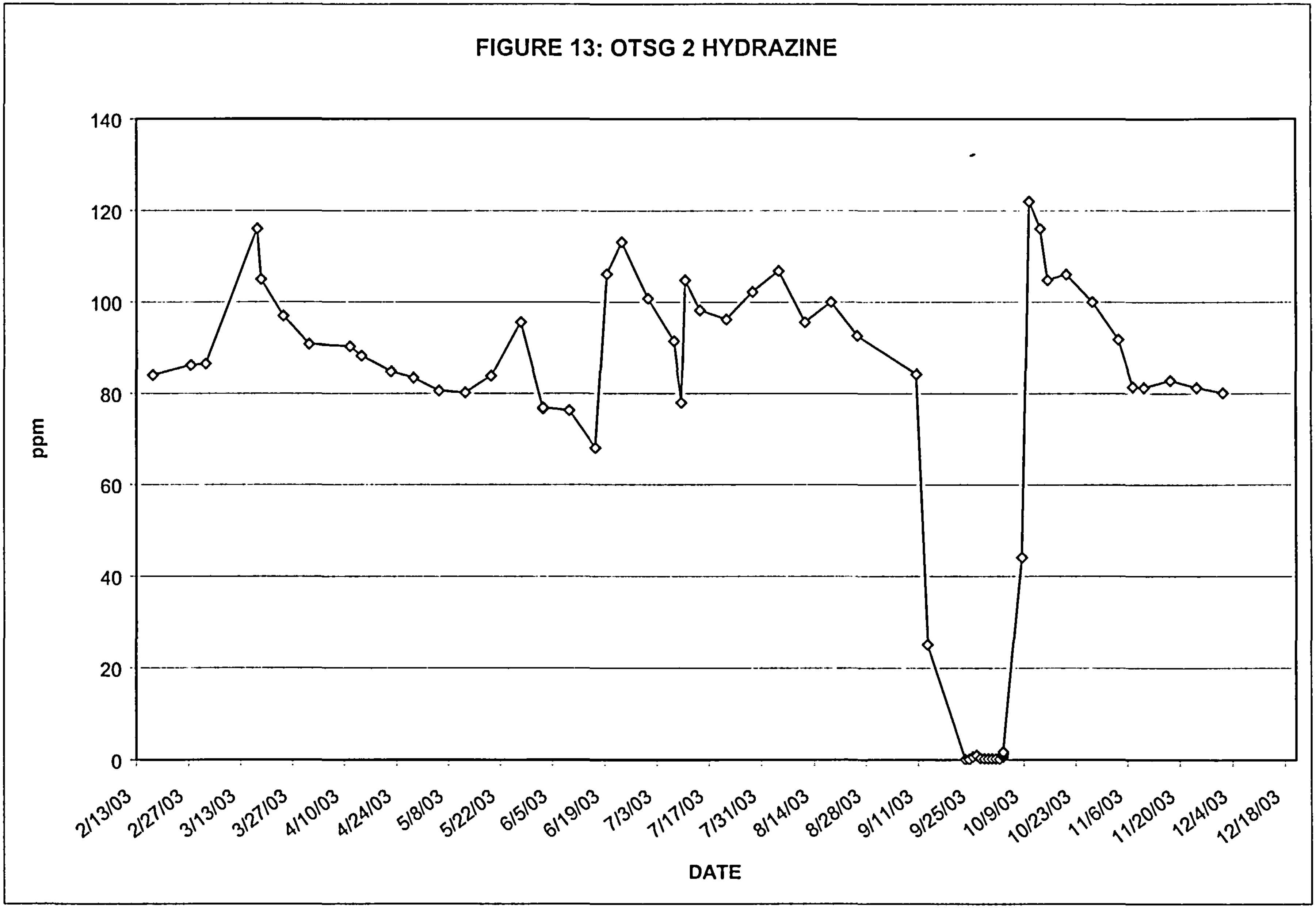


FIGURE 13: OTSG 2 HYDRAZINE
140
120
100
80
60
40
20
0
ppm
2/13/03
2/27/03
3/13/03
3/27/03
4/10/03
4/24/03
5/8/03
5/22/03
6/5/03
6/19/03
7/3/03
7/17/03
7/31/03
8/14/03
8/28/03
9/11/03
9/25/03
10/9/03
10/23/03
11/6/03
11/20/03
12/4/03
12/18/03
DATE

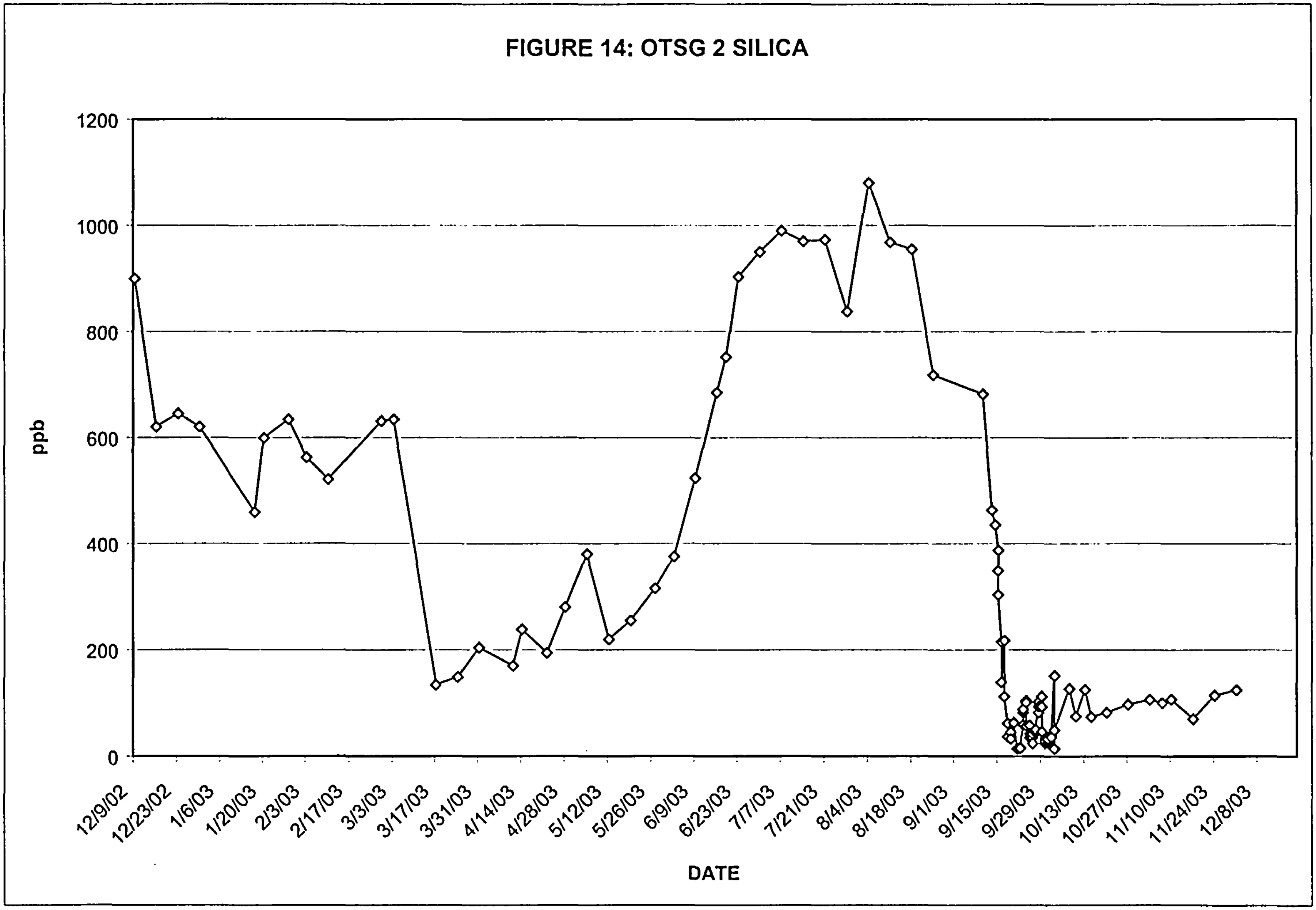
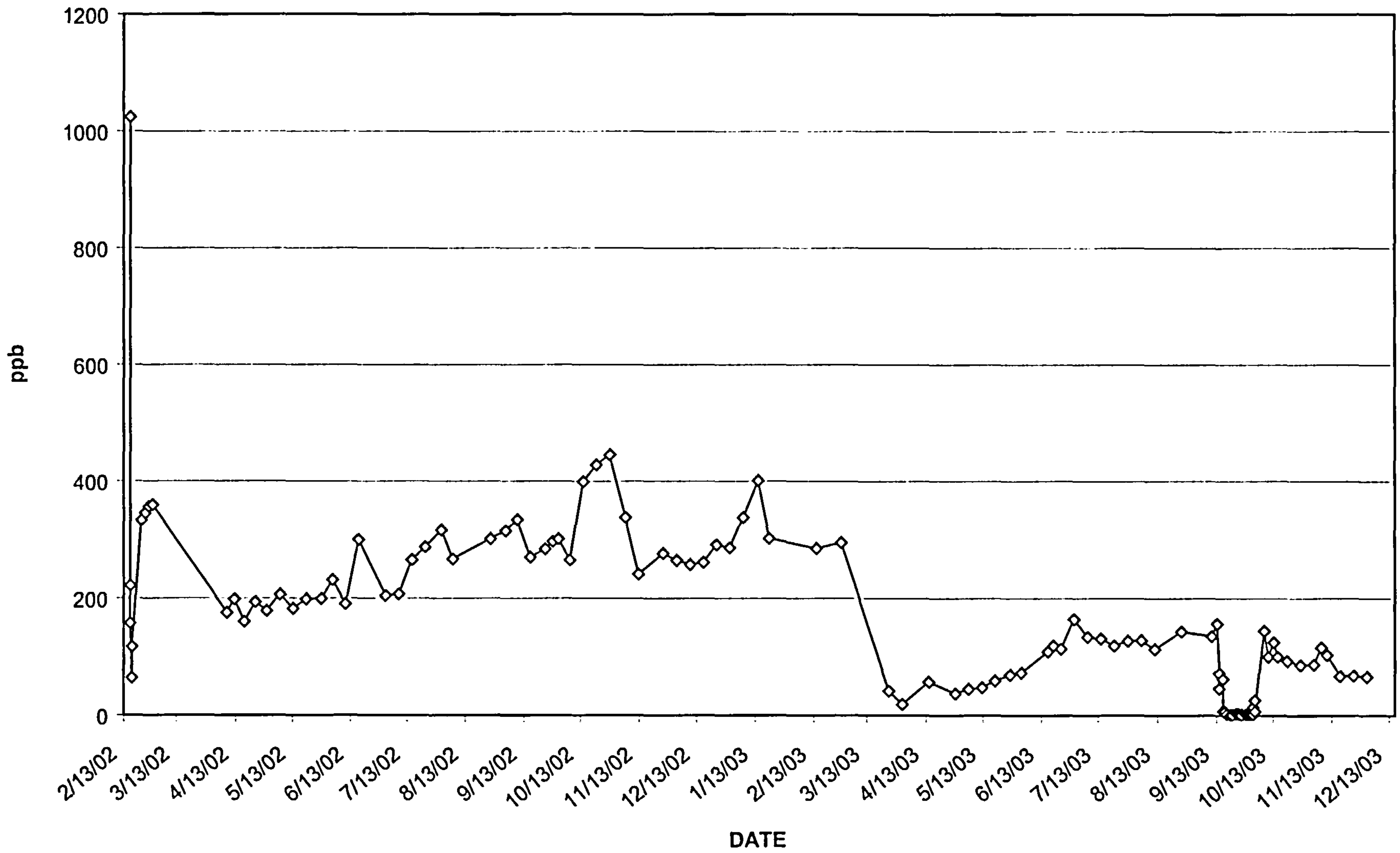


FIGURE 14: OTSG 2 SILICA
ppb
1200
1000
800
600
400
200
0
12/9/02
12/23/02
1/6/03
1/20/03
2/3/03
2/17/03
3/3/03
3/17/03
3/31/03
4/14/03
4/28/03
5/12/03
5/26/03
6/9/03
6/23/03
7/7/03
7/21/03
8/4/03
8/18/03
9/1/03
9/15/03
9/29/03
10/13/03
10/27/03
11/10/03
11/24/03
12/8/03
DATE

FIGURE 15: OTSG 2 SODIUM



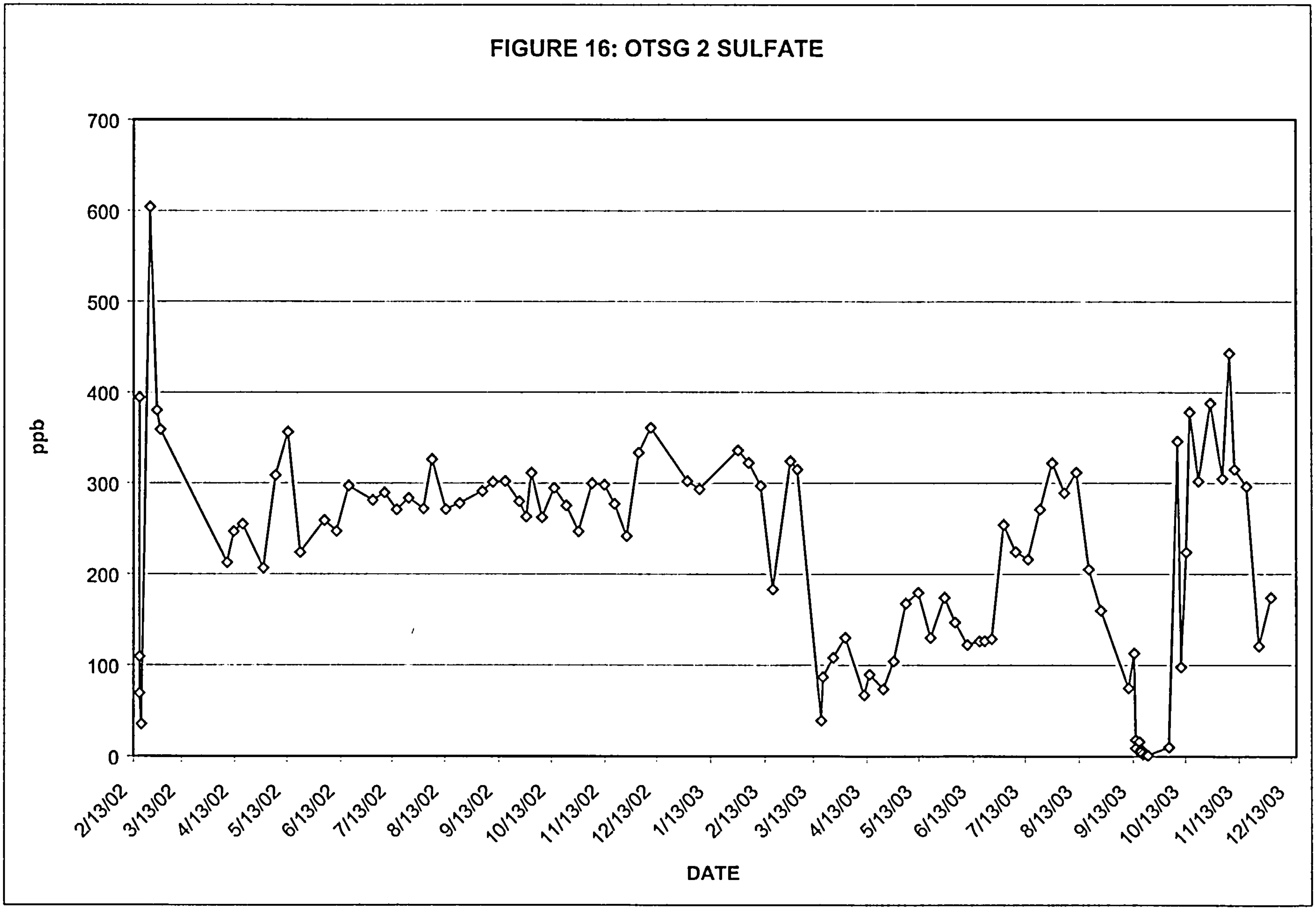


FIGURE 16: OTSG 2 SULFATE
ppb
700
600
500
400
300
200
100
0
2/13/02
3/13/02
4/13/02
5/13/02
6/13/02
7/13/02
8/13/02
9/13/02
10/13/02
11/13/02
12/13/02
1/13/03
2/13/03
3/13/03
4/13/03
5/13/03
6/13/03
7/13/03
8/13/03
9/13/03
10/13/03
11/13/03
12/13/03
DATE

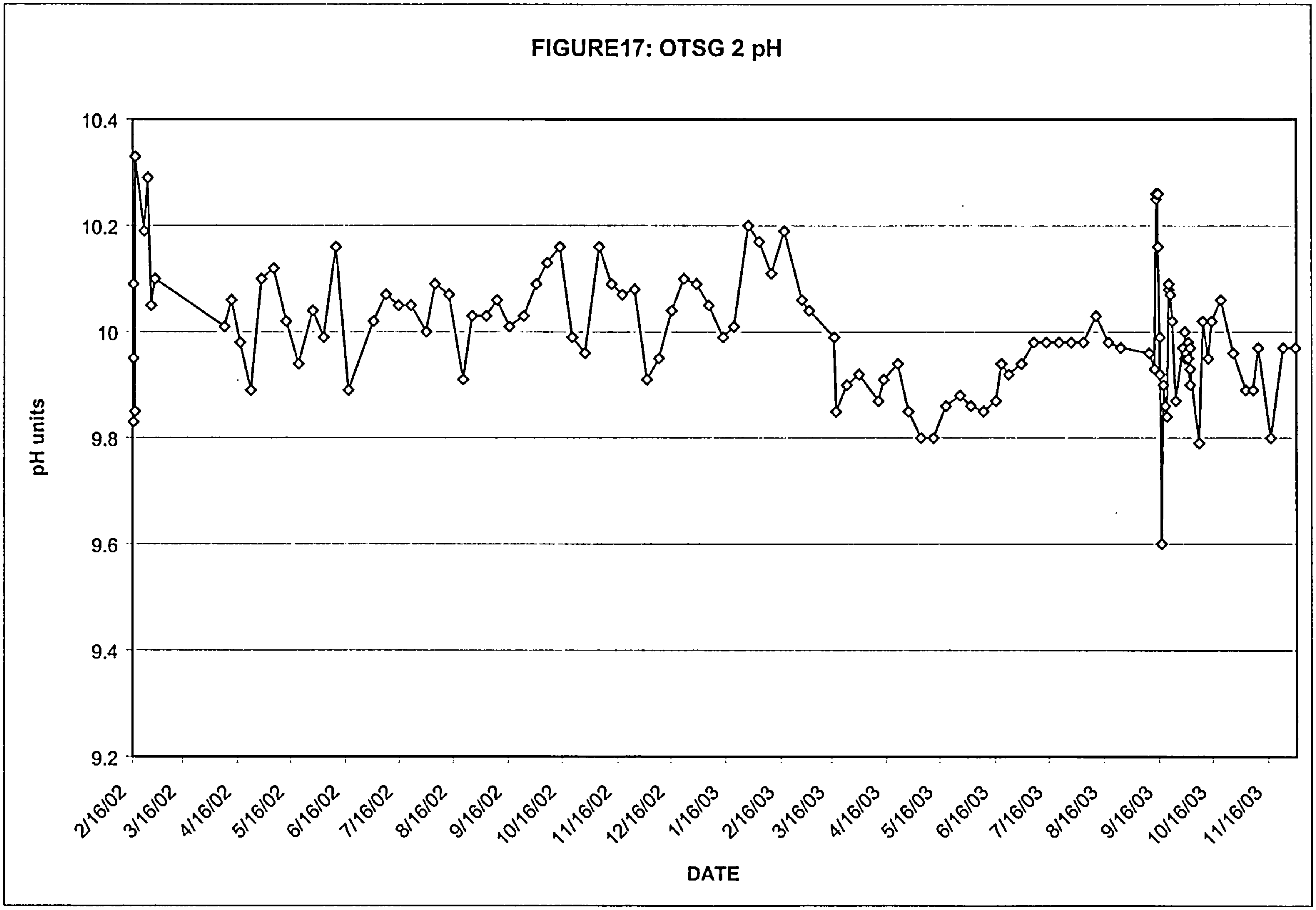
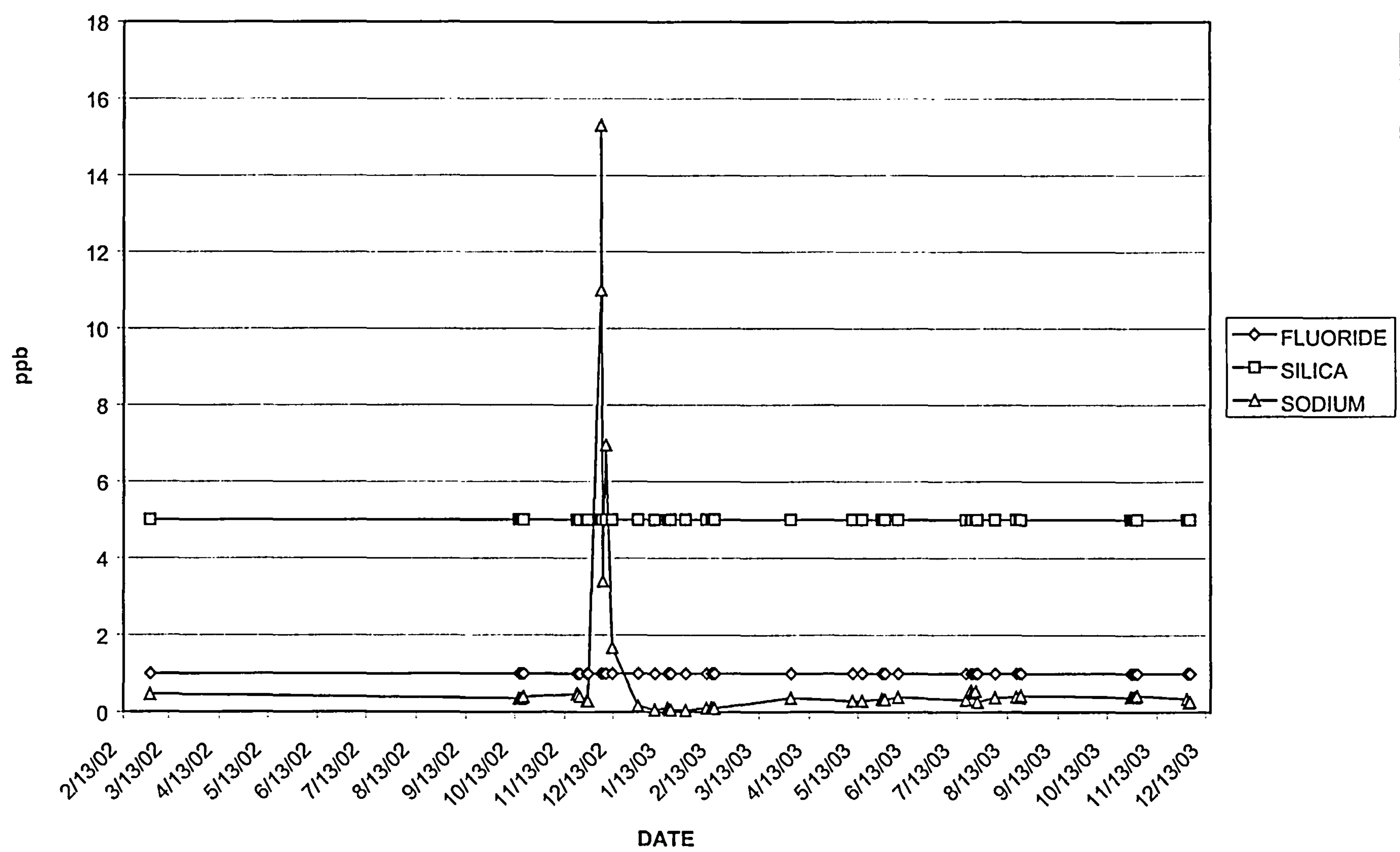


FIGURE17: OTSG 2 pH
10.4
10.2
10
9.8
9.6
9.4
9.2
pH units
2/16/02
3/16/02
4/16/02
5/16/02
6/16/02
7/16/02
8/16/02
9/16/02
10/16/02
11/16/02
12/16/02
1/16/03
2/16/03
3/16/03
4/16/03
5/16/03
6/16/03
7/16/03
8/16/03
9/16/03
10/16/03
11/16/03
DATE

FIGURE 18: DEMINERALIZED WATER



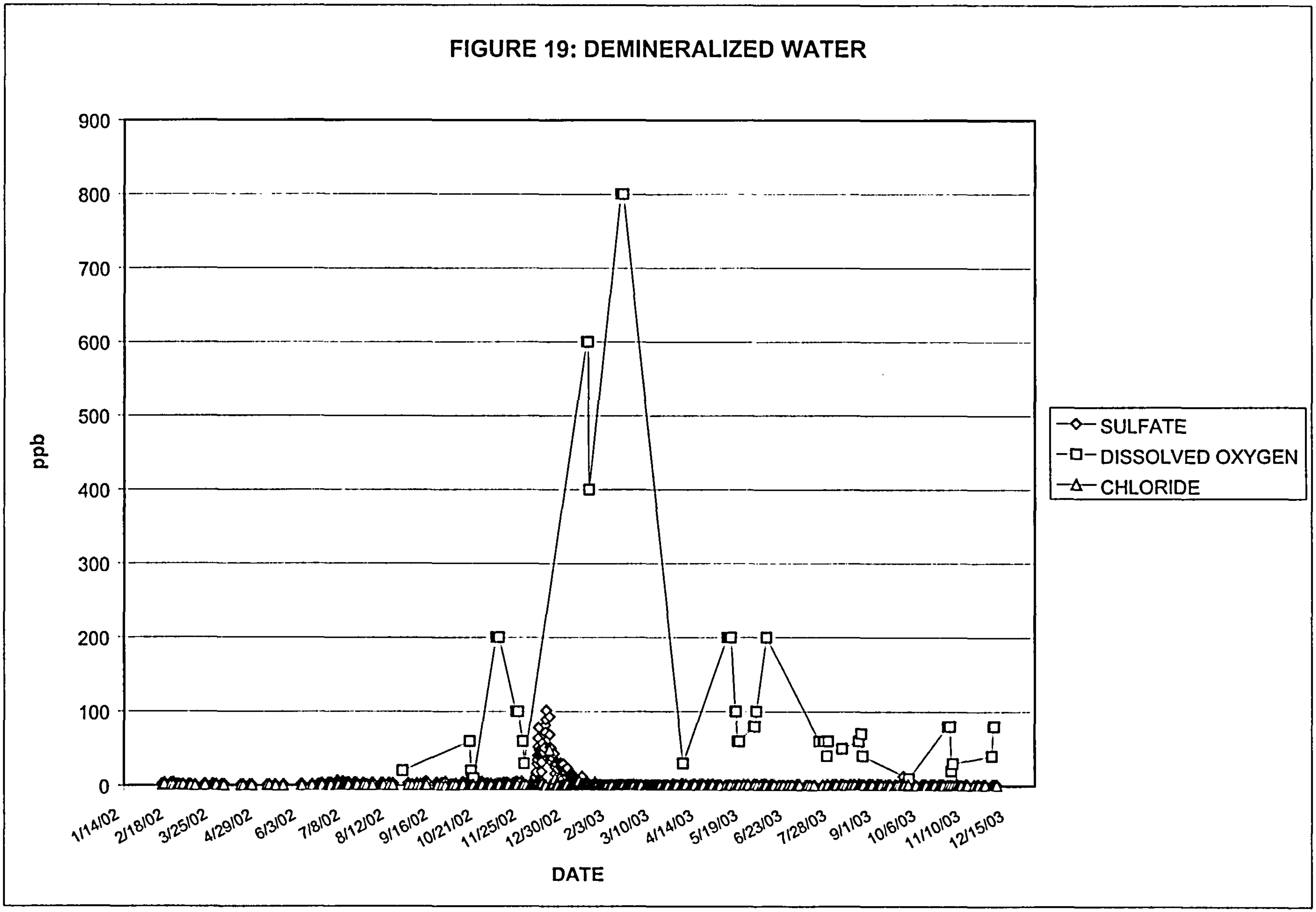
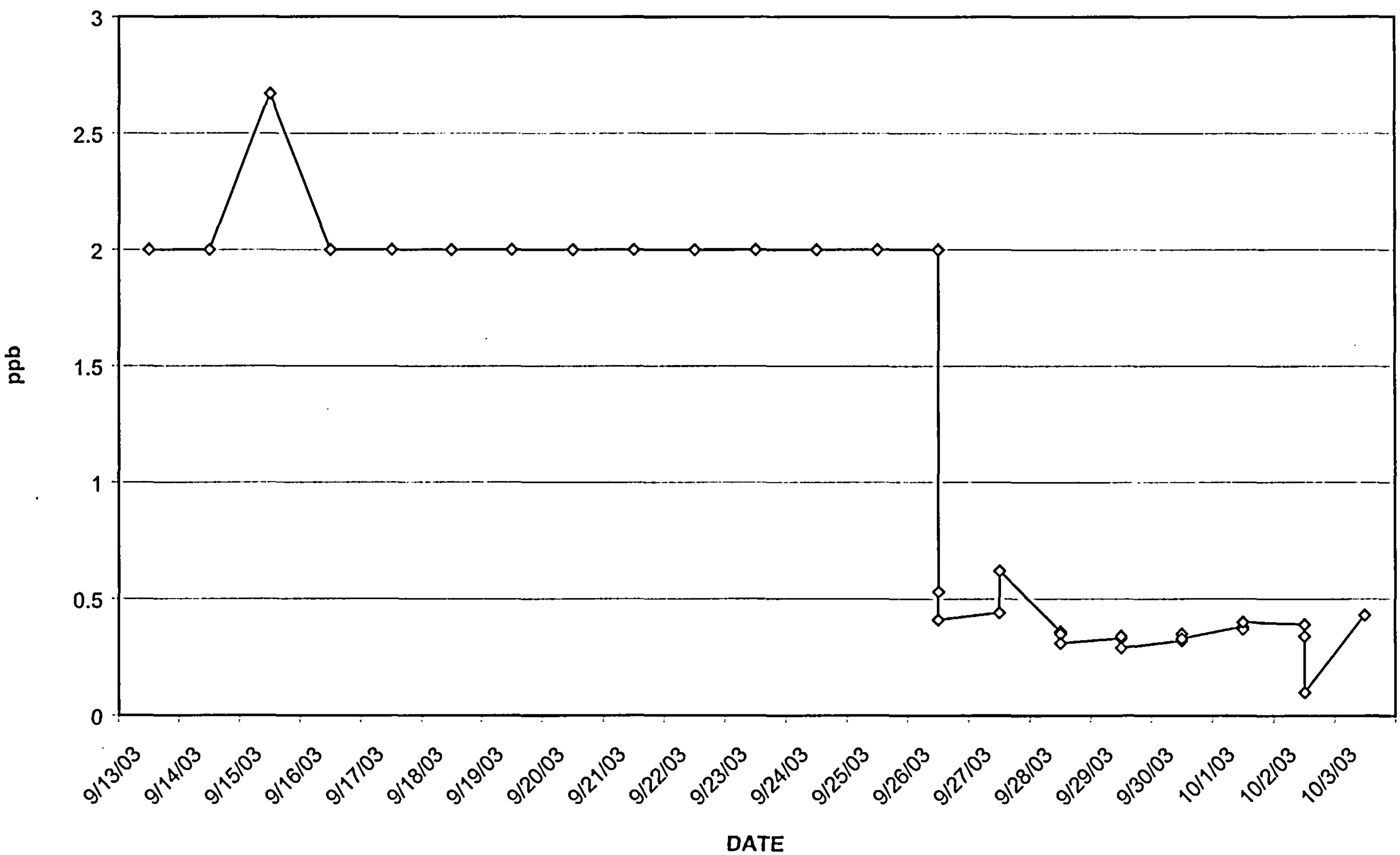


FIGURE 19: DEMINERALIZED WATER
900
800
700
600
500
400
300
200
100
0
ppb
1/14/02
2/18/02
3/25/02
4/29/02
6/3/02
7/8/02
8/12/02
9/16/02
10/21/02
11/25/02
12/30/02
2/3/03
3/10/03
4/14/03
5/19/03
6/23/03
7/28/03
9/1/03
10/6/03
11/10/03
12/15/03
DATE
SULFATE
DISSOLVED OXYGEN
CHLORIDE

FIGURE 20: NOPT FEEDWATER DISSOLVED OXYGEN



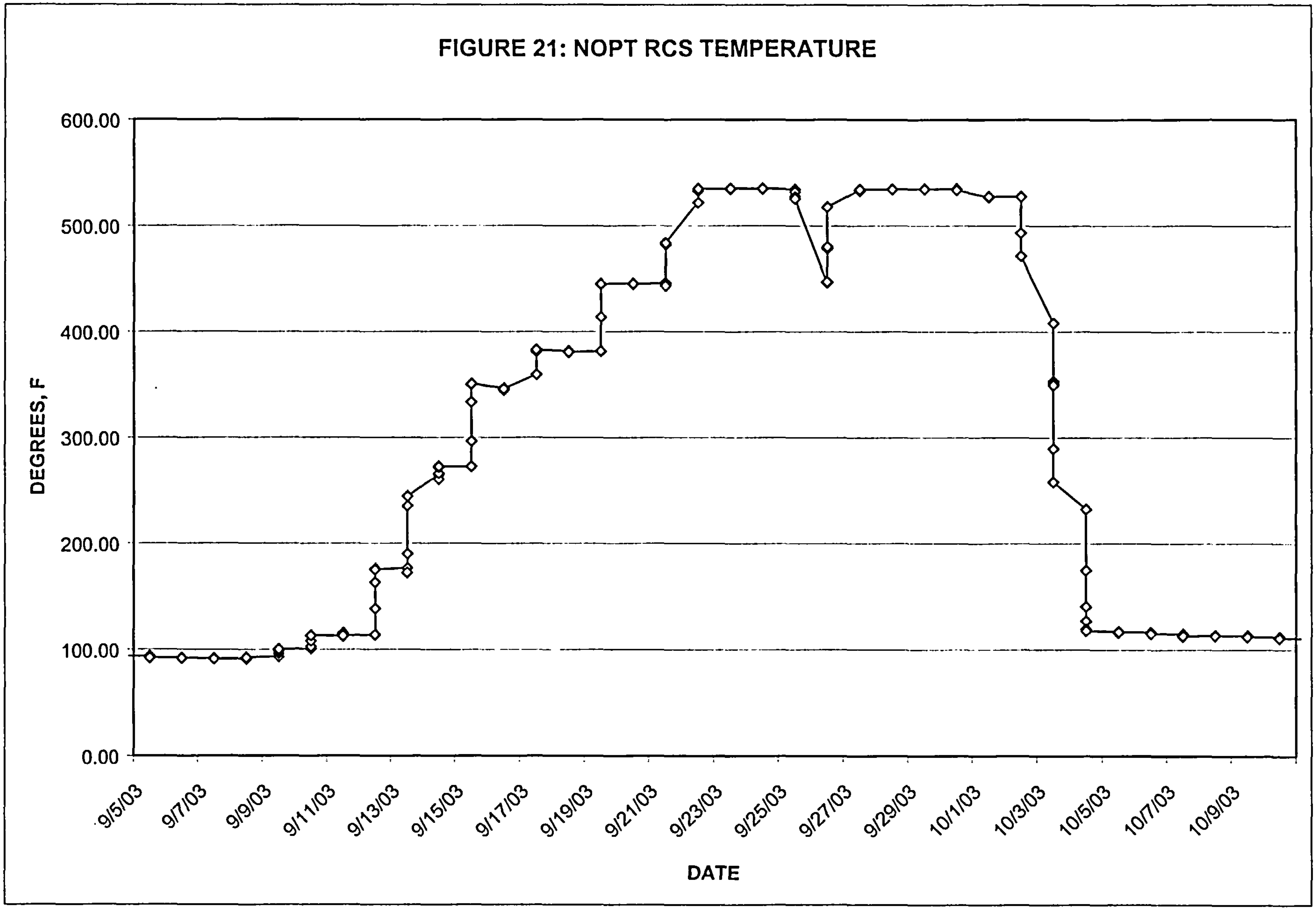


FIGURE 21: NOPT RCS TEMPERATURE
600.00
500.00
400.00
300.00
200.00
100.00
0.00
DEGREES, F
9/5/03
9/7/03
9/9/03
9/11/03
9/13/03
9/15/03
9/17/03
9/19/03
9/21/03
9/23/03
9/25/03
9/27/03
9/29/03
10/1/03
10/3/03
10/5/03
10/7/03
10/9/03
DATE

FIGURE 22: NOPT FEEDWATER SODIUM

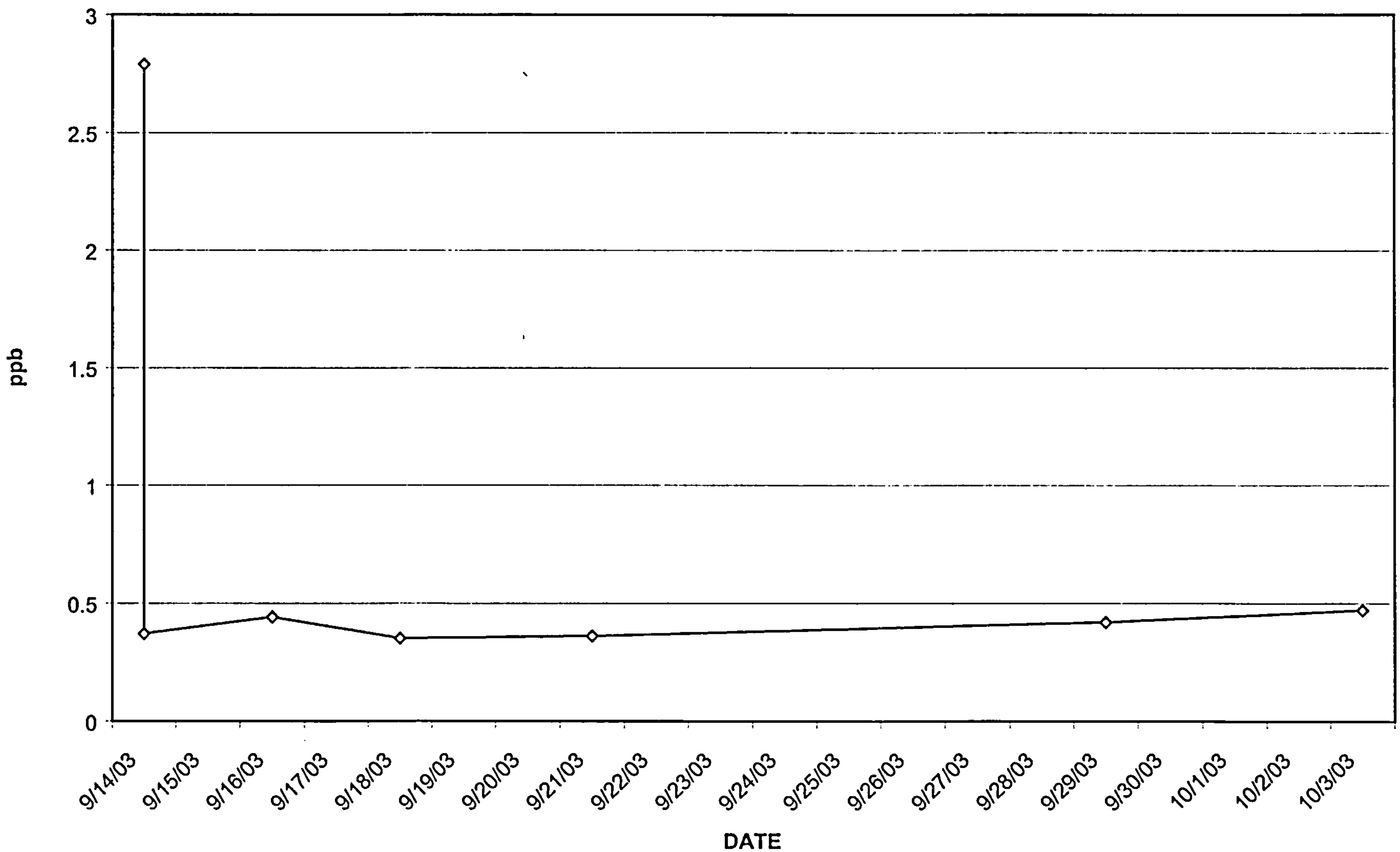
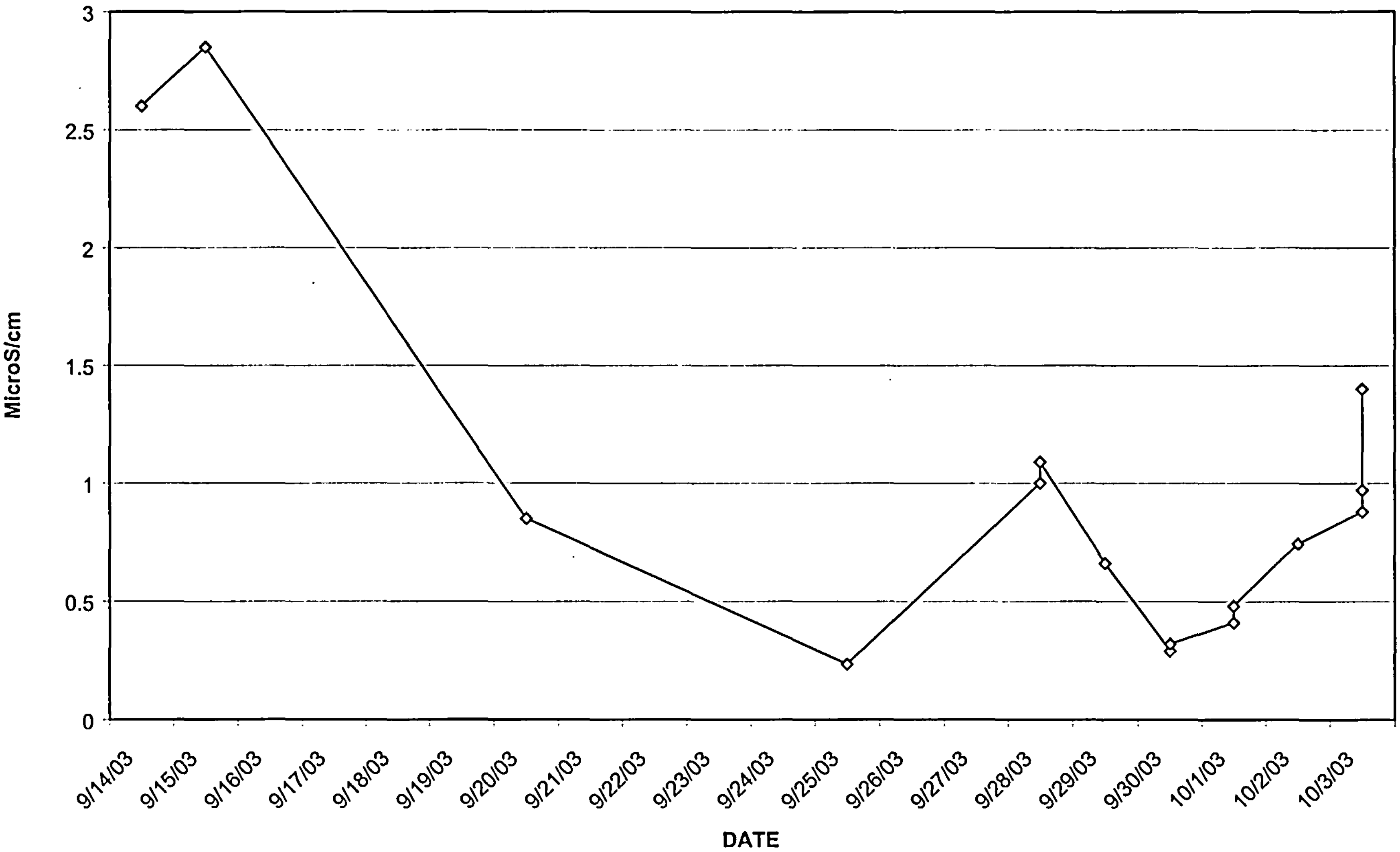


FIGURE 23: NOPT FEEDWATER CATION CONDUCTIVITY



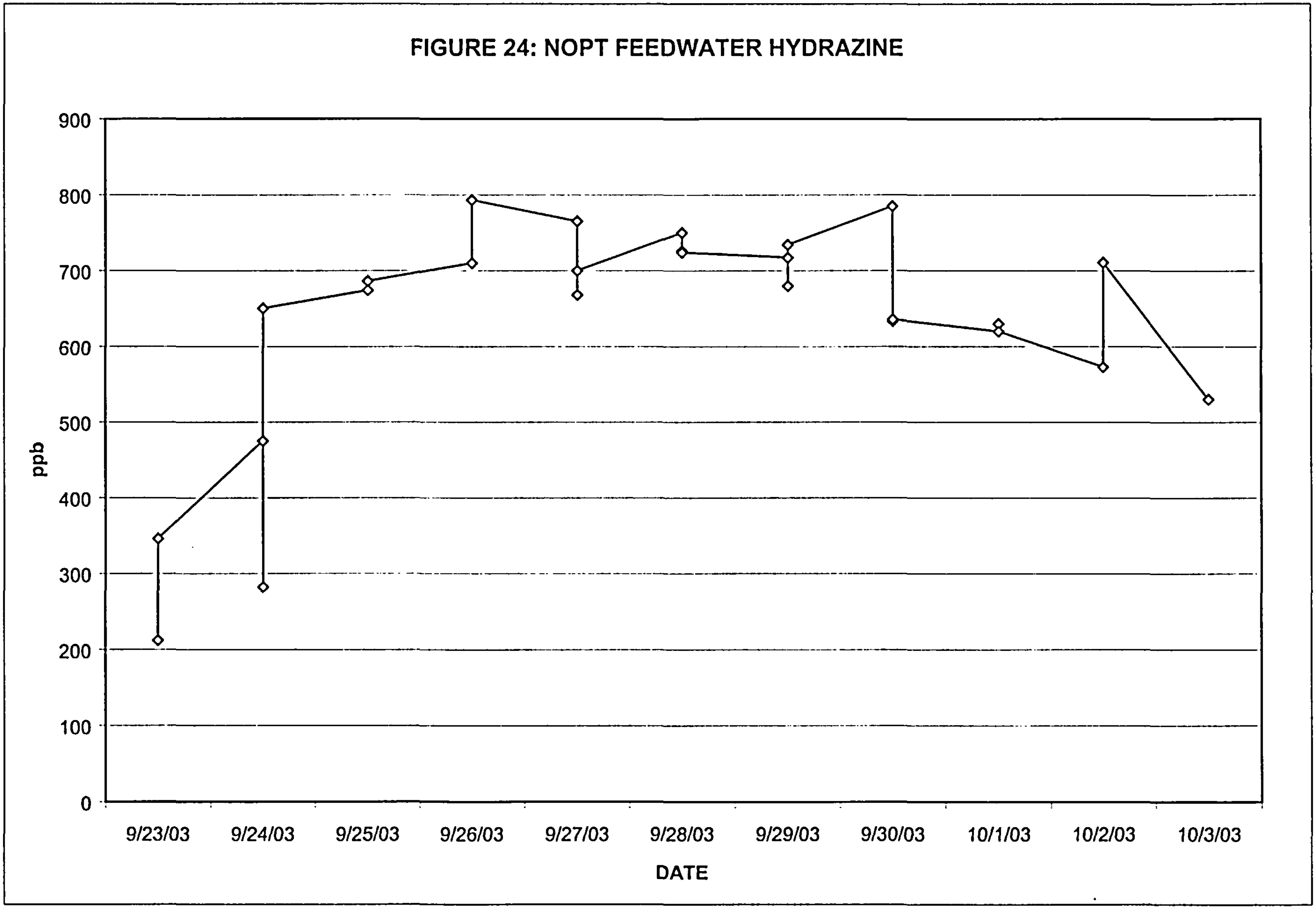


FIGURE 24: NOPT FEEDWATER HYDRAZINE
ppb
900
800
700
600
500
400
300
200
100
0
9/23/03
9/24/03
9/25/03
9/26/03
9/27/03
9/28/03
9/29/03
9/30/03
10/1/03
10/2/03
10/3/03
DATE

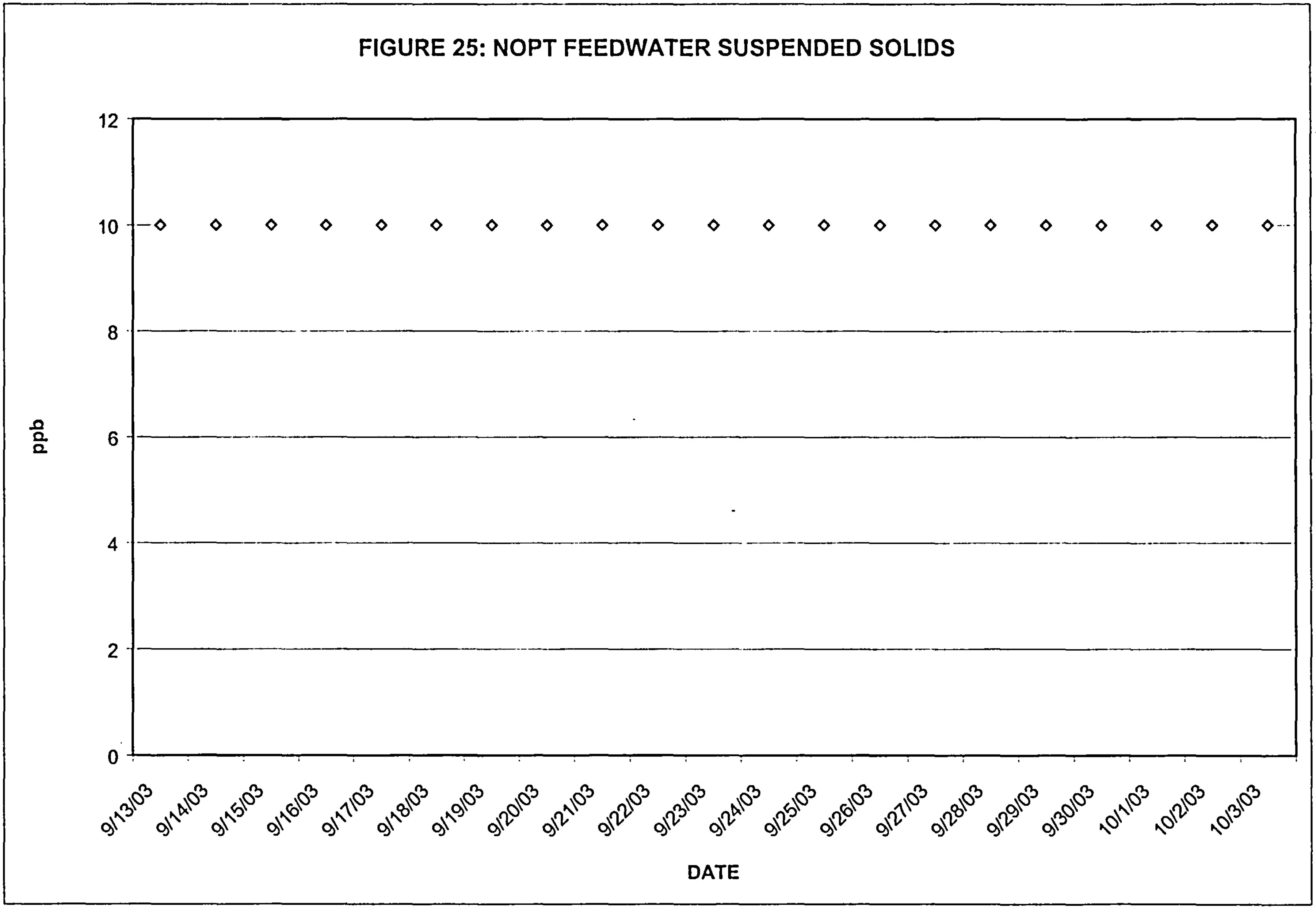
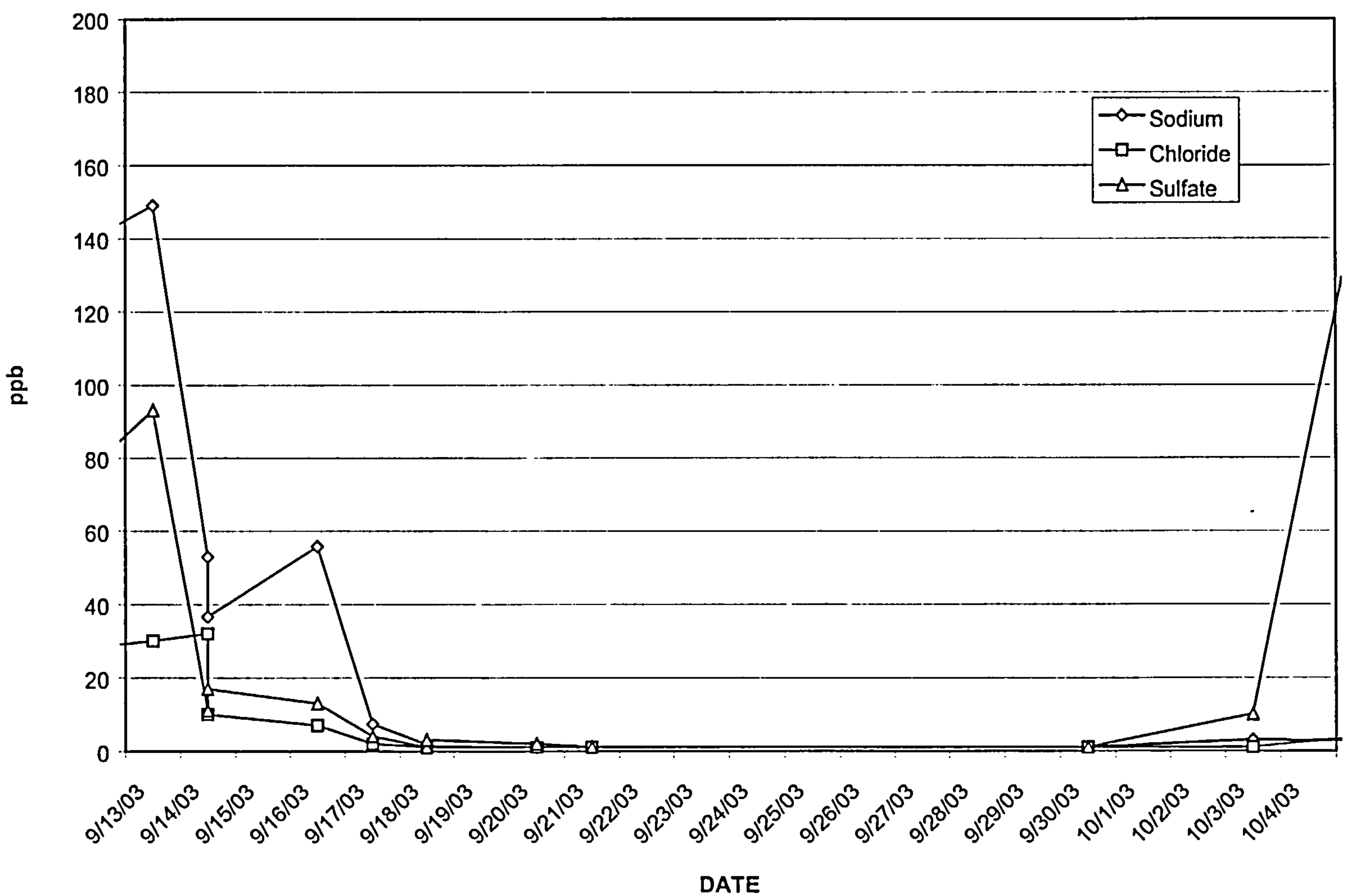


FIGURE 25: NOPT FEEDWATER SUSPENDED SOLIDS
12
10
8
6
4
2
0
ppb
9/13/03
9/14/03
9/15/03
9/16/03
9/17/03
9/18/03
9/19/03
9/20/03
9/21/03
9/22/03
9/23/03
9/24/03
9/25/03
9/26/03
9/27/03
9/28/03
9/29/03
9/30/03
10/1/03
10/2/03
10/3/03
DATE

FIGURE 26: NOPT OTSG 1 CHEMISTRY



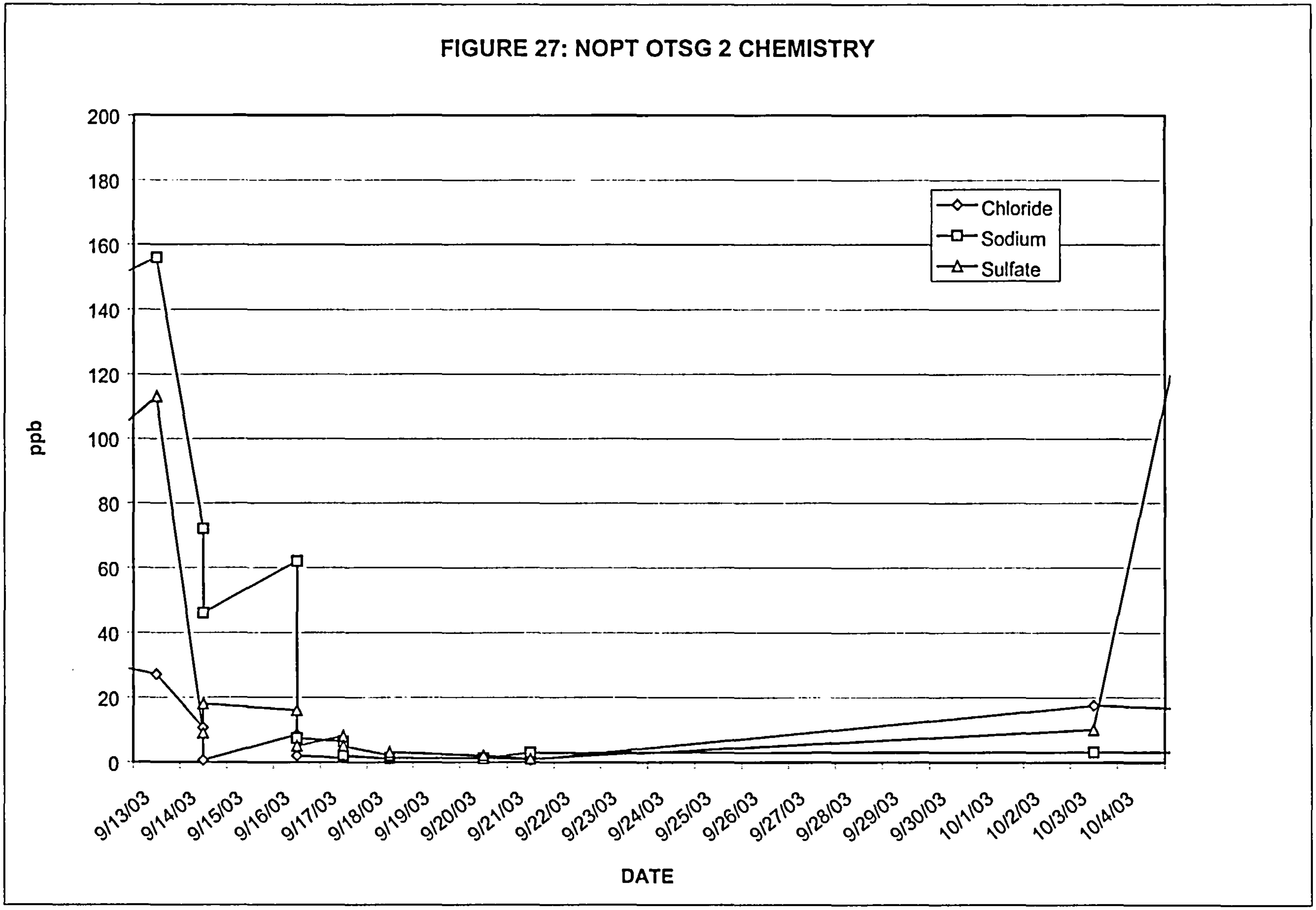


FIGURE 27: NOPT OTSG 2 CHEMISTRY
Chloride
Sodium
Sulfate
ppb
200
180
160
140
120
100
80
60
40
20
0
9/13/03
9/14/03
9/15/03
9/16/03
9/17/03
9/18/03
9/19/03
9/20/03
9/21/03
9/22/03
9/23/03
9/24/03
9/25/03
9/26/03
9/27/03
9/28/03
9/29/03
9/30/03
10/1/03
10/2/03
10/3/03
10/4/03
DATE

APPENDIX A: OUTAGE OTSG EVENT TIMELINE

Date	Time	OTSG#1	Secondary	Primary	Nitrogen	OTSG#2	Level	Level**	Nitrogen	General
			Level	Level			In. FR	Primary		Comments
			In. FR	ft.				ft.		
2/16/02	10:30	Start Filling								
	10:40					Start Filling				
	12:24					Draining				
	14:51		90% OR							
	19:04						90% OR			
	19:11		90% OR							
	22:38	Complete filling								
	23:41	Start Draining				Start Filling				
2/17/02	0:35					Start Draining				
	1:53	Start Draining								
2/19/02	23:09	On WLU Recirc.?								
	23:40	Start Filling	530							
2/20/02										
	0:05	WLU chem add				WLU chem add				
	1:00									
	5:41					Start Filling				
	5:52	On WLU Recirc.?				On WLU Recirc.?				
2/26/02	11:39			22.5				22.5		
	15:52			23.5				23.5		
3/1/02	0:09	Stop Recirc.								
	0:17					Stop Recirc.				
3/5/02	2:00	Start Draining	650							
	2:30	Stop Drain	600							
	4:39				5 psi				5 psi	
	17:16					Start Draining				
	22:05					Complete Draining	370			
	22:07	Complete Draining	0							
	1:32			Strart Drain				Start Drain		
3/15/02	5:15			20.5				20.5		
	18:00			0				0		
3/16/02	5:02			18.8				18.8		
3/17/02	2:10				2.7 psi					
	5:10				1 psi					
	20:00				Add					
3/18/02	4:00				Add					
3/22/02	9:28				Add					
	15:14				Add					
	22:54				Add					

Date	Time	OTSG#1	Secondary	Primary	Nitrogen	OTSG#2	Level	Level**	Nitrogen	General
			Level	Level			In. FR	Primary		Comments
			In. FR	ft.				ft.		
3/23/02	5:51				Add					
	8:55				Add					
	14:50				Add					
	21:10				Add					
3/24/02	3:22				Add					
	9:30				Add					
	16:20				Add					
	20:37				Add					
3/25/02	2:50				Add					
	8:30				Add					
	13:40				Add					
	17:56				Add					
	23:01				Add					
3/26/02	2:43				Add					
	7:45				Add					
	13:00				Add					
	16:51				Add					
	21:36				Add					
3/27/02	2:06				Add					
	4:50				Add					
	9:20				Add					
	16:17				Add					
	20:55				Add					
3/28/02	0:18				Add					
	3:57				Add					
	10:00				Add					
	21:46				Add					
3/29/02	2:09				Add				Add	
	5:00				Add				Add	
	11:06				Add				Add	
	16:10				Add				Add	
	21:12									
3/30/02	3:01									
	9:36									
	15:56				Add				Add	
3/31/02	4:40									
	10:03				Add				Add	
	15:53				Add				Add	
	22:04				Add				Add	
4/2/02	8:40				Add				Add	
	15:33				Add				Add	

Date	Time	OTSG#1	Secondary Level In. FR	Primary Level ft.	Nitrogen	OTSG#2	Level In. FR	Level** Primary ft.	Nitrogen	General Comments
4/3/02	1:52				Add				Add	
	9:19				Add				Add	
	13:02				Off				Add	
	16:50				Add				Add	
	17:09				Add				Add	
4/4/02	10:30	Start Filling	0		0					
	10:43								Add	
	21:55					Start Filling	280			
4/5/02	0:17	WLU Chem. Added				WLU Chem. Added				
	14:07	Complete Filling			623					
	16:29					Complete Filling	650			
4/6/02	3:37					On WLU Recirc.?				
	4:40	On WLU Recirc.?								
4/7/02	19:30				0		0		No	Both Drained
4/9/02	11:08					Stop Recirc.				
	11:35					Stop Recirc.				
4/11/02	13:04					On WLU Recirc.?				
5/12/02	18:18	On WLU Recirc.?				On WLU Recirc.?				MSVs found closed, no recirc. path, opened.
5/15/02	20:44					On WLU Recirc.				
6/10/02	5:30	Stop Recirc.								
	23:46			0				0		
6/11/02	0:46			3.6				3.6		
	2:51			13.6				13.6		
	4:34			23.5				23.5		
	11:25			23.5						
6/12/02	8:13	On WLU Recirc.?								
	23:30					Stop Recirc.				
6/13/02	12:56					On WLU Recirc.				
	13:13					On WLU Recirc.				
6/27/02	13:15					On WLU Recirc.				
6/28/02	10:09					Stop Recirc.				
	13:18					On WLU Recirc.				
	13:29					On WLU Recirc.				
	16:58			0.4				0.4		
6/30/02	8:43									Start draining RCS cold legs
	9:50									Completed draining RCS cold legs

Date	Time	OTSG#1	Secondary Level In. FR	Primary Level ft.	Nitrogen	OTSG#2	Level In. FR	Level** Primary ft.	Nitrogen	General Comments
7/5/02										Nozzle dams installed
7/221/02	11:49			18.1				18.1		
7/22/02	4:28			23.3				23.3		
7/28/02	18:21					On WLU Recirc.				
7/29/02	18:11					On WLU Recirc.				
7/30/02	2:20			0				0		
7/31/02		Stop Recirc.								
8/3/02	11:25	On WLU Recirc.								
8/18/02	7:04	On WLU Recirc.								CR-02-4431: WLU OTSG#1 valves misaligned.
11/20/02	6:51	Added water	Out vents			Added water	Out vents			
1/26/03	13:15			11				11		
1/27/03	18:38			0.3				0.3		
2/1/03	14:20			6.1				6.1		
	17:17			22.2				22.2		
2/28/03	4:34			14				14		
3/1/03	5:28			20				20		
3/2/03	14:40	Start Draining								
	20:30				5 psi					
	22:09				5 psi					
3/3/03	0:35				5 psi					
	4:53	Complete Draining	0							
	16:58									SG#1 vented for maintenance
3/4/03	1:10			23.5				23.5		
3/5/03	16:26					Stop Recirc.				Preparation for draining
	18:00	Start Filling								
	19:45	WLU Chem. Added								
3/6/03	0:49								5 psi	
	1:04					Start Draining				
	6:04			0						
	7:01	Complete Filling								
	12:05	On WLU Recirc.								
	17:35					Complete Draining	370			
3/10/03	13:08					Start Filling				
3/12/03	22:57					Start Filling	594			

Date	Time	OTSG#1	Secondary	Primary	Nitrogen	OTSG#2	Level	Level**	Nitrogen	General
			Level	Level			In. FR	Primary		Comments
			In. FR	ft.				ft.		
3/13/03						WLU Chem. Added				Nozzle dams removed
	0:26					Complete Filling				
3/15/03	14:54	On WLU Recirc.				On WLU Recirc.				
	11:30	Start Depress.								
	12:10	Complete Depress.								
	13:20				2-3 psi					
	16:18				22 psi					
	16:32	On WLU Recirc.				Stop Recirc.				
3/23/03	14:00					On WLU Recirc.				
4/7/03	4:07	Stop Recirc.								
	4:11					Stop Recirc.				
4/10/03	14:40	On WLU Recirc.				On WLU Recirc.				
4/16/03	22:12	On WLU Recirc.				On WLU Recirc.				
	22:39					Off recirc.				
5/28/03	22:09	Stop Recirc.								MSV repair
5/30/03	7:48					On WLU Recirc.				
6/9/03	18:04	On WLU Recirc.								
7/2/03	15:54					On WLU Recirc.				
7/25/03	14:25	Stop Recirc.								
8/15/03	0:00		615				621			
8/15/03	5:40					On WLU Recirc.				
	5:45	On WLU Recirc.								
8/21/03	12:00		616							
8/22/03	7:00		615							
8/27/03	9:00		614							
9/1/03	0:35	note				note				note: Both removed per DB-OP-06230
	3:23	Start Draining	614			Start Draining				
	4:00						615			
	8:00		403							
	10:00						397			
	23:00		404							
9/3/03	7:09									BEGIN PLANT HEATUP
9/4/03	15:00		410				403			
9/5/03	2:05				Add, 4 psi				Add, 2 psi	

Date	Time	OTSG#1	Secondary	Primary	Nitrogen	OTSG#2	Level	Level**	Nitrogen	General
			Level	Level			In. FR	Primary		Comments
			In. FR	ft.				ft.		
9/7/03	16:00		426							
	11:00		446				443			
	18:30									RCS at 100-110 F
9/10/03	14:42				Add, 4 psi				Add, 4 psi	
	15:15				20 psi				23 psi	
	17:00	Start Draining	425			Start Draining	440			
	18:15	Stop Draining	370							
	19:51					Stop Draining	390			
9/12/03	2:00		390							
	3:00		440							
	14:48	Start Filling								
	15:00						367			
	15:28	Stopped Filling	375-405							
	19:00						414			
9/13/03	7:12									RCS at 179 F
	10:00		381				382			
	16:00						472			
	17:00		449							
9/14/03	16:00						300			
	23:00		280							
9/15/03	3:00		319							
	10:45	Start FS&D				Start FS&D				
	10:55	Start 2 hr soak								
	11:18					Start 2 hr soak				
	12:55	Ended 2 hr soak,								
		Drain to Condenser								
	13:19					Ended 2 hr soak,				
						Drain to Condenser				
	22:00						57			
9/16/03	1:00		58				334			
	2:09					Filled and				
						Start 2 hr soak				
	3:26	Filled and								
		Start 2 hr soak								
	4:13					Ended 2 hr soak,				
						Start Draining				
	5:35	Ended 2 hr soak,								
		Start Draining								
	6:00		303							
	9:00						65			

Date	Time	OTSG#1	Secondary Level In. FR	Primary Level ft.	Nitrogen	OTSG#2	Level In. FR	Level** Primary ft.	Nitrogen	General Comments
9/16/03	11:00		60							
	14:00						329			
	16:00		324							
	21:00						67			
9/17/03	0:00		61							
	3:00		321							
	4:00						324			
	4:18					Ended 2 hr soak,				
						Start Draining				
	4:33	Ended 2 hr soak,								
		Start Draining								
	11:00		44							
	14:00						46			
9/22/03	6:00		53							
	23:00						55			
10/2/03	21:00						50			
10/3/03	0:00						314			
	5:00						46			
	19:00		42							
	21:00						60			
	22:00						257			
10/4/03	0:00					Start Filling	393			
						From Condensate				
	22:00	Start Filling								
		From Condensate								
	22:49	Stop Filling	575							
	23:20					Stopped Filling	575			
10/5/03	0:00						563			
	4:00						484			
	15:00		650							
	17:00						635			
	18:00		616							
	19:00						615			
	20:03									Condensate Shutdown/WLU
10/7/03	0:00		650							
	1:00						650			
10/8/03	15:00		619							
10/14/03	16:48						619			
10/22/03	21:12					Stop WLU Recirc.				
	0:00						608			
10/23/03	5:00						612			

Date	Time	OTSG#1	Secondary Level In. FR	Primary Level ft.	Nitrogen	OTSG#2	Level In. FR	Level** Primary ft.	Nitrogen	General Comments
10/24/03	0:05					Start WLU Recirc.				
	0:08	Stop WLU Recirc.								
	21:18	Start WLU Recirc.								
11/1/03	0:40				Add					
	1:24	Start Draining	565							
	14:23	stop draining	300							
	16:30				Isolated					
11/2/03	1:00		297							
	2:00		650							
11/5/03	17:00		319							
11/6/03	2:20	Complete Filling								
	3:00		650							
	3:55	Start WLU Recirc.								
	14:00						595			
	14:10					Start Filling	588			
	16:00						650			
11/7/03	9:37	WLU Recirc.				WLU Recirc.				
	16:00						620			
11/8/03	10:35	Started Chem. Add.								
	11:15	Stopped Chem. Add.								
12/1/03	11:54					Stop WLU Recirc.				
12/2/03	0:00						613			
12/3/03	0:00		609							
12/4/03	14:23					Start WLU Recirc.				

FRAMATOME DOCUMENT 51-5034594-02

A Steam Generator Tubing Operational Assessment for Davis Besse

(19 pages follow)

FRAMATOME ANP

ENGINEERING INFORMATION RECORD

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Title A Steam Generator Tubing Operational Assessment for Davis Besse

PREPARED BY:		REVIEWED BY:	
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Technical Manager Statement: Initials [initials]

Reviewer is Independent.

Remarks:

This report describes the results of an operational assessment for steam generator tubing at Davis Besse mid cycle 14.

FENOC
ENGINEERING DOCUMENT REVIEW

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BY: [signature] DATE: 12/10/03

Table of Contents

Record of Revisions

Section	Revision	Description
All	00	Original Release
All	01	Updated to Include Lower TEC
All	02	Updated to Include a Discussion of Projected Numbers of Indications

1.0 Introduction

An operational assessment for the first mid cycle of operation after 13RFO at Davis Besse was performed. The previous operational assessment[1] for a full cycle length of 1.85 EFPY was reviewed and updated as needed. Recent degradation growth rate information[2] for OTSG plants was compared to parameters used for the full cycle length analysis. No updates were required. The previous analysis remains valid and is bounding for mid cycle operation. Projections for the number of indications expected at a mid cycle inspection were developed to provide a basis for evaluation of degradation progression rates.

The limiting form of tubing degradation at Davis Besse is considered to be freespan axial ODSCC/ IGA (groove IGA). A recently developed eddy current signal amplitude approach[3] to CMOA analyses is provided for this mechanism. It provides a check of conventional physical sizing methodologies and is more directly related to noise effects on detection sensitivity requirements.

2.0 Operational Assessment for Mid Cycle 14

Table 2.1 lists previous operational assessment results[1] for full cycle operation in Cycle 14. A bounding approach was used with all input at worst case 95th percentile values. Upon review of latest information[2], degradation growth rate parameters remain either appropriate or conservative. Since margins exist for a bounding approach to full cycle operation, structural requirements are met for mid cycle operation. As was the case for full cycle operation, projected mid cycle SLB leakage is zero other than that nominally associated with preexisting degradation in rolled tube ends in the upper tubesheet as well as leakage from mechanical sleeves and plugs. A conservative projection for mid cycle SLB leakage is the same as for full cycle, 0.11 gpm in the limiting steam generator, S/G A. However, since this projection was developed tube end cracking was found in a sister OTSG in the lower tubesheet[4]. Based on this information, the limiting projected full cycle SLB leak rate at Davis Besse should be increased by 7% to account for undiscovered lower tube end cracks. This leads to a revised value of 0.12 gpm. The time for degradation growth at mid cycle, estimated as 1.4 EFPY, is less than full cycle, 1.85 EFPY, structural margins at mid cycle will increase by about 15% compared to those for full cycle operation.

Structural integrity for freespan axial ODSCC was determined via a multi-cycle Monte Carlo approach[1,5]. Updated results for mid cycle operation are shown in Figure 2.1. This plot shows the distribution of worst case burst pressures. The 95th percentile worst case burst pressure is about 5370 psi, well above a nominal 3ΔP of 4050 psi. Similar results for full cycle operation are shown in Figure 2.2. Here, the 95th percentile worst case burst pressure is about 4300 psi. Figure 2.3 shows the distribution of projected number of detected indications at mid cycle. This is to be compared to the distribution of projected number of detected indications of freespan axial ODSCC/IGA for full cycle operation shown in Figure 2.4. For mid cycle the best estimate is 8 compared to about 10 for full cycle.

Table 2.2 provides a summary of projected number of degradation sites for full and mid cycle operation for the active degradation mechanisms at Davis Besse. Wear indications are left in service if NDE maximum depths are less than 40% TW. The rate of appearance of new wear indications is very small. Hence, cycle length has little effect on the estimated total number of wear indications. All other degradation mechanisms follow a plug on detection repair scenario, thus cycle length will affect the expected number of new indications. Overall the projected number of indications at mid cycle with a plug/repair on detection repair scenario is about 60% of the number expected for full cycle operation. In terms of a comparison of projected numbers of indications for 13RFO versus observed numbers of indications at 13RFO, the following points are noted:

- Freespan axial ODSCC was first observed at 13RFO. Projections for the initial onset of a degradation mechanism are highly variable. Accordingly, 8 were observed while 2 were projected.
- For roll transition PWSCC, a projection of 2 versus an observation of 2 is excellent.

- Projections for axial PWSCC at tube ends were intentionally conservative. Inspection results at 11RFO and 12RFO led to a Weibull slope of 14 compared to a more realistic maximum slope of 6. The observed number of indications at 13RFO reflects a more realistic Weibull slope. It takes about 3 inspections to develop a reliable Weibull slope.
- The difference between projected and observed numbers of upper bundle volumetric IGA indications for 13RFO is due to improved detection sensitivity as a result of chemical cleaning performed at 12RFO.
- Use of a new eddy current technique at 13RFO combined with chemical cleaning at 12RFO led to a low projection compared to the observed number of indications, 220 versus 288. The eddy current technique for 14RFO mid cycle will be the same as for 13RFO.

For mid cycle operation of about 1.4 EFPY, projected structural margins are about 15% greater than full cycle operational, projected numbers of indications remain the same for wear and decrease by about 20% for other degradation mechanisms and projected SLB leakage remains at nominal projected values due to mechanical plugs and sleeves and preexisting PWSCC in rolled lengths at upper tubesheet expansion transitions. As noted in another report[6], degradation growth is not expected over the extended length of downtime prior to startup for Cycle 14. A substantial margin exists for any unexpected degradation growth that may have occurred.

Table 2.1
Bounding Operational Assessment Results for Full Cycle Operation

Degradation Mechanism	BOC Worst Case Degradation	95th Percentile Degradation Growth for 1.85 EFPY	EOC Bounding Axial Length	EOC Bounding Circ Length	Projected Degradation Severity	EOC Allowable Degradation Severity	Structural Margin
Wear	47.7 % TW Avg. Depth	5.4%TW	0.4"	NA	53.1%TW Avg. Depth	69.7%TW Avg. Depth	16.6%TW Avg. Depth
Volumetric IGA (Axial Force Loading)	46.0 %TW Avg. Depth	15.5 %TW Avg. Depth	0.32"	0.32"	0.20" Eff. 100%TW Length	0.37" Eff. 100%TW Length	0.17" Eff. 100%TW Length
Volumetric IGA (Pressure Loading)	46.0 %TW Avg. Depth	15.5 %TW Avg. Depth	0.32"	0.32	61.8%TW Avg. Depth	72.3%TW Avg. Depth	11.5%TW Avg. Depth
Circumferential SCC at Top Span Dents	35.9 %TW Avg. Depth	22.5 %TW Avg. Depth	NA	0.38" (75°)	0.23" Eff. 100%TW Length	0.37" Eff. 100%TW Length	0.14" Eff. 100%TW Length

Table 2.2
Both Found and Projected Numbers of Indications for Limiting Steam Generator Normalized to 100% Inspection Scope

Degradation Mechanism	Found 12RFO	Projected 13RFO	Found 13RFO	Projected 14RFO without Mid Cycle	Projected Mid Cycle
Freespan Axial ODSCC	0	2	8	10	8
Roll Transition PWSCC	0	2	2	5	4
Tube End Axial PWSCC	30	140	69	63 new	54 new
Upper Bundle Volumetric IGA	15	15	66	66	51
Wear	177	220	288	288	288
Tube End Circumferential PWSCC	0	na	5	5	4
Circumferential Cracking at Upper Bundle Dents	0	na	2	2	1

Notes:

- Freespan axial ODSCC was first observed at 13RFO. Projections for the initial onset of a degradation mechanism are highly variable. Accordingly, 8 were observed while 2 were projected.
- For roll transition PWSCC, a projection of 2 versus an observation of 2 is excellent.
- Projections for axial PWSCC at tube ends were intentionally conservative. Inspection results at 11RFO and 12RFO led to a Weibull slope of 14 compared to a more realistic maximum slope of 6. The observed number of indications at 13RFO reflects a more realistic Weibull slope. It takes about 3 inspections to develop a reliable Weibull slope.
- The difference between projected and observed numbers of upper bundle volumetric IGA indications for 13RFO is due to improved detection sensitivity as a result of chemical cleaning performed at 12RFO.
- Use of a new eddy current technique at 13RFO combined with chemical cleaning at 12RFO led to a low projection compared to the observed number of indications, 220 versus 288. The eddy current technique for 14RFO mid cycle will be the same as for 13RFO.

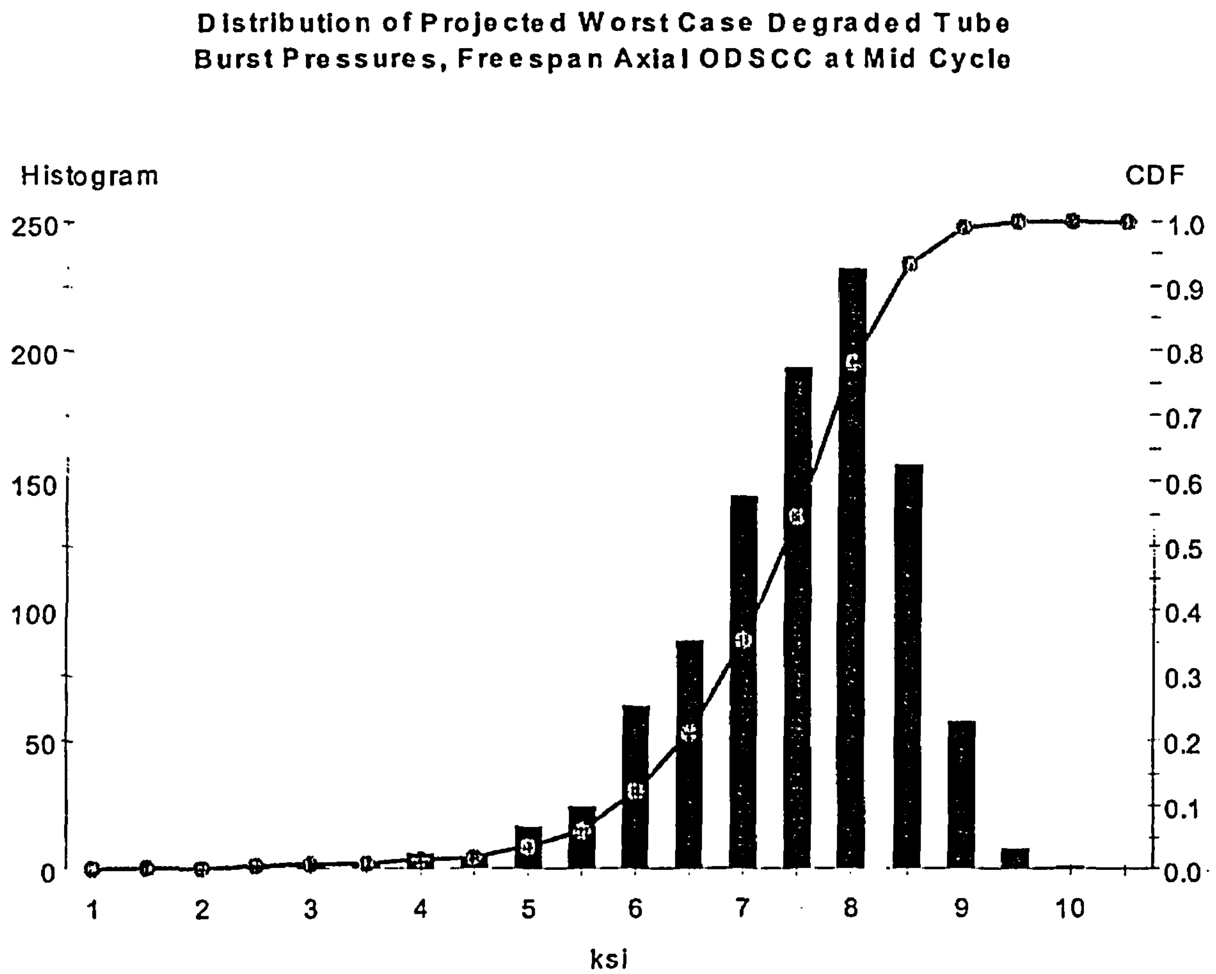

Figure 2.1 Distribution of Projected Worst Case Burst Pressures for Axial ODSCC/IGA at Mid Cycle.

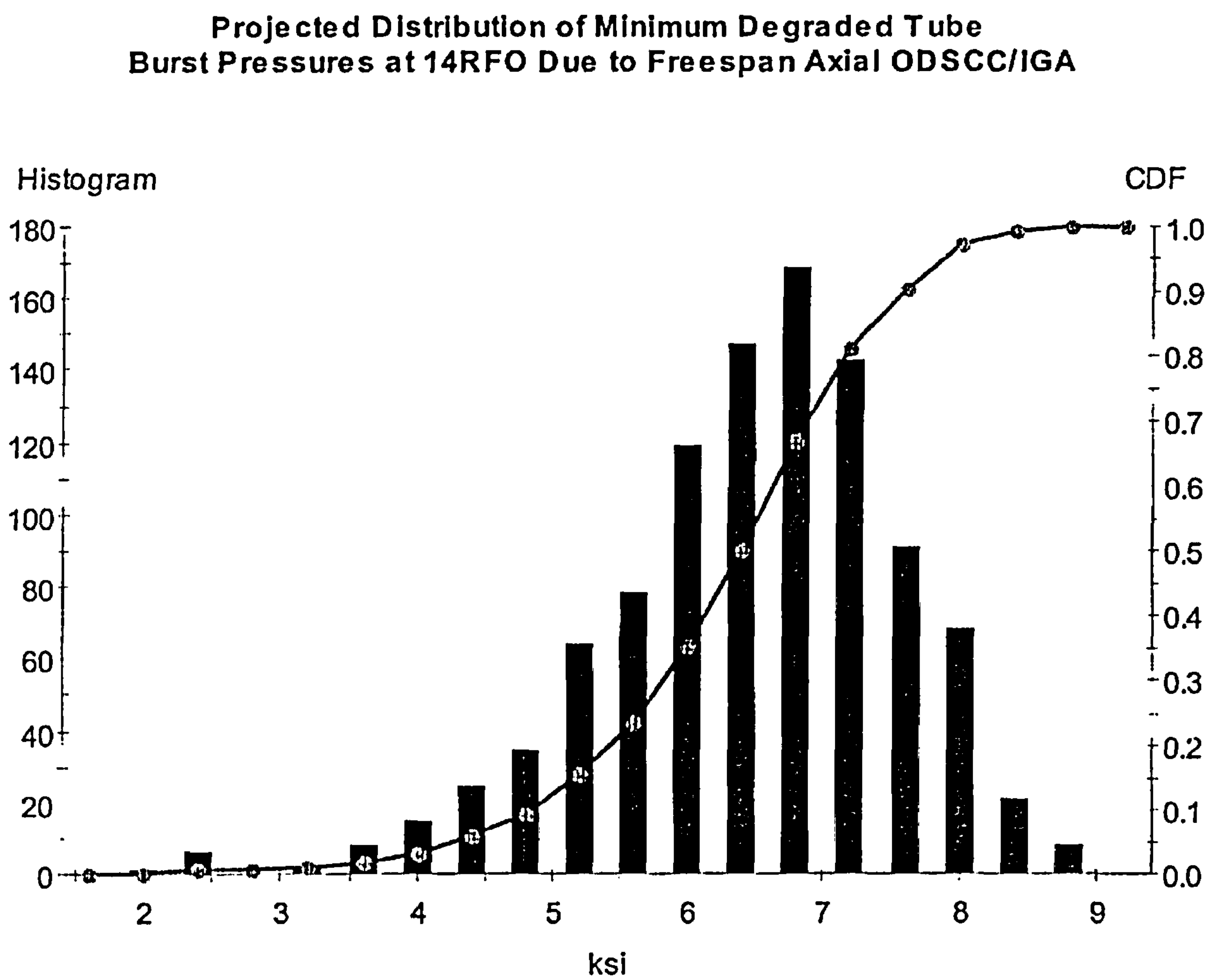

Figure 2.2 Distribution of Projected Worst Case Burst Pressures for Axial ODSCC/IGA after Full Cycle Operation, 14RFO.

Distribution of Expected Number of Freespan ODSCC Indications at Mid Cycle

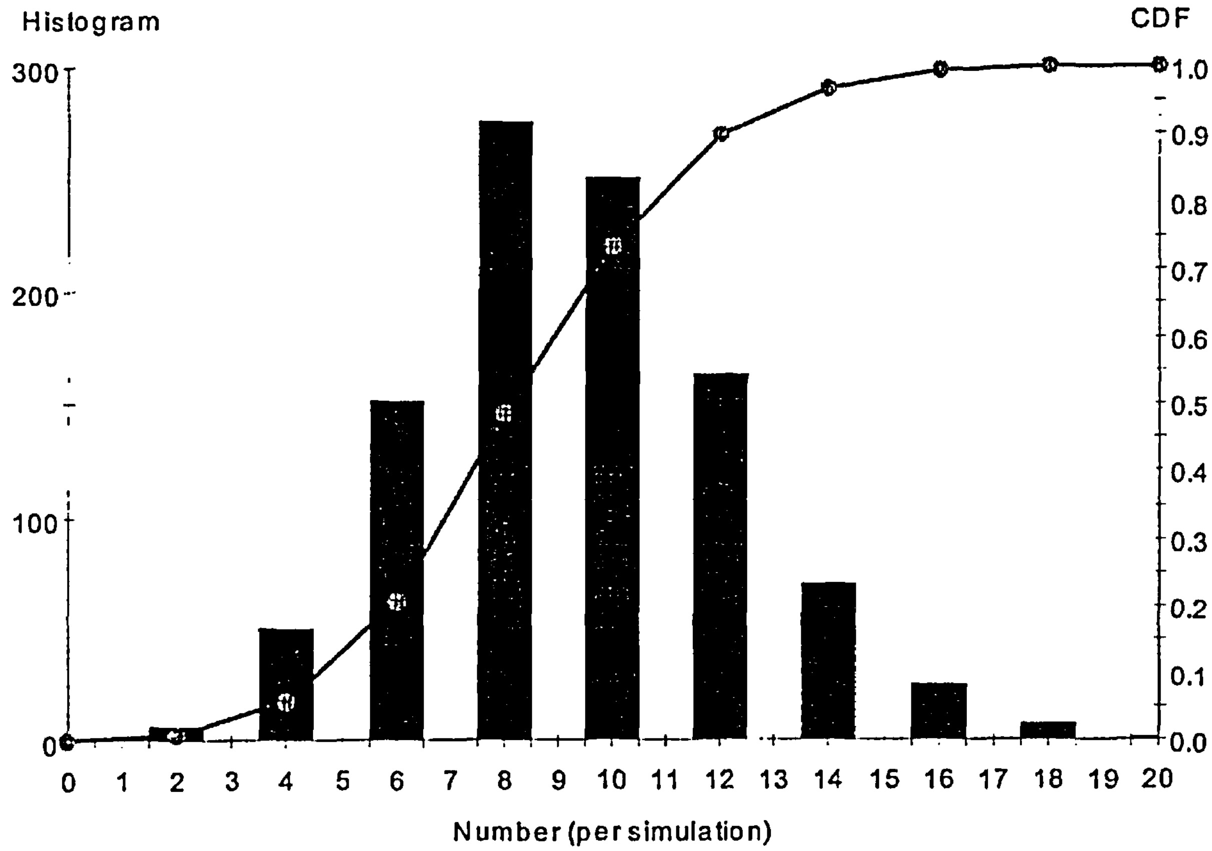

Figure 2.3 **Distribution of Projected Number of Detected Freespan Axial ODSCC/IGA Sites at Mid Cycle 14 Inspection.**

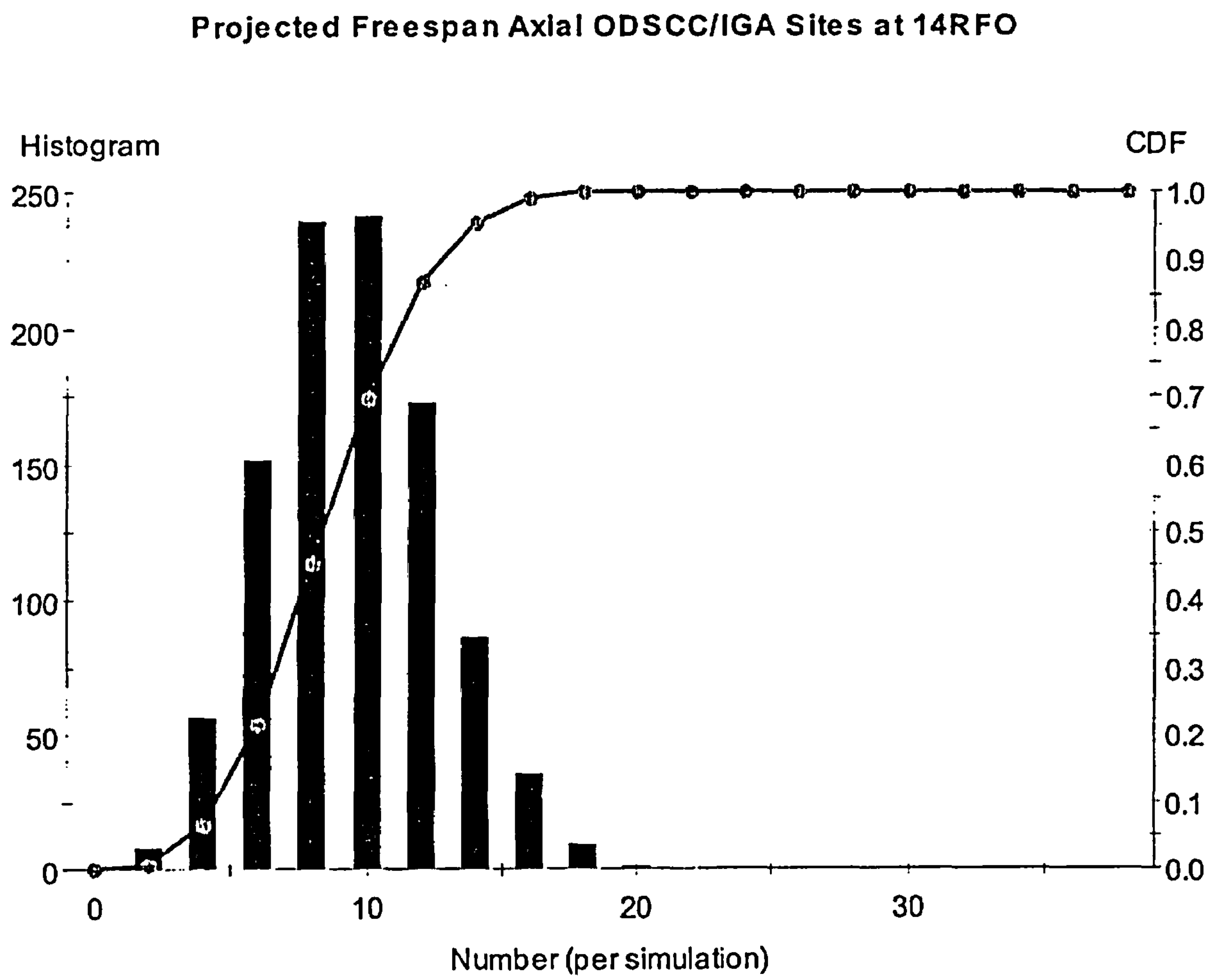

Figure 2.4 Distribution of Projected Number of Detected Freespan Axial ODSCC/IGA Sites For Full Cycle Operation.

3.0 Signal Amplitude Approach to CMOA

NDE measurements of physical crack dimensions provide an indirect route to CMOA analyses and the evaluation of the effect of eddy current noise on the probability of detection of degradation as a function of degradation severity. A more direct route is provided by correlating burst pressure with eddy current signal amplitude. The burst pressure of tubing with axial ODSCC/IGA degradation can be related to the signal amplitude of the Plus Point probe and the length of degradation as measured via the Plus Point probe[3]. Figure 3.1 shows a plot of measured burst pressure versus a calculated burst pressure using peak to peak Plus Point voltage and Plus Point length as input. This relationship was specifically developed for OTSG tubing. Similar formulations are available for other tubing sizes as well as for axial PWSCC. Measured burst pressures are for tubing with actual service induced axial ODSCC/IGA. The burst pressure equation is given by:

$$\boxed{P_B = 0.58\left(S_y + S_u\right)\frac{t}{R_i}\left[1 - \frac{L_{pp}}{L_{pp} + 2t} \bullet \frac{(0.79 + 0.184 \bullet \ln(V_{pp}))}{1.29}\right]}$$

where, t is the wall thickness, R_i is the mean radius, S_y is the yield strength, S_u is the ultimate strength, L_{pp} is the Plus Point length and V_{pp} is the peak to peak Plus Point voltage. If $S_y + S_u$ are taken as the average value at temperature of 136,590 psi, actual burst pressures are normally distributed about the calculated burst pressure with a standard deviation of 646 psi. Hence, uncertainties in the burst pressure due to relationship uncertainty and material property variation are easily considered. If a degradation site is undetected, growth over the next cycle of operation must be considered. Degradation growth leads to a decrease in burst pressure. Thus, in order to meet the 3ΔP minimum burst strength requirement at EOC, undetected degradation must exhibit a burst strength considerably higher than 3ΔP at BOC. A degradation growth allowance can be accommodated using the growth rate distributions of conventional CMOA analysis. Monte Carlo calculations combined the uncertainties in material tensile properties, burst equation uncertainties and growth allowances leading to the results of Figure 3.2. The limiting combinations of Plus Point voltages and lengths that must be detected in order to meet a 3ΔP after 1.85 EFPY and 1.4 EFPY of operation are illustrated the probability of interest, 0.95. This is more conservative than the probability of 0.90 specified by the EPRI Tube Integrity Assessment Guidelines[4]. If degradation sites are present in the steam generator with a degradation severity above the must detect curve, then detection is required to meet the minimum required EOC burst pressure.

Since axial ODSCC/IGA is detected with the bobbin probe in OTSG's, the correspondence of Plus Point voltage for SAI/MAI indications to the bobbin probe voltage of NQI indications needs to be considered. Limited data suggests a minimum 1 to 1 correspondence. A further evaluation is in progress. Early results indicate that increased emphasis on the absolute bobbin probe signal is worthwhile.

One check of the reasonableness of the must detect curves is provided by consideration of the Plus Point voltage-length correlation with burst pressure as applied to years of results of in situ pressure testing. Figure 3.3 plots condition monitoring acceptance curves for meeting a temperature compensated minimum burst pressure of 4050 psi at probabilities of 0.95, 0.90 and 0.50. Plus Point voltages and lengths for indications which passed in situ testing at a 4050 psi target pressure are also shown in Figure 3.3. Large amplitude signals that passed in situ testing are found to be confounded with dent and ding signals leading to a large peak to peak signal. Only one burst pressure in situ failure has been observed after a very large number of in situ tests in OTSG plants. It is plotted as a large diamond symbol and lies very close to the 50/50 burst line. The correlation of burst pressure with Plus Point voltage and length is in excellent agreement with years of in situ testing results. For completeness, Figure 3.4 shows some historical in situ data and the empirical CM curve which has been used in the past. The historical empirical curve and present Monte Carlo calculations agree remarkably well.

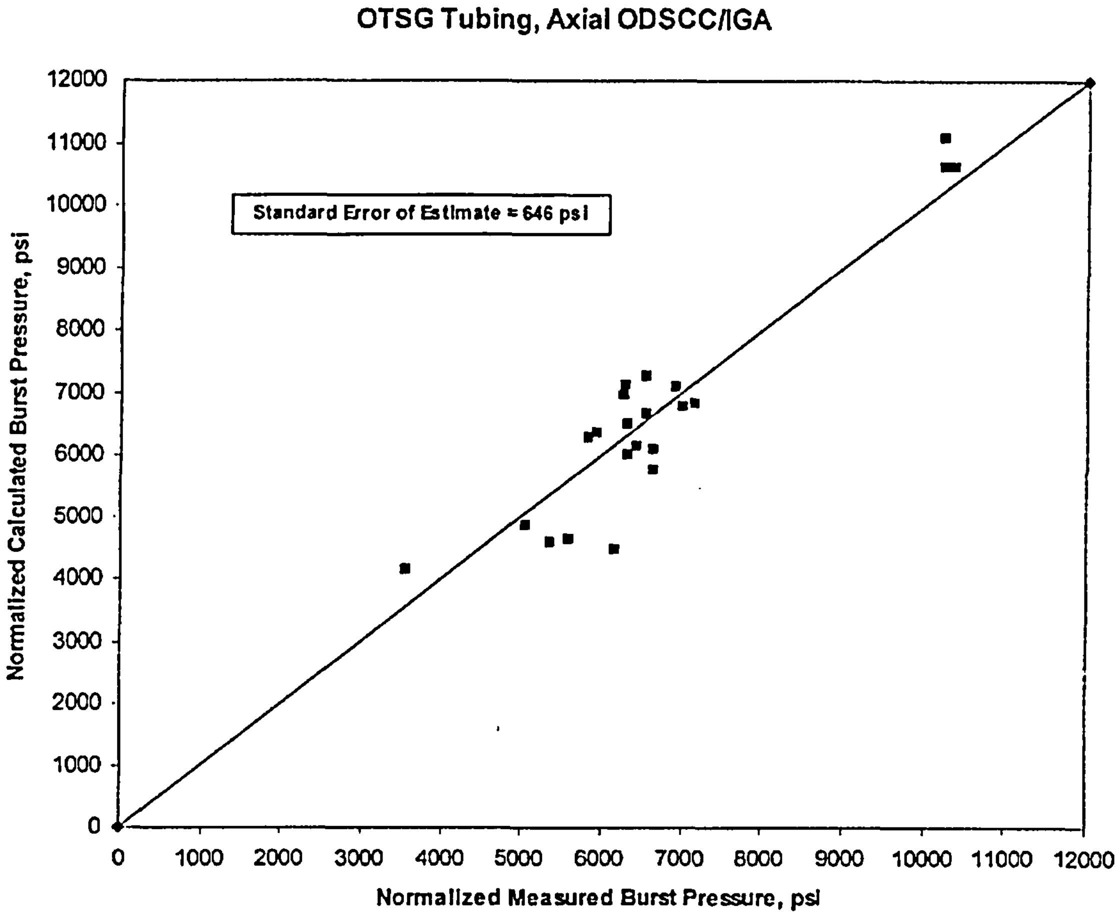

Figure 3.1 Burst Pressure Calculated from Plus Point Voltage and Plus Point Length Versus Normalized Measured Burst Pressure.

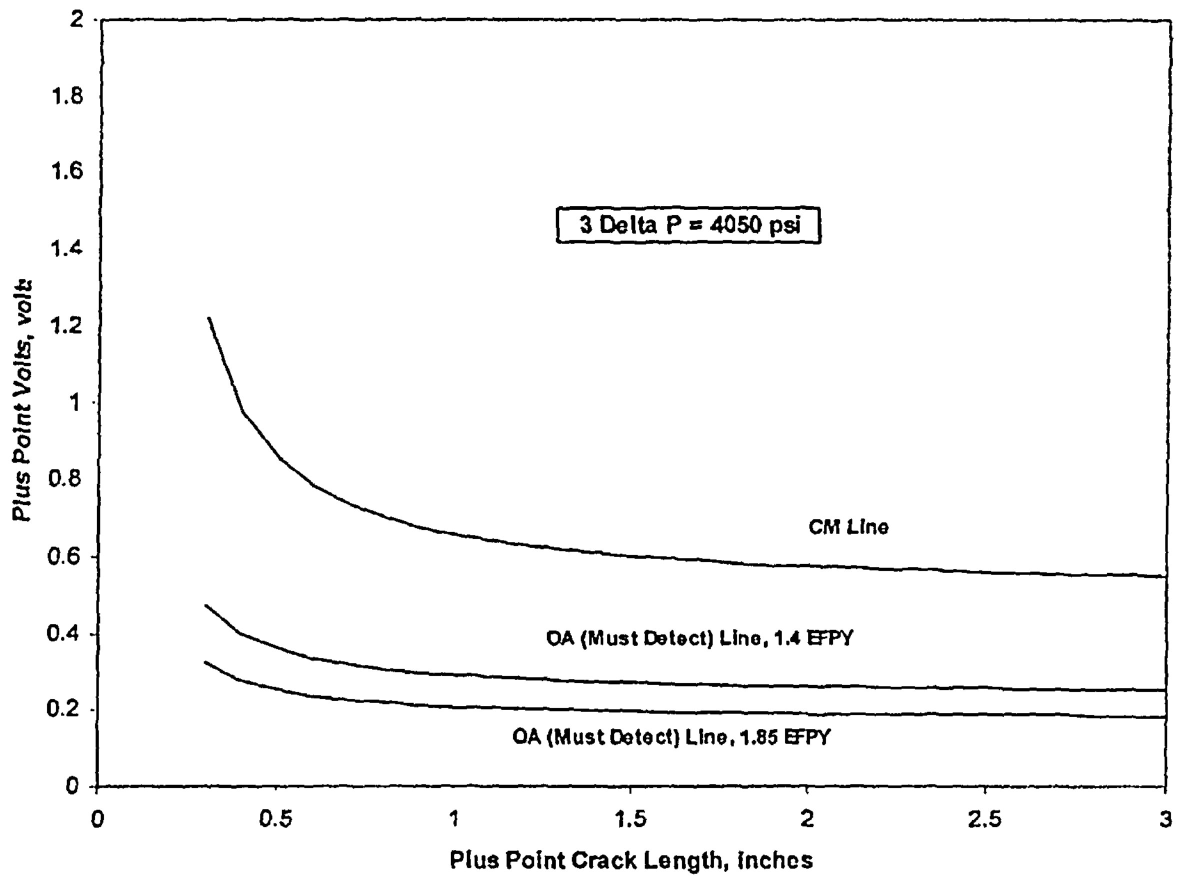

Figure 3.2 Plus Point Voltage and Length Condition Monitoring and Operational Assessment (Must Detect) Curves for Freespan Axial ODSCC/IGA at 4050 psi at 0.95 Probability

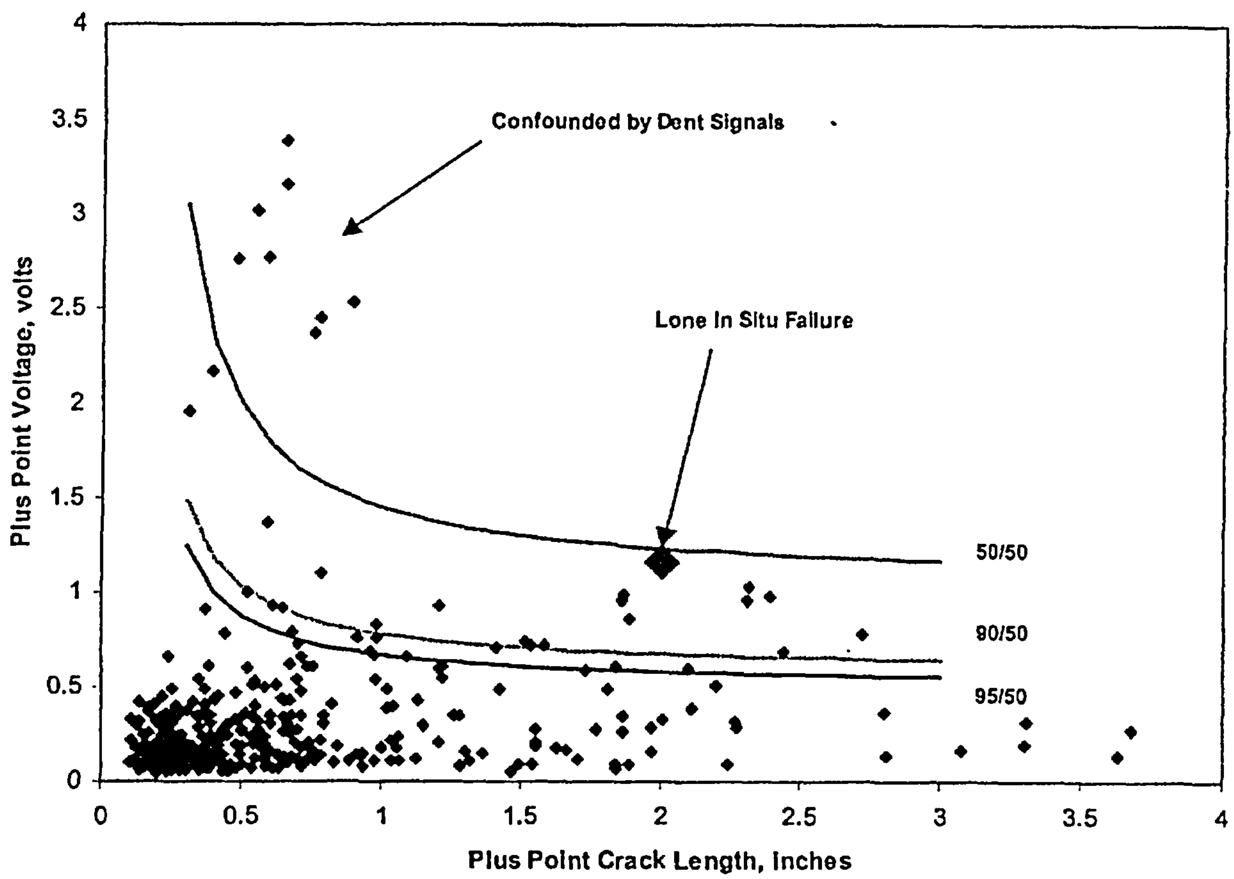

Figure 3.3 Combinations of Plus Point Voltages and Lengths Meeting Condition Monitoring via Analysis Compared to In Situ Test Results for a Temperature Compensated Target Pressure of 4050 psi.

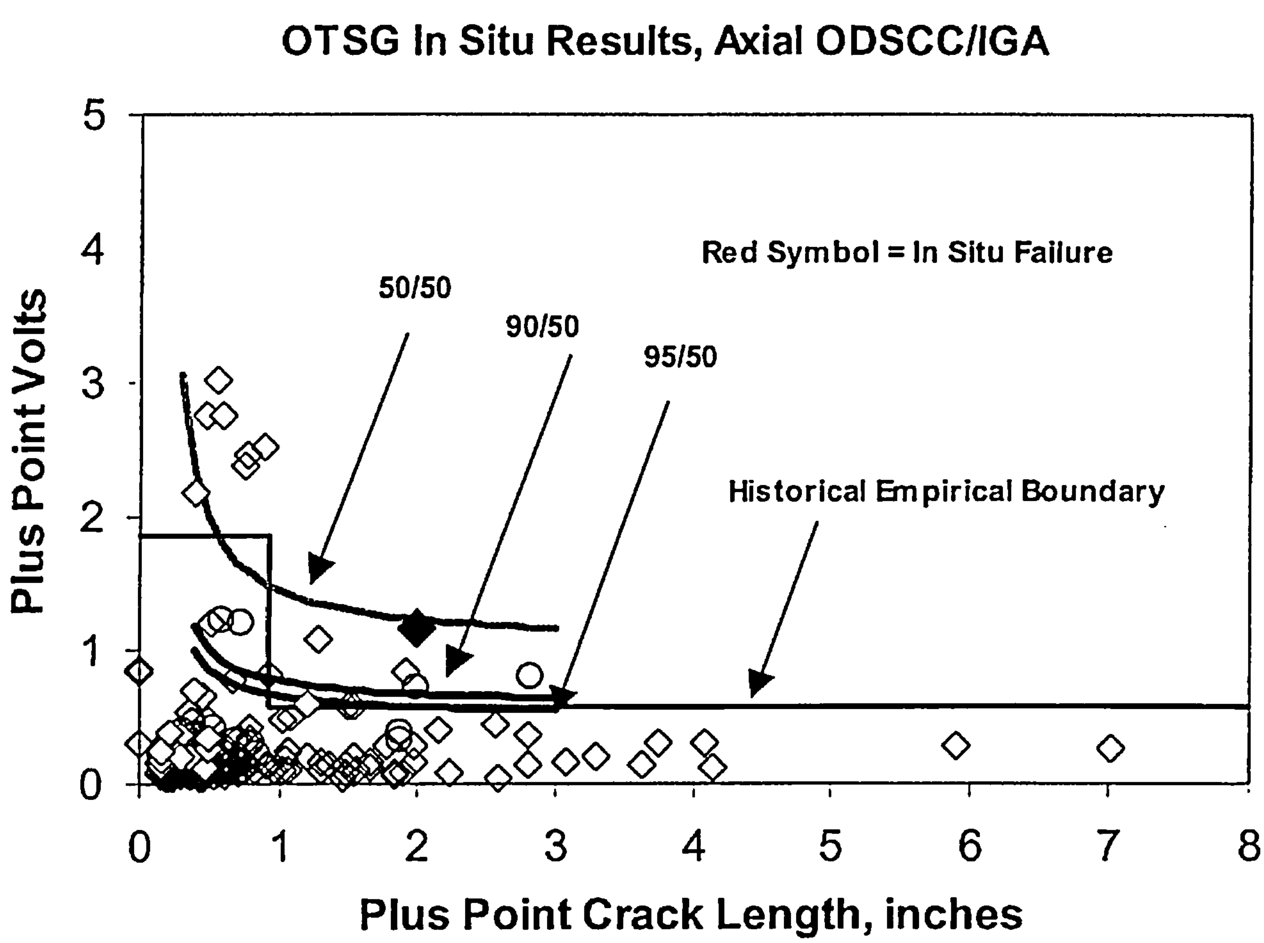

Figure 3.4 Historical In Situ Data and Previous Empirical CM Acceptance Boundary

4.0 Conclusions

An operational assessment for the first mid cycle of operation after 13RFO at Davis Besse was performed. The previous operational assessment[1] for a full cycle length of 1.85 EFPY was reviewed and updated as needed. Recent degradation growth rate information[2] for OTSG plants was compared to parameters used for the full cycle length analysis. No updates were required. The previous analysis remains valid and is bounding for mid cycle operation. Projections for the number of indications expected at a mid cycle inspection were developed to provide a basis for evaluation of degradation progression rates.

For mid cycle operation of about 1.4 EFPY, projected structural margins are about 15% greater than full cycle operational, projected numbers of indications remain the same for wear and decrease by about 20% for other degradation mechanisms and projected SLB leakage remains at nominal projected values due to plugs, sleeves and preexisting PWSCC in rolled lengths at upper tubesheet expansion transitions. As noted in another report[5], degradation growth is not expected over the extended length of downtime prior to startup for Cycle 14. A substantial margin exists for any unexpected degradation growth that may have occurred.

The burst pressure of OTSG tubing with axial ODSCC/IGA degradation can be related to the signal amplitude of the Plus Point probe and the length of degradation as measured via the Plus Point probe[3]. A CMOA approach using Plus Point signal amplitude is described. This approach provides a check and verification of conventional NDE sizing and analysis methodologies.

5.0 References

1. Begley, J. A. and Begley, T. F., "A CMOA Evaluation of Steam Generator Tubing at Davis Besse, FA-DB-011-0, ForeLine Associates LLC, April, 2002.

2. Begley, J. A., "Degradation Growth Rates in OTSG Tubing", Framatome-ANP Document 51-5022969-00, Framatome ANP, September, 2003.

3. Begley, J. A. and Colgan, K. A., "Correlation of Burst Pressure with +Pnt Voltage and Length for OTSG Axial ODSCC/IGA, 32-5030334-00, Framatome ANP, July, 2003.

4. Begley, J. A. and Martin, C., "A CMOA Evaluation of Steam Generator Tubing, 13RFO at CR3", 51-5035818-01, October, 2003.

5. "Steam Generator Integrity Assessment Guidelines", EPRI Report, TR-107621, Rev. 1, March 2000.

6. Bell, M. J., "DB-1 Steam Generator Shutdown/Lay Up Chemistry Assessment", Framatome ANP Document 51-5033009-02, November, 2003.

Docket Number 50-346
License Number NPF-3
Serial Number 3000
Enclosure 2

COMMITMENT LIST

The following list identifies those actions committed to by the Davis-Besse Nuclear Power Station (DBNPS) in this document. Any other actions discussed in the submittal represent intended or planned actions by the DBNPS. They are described only for information and are not regulatory commitments. Please notify the Manager – Regulatory Affairs (419-321-8450) at the DBNPS of any questions regarding this document or any associated regulatory commitments.

COMMITMENTS	DUE DATE
The DBNPS staff will assure that the steam generator layup and storage conditions subsequent to the time period assessed in Framatome-ANP Document 51-5033009-03 were consistent with the conclusions of that assessment.	March 9, 2004