NRC FORM 464 Part I (6-1998)

U.S. NUCLEAR REGULATORY COMMISSION

RESPONSE TO FREEDOM OF INFORMATION ACT (FOIA) / PRIVACY ACT (PA) REQUEST

FOIA/PA	RESPONSE NUMBER
2000-0096	4

RESPONSE TYPE: ☑ FINAL ☐ PARTIAL

REQUESTER: Mr. Jim Warren

DATE: MAR 29 2000

PART I. -- INFORMATION RELEASED

☐ No additional agency records subject to the request have been located.

☐ Requested records are available through another public distribution program. See Comments section.

☑ APPENDICES H — Agency records subject to the request that are identified in the listed appendices are already available for public inspection and copying at the NRC Public Document Room.

☑ APPENDICES I — Agency records subject to the request that are identified in the listed appendices are being made available for public inspection and copying at the NRC Public Document Room.

☑ Enclosed is information on how you may obtain access to and the charges for copying records located at the NRC Public Document Room, 2120 L Street, NW, Washington, DC.

☑ APPENDICES I — Agency records subject to the request are enclosed.

☐ Records subject to the request that contain information originated by or of interest to another Federal agency have been referred to that agency (see comments section) for a disclosure determination and direct response to you.

☐ We are continuing to process your request.

☐ See Comments.

PART I.A -- FEES

AMOUNT * $

* See comments for details

☐ You will be billed by NRC for the amount listed.

☐ You will receive a refund for the amount listed.

☐ None. Minimum fee threshold not met.

☑ Fees waived.

PART I.B -- INFORMATION NOT LOCATED OR WITHHELD FROM DISCLOSURE

☐ No agency records subject to the request have been located.

☐ Certain information in the requested records is being withheld from disclosure pursuant to the exemptions described in and for the reasons stated in Part II.

☐ This determination may be appealed within 30 days by writing to the FOIA/PA Officer, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001. Clearly state on the envelope and in the letter that it is a "FOIA/PA Appeal."

PART I.C COMMENTS (Use attached Comments continuation page if required)

SIGNATURE - FREEDOM OF INFORMATION ACT AND PRIVACY ACT OFFICER

Carol Ann Reed Carol Ann Reed

==== TCON24 ========== Accession Number - 9910130322 ====== Start ==== End ===
Availability: PDR Format: TXT Microfilm Address: A9488-245 A9488-265
Size: 19pp.

Document Type: Inspection report, NRC-generated Issued: 991004
Desc/: Insp repts 50-250/99-05 & 50-251/99-05 on 990725-0904.No violations
Title: noted.Major areas inspected:aspects of licensee
: operations,maint,engineering & plant support.
:
Authors: * Region 2 (RII, Post 820201)

Recipients:

Dockets: 05000250 50-250 Turkey Point Plant, Unit 3, Florida Power and Light C
05000251 50-251 Turkey Point Plant, Unit 4, Florida Power and Light C
Inspection Report # 50-250/99-05
Inspection Report # 50-251/99-05

File Locations: PDR ADOCK 05000250 Q 991004 Package: 9910130319 A
PDR ADOCK 05000251 Q 991004

Use HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.
<Replace>
Count: *0

H/1

==== TCON24 ========== Accession Number - 9907150057 ====== Start ==== End ===
Availability: PDR Format: TXT Microfilm Address: A8584-133 A8584-145
Size: 13pp.

Document Type: **Inspection report, NRC-generated** Issued: **990702**
Desc/: **Insp repts 50-250/99-03 & 50-251/99-03 on 990502-0612.No violations**
Title: **noted.Major areas inspected:aspects of licensee**
: **operations,maint,engineering & plant support.**
:
Authors: * **Region 2 (RII, Post 820201)**

Recipients:

Dockets: **05000250 50-250 Turkey Point Plant, Unit 3, Florida Power and Light C**
05000251 50-251 Turkey Point Plant, Unit 4, Florida Power and Light C
Inspection Report # 50-250/99-03
Inspection Report # 50-251/99-03

File Locations: **PDR ADOCK 05000250 Q** **990702** Package: **9907150053 A**
PDR ADOCK 05000251 Q **990702**
Use HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.
Count: *0 <Replace>

==== TCON24 ========== Accession Number - 9810300015 ====== Start ==== End ==
Availability: PDR Format: TXT Microfilm Address: A5663-064 A5663-094
Size: 28pp.

Document Type: Inspection report, NRC-generated Issued: 980922
Desc/: Insp repts 50-250/98-09 & 50-251/98-09 on 980727-31 & 0810- 14.No
Title: violations noted.Major areas inspected:operations, maint &
: engineering.
:
Authors: * Region 2 (RII, Post 820201)

Recipients:

Dockets: 05000250 50-250 Turkey Point Plant, Unit 3, Florida Power and Light C
05000251 50-251 Turkey Point Plant, Unit 4, Florida Power and Light C
Inspection Report # 50-250/98-09
Inspection Report # 50-251/98-09

File Locations: PDR ADOCK 05000250 Q 980922 Package: 9810300013 A
PDR ADOCK 05000251 Q 980922
Use HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.
Count: *0 <Replace>

==== TCON24 ========== Accession Number - 9801220123 ====== Start ==== End ===
Availability: PDR Format: TXT Microfilm Address: A1875-134 A1875-178
Size: 45pp.

Document Type: Inspection report, NRC-generated Issued: 980109
Desc/: Insp repts 50-250/97-12 & 50-251/97-12 on 971102-1213. Violations
Title: noted.Major areas inspected:operations,maint, engineering & plant
: support re radiological emergency plan implementing procedures.
:
Authors: * Region 2 (RII, Post 820201)

Recipients:

Dockets: 05000250 50-250 Turkey Point Plant, Unit 3, Florida Power and Light C
05000251 50-251 Turkey Point Plant, Unit 4, Florida Power and Light C
Inspection Report # 50-250/97-12
Inspection Report # 50-251/97-12

File Locations: PDR ADOCK 05000250 Q 980109 Package: 9801220111 B
PDR ADOCK 05000250 F 980109

Use HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.
Count: *0 <Replace>

==== TCON24 ========== Accession Number - 9709150149 ====== Start ==== End ===

Availability: PDR   Format: TXT   Microfilm Address: A0373-216 A0373-268

Size: 53pp.

Document Type: Inspection report, NRC-generated   Issued: 970905

Desc/: Insp repts 50-250/97-08 & 50-251/97-08 on 970628-0809.No violations

Title: noted.Major areas inspected:licensee operations, maint,engineering &

: plant support.

:

Authors: *   Region 2 (RII, Post 820201)

Recipients:

Dockets: 05000250 50-250 Turkey Point Plant, Unit 3, Florida Power and Light C

05000251 50-251 Turkey Point Plant, Unit 4, Florida Power and Light C

Inspection Report # 50-250/97-08

Inspection Report # 50-251/97-08

File Locations: PDR ADOCK 05000250 Q   970905 Package: 9709150146 A

PDR ADOCK 05000251 Q   970905

Use HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.

Count: *0   <Replace>

<<NUDOCS/AD>> Nuclear Regulatory Commission

==== TCON24 ========== Accession Number - 9605100199 ====== Start ==== End ===
Availability: PDR   Format: *   Microfilm Address: 88226-261 88226-300
Size: 40pp.

Document Type: Incoming Correspondence   Issued: 960503
Desc/: Responds to RAI re proposed amend concerning thermal power uprate.
Title:
:
:

Authors: HOVEY,R.J.   Florida Power & Light Co.

Recipients: *   Document Control Branch (Document Control Desk) (

Dockets: 05000250 50-250 Turkey Point Plant, Unit 3, Florida Power and Light C
05000251 50-251 Turkey Point Plant, Unit 4, Florida Power and Light C
Other Related Number L-96-117

File Locations: PDR ADOCK 05000250 P   960503 Package: 9605100199 #
PDR ADOCK 05000251 P   960503

Jse HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.
<Replace>
Count: *0

==== TCON24 ========== Accession Number - 9611130152 ====== Start ==== End ===
Availability: PDR Format: * Microfilm Address: 90724-339 90724-347
Size: 9pp.

Document Type: Incoming Correspondence Issued: 961106
Desc/: Informs that several plant mods have been completed to support therm
Title: power uprate.Revised descriptions in ERDS data point library encl.
:
:
Authors: HOVEY,R.J. Florida Power & Light Co.

Recipients: * Document Control Branch (Document Control Desk) (

Dockets: 05000250 50-250 Turkey Point Plant, Unit 3, Florida Power and Light C

Other Related Number L-96-282

File Locations: PDR ADOCK 05000250 F 961106 Package: 9611130152 #

Use HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.
Count: *0 <Replace>

==== TCON24 ========== Accession Number - 9611140236 ====== Start ==== End ===
Availability: PDR Format: TXT Microfilm Address: 90887-196 90887-201
Size: 6pp.

Document Type: Licensee Event Report (See also AO,RO) Issued: 961106
Desc/: LER 96-011-00:on 961009,potential for overpressurizing post accident
Title: containment vent filter housings occurred.Caused by improper change :t
: mgt.Monitoring sys operating procedures revised.W/961106 ltr.
:

Authors: HICKEY,J.A. Florida Power & Light Co.
HOVEY,R.J. Florida Power & Light Co.
Recipients: * Document Control Branch (Document Control Desk) (

Dockets: 05000250 50-250 Turkey Point Plant, Unit 3, Florida Power and Light C

Licensee Event Rpt # 96-011 961009 Event Date
Other Related Number L-96-292

File Locations: PDR ADOCK 05000250 S 961106 Package: 9611140236 #

Jse HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.
Count: *0 <Replace>

==== TCON24 ========== Accession Number - 9611140314 ====== Start ====
Availability: PDR Format: * Microfilm Address: 90814-351 90814-
Size: 9pp.

Document Type: Incoming Correspondence Issued: 961106
Desc/: Informs of completion of plant modifications to support thermal power
Title: uprate.Revisions to ERDS Data Point Library, encl.
:
:

Authors: HOVEY,R.J. Florida Power & Light Co.

Recipients: * Document Control Branch (Document Control Desk) (

Dockets: 05000251 50-251 Turkey Point Plant, Unit 4, Florida Power and Light C

Other Related Number L-96-284

File Locations: PDR ADOCK 05000251 P 961106 Package: 9611140314 #

Use HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.
Count: *0 <Replace>

<<NUDOCS/AD>> Nuclear Regulatory Commission

==== TCON24 ========== Accession Number - 9703270315 ====== Start ==== End ===

Availability: PDR Format: TXT Microfilm Address: 92264-173 92264-215

Size: 44pp.

Document Type: **Inspection report, NRC-generated** Issued: **970307**

Desc/: **Insp repts 50-250/97-01 & 50-251/97-01 on 970101-0215.No violations**

Title: **noted.Major areas inspected:operations, maintenance,engineering &**

: **plant support.**

:

Authors: * **Region 2 (RII, Post 820201)**

Recipients:

Dockets: **05000250 50-250 Turkey Point Plant, Unit 3, Florida Power and Light C**

05000251 50-251 Turkey Point Plant, Unit 4, Florida Power and Light C

Inspection Report # 50-250/97-01

Inspection Report # 50-251/97-01

File Locations: **PDR ADOCK 05000250 Q** **970307** Package: **9703270314 A**

PDR ADOCK 05000251 Q **970307**

Use HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.

<Replace>

Count: *0

==== TCON24 ========== Accession Number - 7906210274 ====== Start ==== End ===
Availability: PDR Format: * Microfilm Address: 15149-147 15149-150
Size: 4pp.

Document Type: Pleadings Issued: 790508
Desc/: Applicant motion to dismiss proceeding.Disposition of power increase
Title: safety aspects should be governed by 10CFR2.760.Urges that date be se
: for NRC response to amend issue.Certificate of Svc encl.
:
Authors: TROWBRIDGE,G.F. Shaw, Pittman, Potts & Trowbridge

Recipients:

Dockets: 05000261 50-261 H.B. Robinson Plant, Unit 2, Carolina Power & Light C

790510 Docket Date

File Locations: PDR ADOCK 05000261 G 790508 Package: 7906210274 #

Use HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.
Count: *0 <Replace>

<<NUDOCS/AD>> Nuclear Regulatory Commission

==== TCON24 ========== Accession Number - 7905040309 ====== Start ==== End ===
Availability: PDR Format: * Microfilm Address: * -* * -*
Size: 30pp.

Document Type: Safety Evaluation Report Issued: 790330
Desc/: Suppl 2 to 740520 safety evaluation of proposed amend to License
Title: DPR-23,allowing power increase from 2,200 MWt to 2,300 MWt.

Authors: * Operating Reactors Branch 1 (Pre 790625)

Recipients:

Dockets: 05000261 50-261 H.B. Robinson Plant, Unit 2, Carolina Power & Light C

File Locations: PDR ADOCK 05000261 P 790330 Package: 7905040307 A

Use HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.
Count: *0 <Replace>

==== TCON24 ========== Accession Number - 7905040307 ====== Start ==== End ===

Availability: PDR Format: * Microfilm Address: * -* * -*

Size: 2pp.

Document Type: Outgoing correspondence Issued: 790330

Desc/: Forwards Suppl 2 to 740520 safety evaluation of proposed power

Title: increase.

:

:

Authors: SCHWENCER,A. Operating Reactors Branch 1 (Pre 790625)

Recipients: JONES,J.A. Carolina Power & Light Co.

Dockets: 05000261 50-261 H.B. Robinson Plant, Unit 2, Carolina Power & Light C

File Locations: PDR ADOCK 05000261 P 790330 Package: 7905040307 *

Use HOME/TAB To View Additional Information, ENTER To View Text, ESCape To Exit.

Count: *0 <Replace>

FARLEY Units 1 and 2

Dockets 50-348 & 50-364

Publicly Available

Records Available In the PDR

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

9910290206 Non-proprietary, "Farley Units 1 & 2 LBB Calculation Results Due to SG Replacement & SG Snubber Elimination Programs."

FROM: * AFFIL: EMVWEST

TO: AFFIL:

ISSUED: 991006 AVAIL: PDR 5pp. DOCUMENT TYPE: TRZAR FPAC: 9910290202B

TASK: ODID: NSD-SAE-ESI-99-DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A9718 316 A9718 320 RIDS:

9910290204 Requests withholding of proprietary rept NSD-SAE-ESI-99-389, "Farley Units 1 & 2 LBB Calculation Results Due to SG Replacement & SG Snubber Elimination Programs."

FROM: GALEMBUSH,J.S. AFFIL: EMVWEST

TO: COLLINS,S.J. AFFIL: NIRCTQ

ISSUED: 991006 AVAIL: PDR 8pp. DOCUMENT TYPE: CLINC FPAC: 9910290202A

TASK: ODID: CAW-99-1363 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A9718 308 A9718 315 RIDS:

9910290202 Forwards non-proprietary & proprietary versions of "Farley Units 1 & 2 LBB Calculation Results Due to SG Replacement & SG Snubber Elimination Programs," used to support SG replacement project.Proprietary encl withheld.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 991018 AVAIL: PDR 3pp. DOCUMENT TYPE: CLINC FPAC: 9910290202*

TASK: ODID: NEL-99-0359 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A9718 305 A9718 320 RIDS: AP01

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

9909210092 Insp repts 50-348/99-05 & 50-364/99-05 on 990627-0807.No violations noted.Major areas inspected:operations, maintenance,engineering & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 990902 AVAIL: PDR 7pp. DOCUMENT TYPE: TIINSP FPAC: 9909210089A

TASK: ODID: 50-348/99-05 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A9238 171 A9238 177 RIDS:

9907260080 Forwards response to NRC 990702 RAI re SG replacement related TS change request submitted 981201.Ltr contains no new commitments.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 990719 AVAIL: PDR 15pp. DOCUMENT TYPE: CLINC FPAC: 9907260080#

TASK: ODID: NEL-99-0269 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A8732 336 A8732 350 RIDS: A001

9904290244 Forwards corrected ITS markup pages to replace pages in 981201 license amend requests for SG replacement.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 990421 AVAIL: PDR 5pp. DOCUMENT TYPE: CLINC FPAC: 9904290244*

TASK: ODID: NEL-99-0129 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A7887 164 A7887 180 RIDS: A001

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

9903300089 Insp repts 50-348/99-01 & 50-364/99-01 on 990110-0220. Violations noted.Major areas inspected:operations, maintenance,engineering & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 990319 AVAIL: PDR 10pp. DOCUMENT TYPE: TIINSP FPAC: 9903300088A

TASK: ODID: 50-348/99-01 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A7534 325 A7534 334 RIDS:

9903090338 Forwards Relief Request RR-40 for Units 1 & 2 for SG primary nozzles inside radius.Util requests NRC approval of propose d relief request by Mar 4,2000 to support Unit 1 SG replacement outage in spring of 2000 & Unit 2 SG in 2001.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 990225 AVAIL: PDR 6pp. DOCUMENT TYPE: CLINC FPAC: 9903090338#

TASK: ODID: NEL-99-0052 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A7178 006 A7178 011 RIDS: A047

9903020262 Safety evaluation supporting amends 141 & 133 to licenses NPF-2 & NPF-8,respectively.

FROM: * AFFIL: N*******

TO: AFFIL:

ISSUED: 990219 AVAIL: PDR 2pp. DOCUMENT TYPE: TRSER FPAC: 9903020254B

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A7031 357 A7031 358 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

9901210096 Insp repts 50-348/98-07 & 50-364/98-07 on 981018-1128.No violations noted.Major areas inspected:licensee operations, maint,engineering & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 981228 AVAIL: PDR 4pp. DOCUMENT TYPE: TIINSP FPAC: 9901210091A

TASK: ODID: 50-348/98-07 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A6602 028 A6602 044 RIDS:

9810300154 Insp repts 50-348/98-05 & 50-364/98-05 on 980712-0829.No violations noted.Major areas inspected:operations,maint, engineering & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 980928 AVAIL: PDR 16pp. DOCUMENT TYPE: TIINSP FPAC: 9810300151A

TASK: ODID: 50-348/98-05 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A5663 343 A5663 358 RIDS:

9810210103 NRC Info Notice 98-040, "Design Deficiencies Can Lead to Reduced ECCS Pump Net Positive Head During Design-Basis Accidents."

FROM: ROE,J.W. AFFIL: N*******

TO: AFFIL:

ISSUED: 981026 AVAIL: PDR 9pp. DOCUMENT TYPE: TIIEIN FPAC: 9810210103#

TASK: ODID: IEIN-98-040 DIN: DPN: DRN:

DOCKET NO: FICHE: A5629 163 A5629 171 RIDS: DF03

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

9810160211 Proposed tech specs section 6,providing recognition of addl mgt positions associated with SG replacement project & providing ability to approve procedures re project which may affect nuclear safety.

FROM: * AFFIL: EUTSNOC

TO: AFFIL:

ISSUED: 981012 AVAIL: PDR 6pp. DOCUMENT TYPE: TSTECH FPAC: 9810160210A

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A5542 292 A5542 297 RIDS:

9810160210 Application for amends to licenses NPF-2 & NPF-8,revising section 6 of TS by recognizing addl mgt positions associated with SG replacement project & providing ability to approve procedures re project which may affect nuclear safety.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 981012 AVAIL: PDR 8pp. DOCUMENT TYPE: TLAOOL FPAC: 9810160210*

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A5542 284 A5542 297 RIDS: A001

9809140309 Informs of input error in limiting small break LOCA analyses submitted to & approved by NRC for JM Farley Plant,Units 1 & 2 power uprates.Error is reported IAW 10CFR50.56,since absolute value of error is in excess of 50 F.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 980910 AVAIL: PDR 6pp. DOCUMENT TYPE: CLINC FPAC: 9809140309#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A5091 318 A5091 323 RIDS: A001

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

9807080315 Insp repts 50-348/98-03 & 50-364/98-03 on 980412-0530.No violations noted.Major areas inspected:licensee operations, engineering,maint & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 980701 AVAIL: PDR 49pp. DOCUMENT TYPE: TIINSP FPAC: 9807080308B

TASK: ODID: 50-348/98-03 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A4048 087 A4048 139 RIDS:

9805060050 Safety evaluation supporting amends 137 & 129 to licenses NPF-02 & NPF-08,respectively.

FROM: * AFFIL: N*******

TO: AFFIL:

ISSUED: 980429 AVAIL: PDR 80pp. DOCUMENT TYPE: TRSER FPAC: 9805060042B

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A3348 081 A3348 162 RIDS:

9804240274 Forwards revised response to request for addl info re power uprate facility operating licenses & Tech Specs change request.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 980417 AVAIL: PDR 16pp. DOCUMENT TYPE: CLINC FPAC: 9804240274#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A3180 251 A3180 266 RIDS: A001

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

9804220253 Forwards EA & FONSI re power uprate for plant,Units 1 & 2. Proposed amend would change max reactor core power level for facility operation from 2,652 MWt to 2,275 MWt.

FROM: ZIMMERMAN,J.I. AFFIL: N*******

TO: MOREY,D.N. AFFIL: EUTSNOC

ISSUED: 980417 AVAIL: PDR 3pp. DOCUMENT TYPE: CLOUT FPAC: 9804220253*

TASK: ODID: TAC M98120 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A3143 304 A3143 314 RIDS: DF01

9803240033 Revised pages 58 & 59 to "FNP,Units 1 & 2,Power Uprate Project BOP Licensing Rept."

FROM: * AFFIL: EUTSNOC

TO: AFFIL:

ISSUED: 980316 AVAIL: PDR 4pp. DOCUMENT TYPE: TRZAR FPAC: 9803240030A

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A2857 355 A2857 358 RIDS:

9803240030 Forwards response to 980311 telcon re license amend request to allow operation at increased reactor core power level of 2775 MWt.Revised pages 58 & 59 of "FNP,Units 1 & 2,Power Uprate Project BOP Licensing Rept," encl.

FROM: WOODARD,J.D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 980316 AVAIL: PDR 3pp. DOCUMENT TYPE: CLINC FPAC: 9803240030*

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A2857 352 A2857 358 RIDS: A001

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

9803190030 Application for amends to licenses NPF-2 & NPF-8 to revise existing TS in entirety.Amend consists primarily of conversion of current TS to improved TS,per NUREG-1431,rev 1.Vols 1-10 contain listed attachments.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 980312 AVAIL: PDR 77pp. DOCUMENT TYPE: TLAOOL FPAC: 9803190030*

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A2816 001 A2825 247 RIDS: A001

9803100270 Responds to RAI related to power uprate facility operating licenses & TS change requests.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 980303 AVAIL: PDR 17pp. DOCUMENT TYPE: CLINC FPAC: 9803100270#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A2571 329 A2571 345 RIDS: A001

9803040465 Forwards response to 980210 & 13 RAI re power uprate license amend request allowing operation of increased reactor core power level of 2775 Mwt.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 980226 AVAIL: PDR 22pp. DOCUMENT TYPE: CLINC FPAC: 9803040465#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A2462 189 A2462 210 RIDS: A001

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

9802190132 Revised proposed changes to TS page 6-19a for power uprate.

FROM: * AFFIL: EUTSNOC

TO: AFFIL:

ISSUED: 980212 AVAIL: PDR 5pp. DOCUMENT TYPE: TSTECH FPAC: 9802190131A

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A2244 326 A2244 330 RIDS:

9802190131 Forwards responses to questions raised during 980109,29 & 980202 telcons re power uprate facility OLs & TS change request.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 980212 AVAIL: PDR 11pp. DOCUMENT TYPE: CLINC FPAC: 9802190131*

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A2244 315 A2244 330 RIDS: A001

9802060194 Submits response to request for addl info re power uprate facility operating licenses & Tech Specs change request.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 980123 AVAIL: PDR 20pp. DOCUMENT TYPE: CLINC FPAC: 9802060194#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A2135 311 A2135 330 RIDS: A001

U.S. NUCLEAR REGULATORY COMMISSION
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9801210292 Insp repts 50-348/97-14 & 50-364/97-14 on 971019-1129. Violations noted.Major areas inspected:operations, engineering,maintenance & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 971229 AVAIL: PDR 36pp. DOCUMENT TYPE: TIINSP FPAC: 9801210252B

TASK: ODID: 50-348/97-14 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A1856 196 A1856 231 RIDS:

9801080314 Forwards response to RAI related to power uprate facility operating licenses & TSs change request.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 971231 AVAIL: PDR 5pp. DOCUMENT TYPE: CLINC FPAC: 9801080314#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A1753 353 A1753 357 RIDS: A001

9712150340 Summary of 971120 meeting w/Southern Nuclear Operating Co to discuss matters related to steam generator replacement projects proposed for both Farley nuclear units.List of attendees enclosed.

FROM: GLEAVES,W. AFFIL: N*******

TO: * AFFIL: N*******

ISSUED: 971205 AVAIL: PDR 34pp. DOCUMENT TYPE: CNMINS FPAC: 9712150340#

TASK: ODID: TAC M72416 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A1460 015 A1460 048 RIDS: DF01

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9712150241 Submits description of evaluation method discussed in 971204 telcon re BE-LBLOCA evaluation for SG replacement project.

FROM: MOREY,D. AFFIL: EUTSNOC
TO: * AFFIL: NIRCTQ
ISSUED: 971209 AVAIL: PDR 4pp. DOCUMENT TYPE: CLINC FPAC: 9712150241#
TASK: ODID: DIN: DPN: DRN:
DOCKET NO: 05000348 FICHE: A1467 264 A1467 267 RIDS: A001

9711250119 Corrected page 4-12 to WCAP-14723, "Farley Nuclear Plant Units 1 & 2 Power Uprate Project NSSS Licensing Rept."

FROM: * AFFIL: EMVWEST
TO: AFFIL:
ISSUED: 971119 AVAIL: PDR 2pp. DOCUMENT TYPE: TRTOPR FPAC: 9711250019C
TASK: ODID: DIN: DPN: DRN:
DOCKET NO: 05000348 FICHE: A1257 142 A1257 143 RIDS:

9711250019 Forwards nonproprietary & proprietary versions of "SNC Response to NRC RAI on BELOCA," in response to RAI re power uprate facility OLs & TS change request.W/responses to questions 1-11 & 13-33,affidavit & authorization ltr.

FROM: MOREY,D. AFFIL: EUTSNOC
TO: * AFFIL: NIRCTQ
ISSUED: 971119 AVAIL: PDR 59pp. DOCUMENT TYPE: CLINC FPAC: 9711250019*
TASK: ODID: DIN: DPN: DRN:
DOCKET NO: 05000348 FICHE: A1257 059 A1257 143 RIDS: AP01

Add: 9709250134 Non-proprietary SNC response to NRC 8/21/97 RAI MF A0560-19 A0560-26

U.S. NUCLEAR REGULATORY COMMISSION
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9711140169 Notification of 971120 meeting w/util in Rockville,MD to discuss Southern Nuclear Operating Co,Inc plans & schedule for SG replacement.

FROM: ZIMMERMAN,J.I. AFFIL: N*******

TO: BERKOW,H.N. AFFIL: N*******

ISSUED: 971031 AVAIL: PDR 4pp. DOCUMENT TYPE: CMMEMO FPAC: 9711140169#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: A1148 348 A1148 351 RIDS: DF01

9707300124 Requests approval for "proposed alternative" be extended to SG replacement outages currently scheduled for Unit 1 16th refueling outage & Unit 2 14th refueling outage.SNC has made decision to replace SGs in both units.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 970725 AVAIL: PDR 1p. DOCUMENT TYPE: CLINC FPAC: 9707300124#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: 93980 263 93980 263 RIDS: A001

9707280217 Forwards suppl to 970701 request for addl info related to power uprate submittal for plant,Units 1 & 2.

FROM: ZIMMERMAN,J.I. AFFIL: N*******

TO: MOREY,D.N. AFFIL: EUTSNOC

ISSUED: 970724 AVAIL: PDR 7pp. DOCUMENT TYPE: CLOUT FPAC: 9707280217#

TASK: ODID: TAC M98120 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: 93950 021 93950 027 RIDS: DF01

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9707080365 NRC Info Notice 97-051, "Problems Experienced w/Loading & Unloading Spent Nuclear Fuel Storage & Transportation of Casks."

FROM: SLOSSON,M.M. AFFIL: N*******

TO: AFFIL:

ISSUED: 970711 AVAIL: PDR 11pp. DOCUMENT TYPE: TIIEIN FPAC: 9707080365#

TASK: ODID: IEIN-97-051 DIN: DPN: DRN:

DOCKET NO: FICHE: 93946 345 93946 355 RIDS: DF01

9707080120 Forwards RAI re power uprate submittal for plant,Units 1 & 2 to allow for increase in licensed thermal power from 2652 MWt to 2775 MWt.Westinghouse nonproprietary class 3 rept WCAP-14723 was included w/licensee submittal.

FROM: ZIMMERMAN,J.I. AFFIL: N*******

TO: MOREY,D.N. AFFIL: EUTSNOC

ISSUED: 970701 AVAIL: PDR 11pp. DOCUMENT TYPE: CLOUT FPAC: 9707080120#

TASK: ODID: TAC M98120 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: 93665 346 93665 356 RIDS: DF01

9703040373 "Farley Nuclear Plant Units 1 & 2 Power Uprate Project BOP Licensing Rept."

FROM: * AFFIL: EUTSNOC

TO: AFFIL:

ISSUED: 970214 AVAIL: PDR 88pp. DOCUMENT TYPE: TRZAR FPAC: 9703040325C

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: 91966 140 91966 227 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
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9703040367 Non-proprietary version of WCAP-14723, "Farley Nuclear Plant Units 1 & 2 Power Uprate Project NSSS Licensing Rept."

FROM: * AFFIL: EMVWEST

TO: AFFIL:

ISSUED: 970131 AVAIL: PDR 393pp. DOCUMENT TYPE: TRTOPR FPAC: 9703040325B

TASK: ODID: WCAP-14723 DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: 91965 111 91966 139 RIDS:

9607220160 NRC Info Notice 96-041, "Effects of Decrease in Feedwater Temperature on Nuclear Instrumentation."

FROM: GRIMES,B.K. AFFIL: N*******

TO: AFFIL:

ISSUED: 960726 AVAIL: PDR 10pp. DOCUMENT TYPE: TIIEIN FPAC: 9607220160#

TASK: ODID: IEIN-96-041 DIN: DPN: DRN:

DOCKET NO: FICHE: 89242 333 89242 342 RIDS: DF01

9606140003 Application for amends to licenses NPF-2 & NPF-8,providing improved operating margins as well as increased flexibility w/respect to core designs & plant operating strategy. Rev 2 to NSD-NT-OPL-96-152 withheld.

FROM: MOREY,D. AFFIL: EUTSNOC

TO: * AFFIL: NIRCTQ

ISSUED: 960612 AVAIL: PDR 3pp. DOCUMENT TYPE: TLAOOL FPAC: 9606140003*

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000348 FICHE: 88781 117 88781 257 RIDS: A001

U.S. NUCLEAR REGULATORY COMMISSION
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9310070159 NRC Info Notice 93-082, "Recent Fuel & Core Performance Problems in Operating Reactors."

FROM: GRIMES,B.K. AFFIL: NRRBPO

TO: AFFIL:

ISSUED: 931012 AVAIL: PDR 11pp. DOCUMENT TYPE: TIIEIN FPAC: 9310070159#

TASK: ODID: IEIN-93-082 DIN: DPN: DRN:

DOCKET NO: FICHE: 77289 001 77289 012 RIDS: DF03

9111190139 NRC Info Notice 91-075, "Static Head Corrections Mistakenly Not Included in Pressure Transmitter Calibr Procedures."

FROM: ROSSI,C.E. AFFIL: NRRBTA

TO: AFFIL:

ISSUED: 911125 AVAIL: PDR 3pp. DOCUMENT TYPE: TIIEIN FPAC: 9111190139#

TASK: ODID: IEIN-91-075 DIN: DPN: DRN:

DOCKET NO: FICHE: 59881 112 59881 115 RIDS:

8811040324 Suppl 3 to NRC Info Notice 86-106, "Feedwater Line Break." Svc list encl.

FROM: ROSSI,C.E. AFFIL: NRRBTA

TO: AFFIL:

ISSUED: 881110 AVAIL: PDR 113pp. DOCUMENT TYPE: TIIEIN FPAC: 8811040324#

TASK: ODID: IEIN-86-106 S03DIN: DPN: DRN:

DOCKET NO: FICHE: 47559 072 47559 184 RIDS:

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8409110367 IE Info Notice 84-73, "Downrating of Self-Aligning Ball Bushings Used in Snubbers." Svc list encl.

FROM: JORDAN,E.L. AFFIL: NIEEM

TO: AFFIL:

ISSUED: 840914 AVAIL: PDR 115pp. DOCUMENT TYPE: TIIEIN FPAC: 8409110367#

TASK: ODID: IEIN-84-73 DIN: DPN: DRN:

DOCKET NO: FICHE: 26653 194 26653 312 RIDS:

North Anna Units 1 and 2

Dockets 50-338 & 50-339

Publicly Available

Records Available In the PDR

U.S. NUCLEAR REGULATORY COMMISSION
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9904210144 Insp repts 50-338/99-01 & 50-339/99-01 on 990131-0313. Violations noted.Major areas inspected:operations, engineering,maintenance & plant support.In addition,results of insp by region based fire protection specialist encl.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 990412 AVAIL: PDR 27pp. DOCUMENT TYPE: TIINSP FPAC: 9904210142A

TASK: ODID: 50-338/99-01 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: A7727 215 A7727 241 RIDS:

9810210103 NRC Info Notice 98-040, "Design Deficiencies Can Lead to Reduced ECCS Pump Net Positive Head During Design-Basis Accidents."

FROM: ROE,J.W. AFFIL: N*******

TO: AFFIL:

ISSUED: 981026 AVAIL: PDR 9pp. DOCUMENT TYPE: TIIEIN FPAC: 9810210103#

TASK: ODID: IEIN-98-040 DIN: DPN: DRN:

DOCKET NO: FICHE: A5629 163 A5629 171 RIDS: DF03

9806090227 Insp repts 50-338/98-02,50-339/98-02 & 72-0016/98-02 on 980308-0418.Violations noted.Major areas inspected: operations,maint,engineering & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 980518 AVAIL: PDR 19pp. DOCUMENT TYPE: TIINSP FPAC: 9806090223B

TASK: ODID: 50-338/98-02 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: A3716 007 A3716 029 RIDS:

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9707310120 Insp repts 50-338/97-04 & 50-339/97-04 on 970518-0621.No violations noted.Major areas inspected:operations,maint, engineering & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 970721 AVAIL: PDR 30pp. DOCUMENT TYPE: TIINSP FPAC: 9707310113A

TASK: ODID: 50-338/97-04 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 93974 173 93974 205 RIDS:

9707080365 NRC Info Notice 97-051, "Problems Experienced w/Loading & Unloading Spent Nuclear Fuel Storage & Transportation of Casks."

FROM: SLOSSON,M.M. AFFIL: N*******

TO: AFFIL:

ISSUED: 970711 AVAIL: PDR 11pp. DOCUMENT TYPE: TIIEIN FPAC: 9707080365#

TASK: ODID: IEIN-97-051 DIN: DPN: DRN:

DOCKET NO: FICHE: 93946 345 93946 355 RIDS: DF01

9607220160 NRC Info Notice 96-041, "Effects of Decrease in Feedwater Temperature on Nuclear Instrumentation."

FROM: GRIMES,B.K. AFFIL: N*******

TO: AFFIL:

ISSUED: 960726 AVAIL: PDR 10pp. DOCUMENT TYPE: TIIEIN FPAC: 9607220160#

TASK: ODID: IEIN-96-041 DIN: DPN: DRN:

DOCKET NO: FICHE: 89242 333 89242 342 RIDS: DF01

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

9510240272 Proposed TS 4.4.5.1,Table 4.4-1,reducing from two to one min number of SGs required to be inspected during first ISI following SG replacement.

FROM: * AFFIL: EUTVEPC

TO: AFFIL:

ISSUED: 951017 AVAIL: PDR 6pp. DOCUMENT TYPE: TSTECH FPAC: 9510240269A

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000339 FICHE: 85929 227 85929 232 RIDS:

9510240269 Application for amend to license NPF-7,modifying Table 4.4-1 of TS 4.4.5.1 to reduce from two to one min number of SGs required to be inspected during first ISI following SG replacement.

FROM: O'HANLON,J.P. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 951017 AVAIL: PDR 10pp. DOCUMENT TYPE: TLAOOL FPAC: 9510240269*

TASK: ODID: 95-533 DIN: DPN: DRN:

DOCKET NO: 05000339 FICHE: 85929 217 85929 232 RIDS: A001

9508090201 Forwards ISI summary rept re 1995 SG replacement of refueling outage.

FROM: O'HANLON,J.P. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 950802 AVAIL: PDR 2pp. DOCUMENT TYPE: CLINC FPAC: 9508090201*

TASK: ODID: 95-31 DIN: DPN: DRN:

DOCKET NO: 05000339 FICHE: 84994 001 84994 230 RIDS: A047

U.S. NUCLEAR REGULATORY COMMISSION
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9507240377 Insp repts 50-338/95-11 & 50-339/95-11 on 950521-0617. Violations noted.Major areas inspected:plant status,plant operations,maint observations,surveillance observations, on-site engineering,plant support & previous insp items.

FROM: MCWHORTER,R. AFFIL: NE R2

TO: AFFIL:

ISSUED: 950713 AVAIL: PDR 19pp. DOCUMENT TYPE: TIINSP FPAC: 9507240369B

TASK: ODID: 50-338/95-11 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 84824 043 84824 061 RIDS:

9507140172 Insp rept 50-339/95-10 on 950430-0603.No violations noted. Major areas inspected:plant status & SG replacement.

FROM: TAYLOR,D.R. AFFIL: NE R2

TO: AFFIL:

ISSUED: 950629 AVAIL: PDR 26pp. DOCUMENT TYPE: TIINSP FPAC: 9507140169A

TASK: ODID: 50-339/95-10 DIN: DPN: DRN:

DOCKET NO: 05000339 FICHE: 84760 318 84760 343 RIDS:

9505310022 Insp rept 50-339/95-05 on 950325-0429.No violations noted. Major areas inspected:plant status & SG replacement project.

FROM: TAYLOR,D.R. AFFIL: NE R2

TO: AFFIL:

ISSUED: 950522 AVAIL: PDR 28pp. DOCUMENT TYPE: TIINSP FPAC: 9505310019A

TASK: ODID: 50-339/95-05 DIN: DPN: DRN:

DOCKET NO: 05000339 FICHE: 84094 103 84094 130 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
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9504240060 Insp repts 50-338/95-02 & 50-339/95-02 on 950219-0318.No violations noted.Major areas inspected:plant status,prompt on-site response to events,plant operations,maint & surveillance observations & plant support activities.

FROM: TAYLOR,D.R. AFFIL: NE R2

TO: AFFIL:

ISSUED: 950412 AVAIL: PDR 14pp. DOCUMENT TYPE: TIINSP FPAC: 9504240053A

TASK: ODID: 50-338/95-02 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 83598 060 83598 073 RIDS:

9504070116 Requests relief from requirements of ASME Section XI Code associated w/extent of exams practical for upcoming North Anna Unit 2 SG replacement.ISI program relief request NDE-22 for North Anna Unit 2 encl.

FROM: O'HANLON,J.P. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 950403 AVAIL: PDR 11pp. DOCUMENT TYPE: CLINC FPAC: 9504070116#

TASK: ODID: 95-127 DIN: DPN: DRN:

DOCKET NO: 05000339 FICHE: 83466 321 83466 334 RIDS: A047

9503200177 Insp repts 50-338/95-01 & 50-339/95-01 on 950122-0218. Violations noted.Major areas inspected:plant status,prompt response to on-site events,plant operations,maint observations & surveillance observations.

FROM: MCWHORTER,R.D. AFFIL: NE R2

TO: AFFIL:

ISSUED: 950313 AVAIL: PDR 18pp. DOCUMENT TYPE: TIINSP FPAC: 9503200175A

TASK: ODID: 50-338/95-01 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 83176 312 83176 329 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
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9503070264 Responds to util 941110 request for reduction in scope of NRC reviews & insp activities for forthcoming plant SG replacement project in spring of 1995.Informs that NRC does not intend to audit\review util SG replacement.

FROM: MATTHEWS,D.B. AFFIL: N*******

TO: O'HANLON,J.P. AFFIL: EUTVEPC

ISSUED: 950303 AVAIL: PDR 4pp. DOCUMENT TYPE: CLOUT FPAC: 9503070264#

TASK: ODID: TAC M91373 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 82990 065 82990 068 RIDS: DF01

9502140114 Insp repts 50-338/94-31 & 50-339/94-31 on 941225-950121. Noncited violations identified.Major areas inspected:plant operations,maint & surveillance observations,plant status on-site engineering & SG replacement.

FROM: MCWHORTER,R.D. AFFIL: NE R2

TO: AFFIL:

ISSUED: 950130 AVAIL: PDR 12pp. DOCUMENT TYPE: TIINSP FPAC: 9502140112A

TASK: ODID: 50-338/94-31 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 82714 247 82714 258 RIDS:

9501170081 Provides notification of temporary special security measures to be implemented for containment access facility being const to support plant Unit 2 SG replacement/refueling outage.Encl withheld.

FROM: O'HANLON,J.P. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 950106 AVAIL: PDR 2pp. DOCUMENT TYPE: CLINC FPAC: 9501170081#

TASK: ODID: 94-737 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 82378 261 82378 262 RIDS: IE53

U.S. NUCLEAR REGULATORY COMMISSION
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9410180190 Withraws 940728 proposed LAR for use of Westinghouse laser-welded sleeving process for repair of defects in SG tubes. Util decided to conduct North Anna Power Station,Unit 2 SG replacement during spring 1995 outage.

FROM: O'HANLON,J.P. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 941011 AVAIL: PDR 1p. DOCUMENT TYPE: CLINC FPAC: 9410180190#

TASK: ODID: 94-563 DIN: DPN: DRN:

DOCKET NO: 05000339 FICHE: 81371 338 81371 338 RIDS: A001

9404010277 Notice of withdrawal of 930702 application for amend to licenses NPF-4 & NPF-7,revising TS re steam generator insp reduction after steam generator replacement.

FROM: ENGLE,L.B. AFFIL: NRRBPP22

TO: AFFIL:

ISSUED: 940328 AVAIL: PDR 2pp. DOCUMENT TYPE: TFFRN FPAC: 9404010275A

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 78735 236 78735 238 RIDS:

9404010275 Forwards notice of 940301 withdrawal of 930702 application for amends to licenses NPF-4 & NPF-7,modifying TS re steam generator insp reduction after steam generator replacement.

FROM: ENGLE,L.B. AFFIL: NRRBPP22

TO: STEWART,W.L. AFFIL: EUTVEPC

ISSUED: 940328 AVAIL: PDR 1p. DOCUMENT TYPE: CLOUT FPAC: 9404010275*

TASK: ODID: TAC M87029 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 78735 235 78735 238 RIDS: DF01

U.S. NUCLEAR REGULATORY COMMISSION
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9403090173 Withdraws 930702 application for amends to licenses NPF-4 & NPF-7 to reduce from two to one min number of SGs required to be inspected during first ISI following SG replacement, based on discussions w/NRC during 940215 telcon.

FROM: STEWART,W.L. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 940301 AVAIL: PDR 1p. DOCUMENT TYPE: CLINC FPAC: 9403090173#

TASK: ODID: 94-103 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 78436 355 78436 355 RIDS: A001

9310070159 NRC Info Notice 93-082, "Recent Fuel & Core Performance Problems in Operating Reactors."

FROM: GRIMES,B.K. AFFIL: NRRBPO

TO: AFFIL:

ISSUED: 931012 AVAIL: PDR 11pp. DOCUMENT TYPE: TIIEIN FPAC: 9310070159#

TASK: ODID: IEIN-93-082 DIN: DPN: DRN:

DOCKET NO: FICHE: 77289 001 77289 012 RIDS: DF03

9307150048 Proposed tech specs changes to reduce minimum number of SGs required to be opened for insp during first insp following SG replacement.

FROM: * AFFIL: EUTVEPC

TO: AFFIL:

ISSUED: 930702 AVAIL: PDR 6pp. DOCUMENT TYPE: TSTECH FPAC: 9307150044A

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 75685 125 75685 130 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
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9307150044 Application for amends to licenses NPF-4 & NPF-7 modifying table 4.4-1 of TS 4.4.5.1 to reduce minimum number of SGs required to be opened for insp during first insp (i.e.,refueling outage)following SG replacement.

FROM: STEWART,W.L. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 930702 AVAIL: PDR 8pp. DOCUMENT TYPE: TLAOOL FPAC: 9307150044*

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 75685 117 75685 130 RIDS: A001

9307020261 Insp repts 50-338/93-14 & 50-339/93-14 on 930404-0508. Violation noted.Major areas inspected:plant status,followup of operational events,operational safety verification,maint & surveillance observation & action on previous insp items.

FROM: LESSER,M.S. AFFIL: NE R2

TO: AFFIL:

ISSUED: 930603 AVAIL: PDR 32pp. DOCUMENT TYPE: TIINSP FPAC: 9307020247B

TASK: ODID: 50-338/93-14 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 75542 330 75542 361 RIDS:

9304200080 Insp repts 50-338/93-11 & 50-339/93-11 on 930308-12.No violations noted.Major areas inspected:post-weld heat treatment,review of radiographs,cleanliness insps of primary & secondary boundary spaces & sys hydrostatic testing.

FROM: ECONOMOS,N. AFFIL: NE R2

TO: AFFIL:

ISSUED: 930408 AVAIL: PDR 17pp. DOCUMENT TYPE: TIINSP FPAC: 9304200067A

TASK: ODID: 50-338/93-11 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 74626 114 74626 129 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
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9303300062 Insp repts 50-338/93-01 & 50-339/93-01 on 930115-0211.Two noncited violations identified.Major areas inspected:program organization & mgt controls,HP technician training & operational & administrative controls.

FROM: AFFIL:

TO: AFFIL:

ISSUED: 930312 AVAIL: PDR 23pp. DOCUMENT TYPE: TIINSP FPAC: 9303300055A

TASK: ODID: 50-338/93-01 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 74387 049 74387 071 RIDS:

9303020383 Insp repts 50-338/93-04 & 50-339/93-04 on 930111-15 & 25-29. No violations or deviations noted.Major areas inspected: steam generator replacement project activities,including severing of piping attached to SGs.

FROM: ECONOMOS,N. AFFIL: NE R2

TO: AFFIL:

ISSUED: 930223 AVAIL: PDR 18pp. DOCUMENT TYPE: TIINSP FPAC: 9303020376A

TASK: ODID: 50-338/93-04 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 74021 181 74021 198 RIDS:

9302230108 Partially withheld insp repts 50-338/93-06 & 50-339/93-06 on 930125-29.No violations noted.Major areas inspected: physical security program,including protected vital area barriers.Portions withheld (ref 10CFR2.790).

FROM: TILLMAN,A. AFFIL: NE R2

TO: AFFIL:

ISSUED: 930211 AVAIL: PDR 2pp. DOCUMENT TYPE: TIINSP FPAC: 9302230096A

TASK: ODID: 50-338/93-06 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 64874 238 64874 239 RIDS:

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9302160089 Insp repts 50-338/93-05 & 50-339/93-05 on 930111-15.No violations or deviations noted.Major areas inspected:control of heavy loads in containment & crane insps to be performed during SG replacement project.

FROM: BURNETT,P.T. AFFIL: NE R2

TO: AFFIL:

ISSUED: 930205 AVAIL: PDR 5pp. DOCUMENT TYPE: TIINSP FPAC: 9302160072A

TASK: ODID: 50-338/93-05 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 64813 038 64813 042 RIDS:

9212290122 Insp repts 50-338/92-28 & 50-339/92-28 on 921116-20.No violations or deviations noted.Major areas inspected:to observe certain activities in preparation for SG Replacement Project in unit 1 & to review approved welding procedures.

FROM: ECONOMOS,N. AFFIL: NE R2

TO: AFFIL:

ISSUED: 921215 AVAIL: PDR 7pp. DOCUMENT TYPE: TIINSP FPAC: 9212290115A

TASK: ODID: 50-338/92-28 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 64437 291 64437 297 RIDS:

9212040260 Insp repts 50-338/92-25 & 50-339/92-25 on 921102-06.No violations noted.Weaknesses noted re heavy loads program. Major areas inspected:post-refueling startup tests,routine surveillance of core performance & control of heavy loads.

FROM: BURNETT,P.T. AFFIL: NE R2

TO: AFFIL:

ISSUED: 921125 AVAIL: PDR 9pp. DOCUMENT TYPE: TIINSP FPAC: 9212040251A

TASK: ODID: 50-338/92-25 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 64134 080 64134 088 RIDS:

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9211180001 LER 92-013-00:on 921021,determined that ESF response time testing for AFW pump not performed.Caused by personnel error,resulting in inadequate surveillance test procedure. Testing performed & procedures revised.W/921110 ltr.

FROM: KANE,G.E. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 921110 AVAIL: PDR 5pp. DOCUMENT TYPE: TRLER FPAC: 9211180001#

TASK: ODID: 92-013 DIN: 92-013 DPN: DRN: 00

DOCKET NO: 05000338 FICHE: 63976 063 63976 067 RIDS: IE22

9210280294 Vols 1-3 of Design Package DC 90-13-1, "North Anna Power Station Unit 1 SG Replacement."

FROM: * AFFIL: EUTVEPC

TO: AFFIL:

ISSUED: 920930 AVAIL: PDR 1,369pp. DOCUMENT TYPE: TRZAR FPAC: 9210280288A

TASK: ODID: DC 90-13-1 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 63805 012 63808 300 RIDS:

9210280288 Forwards Vols 1-3 of Design Change Package 90-13-1, "North Anna Power Station Unit 1 SG Replacement." W/53 nonproprietary drawings & 10 proprietary drawings. Proprietary drawings withheld.

FROM: BOWLING,M.L. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 921023 AVAIL: PDR 4pp. DOCUMENT TYPE: CLINC FPAC: 9210280288*

TASK: ODID: 92-684 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 63805 001 63808 300 RIDS: A001

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9210070079 Forwards Westinghouse proprietary application to withhold util submittal entitled, "70% Draft Design Change Package 90-13-1 for SG Replacement Activity at North Anna Unit 1." Encls withheld (ref 10CFR2.790).

FROM: BOWLING,M.L. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 920922 AVAIL: PDR 3pp. DOCUMENT TYPE: CLINC FPAC: 9210070079*

TASK: ODID: 92-608 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 63463 312 63463 314 RIDS: AP01

9204010356 Summary of 920323 meeting w/util re plant steam generator replacement program.List of attendees encl.

FROM: ENGLE,L.B. AFFIL: NRRBPP22

TO: * AFFIL: NRRBPP22

ISSUED: 920327 AVAIL: PDR 60pp. DOCUMENT TYPE: CNMINS FPAC: 9204010356#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 61208 251 61208 310 RIDS: DF01

9203030263 Application for amend to license NPF-4,requesting that amend request in 920128 ltr to limit max reactor power to 95% of rated thermal power until steam generator replacement be processed as emergency change per 10CFR50.91(a)(5).

FROM: STEWART,W.L. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 920227 AVAIL: PDR 9pp. DOCUMENT TYPE: TLAOOL FPAC: 9203030263#

TASK: ODID: 92-042A DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 60819 032 60819 040 RIDS: A001

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9202030109 Application for amend to License NPF-4,modifying License Condition 2.D(1) re max power level to add footnote which states that max reactor power level shall be limited to 95% of rated thermal power.

FROM: STEWART,W.L. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 920128 AVAIL: PDR 3pp. DOCUMENT TYPE: TLAOOL FPAC: 9202030109*

TASK: ODID: 92-042 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 60473 147 60473 202 RIDS: A001

9201270008 Application for amend to License NPF-4,allowing one-time extension of specific surveillance requirements for ninth cycle to permit surveillance testing to coincide w/steam generator replacement program.

FROM: STEWART,W.L. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 920120 AVAIL: PDR 17pp. DOCUMENT TYPE: TLAOOL FPAC: 9201270008#

TASK: ODID: 92-001 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 60397 105 60397 121 RIDS: A001

9111190139 NRC Info Notice 91-075, "Static Head Corrections Mistakenly Not Included in Pressure Transmitter Calibr Procedures."

FROM: ROSSI,C.E. AFFIL: NRRBTA

TO: AFFIL:

ISSUED: 911125 AVAIL: PDR 3pp. DOCUMENT TYPE: TIIEIN FPAC: 9111190139#

TASK: ODID: IEIN-91-075 DIN: DPN: DRN:

DOCKET NO: FICHE: 59881 112 59881 115 RIDS:

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9110250133 Submits revised outage schedules & operating cycles for 1992 & 1993 for facility due to steam generator replacement schedule change.Outage forecast table encl.

FROM: STEWART,W.L. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 911011 AVAIL: PDR 3pp. DOCUMENT TYPE: CLINC FPAC: 9110250133#

TASK: ODID: 91-605 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 59458 275 59458 277 RIDS: IE26

9110210204 Notification of 911022 counterparts meeting w/util in Glen Allen,VA to discuss status of planned mods to CCW sys, DCRDR,resolution of SRV setpoint drift & insp plans & issue & steam generator replacement oversight.Agenda encl.

FROM: BUCKLEY,B.C. AFFIL: NRRBPP2T

TO: BERKOW,H.N. AFFIL: NRRBPP2T

ISSUED: 911011 AVAIL: PDR 4pp. DOCUMENT TYPE: CMMEMO FPAC: 9110210204#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: FICHE: 59433 043 59433 046 RIDS: DF01

9010100106 Insp Repts 50-338/90-19 & 50-339/90-19 on 900820-24. Violations noted but not cited.Major areas inspected: licensee radiation protection program consisting of review in areas of external & internal exposure control.

FROM: GLOERSEN,W.B. AFFIL: NE R2

TO: AFFIL:

ISSUED: 900914 AVAIL: PDR 12pp. DOCUMENT TYPE: TIINSP FPAC: 9010100105A

TASK: ODID: 50-338/90-19 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 55422 027 55422 038 RIDS:

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8906270080 Insp Repts 50-338/89-15 & 50-339/89-15 on 890501-05. Violation noted.Major areas inspected:radiation protection program,including review of areas of external & internal exposure control & program to maintain doses ALARA.

FROM: GLOERSEN,W.B. AFFIL: NE R2

TO: AFFIL:

ISSUED: 890602 AVAIL: PDR 19pp. DOCUMENT TYPE: TIINSP FPAC: 8906270076B

TASK: ODID: 50-338/89-15 DIN: DPN: DRN:

DOCKET NO: 05000338 FICHE: 50319 018 50319 036 RIDS:

8811040324 Suppl 3 to NRC Info Notice 86-106, "Feedwater Line Break." Svc list encl.

FROM: ROSSI,C.E. AFFIL: NRRBTA

TO: AFFIL:

ISSUED: 881110 AVAIL: PDR 113pp. DOCUMENT TYPE: TIIEIN FPAC: 8811040324#

TASK: ODID: IEIN-86-106 S03DIN: DPN: DRN:

DOCKET NO: FICHE: 47559 072 47559 184 RIDS:

8409110367 IE Info Notice 84-73, "Downrating of Self-Aligning Ball Bushings Used in Snubbers." Svc list encl.

FROM: JORDAN,E.L. AFFIL: NIEEM

TO: AFFIL:

ISSUED: 840914 AVAIL: PDR 115pp. DOCUMENT TYPE: TIIEIN FPAC: 8409110367#

TASK: ODID: IEIN-84-73 DIN: DPN: DRN:

DOCKET NO: FICHE: 26653 194 26653 312 RIDS:

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8007070079 Requests action concerning defective demineralizer design, related corrosion & cracking in steam generators & turbine discs.Commends NRC decision to require EIS re experimental replacement of steam generators.

FROM: ALLEN,J. AFFIL: ECINAEC

TO: BRADFORD,P. AFFIL: NRCC

ISSUED: 800218 AVAIL: PDR 4pp. DOCUMENT TYPE: CLINC FPAC: 8007070059D

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: FICHE: 18385 229 18385 232 RIDS:

Summer

Docket 50-395

Publicly Available

Records Available in the PDR

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9906170130 Insp rept 50-395/99-03 on 990328-0508.Six violations of NRC requirements occurred & being treated as non-cited violations.Major areas inspected:aspects of licensee operations,maint,engineering & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 990607 AVAIL: PDR 27pp. DOCUMENT TYPE: TIINSP FPAC: 9906170129A

TASK: ODID: 50-395/99-03 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: A8352 125 A8352 151 RIDS:

9810210103 NRC Info Notice 98-040, "Design Deficiencies Can Lead to Reduced ECCS Pump Net Positive Head During Design-Basis Accidents."

FROM: ROE,J.W. AFFIL: N*******

TO: AFFIL:

ISSUED: 981026 AVAIL: PDR 9pp. DOCUMENT TYPE: TIIEIN FPAC: 9810210103#

TASK: ODID: IEIN-98-040 DIN: DPN: DRN:

DOCKET NO: FICHE: A5629 163 A5629 171 RIDS: DF03

9809090104 Insp rept 50-395/98-06 on 980628-0725.No violations noted. Major areas inspected:operations,maintenance,engineering & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 980924 AVAIL: PDR 22pp. DOCUMENT TYPE: TIINSP FPAC: 9809090102A

TASK: ODID: 50-395/98-06 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: A4957 317 A4957 338 RIDS:

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9806090081 Insp rept 50-395/98-03 on 980330-0417.Violations noted. Major areas inspected:operations,maint,engineering & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 980529 AVAIL: PDR 29pp. DOCUMENT TYPE: TIINSP FPAC: 9806090075B

TASK: ODID: 50-395/98-03 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: A3699 283 A3699 311 RIDS:

9801210176 Insp rept 50-395/97-13 on 971019-1129.Violations noted.Major areas inspected:operations,maint,engineering & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 971223 AVAIL: PDR 46pp. DOCUMENT TYPE: TIINSP FPAC: 9801210167B

TASK: ODID: 50-395/97-13 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: A1856 289 A1856 334 RIDS:

9707080365 NRC Info Notice 97-051, "Problems Experienced w/Loading & Unloading Spent Nuclear Fuel Storage & Transportation of Casks."

FROM: SLOSSON,M.M. AFFIL: N*******

TO: AFFIL:

ISSUED: 970711 AVAIL: PDR 11pp. DOCUMENT TYPE: TIIEIN FPAC: 9707080365#

TASK: ODID: IEIN-97-051 DIN: DPN: DRN:

DOCKET NO: FICHE: 93946 345 93946 355 RIDS: DF01

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9705080290 Insp rept 50-395/97-01 on 970209-0322.No violations noted. Major areas inspected:operations,maintenance,engineering & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 970417 AVAIL: PDR 37pp. DOCUMENT TYPE: TIINSP FPAC: 9705080281A

TASK: ODID: 50-395/97-01 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 92802 252 92802 293 RIDS:

9703280081 Insp rept 50-395/96-15 on 961229-970208.Violations noted. Major areas inspected:operations,maintenance,engineering & plant support.

FROM: * AFFIL: NE R2

TO: AFFIL:

ISSUED: 970310 AVAIL: PDR 34pp. DOCUMENT TYPE: TIINSP FPAC: 9703280069B

TASK: ODID: 50-395/96-15 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 92274 009 92274 046 RIDS:

9610010147 "Startup Report for VC Summer Nuclear Station Power Uprate."

FROM: * AFFIL: EUTSCEG

TO: AFFIL:

ISSUED: 960923 AVAIL: PDR 6pp. DOCUMENT TYPE: TSTEST FPAC: 9610010143A

TASK: ODID: RC-96-0229 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 89884 338 89884 343 RIDS:

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9610010143 Forwards Startup Rept for VCSNS Power Uprate.

FROM: TAYLOR,G.J. AFFIL: EUTSCEG

TO: * AFFIL: NIRCTQ

ISSUED: 960923 AVAIL: PDR 1p. DOCUMENT TYPE: CLINC FPAC: 9610010143*

TASK: ODID: RC-96-0229 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 89884 337 89884 343 RIDS: IE26

9607220160 NRC Info Notice 96-041, "Effects of Decrease in Feedwater Temperature on Nuclear Instrumentation."

FROM: GRIMES,B.K. AFFIL: N*******

TO: AFFIL:

ISSUED: 960726 AVAIL: PDR 10pp. DOCUMENT TYPE: TIIEIN FPAC: 9607220160#

TASK: ODID: IEIN-96-041 DIN: DPN: DRN:

DOCKET NO: FICHE: 89242 333 89242 342 RIDS: DF01

9501240077 Insp rept 50-395/94-27 on 941101-1216.Violations noted.Major areas inspected:activities associated w/SG replacement project.

FROM: AFFIL:

TO: AFFIL:

ISSUED: 950110 AVAIL: PDR 21pp. DOCUMENT TYPE: TIINSP FPAC: 9501240066B

TASK: ODID: 50-395/94-27 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 82419 274 82419 294 RIDS:

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9501030177 Discusses 941215 meeting held in Region II ofc re results of util SG replacement outage & informs that meeting provided better understanding of project including challenges,mods & assessments made.Attendees list encl.

FROM: MERSCHOFF,E.W. AFFIL: NE R2

TO: SKOLDS,J.L. AFFIL: EUTSCEG

ISSUED: 941220 AVAIL: PDR 123pp. DOCUMENT TYPE: CLOUT FPAC: 9501030177#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 82173 046 82173 168 RIDS: IE45

9411300037 Notification of significant licensee meeting w/util on 941215 to review SG replacement outage.

FROM: CANTRELL,F.S. AFFIL: NE R2

TO: * AFFIL: NE R2

ISSUED: 941027 AVAIL: PDR 2pp. DOCUMENT TYPE: CMMEMO FPAC: 9411300037#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 81871 182 81871 183 RIDS: IE45

9411290084 Insp rept 50-395/94-24 on stated date.Violations noted.Major areas inspected:activities associated w/steam generator replacement.

FROM: AFFIL:

TO: AFFIL:

ISSUED: 941118 AVAIL: PDR 33pp. DOCUMENT TYPE: TIINSP FPAC: 9411290079B

TASK: ODID: 50-395/94-24 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 81858 256 81858 288 RIDS:

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9411250031 Amend 119 to license NPF-12,changing TS to support SG replacement.

FROM: BATEMAN,W.H. AFFIL: NRRBPP21

TO: AFFIL:

ISSUED: 941118 AVAIL: PDR 38pp. DOCUMENT TYPE: TLLOLL FPAC: 9411250030A

TASK: ODID: NPF-12 A 119 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 81841 272 81841 309 RIDS:

9411250030 Forwards amend 119 to license NPF-12 & safety evaluation. Amend changes TS to support SG replacement.

FROM: WUNDER,G.F. AFFIL: NRRBPP21

TO: SKOLDS,J.L. AFFIL: EUTSCEG

ISSUED: 941118 AVAIL: PDR 3pp. DOCUMENT TYPE: CLOUT FPAC: 9411250030*

TASK: ODID: TAC M88172 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 81841 269 81841 339 RIDS: DF01

9411210068 Imforms of arrangements made re mgt meeting to be held on 941215 in Atlanta,GA re SG replacement outage.Proposed meeting agenda encl.

FROM: BOGER,B.A. AFFIL: NE R2

TO: SKOLDS,J.L. AFFIL: EUTSCEG

ISSUED: 941027 AVAIL: PDR 3pp. DOCUMENT TYPE: CLOUT FPAC: 9411210068#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 81785 003 81785 005 RIDS: IE01

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9411070050 Insp rept 50-395/94-22 on 940901-30.Violations noted.Major areas inspected:SG Replacement Project.

FROM: AFFIL:

TO: AFFIL:

ISSUED: 941020 AVAIL: PDR 14pp. DOCUMENT TYPE: TIINSP FPAC: 9411070044B

TASK: ODID: 50-395/94-22 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 81604 146 81604 159 RIDS:

9410260147 Forwards basis for & description of revised SLB & FWLB analyses & results of revised analyses,supporting SG replacement TS Change Request TSP 930015.Revised page incorporating approved amend 116 to TS also encl.

FROM: SKOLDS,J.L. AFFIL: EUTSCEG

TO: WUNDER,G.F. AFFIL: NIRCTQ

ISSUED: 941020 AVAIL: PDR 47pp. DOCUMENT TYPE: CLINC FPAC: 9410260147*

TASK: ODID: RC-94-0275 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 81456 134 81456 181 RIDS: A001

9410210166 Forwards response to questions on EQ for SG replacement,per 931029 submittal of majority of safety analysis results & associated TS changes for SG replacement.

FROM: SKOLDS,J.L. AFFIL: EUTSCEG

TO: WUNDER,G.F. AFFIL: NIRCTQ

ISSUED: 941017 AVAIL: PDR 3pp. DOCUMENT TYPE: CLINC FPAC: 9410210166#

TASK: ODID: RC-94-0270 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 81426 303 81426 305 RIDS: A001

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9409160188 Discusses 940831 meeting w/util re preparations,safety assessment aspects & schedule for 940909 refueling outage 8 & SG replacement combined multiproject.

FROM: BOGER,B.A. AFFIL: NE R2

TO: SKOLDS,J.L. AFFIL: EUTSCEG

ISSUED: 940906 AVAIL: PDR 29pp. DOCUMENT TYPE: CLOUT FPAC: 9409160188#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 80907 049 80907 078 RIDS: IE45

9409130457 Partially withheld insp rept 50-395/94-18 on 940718-0818 (ref 10CFR73.21).Apparent violations being considered for escalated enforcement action.Major areas inspected:alarm stations,safeguards info,security training & qualification.

FROM: THOMPSON,D.H. AFFIL: NE R2

TO: AFFIL:

ISSUED: 940831 AVAIL: PDR 2pp. DOCUMENT TYPE: TIINSP FPAC: 9409130450A

TASK: ODID: 50-395/94-18 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 80848 236 80848 237 RIDS:

9409020024 Notification of 940831 meeting w/util in Atlanta,GA to discuss refueling outage 8 & SG replacement plans.

FROM: CANTRELL,F.S. AFFIL: NE R2

TO: * AFFIL: NE R2

ISSUED: 940819 AVAIL: PDR 2pp. DOCUMENT TYPE: CMMEMO FPAC: 9409020024#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 80736 066 80736 067 RIDS: IE45

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9407110101 Insp rept 50-395/94-14 on 940606-10.No violations noted. Major areas inspected:licensee SGRP mgt organization & staffing,nonconformance program & implementation of QA requirements.

FROM: KLEINSORGE,P.E. AFFIL: NE R2

TO: AFFIL:

ISSUED: 940623 AVAIL: PDR 8pp. DOCUMENT TYPE: TIINSP FPAC: 9407110094A

TASK: ODID: 50-395/94-14 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 80133 339 80133 346 RIDS:

9405240197 Forwards response to NRC 940425 RAI for SG replacement (SGR) review.Rev to pages xiv & 3.2-3 of 931029,submittal supporting SGR TS changes.Informs that minor rev to LOCA hydraulic loads on core barrel made.

FROM: SKOLDS,J.L. AFFIL: EUTSCEG

TO: WUNDER,G.F. AFFIL: NIRCTQ

ISSUED: 940518 AVAIL: PDR 13pp. DOCUMENT TYPE: CLINC FPAC: 9405240197#

TASK: ODID: RC-94-0141 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 79487 342 79487 354 RIDS: A001

9405030159 Responds to 931029 ltr re RAI for steam generator replacement review & provides questions to be addressed.

FROM: WUNDER,G.F. AFFIL: NRRBPP21

TO: SKOLDS,J.L. AFFIL: EUTSCEG

ISSUED: 940425 AVAIL: PDR 4pp. DOCUMENT TYPE: CLOUT FPAC: 9405030159#

TASK: ODID: TAC M88172 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 79129 218 79129 221 RIDS: DF01

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9403280200 Insp rept 50-395/94-06 on 940222-24.No violations or deviations noted.Major areas inspected:SG replacement project.

FROM: KLEINSORGE,W.P. AFFIL: NE R2

TO: AFFIL:

ISSUED: 940316 AVAIL: PDR 6pp. DOCUMENT TYPE: TIINSP FPAC: 9403280193A

TASK: ODID: 50-395/94-06 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 78653 252 78653 257 RIDS:

9403170303 Proposed tech specs re steam generator replacement.

FROM: * AFFIL: EUTSCEG

TO: AFFIL:

ISSUED: 940311 AVAIL: PDR 72pp. DOCUMENT TYPE: TSTECH FPAC: 9403170301A

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 78607 005 78607 077 RIDS:

9402280004 Confirms telephone conversation between RM Fowlks & FS Cantrell re briefing on plant SG Replacement Project to be conducted at Region II office on 940222.Proposed meeting agenda encl.

FROM: MERSCHOFF,E.W. AFFIL: NE R2

TO: SKOLDS,J.L. AFFIL: EUTSCEG

ISSUED: 940214 AVAIL: PDR 3pp. DOCUMENT TYPE: CLOUT FPAC: 9402280004#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 78275 043 78275 045 RIDS: IE01

U.S. NUCLEAR REGULATORY COMMISSION
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9402150162 Insp rept 50-395/94-01 on 940110-14 No violations noted. Major areas inspected:area of SG replacement project.

FROM: KLEINSORGE,W.P. AFFIL: NE R2

TO: AFFIL:

ISSUED: 940125 AVAIL: PDR 6pp. DOCUMENT TYPE: TIINSP FPAC: 9402150155A

TASK: ODID: 50-395/94-01 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 78111 028 78111 033 RIDS:

9401030371 Informs that licensee decided to reanalyze SBLOCA w/o credit for increase in SI flow for listed reasons,w/respect to SG replacement project.

FROM: SKOLDS,J.L. AFFIL: EUTSCEG

TO: WUNDER,G.F. AFFIL: NIRCTQ

ISSUED: 931221 AVAIL: PDR 2pp. DOCUMENT TYPE: CLINC FPAC: 9401030371#

TASK: ODID: RC-93-0311 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 77679 359 77679 360 RIDS: A001

9312230108 Application for amend to license NPF-12,consisting of TS Change TSP 930017,revising Figures 3.9-1 & 3.9-2 to permit storage of fuel assemblies in Region 2 & 3,respectively,of spent fuel storage racks.

FROM: SKOLDS,J.L. AFFIL: EUTSCEG

TO: * AFFIL: NIRCTQ

ISSUED: 931213 AVAIL: PDR 4pp. DOCUMENT TYPE: TLAOOL FPAC: 9312230108*

TASK: ODID: RC-93-0304 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 77630 136 77630 241 RIDS: A001

U.S. NUCLEAR REGULATORY COMMISSION
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9312220073 Summary of 931130 meeting w/SCE&G in Rockville,MD re licensee upcoming SG replacement,scheduled to begin Sept 1994.List of attendees encl.

FROM: WUNDER,G.F. AFFIL: NRRBPP22

TO: * AFFIL: NRRBPP22

ISSUED: 931215 AVAIL: PDR 121pp. DOCUMENT TYPE: CNMINS FPAC: 9312220073#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 77562 100 77562 220 RIDS: DF01

9311120077 Notification of 931130 meeting w/util in Rockville,MD to discuss SG replacement.

FROM: WUNDER,G.F. AFFIL: NRRBPP21

TO: BAJWA,S.S. AFFIL: NRRBPP21

ISSUED: 931109 AVAIL: PDR 3pp. DOCUMENT TYPE: CMMEMO FPAC: 9311120077#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 77177 198 77177 201 RIDS: DF01

9311080057 Proposed tech specs supporting SG replacement.

FROM: * AFFIL: EUTSCEG

TO: AFFIL:

ISSUED: 931029 AVAIL: PDR 35pp. DOCUMENT TYPE: TSTECH FPAC: 9311080047A

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 77136 019 77136 053 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
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9310070159 NRC Info Notice 93-082, "Recent Fuel & Core Performance Problems in Operating Reactors."

FROM: GRIMES,B.K. AFFIL: NRRBPO

TO: AFFIL:

ISSUED: 931012 AVAIL: PDR 11pp. DOCUMENT TYPE: TIIEIN FPAC: 9310070159#

TASK: ODID: IEIN-93-082 DIN: DPN: DRN:

DOCKET NO: FICHE: 77289 001 77289 012 RIDS: DF03

9307020147 Insp rept 50-395/93-16 on 930517-21.Deviation noted.Major areas inspected:design changes & mods & engineering support activities.

FROM: THOMAS,M. AFFIL: NE R2

TO: AFFIL:

ISSUED: 930618 AVAIL: PDR 16pp. DOCUMENT TYPE: TIINSP FPAC: 9307020134B

TASK: ODID: 50-395/93-16 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 75542 080 75542 095 RIDS:

9305110079 Nonproprietary "Primary Loop Leak-Before-Break Reconciliation to Account for Effects of SG Replacement/ Uprating."

FROM: LEE,Y.S. AFFIL: EMVWEST

TO: AFFIL:

ISSUED: 930430 AVAIL: PDR 20pp. DOCUMENT TYPE: TRTOPR FPAC: 9305110064C

TASK: ODID: WCAP-13694 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 74886 288 74886 308 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
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9305110074 Requests that proprietary WCAP-13605, "Primary Loop Leak-Before-Break Reconciliation to Account for Effects of SG Replacement/Uprating" be withheld,per 10CFR2.790.

FROM: LIPARULO,N.J. AFFIL: EMVWEST

TO: MURLEY,T. AFFIL: NIRCTQ

ISSUED: 930416 AVAIL: PDR 9pp. DOCUMENT TYPE: CLINC FPAC: 9305110064B

TASK: ODID: CAW-93-451 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 74886 279 74886 287 RIDS:

9305040219 Insp rept 50-395/93-13 on 930412-16.No violations or deviations noted.Major areas inspected:ISI,SG tube specimen removal,SG replacement project & Flow Accelerated Corrosion.

FROM: KLEINSORGE,W.P. AFFIL: NE R2

TO: AFFIL:

ISSUED: 930426 AVAIL: PDR 9pp. DOCUMENT TYPE: TIINSP FPAC: 9305040209A

TASK: ODID: 50-395/93-13 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 74827 280 74827 288 RIDS:

9210060163 Summary of 920812 meeting w/util in Rockville,MD re steam generator replacement.List of attendees & licensee handout used in meeting encl.

FROM: WUNDER,G.F. AFFIL: NRRBPP21

TO: * AFFIL: NRRBPP21

ISSUED: 920923 AVAIL: PDR 41pp. DOCUMENT TYPE: CNMINS FPAC: 9210060163#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 63392 304 63392 343 RIDS: DF01

U.S. NUCLEAR REGULATORY COMMISSION
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9206120008 Forwards proposed schedule for submittal of info to support steam generator replacement.Delta Design 75 requirements & performance data will be submitted by 920831.

FROM: SKOLDS,J.L. AFFIL: EUTSCEG

TO: WUNDER,G.F. AFFIL: NIRCTQ

ISSUED: 920604 AVAIL: PDR 7pp. DOCUMENT TYPE: CLINC FPAC: 9206120008#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 62025 338 62025 344 RIDS: A001

9201290221 Summary of 920109 meeting w/util in Rockville,MD to discuss licensee proposed SG replacement program.

FROM: WUNDER,G.F. AFFIL: NRRBPP21

TO: * AFFIL: NRRBPP21

ISSUED: 920122 AVAIL: PDR 27pp. DOCUMENT TYPE: CNMINS FPAC: 9201290221#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 60400 001 60400 027 RIDS: DF01

9201060079 Notification of 920109 meeting w/util in Rockville,MD to discuss steam generator replacement at facility.

FROM: WUNDER,G.F. AFFIL: NRRBPP21

TO: ADENSAM,E.G. AFFIL: NRRBPP21

ISSUED: 911231 AVAIL: PDR 3pp. DOCUMENT TYPE: CMMEMO FPAC: 9201060079#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 60214 286 60214 288 RIDS: DF01

U.S. NUCLEAR REGULATORY COMMISSION
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9111190139 NRC Info Notice 91-075, "Static Head Corrections Mistakenly Not Included in Pressure Transmitter Calibr Procedures."

FROM: ROSSI,C.E. AFFIL: NRRBTA

TO: AFFIL:

ISSUED: 911125 AVAIL: PDR 3pp. DOCUMENT TYPE: TIIEIN FPAC: 9111190139#

TASK: ODID: IEIN-91-075 DIN: DPN: DRN:

DOCKET NO: FICHE: 59881 112 59881 115 RIDS:

9109240381 Insp rept 50-395/91-18 on 910812-16.Violations noted but not cited.Major areas inspected:dose assessment,semiannual rept, environ monitoring,QA audits & radwaste storage.

FROM: SEYMOUR,D.A. AFFIL: NE R2

TO: AFFIL:

ISSUED: 910904 AVAIL: PDR 20pp. DOCUMENT TYPE: TIINSP FPAC: 9109240378A

TASK: ODID: 50-395/91-18 DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 59185 065 59185 084 RIDS:

9108270195 Notification of 910828 meeting w/util in Rockville,Md to discuss util SG replacement & technical support issues.

FROM: WUNDER,G.F. AFFIL: NRRBPP21

TO: ADENSAM,E.G. AFFIL: NRRBPP21

ISSUED: 910822 AVAIL: PDR 3pp. DOCUMENT TYPE: CMMEMO FPAC: 9108270195#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000395 FICHE: 58893 005 58893 007 RIDS: DF01

U.S. NUCLEAR REGULATORY COMMISSION
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8811040324 Suppl 3 to NRC Info Notice 86-106, "Feedwater Line Break." Svc list encl.

FROM: ROSSI,C.E. AFFIL: NRRBTA

TO: AFFIL:

ISSUED: 881110 AVAIL: PDR 113pp. DOCUMENT TYPE: TIIEIN FPAC: 8811040324#

TASK: ODID: IEIN-86-106 S03DIN: DPN: DRN:

DOCKET NO: FICHE: 47559 072 47559 184 RIDS:

8409110367 IE Info Notice 84-73, "Downrating of Self-Aligning Ball Bushings Used in Snubbers." Svc list encl.

FROM: JORDAN,E.L. AFFIL: NIEEM

TO: AFFIL:

ISSUED: 840914 AVAIL: PDR 115pp. DOCUMENT TYPE: TIIEIN FPAC: 8409110367#

TASK: ODID: IEIN-84-73 DIN: DPN: DRN:

DOCKET NO: FICHE: 26653 194 26653 312 RIDS:

Surry Units 1 and 2

Dockets 50-280 & 50-281

Publicly Available

Records Available In the PDR

U.S. NUCLEAR REGULATORY COMMISSION
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9810210103 NRC Info Notice 98-040, "Design Deficiencies Can Lead to Reduced ECCS Pump Net Positive Head During Design-Basis Accidents."

FROM: ROE,J.W. AFFIL: N*******

TO: AFFIL:

ISSUED: 981026 AVAIL: PDR 9pp. DOCUMENT TYPE: TIIEIN FPAC: 9810210103#

TASK: ODID: IEIN-98-040 DIN: DPN: DRN:

DOCKET NO: FICHE: A5629 163 A5629 171 RIDS: DF03

9707080365 NRC Info Notice 97-051, "Problems Experienced w/Loading & Unloading Spent Nuclear Fuel Storage & Transportation of Casks."

FROM: SLOSSON,M.M. AFFIL: N*******

TO: AFFIL:

ISSUED: 970711 AVAIL: PDR 11pp. DOCUMENT TYPE: TIIEIN FPAC: 9707080365#

TASK: ODID: IEIN-97-051 DIN: DPN: DRN:

DOCKET NO: FICHE: 93946 345 93946 355 RIDS: DF01

9607220160 NRC Info Notice 96-041, "Effects of Decrease in Feedwater Temperature on Nuclear Instrumentation."

FROM: GRIMES,B.K. AFFIL: N*******

TO: AFFIL:

ISSUED: 960726 AVAIL: PDR 10pp. DOCUMENT TYPE: TIIEIN FPAC: 9607220160#

TASK: ODID: IEIN-96-041 DIN: DPN: DRN:

DOCKET NO: FICHE: 89242 333 89242 342 RIDS: DF01

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

9310070159 NRC Info Notice 93-082, "Recent Fuel & Core Performance Problems in Operating Reactors."

FROM: GRIMES,B.K. AFFIL: NRRBPO

TO: AFFIL:

ISSUED: 931012 AVAIL: PDR 11pp. DOCUMENT TYPE: TIIEIN FPAC: 9310070159#

TASK: ODID: IEIN-93-082 DIN: DPN: DRN:

DOCKET NO: FICHE: 77289 001 77289 012 RIDS: DF03

9111190139 NRC Info Notice 91-075, "Static Head Corrections Mistakenly Not Included in Pressure Transmitter Calibr Procedures."

FROM: ROSSI,C.E. AFFIL: NRRBTA

TO: AFFIL:

ISSUED: 911125 AVAIL: PDR 3pp. DOCUMENT TYPE: TIIEIN FPAC: 9111190139#

TASK: ODID: IEIN-91-075 DIN: DPN: DRN:

DOCKET NO: FICHE: 59881 112 59881 115 RIDS:

9110210204 Notification of 911022 counterparts meeting w/util in Glen Allen,VA to discuss status of planned mods to CCW sys, DCRDR,resolution of SRV setpoint drift & insp plans & issue & steam generator replacement oversight.Agenda encl.

FROM: BUCKLEY,B.C. AFFIL: NRRBPP2T

TO: BERKOW,H.N. AFFIL: NRRBPP2T

ISSUED: 911011 AVAIL: PDR 4pp. DOCUMENT TYPE: CMMEMO FPAC: 9110210204#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: FICHE: 59433 043 59433 046 RIDS: DF01

U.S. NUCLEAR REGULATORY COMMISSION
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9101220501 LER 90-019-00:on 901218,all six main feedwater flow transmitters found isolated,equalized & drained.Caused by personnel error.Policy re personnel responsible for performing valve manipulation will be reviewed.W/910114 ltr.

FROM: KANSLER,M.R. AFFIL: EUTVEPC

TO: * AFFIL: NIRCTQ

ISSUED: 910114 AVAIL: PDR 5pp. DOCUMENT TYPE: TRLER FPAC: 9101220501#

TASK: ODID: 90-019 DIN: 90-019 DPN: DRN: 00

DOCKET NO: 05000280 FICHE: 56523 321 56523 325 RIDS: IE22

8811040324 Suppl 3 to NRC Info Notice 86-106, "Feedwater Line Break." Svc list encl.

FROM: ROSSI,C.E. AFFIL: NRRBTA

TO: AFFIL:

ISSUED: 881110 AVAIL: PDR 113pp. DOCUMENT TYPE: TIIEIN FPAC: 8811040324#

TASK: ODID: IEIN-86-106 S03DIN: DPN: DRN:

DOCKET NO: FICHE: 47559 072 47559 184 RIDS:

8510230234 Forwards Press Release 84-94 re NRC proposed imposition of civil penalty in amount of $40,000 against util for allegedly assuming that all hydraulic snubbers rebuilt during steam generator replacement projects.

FROM: KAMMERER,C. AFFIL: NRCCA

TO: AFFIL:

ISSUED: 840731 AVAIL: PDR 2pp. DOCUMENT TYPE: CLOUT FPAC: 8510230016A

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000000 FICHE: 33109 100 33109 101 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

8409110367 IE Info Notice 84-73, "Downrating of Self-Aligning Ball Bushings Used in Snubbers." Svc list encl.

FROM: JORDAN,E.L. AFFIL: NIEEM

TO: AFFIL:

ISSUED: 840914 AVAIL: PDR 115pp. DOCUMENT TYPE: TIIEIN FPAC: 8409110367#

TASK: ODID: IEIN-84-73 DIN: DPN: DRN:

DOCKET NO: FICHE: 26653 194 26653 312 RIDS:

8204230447 Expresses appreciation for use of video tape cassette re steam generator replacement project.Portions of tape were used during 811204 Commission briefing.

FROM: O'REILLY,J.P. AFFIL: NIE2D

TO: LEASBURG,R.H. AFFIL: EUTVEPC

ISSUED: 811230 AVAIL: PDR 1p. DOCUMENT TYPE: CLOUT FPAC: 8204230447#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 12817 154 12817 154 RIDS: IE31

8110190371 Forwards notice of proposed issuance of amends to facility OL,approving steam generator replacement program.

FROM: REID,R.W. AFFIL: NOROLOR4

TO: PROFFITT,W.L. AFFIL: EUTVEPC

ISSUED: 771021 AVAIL: PDR 2pp. DOCUMENT TYPE: CLOUT FPAC: 8110190066B

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 10265 265 10265 271 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
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8104300304 IE Insp Repts 50-280/81-07 & 50-281/81-07 on 810302-05.No noncompliance noted.Major areas inspected:steam generator replacement,IE Info Notice 81-04,cracking in main steam & feedwater lines & IE Bulletin 79-13.

FROM: CROWLEY,B.R. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 810317 AVAIL: PDR 7pp. DOCUMENT TYPE: TIINSP FPAC: 8104300300A

TASK: ODID: 50-280/81-07 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 08398 011 08398 017 RIDS:

8103170585 LER 81-001/01T-0:on 810225,w/unit defueled for steam generator replacement,routine testing exam of loop A main steam piping revealed linear indications.Caused by corrosion pitting.Subj areas will be repaired.

FROM: WILSON,J.L. AFFIL: EUTVEPC

TO: * AFFIL: NOIR2

ISSUED: 810311 AVAIL: PDR 3pp. DOCUMENT TYPE: TRLER FPAC: 8103170579A

TASK: ODID: 81-001 DIN: 81-001 DPN: DRN: 0

DOCKET NO: 05000280 FICHE: 07939 245 07939 247 RIDS: A002

8103040814 IE Insp Repts 50-280/80-42 & 50-281/80-46 on 801203-05.No noncompliance noted.Major areas inspected:followup on IE Bulletin 80-11 re masonry wall design & status of const for steam generator replacement.

FROM: LENAHAN,J.J. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 810128 AVAIL: PDR 5pp. DOCUMENT TYPE: TIINSP FPAC: 8103040807A

TASK: ODID: 50-280/80-42 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 07812 166 07812 170 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
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8103040479 PNO-II-81-019:on 810223 & 24,during steam generator replacement outage,ultrasonic insp detected linear defect in base metal on pipe in 30-inch main steam line of steam generators A,B & C.Cause under investigation.

FROM: SHYMLOCK,M. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 810225 AVAIL: PDR 2pp. DOCUMENT TYPE: TIPNOT FPAC: 8103040479#

TASK: ODID: PNO-II-81-019 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 07812 340 07812 341 RIDS: K001

8010090309 PNO-II-80-141:on 800814,unit achieved criticality following extended outage for steam generator replacement.Reactor will remain at low power for 24-h to conduct physics testing.No further action anticipated.

FROM: HARDIN,A.K. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 800815 AVAIL: PDR 1p. DOCUMENT TYPE: TIPNOT FPAC: 8010090309#

TASK: ODID: PNO-II-80-141 DIN: DPN: DRN:

DOCKET NO: 05000281 FICHE: 03627 362 03627 362 RIDS:

8009230013 Motion for stay of effectiveness of Amend 47 to OL, authorizing replacement of steam generators,pending appeal before US Court of Appeals for DC Circuit in which FES is challenged.W/Civil pleadings & excerpts of NUREG-0523.

FROM: DOUGHERTY,J.B. AFFIL: ECIPOTOM

TO: * AFFIL: NRCC

ISSUED: 800918 AVAIL: PDR 111pp. DOCUMENT TYPE: TTPLED FPAC: 8009230013#

TASK: ODID: ISSUANCES OLA DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 06596 088 06596 198 RIDS: DS03

U.S. NUCLEAR REGULATORY COMMISSION
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8007070079 Requests action concerning defective demineralizer design, related corrosion & cracking in steam generators & turbine discs.Commends NRC decision to require EIS re experimental replacement of steam generators.

FROM: ALLEN,J. AFFIL: ECINAEC

TO: BRADFORD,P. AFFIL: NRCC

ISSUED: 800218 AVAIL: PDR 4pp. DOCUMENT TYPE: CLINC FPAC: 8007070059D

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: FICHE: 18385 229 18385 232 RIDS:

8005140076 Summary of ACRS Subcommittee on Surry Nuclear Power Station 800123 meeting in Washington,DC re review of proposed results of steam generator replacement.

FROM: * AFFIL: NACRS

TO: * AFFIL: NACRS

ISSUED: 800414 AVAIL: PDR 22pp. DOCUMENT TYPE: CNMINS FPAC: 8005140076#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 04952 001 04952 022 RIDS:

8005120400 Confirms 800505 telcon re util 800429 ltr delaying steam generator replacement.Replacement will begin in Fall 1980.

FROM: SYLVIA,B.R. AFFIL: EUTVEPC

TO: DENTON,H.R. AFFIL: NRRD

ISSUED: 800509 AVAIL: PDR 1p. DOCUMENT TYPE: CLINC FPAC: 8005120400#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 04907 196 04907 196 RIDS: A001

U.S. NUCLEAR REGULATORY COMMISSION
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8005020159 Notifies NRC of plans to delay steam generator replacement. Facility will be shut down in Sept 1980 for refueling & returned to svc for 18 months before replacing steam generator.

FROM: SYLVIA,B.R. AFFIL: EUTVEPC

TO: DENTON,H.R. AFFIL: NRRD

ISSUED: 800429 AVAIL: PDR 2pp. DOCUMENT TYPE: CLINC FPAC: 8005020159#

TASK: ODID: 374 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 18386 210 18386 211 RIDS: A001

8004220318 Discusses options for disposal of reactor coolant pipe from Unit 1 steam generator replacement.Preferred option is onsite storage.

FROM: SYLVIA,B.R. AFFIL: EUTVEPC

TO: DENTON,H.R. AFFIL: NORD

ISSUED: 800418 AVAIL: PDR 2pp. DOCUMENT TYPE: CLINC FPAC: 8004220318#

TASK: ODID: 311 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 04660 009 04660 010 RIDS: A001

8004150249 Notification of ACRS Subcommittee on Surry Nuclear Station 800123 meeting in Washington,DC to continue review of steam generator replacement program.

FROM: HOYLE,J.C. AFFIL: NRCSEY

TO: AFFIL:

ISSUED: 791220 AVAIL: PDR 3pp. DOCUMENT TYPE: TFFRN FPAC: 8004150249#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: FICHE: 04586 348 04586 350 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
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8002060393 PNO-II-79-048:on 791227,portable heater caught fire in containment area,requiring bldg evacuation.No injuries.Work limited prior to atmospheric testing.Unit shut down for steam generator replacement.

FROM: WEBSTER,R.H. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 791228 AVAIL: PDR 1P. DOCUMENT TYPE: TIPNOT FPAC: 8002060393#

TASK: ODID: PNO-II-79-048 DIN: DPN: DRN:

DOCKET NO: 05000281 FICHE: 01929 350 01929 350 RIDS:

8001040555 Advises that steam generator replacement will be considered complete on 791231 for purpose of progress reporting requirements.Final rept to be issued by 800229.

FROM: STALLINGS,C.M. AFFIL: EUTVEPC

TO: DENTON,H.R. AFFIL: NORD

ISSUED: 800102 AVAIL: PDR 1p. DOCUMENT TYPE: CLINC FPAC: 8001040555#

TASK: ODID: 1183 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 01685 105 01685 105 RIDS: A001

7912050555 IE Insp Rept 50-281/79-77 on 791002-05.No noncompliance noted.Major areas inspected:auxiliary bldg,steam generator replacement & observation of welding.

FROM: KLEINSORGE,W.P. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 791024 AVAIL: PDR 6pp. DOCUMENT TYPE: TIINSP FPAC: 7912050550A

TASK: ODID: 50-281/79-77 DIN: DPN: DRN:

DOCKET NO: 05000281 FICHE: 01503 158 01503 164 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

7911150574 PNS-79-066:on 790627,Wackenhut security ofc received bomb threat re facilities.Security ofc evacuated & searched;no bomb found.Facilities not operating due to steam generator replacement.

FROM: ERVIN,N.E. AFFIL: NOID

TO: AFFIL:

ISSUED: 790627 AVAIL: PDR 1p. DOCUMENT TYPE: TIPNOT FPAC: 7911150574#

TASK: ODID: PNS-79-066 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 01450 349 01450 349 RIDS:

7911070564 Forwards J Dougherty 790418 petition submitted on behalf of intervenors Potomac Alliance,Citizens Energy Forum,VA Sunshine Alliance & Truth in Power.Requests halt to const & replacement of steam generators.W/o encl.

FROM: DENTON,H.R. AFFIL: NORD

TO: PROFFITT,W.L. AFFIL: EUTVEPC

ISSUED: 791024 AVAIL: PDR 2pp. DOCUMENT TYPE: CLOUT FPAC: 7911070564#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 01293 070 01293 071 RIDS:

7911050492 Director's decision under 10CFR2.206,denying requests of citizen groups for suspension of DPR-37 & for preparation of EIS & programmatic EIS addressing environ impacts of steam generator replacement.

FROM: DENTON,H.R. AFFIL: NORD

TO: AFFIL:

ISSUED: 791024 AVAIL: PDR 73pp. DOCUMENT TYPE: TTDEC FPAC: 7911050486A

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 01268 003 01268 078 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

7910090383 Responds to ltr re shutdown of five nuclear power plants. NRC terminated shutdown order for four of five plants after completion of reanalysis & mods to piping sys.One remains shut down for replacement of steam generators.

FROM: DENTON,H.R. AFFIL: NORD

TO: KENNEDY,W.H. AFFIL: ECI*****

ISSUED: 790921 AVAIL: PDR 2pp. DOCUMENT TYPE: CLOUT FPAC: 7910090383#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: FICHE: 01114 111 01114 115 RIDS:

7910020113 IE Insp Repts 50-280/79-41 & 50-281/79-61 on 790717-20.No noncompliance noted.Major areas inspected:feedwater piping insp per IE Bulletin 79-13,steam generator replacement & inservice insp program.

FROM: BLAKE,J.J. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 790817 AVAIL: PDR 4pp. DOCUMENT TYPE: TIINSP FPAC: 7910020098A

TASK: ODID: 50-280/79-41 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 01062 313 01062 316 RIDS:

7909200160 IE Insp Repts 50-280/79-40 & 50-281/79-40 on 790604-0706.No noncompliance noted.Major areas inspected:plant operations & mgt,including steam generator replacement outage work.

FROM: BURKE,D.J. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 790719 AVAIL: PDR 3pp. DOCUMENT TYPE: TIINSP FPAC: 7909200155A

TASK: ODID: 50-280/79-40 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 00975 003 00975 005 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

7909170437 Discusses insp & replacement of HEPA filters re steam generator replacement project.Requests concurrence in changing frequency of filter replacement from monthly to quarterly to provide better data for surveillance program.

FROM: STALLINGS,C.M. AFFIL: EUTVEPC

TO: DENTON,H.R. AFFIL: NORD

ISSUED: 790913 AVAIL: PDR 1p. DOCUMENT TYPE: CLINC FPAC: 7909170437#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 00956 300 00956 300 RIDS: A001

7908280182 IE Insp Rept 50-281/79-36 on 790417-20.No noncompliance noted.Major areas inspected:licensee work plans & progress of steam generator replacement.

FROM: SANDERS,W.F. AFFIL: NOIR1

TO: AFFIL:

ISSUED: 790620 AVAIL: PDR 3pp. DOCUMENT TYPE: TIINSP FPAC: 7908280174A

TASK: ODID: 50-281/79-36 DIN: DPN: DRN:

DOCKET NO: 05000281 FICHE: 15078 154 15078 156 RIDS:

7908240151 IE Insp Rept 50-281/79-41 on 790529-0601.No noncompliance noted.Major areas inspected:steam generator replacement, welding & associated activities & nondestructive examinations.

FROM: KLEINSORGE,W.P. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 790626 AVAIL: PDR 6pp. DOCUMENT TYPE: TIINSP FPAC: 7908240147A

TASK: ODID: 50-281/79-41 DIN: DPN: DRN:

DOCKET NO: 05000281 FICHE: 00780 125 00780 130 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

7908230691 IE Insp Rept 50-281/79-39 on 790619-22.No noncompliance noted.Major areas inspected:steam generator replacement program QA audits,control of nonconformance repts & welding activities.

FROM: GOUGE,M.J. AFFIL: NOIR2C

TO: AFFIL:

ISSUED: 790706 AVAIL: PDR 4pp. DOCUMENT TYPE: TIINSP FPAC: 7908230688A

TASK: ODID: 50-281/79-39 DIN: DPN: DRN:

DOCKET NO: 05000281 FICHE: 00795 356 00795 359 RIDS:

7908150533 IE Insp Repts 50-280/79-31 & 50-281/79-49 on 790430-0601.No noncompliance noted.Major areas inspected:plant operations & maint,including Unit 2 steam generator replacement outage work,& followup on previously identified items.

FROM: BURKE,D.J. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 790626 AVAIL: PDR 4pp. DOCUMENT TYPE: TIINSP FPAC: 7908150528A

TASK: ODID: 50-280/79-31 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 00678 304 00678 307 RIDS:

7907230724 IE Insp Repts 50-280/79-16 & 50-281/79-24 on 790327-30.No noncompliance noted.Major areas inspected: reactor coolant pipe decontamination & radiation protection aspects of steam generator replacement project.

FROM: EWALD,S.C. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 790515 AVAIL: PDR 5pp. DOCUMENT TYPE: TIINSP FPAC: 7907230708A

TASK: ODID: 50-280/79-16 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 00359 216 00359 220 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

7907200290 IE Insp Rept 50-281/79-30 on 790418-20.No noncompliance noted.Major areas inspected:removal activities,welding operations & welding procedures for steam generator replacement.

FROM: ERB,C.M. AFFIL: NOIR2C

TO: AFFIL:

ISSUED: 790508 AVAIL: PDR 3pp. DOCUMENT TYPE: TIINSP FPAC: 7907200278A

TASK: ODID: 50-281/79-30 DIN: DPN: DRN:

DOCKET NO: 05000281 FICHE: 00411 253 00411 255 RIDS:

7906260603 IE Insp Rept 50-281/79-23 on 790402-05.No noncompliance noted.Major area inspected:steam generator replacement welding activities.

FROM: CROWLEY,B.R. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 790425 AVAIL: PDR 5pp. DOCUMENT TYPE: TIINSP FPAC: 7906260599A

TASK: ODID: 50-281/79-23 DIN: DPN: DRN:

DOCKET NO: 05000281 FICHE: 15078 181 15078 185 RIDS:

7906260201 IE Insp Rept 50-281/79-22 on 790402-05.No noncompliance noted.Major areas inspected:const status re steam generator replacement.

FROM: HERDT,A.R. AFFIL: NOIR2C

TO: AFFIL:

ISSUED: 790423 AVAIL: PDR 4pp. DOCUMENT TYPE: TIINSP FPAC: 7906260197A

TASK: ODID: 50-281/79-22 DIN: DPN: DRN:

DOCKET NO: 05000281 FICHE: 15078 188 15078 191 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

7906050318 Requests amend to OL in form of proposed Tech Spec Change 78.Forwards required LOCA-ECCS analysis results supporting full-rated power operation after replacement of steam generators.

FROM: STALLINGS,C.M. AFFIL: EUTVEPC

TO: SCHWENCER,A. AFFIL: NOROSR1

ISSUED: 790531 AVAIL: PDR 46pp. DOCUMENT TYPE: CLINC FPAC: 7906050318#

TASK: ODID: 388 DIN: DPN: DRN:

DOCKET NO: 05000281 FICHE: 15078 264 15078 308 RIDS: A001

7905240199 Requests reconsideration of issuance of license Amends 46 & 47 for replacement of steam generators.Also requests public hearing & EIS.

FROM: BERICK,D. AFFIL: EPSEPI

TO: HENDRIE,J. AFFIL: NRCC

ISSUED: 790220 AVAIL: PDR 2pp. DOCUMENT TYPE: CLINC FPAC: 7905240189A

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: * * * * RIDS:

7905240189 Forwards 790220 ltr requesting NRC to conduct hearing & prepare EIS on proposed replacement of steam generators. Related Fr notice encl.

FROM: DENTON,H.R. AFFIL: NORD

TO: PROFFITT,W.L. AFFIL: EUTVEPC

ISSUED: 790404 AVAIL: PDR 2pp. DOCUMENT TYPE: CLOUT FPAC: 7905240189*

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: * * * * RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

7905070118 IE Insp Rept 50-281/79-11 on 790213-16.No noncompliance noted.Major area inspected:steam generator replacement.

FROM: WILCOX,J.D. AFFIL: NOIR2C

TO: AFFIL:

ISSUED: 790314 AVAIL: PDR 3pp. DOCUMENT TYPE: TIINSP FPAC: 7905070115A

TASK: ODID: 50-281/79-11 DIN: DPN: DRN:

DOCKET NO: 05000281 FICHE: * * * * RIDS:

7905040380 Notifies that steam generator replacement program initial progress rept for 790203-0331 is being prepared.Reporting period should cover two months rather than 60 days.

FROM: STALLINGS,C.M. AFFIL: EUTVEPC

TO: DANTON,H.R. AFFIL: NORD

ISSUED: 790502 AVAIL: PDR 1p. DOCUMENT TYPE: CLINC FPAC: 7905040380#

TASK: ODID: 323 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: * * * * RIDS: A001

7905020019 IE Insp Repts 50-280/79-02 & 50-281/79-02 on 790102-0202.No noncompliance noted.Major areas inspected:plant physical barriers & preparations for steam generator replacement.

FROM: BURKE,D.J. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 790312 AVAIL: PDR 9pp. DOCUMENT TYPE: TIINSP FPAC: 7905020012A

TASK: ODID: 50-280/79-02 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: * * * * RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

7904190283 Requests NRC reconsider issuance of Amend 46 & 47 to Licenses DPR-32 & DPR-37,convene public hearing re replacement of steam generators & review negative declaration.

FROM: BERICK,D. AFFIL: EPSEPI

TO: HENDRIE,J.M. AFFIL: NRCC

ISSUED: 790220 AVAIL: PDR 2pp. DOCUMENT TYPE: CLINC FPAC: 7904190261B

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: * * * * RIDS:

7904130176 Requests action re accident during replacement of steam generator.Suggests suspension of further work until public hearings are held & EIS issued.

FROM: POLLARD,R. AFFIL: ECICEA

TO: HENDRIE,J.M. AFFIL: NRCC

ISSUED: 790221 AVAIL: PDR 1p. DOCUMENT TYPE: CLINC FPAC: 7904130175A

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 15247 028 15247 028 RIDS:

7903280075 IE Insp Repts 50-280/79-04 & 50-281/79-04 on 790115-19.No noncompliance noted.Major areas inspected:steam generator replacement.

FROM: WILCOX,J.D. AFFIL: NOIR2

TO: AFFIL:

ISSUED: 790213 AVAIL: PDR 3pp. DOCUMENT TYPE: TIINSP FPAC: 7903280074A

TASK: ODID: 50-280/79-04 DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 15087 252 15087 254 RIDS:

U.S. NUCLEAR REGULATORY COMMISSION
NUDOCS PARTIAL RECORD FORMAT REPORT

7902260597 Forwards citizen 781229 request for NRC to conduct hearing & prepare EIS on proposed replacement of steam generators.

FROM: DENTON,H.R. AFFIL: NORD

TO: PROFFITT,W.L. AFFIL: EUTVEPC

ISSUED: 790201 AVAIL: PDR 2pp. DOCUMENT TYPE: CLOUT FPAC: 7902260597*

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 27762 019 27762 023 RIDS:

7902120213 Forwards 781229 ltr from North Anna Environ Coalition to NRC,requesting EIS before steam generator replacement. Supports request & urges public hearing on issue.

FROM: * AFFIL: ECITIP

TO: * AFFIL: NRCSEY

ISSUED: 790124 AVAIL: PDR 3pp. DOCUMENT TYPE: CLINC FPAC: 7902120213#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 03099 358 03099 360 RIDS:

7901110333 Requests thorough EIS on VEPCO's proposed steam generator replacement & asks Commission to hold public hearing requiring VEPCO to show cause why hazardous procedure should be allowed.

FROM: ALLEN,J. AFFIL: ECINAEC

TO: * AFFIL: NRCSEY

ISSUED: 781229 AVAIL: PDR 2pp. DOCUMENT TYPE: CLINC FPAC: 7901110333#

TASK: ODID: DIN: DPN: DRN:

DOCKET NO: 05000280 FICHE: 15247 055 15247 058 RIDS:

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

OCT 0 5 1978

MEMORANDUM FOR: A. Schwencer, Chief, Operating Reactors Branch No. 1
Division of Operating Reactors

FROM: V. S. Noonan, Chief, Engineering Branch
Division of Operating Reactors

SUBJECT: SURRY UNITS 1 AND 2 - STEAM GENERATOR REPAIR PROGRAM (TAC 7108)

Plant Name: Virginia Electric and Power Company - Surry Units 1 and 2
NSSS Vendor: Westinghouse
Docket Numbers: 50-280 and 281
Operating Reactors Branch and Project Manager: ORB-1, D. Neighbors
Description of Task: Review of Steam Generator Repair Program
Review Status: Complete

The Engineering Branch, Division of Operating Reactors, has reviewed Virginia Electric and Power Company's proposed steam generator repair program for Surry Units 1 and 2. The document reviewed was entitled, "Steam Generator Repair Program, Surry Power Station Unit Nos. 1 and 2" including Revisions 1 thru 6.

We have concluded that the repair program is acceptable. Our input to the overall safety evaluation report is attached.

Vincent S. Noonan, Chief
Engineering Branch
Division of Operating Reactors

Enclosure: As stated

Contact: R. LaGrange
49-28060

cc: See page 2

7810180058

cc: V. Stello
B. Grimes
D. Eisenhut
J. P. Knight
B. D. Liaw
F. Almeter
J. Strosnider
W. Russell
D. Neighbors
R. LaGrange

OCT 0 5 1978

SURRY UNITS 1 & 2
STEAM GENERATOR REPAIR PROGRAM

SAFETY EVALUATION REPORT

ENGINEERING BRANCH
DIVISION OF OPERATING REACTORS

INTRODUCTION

History of Steam Generator Operation

Surry Units 1 and 2 began commercial operation on December 22, 1972, and May 1, 1973, respectively. Like almost all units with U-tube design steam generators, they began operation utilizing a sodium phosphate secondary water chemistry treatment. This treatment was designed to remove precipitated or suspended solids by blowdown and was successful as a scale inhibitor. However, during early use many PWR U-tubed steam generators with Inconel 600 tubing experienced stress corrosion cracking. The cracking was attributed to free caustic which can be formed when the Na/PO_4 ratio exceeds the recommended limit of 2.6. In addition, some of the insoluble metallic phosphates, formed by the reaction of sodium phosphates with the dissolved solids in the feedwater, were not adequately removed by blowdown. These precipitated phosphates tended to accumulate as sludge on the tubesheet and tube supports at the central portion of the tube bundle where restricted water flow and high heat flux occurs. Phosphate concentration (hideout) at crevices in areas of the steam generator, noted above, caused localized wastage resulting in thinning of the tube wall. The problem of stress corrosion cracking was corrected by maintaining the Na/PO_4 ratio between 2.6 and 2.3. Although the recommended Na/PO_4 ratio was maintained, it did not correct the phosphate hideout problem that caused wastage of the Inconel-600. Largely to correct the wastage and caustic stress corrosion cracking encountered with the phosphate treatment, most PWRs with a U-tube design steam generator using a phosphate treatment for the secondary coolant have now converted to an all volatile chemistry (AVT). Both Surry 1 and 2 were converted around January, 1975.

In 1975, radial deformation, or the so-called "denting", of steam generator tubes occurred in several PWR facilities including Surry 1 and 2, after 4 to 14 months operation, following the conversion from a sodium phosphate treatment to an AVT chemistry for the steam generator secondary coolant. Tube denting occurs predominantly in rigid regions or so-called "hard spots" in the tube support plates. These hard spots are located in the tube lanes between the six rectangular flow slots in the support plates near the center of the tube bundle and around the peripherial locations of the support plate where the plate is wedged to the wrapper and shell. The hard sport areas do not contain the array of water circulation holes found elsewhere in the support plates.

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The phenomenon of denting has been attributed to the accelerated corrosion of the carbon steel support plates at the tube/tube support plate intersections (annuli). The corrosion product (magnetite) from the carbon steel plate occupies approximately twice the volume of the material corroded. Thus, the continuing corrosion exerts sufficient compressive forces to diametrically deform the tube and crack the tube support plate ligaments between the tube holes and water circulation holes. As a result of the tube support plate deformation, the rectangular flow slots began to "hourglass;" i.e., the central portion of the parallel flow slot walls have moved closer so that some of flow slots are closed or narrower in the center than at the ends.

On September 15, 1976, during noraml operation, one U-tube in the innermost row parallel to the rectangular flow slots in steam generator A at Surry Unit No. 2 rapidly developed a substantial primary to secondary leak (about 80 gpm). After removal of the damaged tube and subsequent laboratory analysis, it was established that the leak resulted from an axial crack, approximately 4-1/4 inches in length, in the U-bend apex due to intergranular stress corrosion cracking that initiated from the primary side. Since the initial parallel flow slot wall in the top support plate has moved closer, the support plate material around the tubes nearest this central portion of these flow slots has also moved inward, in turn forcing an inward displacement of the legs of the U-bends at these locations. This inward movement of the legs of the U-bends at these locations caused increase in the hoop strain and ovality of the tubes at the U-bend apex. It is this additional increase in strain at the apex of the U-bend which is believed to be required to initiate stress corrosion cracking of the Inconel 600 alloy tubing exposed to PWR primary coolant.

Subsequent to the 80 gpm leak at Surry Unit 2, the NRC has imposed augmented inservice inspection requirements on Surry Units 1 and 2, Turkey Point Units 3 and 4, San Onofre Unit 1 and Indian Point Unit 2. In addition, operating restrictions and limited periods of operation, typically six months, between inspections are also imposed on severly degraded units, i.e., Surry Units 1 and 2 and Turkey Point Units 3 and 4. The augmented inspection requirements include an assessment of the magnitude and progression of tube denting, and support plate deformation and/or cracking.

Reasons for Steam Generator Replacement

The six steam generators at Surry Units 1 and 2 have all undergone a significant amount of degradation since they began operation. The wastage and denting phenomena, discussed earlier, have led to tube wall thinning, support plate flow slot hourglassing and plate ligament cracking, tube denting, stress corrosion cracking, and several instances of primary to secondary leakage through cracked tubes. As of September, 1978, tube plugging for various

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reasons has resulted in removing 21.4% of the steam generator tubes in Unit 1 and 21.5% of the tubes in Unit 2 from continuing service.

Due to the continuing denting related problems, the certainty of additional tube plugging that may result in power de-rating, and the economic considerations for operating with substantially reduced heat transfer capacities on the two units, Virginia Electric and Power Company (VEPCO) submitted a proposal for the replacement of the degraded portions of the steam generators.

DESCRIPTION OF REPLACEMENT STEAM GENERATORS

Mechanical Design and Materials Changes

During 1975 several modifications were made to the exisiting steam generators to increase the circulation ratio. The modifications consisted of removing the downcomer resistance plate, improving the moisture separators, modifying the blowdown arrangement inside the steam generators, installing tube lane blocking devices, and modifying the feedring. These modifications will be retained or improved upon in the replacement steam generators. Also, additional modifications, as discussed below, will be incorporated into the replacements.

A flow distribution baffle plate, located 18" above the tubesheet, will be used in the replacement generators. The baffle plate is designed to assist and direct the lateral flow across the tubesheet surface, minimize the number of tubes exposed to sludge, and cause the sludge to deposit near the center of the tube bundle at the blowdown intake.

An improved blowdown system is to be incorporated in the replacement steam generators. The new system will increase blowdown capacity and utilize two 2-inch Schedule 40 Inconel internal blowdown pipes. The blowdown intake location is coordinated with the baffle plate design so that the maximum intake is located where the greatest amount of sludge is expected to deposit.

Unlike the existing design, the replacement generators will have all the tubes expanded to the full depth of the tubesheet to eliminate the potential contaminant concentration sites.

The tube support plate material will be changed from carbon steel to SA-240 Type 405 ferritic stainless steel. The baffle plate discussed earlier will also be constructed of SA-240 Type 405. The licensee states that this material is much more corrosion resistant in the chemistry expected during operation of the steam generator than is the currently utilized carbon steel. Corrosion of SA-240 will result in an oxide which occupies approximately the same volume as the parent material, whereas corrosion of carbon steel results in oxides which have approximately twice the volume of the parent material.

The tube support plates in the replacement steam generators will be the new quatrefoil design. The quatrefoil design, consisting of four flow lobes and four support lands, provides support to the tube while allowing water flow around it. This design has a lower pressure drop across the thickness of the plate than the existing drilled circulation hole design and results in higher average flow velocities along the tubes, which should prevent sludge desposition.

The tubes in the replacement generators will be recessed slightly into the tubesheet holes and then welded to the tubesheet cladding. This design reduces entry pressure losses and eliminates locations for possible crud buildup.

Since the circulation ratio will be greater in the replacement generators, modifications to the moisture separator equipment will be made to accomodate this increase.

The new lower shell assemblies will have additional access ports that will improve access for the inspection of the tubesheet and flow distribution baffle, and assist in slude lancing. A 2-inch nozzle is being added to the upper shell to facilitate the wet layup of the steam generators during periods of inactivity. This nozzle can be used for addition of chemicals to maintain water quality. To lessen downtime and facilitate maintenance and inspection, a 3/8-inch primary shell drain is included in the channel head of the replacement generators to improve a drainage of the channel head. The replacement steam generators will also have closure rings welded inside the channel head at the base of each primary nozzle so that closure plates can be installed during primary chamber maintenance.

Heat Treatment of Tubing

The Inconel 600 tubing used in the replacement steam generators will be thermally treated to reduce residual stresses imparted by tube processing, thereby improving its resistance to stress corrosion. Several benefits are expected to result from this heat treatment such as improved resistance in stress corrosion cracking in NaOH, resistance to intergranular attack in oxygenated environments, and resistance to intergranular attack in sulphur-containing species. The thermal treatment will be within a time-temperature band to avoid formation of a chromium depleted grain boundary layer (sensitization).

ASME Code and Regulatory Guide Implementation

All new component parts of the replacement steam generators will be designed and fabricated to the 1974 edition of the ASME Boiler and Pressure Vessel Code, including all addenda through Winter, 1976. Additionally all piping weld end preps, welding, and nondestructive examination will be in accordance with the applicable sections of the latest edition of the ASME Code. Also, applicable Regulatory Guides will be utilized.

EVALUATION

Effects of Steam Generator Design Changes

Several design changes, as discussed above, will be incorporated in the replacement steam generators. Our evaluation of these changes is given below.

We concur that a flow distribution baffle plate should minimize or at least reduce, the number of tubes exposed to sludge, and cause the sludge to deposit near the blowdown intake. Use of this baffle plate, in conjunction with the increased blowdown capacity, will reduce the potential for tube wastage since fewer tubes will be exposed to less sludge.

Full depth expansion of the tubes in the tubesheet is an improvement over the exisiting partially expanded arrangement and will prevent both crevice boiling and buildup of impurites in the tube to tubesheet crevice region.

A quatrefoil support plate design will be utilized in the replacement steam generators. In contrast, the existing steam generators use drilled hole support plates which have a very limited opening between the tube and tube support plate. The majority of flow in this drilled plate design is through the circulation holes. The tube denting phenomenon, discussed earlier, has occurred when corrosion products (magnetite) have built up in the tube/tube support plate intersections (annuli) to the extent that the gap between the tube and support plate closes completely. The broached or quatrefoil design has no circulation holes and permits substantial flow and much higher flow velocity through the large open spaces. This results in a continuous flushing and scouring action, thus tending to wash out this area and prevent the development of a concentration mechanism for sludge deposits or scales in this area. Additionally, the open areas provide substantial space for tube support plate metal to expand into without exerting major compressive forces on the tubes, even if one assumes that there will continue to be substantial magnetite growth which, as noted below, is rendered insignificant by the use of stainless steel for tube support plates rather than carbon steel.

The quatrefoil support plate design has led to some tube degradation, in the form of a type of erosion cavitation mechanism, in once-through steam generators. Although the licensee has suggested that this will not be a problem in recirculating designs, the staff feels that the phenomenon is not well understood to assume that recirculating type designs will not see this type of degradation. Despite this reservation and for the reasons discussed above with regard to tube denting, we concur that the quatrefoil support plate design is an improvement over the existing drilled hole arrangement and should be less prone to denting.

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The replacement steam generators will use SA-240 Type 405 ferritic stainless steel for both the tube support plates and flow distribution baffle plate. The corrosion data provided indicate that, under the test conditions, Type 405 stainless steel will be a greatly improved material for tube support plates over the carbon steel presently used. In the event that denting reactions be initiated, the staff would have some concern over the propensity of this material for stress corrosion cracking in a chloride environment. However, the licensee appears to have taken the proper precautions in stress relieving it to minimize the likelihood that stress corrosion will occur.

The Inconel 600 tubing will be thermally treated, which should result in improvement in its resistance to stress corrosion cracking in the primary coolant and secondary water, particularly in the U-bend regions. We find this residual stress relieving process to be satisfactory and an improvement over existing practice.

We have also evaluated the licensee's response to a question regarding fatigue and wear of steam generator tubes that could possibly result from flow induced vibration. Conservative calculations show that the maximum value of the alternating stress is well below the endurance limit for the tube material, even if clearances between tubes and support plates are assumed to increase due to mechanical wear. Additionally, average values of wear coefficients for the new support plate material, type 405 stainless steel, are much lower than average values for the old, carbon steel, support plate material. Therefore, we concur that support plate wear and tube fatigue should not be a problem in the new steam generators.

The use of "J-tubes" in the replacement steam generators and the possibility of fatigue problems resulting from flow induced vibration has been addressed by the applicant. J-tubes are very stiff and, therefore, have a very high fundamental frequency relative to frequencies of any concern in a seismic or vibrational analysis. The J-tubes meet the ASME Code fatigue requirements. Also, fatigue failures of J-tubes in operating units have never been encountered. We find the use of J-tubes in the replacement steam generators to be acceptable.

CONCLUSION

Based on the information discussed and the evaluation made above, we conclude that the licensee's proposed steam generator replacement program is acceptable and there is reasonable assurance that the health and safety of the public will not be endangered during the execution of the program or following its completion. We further conclude that the new steam generator design has incorporated features to eliminate the potential for various forms of tube degradation observed to date.

OCT 21 1978

MEMORANDUM FOR: A. Schwencer, Chief, Operating Reactors Branch #1, Division of Operating Reactors

FROM: D. Eisenhut, Assistant Director, Systems & Projects, Division of Operating Reactors

SUBJECT: DRAFT SAFETY EVALUATION OF STEAM GENERATOR REPLACEMENT PROGRAM AT SURRY UNITS 1 & 2

Plant Name: Surry Units 1 & 2
Docket No.: 50-280
Responsible Branch: ORB #1
Project Manager: D. Neighbors
Reviewing Branch: Plant Systems Branch
Status: Complete

Enclosed is the Plant Systems Branch input to the Safety Evaluation Report for the replacement of steam generators at Surry Power Station Units 1 and 2.

Our review covered the following areas: Quality assurance, Fire Protection, measures to protect safety-related structures, systems and components and procedures for restoration and startup of the repaired unit. We have found that the licensee's program provides adequate measures in these areas for the safe execution of the planned steam generator repairs.

D. G. Eisenhut, Assistant Director
Systems and Projects
Division of Operating Reactors

Enclosure:
As stated

Contact: S. MacKay
X28077

cc w/enclosure
D. Eisenhut
G. Lainas
B. Buckley
Sm MacKay
D. Neighbors
D. Tondi
R. Ferguson
R. Colmar
S. Rhow
M. Virgilio
E. Sylvester

OFFICE	DOR:PSB	DOR:SL/PSB	DOR:C/PSB	SL/PSB:DOR	SL/PSB:DOR	DOR:AD/S&P
SURNAME	SMacKay LL	BBuckley	GLainas	DTondi	RFerguson	DEisenhut
DATE	10/10/78	10/10/78	10/19/78	10/ /78	10/17/78	10/ /78

NRC FORM 318 (9-76) NRCM 0240

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MEMORANDUM FOR: A. Schwencer, Chief, Operating Reactors Branch No. 1, DOR

FROM: G. Knighton, Chief, Environmental Evaluation Branch, DOR

SUBJECT: SURRY - STEAM GENERATOR REPAIR PROJECT - LICENSE CONDITION CHANGE (TAC 12114)

PLANT NAME: Surry Power Station Units No. 1 and 2
DOCKET NOS:: 50-280, -281
RESPONSIBLE BRANCH: ORB #1
PROJECT MANAGER: D. Neighbors
REVIEW STATUS: EEB - Complete

By letter dated August 31, 1979, the Virginia Electric and Power Company (the licensee) requested a change to a license condition which applies to the steam generator replacement project for both units. The current license condition requires the use of temporary containment and ventilation systems for certain cutting and grinding operations. The licensee proposes to amend this requirement such that temporary containment systems will be used based on ALARA considerations as determined by the Health Physics Coordinator. The reason for the proposed change is that experience gained during the replacement project for Unit 2 showed that, in some cases, the installation and removal of temporary containment systems resulted in more personnel radiation exposure from direct radiation sources than they saved by minimizing the spread of loose surface contamination.

We have reviewed the licensee's request and based upon discussions with Surry personnel during site visits and their submittal, we find the proposed change acceptable. A safety evaluation supporting the proposed change is attached.

(s) L. Barrett for

George W. Knighton, Chief
Environmental Evaluation Branch
Division of Operating Reactors

Enclosure:
As stated

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EEB Reading
NRR Reading
G. Knighton
L. Barrett
G. Cwalina

cc: D. Eisenhut, J. Miller, W. Gammill, D. Neighbors, W. Kreger, D. Collins, T. Murphy, J. Minns, M. Grotenhuis, H. Silver, W. Pasedag, Section B/EEB

7912130147

OFFICE	Contact: G. Cwalina, EEB/DOR		EEB/DOR	EEB/DOR	EEB/DOR	Act.D/S&S/DOR
SURNAME	28066		GCwalina/vg	LBarrett	GKnighton	Miller
DATE			11/14/79	11/15/79	11/ /79	11/ /79

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

Enclosure No. 1

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION SUPPORTING AMENDMENT NO. TO LICENSE NO.

VIRGINIA ELECTRIC AND POWER COMPANY

SURRY POWER STATION UNITS 1 AND 2

DOCKET NOS. 50-280, -281

Introduction

By letter dated August 31, 1979, the Virginia Electric and Power Company (the licensee) requested a change to License Condition 3.6.2.b. for the Surry Station steam generator replacement project. The current license condition requires the use of temporary containment and ventilation systems whenever cutting and grinding operations involving components with removable radioactive contamination > 2200 DPM/100 cm^2 are being performed. The change requested would allow the Health Physics Coordinator to determine the need for these systems on a case-by-case basis.

Discussion

The purpose of the original license was to protect the workers and the environment from airborne contaminants released as a result of cutting and grinding operations.

It has been determined, however, that the installation of temporary containment systems can result in a higher occupational radiation exposure to personnel when compared to direct operations without the use of the temporary containments. This can occur because the radiation exposures received by personnel installing and removing the temporary containments may exceed the exposures caused by the spread of radioactive contamination especially for operations involving low contamination level components in relatively high direct radiation fields. In addition, samples taken during cutting operations has shown that airborne activity generated tended to be localized to the extent that only those workers performing the operation would be exposed to the contaminants. Adequate protection could be provided by use of respiratory equipment. This technique would allow for protection from airborne contamination while subsequently reducing exposures caused by the installation of temporary systems. The proposed change will provide further assurance that occupational exposures will be maintained As Low As Reasonably Achievable (ALARA).

We have reviewed the licensee's submittal and the basis for the proposed change. In addition, we have discussed the submittal with the licensee and OIE inspectors during site visits. Based on our review and discussions, we find the licensee's proposal acceptable.

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Conclusion

We have concluded based on the above considerations that the proposed change to license condition 3.6.2.b. is acceptable.

We also conclude that: (1) because the amendment does not involve a significant increase in the probability or consequences of accidents previously considered, and does not involve a significant decrease in a safety margin, the amendment does not involve a significant hazards consideration; (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner; and (3) such activities will be conducted in compliance with the Commission's regulations and the issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public.

2129 215

MAR 11 1980

MEMORANDUM FOR: William Regan, Chief, Environmental Projects Branch, DSE

FROM: George W. Knighton, Chief, Environmental Evaluation Branch, DOR

SUBJECT: SURRY STEAM GENERATOR EIS INPUT

Attached is a copy of EEB's input to the Surry Steam Generator Replacement EIS. This input was given informally to Phil Cota of your branch on March 7, 1980, as promised.

Sincerely,

Original signed by
George W. Knighton

George W. Knighton, Chief
Environmental Evaluation Branch
Division of Operating Reactors

Attachments:
As stated

cc: D. Eisenhut
P. Cota
J. Miller
D. Neighbors
R. Vollmer
T. Murphy

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DATE	3/11/80					

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INSERT A

The replacement of the 3 generators in Surry Unit 2 was completed in 37 weeks in 1979. The total occupational dose received by workers at Surry Unit 2 during the replacement was 2140 man-rem. The dose rates at Surry Unit 1 are 30-40% higher than at Unit 2. However, VEPCO believes that their experience from completing the Unit 2 replacement will allow them to do a more effective job of maintaining exposures ALARA on Unit 1. Therefore, VEPCO believes that their original estimate of 2070 man-rem per unit is reasonable for Unit 1. We followed the work at Unit 2 closely and we agree that 2070 man-rem is a reasonable estimate for Unit 1.

INSERT B

In the most recent environmental statements for new nuclear power plants, we have provided an estimate of 500 man-rem per reactor unit as the average annual occupational dose. This average is ~~explained to be~~ an average over the life of the plant (30-40 years). This estimate is based on reported data from operating power reactors; a summary of that data is provided in Table 4.2. That data shows that 500 man-rem per reactor unit per year is roughly the average of the wide range of doses incurred at all light water cooled reactor units over the last several years. The amount of dose incurred at any single reactor unit in a year is highly dependent on the amount of major maintenance which becomes necessary that year. Every year several units perform some items of major maintenance which result in doses well above the average of 500 man-rem/y. These doses are included in the average and we do not consider them to be significant deviations from the average. Simply put, steam generator replacement is major maintenance which will result in an annual dose for the unit above the average. However, as Table 4.2 shows the 2070 man-rem is within the usual range of doses about the average for one unit in a year. Therefore, we conclude that the occupational dose (2070 man-rem) associated with replacement of the steam generators at each Surry unit ~~represents~~ results in an insignificant and acceptable environmental impact.

Table 4.2

Occupational Dose at U.S. Light

Water Reactors (man-rem per reactor unit)

Year	Average	Low	High
1975	475	21	2022
1976	499	74	2648
1977	570	87	3142
1978	437	158	1621

INSERT C

The average annual dose to an individual due to natural background radiation in the United Stated is roughly 0.1 rem. However, there are very broad (local) variations in the average dose due to a number of factors such as altitude (above sea-level and geologic formations. As altitude increases, the dose rate from cosmic radiation (radiation from space) increases. Because Denver, Colorado is at a much high altitude than Washington, D. C., the average natural background dose in Denver is roughly 0.08 rem per year larger than in Washington. ~~We~~ Multiplying 0.08 rem per year times 50 years (a conservative estimate of average lifespan) ~~to~~ calculates that an individual would receive 4 rem more dose from a lifetime of exposure to natural background radiation in Denver than he would receive in Washington. The estimated dose of ~~4140~~ 2070 man-rem ~~for both units~~ will be spread over at least ~~2000~~ 1200 workers over a two year period ~~(probably between 2500 and 3500 workers)~~. Therefore, the average dose to a worker for this project will be roughly 2 rem half of the variation in natural background radiation described above. space – space

In a different view, 2000 people living in Denver would receive 8000 more man-rem from a lifetime of exposure to natural background than 2000 people living in Washington. Clearly the people of Denver consider their exposure to natural background radiation to be acceptable, if they did not, they would all move away from Denver. Taking this argument a step farther, ~~we~~ it is noted that practically no one would even consider the increase in dose as a negative factor in his decision to move from Washington to Denver. Therefore, we conclude that based on a comparision with dose due to natural background radiation the estimated dose for the steam generator replacement represents an insignificant and acceptable impact.

Optional

INSERT D

We calculate that 4140 man-rem, the occupational dose estimate to replace the steam generators at both units, corresponds to a risk of less than one premature fatal cancer. We also calculate that 4140 man-rem corresponds to a risk of one genetic effect to the ensuing five generations. These risks are based on risk estimators derived in the BEIR report[14] from data for the population as a whole. For a selected population such as is likely for the exposed workers involved in the repair program consisting mainly of males in age range from 20 to 40, these risks would tend to be somewhat less. These risks are incremental risks, risks in addition to the normal risks of cancer and genetic effects we all face continuously. For a population of 2000 these normal risks would result in roughly 300 cancer deaths and 120 genetic effects (genetic effects are genetic diseases or malformations).

The environmental impact created by these releases are less than those stated in the Surry FES?

INSERT E

As state above, steam generator replacement at Surry Unit 2 was completed in 1979. Table 4.3 shows the actual releases for Unit 2. As expected all of the releases were ~~much~~ lower than they would have been during [illegible] normal operation. ~~with the exception of particulates. The particulate releases were in the same range as normal particulate releases.~~ Iodine releases were much lower than estimated; the overestimate is of no concern as both the estimated and measured releases are many times lower than normal releases. While no release estimate was made for noble gases, we and VEPCO fully expected minimal releases of noble gas during refueling. The Unit 2 release of 100 curies of noble gases is consistent with our expectations and many times lower than normal releases. Therefore, the release estimates have not been changed in light of the Unit 2 measurements.

INSERT F

Steam generator replacement operations at Unit 2 generated 1600 cubic meter of waste containing 64 curies of radioactivity. Both the volume and radioactive content of the solid radioactive waste generated ~~were of the same order of magnitude as~~ are comparable to our estimates.

ENVIRONMENTAL IMPACT APPRAISAL

BY THE OFFICE OF NUCLEAR REACTOR REGULATION

LICENSE NOS. DPR-32 AND DPR-37

VIRGINIA ELECTRIC AND POWER COMPANY

SURRY POWER STATION, UNITS 1 AND 2

DOCKET NOS. 50-280 AND 50-281

STEAM GENERATOR REPAIR AT SURRY POWER STATION

1.0 Proposed Action

Virginia Electric and Power Company (VEPCO) proposes to repair the six degraded steam generators in Units 1 and 2 of the Surry Power Station by replacing the lower assembly of each steam generator.

2.0 Background

2.1 History of Tube Degradation in Steam Generators

Since the Surry Units began generating power in 1972 and 1973, they have experienced a history of excessive tube degradation in the steam generators, resulting in the present condition in which approximately 24% of the tubes in Unit 1 and about 21% of the tubes in Unit 2 have been plugged to prevent the transfer of radioactivity from the primary coolant to the steam system.

The tube degradation is ascribed to a corrosion-related phenomenon called "denting," which involves the buildup of corrosion products in the crevices between the Inconel-600 heat exchanger tubes and the carbon steel tube support plates. As the corrosion product volume expands, the tubes are "dented," and occasionally develop leaks. The plugging of the damaged steam generator tubes affects the thermal and hydraulic performance of the steam generators. The degradation and resultant plugging of the tubes is continuing, and will soon result in serious and expensive operating restrictions such as derating. Another consequence of the tube degradation is the increased occupational exposure to radiation received by workers during the augmented inspection and plugging operations required on the steam generators because of their degraded condition.

The licensee's proposal to eliminate the tube degradation problem is described in detail in Reference 1, "Steam Generator Repair Program, Surry Power Station, Units 1 and 2," consisting of the original submittal dated August 17, 1977, with revisions dated December 2, 1977; April 21, June 2, June 13, June 30, September 1, October 25, and November 10, 1978. In order to provide the NRC staff with an independent basis for evaluating the radiological impacts associated with the repair of degraded steam generators at large pressurized water reactors (PWRs), we have contracted with Battelle Pacific Northwest Laboratories (PNL) to perform a generic radiological assessment of the steam generator repair and disposal operations. This assessment has been published in an NRC report,[2] NUREG/CR-0199, "Radiological Assessment of Steam Generator Removal and Replacement."

Information useful to the environmental review was also obtained from the NRC staff's Safety Evaluation Report (SER)[3] on the repair project, particularly the sections evaluating (1) the measures to reduce corrosion, (2) the As Low As is Reasonably Achievable (ALARA) considerations, and (3) the radiological consequences of postulated accidents.

3.0 Description of the Proposed Repair Method

A drawing showing the principal parts of a typical steam generator is presented in Figure 1. Figure 2 shows the regions where the main cuts are proposed to remove the degraded steam generator. It shows also the radiation levels in these regions. A brief description of VEPCO's proposed repair procedure follows.

In preparation for the repair of the steam generators in Surry Unit No. 2, all of the fuel will be removed from the reactor core and placed in the spent fuel pool. Then one of the three steam generators will be cut out of the reactor system. Present plans are to cut through the inlet and outlet reactor coolant piping, and through the steam line piping and feedwater piping. The steam generator wall will be cut on the transition zone between the lower assembly and the larger diameter upper shell assembly. The upper assembly will be lifted off and stored inside the containment vessel. The lower assembly will be lifted by crane from its support, tipped on its side, and transported out of the containment through the equipment hatch. It will then be transported to the concrete vault where it will be stored until the station is decommissioned. The replacement lower assembly will be transported into the containment and placed on its support. The old upper assembly, after some refurbishment, and the new lower assembly will be welded together in the field. The piping mentioned above will be welded to the repaired steam generator.

The same procedure will be followed for the other two steam generators. It is anticipated that the unit will be out of service for about six months. After Unit No. 2 is back in service, Unit No. 1 will be shut down to commence repairs on its steam generators.

A number of changes (see Sections 2.3 through 2.7 of Reference 1) have been made in the materials, the design and the operating procedure for the replacement steam generators to assure that the corrosion and denting problems will not recur. Among the more important of these changes are (1) using All-Volatile-Treatment chemistry control in the secondary system from the beginning of operation, (2) using corrosion resistant SA240 Type 405 ferritic stainless steel rather than carbon steel for the support plate material, (3) thermally treating the Inconel 600 heat exchanger tubes for better corrosion resistance,

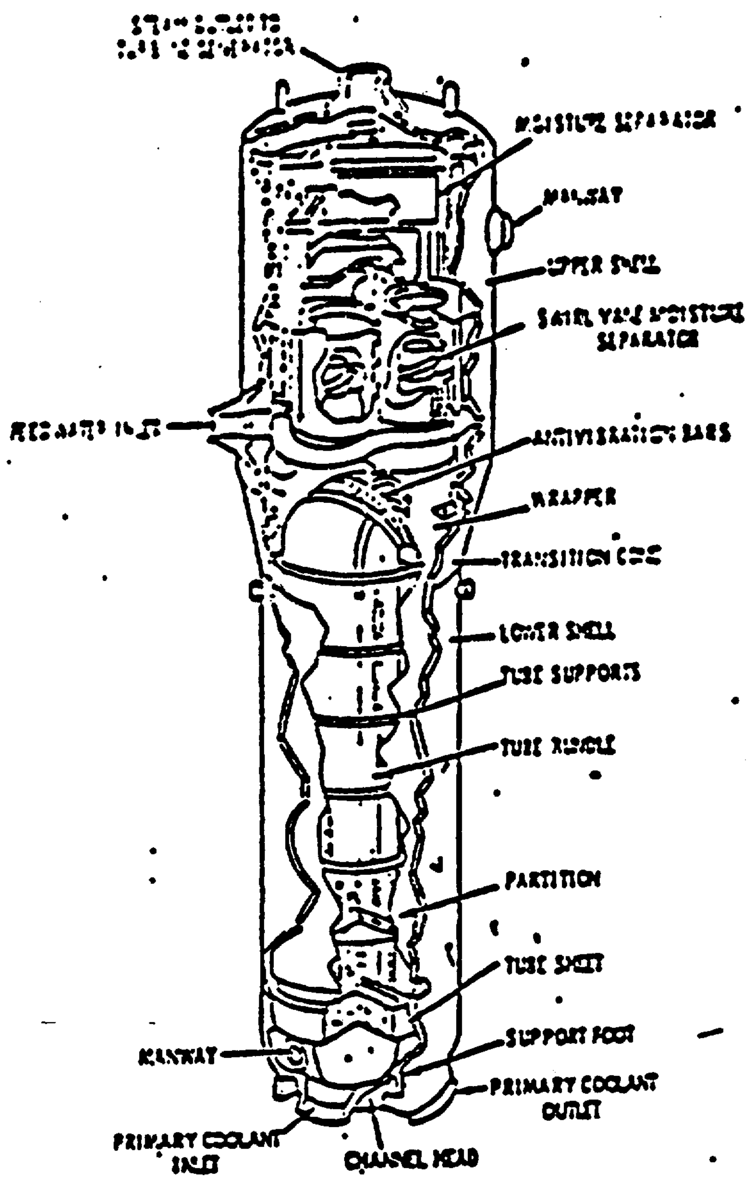

FIGURE 1. Typical Steam Generator

POOR ORIGINAL

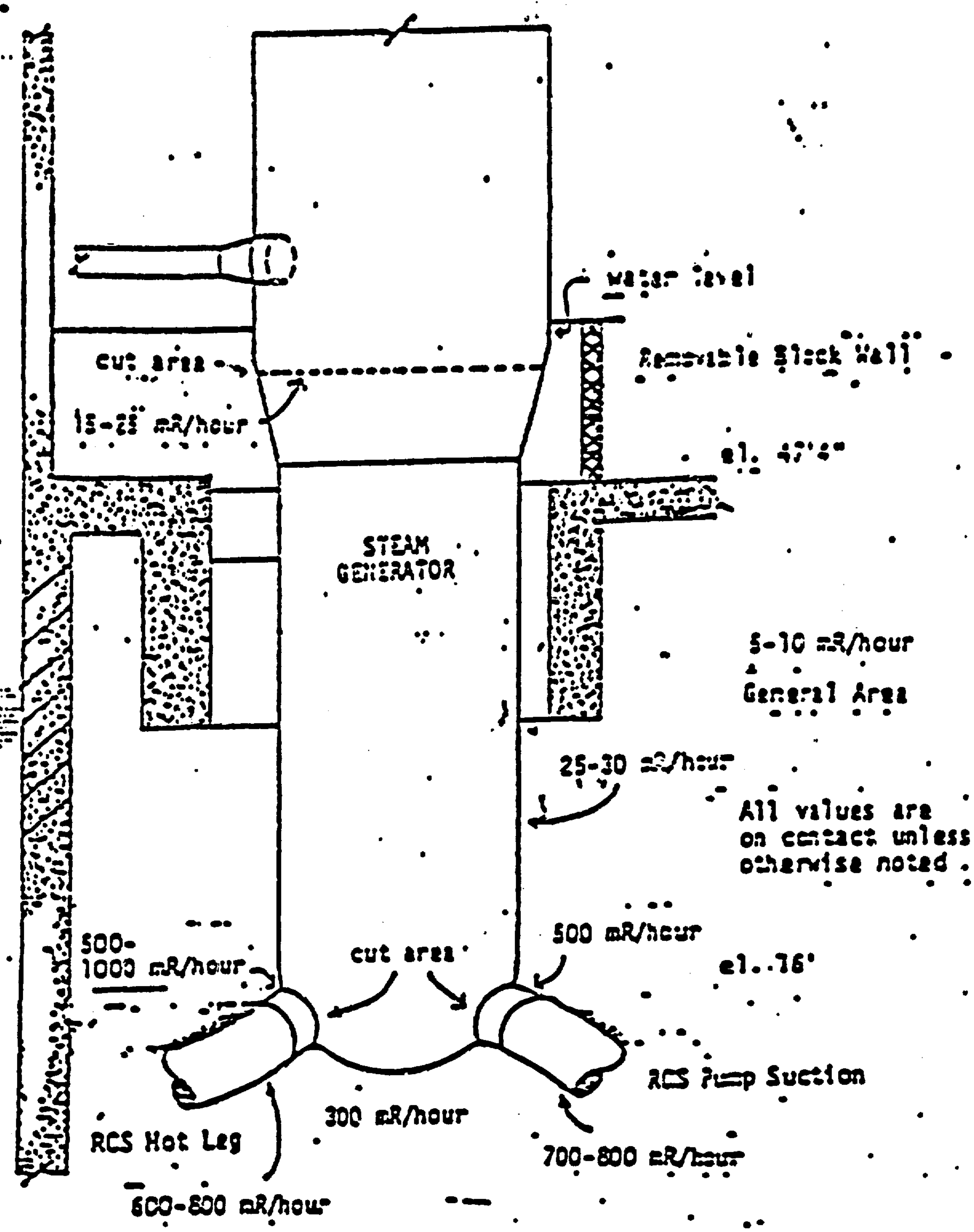

FIGURE 2
TYPICAL RADIATION LEVELS AROUND STEAM GENERATORS WITH PRIMARY SIDE DRAINED AND SECONDARY SIDE AT 72% LEVEL

and (4) using a broached hole pattern with a quatrefoil design in the support plates rather than separately drilled flow holes to minimize the accumulation of corrosion products where the tubes pass through the plates. The staff's review of the expected effects of the proposed changes is presented in detail in the introductory section of the SER[3] for the repair project. We have concluded in the SER that the new steam generator design incorporates features to eliminate the potential for the various forms of tube degradation observed to date.

The licensee proposes to store the six degraded steam generator lower assemblies for the life of the plant in an above-ground concrete structure with walls about 3 feet thick. The structure will be sealed against water intrusion, but will be provided with an internal sump to collect any water which may get in by means such as condensation. Ventilation to allow for thermal expansion and contraction of the air inside the structure will be provided through high efficiency particulate air filters. Several removable 2-inch plugs will be provided to permit the conduct of radiation surveys without entering the structure.

The method of ultimate disposal will be decided when the reactor itself is scheduled for decommissioning.

4.0 Environmental Impacts of Steam Generator Repair Project

4.1 Radiological Assessment

4.1.1 Occupational Exposure

The generic radiological assessment of steam generator repair, prepared for the NRC by PNL and reported in NUREG/CR-0199, provides an upper bound estimate of the occupational doses and off-site radiological releases associated with the repair of steam generators at a large PWR. The conservatisms in PNL's methods of assessment, described below, provide the opportunity to reduce occupational doses for the repair operations in specific cases considerably below the generic estimates in NUREG/CR-0199.

The PNL generic estimates of occupational exposure (man-rem) were derived by multiplying maintenance activity man-hours by exposure rates (rem/hour) for the repair activities. Maintenance activities were developed by PNL as a composite of the work descriptions for removal and replacement of the steam generators at Surry and Turkey Point as determined by VEPCO and Florida Power and Light Company. Man-hour estimates for each activity were developed by PNL based on prior experience with similar activities, using standard estimating techniques. Exposure rates were based on information from several sources including data from measurements made at several operating

PNLs including the Surry Units. PNL usually selected exposure rate values on the high end of the range of values measured at the several plants.

The generic estimate of the total collective occupational whole body dose for the repair of three steam generators was presented in NUREG/CR-0199 as a range of values, 3380 to 5840 man-rem. Both ends of this range were conservatively estimated and represent upper bound values. The upper value, 5840 man-rem, was estimated assuming no credit for dose saving techniques. The lower value, 3380 man-rem, was estimated taking credit only for three dose reduction methods: (1) shielding by raising the steam generator water level, (2) using a limited amount of remote tooling, and (3) increasing the source-to-receiver distance. VEPCO's total estimate of 2070 man-rem per unit included not only these dose reduction measures but also measures such as additional temporary lead shielding, local decontamination, pre-job planning and pre-job training. The dose reduction procedures proposed by VEPCO are discussed in more detail in our SER.[3]

In view of the above discussion, the lower end of the generic range, 3380 man-rem, is the appropriate estimate for comparison with VEPCO's estimate of 2070 man-rem per unit. A summary comparing VEPCO's estimates with our generic estimates in NUREG/CR-0199 for the four main phases of the project is given in Table 4.1.

Table 4.1
Comparison of Occupational Collective Whole Body Dose Estimates

Phase	NRC Generic Estimate Dose, man-rem/unit	VEPCO Estimate Dose, man-rem/unit
Preparation	450-810	599
Removal	1100-1700	559
Installation	1800-330	877
Storage	30	35
Total	3380-5840	2070

The discrepancies between the detailed estimates are accounted for by the same factors discussed above for the total estimates. VEPCO's calculations of doses used commonly accepted practices for calculating doses and took into account the dose reduction measures proposed to maintain doses As Low As Reasonably Achievable (ALARA), including local decontamination, temporary lead shielding, pre-job planning, pre-job training and use of remote tools where practicable. In Section 6 of Reference 1, VEPCO has documented its consideration of the guidance with regard to ALARA issues in Regulatory Guide 8.8, Revision 2.[4] We have reviewed VEPCO's treatment of ALARA issues in detail in Section 4 of the SER.[3] We concluded that VEPCO's efforts to maintain occupational doses ALARA during the repair effort are reasonable.

In summary, the above discussion shows that the differences between the lower generic estimate (3330 man-rem per unit) and VEPCO's estimate (2070 man-rem per unit) can be reconciled by (1) the use of lower dose rates measured at Surry in the VEPCO estimate and (2) the use of more dose reducing measures by VEPCO than in the generic estimate. We therefore conclude that VEPCO's estimate of 2070 man-rem is a more realistic estimate than 3330 man-rem for the repair of the steam generators in one Surry unit. ~~Consequently, in the remainder of this~~ appraisal, we have used 2070 man-rem per unit as the occupational dose for the steam generator repair work at Surry. INSERT A

To put into perspective the occupational doses to be incurred in repairing steam generators, it is helpful to compare these doses (1) with those expected from the normal operation of nuclear plants, (2) with the projected long-term man-rem saving resulting from steam generator repair and (3) ~~with the doses from major maintenance operations at other plants.~~ with doses ~~we all~~ received from natural background radiation.

Although the AEC was starting to compile occupational exposure estimates for nuclear power plant operation at the time that the Surry 1 and 2 FES was prepared in 1972, such exposures were not specifically considered in the Surry 1 and 2 FES.

~~In recent environmental statements, we have estimated an annual occupational dose of about 500 man-rem per nuclear unit, averaged over the life of the plant (30-40 years). This value is based on the average of annual doses received at operating plants. In 1977, the average occupational dose per unit for light water reactors in the United States was 570 man-rem.[5] The 1977 doses ranged from 87 to 3142 man-rem per reactor unit, with major maintenance during the year accounting for the larger values. Occasional large doses associated with major maintenance, such as the 2070 man-rem dose per unit for the proposed steam generator repair, will occur. NRC regulations require that measures be taken to keep these doses ALARA.~~ INSERT B

In 1975, 1976 and 1977, workers at Surry Units 1 and 2 received whole body doses of 638 man-rem,[1] 1287 man-rem[1] and 1410 man-rem,[6] respectively, during the inspection and plugging of degraded steam generator tubes. The total occupational doses for the two units were 1649 man-rem in 1975, 3163 man-rem in 1976, and 2416 man-rem in 1977.[5] These doses are higher than the ~~570~~ 581 man-rem per year average for U.S. light water reactors. ~~in 1977.~~ As mentioned at the end of Section 3, we concluded in the SER that the proposed repair would eliminate the potential for the kinds of the tube degradation observed to date. Based on our experience with plants without severe denting problems and the staff conclusion regarding corrosion reduction, doses due to the inspection and plugging of degraded tubes would be markedly reduced, and we conclude that occupational exposure after the repair will be reduced by hundreds of man-rem per year for the two units. This would result in total occupational exposures at Surry approaching more closely the national average value for light water reactors (~~370~~ 500 man-rem per unit) ~~in 1977~~. We further conclude that the dose savings of hundreds of man-rem per year would over a period of years tend to offset the immediate one-time dose of ~~2073~~ man-rem for repairing the three steam generators in ~~each~~ both units. ~~4140~~ 2070

VEPCO has estimated that the after-repair occupational dose for the inspection and repair of degraded steam generator tubes will be reduced to 25 man-rem per year for the two Surry units. Although the 25 man-rem per year appears to be a reasonable number for Regulatory Guide 1.83 inspections, we have conservatively estimated a higher value of 100 man-rem per year to account for additional inspections which may be performed to check the initial performance of the improved steam generators and to correspond more closely to recent industry experience.

The saving of occupational exposure resulting from the repair effort may be estimated by subtracting the estimated annual dose after repair from the observed annual dose before repair. The doses of 1287 man-rem in 1976 and 1410 man-rem in 1977 are considered representative of exposures related to steam generator operation before repair. The 638 man-rem dose in 1975 is not representative of operation with degraded steam generators because significant tube degradation was not observed in Unit I until September 1975 and in Unit II until January 1976. Subtracting the after-repair dose of 100 man-rem from the before-repair range of 1287 to 1410 man-rem leads to a saving of 1187 to 1310 man-rem per year. At these rates of saving, the 4140 2070 man-rem cost of the repair would be offset in 3 to 4 years.

ck

Operating experience at the Surry plant over the last three years demonstrates that the steam generators can continue to operate with the degraded tubes plugged, but frequent inspection and plugging as performed during the last three years would be required to assure that the integrity of the steam generators would be maintained. At the current rate of tube plugging, about 3% per year, it is the staff's judgment that, with continued inspections and plugging, the Surry units could continue to operate for some period and, even if reduced power were required, the economic balance would favor continued operation of the units, as opposed to decommissioning the reactors. On the other hand, continued degradation of the integrity of a major component such as steam generators, results in continued small reductions in overall safety margins.

This potential has been carefully considered on the basis of the results of each inspection over the past ~~three~~ four years. While these margins remain acceptable, any continued degradation would require continued careful assessment to assure that degradation does not become excessive.

The additional health risks due to these doses over normal risks are quite small, less than one percent of normal risks to the project work force as a whole.

INSERT 'C' — gK

normal

In summary, the staff has drawn the following conclusions regarding occupational radiation exposure. VEPCO's estimate of 2070 man-rem per unit for the repair of the steam generators is reasonable. This dose falls within the range of annual occupational doses which have been observed in recent years. Our review in the Safety Evaluation Report[3] concludes that VEPCO is taking the necessary steps to insure that occupational doses will be maintained ALARA. ~~Finally,~~ The renovation of the steam generators will lead to occupational dose reductions of hundreds of man-rem per year. These dose savings over a period of several years will outweigh the immediate large one-time dose resulting from the repair operation. The individual risks associated with the exposures involved in the repair program will be controlled and limited so as not to exceed the limits set forth in 10 CFR Part 20 for occupational exposure. These limits assure that the hazard to any exposed individual is extremely small.

~~Even should there be an incremental 2000 man-rem per reactor increase in occupational exposure, the increased risk of premature fatal cancer induction is predicted to be less than one event (e.g., 0.2 events risk estimation from data for the population as a whole as given in the BEIR report)[14]. The increased risk of this exposure on genetic effects to the ensuing five generations is also predicted to be less than one event (e.g., 0.5 events risk estimation from data for the population as a whole as given in the BEIR report). For a selected population such as is likely for the exposed workers involved in the repair program consisting principally of males in the age ranges from 20 to 40, these risks would tend to be somewhat less.~~

For the foregoing reasons, the Staff concludes that the environmental effect due to occupational radiation exposure is ~~not significant.~~ insignificant and acceptable

4.1.2 Public Radiation Exposure

Our independent analysis of the gaseous and liquid releases of radioactivity from the plant site during the steam generator repair project is based in large part on the generic report,[2] NUREG/CR-0199, prepared by Pacific Northwest Laboratories for the NRC. The estimates of releases in this report are upper bound values, based on conservatively high estimates for each type of release.

The doses to the work force as a whole and to the average worker will be within the variations in lifetime doses due to natural background radiation in the U.S.

Average 76/77

Table 4.3

Radioactive Effluents from Surry Station

Type of Radioactive Effluent	Steam Generator Repair: VEPCO Release Estimates (Ci/Unit)	Actual Surry Unit 2 Releases (Ci/Unit)	Steam Generator Repair: NUREG/CR-0199 Release Estimates (Ci/Unit)	Operating Experience: Surry 1976 Average Releases (Ci/Unit)	Operating Experience: Surry 1977 Average Releases (Ci/Unit)	FES: Annual Average Release Estimates (Ci/Unit/Yr)
GASEOUS						
Noble Gases	-	100	-	9600	9510	3360
Halogens (Iodines)	0.0045	0.0000057	included in particulates	0.27	0.24	0.92
Particulates	0.0031	.0013	0.0001	0.041	0.001	-
Tritium	8.5		-	19	44	-
LIQUID						
Mixed fission & activation products	0.35	0.5	0.14	17	3.8	53
Tritium	0.1		190	390	204	1000

Similar estimates of the gaseous and liquid effluents during the repair were made by VEPCO in Reference 1. These estimates were based on the specific equipment design and procedures to be used at the Surry plant. Table 4.3 presents the NUREG/CR-0199 estimates[2] and VEPCO's estimates[1] of the radioactive effluents which will be released as a result of the repair effort. Table 4.3 also presents Surry's reported average radioactive effluent releases for 1976[12] and 1977,[6] and the annual average radioactive effluent release estimates presented in the Surry FES.[7] Table 4.3 shows that the releases estimated by VEPCO and the generic report for the repair effort are much lower (except for the airborne particulates) than the Surry 1976 and 1977 releases and the FES annual average estimates. For airborne particulates, the VEPCO estimates of releases are in the same range as or lower than the 1976 and 1977 releases in Table 4.3. The Surry FES[7] does not present numerical estimates of airborne particulate and tritium releases. However, airborne particulates and tritium are small dose contributors compared to radioiodine and noble gases for the highest dose pathways of exposure to individuals in the general public. Therefore, the conclusions regarding dose consequences presented in the FES are still valid.

The VEPCO estimates of gaseous releases from the repair effort are larger than the NRC generic estimates because the VEPCO values include the releases from fuel unloading and reloading, which are much larger than the gaseous releases from the rest of the repair operation. VEPCO's figures are based mainly on experience at Surry with refueling operations. The refueling releases were not included in the NUREG/CR-0199 estimate, since the utility normally would plan to carry out the steam generator repair during a scheduled shutdown for refueling. For the other gaseous releases such as those from pipe cutting, VEPCO used commonly accepted calculational methods, for example in calculating the kerf for each cut and in assuming that all radioactive material adhering to the inner cut surface would become airborne. Therefore, we conclude that VEPCO's estimates of gaseous releases, including those from the fuel handling operations, were carried out in an acceptable manner and represent reasonable estimates.

In Table 4.~~2~~3, the estimates for liquid releases of tritium vary widely because VEPCO plans to store the primary reactor coolant water for re-use, whereas the generic (NUREG/CR-0199) estimate assumes that the coolant is discharged after processing for nuclides other than tritium. The VEPCO estimate for the release of mixed fission and activation products is larger than the generic estimate because the latter did not include the releases of the secondary coolant nor the local decontamination solutions. Both estimates included the activities in laundry waste water. VEPCO based its estimates of releases from the laundry waste water and secondary coolant on past measurements of these sources at Surry. VEPCO used commonly accepted methods to calculate the releases from local decontamination solutions. Based on these several considerations, we conclude that the licensee has made reasonable estimates of the radioactive liquid effluents during the repair effort, and that these estimates correspond, as well, to our own best estimates. ← INSERT E

Our estimates of dose to individuals and to the population as a whole in the area surrounding the Surry site are based on the radioactive effluents which VEPCO estimated for the repair effort (summarized in Table 4.2) and on the calculational methods presented in Regulatory Guides 1.109, 1.111 and 1.113.[119,8] We conclude that offsite individuals will receive doses from the repair effort of the same order or less than the annual dose consequences presented in the FES.[7] The doses to the population within 50 miles will be less than 5 man-rem to the thyroid or total body from liquid effluents, and less than 2 man-rem to the thyroid or total body from airborne effluents. Every year the same population (about 2 million) will receive a total body dose of more than 100,000 man-rem from the natural background radiation in the vicinity of Surry (0.065 rem per year).[13] Thus, the population total body dose from the repair effort is less than 0.01% of the annual dose due to natural background. On these bases, we conclude that the doses to individuals in unrestricted areas and to the population within 50 miles due to gaseous and liquid effluents from the repair project will ~~not~~ be ~~environmentally significant.~~ insignificant and acceptable ← STET

VEPCO has estimated that the repair effort will generate 740 cubic meters of solid waste per unit containing 19 curies of radioactivity.[1] Based on the information presented in NUREG/CR-0199, we estimate that 2300 cubic meters of solid waste containing 37 curies of radioactivity will be generated per unit.[2] Our estimate is higher than the licensee's estimate because we assumed that all of the radioactivity in the solutions from main coolant pipe decontamination would be solidified. Neither of these estimates include the radioactivity on the inside surfaces of the old steam generators. In 1976 and 1977, Surry generated an annual average of 370 cubic meters of solid waste per unit containing 310 curies per unit of radioactivity.[6, 3] The amount of radioactivity in the wastes from the repair effort will be about ten percent of this average annual production during operation. Since the solid wastes represent an impact which is a small part of the impact from solid wastes from normal operation, we conclude that the radiological impact is not environmentally significant.

INSERT F

On the basis of long term onsite storage of the degraded steam generators until the reactors are decommissioned, there will be essentially no radioactive effluents from the generators for 30 years. Final disposal at that time will result in small offsite gaseous and liquid radioactive releases, because a large fraction of the radioactive nuclides in the steam generators will have decayed in 30 years.

The stored steam generators will present a source of direct and scattered radiation. We estimate that each steam generator will contain about ~~2700~~ 1090 Ci of radioactivity. ~~including 720 Ci of Cobalt-60, the principal contributor to direct dose.~~ This is based on the estimate of the contamination of steam generator primary side surfaces given in NUREG/CR-0199.[2] The staff estimated a dose rate of less than 0.0001 milli-rem per hour at the nearest site boundary due to this activity. An individual spending an entire year at this location would receive less than 1 milli-rem of radiation exposure. This dose dose rate would be approximately halved every 5 years because of the decay of the principal contributing activity, Co-60. VEPCO made a similar calculation and reached the same conclusion. Since this dose represents roughly one percent of the annual dose from natural background,[12] the staff concludes that the direct dose impact to the public from the stored generators will be ~~minimal and not environmentally significant.~~ insignificant and acceptable

STET

The repair effort will return the plant to the design condition on which our evaluation in the FES[7] was based. Therefore, we conclude that the estimates of routine releases of radioactivity and the potential doses to the public from those effluents after the repair will remain as presented in the FES.

Since our estimates of radioactive effluents from Surry during normal operation after the repair effort are about the same or lower than those effluents presented in the FES,[7] we conclude that the impact on biota other than man will be no greater than that impact presented in the FES.

In summary, the offsite doses resulting from the steam generator repair will be less than those from recent plant operation since the expected releases of radioactive material as a result of the repair effort will be less than the releases from normal operation. These doses are comparable to doses presented in the FES[7], and small compared to the annual doses from natural background radiation. Therefore the radiological impact of the repair project to the public will not significantly affect the human environment ~~and is acceptable.~~ delete

4.2 Economic Costs of Steam Generator Repair

VEPCO has estimated that, over the life of the plant, the proposed steam generator repair project will result in a net dollar savings of at least \$125,000,000 compared with the cost of continued operation of the existing steam generators, with an optimistic assumed scenario of tube plugging and derating. The cost of purchasing and installing the steam generator lower assemblies and associated activities is estimated at about \$66,000,000 for the two units.

The cost of onsite storage and final disposal of the six degraded lower assemblies is expected to be about \$1,000,000. The estimate for replacement power during the outage for repair is about \$66,000,000. The total project cost is therefore about \$133,000,000.

The cost of replacement power during the outage is based on the higher fuel costs of coal, oil and gas-fired units which VEPCO would press into service to replace the power lost by the shutdown of one of the Surry Units. The VEPCO estimate of \$66,000,000 based on differential fuel costs is reasonable in view of the total value of the replacement power: 822,500 kW x 0.6 capacity factor x 360 days x 24 hours/day x \$.04/kWhr = \$183,000,000. VEPCO's estimate of \$66,000,000 corresponds to a fuel differential cost of about \$0.014/kW hr between fossil-fired plants and a nuclear plant. We consider this differential cost estimate reasonable.

The VEPCO estimated net saving of \$125,000,000 is based largely on the cost of replacement power due to derating. We assessed the reasonableness of this estimate by comparing it to the cost of replacement power if both units had to be derated. The cost would be about \$360,000,000 after 10 years of derating at an assumed rate of 3% per year (the current rate of tube degradation is greater than 3% per year). Therefore, VEPCO's estimate that \$125,000,000 would be saved over the life of the plant even after spending \$133,000,000 for the steam generator repair is conservative.

The VEPCO estimate of \$1,000,000 for final disposal of the degraded steam generators assumes onsite storage for 30 years followed by sectioning and shipment to a licensed burial facility for low-level waste. This estimate is not out of line when compared to recent estimates[13] for the decommissioning of complete reactors by dismantlement after a cooling period (about \$30,000,000).

This consideration of costs does not take into account the continuing costs of tube inspection and plugging services, nor the costs of possible future modifications to control corrosion, if the repair is not done. It also does not consider the cost of the current lack of reliability and availability. In 1976, Surry Unit 1 was offline for 36 days and Unit 2 for 139 days for tube inspection and plugging. In 1977, the outage times for tube inspection and plugging were 50 days for Unit 1 and 70 days for Unit 2.

In Section 5, the economic and other impacts of alternative methods of repairing the steam generators will be compared.

4.3 Non-Radiological Environmental Costs

The non-radiological impacts of the repair project on the environment are small compared to those of building and operating the reactors. These small costs include the commitment of about one acre of land on the site for the storage of the degraded steam generators for the life of the station. There will be some noise generated by onsite equipment and a small effect on local traffic by approximately 125 construction workers per shift, but these effects will be insignificant.

The material costs of the proposed action will include about 1350 tons of carbon steel, 48 tons of stainless steel, 3000 cubic yards of concrete. These quantities are about 2% of the quantity of steel and about 8% of the concrete used in the original construction of the plant.

4.4 Environmental Impact of Postulated Accidents

As is discussed in our SER,[3] the design and plant operating parameters which are relevant to accident analyses will not change as a result of the steam generator repair effort. Therefore, the assessment of the environmental impact of postulated accidents presented in the final environmental statements for Surry Units 1 and 2 will be unchanged and remain valid. However, there are a few types of accidents which are possible due to the operations involved in the repair effort.

One such postulated accident is the rupture of the Reactor Water Storage Tank by a crane drop. The bounds of the radiological consequences of this accident were discussed in the FES[7] for Surry Unit 2 under the heading -"Release of liquid waste contents."

A second type of postulated accident related to the repair effort would involve the dropping and rupture of a removed steam generator outside the reactor containment while it was being transported to the storage vault. This accident would involve the rupture of the steel covers which will have been welded over each of the steam generator cuts to prevent the spread of the neutron-activated corrosion products adhering to the inner surfaces. The method used to assess the radiological consequences of a rupture which could release contamination on the primary side surfaces to the atmosphere is described in the SER.[3] To obtain a more realistic estimate for the purpose of evaluating the environmental impact, we used an atmospheric dispersion factor of 1.6×10^{-4} seconds per cubic meter. On this basis, we concluded that this accident would result in a dose of 0.05 rem to the lungs of an individual at the site boundary.

The dose consequences of a drop accident inside containment would be lower since the containment ventilation system would reduce the radioactivity released to the environment.

In summary, we concluded that the consequences of postulated accidents from the repair operation would be not environmentally significant ~~and are~~ acceptable.

delete

5.0 Impacts of Alternatives

The basic choices of future action regarding the tube degradation problem are (1) repair of the degraded steam generators, (2) continuation of the present mode of operation, with increasing costs in plant efficiency and occupational exposure, and (3) shutdown of the Surry Units 1 and 2, and replacement by generating plants of different design. VEPCO opted for repairing the degraded steam generators, with changes in design, materials and operating procedures calculated to eliminate the tube denting problem.

In the absence of methods to arrest or greatly reduce denting, the continuation of operation for an extended period in the present mode is impractical. With tube degradation and plugging continuing at the present rate, the units would soon be required to operate at lower power. VEPCO has estimated the cost of replacement power, based on fuel differential costs, to be about $180,000 per day for the shutdown of a unit. Consequently, the cost of derating the Surry units would be high. Also, the man-rem cost of occupational exposure during inspection and plugging of tubes would continue to be high, resulting in a dose higher than 4140 man-rem in 3 or 4 years. Laboratory test programs on the denting phenomenon are currently underway to define the corrosion process more precisely and to develop preventive measures such as corrosion inhibitors. While the combination of steam generator secondary side cleaning and corrosion inhibitors is being studied by some utilities to combat denting in its early stages, the denting phenomenon at Surry is too advanced for such measures to be practical. Therefore, VEPCO cannot count on a greatly reduced future rate of tube degradation to justify continuing the present mode of operation.

The option of shutting down the Surry station and replacing it with a plant of different design is easily shown to be much more costly than that of repairing the steam generators. VEPCO estimates (Section 5.5.1.3 of Reference 1) that the capital cost of new nuclear units with improved steam generators would be about $2.7 billion dollars and would require about 12½ years to build. New fossil units would cost about $1.2 billion and require about 8 years to build. (We consider the coal estimate low; capital cost for a coal-fired plant is usually about 80% of that for a nuclear plant.) Florida Power and Light Company made a similar comparison for repairing the steam generators in Turkey Point Units 3 and 4. Their estimate was about $77/kW for the proposed steam generator repair operation, compared to $224/kW for gas turbine units, $1059/kW for a coal-fired plant, and $1448/kW for a nuclear plant of improved design. Although the Turkey Point estimates are in different terms, the cost comparison again overwhelmingly favors the repair option. For these reasons, the plant replacement option is not economically feasible. In addition, there would be significant environmental impacts from such a large scale construction operation. The most practical overall option is therefore to repair the degraded steam generators.

In the remainder of this section, we shall consider the radiological and economic costs of several alternative ways of repairing and disposing of the degraded steam generators. An important item in estimating economic costs is the cost of replacement power during unit outage. VEPCO's cost estimate of $66,000,000 for the power needed during the 180 day outage of each unit corresponds to a replacement power cost of nearly $200,000 per unit per day of outage.

5.1 Decontamination

VEPCO has estimated (Section 5.5.2.1 of Reference 1) that chemical decontamination of the steam generators before cutting would result in a net saving of 300 to 400 man-rem per unit in occupational exposure. However, it would cost about 1.5 months in additional outage of each unit. Replacement power for this additional outage would cost about $9,000,000. In addition, about 200,000 gallons of radioactive waste would be produced.

VEPCO also considered mechanical decontamination of the inner surfaces of the steam generator, but estimated that the occupational exposure during the decontamination operation would exceed the later saving in dose to workers.

Based on our knowledge of the limited experience of the nuclear industry in large scale, high volume chemical decontamination of reactor coolant systems, we can make the following statements. Most importantly, decontamination would add significant expense and time delays to the repair effort, including the cost of replacement power during those time delays. There is a degree of uncertainty about the compatibility of the decontamination fluid with materials in the coolant system. The research and testing which would be required to provide adequate assurance of material compatibility to obtain our approval to decontaminate would adversely impact on the cost and schedule of this repair effort. While the lower dose rates resulting from decontamination would reduce occupational dose during the repair operations, occupational radiation doses received during the decontamination effort itself would partially offset the dose reduction. Decontamination would not remove the radioactivity inside tubes which are plugged. Large volumes of contaminated fluids would be produced and require processing. That processing would incur further costs and occupational dose. In summary, we conclude that the costs of decontamination including costs due to time delays would outweigh the dose savings. Therefore, the use of large scale decontamination in this repair effort is not a viable option.

5.2 Retubing of Existing Steam Generators

The retubing operation would involve (1) removing the upper or dome portion of the steam generator, (2) removing the lower assembly internals and tubes, (3) replacing the latter with state-of-the-art internals and tubes, and (4) refurbishing the upper internals, and (5) welding the dome back in place. VEPCO has estimated (Section 5.5.1.2 of Reference 1) that the cost of this operation in both dollars and occupational exposure would be higher than the proposed replacement of the complete lower assembly. VEPCO further points out that shop fabrication of new lower assemblies would provide more positive assurance that the quality of the repaired generators was acceptable.

On the other hand, the staff is aware of recent developments by Westinghouse in the technology of in-place refurbishment which show some promise of reducing unit outage and personnel exposure below the values for VEPCO's proposed repair method. However, at this time not enough information is available for us to make a detailed assessment of the retubing alternative.

A detailed proposal for our review is expected in the near future. If our assessment is favorable, in-place retubing may be an alternative for steam generator repairs in the future. However, in the time frame contemplated for the proposed licensing action, this is not considered to be an available alternative to the proposed action.

5.3 Replacement of the Entire Steam Generator

For this alternative, a construction opening in the containment wall about 20 feet wide and 40 feet high would be required, since the upper assembly of the steam generator could not pass through the existing equipment hatch. The personnel exposure for this alternative would be about the same as for the proposed repair, because essentially the same high-dose operations will be required in each case. Elimination of the cut across the diameter of each steam generator results in only a small saving of radiation exposure. The capital costs are estimated to be about 15% higher. The principal cost difference is due to an estimated additional outage of about 100 days per unit for the alternative. This corresponds to an additional requirement of about $40,000,000 worth of replacement power during the repair of both units, calculated at the rate of about $180,000 per day of outage per unit. For these reasons, the staff concludes that VEPCO's proposed repair method is preferable.

5.4 Alternate Disposal Methods

In the Appendix to NUREG/CR-0199[2] the radiological costs of several alternative methods for the disposal of the degraded steam generators are evaluated. The results of this analysis are summarized in Table 5.1.

Table 5.1 Steam Generator Disposal Alternatives

Option	Approximate Man-Rem per Steam Generator	Approximate Airborne Release Ci per Generator
Long-term[a] storage (including surveillance) with intact shipment	10	Negligible[b]
Long-term[a] storage with cut-up and shipment	16	0.005
Shorter-term storage with cut-up - at 5 yr	230	0.026
- at 15 yr	50	0.015
Immediate intact shipment	2.4[c]	Negligible[b]
Immediate cut-up and shipment by rail/truck - no decontamination	580	0.042
Immediate cut-up and shipment by rail/truck - with chemical decontamination	270	0.010

[a] 30 to 40 years

[b] Since the steam generator will be sealed before it is removed from containment, no release of radioactive material is expected during the repair operation.

[c] Estimates for short-term storage followed by intact shipment would be only slightly larger than this, perhaps 5 man-rem.

It is seen that the options involving intact shipment would have the lower radiological costs; but intact shipment is possible only by barge and at present there is no licensed burial ground with facilities for off-loading an entire lower assembly from a barge.

The next best alternative, radiologically, would be long-term storage of the generators onsite until the reactors are decommissioned, followed by sectioning and shipment at that time. This is the plan proposed by VEPCO.

Immediate cut-up and shipment to a burial facility would involve a substantial cost in occupational exposure, even after chemical decontamination. Comparing Tables 5.1 and 4.2, it is seen that the airborne releases from the segmenting operation would be larger than those from the rest of the repair effort.

The two disposal alternatives considered by VEPCO (Section 5.5.2.2 of Reference 1) were immediate intact barge shipment and near-term sectioning for off-site disposal. The estimated economic and radiological costs are given in Table 5.2 for the disposal of six steam generators.

Table 5.2 Costs of Alternate Disposal Methods (VEPCO)

Method	Cost, dollars	Exposure[a], man-rem
On-site Storage With Final Disposal at Decommissioning	1,000,000	80
Intact Barge Shipment	1,200,000 to 1,500,000	200
Near-term Sectioning	3,700,000	1000 to 2000

[a]Note that these doses are for six lower assemblies. The estimates in Table 5.1 are for one lower assembly.

According to the VEPCO estimates, the proposed disposal method of on-site storage with final disposition at the time of plant decommissioning should result in the least cost in dollars and in radiation exposure. The staff agrees that the proposed disposal method costs less in radiation exposure than alternatives available at present. The proposed onsite storage leaves open the option of intact barge shipment in the event that a burial ground with adequate off-loading facilities becomes available.

6.0 Basis and Conclusion for not Preparing an Environmental Impact Statement

We have reviewed the proposed steam generator repair action and have reached the following conclusions.

(1) The proposed replacement of the lower assemblies of the steam generator is the best available option, from both the radiological and economic standpoints, for eliminating the tube degradation problem.

(2) The one time occupational exposure of 2073 per unit is larger than the average annual occupational exposure associated with the operation of a nuclear power plant. However, such occupational exposures or larger exposures would be incurred in a few years by continued operation at Surry even absent the proposed action. In the long run the proposed action will cause occupational exposures at an operating Surry facility to be reduced on a long term cumulative basis as well as on an annual basis. Therefore it does not appear that there will be a substantial increase in occupational radiation exposure caused by the work authorized.

We have reviewed the dose reduction measures to be used by the applicant and conclude that the doses would be ALARA. We have also considered the health effects resulting from such exposure and concluded that these are not significant.

(3) The new steam generator design incorporates features which will eliminate the potential for the various forms of tube degradation observed to date.

(4) The restoration would restore the generators to the condition evaluated in the FES and would result in an occupational dose saving of hundreds of man-rem per year, because there would be a marked reduction in the amount of tube inspection and tube plugging required to keep the generators in acceptable operating condition.

(5) Offsite doses resulting from the steam generator repair will be less than those from recent plant operations, comparable to doses presented in the FES[7], and small compared to the annual doses from natural background radiation. Therefore, the offsite doses will not be significant.

On the basis of the foregoing analysis, the staff concludes that the proposed steam generator repair action will not significantly affect the quality of the human environment.

We have reviewed this proposed facility modification relative to the requirements set forth in 10 CFR Part 51 and the Council of Environmental Quality's Guidelines, 40 CFR 1500.6. We have determined that the proposed license amendment will not significantly affect the quality of the human environment. Therefore, the staff has found that an environmental impact statement need not be prepared, and that pursuant to 10 CFR 51.5(c), the issuance of a negative declaration to this affect is appropriate.

REFERENCES

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2. NUREG/CR-0199, "Radiological Assessment of Steam Generator Removal and Replacement," G. R. Hoenes, D. A. Waite, and W. D. McCormack, Pacific Northwest Laboratories, June 1978.

3. Safety Evaluation Report for the Surry Power Station Steam Generator Replacement, U. S. Nuclear Regulatory Commission, December 1978.

4. Regulatory Guide 8.8, "Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations will be As Low As is Reasonably Achievable", (Revision 2), U.S. Nuclear Regulatory Commission.

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10. NUREG/CR-0130, "Technology, Safety and Cost of Decommissioning a Reference Pressurized Water Reactor," R. I. Smith, G. J. Konzek and W. E. Kennedy, Jr., Pacific Northwest Laboratories, June 1978.

11. Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," (Revision 1), U.S. Nuclear Regulatory Commission.

12. NUREG-0367, "Radioactive Materials Released from Nuclear Power Plants (1976)," T.R. Decker, U.S. Nuclear Regulatory Commission, March 1978.

13. NCRP No. 45, "Natural Background Radiation in the United States," National Council on Radiation Protection and Measurements, 1975.

14. "The Effects on Populations of Exposure to Low Levels of Ionizing Radiation", (BEIR Report), National Academy of Sciences, November 1972, Reprinted July 1974.

MAR 1 1 1980

MEMORANDUM FOR: William Regan, Chief, Environmental Projects Branch, DSE

FROM: George W. Knighton, Chief, Environmental Evaluation Branch, DOR

SUBJECT: SURRY STEAM GENERATOR EIS INPUT

Attached is a copy of EEB's input to the Surry Steam Generator Replacement EIS. This input was given informally to Phil Cota of your branch on March 7, 1980, as promised.

Sincerely,

Original signed by
George W. Knighton

George W. Knighton, Chief
Environmental Evaluation Branch
Division of Operating Reactors

Attachments:
As stated

cc: D. Eisenhut
P. Cota
J. Miller
D. Neighbors
R. Vollmer
T. Murphy

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The replacement of the 3 generators in Surry Unit 2 was completed in 37 weeks in 1979. The total occupational dose received by workers at Surry Unit 2 during the replacement was 2140 man-rem. The dose rates at Surry Unit 1 are 30-40% higher than at Unit 2. However, VEPCO believes that their experience from completing the Unit 2 replacement will allow them to do a more effective job of maintaining exposures ALARA on Unit 1. Therefore, VEPCO believes that their original estimate of 2070 man-rem per unit is reasonable for Unit 1. We followed the work at Unit 2 closely and we agree that 2070 man-rem is a reasonable estimate for Unit 1.

INSERT B

In the most recent environmental statements for new nuclear power plants, we have provided an estimate of 500 man-rem per reactor unit as the average annual occupational dose. This average is the ~~explained to be~~ an average over the life of the plant (30-40 years). This estimate is based on reported data from operating power reactors; a summary of that data is provided in Table 4.2. That data shows that 500 man-rem per reactor unit per year is roughly the average of the wide range of doses incurred at all light water cooled reactor units over the last several years. The amount of dose incurred at any single reactor unit in a year is highly dependent on the amount of major maintenance which becomes necessary that year. Every year several units perform some items of major maintenance which result in doses well above the average of 500 man-rem. These doses are included in the average and we do not consider them to be significant deviations from the average. Simply put, steam generator replacement is major maintenance which will result in an annual dose for the unit above the average. However, as Table 4.2 shows the 2070 man-rem is within the usual range of doses about the average for one unit in a year. Therefore, we conclude that the occupational dose (2070 man-rem) associated with replacement of the steam generators at each Surry unit ~~represents~~ results in an insignificant and acceptable environmental impact.

Table 4.2

Occupational Dose at U.S. Light Water Reactors (man-rem per reactor unit)

Year	Average	Low	High
1975	475	21	2022
1976	499	74	2648
1977	570	87	3142
1978	497	158	1621

INSERT C

The average annual dose to an individual due to natural background radiation in the United Stated is roughly 0.1 rem. However, there are very broad (local) variations in the average dose due to a number of factors such as altitude (above sea-level) and geologic formations. As altitude increases, the dose rate from cosmic radiation (radiation from space) increases. Because Denver, Colorado is at a much high altitude than Washington, D. C., the average natural background dose in Denver is roughly 0.08 rem per year larger than in Washington. ~~We~~ Multiplying 0.08 rem per year times 50 years (a conservative estimate of average lifespan) ~~to~~ calculates that an individual would receive 4 rem more dose from a lifetime of exposure to natural background radiation in Denver than he would receive in Washington. The estimated dose of ~~4140~~ 2070 man-rem ~~for both units~~ will be spread over at least ~~2000~~ 1200 workers over a two year period ~~(probably between 2500 and 3500 workers)~~. Therefore, the average dose to a worker for this project will be roughly 2 rem half of the variation in natural background radiation described above. space – space

In a different view, 2000 people living in Denver would receive 8000 more man-rem from a lifetime of exposure to natural background than 2000 people living in Washington. Clearly the people of Denver consider their exposure to natural background radiation to be acceptable, if they did not, they would all move away from Denver. Taking this argument a step farther, it is ~~we~~ noted that practically no one would even consider the increase in dose as a negative factor in his decision to move from Washington to Denver. Therefore, we conclude that based on a comparision with dose due to natural background radiation the estimated dose for the steam generator replacement represents an insignificant and acceptable impact.

Optional

INSERT D

We calculate that 4140 man-rem, the occupational dose estimate to replace the steam generators at both units, corresponds to a risk of less than one premature fatal cancer. We also calculate that 4140 man-rem corresponds to a risk of one genetic effect to the ensuing five generations. These risks are based on risk estimators derived in the BEIR report[14] from data for the population as a whole. For a selected population such as is likely for the exposed workers involved in the repair program consisting mainly of males in age range from 20 to 40, these risks would tend to be somewhat less. These risks are incremental risks, risks in addition to the normal risks of cancer and genetic effects we all face continuously. For a population of 2000 these normal risks would result in roughly 300 cancer deaths and 120 genetic effects (genetic effects are genetic diseases or malformations).

T: environmental impact caus[illegible] by [illegible] releases are less than [illegible] stated in the Surry FES?

INSERT E

As state above, steam generator replacement at Surry Unit 2 was completed in 1979. Table 4.3 shows the actual releases for Unit 2. As expected all of the releases were ~~much~~ lower than they would have been during [illegible] normal operation ~~with the exception of particulates. The particulate releases were in the same range as normal particulate releases.~~ Iodine releases were much lower than estimated; the overestimate is of no concern as both the estimated and measured releases are many times lower than normal releases. While no release estimate was made for noble gases, we and VEPCO fully expected minimal releases of noble gas during refueling. The Unit 2 release of 100 curies of noble gases is consistent with our expectations and many times lower than normal releases. Therefore, the relase estimates have ~~not~~ n been changed in light of the Unit 2 measurements.

INSERT F

Steam generator replacement operations at Unit 2 generated 1600 cubic meter of waste containing 64 curies of radioactivity. Both the volume and radioactive content of the solid radioactive waste generated ~~were of the same order of magnitude as~~ are comparable to our estimates.

ENVIRONMENTAL IMPACT APPRAISAL

BY THE OFFICE OF NUCLEAR REACTOR REGULATION

LICENSE NOS. DPR-32 AND DPR-37

VIRGINIA ELECTRIC AND POWER COMPANY

SURRY POWER STATION, UNITS 1 AND 2

DOCKET NOS. 50-280 AND 50-281

STEAM GENERATOR REPAIR AT SURRY POWER STATION

1.0 Proposed Action

Virginia Electric and Power Company (VEPCO) proposes to repair the six degraded steam generators in Units 1 and 2 of the Surry Power Station by replacing the lower assembly of each steam generator.

2.0 Background

2.1 History of Tube Degradation in Steam Generators

Since the Surry Units began generating power in 1972 and 1973, they have experienced a history of excessive tube degradation in the steam generators, resulting in the present condition in which approximately 24% of the tubes in Unit 1 and about 21% of the tubes in Unit 2 have been plugged to prevent the transfer of radioactivity from the primary coolant to the steam system.

The tube degradation is ascribed to a corrosion-related phenomenon called "denting," which involves the buildup of corrosion products in the crevices between the Inconel-600 heat exchanger tubes and the carbon steel tube support plates. As the corrosion product volume expands, the tubes are "dented," and occasionally develop leaks. The plugging of the damaged steam generator tubes affects the thermal and hydraulic performance of the steam generators. The degradation and resultant plugging of the tubes is continuing, and will soon result in serious and expensive operating restrictions such as derating. Another consequence of the tube degradation is the increased occupational exposure to radiation received by workers during the augmented inspection and plugging operations required on the steam generators because of their degraded condition.

The licensee's proposal to eliminate the tube degradation problem is described in detail in Reference 1, "Steam Generator Repair Program, Surry Power Station, Units 1 and 2," consisting of the original submittal dated August 17, 1977, with revisions dated December 2, 1977; April 21, June 2, June 13, June 30, September 1, October 25, and November 10, 1978. In order to provide the NRC staff with an independent basis for evaluating the radiological impacts associated with the repair of degraded steam generators at large pressurized water reactors (PWRs), we have contracted with Battelle Pacific Northwest Laboratories (PNL) to perform a generic radiological assessment of the steam generator repair and disposal operations. This assessment has been published in an NRC report,[2] NUREG/CR-0199, "Radiological Assessment of Steam Generator Removal and Replacement."

Information useful to the environmental review was also obtained from the NRC staff's Safety Evaluation Report (SER)[3] on the repair project, particularly the sections evaluating (1) the measures to reduce corrosion, (2) the As Low As is Reasonably Achievable (ALARA) considerations, and (3) the radiological consequences of postulated accidents.

3.0 Description of the Proposed Repair Method

A drawing showing the principal parts of a typical steam generator is presented in Figure 1. Figure 2 shows the regions where the main cuts are proposed to remove the degraded steam generator. It shows also the radiation levels in these regions. A brief description of VEPCO's proposed repair procedure follows.

In preparation for the repair of the steam generators in Surry Unit No. 2, all of the fuel will be removed from the reactor core and placed in the spent fuel pool. Then one of the three steam generators will be cut out of the reactor system. Present plans are to cut through the inlet and outlet reactor coolant piping, and through the steam line piping and feedwater piping. The steam generator wall will be cut on the transition zone between the lower assembly and the larger diameter upper shell assembly. The upper assembly will be lifted off and stored inside the containment vessel. The lower assembly will be lifted by crane from its support, tipped on its side, and transported out of the containment through the equipment hatch. It will then be transported to the concrete vault where it will be stored until the station is decommissioned. The replacement lower assembly will be transported into the containment and placed on its support. The old upper assembly, after some refurbishment, and the new lower assembly will be welded together in the field. The piping mentioned above will be welded to the repaired steam generator.

The same procedure will be followed for the other two steam generators. It is anticipated that the unit will be out of service for about six months. After Unit No. 2 is back in service, Unit No. 1 will be shut down to commence repairs on its steam generators.

A number of changes (see Sections 2.3 through 2.7 of Reference 1) have been made in the materials, the design and the operating procedure for the replacement steam generators to assure that the corrosion and denting problems will not recur. Among the more important of these changes are (1) using All-Volatile-Treatment chemistry control in the secondary system from the beginning of operation, (2) using corrosion resistant SA240 Type 405 ferritic stainless steel rather than carbon steel for the support plate material, (3) thermally treating the Inconel 600 heat exchanger tubes for better corrosion resistance,

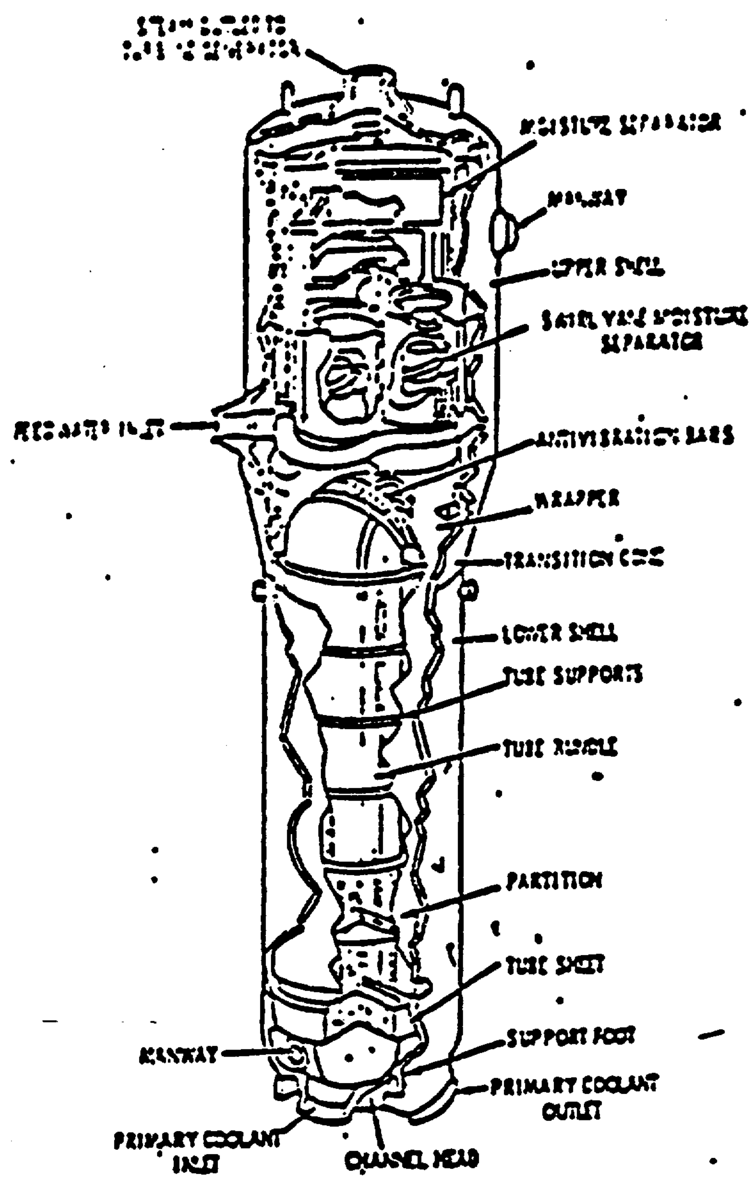

FIGURE 1. Typical Steam Generator

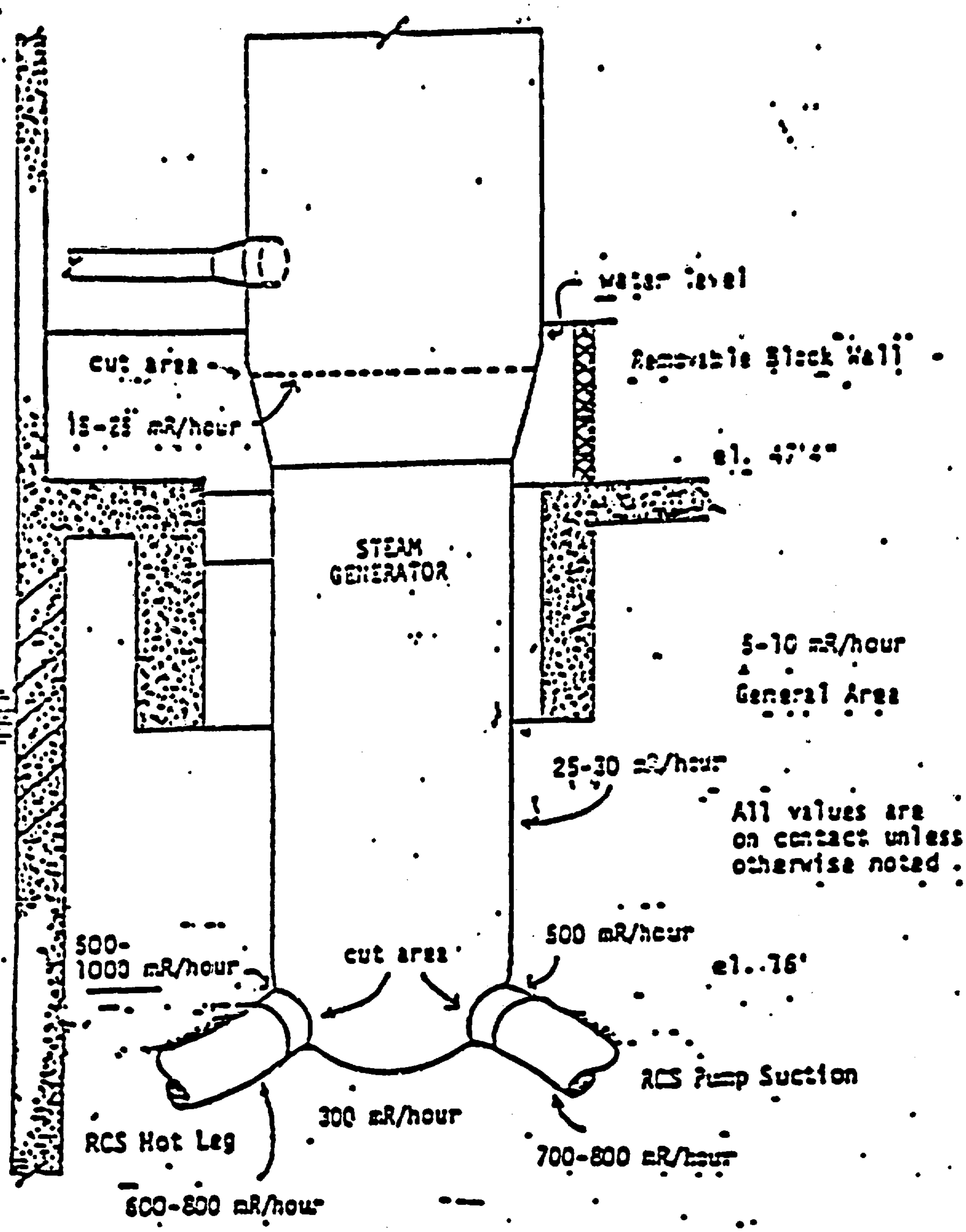

FIGURE 2
TYPICAL RADIATION LEVELS AROUND STEAM GENERATORS
WITH PRIMARY SIDE DRAINED AND SECONDARY SIDE AT
72% LEVEL

and (4) using a broached hole pattern with a quatrefoil design in the support plates rather than separately drilled flow holes to minimize the accumulation of corrosion products where the tubes pass through the plates. The staff's review of the expected affects of the proposed changes is presented in detail in the introductory section of the SER[3] for the repair project. We have concluded in the SER that the new steam generator design incorporates features to eliminate the potential for the various forms of tube degradation observed to date.

The licensee proposes to store the six degraded steam generator lower assemblies for the life of the plant in an above-ground concrete structure with walls about 3 feet thick. The structure will be sealed against water intrusion, but will be provided with an internal sump to collect any water which may get in by means such as condensation. Ventilation to allow for thermal expansion and contraction of the air inside the structure will be provided through high efficiency particulate air filters. Several removable 2-inch plugs will be provided to permit the conduct of radiation surveys without entering the structure.

The method of ultimate disposal will be decided when the reactor itself is scheduled for decommissioning.

4.0 Environmental Impacts of Steam Generator Repair Project

4.1 Radiological Assessment

4.1.1 Occupational Exposure

The generic radiological assessment of steam generator repair, prepared for the NRC by PNL and reported in NUREG/CR-0199, provides an upper bound estimate of the occupational doses and off-site radiological releases associated with the repair of steam generators at a large PWR. The conservatisms in PNL's methods of assessment, described below, provide the opportunity to reduce occupational doses for the repair operations in specific cases considerably below the generic estimates in NUREG/CR-0199.

The PNL generic estimates of occupational exposure (man-rem) were derived by multiplying maintenance activity man-hours by exposure rates (rem/hour) for the repair activities. Maintenance activities were developed by PNL as a composite of the work descriptions for removal and replacement of the steam generators at Surry and Turkey Point as determined by VEPCO and Florida Power and Light Company. Man-hour estimates for each activity were developed by PNL based on prior experience with similar activities, using standard estimating techniques. Exposure rates were based on information from several sources including data from measurements made at several operating

PWRs including the Surry Units. PNL usually selected exposure rate values on the high end of the range of values measured at the several plants.

The generic estimate of the total collective occupational whole body dose for the repair of three steam generators was presented in NUREG/CR-0199 as a range of values, 3380 to 5840 man-rem. Both ends of this range were conservatively estimated and represent upper bound values. The upper value, 5840 man-rem, was estimated assuming no credit for dose saving techniques. The lower value, 3380 man-rem, was estimated taking credit only for three dose reduction methods: (1) shielding by raising the steam generator water level, (2) using a limited amount of remote tooling, and (3) increasing the source-to-receiver distance. VEPCO's total estimate of 2070 man-rem per unit included not only these dose reduction measures but also measures such as additional temporary lead shielding, local decontamination, pre-job planning and pre-job training. The dose reduction procedures proposed by VEPCO are discussed in more detail in our SER.[3]

In view of the above discussion, the lower end of the generic range, 3380 man-rem, is the appropriate estimate for comparison with VEPCO's estimate of 2070 man-rem per unit. A summary comparing VEPCO's estimates with our generic estimates in NUREG/CR-0199 for the four main phases of the project is given in Table 4.1.

Table 4.1
Comparison of Occupational Collective Whole Body Dose Estimates

Phase	NRC Generic Estimate Dose, man-rem/unit	VEPCO Estimate Dose, man-rem/unit
Preparation	450-810	599
Removal	1100-1700	559
Installation	1800-330	877
Storage	30	35
Total	3380-5840	2070

The discrepancies between the detailed estimates are accounted for by the same factors discussed above for the total estimates. VEPCO's calculations of doses used commonly accepted practices for calculating doses and took into account the dose reduction measures proposed to maintain doses As Low As Reasonably Achievable (ALARA), including local decontamination, temporary lead shielding, pre-job planning, pre-job training and use of remote tools where practicable. In Section 6 of Reference 1, VEPCO has documented its consideration of the guidance with regard to ALARA issues in Regulatory Guide 8.8, Revision 2.[4] We have reviewed VEPCO's treatment of ALARA issues in detail in Section 4 of the SER.[3] We concluded that VEPCO's efforts to maintain occupational doses ALARA during the repair effort are reasonable.

In summary, the above discussion shows that the differences between the lower generic estimate (3330 man-rem per unit) and VEPCO's estimate (2070 man-rem per unit) can be reconciled by (1) the use of lower dose rates measured at Surry in the VEPCO estimate and (2) the use of more dose reducing measures by VEPCO than in the generic estimate. We therefore conclude that VEPCO's estimate of 2070 man-rem is a more realistic estimate than 3330 man-rem for the repair of the steam generators in one Surry unit. Consequently, in the remainder of this appraisal, we have used 2070 man-rem per unit as the occupational dose for the steam generator repair work at Surry. INSERT A

To put into perspective the occupational doses to be incurred in repairing steam generators, it is helpful to compare these doses (1) with those expected from the normal operation of nuclear plants, (2) with the projected long-term man-rem saving resulting from steam generator repair and (3) ~~with the doses from major maintenance operations at other plants.~~ with doses ~~we all~~ received from natural background radiation.

Although the AEC was starting to compile occupational exposure estimates for nuclear power plant operation at the time that the Surry 1 and 2 FES was prepared in 1972, such exposures were not specifically considered in the Surry 1 and 2 FES.

~~In recent environmental statements, we have estimated an annual occupational dose of about 500 man-rem per nuclear unit, averaged over the life of the plant (30-40 years). This value is based on the average of annual doses received at operating plants. In 1977, the average occupational dose per unit for light water reactors in the United States was 570 man-rem.[5] The 1977 doses ranged from 87 to 3142 man-rem per reactor unit, with major maintenance during the year accounting for the larger values. Occasional large doses associated with major maintenance, such as the 2070 man-rem dose per unit for the proposed steam generator repair, will occur. NRC regulations require that measures be taken to keep these doses ALARA.~~ INSERT B

In 1975, 1976 and 1977, workers at Surry Units 1 and 2 received whole body doses of 638 man-rem,[1] 1287 man-rem[1] and 1410 man-rem,[6] respectively, during the inspection and plugging of degraded steam generator tubes. The total occupational doses for the two units were 1649 man-rem in 1975, 3163 man-rem in 1976, and 2416 man-rem in 1977.[5] These doses are higher than the ~~570~~ 583 man-rem per year average for U.S. light water reactors ~~in 1977~~. As mentioned at the end of Section 3, we concluded in the SER that the proposed repair would eliminate the potential for the kinds of the tube degradation observed to date. Based on our experience with plants without severe denting problems and the staff conclusion regarding corrosion reduction, doses due to the inspection and plugging of degraded tubes would be markedly reduced, and we conclude that occupational exposure after the repair will be reduced by hundreds of man-rem per year for the two units. This would result in total occupational exposures at Surry approaching more closely the national average value for light water reactors (~~370~~ 500 man-rem per unit) ~~in 1977~~. We further conclude that the dose savings of hundreds of man-rem per year would over a period of years tend to offset the immediate one-time dose of ~~2073~~ man-rem for repairing the three steam generators in ~~each~~ both units. ~~4140~~ 2070

VEPCO has estimated that the after-repair occupational dose for the inspection and repair of degraded steam generator tubes will be reduced to 25 man-rem per year for the two Surry units. Although the 25 man-rem per year appears to be a reasonable number for Regulatory Guide 1.83 inspections, we have conservatively estimated a higher value of 100 man-rem per year to account for additional inspections which may be performed to check the initial performance of the improved steam generators and to correspond more closely to recent industry experience.

The saving of occupational exposure resulting from the repair effort may be estimated by subtracting the estimated annual dose after repair from the observed annual dose before repair. The doses of 1287 man-rem in 1976 and 1410 man-rem in 1977 are considered representative of exposures related to steam generator operation before repair. The 638 man-rem dose in 1975 is not representative of operation with degraded steam generators because significant tube degradation was not observed in Unit I until September 1975 and in Unit II until January 1976. Subtracting the after-repair dose of 100 man-rem from the before-repair range of 1287 to 1410 man-rem leads to a saving of 1187 to 1310 man-rem per year. At these rates of saving, the 4140 2070 man-rem cost of the repair would be offset in 3 to 4 years.

ck

Operating experience at the Surry plant over the last three years demonstrates that the steam generators can continue to operate with the degraded tubes plugged, but frequent inspection and plugging as performed during the last three years would be required to assure that the integrity of the steam generators would be maintained. At the current rate of tube plugging, about 3% per year, it is the staff's judgment that, with continued inspections and plugging, the Surry units could continue to operate for some period and, even if reduced power were required, the economic balance would favor continued operation of the units, as opposed to decommissioning the reactors. On the other hand, continued degradation of the integrity of a major component such as steam generators, results in continued small reductions in overall safety margins.

This potential has been carefully considered on the basis of the results of each inspection over the past ~~three~~ four years. While these margins remain acceptable, any continued degradation would require continued careful assessment to assure that degradation does not become excessive.

The additional health risks due to these doses over normal risks are quite small, less than one percent of normal risk to the project work force as a whole.

INSERT 'C' — JK

normal

In summary, the staff has drawn the following conclusions regarding occupational radiation exposure. VEPCO's estimate of 2070 man-rem per unit for the repair of the steam generators is reasonable. This dose falls within the normal range of annual occupational doses which have been observed in recent years. Our review in the Safety Evaluation Report[3] concludes that VEPCO is taking the necessary steps to insure that occupational doses will be maintained ALARA. ~~Finally,~~ The renovation of the steam generators will lead to occupational dose reductions of hundreds of man-rem per year. These dose savings over a period of several years will outweigh the immediate large one-time dose resulting from the repair operation. The individual risks associated with the exposures involved in the repair program will be controlled and limited so as not to exceed the limits set forth in 10 CFR Part 20 for occupational exposure. These limits assure that the hazard to any exposed individual is extremely small.

The doses to the work force as a whole and to the average worker will be within the variations in lifetime doses due to natural background radiation in the U.S.

~~Even should there be an incremental 2000 man-rem per reactor increase in occupational exposure, the increased risk of premature fatal cancer induction is predicted to be less than one event (e.g., 0.2 events risk estimation from data for the population as a whole as given in the BEIR report)[14]. The increased risk of this exposure on genetic effects to the ensuing five generations is also predicted to be less than one event (e.g., 0.5 events risk estimation from data for the population as a whole as given in the BEIR report). For a selected population such as is likely for the exposed workers involved in the repair program consisting principally of males in the age ranges from 20 to 40, these risks would tend to be somewhat less.~~

For the foregoing reasons, the Staff concludes that the environmental effect due to occupational radiation exposure is ~~not significant~~ insignificant and ~~acceptable~~ acceptable.

4.1.2 Public Radiation Exposure

Our independent analysis of the gaseous and liquid releases of radioactivity from the plant site during the steam generator repair project is based in large part on the generic report,[2] NUREG/CR-0199, prepared by Pacific Northwest Laboratories for the NRC. The estimates of releases in this report are upper bound values, based on conservatively high estimates for each type of release.

Table 4.~~2~~ 3

Radioactive Effluents from Surry Station

Type of Radioactive Effluent	Steam Generator Repair: VEPCO Release Estimates (Ci/Unit)	Actual Surry Unit 2 Releases (Ci/Unit)	Steam Generator Repair: NUREG/CR-0199 Release Estimates (Ci/Unit)	Operating Experience: Surry 1976 Average Releases (Ci/Unit)	Operating Experience: Surry 1977 Average Releases (Ci/Unit)	Average 76/77	FES: Annual Average Release Estimates (Ci/Unit/Yr)
GASEOUS							
Noble Gases	-	100	-	9600	9510	0	3360
Halogens (Iodines)	0.0045	0.0000087	included in particulates	0.27	0.24	0	0.92
Particulates	0.0031	.0013	0.0001	0.041	0.001	0	-
Tritium	8.5		-	19	44	0	-
LIQUID							
Mixed fission & activation products	0.35	0.5	0.14	17	3.8	0	53
Tritium	0.1		190	390	204	0	1000

- 10 -

Similar estimates of the gaseous and liquid effluents during the repair were made by VEPCO in Reference 1. These estimates were based on the specific equipment design and procedures to be used at the Surry plant. Table 4.2[3] presents the NUREG/CR-0199 estimates[2] and VEPCO's estimates[1] of the radioactive effluents which will be released as a result of the repair effort. Table 4.2[3] also presents Surry's reported average radioactive effluent releases for 1976[12] and 1977,[4] and the annual average radioactive effluent release estimates presented in the Surry FES.[7] Table 4.2[3] shows that the releases estimated by VEPCO and the generic report for the repair effort are much lower (except for the airborne particulates) than the Surry 1976 and 1977 releases and the FES annual average estimates. For airborne particulates, the VEPCO estimates of releases are in the same range as or lower than the 1976 and 1977 releases in Table 4.2.[3] The Surry FES[7] does not present numerical estimates of airborne particulate and tritium releases. However, airborne particulates and tritium are small dose contributors compared to radioiodine and noble gases for the highest dose pathways of exposure to individuals in the general public. Therefore, the conclusions regarding dose consequences presented in the FES are still valid.

The VEPCO estimates of gaseous releases from the repair effort are larger than the NRC generic estimates because the VEPCO values include the releases from fuel unloading and reloading, which are much larger than the gaseous releases from the rest of the repair operation. VEPCO's figures are based mainly on experience at Surry with refueling operations. The refueling releases were not included in the NUREG/CR-0199 estimate, since the utility normally would plan to carry out the steam generator repair during a scheduled shutdown for refueling. For the other gaseous releases such as those from pipe cutting, VEPCO used commonly accepted calculational methods, for example in calculating the kerf for each cut and in assuming that all radioactive material adhering to the inner cut surface would become airborne. Therefore, we conclude that VEPCO's estimates of gaseous releases, including those from the fuel handling operations, were carried out in an acceptable manner and represent reasonable estimates.

In Table 4.~~2~~3, the estimates for liquid releases of tritium vary widely because VEPCO plans to store the primary reactor coolant water for re-use, whereas the generic (NUREG/CR-0199) estimate assumes that the coolant is discharged after processing for nuclides other than tritium. The VEPCO estimate for the release of mixed fission and activation products is larger than the generic estimate because the latter did not include the releases of the secondary coolant nor the local decontamination solutions. Both estimates included the activities in laundry waste water. VEPCO based its estimates of releases from the laundry waste water and secondary coolant on past measurements of these sources at Surry. VEPCO used commonly accepted methods to calculate the releases from local decontamination solutions. Based on these several considerations, we conclude that the licensee has made reasonable estimates of the radioactive liquid effluents during the repair effort, and that these estimates correspond, as well, to our own best estimates. ← INSERT E

Our estimates of dose to individuals and to the population as a whole in the area surrounding the Surry site are based on the radioactive effluents which VEPCO estimated for the repair effort (summarized in Table 4.2) and on the calculational methods presented in Regulatory Guides 1.109, 1.111 and 1.113.[11,9,8] We conclude that offsite individuals will receive doses from the repair effort of the same order or less than the annual dose consequences presented in the FES.[7] The doses to the population within 50 miles will be less than 5 man-rem to the thyroid or total body from liquid effluents, and less than 2 man-rem to the thyroid or total body from airborne effluents. Every year the same population (about 2 million) will receive a total body dose of more than 100,000 man-rem from the natural background radiation in the vicinity of Surry (0.065 rem per year).[13] Thus, the population total body dose from the repair effort is less than 0.01% of the annual dose due to natural background. On these bases, we conclude that the doses to individuals in unrestricted areas and to the population within 50 miles due to gaseous and liquid effluents from the repair project will ~~not~~ be ~~environmentally significant.~~ insignificant and acceptable ← STET

VEPCO has estimated that the repair effort will generate 740 cubic meters of solid waste per unit containing 19 curies of radioactivity.[1] Based on the information presented in NUREG/CR-0199, we estimate that 2300 cubic meters of solid waste containing 37 curies of radioactivity will be generated per unit.[2] Our estimate is higher than the licensee's estimate because we assumed that all of the radioactivity in the solutions from main coolant pipe decontamination would be solidified. Neither of these estimates include the radioactivity on the inside surfaces of the old steam generators. In 1976 and 1977, Surry generated an annual average of 370 cubic meters of solid waste per unit containing 310 curies per unit of radioactivity.[6,2] The amount of radioactivity in the wastes from the repair effort will be about ten percent of this average annual production during operation. Since the solid wastes represent an impact which is a small part of the impact from solid wastes from normal operation, we conclude that the radiological impact is not environmentally significant.

INSERT F

On the basis of long term onsite storage of the degraded steam generators until the reactors are decommissioned, there will be essentially no radioactive effluents from the generators for 30 years. Final disposal at that time will result in small offsite gaseous and liquid radioactive releases, because a large fraction of the radioactive nuclides in the steam generators will have decayed in 30 years.

The stored steam generators will present a source of direct and scattered radiation. We estimate that each steam generator will contain about ~~2700~~ 1090 Ci of radioactivity. ~~including 750 Ci of Cobalt-60, the principal contributor to direct dose.~~ This is based on the estimate of the contamination of steam generator primary side surfaces given in NUREG/CR-0199.[2] The staff estimated a dose rate of less than 0.0001 milli-rem per hour at the nearest site boundary due to this activity. An individual spending an entire year at this location would receive less than 1 milli-rem of radiation exposure. This dose would be approximately halved every 5 years because of the decay of the principal contributing activity, Co-60. VEPCO made a similar calculation and reached the same conclusion. Since this dose represents roughly one percent of the annual dose from natural background,[12] the staff concludes that the direct dose impact to the public from the stored generators will be ~~minimal and not environmentally significant.~~ insignificant and acceptable

dose rate

STET

The repair effort will return the plant to the design condition on which our evaluation in the FES[7] was based. Therefore, we conclude that the estimates of routine releases of radioactivity and the potential doses to the public from those effluents after the repair will remain as presented in the FES.

Since our estimates of radioactive effluents from Surry during normal operation after the repair effort are about the same or lower than those effluents presented in the FES,[7] we conclude that the impact on biota other than man will be no greater than that impact presented in the FES.

In summary, the offsite doses resulting from the steam generator repair will be less than those from recent plant operation since the expected releases of radioactive material as a result of the repair effort will be less than the releases from normal operation. These doses are comparable to doses presented in the FES[7], and small compared to the annual doses from natural background radiation. Therefore the radiological impact of the repair project to the public will not significantly affect the human environment ~~and is acceptable.~~ delete

4.2 Economic Costs of Steam Generator Repair

VEPCO has estimated that, over the life of the plant, the proposed steam generator repair project will result in a net dollar savings of at least $125,000,000 compared with the cost of continued operation of the existing steam generators, with an optimistic assumed scenario of tube plugging and derating. The cost of purchasing and installing the steam generator lower assemblies and associated activities is estimated at about $66,000,000 for the two units.

The cost of onsite storage and final disposal of the six degraded lower assemblies is expected to be about $1,000,000. The estimate for replacement power during the outage for repair is about $66,000,000. The total project cost is therefore about $133,000,000.

The cost of replacement power during the outage is based on the higher fuel costs of coal, oil and gas-fired units which VEPCO would press into service to replace the power lost by the shutdown of one of the Surry Units. The VEPCO estimate of $66,000,000 based on differential fuel costs is reasonable in view of the total value of the replacement power: 822,500 kW x 0.6 capacity factor x 360 days x 24 hours/day x $.04/kWhr = $183,000,000. VEPCO's estimate of $66,000,000 corresponds to a fuel differential cost of about $0.014/kW hr between fossil-fired plants and a nuclear plant. We consider this differential cost estimate reasonable.

The VEPCO estimated net saving of $125,000,000 is based largely on the cost of replacement power due to derating. We assessed the reasonableness of this estimate by comparing it to the cost of replacement power if both units had to be derated. The cost would be about $360,000,000 after 10 years of derating at an assumed rate of 3% per year (the current rate of tube degradation is greater than 3% per year). Therefore, VEPCO's estimate that $125,000,000 would be saved over the life of the plant even after spending $133,000,000 for the steam generator repair is conservative.

The VEPCO estimate of $1,000,000 for final disposal of the degraded steam generators assumes onsite storage for 30 years followed by sectioning and shipment to a licensed burial facility for low-level waste. This estimate is not out of line when compared to recent estimates[13] for the decommissioning of complete reactors by dismantlement after a cooling period (about $30,000,000).

This consideration of costs does not take into account the continuing costs of tube inspection and plugging services, nor the costs of possible future modifications to control corrosion, if the repair is not done. It also does not consider the cost of the current lack of reliability and availability. In 1976, Surry Unit 1 was offline for 36 days and Unit 2 for 139 days for tube inspection and plugging. In 1977, the outage times for tube inspection and plugging were 50 days for Unit 1 and 70 days for Unit 2.

In Section 5, the economic and other impacts of alternative methods of repairing the steam generators will be compared.

4.3 Non-Radiological Environmental Costs

The non-radiological impacts of the repair project on the environment are small compared to those of building and operating the reactors. These small costs include the commitment of about one acre of land on the site for the storage of the degraded steam generators for the life of the station. There will be some noise generated by onsite equipment and a small effect on local traffic by approximately 125 construction workers per shift, but these effects will be insignificant.

The material costs of the proposed action will include about 1350 tons of carbon steel, 48 tons of stainless steel, 3000 cubic yards of concrete. These quantities are about 2% of the quantity of steel and about 8% of the concrete used in the original construction of the plant.

4.4 Environmental Impact of Postulated Accidents

As is discussed in our SER,[3] the design and plant operating parameters which are relevant to accident analyses will not change as a result of the steam generator repair effort. Therefore, the assessment of the environmental impact of postulated accidents presented in the final environmental statements for Surry Units 1 and 2 will be unchanged and remain valid. However, there are a few types of accidents which are possible due to the operations involved in the repair effort.

One such postulated accident is the rupture of the Reactor Water Storage Tank by a crane drop. The bounds of the radiological consequences of this accident were discussed in the FES[7] for Surry Unit 2 under the heading -"Release of liquid waste contents."

A second type of postulated accident related to the repair effort would involve the dropping and rupture of a removed steam generator outside the reactor containment while it was being transported to the storage vault. This accident would involve the rupture of the steel covers which will have been welded over each of the steam generator cuts to prevent the spread of the neutron-activated corrosion products adhering to the inner surfaces. The method used to assess the radiological consequences of a rupture which could release contamination on the primary side surfaces to the atmosphere is described in the SER.[3] To obtain a more realistic estimate for the purpose of evaluating the environmental impact, we used an atmospheric dispersion factor of 1.6×10^{-4} seconds per cubic meter. On this basis, we concluded that this accident would result in a dose of 0.05 rem to the lungs of an individual at the site boundary.

The dose consequences of a drop accident inside containment would be lower since the containment ventilation system would reduce the radioactivity released to the environment.

In summary, we concluded that the consequences of postulated accidents from the repair operation would be not environmentally significant ~~and are~~ acceptable.

5.0 Impacts of Alternatives

delete

The basic choices of future action regarding the tube degradation problem are (1) repair of the degraded steam generators, (2) continuation of the present mode of operation, with increasing costs in plant efficiency and occupational exposure, and (3) shutdown of the Surry Units 1 and 2, and replacement by generating plants of different design. VEPCO opted for repairing the degraded steam generators, with changes in design, materials and operating procedures calculated to eliminate the tube denting problem.

In the absence of methods to arrest or greatly reduce denting, the continuation of operation for an extended period in the present mode is impractical. With tube degradation and plugging continuing at the present rate, the units would soon be required to operate at lower power. VEPCO has estimated the cost of replacement power, based on fuel differential costs, to be about $180,000 per day for the shutdown of a unit. Consequently, the cost of derating the Surry units would be high. Also, the man-rem cost of occupational exposure during inspection and plugging of tubes would continue to be high, resulting in a dose higher than 4140 man-rem in 3 or 4 years. Laboratory test programs on the denting phenomenon are currently underway to define the corrosion process more precisely and to develop preventive measures such as corrosion inhibitors. While the combination of steam generator secondary side cleaning and corrosion inhibitors is being studied by some utilities to combat denting in its early stages, the denting phenomenon at Surry is too advanced for such measures to be practical. Therefore, VEPCO cannot count on a greatly reduced future rate of tube degradation to justify continuing the present mode of operation.

The option of shutting down the Surry station and replacing it with a plant of different design is easily shown to be much more costly than that of repairing the steam generators. VEPCO estimates (Section 5.5.1.3 of Reference 1) that the capital cost of new nuclear units with improved steam generators would be about $2.7 billion dollars and would require about 12½ years to build. New fossil units would cost about $1.2 billion and require about 8 years to build. (We consider the coal estimate low; capital cost for a coal-fired plant is usually about 80% of that for a nuclear plant.) Florida Power and Light Company made a similar comparison for repairing the steam generators in Turkey Point Units 3 and 4. Their estimate was about $77/kW for the proposed steam generator repair operation, compared to $224/kW for gas turbine units, $1059/kW for a coal-fired plant, and $1448/kW for a nuclear plant of improved design. Although the Turkey Point estimates are in different terms, the cost comparison again overwhelmingly favors the repair option. For these reasons, the plant replacement option is not economically feasible. In addition, there would be significant environmental impacts from such a large scale construction operation. The most practical overall option is therefore to repair the degraded steam generators.

In the remainder of this section, we shall consider the radiological and economic costs of several alternative ways of repairing and disposing of the degraded steam generators. An important item in estimating economic costs is the cost of replacement power during unit outage. VEPCO's cost estimate of $66,000,000 for the power needed during the 180 day outage of each unit corresponds to a replacement power cost of nearly $200,000 per unit per day of outage.

5.1 Decontamination

VEPCO has estimated (Section 5.3.2.1 of Reference 1) that chemical decontamination of the steam generators before cutting would result in a net saving of 300 to 400 man-rem per unit in occupational exposure. However, it would cost about 1.5 months in additional outage of each unit. Replacement power for this additional outage would cost about $9,000,000. In addition, about 200,000 gallons of radioactive waste would be produced.

VEPCO also considered mechanical decontamination of the inner surfaces of the steam generator, but estimated that the occupational exposure during the decontamination operation would exceed the later saving in dose to workers.

Based on our knowledge of the limited experience of the nuclear industry in large scale, high volume chemical decontamination of reactor coolant systems, we can make the following statements. Most importantly, decontamination would add significant expense and time delays to the repair effort, including the cost of replacement power during those time delays. There is a degree of uncertainty about the compatibility of the decontamination fluid with materials in the coolant system. The research and testing which would be required to provide adequate assurance of material compatibility to obtain our approval to decontaminate would adversely impact on the cost and schedule of this repair effort. While the lower dose rates resulting from decontamination would reduce occupational dose during the repair operations, occupational radiation doses received during the decontamination effort itself would partially offset the dose reduction. Decontamination would not remove the radioactivity inside tubes which are plugged. Large volumes of contaminated fluids would be produced and require processing. That processing would incur further costs and occupational dose. In summary, we conclude that the costs of decontamination including costs due to time delays would outweigh the dose savings. Therefore, the use of large scale decontamination in this repair effort is not a viable option.

5.2 Retubing of Existing Steam Generators

The retubing operation would involve (1) removing the upper or dome portion of the steam generator, (2) removing the lower assembly internals and tubes, (3) replacing the latter with state-of-the-art internals and tubes, and (4) refurbishing the upper internals, and (5) welding the dome back in place. VEPCO has estimated (Section 5.5.1.2 of Reference 1) that the cost of this operation in both dollars and occupational exposure would be higher than the proposed replacement of the complete lower assembly. VEPCO further points out that shop fabrication of new lower assemblies would provide more positive assurance that the quality of the repaired generators was acceptable.

On the other hand, the staff is aware of recent developments by Westinghouse in the technology of in-place refurbishment which show some promise of reducing unit outage and personnel exposure below the values for VEPCO's proposed repair method. However, at this time not enough information is available for us to make a detailed assessment of the retubing alternative.

A detailed proposal for our review is expected in the near future. If our assessment is favorable, in-place retubing may be an alternative for steam generator repairs in the future. However, in the time frame contemplated for the proposed licensing action, this is not considered to be an available alternative to the proposed action.

5.3 Replacement of the Entire Steam Generator

For this alternative, a construction opening in the containment wall about 20 feet wide and 40 feet high would be required, since the upper assembly of the steam generator could not pass through the existing equipment hatch. The personnel exposure for this alternative would be about the same as for the proposed repair, because essentially the same high-dose operations will be required in each case. Elimination of the cut across the diameter of each steam generator results in only a small saving of radiation exposure. The capital costs are estimated to be about 15% higher. The principal cost difference is due to an estimated additional outage of about 120 days per unit for the alternative. This corresponds to an additional requirement of about $40,000,000 worth of replacement power during the repair of both units, calculated at the rate of about $180,000 per day of outage per unit. For these reasons, the staff concludes that VEPCO's proposed repair method is preferable.

5.4 Alternate Disposal Methods

In the Appendix to NUREG/CR-0199[2] the radiological costs of several alternative methods for the disposal of the degraded steam generators are evaluated. The results of this analysis are summarized in Table 5.1.

Table 5.1 Steam Generator Disposal Alternatives

Option	Approximate Man-Rem per Steam Generator	Approximate Airborne Release Ci per Generator
Long-term[a] storage (including surveillance) with intact shipment	10	Negligible[b]
Long-term[a] storage with cut-up and shipment	16	0.005
Shorter-term storage with cut-up - at 5 yr	230	0.026
- at 15 yr	50	0.015
Immediate intact shipment	2.4[c]	Negligible[b]
Immediate cut-up and shipment by rail/truck - no decontamination	530	0.042
Immediate cut-up and shipment by rail/truck - with chemical decontamination	270	0.010

[a] 30 to 40 years

[b] Since the steam generator will be sealed before it is removed from containment, no release of radioactive material is expected during the repair operation.

[c] Estimates for short-term storage followed by intact shipment would be only slightly larger than this, perhaps 5 man-rem.

It is seen that the options involving intact shipment would have the lower radiological costs; but intact shipment is possible only by barge and at present there is no licensed burial ground with facilities for off-loading an entire lower assembly from a barge.

The next best alternative, radiologically, would be long-term storage of the generators onsite until the reactors are decommissioned, followed by sectioning and shipment at that time. This is the plan proposed by VEPCO.

Immediate cut-up and shipment to a burial facility would involve a substantial cost in occupational exposure, even after chemical decontamination. Comparing Tables 5.1 and 4.2, it is seen that the airborne releases from the segmenting operation would be larger than those from the rest of the repair effort.

The two disposal alternatives considered by VEPCO (Section 5.5.2.2 of Reference 1) were immediate intact barge shipment and near-term sectioning for off-site disposal. The estimated economic and radiological costs are given in Table 5.2 for the disposal of six steam generators.

Table 5.2 Costs of Alternate Disposal Methods (VEPCO)

Method	Cost, dollars	Exposure[a], man-rem
On-site Storage With Final Disposal at Decommissioning	1,000,000	80
Intact Barge Shipment	1,200,000 to 1,500,000	200
Near-term Sectioning	[illegible],700,000	1000 to 2000

[a]Note that these doses are for six lower assemblies. The estimates in Table 5.1 are for one lower assembly.

According to the VEPCO estimates, the proposed disposal method of on-site storage with final disposition at the time of plant decommissioning should result in the least cost in dollars and in radiation exposure. The staff agrees that the proposed disposal method costs less in radiation exposure than alternatives available at present. The proposed onsite storage leaves open the option of intact barge shipment in the event that a burial ground with adequate off-loading facilities becomes available.

6.0 Basis and Conclusion for not Preparing an Environmental Impact Statement

We have reviewed the proposed steam generator repair action and have reached the following conclusions.

(1) The proposed replacement of the lower assemblies of the steam generator is the best available option, from both the radiological and economic standpoints, for eliminating the tube degradation problem.

(2) The one time occupational exposure of 2070 per unit is larger than the average annual occupational exposure associated with the operation of a nuclear power plant. However, such occupational exposures or larger exposures would be incurred in a few years by continued operation at Surry even absent the proposed action. In the long run the proposed action will cause occupational exposures at an operating Surry facility to be reduced on a long term cumulative basis as well as on an annual basis. Therefore it does not appear that there will be a substantial increase in occupational radiation exposure caused by the work authorized.

We have reviewed the dose reduction measures to be used by the applicant and conclude that the doses would be ALARA. We have also considered the health effects resulting from such exposure and concluded that these are not significant.

(3) The new steam generator design incorporates features which will eliminate the potential for the various forms of tube degradation observed to date.

(4) The restoration would restore the generators to the condition evaluated in the FES and would result in an occupational dose saving of hundreds of man-rem per year, because there would be a marked reduction in the amount of tube inspection and tube plugging required to keep the generators in acceptable operating condition.

(5) Offsite doses resulting from the steam generator repair will be less than those from recent plant operations, comparable to doses presented in the FES[7], and small compared to the annual doses from natural background radiation. Therefore, the offsite doses will not be significant.

On the basis of the foregoing analysis, the staff concludes that the proposed steam generator repair action will not significantly affect the quality of the human environment.

We have reviewed this proposed facility modification relative to the requirements set forth in 10 CFR Part 51 and the Council of Environmental Quality's Guidelines, 40 CFR 1500.6. We have determined that the proposed license amendment will not significantly affect the quality of the human environment. Therefore, the staff has found that an environmental impact statement need not be prepared, and that pursuant to 10 CFR 51.5(c), the issuance of a negative declaration to this affect is appropriate.

REFERENCES

1. Steam Generator Repair Program, Surry Power Station, Unit Nos. 1 and 2, Virginia Electric and Power Company, August 17, 1977, and revisions dated December 2, 1977; April 2[illegible], June 2, June 13, June 30, September [illegible], October 25, and November 10, 1978.

2. NUREG/CR-0199, "Radiological Assessment of Steam Generator Removal and Replacement," G. R. Hoenes, D. A. Waite, and W. D. McCormack, Pacific Northwest Laboratories, June 1978.

3. Safety Evaluation Report for the Surry Power Station Steam Generator Replacement, U. S. Nuclear Regulatory Commission, December 1978.

4. Regulatory Guide 8.8, "Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations will be As Low As is Reasonably Achievable", (Revision 2), U.S. Nuclear Regulatory Commission.

5. NUREG-0482, "Occupational Radiation Exposure at Light Water Cooled Power Reactors 1977," L. J. Peck, U. S. Nuclear Regulatory Commission, November 1978.

6. "Annual Operating Report of Surry Power Station for 1977," Virginia Electric and Power Company.

7. "Final Environmental Statement related to the operation of Surry Power Station, Unit 2," U. S. Nuclear Regulatory Commission, June 1972.

8. Regulatory Guide 1.113, "Estimating Aquatic Dispersion of Effluents from Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I," U. S. Nuclear Regulatory Commission.

9. Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors," (Revision 1), U. S. Nuclear Regulatory Commission.

10. NUREG/CR-0130, "Technology, Safety and Cost of Decommissioning a Reference Pressurized Water Reactor," R. I. Smith, G. J. Konzek and W. E. Kennedy, Jr., Pacific Northwest Laboratories, June 1978.

11. Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," (Revision 1), U.S. Nuclear Regulatory Commission.

12. NUREG-0367, "Radioactive Material Releases from Nuclear Power Plants (1976)," T.R. Decker, U.S. Nuclear Regulatory Commission, March 1978.

13. NCRP No. 45, "Natural Background Radiation in the United States," National Council on Radiation Protection and Measurements, 1975.

14. "The Effects on Populations of Exposure to Low Levels of Ionizing Radiation", (BEIR Report), National Academy of Sciences, November 1972, Reprinted July 1974.

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

OCT 2 6 1992

Docket No.: 50-338

MEMORANDUM FOR: Herbert N. Berkow, Director
Project Director II-2
Division of Reactor projects I/II

FROM: James A. Norberg, Chief
Mechanical Engineering Branch
Division of Engineering

SUBJECT: SAFETY EVALUATION ON STEAM GENERATOR REPLACEMENT PROJECT-NORTH ANNA POWER STATION UNIT 1 (TAC NO. M84139)

REFERENCE: Submittal, M. L. Bowling (VEPCO) to L. B. Engle (NRC), dated July 16, 1992

The referenced submittal provides an engineering review and safety evaluation for replacement of the three North Anna Unit 1 (NA-1) steam generator lower assemblies and the temporary modifications. This document also provides a description of construction activities associated with the implementation of the steam generator repair.

The Mechanical Engineering Branch (EMEB) has reviewed this licensee's submittal. Particularly, the following areas are covered:

1. Changes in piping configurations
2. Modifications in SG supports
3. Removal of pipe whip restraints
4. Evaluation of seismic loading

Based on the information provided by the licensee, the staff concludes that the NA-1 steam generator replacement project is performed in accordance with the current industry practice for such activities and is generally acceptable in the areas reviewed by EMEB. Specifically, all piping and pipe supports of the reactor coolant system, main steam system, and feedwater system will be reinstalled to their original configurations. Furthermore, all applicable design basis seismic and stress analyses have either been reevaluated or reperformed to verify the capability of the repaired systems to perform their intended functions.

The staff has concerns, however, over the use of Code Case N-411 damping values as stated in the draft UFSAR Section 3.7.3. According to Regulatory Guide (RG) 1.84, "Design and Fabrication Code Case Acceptability, ASME Section III Division I," these damping values may be used only in those analyses in which current seismic spectra and procedures are employed. To utilize these alternate damping values, the licensee should either comply with all the RG 1.84 requirements or, otherwise, provide a justification for staff review.

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Our safety evaluation and SALP input are enclosed.

ORIGINAL SIGNED BY:

James A. Norberg, Chief
Mechanical Engineering Branch
Division of Engineering

Enclosures: as stated

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ENCLOSURE 1
SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION
STEAM GENERATOR REPLACEMENT PROJECT
VIRGINIA ELECTRIC POWER COMPANY
NORTH ANNA NUCLEAR POWER STATION UNIT 1

INTRODUCTION

The three Westinghouse Model 51 steam generators (SGs) 1-RC-E-1A, 1B, and 1C of North Anna Unit 1 have experienced corrosion-related degradation that require periodic inspection and plugging of SG tubes to ensure their continued safe and reliable operation. Despite improvements in secondary water chemistry, tube degradation has continued over the years in the SGs.

In the current plant configuration, the plant is limited to 95% power. In addition, the current status of the existing SGs will require extensive tube inspections which will result in significant dose to personnel. The primary causes of the degradation are: (1) intergranular stress corrosion cracking in the tubing in the tubesheet region and at support plate intersections, (2) [mechanical wear of the tubing at tube-to-anti-vibration bar intersections, and (3) primary side stress cracking of tight radius U-bends in the tubing.

As stated in the licensee's submittal of July 16, 1992, the licensee determined to correct the deficiencies by providing a SG with enhanced material to resist the previously exhibited degradation mechanisms. In addition, the feedwater, SG blowdown lines, and the SG drains will be replaced with chrome-moly material to provide improved capability in erosion/corrosion resistance. Such a new SG consists of the original steam dome and a replacement SG lower assembly. The three new SG lower assemblies are designed and fabricated to be physical duplicates of the original lower assemblies.

Certain design changes and enhancements have been made in the new SG lower tube bundle assemblies which address the operating experience of the original SGs and which enhance the overall reliability and maintainability of the SGs. The repairment is confined to removal and replacement of the lower assemblies mainly due to limitations on the diameter of equipment that can be moved through the equipment hatch.

Implementation of the repair will be accomplished by severing the reactor coolant piping and all attached piping at the SG nozzles, severing the SGs within the transition cone and removing the lower assemblies from the containment. The steam domes will remain in containment and will be modified for the installation of a flow restrictor in the steam outlet nozzle. The existing downcomer flow resistance plates on the wrapper plate will be removed and the shells will be prepared for welding to the lower assemblies. The new shop-fabricated SG lower assemblies will be transported into the containment through the equipment hatch and cónnected to the original steam domes.

EVALUATION

The licensee's July 16, 1992, submittal contains a copy of the draft design change package (DCP), 90-13, "Steam Generator Repair." This draft DCP provides an engineering review and safety evaluation for replacement of the three NA-1 SG lower assemblies and the temporary modifications and construction activities associated with the implementation of the SG repair. This evaluation addresses the effects of the steam generator replacement (SGR) on the following issues:

1. Changes in piping configurations
2. Modifications in SG supports
3. Removal of pipe whip restraints
4. Evaluation of seismic loading

As part of the SG repair, heavy loads must be rigged into, out of, and within the containment building. To ensure safe performance of these rigging activities, the licensee performed a detailed analysis to determine the most efficient and safe methods for handling the SG components. In this regard, the evaluation of safe load pathways, heavy loads, polar crane stress, and impact analysis will be performed by the Plant Systems Branch (SPLB).

Changes in Piping Configurations

All piping attached to the SGs will be severed and portions removed to provide clearance for SG removal. This piping will be reconnected to the repaired SGs in the original configuration. In some cases the removed piping sections and associated fittings may be discarded and replaced with new piping and fittings of the same configurations. A detailed design effort was performed to establish the various cut locations for the piping based on the most efficient and safe methods of handling the SGs and components.

An enhancement has been made for the SG blowdown piping from the SG nozzles to the existing 3" diameter header. The coupling size of the SG blowdown nozzles has been increased to 2-1/2." The existing 2" blowdown piping from these nozzles to the 3" headers will be replaced with 2-1/2" chrome-moly steel pipe for increased erosion/corrosion resistance. This modification will provide for additional blowdown capacity. The licensee has evaluated and seismically qualified this modified piping configuration in accordance with ANSI B31.1-1967 Power Piping Code.

In order to minimize the extent of reanalysis of affected piping, the licensee maintains the existing arrangement/layout and locations of pipe supports within tolerances shown on applicable station drawings. Following reinstallation of piping, cold gap measurements for critical components will be verified against the station drawings.

Travel stops will be provided on spring hangers on any piping affected by cutting prior to making the severance cuts.

Modifications in SG Supports

The SG upper restraint will be replaced with an equivalent restraint. Demolition of the existing upper restraint is required due to difficulties associated with their removal from the SGs and the effort involved to reuse them. In order to facilitate the removal of the upper restraint, a temporary support is required at each SG. This temporary support will be installed under the existing SG upper restraint and adjustments will be made so that the existing restraint is adequately supported during removal of the lower SG assembly. The existing restraint will be cut and each half ring moved away from the SG. Then the SG lower assembly is removed, followed by the removal of the existing upper restraint. For installation, a new upper restraint equivalent to the old one will be placed on the temporary support. The new SG lower assembly is installed and then the new SG upper restraint is bolted together per design basis requirements. The temporary support will finally be removed prior to plant startup.

Removal of Pipe Whip Restraints

Removal of pipe whip restraints is addressed in DCP 90-06, "Pipe Whip Restraint Removal," which is a part of the overall project scope. It appears that the floor-mounted reactor coolant loop pipe whip restraints which are adjacent to the steam generator supports will be removed.

Since this particular DCP is not available for staff review, no evaluation of this issue will be included here.

Evaluation of Seismic Loading

All the piping and pipe supports of the reactor coolant system, main steam system, and feedwater system will be reinstalled to their original configurations. All applicable design basis seismic and stress analyses have either been reevaluated or reperformed to verify the capability of the repaired systems to perform their intended functions.

In reviewing draft UFSAR Section 3.7.3, the staff identified concerns regarding the use of Code Case N-411 damping values in the North Anna Unit 1 piping seismic analysis. According to Regulatory Guide (RG) 1.84, "Design and Fabrication Code Case Acceptability, ASME Section III Division I," these damping values may be used only in those analyses in which current seismic spectra and procedures are employed. In order to use the Code Case damping values, therefore, the licensee should comply with the RG 1.84 requirements, or, otherwise, provide a justification for staff review.

CONCLUSION

Based on the above evaluation of the licensee's DCP 90-13, the staff concludes that the SGR project is performed in accordance with the current industry practice for steam generator replacement and is generally acceptable in the areas reviewed by the staff. There is one exception, however, in the area of seismic piping analysis. According to RG 1.84, the Code Case N-411 damping values may be used only in those analyses in which current seismic spectra and procedures are employed. North Anna Unit 1 design spectra are not the current seismic spectra as recommended in RG 1.60. Therefore, the licensee should provide the justification for using such damping values for the North Anna Unit 1 project, for staff review.

SALP INPUT

LICENSEE: Virginia Electric Power Company

REVIEW: Arnold Lee

FUNCTIONAL ACTIVITY; SAFETY EVALUATION ON STEAM GENERATOR REPLACEMENT PROJECT

FACILITY NAME; North Anna Power Station Unit 1

SUMMARY OF REVIEW

Perform a safety review of the adequacy of the licensee's steam generator replacement project. Determine whether the methodologies and the implementation procedures of the repair are in accordance with the general industry practice and are in compliance with the NRC regulatory guidelines. Determine whether the replacement project would affect the existing piping configurations an would invalidate the commitments stated in the UFSAR.

NARRATIVE DISCUSSION OF LICENSEE PERFORMANCE - FUNCTIONAL AREA ENGINEERING/TECHNICAL SUPPORT

The licensee appears to be conscientious in pursuing NRC objectives. A comprehensive description of the methodologies used for the steam generator replacement project was provided in the licensee's submittal of July 16, 1992. However, this submittal is regarded only as a draft design change package. In particular, the sections of revised UFSAR that are included in the submittal are in the mark-up form. Licensee management's commitment in providing an auditable, final document for staff review is warranted.

Docket No. 50-338

February 24, 1993

Mr. W. L. Stewart
Senior Vice President - Nuclear
Virginia Electric and Power Company
5000 Dominion Blvd.
Glen Allen, Virginia 23060

Dear Mr. Stewart:

SUBJECT: FINAL REPORT-STEAM GENERATOR REPLACEMENT PROGRAM (SGRP) 50.59 AUDIT/REVIEW: NORTH ANNA POWER STATION, UNIT NO. 1 (NA-1)

The NRC has completed one portion of an audit/review of your 50.59 SGRP for NA-1. An inspection portion of the audit will continue during the NA-1 SGRP implementation.

The various subjects which the NRC reviewed and the staff's findings are provided in the enclosure to this letter.

As stated in the enclosed final report, the staff's audit/review of the program and analyses supporting your 10 CFR 50.59 evaluation for the NA-1 SGRP was found to be acceptable.

(Original Signed By)
Leon B. Engle, Project Manager
Project Directorate II-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosure:
SRGP Final Report

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ENCLOSURE

FINAL REPORT

STEAM GENERATOR REPLACEMENT PROGRAM (SGRP)

NORTH ANNA POWER STATION, UNIT NO. 1 (NA-1)

VIRGINIA ELECTRIC AND POWER COMPANY (LICENSEE)

DOCKET NO. 50-338

1.0 Dose Estimates And ALARA Precautions

The licensee's dose estimates and ALARA planning for the Steam Generator Replacement Project (SGRP) were reviewed during a November 30 through December 4, 1992, inspection (Inspection Report No. 50-338,339/92-26).

As of October 30, 1992, the licensee's collective dose estimate for the SGRP was approximately 540 man-rem, of which approximately 36 man-rem was associated with the resistance temperature detector (RTD) piping elimination. The 540 man-rem estimate was the latest revision from previous estimates of 688 and 572 man-rem and reflected final job scopes and man-hour estimates determined by the licensee and the contractor. The earlier dose estimates incorporated man-hour estimates based on industry averages. Currently, the licensee has set a dose goal of less than 500 man-rem. Provided the remainder of the SGRP goes as planned, the resulting dose should be considerably less than the licensee's goal. As of February 23, 1993 the estimated dose received is approximately 192 man-rem and the estimated total dose for the SGRP is 321 man-rem.

In addition to reviewing the formulation of the dose estimate, the staff evaluated the licensee's radiation protection (RP) organization, outage planning and preparation, and ALARA initiatives for the SGRP. The RP organization established for the outage appeared experienced and good coordination was observed between the licensee and the outage contractor. The licensee had established a comprehensive training program which included mock-ups, supplemental RP technician training and performance measures, and ALARA supervisory training. In particular, the licensee has made a strong effort to make the mock-ups as realistic as possible.

Pre-planning for the SGRP appeared comprehensive, and the licensee appropriately evaluated and addressed lessons learned from previous steam generator replacements.

Facility and equipment upgrades for the SGRP included the new Decontamination Facility, the Containment Access Facility for processing workers, closed circuit television, upgraded communications equipment, and a remote teledosimetry and air sampling system. Review of selected ALARA job evaluations, preliminary Radiation Work Permits, Radiation Protection Job Guides, and associated procedures identified no concerns. General exposure reduction activities planned for the outage included early boration and peroxide flushing, hot spot flushing, RTD piping elimination, and installation of temporary shielding, as well as decontamination of work areas where appropriate.

2.0 Steam Flow Restricter Modifications

The resident inspector verified that the licensee performed a final inspection of the restrictors at Pensacola, Florida, prior to their being sealed in crates and shipped to the site. The inspector reviewed the inspection report which certified that all required surveillances were accomplished with satisfactory results and that all documentation was reviewed and accepted. Upon receipt at the site, the licensee was only required to verify the shipping release tag and that the crate was intact. The inspector reviewed the results of this inspection and found them to be acceptable.

3.0 Security For Protected Area and Sally Port

Containment has remained a vital area during the project. Access is being controlled through normal methods. The status of the security construction activities was evaluated during a safeguards inspection on November 30, 1992. Based on observation of security operational activities and testing of intrusion detection and assessment capability at the new secondary access control facility during the inspection, no security-related issues were identified that would negatively impact the SGRP outage.

The modification of the security system and installation of a new secondary security access portal and sally port were completed prior to the commencement of the SGRP on January 4, 1993. In addition, 25 contract security personnel have augmented the security forces for the duration of the SGRP.

4.0 Safe Load Pathways, Heavy Loads, Polar Crane Stress And Impact Analysis, if SGs are Inadvertently Dropped

Evaluation of the licensee's analysis of the potential offsite doses resulting from a steam generator drop accident during the outage noted no concerns. Calculated doses at the exclusion area boundary were minimal and a small fraction of the 10 CFR Part 100 limits.

Programmatic review of the licensee's heavy loads and safe load pathways were reviewed as discussed in Inspection Report Nos. 50-338,339/92-20 and 92-25. The safe load pathways, polar crane test and other crane tests have been completed. These items were reviewed during a scheduled inspection during the week of January 24, 1993 by Region II and were found to be acceptable. (Inspection Report Nos. 50-338, 339/93-05).

5.0 SG Materials (applicable codes), Welding Process - Monitor Quality Of Narrow Gap Welding

The applicable codes for the project are as follows:
Fabrication of SG lower assembly, ASME Code Section III 1986; SG repair, ASME Code Section XI (83S83) Controlling Code; Mainsteam, Feedwater, and Blowdown Systems, USAS Code B31.7 Power Piping Code (69 with 70 addenda); SG girth weld, ASME Code Section III 1986, Reactor Coolant Piping, USAS Code B31.7 Power Piping Code (69 with 70 addenda).

Fabrication records and material certifications were reviewed for the following components: (Inspection Report Nos. 50-338,339/92-20 and 92-25) channel head forging, nozzle safe-end forging, tube sheet plate, transition plate, partition plate, lower shell barrel, flow limiter assembly, SG tubing and RCS spare piping elbows. The documents and the information therein appeared complete and consistent with applicable requirements.

Various welding specifications, supporting procedure qualification records and required mechanical testing results were reviewed with no adverse findings.

6.0 Pipe Whip Restraint Removal

The staff has performed a review of the licensee's Design Change Package, DC-90-06-1, Appendix 5.-5 "SG Primary Coolant Pipe Whip Restraint Removal." We concur with the licensee's determination that the removal of the pipe whip restraints will not endanger public health and safety. This is based on the following:

(A) The pipe whip restraints were designed to be passive restraints. They would engage the pipe only if a primary coolant loop pipe break occurred. All primary coolant loop pipe whip restraints are no longer required per the NRC-approved Westinghouse leak-before-break (LBB) analysis (WCAPs 11163/11164) and the staff's Safety Evaluation dated December 5, 1988.

(B) Removal of the restraints provides increased access beneath the steam generators during the SGRP. This increased accessibility will result in reduced work time to install the replacement steam generators, and hence reduce man-rem exposure for the replacement project.

(C) An unreviewed safety question does not exist as a result of the above design change. In addition, the margin of safety for any part of the Technical Specifications has not been reduced. The pipe whip restraints which are to be removed are no longer part of the North Anna plants' design basis. Therefore, their removal cannot affect any limiting condition of operation (LCO) of the Technical Specifications.

Based on the above evaluation, the staff concludes that the licensee's 10 CFR 50.59 evaluation for the removal of the primary coolant loop pipe whip restraints is acceptable.

7.0 Seismic Loading Evaluations

All the piping and pipe supports of the reactor coolant system, main steam system, and feedwater system will be reinstalled to their original configurations. All applicable design basis seismic and stress analyses have either been reevaluated or reperformed to verify the capability of the repaired systems to perform their intended functions.

In reviewing draft UFSAR Section 3.7.3, the staff identified the use of Code Case N-411 damping values in the NA-1 piping seismic analysis. It should be noted that the use of such damping values, as endorsed by Regulatory Guide 1.84, required conformance to certain caveats, one of which was the use of current seismic spectrum and procedures. However, based on the plant-specific approval for the use of these damping values, issued by the NRC in 1985, the staff reviewed the North Anna design basis spectra. It was found that the spectra resemble a Newmark spectrum, generally considered by the staff as a current seismic spectrum. The staff, therefore, finds its use in conjunction with Code Case N-411 damping values to meet the conditions of 10 CFR 50.59 and, therefore, is acceptable.

8.0 SG Support Modifications

The SG upper restraint will be replaced with an equivalent restraint. Removal of the existing upper restraints is required due to difficulties associated with their removal from the SGs and the effort involved to reuse them. In order to facilitate the removal of the upper restraint, a temporary support is required at each SG. This temporary support is installed under the existing SG upper restraint and adjustments made so that the existing restraint is adequately supported during removal of the lower SG assembly. The existing restraint is cut and each half-ring moved away from the SG. Then the SG lower assembly is removed, followed by the removal of the existing upper restraint. For installation, a new upper restraint equivalent to the old one is placed on the temporary support. The new SG lower assembly is installed and then the new SG upper restraint is bolted together per design basis requirements. The temporary support will finally be removed prior to plant startup. The staff concludes that these particular activities are in accordance with current industry practice and meet the conditions of 10 CFR 50.59, and, therefore, are acceptable.

9.0 Unreviewed Safety Questions (Accident Analyses)

The staff has completed the review of the licensee's 10 CFR 50.59 evaluation regarding the steam generator lower assemblies replacement at NA-1. The licensee used the guidelines of NSAC 125 to perform this evaluation. The licensee demonstrated that the steam generator lower assemblies replacement does not adversely impact safe operation of the plant and does not involve an unreviewed safety question or a change to the Technical Specifications (TS). The licensee's evaluation meets the conditions of 10 CFR 50.59 and therefore, the staff finds it acceptable.

10.0 Changes in Pipe Locations or Configuration-Modifications in Piping Penetrations

All piping attached to the SGs is to be severed and portions removed to provide clearance for SG removal. This piping will be reconnected to the repaired SGs in the original configuration. In some cases the removed piping sections and associated fittings may be discarded and replaced with new piping and fittings of the same configurations. A detailed design effort was performed to establish the various cut locations for the piping based on the most efficient and safe methods of handling the SGs and components.

An enhancement has been made for the SG blowdown piping from the SG nozzles to the existing 3" diameter header. The coupling size of the SG blowdown nozzles has been increased to 2-1/2". The existing 2" blowdown piping from these nozzles to the 3" headers will be replaced with 2-1/2" chrome-moly steel pipe for increased erosion/corrosion resistance. This modification will provide for additional blowdown capacity. The licensee has evaluated and seismically qualified this modified piping configuration in accordance with ANSI B31.1-1967 Power Piping Code.

In order to minimize the extent of reanalysis of affected piping, the licensee maintains the existing arrangement/layout and locations of pipe supports within tolerances shown on applicable station drawings. Following reinstallation of piping, cold gap measurements for critical components will be verified against the station drawings. Travel stops will be provided on spring hangers on any piping affected by cutting prior to making the severance cuts.

The staff finds that these particular activities are in accordance with ANSI B31.1-1967 Power Piping Code and meet current industry practice and, therefore, meet the conditions of 10 CFR 50.59 and are acceptable.

11.0 <u>Heavy Loads</u>

The licensee removed all the fuel from the reactor to the spent fuel pool (SFP) before moving the heavy loads involved in the SG replacement. Thereafter, the licensee has elected to follow "safe load paths" wherein heavy loads are not carried in areas in which the spent fuel stored in the SFP could be damaged, either directly by a load drop or indirectly, by damaging system(s) used to cool the SFP during the replacement process.

The staff has reviewed that portion of the submittal dealing with heavy loads and found the licensee's plans acceptable. The licensee's plans to conduct the replacement under the provisions of 10 CFR 50.59, in this area, are also found to be acceptable.

Memorandum Dated February 24, 1993

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Docket No.: 50-338

MEMORANDUM FOR: Herbert Berkow, Director
Project Directorate II-2
Division of Reactor Projects

FROM: Goutam Bagchi, Chief
Civil and Geosciences Branch
Division of Engineering

SUBJECT: STEAM GENERATOR REPLACEMENT DESIGN CHANGE PACKAGE (DCP): NORTH ANNA POWER STATION, UNIT 1, TAC NO. M84139

The staff of the Civil Engineering and Geosciences Branch (ECGB) reviewed the plant's UFSAR changes in the DCP 90-13-1, and find that there is no change in the seismic input and the seismic analysis methods except that a new piping analysis code NUPIPE-SW is used to perform the piping analysis. Thus, the ECGB staff finds the changes acceptable. However, the detailed description of the use of the new computer code NUPIPE-SW should be provided in UFSAR Section 3.9, and the adequacy of the changes should be confirmed by the Mechanical Engineering Branch (EMEB).

We consider our effort on TAC No. M54139 to be complete.

Original signed by:
Goutam Bagchi, Chief
Civil Engineering and Geosciences Branch
Division of Engineering

cc: J. Wiggins
S. Varga
B.D. Liaw
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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

December 15, 1993

Docket No. 50-395

MEMORANDUM FOR: L. Joseph Callan
Acting Associate Director for Projects, NRR

Lawrence J. Chandler, Assistant General Counsel
for Hearings and Enforcement, OGC

Ashok C. Thadani, Director
Division of Systems Safety and Analysis, NRR

Frank J. Congel, Director
Division of Radiation Safety and Safeguards, NRR

James T. Wiggins, Acting Director
Division of Engineering, NRR

FROM: Steven A. Varga, Director
Division of Reactor Projects - I/II, NRR

SUBJECT: LICENSING REQUIREMENTS FOR STEAM GENERATOR REPLACEMENT - VIRGIL C. SUMMER NUCLEAR STATION, UNIT NO. 1 (TAC NO. M88172)

This memorandum is to inform you of the proposed actions by South Carolina Electric & Gas Company (SCE&G) relating to the steam generator replacement at the Virgil C. Summer Nuclear Station, Unit No. 1 (Summer Station). By letter dated November 9, 1993, SCE&G sent in a "Licensing Submittal to Support Replacement Steam Generator Technical Specification Changes for the Virgil C. Summer Nuclear Station." This submittal contains not only the proposed Technical Specification (TS) changes, but also a 10 CFR 50.59 evaluation that determined there is no unreviewed safety question with respect to steam generator replacement. The TS changes and the finding of "no unreviewed safety question" were supported by a common set of safety analyses. A table of contents for the licensing submittal is included as Enclosure 1.

The replacement steam generators are larger than the steam generators currently installed. Enclosure 2 identifies the significant differences between the designs of the current (Model D3) and replacement (Model Delta 75) steam generators. The increased size will cause certain parameters in the TS to change. Enclosure 3 summarizes the TS changes that will be necessary.

With the exception of the TS changes, the licensee intends to replace the steam generators under the provisions of 10 CFR 50.59. The licensee's unreviewed safety question evaluation is included here as Enclosure 4. Memo 4

The licensee based the evaluation of the effect of the steam generator replacement on the analyses in Chapter 15 of the Final Safety Analysis Report (FSAR), and concluded that the LOCA, non-LOCA, and steam generator tube

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rupture conclusions presented in the FSAR remain bounding. The safety analyses that were reviewed in support of the "no unreviewed safety question" determination include:

- Large and small break LOCA analysis
- LOCA hydraulic force analysis
- HELB analysis, including EQ issues
- SGTR analysis
- Reactor cavity pressure evaluation
- Radiological analyses
- Primary component evaluation
- Fluid and auxiliary systems evaluation
- Fuel structural evaluation

The Chapter 15 analyses that come closest to design limits due to the steam generator replacement, but for which no specific TS change is required, are listed below:

- Following a loss of offsite power to the station auxiliaries, the conservative estimates for thyroid doses at the site boundary and low population zone increase from 2.87E-2 and 3.95E-3 rem, respectively, to 4.9E-2 and 8.3E-3 rem, respectively.

- Following a LOCA, the conservative estimate for the thyroid dose at the low population zone increases from 28.9 rem to 30.3 rem. These increased doses are still a small fraction of the 10 CFR Part 100 limits.

- Following a postulated LOCA, the peak containment pressure increases from 25 psig to 37 psig.

- Following a main steam line rupture inside containment, the peak containment pressure increases from 45.96 psig to 53.5 psig. The containment design pressure is 57 psig.

The licensee maintains that as long as none of the revised Chapter 15 analyses exceeds a design limit, then no unreviewed safety question exists. The licensee maintains, therefore, that circumstances, such as increased post-accident containment pressure and higher anticipated post-accident releases, do not necessarily reduce a margin of safety.

The licensee presented one set of safety analyses with the licensing submittal. Since the licensee did not differentiate between the safety analyses that were intended to support the TS changes and the safety analyses that were intended to support the finding of no unreviewed safety question, I believe that the staff should notice and review the licensee's entire submittal.

Within the next several months other licensees will be making design changes similar to those at Summer Station. I would like to meet with you to discuss your recommendations as to noticing the licensee's submittal and to discuss the best way to handle the licensing review of this and future submittals. The project manager will arrange a meeting at your earliest convenience.

Original Signed by: Jose A. Calvo
Steven A. Varga, Director
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

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Within the next several months other licensees will be making design changes similar to those at Summer Station. I would like to meet with you to discuss your recommendations as to noticing the licensee's submittal and to discuss the best way to handle the licensing review of this and future submittals. The project manager will arrange a meeting at your earliest convenience.

José A. Calvo for

Steven A. Varga, Director
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
As stated

SUBMITTAL SCHEDULE AND FORMAT TO SUPPORT STEAM GENERATORS REPLACEMENT TECHNICAL SPECIFICATION CHANGES FOR THE VIRGIL C. SUMMER NUCLEAR STATION

Title	Submittal 1	2	3	4
List of Tables		X	X	X
List of Figures		X	X	X
List Acronyms and Abbreviations		X	X	X
Executive Summary		X	X	X
1.0 Introduction-Description of License Amendment Request			X	X
1.1 Purpose for Change				
1.2 Current License Basis and Function of Identified Technical Specifications				
1.3 Description of Proposed Change				
2.0 Basis for Evaluations/Analyses Performed			X	X
2.1 Design Power Capability Parameters		X		
2.1.1 Discussion of Parameters				
2.1.2 References				
2.2 NSSS Design Transients				
2.3 Control System Setpoints				
2.4 Reactor Protection System/Engineered Safety Features Actuation System Setpoints				
3.0 Safety Evaluations/Analyses				
3.1 Loss of Coolant Accident Analyses				
3.1.1 Large Break LOCA			X	
3.1.2 Small Break LOCA				X
3.1.3 Post-LOCA Long Term Core Cooling Subcriticality			X	
3.1.4 Hot Leg Switchover to Prevent Potential Boron Precipitation			X	
3.1.5 References			X	
3.2 LOCA Hydraulic Forces			X	
3.2.1 Introduction				
3.2.2 Method of Analysis				
3.2.3 Results				
3.2.4 References				

<u>Target Submittal Dates:</u>
1: August 31, 1992
April 30, 1993
3: October 29, 1993
4: December 31, 1993

Target Submittal Dates:
1: August 31, 1992
2: April 30, 1993
3: October 29, 1993
4: December 31, 1993

Target Submittal Dates:
1: August 31, 1992
2: April 30, 1993
3: October 29, 1993
4: December 31, 1993

Title	Submittal 1	2	3	4
4.0 Conclusions			X	
Appendix 1 10 CFR 50.59 (Assessment of Unreviewed Safety Questions)			X	X
Appendix 2 10 CFR 50.92 (No Significant Hazards Determination)			X	X
Appendix 3 Proposed Technical Specification Changes			X	X
Appendix 4 WCAP-13480 "Westinghouse Delta 75 Steam Generator Design and Fabrication Information for the VCSNS"	X		X	
Appendix 5 WCAP-13605 "Primary Loop Leak-Before-Break Reconciliation to Account for the Effects of SGR/Uprating"		X	X	
Appendix 6 VCSNS FSAR Chapter 15 Write-Ups			X	X

Target Submittal Dates:
1: August 31, 1992
2: April 30, 1993
3: October 29, 1993
4: December 31, 1993

Enclosure 2

MODEL D3 AND MODLE DELTA-75 GEOMETRIES

Dimension	Model D3	Modle Delta 75
Overall Length	812 in.	812 in.
Lower Shell ID	129.38 in.	129.38 in.
Upeer Shell ID	168.50 in.	168.50 in.
Heat Transfer Area	48,000 $ft.^2$	75,000 $ft.^2$
Number of Tubes	4674	6307
Tube OD	0.750	0.688
Tube Wall Thickness	0.043	0.040
Tube Bundle Height	328.4 in.	418.4 in.
Tube Material	Alloy 600	Alloy 690
Number of TSP/Baffles	7/1	9/1
TSP/Baffle Material	Carbon Steel	405 SS

TS SECTION	DESCRIPTION	JUSTIFICATION
Figure 2.1-1	Core limits are revised.	Limits revised due to analysis at higher core power.
Table 2.2-1	Various reactor trip system setpoints are changed.	Setpoints are consistent with the new safety limits, uncertainty, and flow.
Table 2.2-1 2.2-1 Bases Table 3.3-1 Table 3.3-2 Table 4.3-1	Delete negative flux rate trip.	This trip is not credited in current analysis.
Table 2.2-1	"Steam Generator Water Level Low-Low" changed to "Steam Generator Water level Low."	Makes the name of the trip consistent with the Bases and other sections of the TS.
2.1.1 Bases	Reference to specific correlations used in DNB analysis removed.	
2.2.1 Bases	Steam/Feedwater flow mismatch activation setpoint increased.	Necessary to support steam generator replacement.
Figure 3.1-3	Shutdown margin limits revised.	Necessary to support steam generator replacement.
3.2.3 3/4.2.3 Bases	Includes 0.1% uncertainty for venturi fouling.	Change made by staff request.
4.2.3.5	Change to RCS flow rate determination method.	Change to Westinghouse methodology for flow rate determination.
Table 3.2-1 3/4.2.5 Bases	Change to DNB parameters to include indication uncertainties.	Necessary to support steam generator replacement.
Table 3.3-4	Change to ESFAS Steam Generator Water Level High-High and LoW-Low setpoints.	Necessary to support steam generator replacement.

TS SECTION	DESCRIPTION	JUSTIFICATION
3/4.4.5 3/4.4.5 Bases	Removal of F^* and L^* criteria.	These are not yet necessary with the new steam generators.
4.4.5.3.a	Requires first ISI.	Necessary to support steam generator replacement.
4.6.1.1.c 3.6.1.2.a.1 3.6.1.2.a.2 4.6.1.2.a 4.6.1.2.c.3 4.6.1.2.d 3.6.1.3.b 4.6.1.3.b 3/4.6.1.4 Bases 3/4.6.1.6 Bases	Changes reference values for P_a and P_t.	Reflects new peak containment pressure following SLB.
5.4.2	Increase in total RCS water/steam volume.	Necessary to support steam generator replacement.
5.4.2	T_{ave} changed from a nominal to an indicated value.	Change made for clarity and consistency throughout the TS.

APPENDIX 1

10CFR50.59
ASSESSMENT OF UNREVIEWED SAFETY QUESTIONS

APPENDIX 1

Assessment of Unreviewed Safety Questions
10CFR50.59

Operation of VCSNS with the proposed Δ75 SGs, revised operating conditions, and requested changes to the Technical Specifications has been evaluated using the guidance of NSAC-125 and 10CFR50.59 and been determined to not represent an unreviewed safety question. A summary justification for this determination follows:

1. **Will the probability of an accident previously evaluated in the FSAR be increased?**

   No.
   Implementation of the Δ75 SGs and revised operating conditions do not contribute to the initiation of any accident evaluated in the FSAR. Supporting factors are as follows:

   - The Δ75 SG is designed in accordance with ASME Code Section III, 1986 edition and other applicable federal, state, and local laws, codes and regulations and meets the original interfaces for the Model D3 SGs with the exception that provisions for a larger blowdown nozzle have been made and the feedwater inlet nozzle is located in the upper shell.

   - All NSSS components (i.e., reactor vessel, RC Pumps, pressurizer, CRDMs, Δ75 SGs, and RCS piping) are compatible with the revised operating conditions. Their structural integrity is maintained during all proposed plant conditions through compliance with the ASME code.

   - Fluid and auxiliary systems which are important to safety are not adversely impacted and will continue to perform their design function.

   - Overall plant performance and operation are not significantly altered by the proposed changes.

   Therefore, since the reactor coolant pressure boundary integrity and system functions are not adversely impacted, the probability of occurrence of an accident evaluated in the VCSNS FSAR will be no greater than the original design basis of the plant.

2. **Will the consequences of an accident previously evaluated in the FSAR be increased?**

   No.
   An extensive analysis has been performed to evaluate the consequences of the following accident types currently evaluated in the VCSNS FSAR:

   - Non-LOCA Events
   - Large Break LOCA
   - Steam Generator Tube Rupture

With the Δ75 SGs and revised operating conditions, the calculated results (i.e., DNBR, Primary and Secondary System Pressure, Peak Clad Temperature, Metal Water Reaction, Challenge to Long Term Cooling, Environmental Conditions Inside and Outside Containment, etc.) for the accidents are similar to those currently reported in the VCSNS FSAR. Select results (i.e., Containment Pressure during a Steam Line Break, Minimum DNBR for Rod Withdrawal from Subcritical, etc.) are slightly more limiting than those currently reported in the FSAR due to the use of the assumed operating conditions with the new Δ75 SGs, and in some cases, use of an uprated core power of 2900 MWt. However, in all cases, the calculated results do not challenge the integrity of the primary/secondary/containment pressure boundary and remain within the regulatory acceptance criteria applied to VCSNS's current licensing basis. The assumptions utilized in the radiological evaluations, described in Section 3.7, are thus appropriate and are judged to provide a conservative estimate of the radiological consequences during accident conditions. Given that calculated radiological consequences are not significantly higher than current FSAR results and remain well within 10CFR100 limits, it is concluded that the consequences of an accident previously evaluated in the FSAR are not increased.

3. **May the possibility of an accident which is different than any already evaluated in the FSAR be created?**

No.
The Δ75 SGs and revised operating conditions will not introduce any new accident initiator mechanisms. Structural integrity of the RCS is maintained during all plant conditions through compliance with the ASME code. No new failure modes or limiting single failures have been identified. Design requirements of auxiliary systems are met with the RSGs. Since the safety and design requirements continue to be met and the integrity of the reactor coolant system pressure boundary is not challenged, no new accident scenarios have been created. Therefore, the types of accidents defined in the FSAR continue to represent the credible spectrum of events to be analyzed which determine safe plant operation.

4. **Will the probability of a malfunction of equipment important to safety previously evaluated in the FSAR be increased?**

No.
The Δ75 SGs and revised operating conditions will not adversely affect the operation of the Reactor Protection System, Engineering Safety Features, or other systems, components, or devices required for accident mitigation. These systems will remain qualified and capable to perform their design function for the revised operating conditions during normal operation and conditions which can evolve during accident conditions. In addition, the NSSS components are compatible with the revised operating conditions and will continue to meet their original design requirement. The integrity of the primary/secondary/containment pressure boundary during normal operation and accident conditions will also not be challenged. Based on the above, it is concluded that the probability of a malfunction of equipment important to safety currently evaluated in the VCSNS FSAR will not be increased.

5. Will the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR be increased?

No.
An extensive analysis has been performed to evaluate the consequences of the following accident types currently evaluated in the VCSNS FSAR:

- Non-LOCA Events
- Large Break LOCA
- Steam Generator Tube Rupture

Consistent with VCSNS's current licensing basis, the effects of a single failure of equipment important to safety have been considered when evaluating the accident consequences. With the Δ75 SGs and revised operating conditions, the calculated results for the accidents are similar to those currently reported in the VCSNS FSAR, with select results being slightly more limiting than those currently reported in the FSAR due to the use of the revised operating conditions with the new Δ75 SGs and , in some cases, use of an uprated core power of 2900 MWt. However, in all cases, the calculated results do not challenge the integrity of the primary/secondary/containment pressure boundary and remain within the regulatory acceptance criteria applied to VCSNS's current licensing basis. Systems and components responses to accident scenarios are not affected. The assumptions utilized in the radiological evaluations, described in Section 3.7, are thus appropriate and are judged to provide a conservative estimate of the radiological consequences during accident conditions. Given that calculated radiological consequences are not significantly higher than current FSAR results and remain well within 10CFR100 limits, it is concluded that the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR are not increased.

6. May the possibility of a malfunction of equipment important to safety different than any already evaluated in the FSAR be created?

No.
The Δ75 SGs and revised operating conditions will not adversely affect the operation of the Reactor Protection System, Engineering Safety Features, or other systems, components, or devices required for accident mitigation. These systems will remain qualified and capable to perform their design function for the revised operating conditions during normal operation and conditions which can evolve during accident conditions. No new failure modes are created.

The Δ75 SGs also meet the original interfaces for the Model D3 SGs with the exception that provisions for a larger blowdown nozzle have been made and the feedwater inlet nozzle is located in the upper shell. These exceptions are judged to not create the possibility of a new equipment malfunction.

The NSSS components, including the new SGs, are also compatible with the revised operating conditions and will continue to meet their original design requirements. Furthermore, analyses demonstrate that the integrity of the primary/secondary/containment pressure boundary will not be challenged during normal operation or accident conditions.

Based on the above, it is concluded that the possibility of a malfunction of equipment important to safety different than any already evaluated in the VCSNS FSAR will not be created.

7. **Will the margin of safety as defined in the BASES to any technical specification be reduced?**

No.
Although the Δ75 SGs and revised operating conditions will require changes to the VCSNS Technical Specifications, it will not invalidate the LOCA, non-LOCA, or SGTR conclusions presented in the FSAR accident analyses (Appendix 6). For all the FSAR non-LOCA transients, the DNB design basis, primary and secondary pressure limits, and dose limits continue to be met. The LOCA peak cladding temperatures remain below the limits specified in 10CFR50.46. The calculated doses resulting from a SGTR event will continue to remain within a small fraction of the 10CFR100 permissible releases. Environmental conditions associated with High Energy Line Breaks (HELB) both inside and outside containment have been evaluated. The containment design pressure will not be violated as a result of the HELB. Equipment qualification will be updated, as necessary, to reflect the revised conditions resulting from HELB. The margin of safety with respect to primary pressure boundary is provided, in part, by the safety factors included in the ASME Code. Since the components remain in compliance with the codes and standards in effect when VCSNS was originally licensed (with the exception of the Δ75 RSGs which use the 1986 ASME Code Section III Edition), the margin of safety is not reduced. Thus, there is no reduction in the margin to safety as defined in the bases of the VCSNS Technical Specifications. As stated above, changes will be required to the Technical Specifications in order to implement the proposed modification.

June 15, 1994

MEMORANDUM FOR: S. Singh Bajwa, Project Director
Project Directorate II-1
Division of Reactor Projects I and II

FROM: Jack R. Strosnider, Chief
Materials and Chemical Engineering Branch
Division of Engineering

SUBJECT: SAFETY EVALUATION OF THE V. C. SUMMER UNIT #1 TECH SPEC CHANGES IN SUPPORT OF PLANNED STEAM GENERATOR REPLACEMENT. TAC NO. M88172.

By letter dated October 29, 1993, South Carolina Electric and Gas Company submitted Technical Specification (TS) changes in support of the planned steam generator (SG) replacement at V. C. Summer Unit #1. The Materials and Chemical Engineering Branch has reviewed the materials engineering changes to the Unit #1 TS and finds the proposed changes to section 3/4.4.5 of the TS to be acceptable. Our detailed evaluation is attached.

Due to the limited nature of the submittal, no significant SALP input is possible. We consider our efforts on this TAC to be complete.

ORIGINAL SIGNED BY:

Jack Strosnider, Chief
Materials and Chemical Engineering Branch
Division of Engineering

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SAFETY EVALUATION REPORT BY THE OFFICE OF NUCLEAR REACTOR REGULATION

TECHNICAL SPECIFICATION CHANGES RELATED TO

THE REPLACEMENT STEAM GENERATORS

V.C.SUMMER NUCLEAR STATION

DOCKET NO. 50-395

TAC NO. M88172

1.0 BACKGROUND

By letter dated October 29, 1993, South Carolina Electric & Gas (SCE&G), the licensee, submitted Technical Specification (TS) amendments related to the planned steam generator replacement at the V. C. Summer Nuclear Station. Part of the submittal included proposed changes (deletions) to the inspection and evaluation requirements for tubes repaired by sleeving. The licensee anticipates that the replacement steam generator tubes (alloy 690) will be substantially immune to the primary water stress corrosion cracking (PWSCC) problems encountered in the existing tubes (alloy 600). Removal of the sleeving evaluation and inspection criteria would leave only tube plugging as a mitigating measure for any tubes that developed significant flaws in the future.

The Materials and Chemical Engineering Branch (EMCB) has reviewed the Materials Engineering related portions of the proposed amendment. The reviewed portion of the TS is section 3/4.4.5, pages 3/4 4-11, 4-12, 4-14, 4-14a, 4-15, 4-15a, and bases section 3/4.4.5, page 3/4 4-3.

2.0 DISCUSSION

Each of the above listed pages contains proposed deletions to the current TS, generally in regard to tube sleeving. A synopsis of each is provided:

Page 3/4 4-11:
Deletes tube sample selection requirements for previously sleeved tubes.

Page 3/4 4-12:
Deletes sampling requirements for tubes evaluated to F^* or L^* criteria.

Page 3/4 4-13:
Clarifies minimum time interval to first inservice inspection after start-up of the new steam generators to occur after <u>at least</u> 6 months of full power operation.

Page 3/4 4-14:
Deletes tube sleeves as a repair option for defective tubes. Only plugging would be allowed. A defect requiring repair is defined as any imperfection greater than or equal to 40% of the nominal wall thickness.

Page 3/4 4-14a:
Deletes, under "Acceptance Criteria" (paragraph 4.4.5.4) definitions: "sleeve inspection" and "repaired tube" (containing a sleeve).

Page 3/4 4-15:
Deletes, under acceptance criteria paragraph, definitions for F^* Distance, F^* Tube, L^* Distance, and L^* Tube. Additionally deletes reference to a tube being operable after sleeve repair, and requirement for submittal of report to the NRC identifying tubes repaired by sleeving. Tube plugging would still be reported, per Specification 6.9.2.

Page 3/4 4-15a:
Deletes reporting requirements for F^* and L^* tubes.

Under Bases section 3/4.4.5, page B 3/4 4-3, references to repairing tubes found defective are deleted. Reference to L^* and F^* analyses is deleted. No sleeving or analyses is allowed, only plugging is allowed.

3.0 CONCLUSION

The staff finds the proposed changes to the V. C. Summer TS, as specifically outlined above, to be acceptable. The staff observes that should the licensee determine that a technical specification change with tube sleeving or other analyses such as the ones deleted be desired in the future, that a technical specification change with appropriate technical justification would be required.

Principal reviewer: G. Hornseth, EMCB
Dated: June 7, 1994

SAFETY EVALUATION REPORT BY THE OFFICE OF NUCLEAR REACTOR REGULATION

TECHNICAL SPECIFICATION CHANGES RELATED TO

THE REPLACEMENT STEAM GENERATORS

V.C.SUMMER NUCLEAR STATION

DOCKET NO. 50-395

TAC NO. M88172

1.0 BACKGROUND

By letter dated October 29, 1993, South Carolina Electric & Gas (SCE&G), the licensee, submitted Technical Specification (TS) amendments related to the planned steam generator replacement at the V. C. Summer Nuclear Station. Part of the submittal included proposed changes (deletions) to the inspection and evaluation requirements for tubes repaired by sleeving. The licensee anticipates that the replacement steam generator tubes (alloy 690) will be substantially immune to the primary water stress corrosion cracking (PWSCC) problems encountered in the existing tubes (alloy 600). Removal of the sleeving evaluation and inspection criteria would leave only tube plugging as a mitigating measure for any tubes that developed significant flaws in the future.

The Materials and Chemical Engineering Branch (EMCB) has reviewed the Materials Engineering related portions of the proposed amendment. The reviewed portion of the TS is section 3/4.4.5, pages 3/4 4-11, 4-12, 4-14, 4-14a, 4-15, 4-15a, and bases section 3/4.4.5, page 3/4 4-3.

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3.0 CONCLUSION

The staff finds the proposed changes to the V. C. Summer TS, as specifically outlined above, to be acceptable. The staff observes that should the licensee determine that a technical specification change with tube sleeving or other analyses such as the ones deleted be desired in the future, that a technical specification change with appropriate technical justification would be required.

Principal reviewer: G. Hornseth, EMCB
Dated: June 7, 1994

June 15, 1994

MEMORANDUM FOR: S. Singh Bajwa, Project Director
Project Directorate II-1
Division of Reactor Projects I and II

FROM: Jack R. Strosnider, Chief
Materials and Chemical Engineering Branch
Division of Engineering

SUBJECT: SAFETY EVALUATION OF THE V. C. SUMMER UNIT #1 TECH SPEC CHANGES IN SUPPORT OF PLANNED STEAM GENERATOR REPLACEMENT. TAC NO. M88172.

By letter dated October 29, 1993, South Carolina Electric and Gas Company submitted Technical Specification (TS) changes in support of the planned steam generator (SG) replacement at V. C. Summer Unit #1. The Materials and Chemical Engineering Branch has reviewed the materials engineering changes to the Unit #1 TS and finds the proposed changes to section 3/4.4.5 of the TS to be acceptable. Our detailed evaluation is attached.

Due to the limited nature of the submittal, no significant SALP input is possible. We consider our efforts on this TAC to be complete.

ORIGINAL SIGNED BY:

Jack Strosnider, Chief
Materials and Chemical Engineering Branch
Division of Engineering

Enclosures:
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June 15, 1994

MEMORANDUM FOR: S. Singh Bajwa, Project Director
Project Directorate II-1
Division of Reactor Projects I and II

FROM: Jack R. Strosnider, Chief
Materials and Chemical Engineering Branch
Division of Engineering

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JUL 26 1994

Docket No.: 50-395

MEMORANDUM FOR: David B. Matthews, Director
Project Directorate II-1
Division of Reactor Projects I/II

FROM: Richard H. Wessman, Chief
Mechanical Engineering Branch
Division of Engineering

SUBJECT: STEAM GENERATOR REPLACEMENT PROJECT - VIRGIL C. SUMMER NUCLEAR STATION, UNIT NO. 1 (TAC NO. M88172)

REFERENCES:
1. Letter of March 12, 1993, from J. L. Skolds, South Carolina Electric and Gas Company (SCE&G), to G. F. Wunder, NRC.
2. Memorandum of December 15, 1993, from S. A. Varga, Director, Division of Reactor Projects - I/II, NRR, to J. T. Wiggins, Division of Engineering, NRR.

In Reference 2, the Mechanical Engineering Branch was informed of the proposed actions by SCE&G relating to the steam generator (SG) replacement project at the Virgil C. Summer Nuclear Station, Unit 1 (VCSNS). In Reference 1, SCE&G submitted a summary of the design criteria used in the reanalysis of piping affected by the replacement of the steam generators.

The Mechanical Engineering Branch has evaluated the aspects of the proposed SG project within its scope of review. Our evaluation and conclusions are presented in the enclosed safety evaluation.

The licensee has stated that the safety reevaluation of piping systems affected by the SG replacement was performed under the provisions of 10 CFR 50.59. This reevaluation was based on standard piping design methodology, loading combinations and ASME Section III design criteria as stated in the VCSNS FSAR, with exceptions. These exceptions took advantage of recent changes in licensing requirements and ASME Section III code design methodology. We have reviewed these exceptions and their effects on the reanalysis of the affected piping, and find them acceptable.

This concludes our effort under TAC No. M88172. In accordance with Office Letter No. 907, a SALP input for this effort is also enclosed.

ORIGINAL SIGNED BY:
KAMAL MANOLY

Richard H Wessman, Chief
Mechanical Engineering Branch
Division of Engineering

Enclosures: As stated

Contact: M. Hartzman
504-2755

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However, the fatigue reevaluations of this piping components were based on the 1977 Edition through 1979 Addenda. In addition, the new SGs were designed to the 1986 Edition of the Code. The design basis code for BOP piping was ASME Section III, 1971 Edition through Summer 1973 Addenda. These editions have all been endorsed by the staff in 10 CFR 50.55a, and are therefore acceptable.

In Reference 3, the licensee submitted additional information regarding the results of the piping reanalyses. Based on the revised requirements, the dynamic effects of pipe breaks in the RCL were excluded from the revised design basis. However, the effects of pipe breaks at RCL branch piping nozzles were still considered. The reevaluation of the NSSS and BOP piping, components and containment penetrations was performed under the same loading combinations as stated in the VCSNS FSAR. The number of snubbers on the steam generators were thus reduced from 15 to 6. The pressurizer surge line which is attached to the hot leg was also reanalyzed for thermal stratification, due to the revised RCL hot leg temperatures. The snubbers on the surge line were thus reduced from 4 to 1. Overall, the number of snubbers decreased from 83 to 50, while the number of rigid restraints increased from 53 to 79. The number of pipe-whip restraints also decreased from 47 to 36. We find this to be reasonable and acceptable.

The licensee also performed a structural reevaluation of the reactor vessel, the reactor internals, the inlet and outlet nozzles, and the control rod drive mechanism housings, due to the revised operating conditions and transient loadings. The Code of Record for the reactor vessel is the 1971 Edition of ASME Section III. The vessel and head flanges and the closure studs were found to have increased cumulative usage factors, which however, were shown to remain well below the ASME Code acceptance limit. The internal hydraulic lift forces were also reevaluated and were found to have minimal effects on the reactor internals. All components were found to satisfy the respective ASME Code allowables.

Structural evaluations of the new steam generators, the pressurizer, the reactor coolant pumps and the control rod drive mechanisms were also performed for the revised operating conditions and new design transients. These components were also found to satisfy the respective ASME Code allowables.

3.0 CONCLUSION

The Mechanical Engineering Branch has reviewed the aspects of the proposed SG replacement project within its scope of review, and finds them acceptable.

4.0 REFERENCES

1. Letter of March 12, 1993, from J. L. Skolds, South Carolina Electric and Gas Company (SCE&G), to G. F. Wunder, NRC.

2. Memorandum of December 15, 1993, from S. A. Varga, Director, Division of Reactor Projects - I/II, NRR, to J. T. Wiggins, Division of Engineering, NRR.

3. Letter of May 18, 1994, from John L. Skolds, SCE&G, to the NRC Document Control Desk.

ENCLOSURE 2

SALP REPORT

LICENSEE: South Carolina Electric and Gas Company (SCE&G)

FACILITY NAME: Virgil C. Summer Nuclear Station (VCSNS)

FUNCTIONAL ACTIVITY: Review topics of the steam generator replacement project within the Mechanical Engineering Branch scope of review.

SUMMARY OF REVIEW/INSPECTION ACTIVITIES

SCE&G intends to replace three existing steam generators at VCSNS under the provisions of 10 CFR 50.59. The EMEB has evaluated the licensing basis, design criteria and methodology of ASME Section III Class 1, 2, and 3 piping systems and components associated with the new SGs and has found them acceptable. No unresolved safety issues resulting from the replacement of the existing SGs have been identified.

NARRATIVE DISCUSSION OF LICENSEE'S PERFORMANCE - FUNCTIONAL AREA

The licensee has been cooperative in this effort and has responded in a timely manner to requests for information.

Author: Mark Hartzman

Date: July 1994

AUG 1 8 1994

MEMORANDUM TO: David B. Matthews, Director
Project Directorate II-1
Division of Reactor Projects I/II
Office of Nuclear Reactor Regulation

FROM: Richard J. Barrett, Chief
Containment Systems and Severe Accident Branch
Division of Systems Safety and Analysis
Office of Nuclear Reactor Regulation

SUBJECT: SER INPUT FOR PROPOSED STEAM GENERATOR REPLACEMENT TECHNICAL SPECIFICATION CHANGE REQUEST, VIRGIL C. SUMMER NUCLEAR STATION, UNIT 1 (TAC No. M88172)

Plant Name: Virgil C. Summer Nuclear Station, Unit 1
Licensee: South Carolina Electric & Gas Company
Review Status: Complete

The Containment Systems and Severe Accident Branch (SCSB) has reviewed those areas of Virgil C. Summer Nuclear Station proposed Steam Generator Replacement Technical Specification Changes submittal dated October 29, 1993 and March 11, 1994 for which it has primary review responsibility. Based on our review, we find the proposed changes acceptable as indicated in the enclosed Safety Evaluation Report (Attachment 1).

Our SALP input is provided as Attachment 2. We consider our efforts on TAC No. M88172 to be complete.

Docket No. 50-395

Attachments:
As stated

cc: G.F. Wunder

CONTACT: Raj Goel, SCSB/DSSA
504-2806

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RMLobel	RJBarrett

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ATTACHMENT 1

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION
CONTAINMENT SYSTEMS AND SEVERE ACCIDENT BRANCH
DIVISION OF SYSTEMS SAFETY AND ANALYSIS
STEAM GENERATOR REPLACEMENT TECHNICAL SPECIFICATION CHANGES
VIRGIL C. SUMMER NUCLEAR STATION, UNIT 1
DOCKET NO 50-395

3.4 Containment Integrity Analyses

The licensee has performed containment integrity analyses to support the replacement of Westinghouse Model D3 with Delta 75 steam generators due to differences in flow and heat transfer areas. The analyses have been performed to ensure that the maximum pressure inside the containment will remain below the containment building design pressure of 57 psig if a design bases LOCA or main steam line break (MSLB) inside containment should occur during plant operation. The analyses also established the pressure and temperature conditions for environmental qualification and operation of safety related equipment. The peak pressure is also used as a basis for the containment leak rate test pressure to ensure that dose limits will not be exceeded in the event of a release of radioactive material to containment in accordance with 10 CFR 50 Appendix J and the technical specifications. The analyses utilized the Engineered Safeguards Design Rating of 2900 MWt core power This conservatively bounds the current licensed core power of 2775 MWt and minimizes future reanalysis effort for a potential stretch power application.

Main Steamline Break Containment Integrity Analysis

The licensee has performed analyses to determine the reactor building (RB) pressure and temperature response during postulated steamline breaks (SLBs) inside containment for a wide range of power levels and break sizes with the Delta 75 replacement steam generators (RSGs) and associated revised operating conditions. The licensee has indicated that reactor building initial conditions and assumptions used in the SLB analyses are consistent with those assumed in the current design basis except for the heat removal rate of the reactor building cooling units (RBCU) which is reduced by more than 50% below current assumptions to allow for future degradation in those units. The analyses were performed for initial power levels of 102%, 75%, 50%, 25%, and 0% and a spectrum of break sizes similar to that in the current FSAR. The SLB mass and energy release and the pressure and temperature analyses have included the effects of various single failures including: failure of a main steam isolation valve, failure of a feedwater isolation valve, failure of electrical channel A, resulting in the loss of one diesel generator and failure to isolate emergency feedwater flow to the faulted SG, and failure of one train of the safety injection system. The SLB mass and energy releases were calculated using the LOFTRAN computer code and RB temperature and pressure using the CONTEMPT-LT 26 computer code. The LOFTRAN and CONTEMPT-LT22 were used in the current design bases analyses. The use of the updated CONTEMPT-LT26 code has been used in other plants for the above analyses and the staff has found the use of this code acceptable.

The SLB reactor building pressure and temperature analyses show increases in both RB pressure and temperature conditions during a postulated SLB with the Delta 75 SGs. In the current RB design basis conditions during a SLB with the Model D3 SGs, the calculated peak RB pressure was 45.96 psig for a 1.4 ft^2 Double Ended Rupture at an initial core power of 102% of 2775 MWt. The calculated peak RB temperature was 321.5°F for a 0.645 ft^2 Split Break at an initial core power of 102% of 2775 MWt. In the RSG analyses, the calculated peak RB pressure increases from 45.96 psig to 53.5 psig for a 1.4 ft^2 double ended SLB at 25% of 2900 MWt which is below the RB design pressure of 57 psig. The licensee indicated that the peak pressure increase is mainly due to a larger secondary water mass. The calculated peak RB temperature increase from 321.5°F calculated in the present analysis to 379.2°F for a 1.4 ft^2 double ended SLB at 102% of 2900 MWt. The peak temperature increase is mainly due to no liquid entrainment in the steam for the double ended break at 102% power. The superheated conditions within the RB are of short duration during the first 100 seconds of the transient. Following spray actuation, the RB remains saturated in the long term and below the RB design temperature of 283°F. The licensee indicated that the containment safety-related equipment will be qualified to operate in an accident environment with pressure and temperature equal to or higher than 57 psig and 379.2°F.

Based on its review, the staff finds the proposed change due to RSGs in peak containment pressure and temperature as a result of postulated SLB is acceptable since the containment design pressure of 57 psig and design temperature of 283°F are not exceeded.

LOCA Containment Integrity Analysis

The licensee has performed analyses to determine the reactor building pressure and temperature response during postulated LOCAs using mass and energy releases which incorporate the RSGs and revised design parameters corresponding to 2900 MWt with updated computer modeling. The RB initial conditions used in the analyses are consistent with those assumed in the current licensing basis analysis except RBCU heat removal capacity is reduced by more than 50% to account for possible future heat transfer degradation of these units. The LOCA analyses are performed for the double ended hot leg (DEHL) guillotine break and the double ended pump suction (DEPS) break with minimum and maximum safety injection cases, minimum RB spray and minimum and maximum RBCU performance. These cases are shown to result in maximum pressure and temperature response. The mass and energy releases in the containment are calculated using Westinghouse topical report WCAP-10325-A and the containment pressure and temperature response is calculated using the CONTEMPT-LT26 computer codes. Westinghouse topical report WCAP-8312A and CONTEMPT-LT22 was used for the current design bases analyses. The updated Westinghouse WCAP-10325 and CONTEMPT-LT26 computer codes have been used for similar analyses of other plants and staff has found the use of these codes acceptable.

The licensee has calculated that the peak RB pressure and temperature occurs for the DEHL break in the updated postulated LOCA analyses which incorporate the RSGs. In the updated analyses, the peak RB pressure increases to 45.1 psig for the DEHL break from the current peak LOCA value of 44.7 psig for the DEPS break. The peak RB temperature increases to 267.4°F for the DEHL break from the current LOCA value of 266.7°F for the DEPS break. The calculated peak RB pressure of 45.1 psig and peak temperature of 267.4°F for the DEHL break is well below the peak RB design pressure of 57 psig and design temperature of 283°F.

Based on its review, the staff finds the proposed change due to RSGs in peak containment pressure and temperature as a result of postulated LOCA is acceptable since the containment design pressure and temperature remain bounding.

Containment Subcompartment Analysis

The licensee has evaluated the short term LOCA mass and energy releases with the RSGs for the containment subcompartment analysis. The subcompartments (steam generator compartments, pressurizer compartment, and reactor cavity) were analyzed for the largest breaks possible in each compartment; pressurizer compartment for spray line and surge line breaks, steam generator compartments for double-ended hot leg and cold leg breaks, and reactor cavity for 150 in^2 cold leg break.

The licensee indicated that the current LOCA pressures, forces, and moments used in the original SG compartment and reactor cavity design analysis remain bounding for the replacement steam generators. The use of the previously approved Leak-Before-Break methodology eliminates the dynamic effects of postulated primary loop ruptures from the design bases. The licensee indicated that based on the change in peak critical mass flux and temperature, the impact on the pressurizer compartment can be conservatively bounded by increasing the surge and spray line mass release by factors of 15% and 10%, respectively. The licensee calculated that the differential pressures resulting from potential increases in surge line and spray line mass and energy releases are shown to increase in the pressurizer compartment and decrease in the surge tank compartment. However, large margins continue to be maintained between the calculated and design pressures.

Based on the results of the LOCA calculations and evaluations described above, the staff finds the proposed change acceptable, since it will not affect the subcompartment design or equipment located in the subcompartments.

Containment Leakage

The licensee has proposed to increase the peak containment pressure (Pa) for leak testing from 47.1 psig to 53.5 psig or (Pt) from 23.6 psig to 26.8 psig based on reanalyzed peak pressure expected from a steam line break event. Since Appendix J to 10 CFR Part 50 requires the licensee to perform leak testing at the peak accident pressure, and the technical specifications require the containment leakage limit, which remains the same, to be satisfied, the staff finds the higher containment pressure with the present leakage limit to be acceptable.

ATTACHMENT 2

SCSB SALP INPUT

Plant Name: Virgil C. Summer Nuclear Station, Unit 1

SER Subject: SER Input for the proposed Technical Specification changes due to Steam Generator Replacement, Containment Systems

TAC No.: M88172

Summary of Review Activities:

The Containment Systems and Severe Accident Branch (SCSB) has reviewed the Virgil C. Summer submittal for Steam Generator Replacement and proposed changes to the plant technical specifications. The changes involved review of Containment Function Design regarding LOCA and MSLB analysis evaluation results due to proposed Steam Generator Replacement and Technical Specification amendment. The staff found the proposed changes acceptable.

Narrative Discussion of Licensee Performance:

The licensee's submittal was fairly complete. When asked for more details, the licensee provided the information in a timely manner.

Author: Raj Goel

Date: August , 1994

September 29, 1994

MEMORANDUM TO: Bruce A. Boger, Acting Director, DRP
Gary M. Holahan, Director, DSSA
Brian W. Sheron, Director, DE
Jose A. Calvo, Acting Director, DRSS

FROM: Gus C. Lainas, Assistant Director
for Region II Reactors
Division of Reactor Projects - I/II

SUBJECT: TASK INTERFACE AGREEMENT - VIRGIL C. SUMMER NUCLEAR STATION, UNIT NO. 1, STEAM GENERATOR REPLACEMENT (TAC NO. 88172)

By letter dated October 29, 1993, South Carolina Electric & Gas Company submitted an amendment request regarding the replacement of the steam generators at Virgil C. Summer Nuclear Station. This TIA presents a plan for the inspection and evaluation activities associated with the steam generator replacement project. The plant is now shut down and steam generator replacement has been started. Restart is scheduled for December 15, 1994.

A detailed list of the inspections and evaluations to be performed and the primary and secondary responsibility for each inspection and evaluation is provided in the Attachment. Except where on site inspection is specifically requested by Region II, the NRR contribution to the evaluation of the steam generator replacement project will be included in a Safety Evaluation that will be issued before restart. This Safety Evaluation will be issued along with the Technical Specification changes that are needed to support operation with the new steam generators and will contain input from the NRR branches identified in the Attachment.

Docket No. 50-395

Attachment: List of Inspections and Evaluations

cc w/attachment:
C. W. Hehl
E. G. Greenman
A. B. Beach
A. Thadani
R. Zimmerman
W. Russell

Contact: G. Wunder
504-1455

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September 29, 1994

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Contact: G. Wunder
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STEAM GENERATOR REPLACEMENT PROJECT

AREAS OF EVALUATION OR INSPECTION

The following areas of inspection and evaluation have been completed:

Engineering and Technical Support

1. Review the design change and modification process to determine if administrative controls have been established and implemented for design activities that are consistent with the licensee's quality assurance program. (Region II)

2. Verify that design changes and modifications made to systems, structures, and components described in the Final Safety Analysis Report (FSAR) are reviewed in accordance with 10 CFR 50.59. (Region II)

Procurement and Receipt Inspection

1. The procurement and receipt inspection activities satisfy applicable quality assurance program requirements. (Region II)

2. The procurement specifications satisfy the design requirements. (Region II)

3. SG and equipment handling and storage provisions and controls are in place to avoid degradation during handling and storage. (Region II)

4. Review the applicable engineering design, modification, and analysis associated with SG lifting and rigging including: (1) crane and rigging equipment, (2) SG component drop analysis, (3) safe load paths, and (4) load lay-down areas. (Region II)

SGRP Support Activities

1. Project management organization and staffing. (Region II)

2. Controls for contractor oversight and interface. (Region II)

3. Plans for identifying, tracking, and resolving nonconformances. (Region II)

4. Plans for implementing quality assurance requirements. (Region II)

ATTACHMENT

5. Plans for the use of "third party" inspection agencies and the extent of their participation. (Region II)

6. Training of licensee and contractor personnel. (Region II)

The following inspections and evaluations will be completed:

Engineering and Technical Support

1. Review key design aspects and modifications for the replacement SGs and other modifications associated with SG replacement to ascertain that applicable requirements have been satisfied. (Region II/NRR)

2. The SG is fabricated according to applicable code requirements and the procurement specifications. (Region II/NRR/RVIB)

Radiation Protection Controls

1. Dose estimates and As Low As Reasonably Achievable (ALARA) considerations. (Region II/NRR)

2. Exposure and contamination controls. (Region II)

3. Emergency contingencies. (Region II/NRR)

4. Project staffing and training plans. (Region II)

SGRP Support Activities

1. Security considerations associated with vital and protected area barriers that may be affected during replacement activities. (Region II)

Cutting, Welding, and NDE

1. Special procedures for cutting, machining, welding, and NDE. (Region II)

2. Training and qualifications for personnel performing cutting, machining, welding, and NDE. (Region II)

3. Set up and testing of cutting and welding equipment. (Region II)

4. Preparations to measure and the measurement of any pipe deflection that may occur after cutting. (Region II)

5. Cutting of reactor coolant system (RCS), steam, and feedwater piping and instrument lines, etc., and where applicable, SG girth cutting. (Region II)

6. Fitup and welding preparations for the new SG. (Region II)

7. Welding of RCS, main steam, feedwater, and other lines and, where applicable, welding of SG girth welds. (Region II)

8. NDE including radiography results and work packages. (Region II)

9. Weld heat treatment. (Region II)

Activities Associated with Lifting and Rigging

1. Preparations and procedures for rigging and heavy lifting including any required crane and rigging inspections, testing, equipment modifications, lay-down area preparations, and training. (Region II)

2. Lifting and rigging of SG components from the containment. (Region II)

3. Movement and lifting of new SG into place. (Region II)

4. Transportation of old/new SGs to/from storage. (Region II)

Interference Removal and Restoration

1. The procedures that control the process for interference removal and the restoration of affected items to their required condition. (Region II)

2. Interference removal including SG and RCS piping restraints, snubbers, and supports and removal of SG restraints ("belly-bands"), snubbers, and supports. (Region II)

3. Removal of piping and instrumentation interfacing the SG. (Region II)

4. Restoration of SG component and piping and RCS restraints, snubbers, and supports. (Region II)

5. Restoration of interferences, piping, and instrumentation. (Region II)

Other Activities

1. Establishment of operating conditions including defueling, RCS draindown, and system isolation and safety tagging/blocking. (Region II)

2. Implementation of radiation protection controls. (Region II)

3. Implementation of quality assurance. (Region II)

4. Cleanliness, flushing, and foreign materials exclusion controls. (Region II)

5. Security considerations. (Region II)

6. Control of combustibles and ignition sources. (Region II)

7. Installation, use, and removal of temporary services. These include temporary structures, systems and components (SSCs) as well as temporary piping supports. Verify that these temporary services have been evaluated for both operational and physical impact on plant equipment and systems important to safety. (Region II)

8. Management controls and oversight including contractor interface and control of nonconformances. (Region II)

Post-Installation Testing

1. The licensee's post-installation inspections and verifications program and its implementation. (Region II)

2. The conduct of RCS hydrostatic testing and review the test results. (Region II)

3. The conduct of the SG secondary side hydrostatic testing and review the test results. (Region II)

4. Calibration and testing of instruments affected by SG replacement. (Region II)

5. The procedures for equipment performance testing required to confirm the design and to establish baseline measurements and the conduct of testing. (Region II)

6. Preservice inspection of new welds. (Region II)

7. Completion of post modification activities such as drawing updates, procedure changes, resolution of outstanding issues, and training. (Region II)

Licensing Actions

1. Review Technical Specification changes and supporting analyses. (NRR/SRXB/SCSB/EMEB/EMCB/PRPB/) (09/30/94)

2. Review Chapter 15 analyses. (NRR) (09/30/94)

3. Issue Safety Evaluation before restart. (NRR/DRP) (10/31/94)

December 5, 1994

MEMORANDUM TO: David B. Matthews, Director
Project Directorate, II-2
Division of Reactor Projects I/II

FROM: Richard H. Wessman, Chief
Mechanical Engineering Branch
Division of Engineering

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION - SURRY POWER STATION, UNITS 1 AND 2 POWER UPRATE AMENDMENT (TAC NOS. M90364 AND M90365)

By letter dated August 30, 1994, the Virginia Electric and Power Company (VEPCo), the licensee, pursuant to 10 CFR 50.90, requested an amendment to Facility Operating Licenses DPR-32 and DPR-37, in support of an increase in core power level from 2441 MWt to 2546 Mwt for Surry Power Station, Units 1 and 2.

The Mechanical Engineering Branch has reviewed the licensee's submittal related to the structural integrity of several safety-related components. These included pressure-retaining piping, components and their supports, reactor internals, core support structures, control rod drive system, and safety-related equipment. Based on our review, we find that additional information is needed in order for us to complete our evaluation. We requested that you forward the attached request for additional information to the licensee for their response.

Docket Nos.: 50-280 and
50-281

Attachment: As stated

CONTACT: C. Wu, NRR
504-2764

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December 5, 1994

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Division of Reactor Projects I/II

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Mechanical Engineering Branch
Division of Engineering

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ATTACHMENT

REQUEST FOR ADDITIONAL INFORMATION
PROPOSED AMENDMENT FOR POWER UPRATE
SURRY POWER STATION, UNITS 1 AND 2

Mechanical Engineering Branch

1. Section 4.1.1 states that the reactor vessel internals were reviewed and found to be acceptable for the uprated core power operating conditions as part of the previous evaluation performed to assess the Surry Improved Fuel design. Provide a discussion of the method used for the review that was conducted on the reactor vessel internals for the power uprate condition including effects of the flow induced vibration. Identify the reactor internal components that were reviewed and the Code used for acceptability of the reactor vessel internals. Also, provide a summary of maximum critical component stresses and calculated fatigue usage factors.

2. In Section 4.1.5, it is stated that review of the previous analysis for the uprated core power with 7% tube plugging verified that the components continue to remain in compliance with the ASME Code, Section III requirements. Provide a discussion addressing the methodology, assumptions and the Code edition used in the evaluation of critical steam generator components. Specify the limiting components evaluated for the uprated power conditions and list the maximum stresses, fatigue usage factors and location of highest stressed areas for both the current design and the uprated power conditions.

3. In Section 4.1.6, provide an evaluation of the increased temperature difference between the hot leg and the cold leg on the pressurizer spray piping and nozzles at the uprated power conditions in comparison with the current design basis analysis. Discuss in detail the evaluation of pressurizer surge line, the pressurizer safety valve and discharge piping, and the pressurizer relief tank for compliance with the design criteria. Specify the Code and edition used for acceptability of pressurizer components.

4. In Section 4.1.7, provide a detailed discussion regarding the evaluation of the NSSS piping and pipe supports, equipment nozzles, and in-line components for the power uprate condition, and include a summary of the analysis results in comparison to the existing design values. The discussion should include the analysis methods and assumptions, and demonstration of compliance with requirements in the Code edition used for the evaluation with regard to stress levels and fatigue considerations.

5. In Section 4.2, the evaluation of balance of plant (BOP) systems did not address effects of the power uprate on the design basis analyses of the postulated pipe rupture locations, pipe whip and jet impingement loads that may affect the adequacy of the safety-related systems, equipment and components. Please provide relevant information concerning these evaluations.

6. In Sections 4.2.7 and 4.2.8, provide an evaluation of the effect of increased pressure at discharge nozzles shown in Tables 4.2.7-1 and 4.2.8-1, on the adequacy of the high pressure and low pressure heater drain discharge piping at the uprated conditions.

7. In Section 4.5, it is stated that the 5th point extraction steam heater drain piping nozzle loads exceed the existing nozzle load allowables. The nozzle will require modification for operation at the uprated temperature. Provide a discussion on the planned modification, schedule, and operational experience at similar operating conditions to ensure that these nozzles will be operating within the design allowables. Table 4.5-1 shows that the operating temperature at the uprated power level is more severe for the 3rd point than for the 5th point extraction steam heater drain piping. Provide a summary of the calculated 3rd point heater drain piping nozzle loads and maximum piping and pipe support stresses in comparison to the appropriate code allowables.

Reference: Attachment 3 to the Virginia Electric and Power Company's August 30, 1994, submittal to USNRC, "Surry Power Station Units 1 and 2 Proposed Power Uprating."

June 23, 1995

MEMORANDUM FOR: Bartholomew C. Buckley, Project Manager (14H-25)
Project Directorate II-3
Division of Reactor Projects I/II

FROM: Eric Weiss, Section Chief
PWR Reactor Systems Section
Reactor Systems Branch
Division of Systems Safety and Analysis

SUBJECT: SER - SURRY POWER UPRATE (TAC NOS. M90364 AND M90365)

Plant Name: Surry Power Station Units 1 and 2
Utility: Virginia Electric and Power Company
TAC No(s).: M90364 and M90365
Docket No(s).: 50-280 and 50-281
Operating License: DPR-32 and DPR-37
Project Directorate: Project Directorate III-2
Project Manager: B. Buckley
Review Branch: SRXB/DSSA
Review Status: Complete

Reactor Systems Branch, DSSA, has reviewed Virginia Electric and Power Company submittals in support of a proposed power uprating of its Surry Units 1 and 2 plants from 2441 MWt to 2546 MWt core power. Also considered in the submittals and our review was an increase in the Surry operating reactor steam generator tube plugging limit to 7%.

We find the proposed power uprating acceptable, as discussed in our Safety Evaluation, Attachment 1. Attachment 2 provides our Systematic Assessment of Licensee Performance input for this review. This concludes our efforts for TAC Nos. M90364 and M90365.

Attachments:
As stated

cc: G. Holahan
H. Berkow (014H-25)
PEB/SALP (012-E4)

Contact: S. Brewer, SRXB/DSSA
415-2887

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

ATTACHMENT 1

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION RELATED TO POWER UPRATING OF SURRY UNITS 1 AND 2 VIRGINIA ELECTRIC AND POWER COMPANY SURRY POWER STATION, UNITS 1 AND 2 DOCKET NOS. 50-280 AND 50-281

1.0 INTRODUCTION

In a submittal of August 30, 1994, as supplemented by a letter dated May 5, 1995, the Virginia Electric and Power Company (Virgina Power) requested amendments to Facility Operating Licenses NPF-32 and NPF-37 for the Surry Power Station (Surry) Units 1 and 2, respectively. Specifically, the amendments would revise the licenses and Technical Specifications (TS) for the Surry units to increase the rated power level from the present specification of 2441 Megawatts thermal (MWt) to a specification of 2546 MWt. The proposed changes would allow the Surry units to operate at a Nuclear Steam Supply System (NSSS) power of 2558 MWt and up to 7% steam generator tube plugging.

2.0 STAFF EVALUATION

The changes would represent an approximate 4.3% increase over the presently licensed core power rating of 2441 MWt. In support of this uprating, the Surry units were reevaluated for operation at an Engineering Safeguards Design Core Power Rating of 2546 MWt and a NSSS power rating of 2558 MWt. The licensee's rerating program also includes consideration of an increase in steam generator tube plugging level to 7%. While accident analyses were performed assuming 15% steam generator tube plugging, the licensee is presently proposing a limit of 7% steam generator tube plugging consistent with assumptions it made in its NSSS component and systems evaluations.

considered in establishing the initial conditions, including the addition of 2% to the initial power to account for calorimetric error.

2.2 STAFF FINDINGS

2.2.1 Core Design

The staff issued License Amendment 116, dated January 6, 1988, allowing the Surry Units to use Surry Improved Fuel (SIF) in the Surry cores. The supporting analyses for this amendment accounted for the incremental replacement of the resident Westinghouse Low Parasitic fuel, considering the varied mixtures of the fuel types during the transitional period.

The licensee currently uses an approved method of analysis, Virginia Power Statistical DNBR Evaluation, to determine the departure from nucleate boiling. The proposed design parameter changes following core uprating implementation were evaluated with respect to those assumed in the Statistical DNBR Evaluation Methodology. The licensee determined that the method of analysis remains valid.

Likewise, the licensee also verified the relevant thermal-hydraulic items considered on a reload basis that could be affected by core uprating which are evaluations of core bypass flow rate, core thermal limits, axial power distribution effects and retained DNBR margin. The core thermal limits were the only items effected by the uprate because a power increase, increases the total temperature rise across the core. The licensee indicated that these effects are modelled in the reload core design and new thermal limits for the uprated condition were generated.

2.2.2 Reactor Coolant System

The licensee's submittal proposes an increase in the steam generator tube plugging limit from 0% to 7%, which was assumed in the licensee's NSSS and component evaluations for the power uprate analyses. The NSSS accident analyses and core thermal hydraulic assessments assume 15% tube plugging. We conclude that the lower flow is acceptable for the uprated power because it is considered in the technical justifications for the power uprating.

In its discussion of RCS topics, the licensee did not identify any other items that could affect the power uprating. We find that the reactor coolant system design adequacy is not affected by the power uprating.

2.2.3 Overpressure Protection

It is required that pressurizer safety valves be designed with sufficient capacity to prevent the pressurizer pressure from exceeding 110% of design pressure following the worst RCS pressure transient. For purposes of analytical justification this event is specified to be a 100% load rejection resulting from a turbine trip with concurrent loss of main feedwater. No credit is taken for operation of the RCS relief valves, steam line relief valves, steam dump system, pressurizer level control system, or direct trip on turbine trip. Reactor scram is initiated by the first safety-grade signal from the reactor protection system.

By letter dated May 5, 1995, the licensee provided documentation of the existing RCS overpressure analysis for Surry and verification of the continued applicability of the existing analysis for operation at uprated conditions. The licensee indicated that Westinghouse WCAP-7769, Revision 1, "Overpressure Protection for Westinghouse pressurized Water Reactors," June 1972, remains valid for Surry units at the uprated conditions.

The analyses in WCAP-7769 demonstrate that, for the Surry units operating at 2546 MWt, the combined capacity of two of the three safety valves is adequate to prevent the reactor coolant system (RCS) pressure from exceeding 110% (2750 psia) of design pressure (2500 psia) during a the most limiting overpressure event (turbine trip without bypass) if credit is taken for the first safety grade signal (high pressurizer pressure) from the reactor protection system. Further, 86% of the total capacity of the three safety valves is needed to meet regulatory criteria if any of four subsequent trips (overtemperature ΔT, high neutron flux, high pressurizer level, low-low steam generator water level) initiate reactor scram.

The licensee also describes its analyses which agree with the WCAP-7769 conclusions regarding the adequacy of the sizing of the Surry safety valves in its uprating report. The limiting event was identified as the Complete Loss of External Electrical Load and is documented in Section 3.5.8 of the Surry Core Uprating Licensing Report. The results of these analyses demonstrate that 94% of the total pressurizer safety valve capacity is required to mitigate the peak pressure of 2745 psia which occurs in the cold leg, 10.2 seconds into the event.

The limiting event was identified as the Complete Loss of External Electrical Load and is documented in Section 3.5.8 of the Surry Core Uprating Licensing Report. The results of these analyses demonstrate that 94% of the total pressurizer safety valve capacity is required to mitigate the peak pressure of 2745 psia which occurs in the cold leg, 10.2 seconds into the event.

Based on the above information, we conclude that, for operation at powers up to the proposed uprated power, the pressurizer safety valve capacity at Surry is adequate to meet the requirements to which Surry was originally licensed.

2.2.4 Auxiliary Feedwater and Residual Heat Removal

The staff review and approval of the Surry auxiliary feedwater system (AFW) was granted by letters dated November 17, 1980 and April 27, 1992. The transients that identify the limiting single-failure and minimum flow requirements for Surry's AFW system are loss of all AC to station auxiliaries and loss of normal feedwater. The existing analyses for the these events were performed assuming the uprated power conditions and are included in the Surry Core Uprate Licensing Report, Sections 3.4.3 and 3.8.1.

The licensee stated that, as a result of the analyses, identified limiting scenarios for single failure and required flow were not changed. We conclude that, since the Surry AFW flow capacity exceeds cooling requirements for the uprated power, cooldown time to residual heat removal (RHR) cut-in conditions would not be significantly affected.

The Residual Heat Removal (RHR) System cooldown analysis was not significantly affected by the uprating. The licensee indicated that the system still has the ability to bring the plant to cold shutdown (≤200°F) in the uprated condition. With two RHR pumps in operation cooldown to 140°F can be achieved 11.4 hours after shutdown. With one pump in operation cooldown to 200°F can be achieved in 40 hours. The staff agrees that the RHR system can continue to perform its intended function in the uprated condition.

2.2.5 Emergency Core Cooling System (ECCS)

The licensee's submittal identifies no adverse impact to ECCS operability or vulnerability to single failure resultant from the power uprating. ECCS performance analyses were evaluated using the Westinghouse large break loss-of-coolant accident (LBLOCA) 1981 Evaluation Model (EM) with Bash. The small break analyses were performed with the Westinghouse NOTRUMP small break LOCA (SBLOCA) EM. Both were approved for use by Virgina Power at the uprated power and increased steam generator tube plugging limit and demonstrate conformance with the requirements of 10 CFR 50.46 and 10 CFR 50 Appendix K, respectively.

The licensee stated that the current LBLOCA analysis, performed in March, 1994, assumes the uprated power and 15% steam generator tube plugging and results in a calculated peak cladding temperature (PCT) of 2120°F and metal/water reaction levels of less than 1.0% core-wide and 8.67% local. These values are within the limits specified in 10 CFR 50.46 (b) (1 - 3) of 2200 °F, less then 1% core-wide metal/water reaction and 17% local metal-water reation, respectively, and assure that the core would remain amenable to cooling as required by 10 CFR 50.46 (b) (4). Meeting the long-term cooling requirement of 10 CFR 50.46 (b) is assured for the uprated power by the continued acceptability of the Surry ECCS design.

The SBLOCA analyses for the uprated power with 15% steam generator tube plugging calculated a PCT of 1852°F, with less than 1.0% core-wide metal/water reaction, and 3.2% local metal/water reaction, which meet the requirements of 10 CFR 50.46 (b) (1 - 3) and are bounded by the LBLOCA analysis results. Satisfaction of 10 CFR 50.46 (b) (4) and (5) for SBLOCA analyses is similar to that for LBLOCA analyses. We conclude that the ECCS analyses provided in support of the power uprate are in compliance with 10 CFR 50.46 and Appendix K. The Surry ECCS design is therefore adequate for the uprated power.

2.2.6 Transient Analyses

The licensee indicated that they reanalyzed or reevaluated all Surry UFSAR Chapter 14 events considering the uprated power. They concluded that certain events did not require reanalyses either because (1) the events do not apply to the plant's present licensed configuration, i.e., Malpositioning of Part-Length Control Rod Assemblies, Startup of Inactive Reactor Coolant Loop, or (2) because existing analyses address the events for uprated conditions, i.e., Turbine-Generator Overspeed, Main Steam Line Break, Excessive Heat Removal Due to Feedwater System Malfunctions, Loss of Normal Feedwater, Control Rod Assembly Ejection, SBLOCA, and LBLOCA.

The licensee provided justification for not reanalyzing by showing that assumptions for the uprated conditions would not significantly affect the existing analyses or that the existing analyses were done assuming the uprated power. We find the licensee's reasons and conclusions acceptable.

Based on their assessment, the licensee concluded that reanalyses of Uncontrolled Control Rod Assembly Withdrawal from a Subcritical Condition and at Power, Control Rod Assembly Drop/misalignment, Chemical and Volume Control System Malfunction, Excessive Load Increase, Loss of Reactor Coolant Flow, Locked Rotor, Loss of Electrical Load, and Steam Generator Tube Rupture events were warranted. The licensee reanalyzed these events using currently approved methodologies.

2.2.6.1 Uncontrolled Control Rod Assembly Withdrawal from a Subcritical Condition

The licensee reanalyzed the rod withdrawal from subcritical event using RETRAN computer code and the associated Virginia Power reactor system transient analysis methodology. RETRAN calculates nuclear power, core heat flux, average fuel, clad and coolant temperatures. The detailed core thermal-hydraulics analysis was performed using the COBRA computer code to generate the MDNBR. The major difference between the previous analysis and the current reanalysis is that the licensee assumes that all three reactor coolant pumps are in operation.

The licensee determined that the core and the reactor coolant system are not adversely affected because the peak thermal core and coolant temperatures in the DNB-limiting case are well below their nominal full power values. The staff finds the licensee analysis and conclusion acceptable.

2.2.6.2 Uncontrolled Control Rod Assembly Withdrawal at Power

The rod assembly withdrawal at power event required reanalysis due to the change in the Overtemperature and Overpower ΔT protection setpoints. The event was reanalyzed RETRAN and COBRA computer codes. The licensee concluded that 1) the DNBR remains above the 95/95 DNBR design limit, (2) the most limiting RCS pressure is below 110% of design pressure and (3) the most limiting main steam pressure is less than 110% of the main steam design pressure. Therefore the staff finds that, in the uprated condition, the Surry plants are able to mitigate the consequences of the uncontrolled control rod assembly withdrawal at power event.

2.2.6.3 Control Rod Assembly Drop/Misalignment

The control rod assembly drop/misalignment event required reanalysis at the uprated condition to generate new plant-specific core thermal limit lines that are used during reload analyses. These new limits were generated by completing the transient and thermal-hydraulic portion of the staff approved methodology. The nuclear analysis will be completed when the reload design calculations are completed for the uprated core.

2.2.6.4 Chemical and Volume Control System Malfunction

The chemical and volume control system (CVCS) malfunction event centers around boron dilution accidents. Boron dilution is a manual operation that is under strict administrative controls limiting rate and duration of dilution. It was necessary to reanalyze the event because the uprated power affects the Overtemperature and Overpressure ΔT setpoints. The licensee reevaluated the administrative controls and alarms to ensure that there remains at least a 15 minute margin from positive indication of a dilution in progress to loss of shutdown margin for corrective operator action during MODES 1 through 4. For MODES 5 and 6 the licensee ensured that primary grade water been isolated from the reactor coolant system 15 minutes following a planned dilution.

The licensee determined that the existing alarms and administrative controls still allow enough time for operator intervention in a credible boron dilution event. The staff finds the licensee's findings acceptable.

2.2.6.5 Excessive Load Increase

The limiting scenarios for excessive load increase event are initiated at full power therefore it was necessary to reanalyze the event for the uprated condition. The analysis was completed with the use of LOFTRAN and Westinghouse standard non-statistical thermal-hydraulic methodology. Four cases were analyzed to demonstrate plant response following a 10% step load increase. The cases included the reactor at the beginning-of-life, manually and automatically controlled and end-of-life and manually and automatically controlled.

In all cases the minimum DNBR remained above the design limit value. Therefore the staff finds the the plant response to excessive load increase in the uprated condition acceptable.

2.2.6.6 Loss of Reactor Coolant Flow

The loss of reactor coolant flow is the limiting DNB event and was therefore reanalyzed in the uprated condition. The analysis includes two cases for loss of reactor coolant flow, loss of three out of three RCPs, from 100% power, due to (1) an undervoltage condition and (2) a frequency decay condition.

The analysis included a transient simulation using RETRAN for thermal-hydraulic plant response. The results were used as input into COBRA computer code for a detailed thermal-hydraulic analysis to compute the DNB margin. The licensee reported that both cases resulted in minimum DNBRs with considerable margin to the DNBR limit value. Therefore, the staff finds the plant response to loss of reactor coolant flow acceptable in the uprated condition.

2.2.6.7 Locked Rotor

The locked rotor event is characterized by the rapid loss of circulation in one Reactor Coolant loop due to the seizure of the reactor coolant pump (RCP). The plant response is simulated by using the RETRAN transient analysis code and the COBRA IIIC/MIT detailed thermal-hydraulics.

In this analysis, the unaffected reactor coolant pumps were assumed to trip, on low coolant flow, two seconds after generation of the reactor trip signal. The licensee stated that this assumption is consistent with the RCP trip assumption made in the locked rotor analysis for the uprating of its North Anna plants approved in an NRC Safety Evaluation Report dated August 25, 1986. The licensee indicated that the analysis resulted in the no rods having a MDNBR less than the statistical DNBR design limit and the RCS and main steam peak pressures remained below 110% of design pressure. The staff finds these results acceptable.

2.2.6.8 Loss of Electrical Load

The complete loss of electrical load was analyzed with the core characteristic of beginning of cycle and with power at 102% of the uprated core power. The licensee uses RETRAN and COBRA computer codes to simulate the plants response to the transient. The licensee indicated that the results of the analysis were (1) the peak RCS and main steam pressures remained below the associated design pressures and (2) the MDNBR remained above the 95/95 DNBR design limit. The staff finds that Surry in the uprated condition can still mitigate the consequences of a complete loss of electrical load.

2.2.6.9 Steam Generator Tube Rupture

The steam generator tube rupture event was analyzed for consequent radiological dose using staff approved methodologies. The thermal-hydraulic component of the accident was simulated with RETRAN. The radiological dose was calculated using an NRC approved methodology and the results were within the 10 CFR 100 limits.

A significant aspect of a steam generator tube rupture scenario, is the immediate cooldown, from full power conditions, to pressure and temperature equilibrium between the primary system and the shell side of the ruptured steam generator. The cooldown is accomplished through the use of the unruptured steam generators fed by the auxiliary feedwater system (AFS). As identified in the discussion of the AFS, the staff concludes that the flow capacity of the AFS continues to exceed cooldown requirements for the uprated power, and that the cooldown times would not be significantly affected. Therefore, the conclusions for the steam generator tube rupture event for the present licensed power of 2441 MWt continue to apply for the uprated power. The licensee's analyses confirm this conclusion for the Surry units.

The licensee's uprating submittal assesses the impact of the power uprate on the results of the existing approved UFSAR Chapter 14 analyses. The transient analyses supporting the power uprating were performed assuming a steam generator plugging level of 15%. The staff reviewed these analyses and concluded that appropriate safety criteria are met.

Based on the above we find the referenced accident analyses acceptable to support operation at the uprated power with a limit of 7% steam generator tube plugging.

2.2.7 Operating Licensee and Technical Specifications Changes

The licensee identified the following Surry operating licensee and technical specification changes related to the power uprating:

2.2.7.1 Operating License Changes

Operating License No. DPR-32 (Unit 1), DPR-37 (Unit 2) - Condition 3.A:

> Maximum Power Level - revise to read "steady state reactor core heat output of 2546 MWt" to reflect uprated power level

Operating License No. DPR-32 (Unit 1), DPR-37 (Unit 2) - Condition 3.N: Delete this condition which refers to control room dose calculations which are being superseded by analyses contained in this license amendment application.

2.2.7.2 Technical Specifications Changes

Page TS 1.0.A (TS 1.0.A) - Definition of RATED POWER - revise to state 2546 MWt

Page TS 2.1-3 (Basis for Figure 2. 1 - 1) - Delete sentence "The three loop operation... to 100% of design flow." This refers to densification effects no longer included in the analysis basis.

TS Figure 2. 1 -1 (Reactor Core Thermal and Hydraulic Safety Limits) - Replace with figure of limits which reflect operation at uprated conditions (4.1-1).

Page TS 2.1-4 (Basis for Figure 2. 1-1) - Revise to reflect relationship between deterministic and statistical analysis basis incorporated into the figure.

Page TS 2.1-5 (Basis for Reactor Control & Protection System) - Revise stated nominal RCS temperature to 573.0°F. Delete * footnote which allows Unit 2 Cycle 12 RCS nominal operating pressure to be reduced to 2135 psig.

Page TS 2.2-2 (Basis for TS 2.2) - Delete * and ** footnotes which refer to reduced PORV and high pressure reactor trip settings for Unit 2 Cycle 12.

Page TS 2.3-2 (TS 2.3.A.2(b)) - High Pressurizer Pressure Reactor Trip - Delete * footnote which refers to a reduced trip setting for Unit 2 Cycle 12.

Page TS 2.3-2 (TS 2.3.A.2(d)) - Overtemperature ΔT - revise T' to equal 573.0°F, the proposed nominal RCS average temperature.

Page 2.3-7 (Basis for Low Flow Reactor Trip) - This paragraph is being revised to emphasize that the low flow trip is the primary trip and that undervoltage and underfrequency trips are considered back-up protection. This reflects the assumptions of the revised complete loss of flow analysis.

Page TS 3.1-1 (TS 3.1.A.1.a) - LCO for Number of Reactor Coolant Pumps - Revise to read "A reactor shall not be brought critical with less than three pumps, in non-isolated loops, in operation." This change reflects the revised analysis of uncontrolled rod withdrawal from a subcritical condition.

Page TS 3.1.3 (TS 3.1.A.3.b) - Pressurizer Safety Valve Lift Settings - Delete the * footnote which refers to expanded pressurizer safety valve lift setting tolerance for the remainder of Cycle 10 and 11 for both units.

TS Page 3.1-16 to 3.1-17a (Basis for Coolant Activity Limits) - The description on these pages has been rewritten, based upon the revised steam generator tube rupture radiological consequences analysis.

Page TS 3.3-7 (Basis for Accumulator valves) - Delete the * footnote which refers to a reduced nominal operating pressure for Unit 2 Cycle 12.

Page 3.6-2 (TS 3.6.E) - SG Secondary I-131 Activity - Delete the sentence "The iodine-131 activity in the secondary side of any steam generator, in an unisolated reactor coolant loop, shall not exceed 9 curies," and revise the next sentence to begin "The specific activity ..." This change reflects the secondary activity assumed in the revised main steamline break radiological analysis, which is a specific activity of 0.10 μCi/cc. A separate limit on total activity is redundant and is not required by the revised analysis.

Page TS 3.6-4 (Basis for ECST Capacity) - Revise basis statement to read "The specified minimum water volume in the 110,000-gallon protected condensate storage tank is sufficient for 8 hours of residual heat removal ..." Add a sentence which reads "It is also sufficient to maintain one unit at hot shutdown for 2 hours, followed by a 4 hour cooldown from 547°F to 350°F (i.e. RHR operating conditions)." This reflects the cooldown capability for operation at uprated conditions.

Page TS 3.6-4 (Basis for Main Steam Safety Valve Capacity) - Revise the statement of main steam safety valve flow capacity to read "... total combined capacity of 3,842,454 pounds per hour at their individual relieving pressure; the total combined capacity of all fifteen main steam code safety valves is 11,527,362 pounds per hour." Revise the second sentence to read "The nominal rating steam flow is 11,260,000." These changes reflect a revised calculation of valve relief capacity and the increased nominal steam flow associated with uprating.

Page TS 3.6-5 (Basis for SG Secondary Activity) - Delete the text starting with "The limit on steam generator ..." through the sentence which ends with "... the specific iodine-131 limit would be .089 uCi/cc." Replace with the following:

"The limit on steam generator secondary side Iodine-131 activity is based on limiting the inhalation dose at the site boundary following a postulated steam line break accident to a small fraction of the 10 CFR 100 limits. The accident analysis, which is performed based on the guidance of NUREG-0800

Section 15.1-5, assumes the release of the entire contents of the faulted steam generator to the atmosphere."

These changes replace the previous description which provided a basis for comparison between the total and the specific activity limits. Since the total activity limit (TS 3.6.E) is being deleted, and the revised analysis does not require a specific total activity, this discussion is not relevant.

Page TS 3.7-26 (Table 3.7-4) - Recirculation Mode Transfer - Revise the RWST Level-Low setting limits to be as follows: ≥11.25% and ≤15.75%. These revised settings reflect the values assumed in the LOCA containment analyses. The setpoint value has been validated by the analyses as providing adequate margin for containment depressurization while ensuring that the low head safety injection pumps will have adequate net positive suction head for operation in sump recirculation mode.

Page TS 3.8-4 (Basis for Figure 3.8-1) - Revise the description of the figure characteristics and numerical ranges to be consistent with the replacement figure.

TS Figure 3.8-1 (Allowable Air Partial Pressure) - This figure, which presents operating limitations for containment air partial pressure, containment bulk average temperature and service water temperature, has been revised in conjunction with the containment integrity analysis. The revised figure allows operation over a range of air partial pressure from 9.0 psia - 10.3 psia and over a temperature range of 75 °F to 125°F.

Page TS 3.10-7 (Basis for Activity Assumed in Fuel Handling Accident) - Revise the description to state that this accident has been analyzed based on the methodology in Regulatory Guide 1.25, assuming that 100% of the gap activity of the highest powered assembly is released after 100 day decay following operation at 2605 MWt. This reflects the revised radiological dose consequences analysis. Delete the * footnote which compares the fuel rod gap activity of 15x15 and 17x17 demonstration assemblies. This information is not relevant to any fuel assemblies currently in Surry cores. Any potential future use of demonstration assemblies will be addressed on a case-specific basis.

Page TS 3.12-12 (TS 3.12.F.1) - DNB Parameters - Revise the temperature limit to state "Reactor Coolant System T_{avg} ≤577°F." This reflects the proposed nominal operating temperature, plus uncertainties which have been accommodated in the revised thermal-hydraulic analyses(4.1-2). Delete the * footnote which refers to reduced nominal pressurizer pressure for Unit 2 Cycle 12.

Page TS 4.1-10a (Table 4.1-2B) - Minimum Frequencies for Sampling Tests - Delete the words "9 Curie" which appears in both Note (4) and (8). This reflects the deletion of the 9 curie total activity limit and thereby makes only a general reference to Specification 3.6.E, which contains the limit.

Page TS 4.4-3 (Basis for Containment Air Partial Pressure Limits) - Revise statement of containment pressure range to read "The containment is maintained at a subatmospheric air partial pressure consistent with TS Figure 3.8-1 depending upon ..."This refers to the applicable figure which presents the range assumed in the containment integrity analysis.

Page TS 5.2-3 (IS 5.2.C.1) - Containment Systems - Revise the stated Recirculation Spray Subsystems flow to be "at least 3000 gpm of water from the containment sump." This reflects the flowrate assumed in the revised containment analysis.

We find the above TS changes acceptable because they are appropriate to the uprated power and are supported by acceptable analyses.

The licensee has also proposed to change Technical Specifications Pages B 3/4 6-1 and B 3/4 6-2 to reflect a change in the identification of the event determining containment conditions. Items related to containment conditions are discussed separately in this report.

3.0 CONCLUSIONS

Based on our review and with reference to past Viginia Power reviews within the scope of the systems areas discussed above, we find the proposed Surry Units 1 and 2 power uprating to 2546 MWt core power (2558 MWt NSSS power) acceptable for steam generator tube plugging up to 7%.

ENCLOSURE 2

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE

FACILITY NAME   Surry Electric Generating Station, Units 1 and 2

SUMMARY OF REVIEW

In a submittal of August 30, 1994, as supplemented by a letter dated May 5, 1995, the Virginia Electric and Power Company (Virgina Power) requested amendments to Facility Operating Licenses NPF-32 and NPF-37 for the Surry Power Station (Surry) Units 1 and 2, respectively. Specifically, the amendments would revise the licenses and Technical Specifications (TS) for the Surry units to increase the rated power level from the present specification of 2441 Megawatts thermal (MWt) to a specification of 2546 MWt. The proposed changes would allow the Surry units to operate at a Nuclear Steam Supply System (NSSS) power of 2558 MWt and up to 7% steam generator tube plugging.

NARRATIVE DISCUSSION OF LICENSEE PERFORMANCE - SAFETY ASSESSMENT/QUALITY VERIFICATION

The licensee's submittal was not organized in the preferred format (Standard Format, SRP). It was necessary for the staff to request clarification. Although the licensee was timely in their responses to RAI, their responses did not always focus on the review concerns.

AUTHORS: S. Brewer/F. Orr
DATE: ________________

MEMORANDUM TO: David B. Matthews, Director
Project Directorate II-2
Division of Reactor Projects II/II

FROM: Charles L. Miller, Chief Original signed by Charles L. Miller
Emergency Preparedness and Radiation
Protection Branch
Division of Technical Support

SUBJECT: ISSUANCE OF SAFETY EVALUATION ON POWER UPRATE
(TAC NOS.: 903645/90365)

PLANT NAME: SURRY POWER STATION UNIT NOS. 1 AND 2
LICENSEE: Virginia Electric and Power Company
DOCKET NOS. 50-280 and 50-281
REVIEW STATUS: Complete

The Emergency Preparedness and Radiation Protection Branch has completed its review of the amendments proposed by the licensee to Operating License Nos. DPR-32 and DPR-37 for Surry Power Station Units No. 1 and 2 related to power uprate. The proposed changes would increase the authorized maximum reactor core power level by 4.3 percent to 2546 megawatts thermal (MWt) from the current limit of 2441 MWt.

We have reviewed the proposed changes and conclude that they are acceptable.

Attached is our SER input. The responsible reviewer is John L. Minns, 415-3166.

Docket Nos. 50-280
and 50-281

ATTACHMENT: Safety Evaluation Report

CONTACT: John L. Minns, NRR/TERB
(301) 415-3166

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

March 31, 1995

MEMORANDUM TO: David B. Matthews, Director
Project Directorate II-2
Division of Reactor Prjects II/II

FROM: Charles L. Miller, Chief Charles L. Miller
Emergency Preparedness and Radiation Protection Branch
Division of Technical Support

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Docket Nos. 50-280
and 50-281

ATTACHMENT: Safety Evaluation Report

CONTACT: John L. Minns, NRR/TERB
(301) 415-3166

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

SAFETY EVALUATION BY THE EMERGENCY PREPAREDNESS AND

RADIATION PROTECTION BRANCH

SURRY POWER STATION UNIT NOS. 1 AND 2

REQUEST FOR POWER UPRATE

INTRODUCTION

By letters dated August 30, 1994, and February 6, 1995, the Virginia Electric and Power Company requested changes to the Operating Licensee Nos. DPR-32 and DPR-37 and the Technical Specifications (TS) for Surry Power Station Unit Nos. 1 and 2, respectively. Specifically, the amendments would revise the TS to increase the present rated core power level of 2441 Megawatts Thermal (MWt) to 2546 MWt. The proposed changes represent 4.5 percent increase over the current licensed power level. The staff reviewed the potential increase in design basis accident (DBA) radiological consequences due to the power uprate.

EVALUATION

The licensee evaluated the impact of the proposed amendment to show that the applicable regulatory acceptance criteria continue to be satisfied for the uprated power conditions. In conducting this evaluation, the licensee evaluated the effect of the power uprate on the DBA radiological consequences. The original licensing DBA source terms for Surry were considered. The licensee also evaluated control room habitability under DBA conditions.

Design Basis Accidents

The licensee stated that the original radiological consequence analyses could not be exactly reconstituted. Therefore, the analyses were performed using methodology described in the UFSAR with the original licensing basis assumption at 2546 MWt (105 percent of current power level). For the uprate analyses, the core radionuclide inventory was based on a power level of 2605 MWt. The licensee's doses are within the dose reference values stated in 10 CFR Part 100 and the Standard Review Plan (SRP). The calculated control room operator doses are within the limits to control room operators given in General Design Criterion (GDC) 19.

ATTACHMENT

The events evaluated for uprate were the loss-of-coolant accident (LOCA), main steam line break (MSLB), steam generator tube rupture (SGTR), locked rotor accident (LRA), the fuel handling accident (FHA) and the waste gas decay tank (WGDT) rupture. The whole body and thyroid dose were calculated for the exclusion area boundary (EAB), the low population zone (LPZ), and the control room. The plant-specific results for power uprate remain well below established regulatory limits. The doses resulting from the accidents analyzed are listed below with the applicable dose limits.

EAB

Accident	UFSAR 2605 MWt (rem)	SER 2546 MWt (rem)	UFSAR 2605 MWt (rem)	SER 2546 MWt (rem)
	Thyroid Dose		Whole Body Dose	
LOCA	224	220	6	7
MSLB	3.6	8	<0.1	<1
SGTR	15.4	28	<0.1	<1
FHA	55	34	1.6	3

LPZ

Accident	UFSAR 2605 MWt (rem)	SER 2546 MWt (rem)	UFSAR 2605 MWt (rem)	SER 2546 MWt (rem)
	Thyroid Dose		Whole Body Dose	
LOCA	12	20	0.2	(<1)
MSLB	0.4	(<1)	<0.1	(<1)
SGTR	0.7	2.5	<0.1	(<1)
FHA	2.4	3	0.1	(<1)

The preceding analysis was based on 105 percent of the uprated power, using methodologies currently approved by the NRC. After reviewing the information submitted by the licensee, the staff concludes that for the uprated power, the analyzed consequences of DBAs will remain within the limits of 10 CFR Part 100 and the GDC 19 and are, therefore, acceptable.

The control room operator doses were estimated using the methodology given in SRP, Section 6.4. These computed offsite and control room operator doses are well within the acceptance criteria given in SRP, Section 15.7.4 and GDC 19, respectively.

Conclusion

Based on our review of the licensee's major assumptions, the methodology used in the licensee's dose calculations, and the staff's original safety evaluation, the staff finds that the offsite radiological consequences and control room operator doses at the uprated power level of 2546 MWt will continue to remain below 10 CFR Part 100 dose reference values and the GDC 19 dose limit. Therefore, the staff concludes that the licensee's request to uprate the authorized maximum reactor core power level by 4.3 percent to 2546 MWt from its current limit of 2441 MWt is acceptable.

Principal Contributor: John L. Minns

April 10, 19.

MEMORANDUM TO: Brian R. Bonser, Senior Resident Inspector
Virgil C. Summer Nuclear Station
Division of Reactor Projects
Region II

FROM: Jacob I. Zimmerman, Project Manager /s/
Project Directorate II-3
Division of Reactor Projects I/II
Office of Nuclear Reactor Regulation

SUBJECT: VIRGIL C. SUMMER NUCLEAR STATION - SPENT FUEL POOL DESIGN BASIS LICENSING REVIEW

This memorandum provides input for the resident inspector's report regarding a review of the spent fuel pool cooling practices and current licensing basis at V.C. Summer Nuclear Station (Summer) operated by South Carolina Electric & Gas Company. Much of this information was gathered during a site visit from March 26-27, 1996.

Summer is scheduled to begin a refueling outage on April 15, 1996, with a planned full core off-load. Summer has performed a full core off-load since the first refueling outage. The current licensing basis (CLB) in the Final Safety Analysis Report (FSAR) describes this as an off-normal practice. However, the NRC Staff is preparing to issue a Power Uprate amendment which will increase the licensed thermal power limit from 2775 to 2900 MWt and change the current licensing basis. Once the amendment is issued and prior to the start of the outage, the licensee plans to revise their spent fuel cooling licensing basis and associated procedures. Some discrepancies were identified, but are not safety-significant.

Docket No. 50-395

Attachment: Inspection Report Input

cc: F. Hebdon
G. Belisle
J. Starefos

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INSPECTION REPORT INPUT

A memo dated February 8, 1996, from John Stolz of NRR directed all NRR project managers to gather and evaluate design basis and operating information for spent fuel cooling systems at operating reactors. The V.C. Summer project manager (PM) visited the site March 26-27, 1996, to gather background information necessary to complete this task.

The spent fuel cooling system consists of two 100-percent-capacity trains, with each train consisting of a spent fuel cooling pump and heat exchanger, with associated instrumentation, piping, and water purification equipment. Both pump motors are powered from Class 1E electrical systems and can also be powered from separate emergency diesel power sources during a loss of offsite power. However, the spent fuel cooling system is considered a non-essential load and requires operator action to provide power to the pumps if offsite power is lost. In addition, the two trains are interconnected such that it is possible to bypass either pump or heat exchanger should it be powered from separate emergency (diesel) power sources. The spent fuel cooling pump controls are located at an auxiliary control panel near the pumps.

The SFP cooling heat exchangers are cooled by the component cooling water (CCW) system with an inlet temperature of 105°F to the heat exchanger shell side. The CCW is cooled by the Service Water Pond which was constructed in a small arm of the Monticello Reservoir.

The project manager reviewed design documents, including the FSAR. The following discrepancies were identified:

(1) An FSAR discrepancy was identified in FSAR Section 9.1.3.3, where the piping lines entering and exiting from the spent fuel pool are located between the normal water level (elevation 461'6") and the design low water level (elevation 460'6") and are provided with anti-syphoning holes to preclude draining the pool below this low water level. However, the Spent Fuel Cooling System Flow Diagram, D-302-651, noted that all piping to and from the spent fuel pool should penetrate pool walls at elevation 460'3". The licensee verified that the drawing had the correct elevation and stated that this discrepancy would be corrected in the next FSAR revision. This revision is scheduled to be issued once the power uprate amendment has been issued.

(2) An FSAR discrepancy was identified in FSAR Table 9.1-1, for the Heat Transfer Rate of the spent fuel heat exchangers. The CLB states the heat transfer rate as: (1) 10/3 Core - 15.2 MBTU/hr (2) 13/3 Core - 21.3 MBTU/hr (per cooler). However, the 1984 rerack amendment dated September 27, 1984, changed the licensing basis heat transfer rate for each train of spent fuel cooling to 14.2 MBTU/hr. The licensee has stated that this discrepancy would be corrected in the next FSAR revision.

(3) The CLB in the FSAR describes a partial core off-load (72 FAs) as the normal design basis cooling situation and a full core off-load (157 FAs) as the off-normal design basis cooling situation. However, the licensee has been performing a full core off-load since the first refueling outage which is an off-normal design basis cooling situation on a normal frequency. While the

spent fuel cooling system was designed to remove such a heatload, it requires both trains of spent fuel cooling to be operable to maintain the spent fuel pool temperature below the design basis limit of 140°F.

The above discrepancies will be considered unresolved items pending resolution by the staff.

In addition, the project manager reviewed information related to past refueling practices, proposed changes to the design basis presented in the power uprate submittals and procedural controls for spent fuel pool related Technical Specification requirements. The PM found the procedural controls to be in place and appropriate. These included requirements on maintaining spent fuel pool level 23 feet above top of irradiated fuel, decay time before moving fuel, spent fuel pool ventilation, spent fuel pool inventory controls, spent fuel pool criticality, drainage desing control, and spent fuel storage burnup.

FSAR sections 9.1.2 and 9.1.3 describe spent fuel storage and spent fuel cooling. The FSAR states that the a partial core off-load (72 FAs) is the normal design basis cooling situation which results in a design basis heat load of 16.4 MBTU/hr and a full core off-load (157 FAs) is the off-normal design basis cooling situation which results in a design basis heat load of 31.3 MBTU/hr. The licensee has been performing a full core off-load since the first refueling outage which is an off-normal design basis cooling situation on a normal frequency. While the spent fuel cooling system was designed to remove such a heatload, it requires both trains of spent fuel cooling to be operable to maintain the spent fuel pool temperature below the design basis limit of 140°F.

The licensee has stated that at no time during the previous outages had they exceeded their design basis temperature or heat load. A review of Refueling Outage 8 data, provided by the licensee, documented that the maximum spent fuel temperature reached during core off-load was 105.3°F which is below the design basis maximum temperature of 140°F.

Summer is scheduled to begin a refueling outage on April 15, 1996, with a planned full core off-load. As stated above, the current licensing basis in the FSAR describes this as an off-normal practice. However, the NRC Staff is preparing to issue a Power Uprate amendment which will increase the licensed thermal power limit from 2775 to 2900 MWt and change the current licensing basis for spent fuel cooling. Once the amendment is issued and prior to the start of the outage, the licensee plans to revise their spent fuel cooling licensing basis and associated procedures as necessary.

In summary, the V.C. Summer spent fuel pool is designed to accommodate a full core off-load. The licensee recognizes the discrepancies noted above and has stated that they will be resolved after issuance of the power uprate amendment in the next FSAR revision. A review of the draft FSAR update appears to incorporate all necessary changes to the CLB as presented in the power uprate submittals. However, a final review of the FSAR and associated procedure revisions will ensure that they have been properly incorporated. No safety-significant discrepancies were identified in this review.

50-348 P64

November 21, 1997

MEMORANDUM TO: Herbert N. Berkow, Director
Project Directorate II-2
Division of Reactor Projects I/II

FROM: Stuart D. Rubin, Acting Chief Original signed by:
Human Factors Assessment Branch Richard Eckenrode (for)
Division of Reactor Controls
and Human Factors

Robert M. Gallo, Chief Original signed by:
Operator Licensing Branch
Division of Reactor Controls
and Human Factors

SUBJECT: PROPOSED POWER UPRATE FOR THE JOSEPH M. FARLEY NUCLEAR PLANT, UNITS 1 AND 2 (TAC NOS. M98120, AND M98121)

The Human Factors Assessment Branch and the Operator Licensing Branch have completed their review of Southern Nuclear Operating Company's submittals related to the proposed power uprate of the Joseph M. Farley Nuclear Plant, Units 1 and 2. The attached results of the staff's review conclude that the power uprate should not adversely affect operator actions or operator reliability. The contacts for this safety evaluation input are Garmon West and Frank Collins, who can be reached at 415-1044 and 415-3173, respectively.

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Attachment: As stated

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November 21, 1997

MEMORANDUM TO: Herbert N. Berkow, Director
Project Directorate II-2
Division of Reactor Projects I/II

FROM: Stuart D. Rubin, Acting Chief Original signed by:
Human Factors Assessment Branch Richard Eckenrode (for)
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Robert M. Gallo, Chief Original signed by:
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WASHINGTON, D.C. 20555-0001

November 21, 1997

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Project Directorate II-2
Division of Reactor Projects I/II

FROM: Stuart D. Rubin, Acting Chief
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Attachment: As stated

Attachment

Safety Evaluation Input Related to the Proposed Power Uprate for the Joseph M. Farley Nuclear Plant Units, 1 and 2

The staff reviewed Southern Nuclear Operating Company's submittals dated February 14 and September 22, 1997, for power uprate. The staff's evaluation of the licensee's responses to five review topics is provided below.

Topic 1 - Discuss whether the power uprate will change the type and scope of plant emergency and abnormal operating procedures. Will the power uprate change the type, scope, and nature of operator actions needed for accident mitigation and will it require any new operator actions?

By letter dated September 22, 1997, the licensee stated that the power uprate would not change the type and scope of plant emergency and abnormal operating procedures. The licensee also stated that the power uprate would not change the type, scope, or nature of operator actions needed for accident mitigation and that it would not require any new operator actions, with one possible exception. This exception arises as a result of an assumed increase in allowable charging and safety injection pump head degradation allowance from 8 percent to 10 percent, which may require opening a pressurizer power-operated relief valve (PORV). The licensee added that (1) the PORV action is consistent with the generic guidance in the Westinghouse Owners Group Emergency Response Guidelines and (2) the increase in charging pump degradation is not directly related to the power uprate. The staff finds the licensee's responses satisfactory.

Topic 2 - Provide examples of operator actions potentially sensitive to power uprate and address whether the power uprate will have any effect on operator reliability or performance. Identify operator actions that would necessitate reduced response times associated with a power uprate. Please specify the expected response times before the power uprate and the reduced response times. What have simulator observations shown relative to operator response times for operator actions that are potentially sensitive to power uprate? Please state why reduced operator response times are needed. Please state whether the reduced time available to the operator as a result of the power uprate will significantly affect the operator's ability to complete manual actions in the times required.

The licensee's letter of September 22, 1997, stated that there were no changes made to operator action assumptions in the Chapter 15 accidents and transients that resulted in reduced operator response times. The licensee stated that emergency response procedure operator actions potentially sensitive to power uprate are those that are performed on the basis of setpoint values that are calculated using the design parameters for power uprate. The licensee noted that changes in design parameters can affect the setpoints calculated for operator actions but should not affect the type and scope of operator actions. Further, the licensee stated that emergency response and normal and operating procedure revisions will be incorporated, where appropriate, before implementation of power uprate. The staff finds the licensee's responses acceptable.

Topic 3 - Discuss any changes the power uprate will have on control room instruments, alarms, and displays. Are zone markings on meters changed (e.g., the normal range, the marginal range, and the out-of-tolerance range)?

The licensee stated in its letter of September 22, 1997, that preliminary engineering reviews indicate that power uprate will have a minimum impact on the control room controls, alarms, and displays. The licensee noted several examples of potential control room changes. One potential change concerned color-coding indicators of normal operating steamline pressure, which may be adjusted to a low value of 770 psig. A second potential change involved the setpoint for the reactor coolant system high T-average annunciator. A third potential change dealt with the setpoints for the low suction pressure of the steam generator feed pump. The licensee stated that required changes would be implemented. The staff finds the licensee's responses satisfactory.

Topic 4 - Discuss any changes the power uprate will have on the Safety Parameter Display System (SPDS).

By letter dated September 22, 1997, the licensee stated that on the basis of an SPDS computer point list review, no SPDS setpoint changes are anticipated at this time. The licensee explained, however, that there is a potential for changes in the plant process computer and/or SPDS scaling/calibration curves and the high/low alarm limits for some uprate-affected instrumentation inputs that are non-SPDS computer points. The staff finds the licensee's responses satisfactory.

Topic 5 - Describe any changes the power uprate will have on the operator training program and the plant simulator. Provide a copy of the post-modification test report (or test abstracts) to document and support the effectiveness of simulator changes as required by ANSI/ANS 3.5-1985, Section 5.4.1.

Specifically, please propose a license condition and/or commitments that address the following:

(a) Provide classroom and simulator training on the power uprate modification.

The licensee's letter of September 22, 1997, stated that classroom and simulator training on the uprate changes for Units 1 and 2 will be provided to operations crews before the Unit 2 startup in the spring of 1998. The staff finds this information acceptable.

(b) Complete simulator changes that are consistent with ANSI/ANS 3.5-1985. Simulator fidelity will be revalidated in accordance with ANSI/ANS 3.5-1985, Section 5.4.1, "Simulator Performance Testing." Simulator revalidation will include comparison of individual simulated systems and components and simulated integrated plant steady-state and transient performance with reference plant responses using similar startup test procedures.

The facility licensee notes that the simulator is referenced to Unit 1, and therefore, final simulator modifications will be implemented following the Unit 1 uprating. The facility licensee also commits to a temporary simulator modification on the basis of the Unit 2 power uprate, including hardware and software changes. Simulator testing will be based on existing simulator certification tests consistent with the requirements of ANSI/ANS 3.5-1985. Best estimate data derived from applicable design change packages and engineering reports will be used to initially validate simulator modifications. The staff finds this information acceptable.

(c) Complete control room and plant process computer system changes as a result of the power uprate.

Hardware and plant process computer modifications will be temporarily implemented before the Unit 2 startup training. Final, permanent implementation will occur following the reference unit modifications. The staff finds this information acceptable.

(d) Modify training and plant simulator relative to issues and discrepancies identified during the startup testing program.

After final modifications to the reference unit and complete implementation of simulator modifications, the simulator will be further evaluated with respect to actual plant performance data and updated accident analysis data. The results of this final testing will be integrated into the quadrennial certification testing program. The staff finds this information acceptable.

On the basis of the information provided by the facility licensee in response to Topic 5, the staff finds the proposed simulator modifications and associated simulator testing plans satisfactory with respect to the facility licensee's commitment to ANSI/ANS 3.5-1985, as endorsed by Regulatory Guide 1.149, Revision 1. On the basis of the licensee's commitments relative to training, the staff finds that the licensee has proposed satisfactory changes to the operator training program as a result of the power uprate.

The staff concludes that the previously discussed review topics associated with the proposed Farley Nuclear Units 1 and 2 power uprate have been or will be satisfactorily addressed. The staff further concludes that the power uprate should not adversely affect operator performance or operator reliability.

Principal Contributors: Garmon West, HHFB/NRR
Frank Collins, HOLB/NRR

T-5C3

May 7, 1997

MEMORANDUM TO: Herbert N. Berkow, Project Director
Project Directorate II-2
Division of Rector Projects I/II

FROM: José A. Calvo, Chief (Original /s/ by J. Calvo)
Electrical Engineering Branch
Division of Engineering

SUBJECT: FARLEY UNITS 1 AND 2 - REQUEST FOR ADDITIONAL INFORMATION PERTAINING TO POWER UPRATE (TAC M98120/98121)

Plant Name:	Joseph M. Farley Nuclear Plant
Utility:	Southern Nuclear Operating Company
Docket Numbers:	50-348 and 50-364
Licensing Status:	OR
Resp. Directorate:	PD II-2/DRP
Project Manager:	J. Zimmerman
Review Branch:	EELB/DE
Review Status:	Incomplete

Attached is a request for additional information (RAI) pertaining to power uprate at Farley Units 1 and 2. The Electrical Engineering Branch needs this information in order to complete the technical specifications change requested with the power uprate. We request that the licensee respond to the RAI as soon as possible.

Docket No.: 50-348 and 50-364

Attachment: As stated

CONTACT: P. Kang, NRR/DE
415-2779

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

May 6, 1997

MEMORANDUM TO: Herbert N. Berkow, Project Director
Project Directorate II-2
Division of Rector Projects I/II

FROM: José A. Calvo, Chief
Electrical Engineering Branch
Division of Engineering

José A. Calvo

SUBJECT: FARLEY UNITS 1 AND 2 - REQUEST FOR ADDITIONAL INFORMATION PERTAINING TO POWER UPRATE (TAC M98120/98121)

Plant Name:	Joseph M. Farley Nuclear Plant
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Docket No.: 50-348 and 50-364

Attachment: As stated

CONTACT: P. Kang, NRR/DE
415-2779

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

REQUEST FOR ADDITIONAL INFORMATION PERTAINING TO POWER UPRATE REQUIRED FOR THE EVALUATION OF THE TECHNICAL SPECIFICATION CHANGE REQUEST FARLEY NUCLEAR PLANT UNITS 1 AND 2

2.15 Safety-Related Electrical Equipment Qualification

Provide the list of the required and qualified radiological doses of the individual safety-related electrical equipment before and after power uprate. In the submittal, it is stated that "for safety-related electrical equipment with uprate doses not bounded by the original design basis, radiological doses at uprate conditions were compared against the dose threshold limits used for the individual components or equipment." We believe that the doses should be bounded by the test report values, not by the dose threshold limits. Explain the differences and why your method is acceptable.

Furnish composite LOCA/MSLB containment temperature profiles before and after power uprate case on the same plot that extends to 30 days. Identify where the composite temperature power uprate profiles are not enveloped by the design basis profile.

Explain why the (power) uprated temperature that exceeds the existing design basis profile by a few degrees (i.e., 5°F) toward the end of the composite temperature profiles (greater than 30,000 seconds) is acceptable by having enough margin between 70 seconds to 10,000 seconds. Should the end of the composite temperature profiles be longer or shorter than 30,000 seconds (8.3 hours)?

2.20 Miscellaneous Electrical Reviews

Provide the impact of the load, voltage, and short circuit values for power uprate conditions at all levels of the station auxiliary electrical distribution system (i.e., the onsite power system, the main generator, and its step-up transformer).

Provide the result of an analysis which used to conclude that: (1) the bounding steady state voltages and motor starting voltages remain within acceptable limits, (2) EDG loadings are within the design ratings, and (3) there are no impact on relay trip set points for loss of voltage or degraded grid voltage protective scheme due to power uprate.

State what would be the negative impact on the stability of the Units by increasing Farley generation to 920 mW per unit.

Clarify the statement, "There is a slight decrease in the margin of stability for limited faults during valley load conditions. Normal system growth offsets the slight decrease in margin of stability within 3 to 5 years." Please elaborate on how the generation increase due to its power uprate will decrease the stability margin, but the stability will improve later on when the system load grows.

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AN INCREASE OF REACTOR POWER AT

COMANCHE PEAK STEAM ELECTRIC STATION, UNIT 2

1. INTRODUCTION

By letter dated December 21, 1998 and supplemented by letters dated July 9, 1999 and July 24, 1999, Texas Utilities Electric Co. requested an uprate of the licensed power for operation of Unit 2 from 3411 MWt to 3445 MWt. The proposed increase in power would cause a change of some plant parameters which required the licensee to re-analyse their supporting safety evaluations. The licensee's evaluations included reviews comparing the effects of the revised design conditions (resulting from the proposed increased licensed power) with the current design conditions (which were evaluated previously). The evaluation input herein focused on the licensee's evaluations of the Steam Generator Blowdown System and the Steam Generator Tubes.

2. STAFF EVALUATION

2.1 Steam Generator Blowdown System

The Steam Generator Blowdown System is used for controlling chemistry of the steam generator shell water within the specified limits and for controlling buildup of solids. The steam generator blowdown flow comes from two locations: the normal blowdown location (lower nozzle) and the supplemental blowdown location (sampling nozzle). Due to the power uprate (to 3445 MWT), to maintain velocity limitations at the lower nozzle, the split of blowdown flow between these two locations is altered by decreasing blowdown flow from the lower nozzle by approximately one percent and by a corresponding increase of the blowdown flow from the sampling nozzle. Since this modification does not change the total blowdown flow from the steam generator, the ability of the system to control the rate of addition of dissolved solids to the secondary system from condenser leakage or makeup water will not be impacted by this revised condition. Also, the reduction of lower nozzle blowdown rate will not cause any significant change in the ability to generate particles in the secondary systems because the blowdown rate still will remain within the range needed for particulate control.

The staff reviewed the licensee's evaluations and concurs with its conclusions that the proposed licensed power uprate will not significantly impact operation of the Steam Generator Blowdown System because neither the rate of addition of dissolved solids nor generation of particles will be affected by it.

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2.2 Steam Generator Tube Integrity

Comanche Peak Unit 2 utilizes four Westinghouse model D5 steam generators. The tubes are thermally treated alloy 600 with full-depth hydraulically expanded tubesheet joints. The tube support plates are made of stainless steel. The staff focused it's review on the licencee's evaluation of the steam generator tubing degradation mechanisms and structural integrity.

2.2.1 Steam Generator Tube Degradation

The proposed one percent uprating of Comanche Peak Steam Electric Station Unit 2 (CPSES-2) will result in an approximate 0.3 °F increase in the primary inlet temperature, T_{hot}, of the steam generators. T_{hot} is considered to be the most sensitive operating parameter with respect to corrosion. The primary system nominal operating pressure of 2250 psia will remain unchanged for the Unit 2 uprate condition. Steam pressure is expected to decrease approximately 4 psi.

CPSES-2 evaluated the effect of the power uprate on the tube degradation mechanisms. CPSES-2 has operated for 5 effective full power years (EFPY) without any corrosion-related degradation of their steam generators. The steam generator tube material, thermally treated alloy 600, is known to have improved corrosion resistance over the mill annealed alloy 600. The steam generator tube expansion transition geometry and manufacturing processes used in producing the Westinghouse model D5 steam generators have also improved the corrosion characteristics of the steam generators at CPSES-2, compared to earlier model steam generators. Byron Unit 2 has steam generators with the same tube material as CPSES-2 and has operated successfully for 13 EFPY under conditions similar to the CPSES-2 uprated conditions with no active corrosion of the steam generator tubing.

The licensee evaluated other parameters which may affect corrosion such as steam temperature and flows for the uprated conditions and has determined that they have a negligible impact on the steam generator tube corrosion. Based on the license's evaluations and industry experience the staff concludes that CPSES-2 steam generators are not expected to experience any significant increase in corrosion due to the power uprate. The staff also finds that the power uprate should not significantly increase any corrosion-related degradation.

2.2.1.1 Anti-Vibration Bar Wear

The licensee evaluated anti-vibration bar (AVB) wear potential caused by flow induced vibrations and other mechanisms using two methods. The first method was a pre-uprating evaluation, using both theoretical considerations and the actual tube wear conditions. The second method was a post uprating evaluation using wear projection technology.[1] The wear projection technology evaluation produces information needed to project wear during operation

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[1]ASME Paper, "An Empirical Wear Projection Technology with Steam Generator Tube Applications and Relations to Work-Rate and Wear Simulations/Tests," T.M. Frick, AD-Vol. 53-2, Fluid-Structure Interaction, Aeroelasticity, Flow-Induced Vibration and Noise, Volume II, Dallas, November 1997.

under the uprated condition.

From the evaluations and the licensee's minimal experience with AVB wear, the licensee concluded that the wear rates prior to the uprating and the projected wear rates after the uprating remain negligible. Based on the licensee's evaluations, the staff finds that the power uprate should not significantly affect the tube wear by the anti-vibration bars.

2.2.1.2 Preheater Wear

The licensee performed a preliminary assessment to estimate the effects of a bounding 4.5 percent power uprate at CPSES-2 with respect to preheater tube wear. A review of eddy current inspection results for preheater tubes was also performed. The licensee stated that there were no tubes plugged as a result of wear in the preheater, and that only two tubes had any indication of tube wear in the preheater region. The maximum wear depth of the limiting tube was estimated to be approximately 5 percent through wall. The licensee concluded from its review of the eddy current data that significant preheater tube wear is not active in the CPSES-2 steam generators.

The power uprate will increase the feedwater flow into the steam generators. This increased flow through the main feedwater nozzle could potentially increase tube wear. The licensee performed an evaluation to estimate the level of increase in tube wear that could potentially occur for the bounding uprated condition. The licensee determined that the rate of wear could increase by a factor of approximately 1.6. Therefore, by increasing the small amount of preheater wear by a factor of 1.6, the amount of wear will still remain negligible.

The licensee will continue to monitor the tubes located in the preheater in accordance with the Steam Generator Integrity Program required by their technical specifications to determine if significant tube wear is occurring. The licensee stated that should tube wear be identified, appropriate actions (such as wear projection, tube plugging/stabilization, or orifice plate modifications) will be considered. The staff finds that the power uprate should not significantly affect the tube wear in the preheater region and in the unlikely event that wear does increase it should be detected by the licensee's periodic tube inspections.

2.2.1.3 Monitoring Tube Degradation

The licensee states that the one percent uprate will not introduce new degradation mechanisms. This is supported by industry experience with similar steam generators. Therefore, the licensee believes that the current steam generator integrity program is acceptable. In the event that a need should develop for additional surveillances or inspection criteria, the licensee will follow its current Steam Generator Integrity Program to develop and determine what changes will be necessary. The licensee concludes that the small one percent power uprate is not sufficient to require pre-emptive changes to the existing program. The staff is satisfied with the licensee's plans to assess tube degradation.

2.2.1.4 Plugging Limit

The licensee performed a structural analysis to determine whether the tube plugging limit of 40 percent in the licensee's technical specifications would remain conservative to support operation at the uprated power conditions. The licensee's uprated analysis addressed the conditions that were historically found to be limiting in analyses performed for this and similar plants. The power uprated analysis determined the minimum required wall thickness to be 0.016 inches (37.2 percent of wall thickness). The 40 percent plugging limit provides for an allowance of 22.8 percent for growth and eddy current measurement uncertainty.

The licensee stated that the technical justification for the current 40 percent technical specification tube plugging limit remains conservative and would not be impacted by the proposed one percent power uprate. The staff finds that the 40 percent plugging limit continues to be appropriate under the proposed power uprate conditions.

The staff reviewed the licensee's evaluations and concludes that the proposed licensed power uprate will not significantly impact operation of the steam generators.

Principal Contributers: Krzysztof Parczewski
Andrea Keim

Mr. Menosm

UNITED STATES
ATOMIC ENERGY COMMISSION
WASHINGTON, D.C. 20545

Rec'd. 5/22/74
JBG

May 20, 1974

Docket No. 50-261

Carolina Power & Light Company
ATTN: Mr. J. A. Jones
Senior Vice President
336 Fayetteville Street
Raleigh, North Carolina 27602

Gentlemen:

The Directorate of Licensing has issued the enclosed Safety Evaluation dated May 20, 1974, regarding your application dated February 1, 1974, for an amendment to License No. DPR-23 for Unit No. 2 of your H. B. Robinson nuclear facility to operate at power levels up to 2300 MW (thermal) Five copies are enclosed for your information and use.

Further consideration of your application for the power increase is pending ACRS review and the expiration of the 30 day notice in the Federal Register (39 FR 14988) of proposed issuance of the action.

Sincerely,

Robert A. Purple

Robert A. Purple, Chief
Operating Reactors Branch #1
Directorate of Licensing

Enclosure:
Safety Evaluation 5/20/74 (5 cys)

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UNITED STATES ATOMIC ENERGY COMMISSION

SAFETY EVALUATION BY THE DIRECTORATE OF LICENSING

DOCKET NO. 50-261

CAROLINA POWER & LIGHT COMPANY

H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

POWER INCREASE

Date: MAY 20 1974

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FIGURE

1.0 INTRODUCTION AND SUMMARY

On July 31, 1970, the Atomic Energy Commission issued Facility Operating License No. DPR-23 to Carolina Power & Light Company (CP&L) authorizing operation of Unit No. 2 at the H. B. Robinson Steam Electric Plant at steady state power levels not in excess of 2200 MWt. By application dated February 1, 1974, and petition notarized February 4, 1974, CP&L requested amendment of License No. DPR-23 to permit operation at steady state power levels not in excess of 2300 MWt.

Robinson-2 was initially designed for operation at 2300 MWt. For our safety evaluation supporting issuance of License No. DPR-23, we reviewed the capability of the plant engineered safety features and the radiological consequences of various postulated accidents at both 2200 MWt and 2300 MWt. We limited operation of Robinson-2 to power levels not in excess of 2200 MWt to limit the fuel cladding temperatures obtained from analysis to values that would preclude the likelihood of autocatalytic reaction of fuel cladding and coolant water in the unlikely event that a loss-of-coolant accident (LOCA) occurs.

Initial criticality of Robinson-2 was achieved on September 20, 1970, and licensed full power was reached on February 23, 1971. The initial low power and full power testing was completed satisfactorily. The observed thermal, hydraulic and nuclear performance of the facility met applicable acceptance criteria. Commercial operation started on March 14, 1971.

We have evaluated Robinson-2 for operation at power levels not in excess of 2300 MWt with the core loading proposed for Fuel Cycle 3. This evaluation is based on review of: (a) WCAP-8243, "H. B. Robinson Unit 2 Justification Of Operation at 2300 MWt," which was incorporated in the petition by reference; (b) proposed changes to the Final Safety Analysis Report which were submitted with the petition; (c) additional information dated March 12, April 12 and 29, 1974, which supports the petition; (d) operation at power levels up to 2200 MWt; and (e) the startup test program results.

Examinations of data from startup testing and power operation by Licensing and Regulatory Operations have shown that the data confirmed design predictions in most areas initially and in the remaining areas after modifications and that the data support operation of Robinson-2 at 2300 MWt. Facility operation during Fuel Cycles 1 and 2 has progressed without significant leakage of fuel cladding. Because of fuel densification and collapse of some sections of fuel cladding in Fuel Cycle 1, operation during Fuel Cycle 2 was initially limited to 75% of licensed power. Our review of fuel densification and the capability of the emergency core cooling system (ECCS) to adequately cool the core in the event that a LOCA occurs was completed on July 25, 1973, and resumption of operation at licensed full power was authorized. Radioactive releases during Fuel Cycles 1 and 2 have been well within 10 CFR Part 20 limits.

We have evaluated the overall ECCS performance and its conformance at 2300 MWt with "Interim Acceptance Criteria for Emergency Core Cooling Systems for Light Water Reactors" published June 29, 1971, and have concluded that the Robinson-2 ECCS meets these criteria.

We have reviewed the transient analyses that were revised by CP&L for 2300 MWt. The results show that the design and performance objectives will be satisfied during the proposed operation at 2300 MWt. In addition, postulated accidents, including the design basis accident, were reexamined for the higher power level. The presently calculated radiological doses resulting from these postulated accidents are acceptable.

On the basis of our review, we have concluded that there is reasonable assurance that the health and safety of the public will not be endangered by the operation of the Robinson-2 at steady state power levels up to a maximum of 2300 MWt.

2.0 REACTOR DESIGN

2.1 Thermal and Hydraulic Design

The nuclear steam supply system design for Robinson-2 is similar to that reviewed and approved for Surry Units 1 and 2. A comparison between the plants is shown in Table 1. Compared to Surry 1/2, Robinson-2 has lower power, higher peaking factors, higher coolant inlet temperature, and higher coolant flow rates. The combination of these thermal-hydraulic parameters results in approximately the same departure from nucleate boiling (DNB) margins for the two plants. Hence, the thermal-hydraulic design for Robinson-2 does not represent any extension of accepted PWR thermal and hydraulic design operating limits.

In the thermal-hydraulic analysis, CP&L has made three changes in the calculation of the heat flux for predicting the departure from nucleate boiling (DNB) for fuel cycle 3. These changes included:

(1) Elimination of the 1.9% reduction in DNB ratio (DNBR) due to pellet eccentricity or clad ovality. Westinghouse performed power spike DNB tests and showed that no differences existed in the predicted critical heat flux between the tests in which the power spike was imposed and the tests in which the power spike was absent.

(2) Elimination of the heat flux engineering hot channel factor which was 1.03. The justification was the same as explained in item 1 above.

(3) Elimination of the 10% DNBR penalty to cover possible effects of clad flattening. Clad flattening is not predicted during fuel cycle 3.

Experimental evidence and justification for the deletion of items 1 and 2 have been documented in WCAP 8219, "Fuel Densification Experimental Results and Model for Reactor Application." The clad flattening analysis and justification is delineated in WCAP-8243, "H. B. Robinson Unit 2 Justification for Operation at 2300 MWt."

We have reviewed the transient analysis that were revised for 2300 MWt operation. The limiting design and performance criteria were not changed from the 2200 MWt analyses. We have concluded that the Robinson-2 thermal-hydraulic design is acceptable for reactor operation at steady state power levels up to 2300 MWt on the basis of: (1) our review of the thermal-hydraulic analyses which showed that the DNB ratio exceeded 1.3 for all transients, and (2) the successful operation of the Robinson-2 plant for more than two years at power levels up to 2200 MWt.

2.2 Fuel Performance

During Fuel Cycles 1 and 2, there was no evidence of leakage of fission products from the fuel rods to the primary coolant. However, toward the end of Fuel Cycle 1, flux spikes indicative of axial gaps and possibly fuel

TABLE 1

THERMAL AND HYDRAULIC DESIGN PARAMETERS

	ROBINSON-2 Present	ROBINSON-2 Proposed	SURRY 1/2 FSAR
Total Heat Output, MWt	2200	2300	2441
Nominal System Pressure, psia	2250	2250	2250
Minimum DNBR for Design Transients	1.3	1.3	1.3
Hot Channel Factors			
Heat flux			
-Nuclear, F_q^N	2.34	2.57	2.39*
-Engineering, F_q^E	1.03	1.03	1.03*
Total	2.41	2.65	2.46*
Enthalpy Rise			
Nuclear $F_{\Delta H}$	1.55	1.55	1.55
Coolant Flow			
Total Flow Rate, lbs/hr	101.5×10^6	101.5×10^6	100.7×10^6
Coolant Temperature, °F			
Nominal Inlet	546	546	543
Average Rise in Core	58	61	63
Heat Transfer			
Active Heat Transfer Surface Area, ft²	42,460	42,460	42,460
Maximum Heat Flux, Btu/hr-ft2	438,700	488,100	534,100
Maximum Thermal Output at 102% operation based on ECCS Limitations (kW/ft)	14.2	15.8 **	15.7*
Fuel Central Temperatures, °F Maximum at 100% Power Power	4000	3800	4050
DNB Ratio - Minimum Ratio			
During: Nominal Operating Conditions	2.01	2.02	1.97
Transients	1.30	1.30	1.30

* Change No. 15 to the Technical Specifications for Surry 1/2

** Revised by letter of 5/17/74

clad collapse, were observed. During the subsequent refueling outage, th replaced fuel assemblies were visually inspected. Of the visible (perip l) fuel rods, 1.3% were found to have collapsed cladding. The fuel rods in this group of fuel assemblies contained uranium dioxide having relatively low density and the rods were not prepressurized with helium.

The remaining fuel assemblies in the reactor were unloaded for inspection. The fuel rods in these assemblies also contained uranium dioxide of relatively low density but were prepressurized with helium. None of the visible rods had collapsed cladding. These assemblies were returned to the core and new fuel assemblies were loaded as planned in place of the assemblies which were not prepressurized.

For Fuel Cycle 2, we initially limited operation of Robinson-2 to 1650 MWt (75% of licensed power) pending completion of our review of fuel densification On completion of our review, we issued Change No. 44 to the Technical Specifications, which permitted CP&L to operate the reactor at power levels up to 2200 MWt provided that the power distribution was limited so that fuel cladding temperatures would not exceed certain values in the event of a LOCA. For fuel with relatively low density (2/3 of the core), the limit was 1800°F, and for fuel with higher density, the limit was 2300°F. CP&L was able to demonstrate to our satisfaction, that the excore flux detectors would provide adequate surveillance of the power distribution at relatively high power levels and that the axial power distribution monitoring system (APDMS) would provide adequate surveillance at the highest power levels.

During the present (second) refueling outage, all the low density fuel is being replaced with improved Westinghouse prepressurized fuel of higher density.

The applicant uses the approved Westinghouse Fuel Densification and Power Spike Models to evaluate the effects of fuel densification in pressurized zircaloy cladding for normal operation and anticipated transient and accident conditions. The fuel densification model, as described in WCAP-8218, is applicable for fuel performance calculations (centerline and average fuel temperatures), for input to power spike evaluations (axial size, frequency and distribution), for determining the fuel stack axial shrinkage factor for the LOCA analysis, and for calculating a temperature uncertainty for accident analysis. A previously approved Westinghouse clad creep model has been used to predict that cladding collapse will not occur during Cycle 3.

Because the reactor will be completely loaded with improved fuel for Fuel Cycle 3 which is scheduled to commence in early June, 1974, we conclude that it is appropriate to decrease the value of the spike peaking penalty factor at the core midplane from 1.17 to 1.04 and to rescind the requirement for limiting the fuel clad temperature to 1800°F for a LOCA. Further, we conclud that the power peaking factors proposed by CP&L in Table 1 can be met using axial offset limits on the excore instrumentation. In this regard, CP& has prepared an appropriately conservative limit, as shown in Figure 1 on p. 2.5, on the power peaking factor as a function of axial offset.

In the area of reactor fuel and fuel performance, the applicant uses approved fuel performance, cladding creep and power spike models. Therefore, in the fuels area, we conclude that operation at 2300 MWt for Cycle 3 is acceptable.

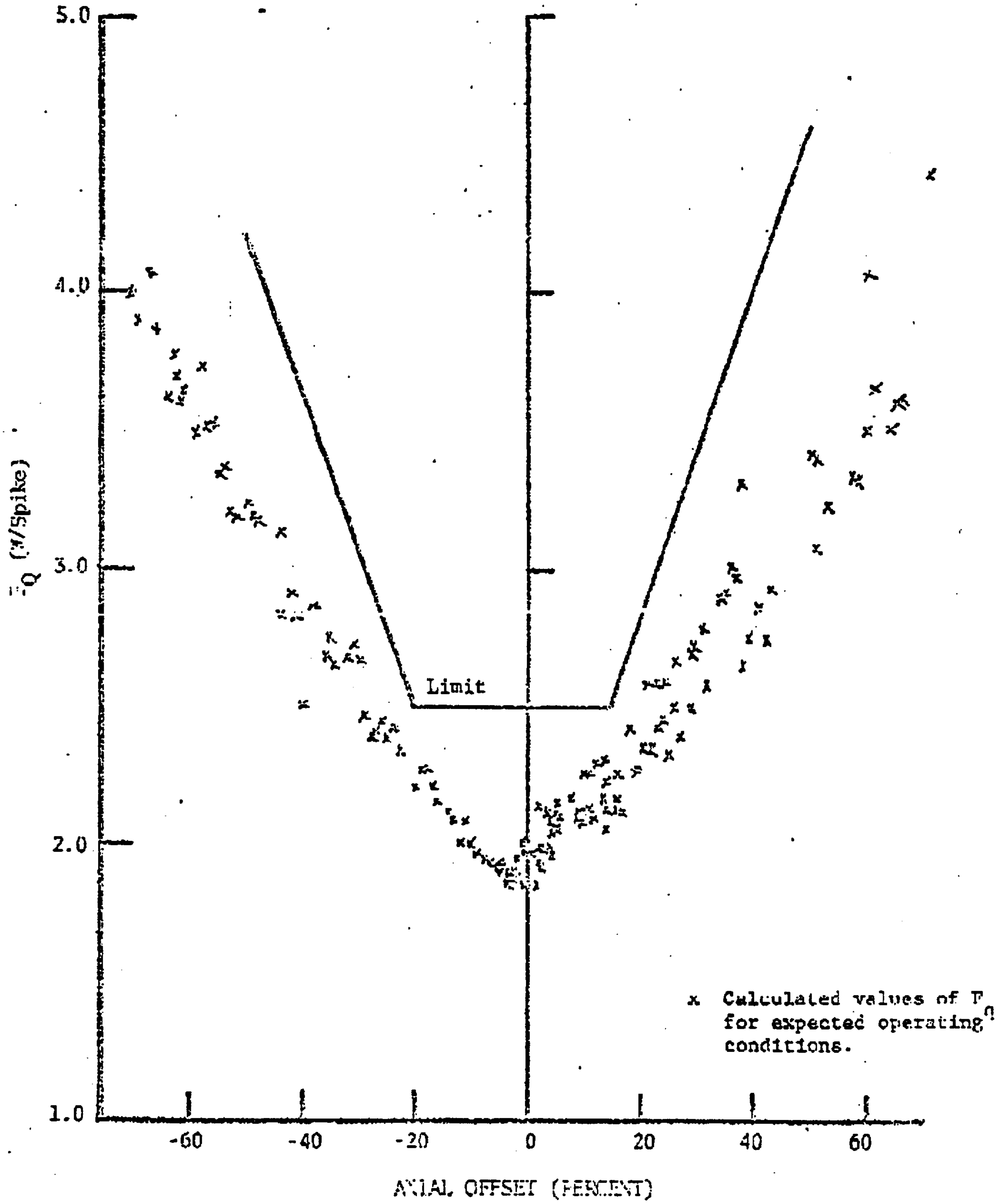

FIGURE 1

F_Q VERSUS AXIAL OFFSET

3.0 CONTAINMENT AND ENGINEERED SAFETY FEATURES

3.1 Containment Tests

The containment structure is a steel-lined concrete vessel which is prestressed in the vertical direction with grouted steel bar tendons and is conventionally reinforced in the circumferential direction. Design pressure for containment is 42 psig. In their petition for the operating license, CP&L calculated that the peak accident pressure would be 38 psig following shutdown from 2300 MWt.

Prior to initial operation of the reactor, structural proof tests of containment were performed successfully at 42.0 psig and at 48.3 psig (115% of design pressure). Technical Specification 4.4.4.2.a requires that proof tests at 42.0 psig be repeated after 3 years and after 20 years of operation. CP&L is performing the 3-year test during the current refueling outage. For this test, CP&L has derived and we have found acceptable, maximum acceptance criteria based on the observed response of the containment structure during the initial proof test.

Prior to initial operation, integrated leak tests of containment were performed at 21 psig and 42 psig with marginal but acceptable results. Technical Specification 4.4.1.1 requires that integrated leak tests at 21 psig be repeated at intervals of approximately 3-1/3 years. CP&L has performed an integrated leak test during the current refueling outage and the results are satisfactory. Our analysis of LOCA indicated that the present technical specification on integrated leak rate, i.e., 0.1% per day for a steam-air mixture, is acceptable for operation at 2300 MWt.

3.2 Emergency Core Cooling System

The design of the safety injection system is essentially that proposed at the time the construction permit was issued. The design provided for both hot and cold leg injection to cool the core during the initial recovery from a LOCA. Pursuant to a change in the Technical Specifications, automatic hot leg injection was eliminated because the emergency coolant may be entrained by the high velocity steam coming from the core and would be ineffective in mitigating the accident.

4.0 ACCIDENT ANALYSES

4.1 Loss-Of-Coolant Accident

The LOCA analysis for plant operation at 2300 MWt was performed at 102% of the core power and at a peak linear power of 15.8 kW/ft for the double ended cold leg guillotine. The analysis considered the effects of fuel densification and was done in accordance with the requirements of the Interim Acceptance Criteria for ECCS. The results indicated that the maximum local rod power that will meet the 2300°F clad temperature limit is 15.8 kW/ft. Based on this limit, 100% core power operation is permissible provided the total peaking factor (F_Q^T) no greater than 2.65 is maintained. The total core metal water reaction is 0.07% for the limiting break.

In the Safety Evaluation Report supporting issuance of the operating license for 2200 MWt, we estimated for the LOCA a thyroid dose of 280 Rem at the site boundary; and for operation at 2300 MWt, we noted that the dose would be approximately 5% higher but still within the guidelines in 10 CFR Part 100. Because this extrapolated thyroid dose for operation at 2300 MWt approaches 10 CFR Part 100 guidelines, we reevaluated the iodine removal effectiveness of the containment spray system and our estimates of the value X/Q appropriate for accident analyses using current methods and criteria. We based our reevaluation on the assumption that the 2-minute delay and override capability will be removed. The LOCA doses calculated with the spray system designed for Robinson-2 are 290 rem to the thyroid for the 0 - 2 hours at the exclusion distance.

We conclude that the plant meets the exposure guidelines of 10 CFR Part 100 at the 2300 MWt power level provided the 2-minute delay and override in the spray additive system actuation is eliminated.

4.2 Steam Line and Steam Generator Tube Rupture Accidents

On the basis of our experience with the evaluation of postulated steam line break and steam generator tube rupture accidents for PWR plants of similar design, we have concluded that the consequences of these accidents can be controlled by limiting the permissible primary and secondary coolant system radioactivity concentrations so that potential offsite doses are relatively small. We will include appropriate limits in the Technical Specifications in our action authorizing operation at 2300 MWt.

4.3 Control Rod Ejection Accident

CP&L has reanalyzed the control rod ejection accident for the worst case, i.e., at the beginning of cycle life. In the unlikely event that a control rod ejection accident occurs, their results indicate for the hottest fuel rod that less than 10% of the fuel would melt and that the stored energy would not exceed 187 cal/gm. These results are acceptable and the accident would not lead to undue risk to the public.

5.0 CONDUCT OF OPERATIONS

5.1 Plant Operation

The startup and power testing program results substantiated design predictions for operation at 2200 MWt. The core thermal and hydraulic performances showed that the core operated within the specified thermal and hydraulic limits. Reactor system stability measurements were within applicable criteria. Control rod reactivity worth measurements and rod insertion scram times were satisfactory.

Overall operation at power has been quite successful although operation has been interrupted on occasion for steam generator testing and power level was temporarily restricted because of fuel densification. Nevertheless, the plant capacity factor has been 66.7% since commercial operation began and 83.5% since the second refueling outage.

5.2 2300 MWt Power Test Program

CP&L has prepared a brief test program to verify that plant performance is acceptable at the slightly higher power density and power level. Before and after increasing power from 2200 MWt to 2300 MWt, CP&L will: (a) determine the power distribution by flux mapping, (b) obtain data to assure that the nuclear instrumentation is properly realigned; (c) perform calorimetric heat balances, and (d) conduct radiation surveys. We conclude that this level of effort in conjunction with surveillance as required by the Technical Specifications is satisfactory for operation.

5.3 Technical Competence

The operating organization, its qualifications and responsibilities, operating procedures, records, maintenance, and review and audit functions have been improved as the result of experience acquired by CP&L since the operating license was issued. The technical staff has increased in size and capability. Additional reactor operating experience gained since the issuance of the operating license has made the staff of CP&L more alert to abnormal and significant events. The general technical performance of the CP&L staff has demonstrated its competence during the startup and power operations to date.

6.0 TECHNICAL SPECIFICATIONS

Several changes to the Technical Specifications involving power level, power distribution, and temperature are necessary. Appropriate changes are being prepared and will be incorporated in the license by amendment.

7.0 REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

7.1 Operation at 2200 MWt

Subject to satisfactory completion of construction and pre-operational testing and giving due regard to certain items addressed in their letter of April 16, 1970, the ACRS found that Robinson-2 can be operated at power levels up to 2200 MWt without undue risk to the health and safety of the public. As indicated in Section 5.0 of this report, construction and pre-operational testing have been satisfactorily completed. The status of the items of additional concern to ACRS are discussed below.

The ACRS stated that further study is required of the bases and means whereby decisions concerning reactor operations will be made in the event of an earthquake in the region of the site. CP&L has installed a strong-motion recorder to monitor horizontal and vertical ground accelerations. In the event that the seismic alarm setpoint, 0.01 g in the horizontal direction, is exceeded, CP&L's Standing Order No. 5 requires that the facility be inspected by the operating crew and that film from the strong-motion recorder be retrieved and processed. If the ground acceleration exceeds 0.2 g in the horizontal direction or 0.16 g in the vertical direction, Standing Order No. 5 requires that the unit be shut down. For Robinson-2, the operating basis earthquake is 0.10 g horizontally and 0.067 g vertically, and the safe shutdown earthquake is 0.20 g horizontally and 0.133 g vertically. We conclude that the requirement for shutdown in the standing order is not acceptably conservative and we will require that the reactor be shut down if the operating basis earthquake is exceeded and remain shut down until inspection of the facility shows that no damage has been incurred which would jeopardize safe operation of the facility or until such damage is repaired.

The ACRS expressed the opinion that a crew of five, as proposed by CP&L, for operation of Robinson-1 (coal-fired) and Robinson-2 (nuclear) would not provide sufficient operator attention for safe operation of Robinson-2. CP&L is operating Units 1 and 2 with a crew of six. Further, Technical Specification 6.1.3.2 requires that two licensed reactor operators and one additional operator perform duties related only to Robinson-2. The shift foreman, who must hold a senior reactor operator's license, is responsible for both units. We have concluded that adding an additional operator to the crew has provided sufficient operator attention for safe operation of Robinson-2.

With regard to fuel rods prepressurized with helium, the need was expressed for surveillance of the rods to assure that they would be capable of withstanding anticipated transients at high burnup levels. As discussed in Section 2.2, monitoring of the flux distribution during operation and inspection of fuel during refueling indicated that bulging of prepressurized fuel rods had not occurred. We conclude that CP&L's program is adequate in this regard.

The ACRS expressed reservations regarding CP&L's plans to perform continuously during the life of the plant leak testing of containment seams and penetrations in lieu of performing periodically integrated leak tests of containment. Further, ACRS recommended additional study of the feasibility of demonstrating the structural integrity of containment during the life of the plant. As described in Section 3.1, periodic containment test requirements have been established for Robinson-2 which are satisfactory to the Regulatory staff.

The ACRS stated that operation with less than three reactor cooling loops in operation should be prohibited until it could be shown that no design limits would be exceeded and that trip points would be reliably reset by automatic means. CP&L has demonstrated to the satisfaction of the Regulatory staff that design limits would not be exceeded at 45% of licensed power with one of the three reactor cooling loops out of service. To assure that the reactor is not operated above this power level with one loop out of service, the plant protection system automatically trips the reactor if these conditions are violated. Further, CP&L stated in an amendment to the Final Safety Analysis Report that the Overtemperature ΔT trip point will be manually reduced to the appropriate level within 1 hour after a cooling loop is removed from service. Subject to these conditions, we found operation of Robinson-2 with two loops in service to be acceptable.

The ACRS recommended that precautions be taken relative to turbine missiles prior to or early in the operation of the plant. Specifically, the ACRS recommended that a redundant turbine overspeed control system be provided and that protection be installed in appropriate areas to protect against damage in the unlikely event of large missiles arising from failure of the turbine rotor. CP&L has installed a redundant turbine overspeed control system and, where necessary to meet our requirements, missile shielding and redundant safeguards components.

Implementation of methods for continuous monitoring of the boron concentration in the primary cooling system and for detecting gross failure of a fuel assembly was suggested by the ACRS as methods are developed. A boron monitoring device has been installed which utilizes a neutron source, however, the device has not been reliable. A radiation monitor has been installed for the detection of failed fuel and has functioned reliably. Relative to development in these areas, we conclude that CP&L's efforts have been satisfactory to date.

The ACRS noted that CP&L had underway studies of means to prevent common mode failures from negating scram action and of design features to make tolerable the consequences of failure to scram during anticipated transients. In response to our recent request, CP&L has agreed to provide by October 1, 1974, their analysis of the consequences of anticipated transients without scram and an indication of any required equipment changes that result from the analysis.

The ACRS also noted that additional review should be performed of the control of hydrogen buildup in containment in the unlikely event of a LOCA. Robinson-2 does not have hydrogen recombiners; however, it does have two independent filter systems so that the hydrogen concentration can be controlled by purging. We have evaluated their system and we find that purging would be required 23 days after LOCA and that the thyroid dose at the outer boundary of the low population zone would be approximately 15 Rem. We conclude that this dose is acceptably low.

7.2 Proposed Operation at 2300 MWt

The application for the Robinson-2 power increase is being reviewed by the ACRS. Their report to the Commission will be placed in the public record.

8.0 CONCLUSION

Based upon our review of the application, of relevant information pertaining to facility operation to date, and of minor modifications to the containment spray system as discussed in this evaluation, we have concluded that with operation of the H. B. Robinson Steam Electric Plant Unit No. 2 at steady state power levels up to a maximum of 2300 MWt, there is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations. The issuance of this amendment will not be inimical to the health and safety of the public.

September 26, 1996

Mr. T. F. Plunkett
President - Nuclear Division
Florida Power and Light Company
P.O. Box 14000
Juno Beach, Florida 33408-0420

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SUBJECT: TURKEY POINT UNITS 3 AND 4 - ISSUANCE OF AMENDMENTS
RE: THERMAL POWER UPRATE (TAC NOS. M94314 AND M94315)

Dear Mr. Plunkett:

The Commission has issued the enclosed Amendment No. 191 to Facility Operating License No. DPR-31 and Amendment No. 185 to Facility Operating License No. DPR-41 for the Turkey Point Plant, Unit Nos. 3 and 4, respectively. The amendments consist of changes to the Technical Specifications (TS) in response to your application dated December 18, 1995, as supplemented on May 3, June 11, July 1, July 3, and August 22, 1996.

The amendments increase the authorized rated thermal power from 2200 Megawatt-thermal (MWt) to 2300 MWt. The amendment also approves changes to the TS to implement uprated power operation.

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly Federal Register notice.

Sincerely,
Original signed by
Richard P. Croteau, Project Manager
Project Directorate II-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket Nos. 50-250 and 50-251

Enclosures:
1. Amendment No.191 to DPR-31
2. Amendment No.185 to DPR-41
3. Safety Evaluation

cc w/enclosures: See next page

Document Name: G:TURKEY\TP94314.AMD * See previous concurrence

OFFICE	LA:PDII-3	PM:PDII-3	PERB *	OGC	D:PDII-3	SRXB *
NAME	BClayton	RCroteau	CMiller *		FHebdon	RJones
DATE	9/10/96	9/19/96	8/29/96	9/ /96	9/9/96	8/13/96
COPY	Yes/No	Yes/No	Yes/No	Yes/No	Yes/No	No

OFFICE	EMEB *	EMCB *	HICB *	SPLB *	EELB *	D:DRPE	SCSB *
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DATE	8/27/96	8/16/96	8/15/96	9/4/96	8/8/96	9/ /96	8/7/96
COPY	Yes/No	Yes/No	Yes/No	Yes/No	Yes/No	Yes/No	Yes/No

OFFICE	ADP 9/15	D:NRR				
NAME	RZimmerman	WRussell				
DATE	9/ /96	9/15/96	/96	/96	/96	/ /96
COPY	Yes/No	Yes/No	Yes/No	Yes/No	Yes/No	Yes/No

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I/22

September 26, 1996

Mr. T. F. Plunkett
President - Nuclear Division
Florida Power and Light Company
P.O. Box 14000
Juno Beach, Florida 33408-0420

SUBJECT: TURKEY POINT UNITS 3 AND 4 - ISSUANCE OF AMENDMENTS
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Project Directorate II-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket Nos. 50-250 and 50-251

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2. Amendment No. 185 to DPR-41
3. Safety Evaluation

cc w/enclosures: See next page

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Florida Power and Light Company

Turkey Point Plant

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

FLORIDA POWER AND LIGHT COMPANY

DOCKET NO. 50-250

TURKEY POINT PLANT UNIT NO. 3

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 191
License No. DPR-31

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Florida Power and Light Company (the licensee) dated December 18, 1995, as supplemented by letters dated May 3, June 11, July 1, July 3, and August 22, 1996, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, Facility Operating License No. DPR-31 items c. and 3.A are hereby amended to read as follows:

   c. There is reasonable assurance (i) that the facility can be operated at steady state power levels up to 2300 megawatts thermal in accordance with this license without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the regulations of the Commission;

   3.A Maximum Power Level

   The applicant is authorized to operate the facility at reactor core power levels not in excess of 2300 megawatts (thermal).

3. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 3.B of Facility Operating License No. DPR-31 is hereby amended to read as follows:

   (B) Technical Specifications and Environmental Protection Plan

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 191 , are hereby incorporated in the license. The Environmental Protection Plan contained in Appendix B is hereby incorporated into the license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

4. This license amendment is effective as of its date of issuance and shall be implemented within 120 days.

FOR THE NUCLEAR REGULATORY COMMISSION

W. Russell

William T. Russell, Director
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical
  Specifications

Date of Issuance: September 26, 1996

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

FLORIDA POWER AND LIGHT COMPANY

DOCKET NO. 50-251

TURKEY POINT PLANT UNIT NO. 4

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No.185
License No. DPR-41

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Florida Power and Light Company (the licensee) dated December 18, 1995, as supplemented by letters dated May 3, June 11, July 1, July 3, and August 22, 1996, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, Facility Operating License No. DPR-41 condition 3.A is hereby amended to read as follows:

   3.A <u>Maximum Power Level</u>

   The reactor shall not be made critical until the tests described in the applicant's letter of April 3, 1973, have been satisfactorily completed. Thereafter, the applicant is authorized to operate the facility at reactor core power levels not in excess of 2300 megawatts (thermal).

3. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 3.B of Facility Operating License No. DPR-41 is hereby amended to read as follows:

   (B) <u>Technical Specifications and Environmental Protection Plan</u>

   The Technical Specifications contained in Appendix A, as revised through Amendment No.185 , are hereby incorporated in the license. The Environmental Protection Plan contained in Appendix B is hereby incorporated into the license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

4. This license amendment is effective as of its date of issuance and shall be implemented within 120 days.

FOR THE NUCLEAR REGULATORY COMMISSION

W. T. Russell

William T. Russell, Director
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical
  Specifications

Date of Issuance: September 26, 1996

ATTACHMENT TO LICENSE AMENDMENT

AMENDMENT NO. 191 FACILITY OPERATING LICENSE NO. DPR-31

AMENDMENT NO. 185 FACILITY OPERATING LICENSE NO. DPR-41

DOCKET NOS. 50-250 AND 50-251

Revise Appendix A as follows:

Remove pages	Insert pages
1-5	1-5
2-2	2-2
2-4	2-4
2-5	2-5
2-7	2-7
2-8	2-8
2-10	2-10
3/4 2-4	3/4 2-4
3/4 2-11	3/4 2-11
3/4 2-16	3/4 2-16
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3/4 3-26	3/4 3-26
3/4 3-27	3/4 3-27
3/4 4-7	3/4 4-7
3/4 4-8	3/4 4-8
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3/4 4-32	3/4 4-32
3/4 4-33	3/4 4-33
3/4 5-5	3/4 5-5
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3/4 7-6	3/4 7-6
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B 3/4 7-5	B 3/4 7-5
B 3/4 7-6	B 3/4 7-6
B 3/4 7-7	B 3/4 7-7
	B 3/4 7-8

QUADRANT POWER TILT RATIO

1.23 QUADRANT POWER TILT RATIO shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater. With one excore detector inoperable, the remaining three detectors shall be used for computing the average.

RATED THERMAL POWER

1.24 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 2300 MWt.

REPORTABLE EVENT

1.25 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 of 10 CFR Part 50.

SHUTDOWN MARGIN

1.26 SHUTDOWN MARGIN shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming all full-length rod cluster assemblies (shutdown and control) are fully inserted except for the single rod cluster assembly of highest reactivity worth which is assumed to be fully withdrawn.

SITE BOUNDARY

1.27 The SITE BOUNDARY shall mean that line beyond which the land or property is not owned, leased, or otherwise controlled by the licensee.

SOLIDIFICATION

1.28 SOLIDIFICATION shall be the conversion of wet wastes into a form that meets shipping and burial ground requirements.

SOURCE CHECK

1.29 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a source of increased radioactivity.

STAGGERED TEST BASIS

1.30 A STAGGERED TEST BASIS shall consist of:

a. A test schedule for n systems, subsystems, trains, or other designated components obtained by dividing the specified test interval into n equal subintervals, and

b. The testing of one system, subsystem, train, or other designated component at the beginning of each subinterval.

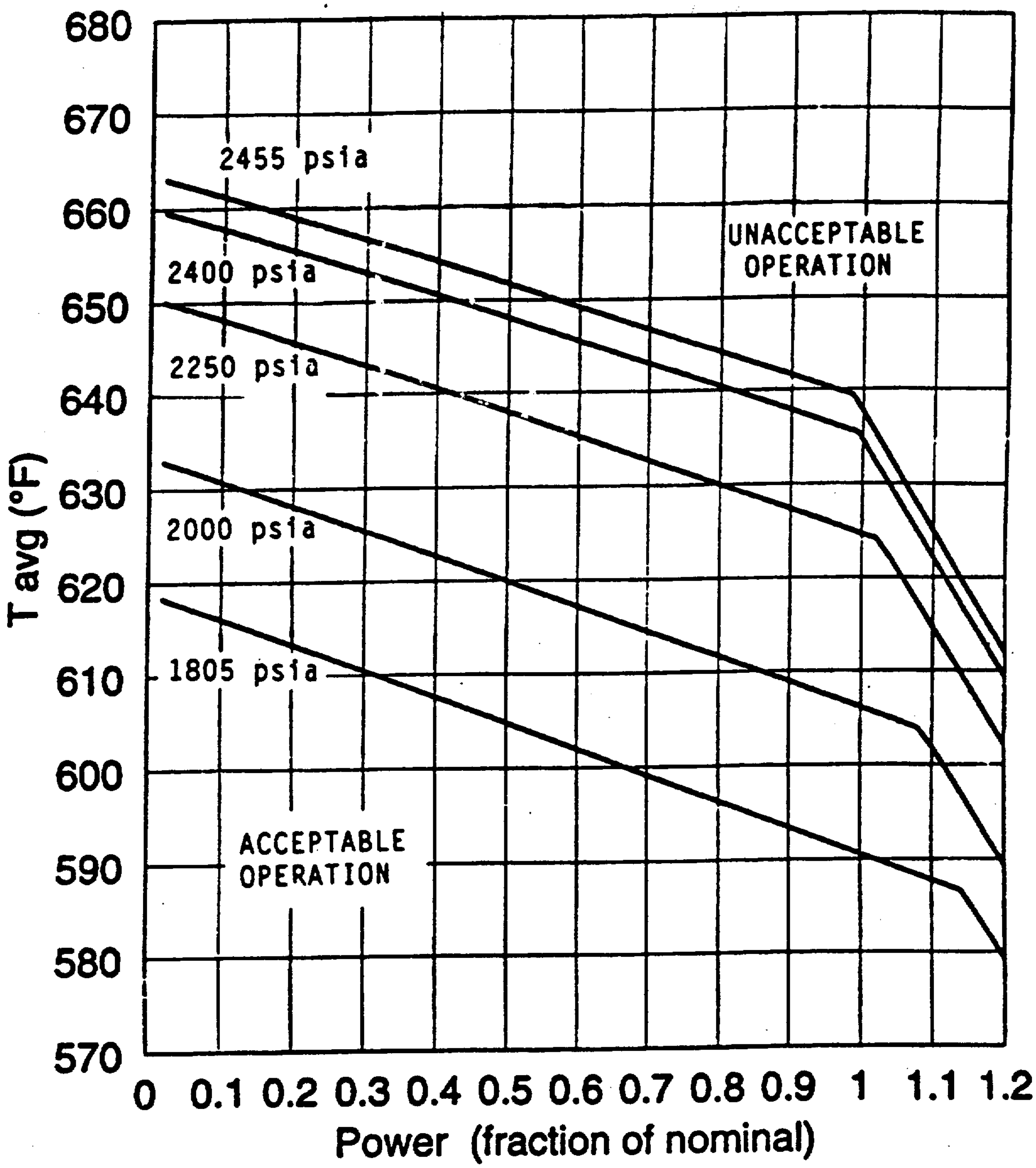

Figure 2.1-1 Reactor Core Safety Limit - Three Loops in Operation

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE	TRIP SETPOINT
1. Manual Reactor Trip	N.A	N.A.
2. Power Range, Neutron Flux		
a. High Setpoint	≤112.0% of RTP**	≤109% of RTP**
b. Low Setpoint	≤28.0% of RTP**	≤25% of RTP**
3. Intermediate Range, Neutron Flux	≤31.0% of RTP**	≤25% of RTP**
4. Source Range, Neutron Flux	≤1.4 X 10^5cps	≤10^5 cps
5. Overtemperature ΔT	See Note 2	See Note 1
6. Overpower ΔT	See Note 4	See Note 3
7. Pressurizer Pressure-Low	≥1817 psig	≥1835 psig
8. Pressurizer Pressure-High	≤2403 psig	≤2385 psig
9. Pressurizer Water Level-High	≤92.2% of instrument span	≤92% of instrument span
10. Reactor Coolant Flow-Low	≥88.8% of loop design flow*	≥90% of loop design flow*
11. Steam Generator Water Level Low-Low	≥8.15% of narrow range instrument span	≥10% of narrow range instrument span

* Loop design flow = 85,000 gpm
** RTP = Rated Thermal Power

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE	TRIP SETPOINT
12. Steam/Feedwater Flow Mismatch Coincident With	Feed Flow ≤23.9% below rated Steam Flow	Feed Flow ≤20% below rated Steam Flow
Steam Generator Water Level-Low	≥8.15% of narrow range instrument span	≥10% of narrow range instrument span
13. Undervoltage - 4.16 kV Busses A and B	≥69% bus voltage	≥70% bus voltage
14. Underfrequency - Trip of Reactor Coolant Pump Breaker(s) Open	≥55.9 Hz	≥56.1 Hz
15. Turbine Trip		
a. Auto Stop Oil Pressure	≥42 psig	≥45 psig
b. Turbine Stop Valve Closure	Fully Closed***	Fully Closed***
16. Safety Injection Input from ESF	N.A.	N.A.
17. Reactor Trip System Interlocks		
a. Intermediate Range Neutron Flux, P-6	$\geq 6.0 \times 10^{-11}$ amps	Nominal 1×10^{-10} amp

*** Limit switch is set when Turbine Stop Valves are fully closed.

TABLE 2.2-1 (Continued)
TABLE NOTATIONS

NOTE 1: OVERTEMPERATURE ΔT

$$\Delta T \left\{\frac{1+\tau_1 S}{1+\tau_2 S}\right\}\left(\frac{1}{1+\tau_3 S}\right) \le \Delta T_0 \left\{K_1 - K_2 \frac{(1+\tau_4 S)}{(1+\tau_5 S)}\left[T\left(\frac{1}{1+\tau_6 S}\right) - T'\right] + K_3(P - P') - f_1(\Delta I)\right\}$$

Where: ΔT = Measured ΔT by RTD Instrumentation

$\frac{1+\tau_1 S}{1+\tau_2 S}$ = Lead/Lag compensator on measured ΔT; τ_1=0s, τ_2 =0s

$\frac{1}{1+\tau_3 S}$ = Lag compensator on measured ΔT; τ_3 = 0s

ΔT_0 = Indicated ΔT at RATED THERMAL POWER

K_1 = 1.24;

K_2 = 0.017/^{o}F;

$\frac{1+\tau_4 S}{1+\tau_5 S}$ = The function generated by the lead-lag compensator for T_{avg} dynamic compensation;

τ_4, τ_5 = Time constants utilized in the lead-lag compensator for T_{avg}, τ_4 = 25s, τ_5 = 3s;

T = Average temperature, ^{o}F;

$\frac{1}{1+\tau_6 S}$ = Lag compensator on measured T_{avg}; τ_6 = 0s

T' ≤ 577.2^{o}F (Nominal T_{avg} at RATED THERMAL POWER);

K_3 = 0.001/psig;

P = Pressurizer pressure, psig;

TABLE 2.2-1 (Continued)

TABLE NOTATIONS (Continued)

NOTE 1: (Continued)

P' $\geq$ 2235 psig (Nominal RCS operating pressure);

S = Laplace transform operator, s^{-1};

and $f_1(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range neutron ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(1) For $q_t - q_b$ between - 50% and + 2%, $f_1(\Delta I) = 0$, where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER;

(2) For each percent that the magnitude of $q_t - q_b$ exceeds - 50%, the ΔT Trip Setpoint shall be automatically reduced by 0.0% of its value at RATED THERMAL POWER; and

(3) For each percent that the magnitude of $q_t - q_b$ exceeds + 2%, the ΔT Trip Setpoint shall be automatically reduced by 2.19% of its value at RATED THERMAL POWER.

NOTE 2: The channels maximum trip setpoint shall not exceed its computed setpoint by more than 0.84% of instrument span.

TABLE 2.2-1 (Continued)

TABLE NOTATIONS (Continued)

NOTE 3: (Continued)

K_6 = $0.0016/^{\circ}F$ for $T > T"$
= 0 for $T \le T"$,

T = As defined in Note 1,

T" $\le 577.2^{\circ}F$ (Nominal T_{avg} at RATED THERMAL POWER)

S = As defined in Note 1, and

$f_2\ (\Delta I)$ = 0 for all ΔI

NOTE 4: The channel's maximum trip setpoint shall not exceed its computed trip setpoint by more than 0.96% of instrument span.

3/4.2.2 HEAT FLUX HOT CHANNEL FACTOR - $F_Q(Z)$

LIMITING CONDITION FOR OPERATION

3.2.2 $F_Q^L(Z)$ shall be limited by the following relationships:

$$F_Q^M(Z) \leq \frac{[F_Q]^{L}}{P}^{X} [K(Z)] \text{ for } P > 0.5$$

$$F_Q^M(Z) \leq \frac{[F_Q]}{0.5}^{LX} [K(Z)] \text{ for } P \leq 0.5$$

where: $[F_Q]^L$ = F_Q limit at RATED THERMAL POWER as specified in the CORE OPERATING LIMITS REPORT

$$P = \frac{\text{Thermal Power}}{\text{Rated Thermal Power}},$$

$[F_Q]^M$ = The Measured Value, and

K(Z) for a given core height, is specified in the K(Z) curve, defined in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: MODE 1

ACTION:

With the measured value of $F_Q^M(Z)$ exceeding its limit:

a. Reduce THERMAL POWER at least 1% for each 1% $F_Q^M(Z)$ exceeds $F_Q^L(Z)$ within 15 minutes and similarly reduce the Power Range Neutron Flux-High Trip Setpoints within the next 4 hours; POWER OPERATION may proceed for up to a total of 72 hours; subsequent POWER OPERATION may proceed provided the Overpower Delta-T Trip Setpoints (value of K_4) have been reduced at least 1% for each 1% $F_Q^M(Z)$ exceeds the $F_Q^L(Z)$; and

b. Identify and correct the cause of the out-of-limit condition prior to increasing THERMAL POWER above the reduced power limit required by ACTION a., above; THERMAL POWER may then be increased provided $F_Q^M(Z)$ is demonstrated through incore mapping to be within its limit.

3/4.2.3 NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR

LIMITING CONDITION FOR OPERATION

3.2.3 $F^N_{\Delta H}$ shall be limited by the following relationship:

$$F^N_{\Delta H} \leq F^{RTP}_{\Delta H}[1.0 + PF_{\Delta H}\ (1-P)],$$

Where: $F^{RTP}_{\Delta H}$ = $F_{\Delta}H$ limit at RATED THERMAL POWER as specified in the CORE OPERATING LIMITS REPORT

$PF_{\Delta H}$ = Power Factor Multiplier for $F_{\Delta}H$ as specified in the CORE OPERATING LIMITS REPORT

$$P = \frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$$

APPLICABILITY: MODE 1.

ACTION:

With $F^N_{\Delta H}$ exceeding its limit:

a. Within 2 hours either:

1. Restore $F^N_{\Delta H}$ to within the above limit, or

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER and reduce the Power Range Neutron Flux - High Trip Setpoint to less than or equal to 55% of RATED THERMAL POWER within the next 4 hours.

b. Within 24 hours of initially being outside the above limit, verify through incore flux mapping that $F^N_{\Delta H}$ has been restored to within the above limit, or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 2 hours.

c. Identify and correct the cause of the out-of-limit condition prior to increasing THERMAL POWER above the reduced THERMAL POWER limit required by ACTION a.2. and/or b., above; subsequent POWER OPERATION may proceed provided that $F^N_{\Delta H}$ is demonstrated, through incore flux mapping, to be within the limit of acceptable operation prior to exceeding the following THERMAL POWER levels:

1. A nominal 50% of RATED THERMAL POWER,

2. A nominal 75% of RATED THERMAL POWER, and

3. Within 24 hours of attaining greater than or equal to 95% of RATED THERMAL POWER.

3/4.2.5 DNB PARAMETERS

LIMITING CONDITION FOR OPERATION

3.2.5 The following DNB-related parameters shall be maintained within the following limits:

a. Reactor Coolant System T_{avg} $\leq$ 581.2°F

b. Pressurizer Pressure $\geq$ 2200 psig*, and

c. Reactor Coolant System Flow $\geq$ 264,000 gpm

APPLICABILITY: MODE 1.

ACTION:

With any of the above parameters exceeding its limit, restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.5.1 Reactor Coolant System T_{avg} and Pressurizer Pressure shall be verified to be within their limits at least once per 12 hours.

4.2.5.2 RCS flow rate shall be monitored for degradation at least once per 12 hours.

4.2.5.3 The RCS flow rate indicators shall be subjected to a CHANNEL CALIBRATION at least once per 18 months.

4.2.5.4 After each fuel loading, and at least once per 18 months, the RCS flow rate shall be determined by precision heat balance after exceeding 90% RATED THERMAL POWER. The measurement instrumentation shall be calibrated within 90 days prior to the performance of the calorimetric flow measurement. The provisions of 4.0.4 are not applicable for performing the precision heat balance flow measurement.

*Limit not applicable during either a THERMAL POWER ramp in excess of 5% of RATED THERMAL POWER per minute or a THERMAL POWER step in excess of 10% of RATED THERMAL POWER.

TABLE 3.3-3

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE	TRIP SETPOINT
1. Safety Injection (Reactor Trip, Turbine Trip, Feedwater Isolation, Control Room Ventilation Isolation, Start Diesel Generators, Containment Phase A Isolation (except Manual SI), Containment Cooling Fans, Containment Filter Fans, Start Sequencer, Component Cooling Water, Start Auxiliary Feedwater and Intake Cooling Water)		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic	N.A	N.A
c. Containment Pressure--High	≤4.5 psig	≤4.0 psig
d. Pressurizer Pressure--Low	≥1712 psig	≥1730 psig
e. High Differential Pressure Between the Steam Line Header and any Steam Line.	≤ 114 psig	≤100 psi
f. Steam Line Flow--High	≤A function defined as follows: A ΔP corresponding to 44% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 116.5% steam flow at full load	≤A function defined as follows: A ΔP corresponding to 40% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 114% steam flow at full load

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM
INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE	TRIP SETPOINT
4. Steam Line Isolation (Continued)		
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure--High-High Coincident with:	≤22.6 psig	≤20.0 psig
Containment Pressure--High	≤ 4.5 psig	≤4.0 psig
d. Steam Line Flow--High	≤A function defined as follows: A ΔP corresponding to 44% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 116.5% steam flow at full load.	≤A function defined as follows: A ΔP corresponding to 40% steam flow at load increasing linearly from 20% load to a value corresponding to 114% steam flow at full load.
Coincident with: Steam Line Pressure--Low	≥588 psig	≥614 psig
or T_{avg}--Low	≥542.5°F	≥543°F
5. Feedwater Isolation		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Safety Injection	See item 1. for all Safety Injection Allowable Values.	See Item 1. above for all Safety Injection Trip Setpoints.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM
INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE	TRIP SETPOINT
5. Feedwater Isolation (Continued)		
c. Steam Generator Water Level High-High	≤81.9% of narrow range instrument span	≤80% of narrow range instrument span
6. Auxiliary Feedwater (3)		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Steam Generator Water Level--Low-Low	≥8.15% of narrow range instrument span.	≥10% of narrow range instrument span.
c. Safety Injection	see Item 1. for all Safety Injection Allowable Values.	See Item 1. above for all Safety Injection Trip Setpoints.
d. Bus Stripping	See Item 7. below for all Bus Stripping Allowable Values.	See Item 7. below for all Bus Stripping Trip Setpoints.
e. Trip of All Main Feedwater Pump Breakers	N.A.	N.A.
7. Loss of Power		
a. 4.16 kV Busses A and B (Loss of Voltage)	N.A.	N.A.

3/4.4.2 SAFETY VALVES

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.2.1 A minimum of one pressurizer Code safety valve shall be OPERABLE* with a lift setting of 2485 psig + 2%, -3%.** ***

APPLICABILITY: MODES 4 and 5.

ACTION:

With no pressurizer Code safety valve OPERABLE, immediately suspend all operations involving positive reactivity changes and place an OPERABLE RHR loop into operation in the shutdown cooling mode.

SURVEILLANCE REQUIREMENTS

4.4.2.1 No additional requirements other than those required by Specification 4.0.5.

*While in MODE 5, an equivalent size vent pathway may be used provided that the vent pathway is not isolated or sealed.

**The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

***All valves tested must have "as left" lift setpoints that are within ± 1% of the lift setting value.

LIMITING CONDITION FOR OPERATION

3.4.2.2 All pressurizer Code safety valves shall be OPERABLE with a lift setting of 2485 psig + 2%, -3%.* **

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With one pressurizer Code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.2.2 No additional requirements other than those required by Specification 4.0.5.

*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

**All valves tested must have "as left" lift setpoints that are within ± 1% of the lift setting value.

MATERIAL PROPERTY BASIS

CONTROLLING MATERIAL: CIRCUMFERENTIAL WELD
INITIAL RT_{NDT}: 10°F

SERVICE PERIOD: 19 EFPY — RT_{NDT} @ 1/4 THICKNESS = 252.5°F

HEATUP RATES: UP TO 60°F/HR — RT_{NDT} @ 3/4 THICKNESS = 200.4°F

NOTE: NO MARGINS ARE GIVEN FOR POSSIBLE INSTRUMENT ERRORS.

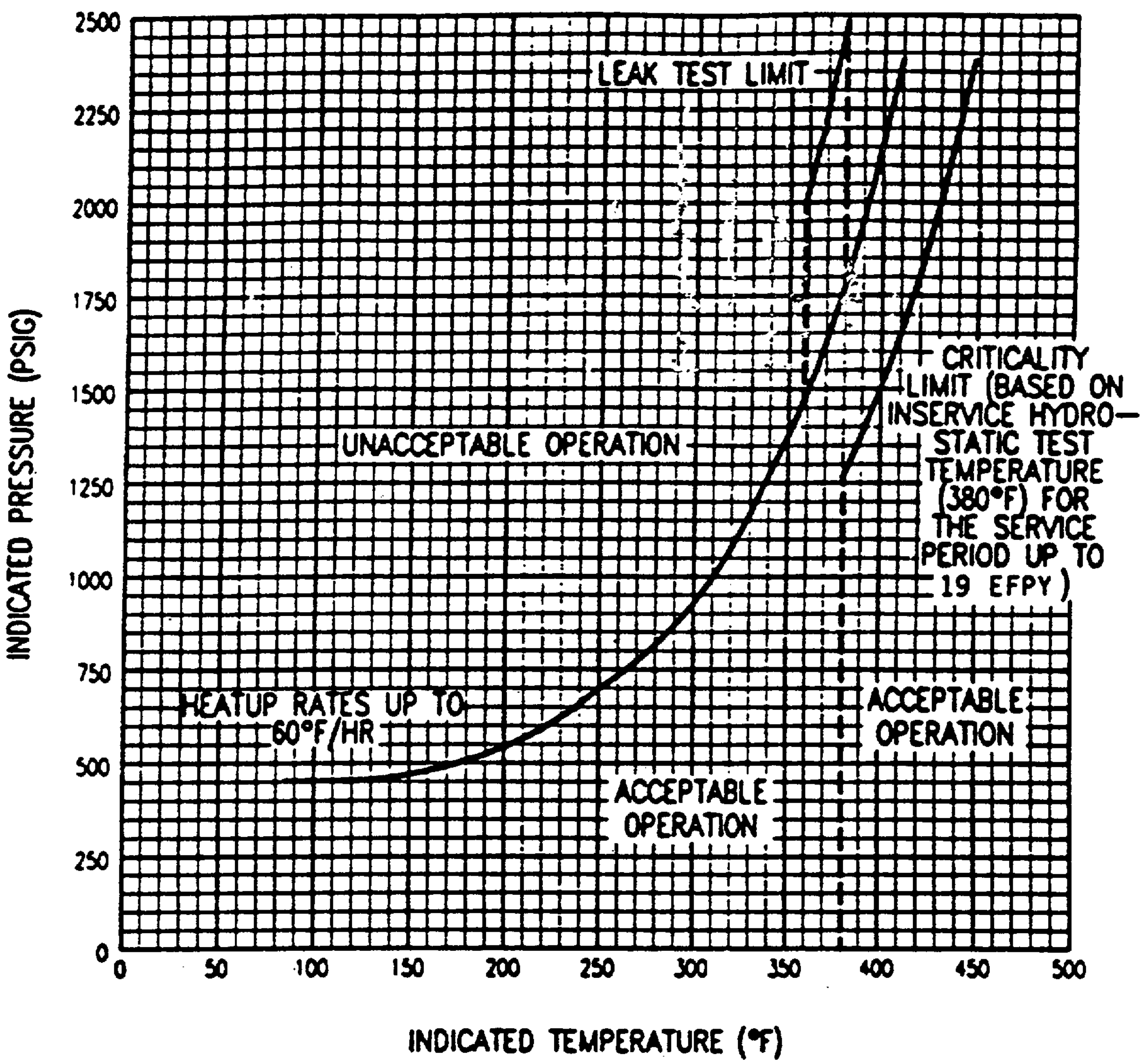

FIGURE 3.4-2

TURKEY POINT UNITS 3 & 4

REACTOR COOLANT SYSTEM HEATUP LIMITATIONS (60°F/hr) - APPLICABLE UP TO 19 EFPY

MATERIAL PROPERTY BASIS

CONTROLLING MATERIAL: CIRCUMFERENTIAL WELD
INITIAL RT_{NDT}: 10°F

SERVICE PERIOD: 19 EFPY — RT_{NDT} @ 1/4 THICKNESS = 252.5°F

HEATUP RATES: UP TO 100°F/HR — RT_{NDT} @ 3/4 THICKNESS = 200.4°F

NOTE: NO MARGINS ARE GIVEN FOR POSSIBLE INSTRUMENT ERRORS.

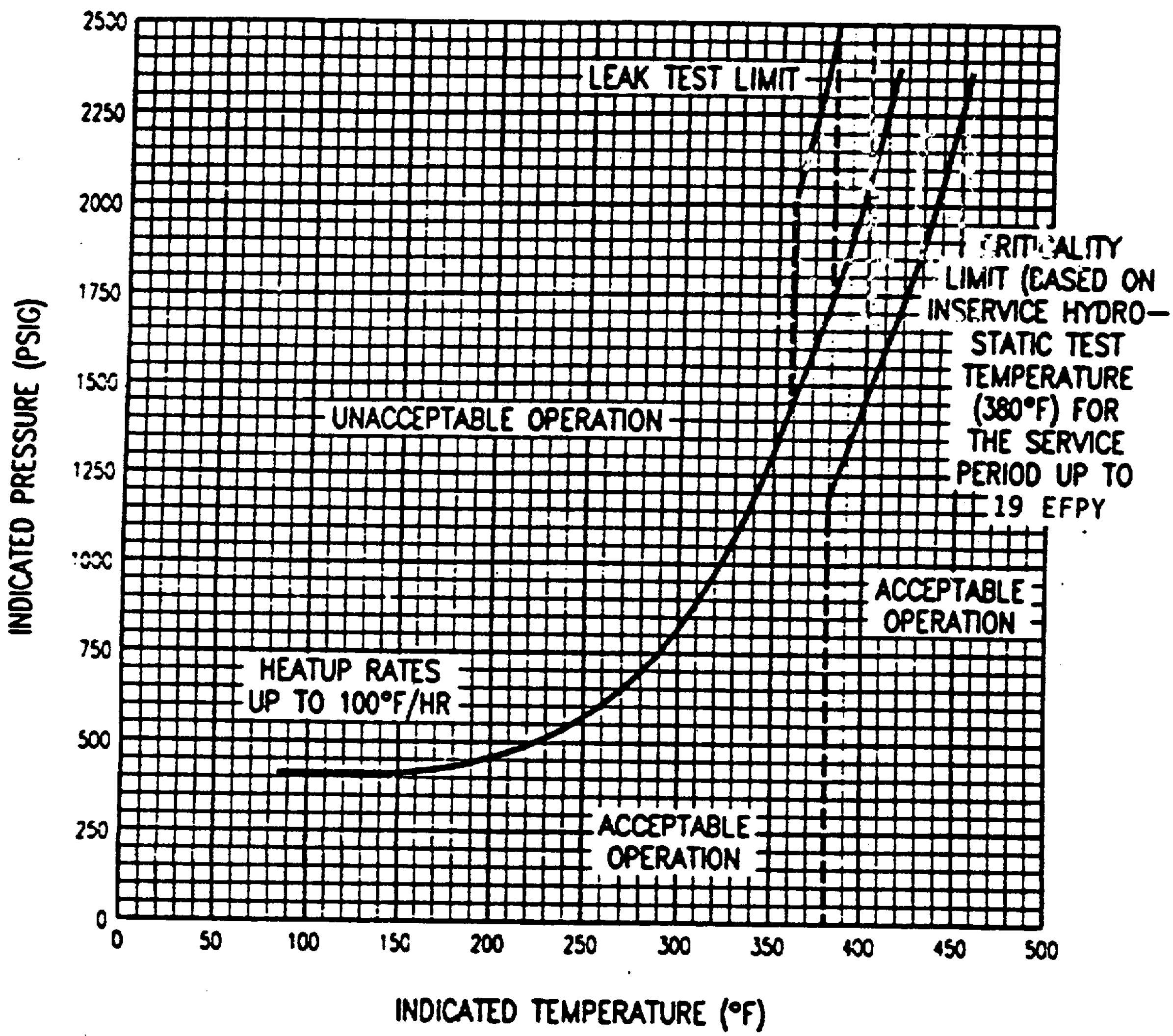

FIGURE 3.4-3

TURKEY POINT UNITS 3 & 4

REACTOR COOLANT SYSTEM HEATUP LIMITATIONS (100°F/hr) - APPLICABLE UP TO 19 EFPY

MATERIAL PROPERTY BASIS

CONTROLLING MATERIAL: CIRCUMFERENTIAL WELD
INITIAL RT_{NDT}: 10°F

RT_{NDT} @1/4 THICKNESS = 252.5°F
RT_{NDT} @3/4 THICKNESS = 200.4°F

SERVICE PERIOD: 19 EFPY
COOLDOWN RATES: UP TO 100°F/HR

NOTE: NO MARGINS ARE GIVEN FOR POSSIBLE INSTRUMENT ERRORS.

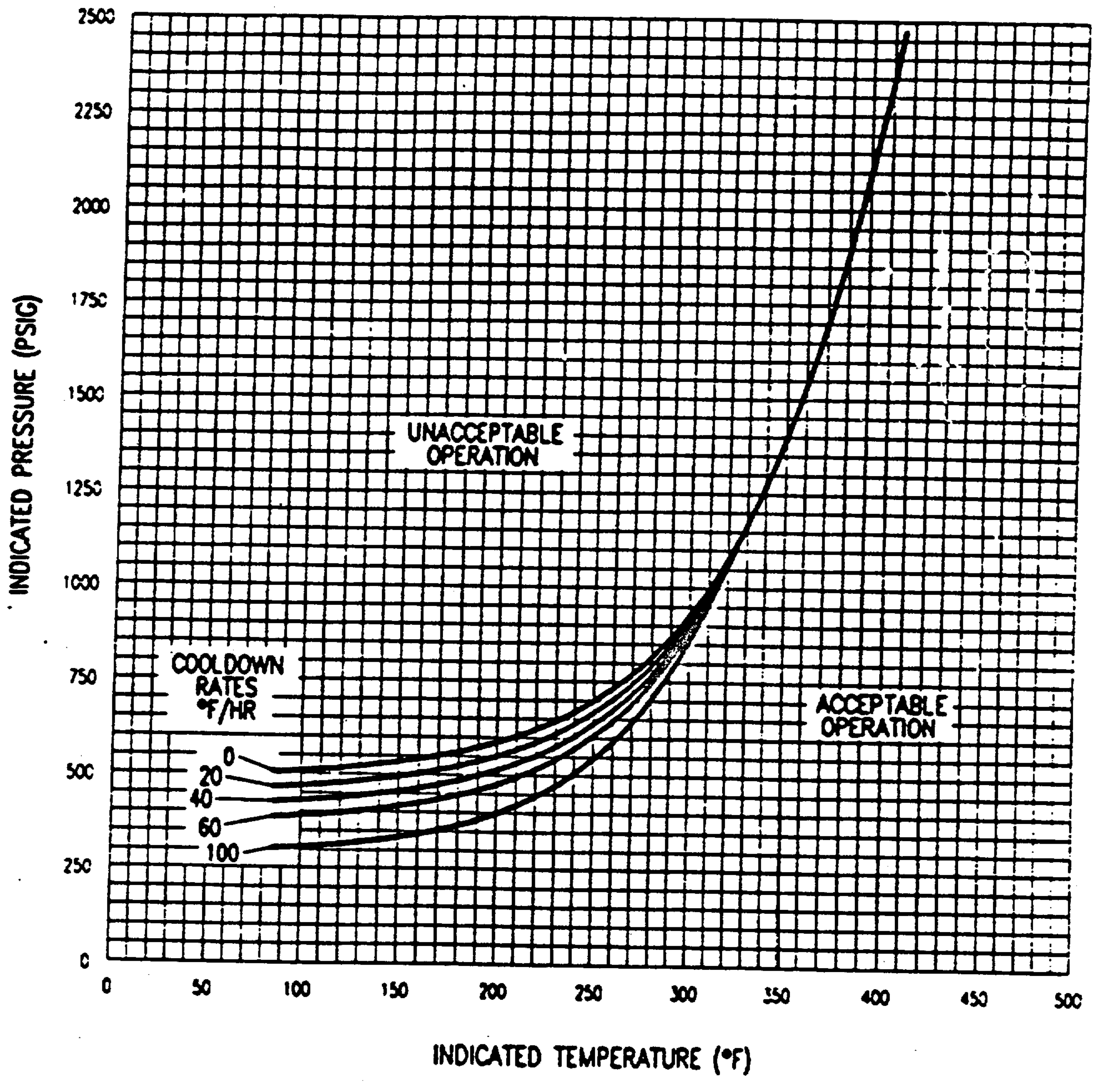

FIGURE 3.4-4

TURKEY POINT UNITS 3 & 4

REACTOR COOLANT SYSTEM COOLDOWN LIMITATIONS (100°F/hr) - APPLICABLE UP TO 19 EFPY

SURVEILLANCE REQUIREMENTS

4.5.2 Each ECCS component and flow path shall be demonstrated OPERABLE:

a. At least once per 12 hours by verifying by control room indication that the following valves are in the indicated positions with power to the valve operators removed:

Valve Number	Valve Function	Valve Position
864A and B	Supply from RWST to ECCS	Open
862A and B	RWST Supply to RHR pumps	Open
863A and B	RHR Recirculation	Closed
866A and B	H.H.S.I. to Hot Legs	Closed
HCV-758*	RHR HX Outlet	Open

To permit temporary operation of these valves for surveillance or maintenance purposes, power may be restored to these valves for a period not to exceed 24 hours.

b. At least once per 31 days by:

1) Verifying that the ECCS piping is full of water by venting the ECCS pump casings and accessible discharge piping,

2) Verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position, and

3) Verifying that each RHR Pump develops the indicated differential pressure applicable to the operating conditions in accordance with Figure 3.5-1 when tested pursuant to Specification 4.0.5.

c. At least once per 92 days by:

1) Verifying that each SI pump develops the indicated differential pressure applicable to the operating conditions when tested pursuant to Specification 4.0.5.

SI pump $\geq$ 1083 psid at a metered flowrate $\geq$ 300 gpm (normal alignment or Unit 4 SI pumps aligned to Unit 3 RWST), or

$\geq$ 1113 psid at a metered flowrate $\geq$ 280 gpm (Unit 3 SI pumps aligned to Unit 4 RWST).

*Air Supply to HCV-758 shall be verified shut off and sealed closed once per 31 days.

EMERGENCY CONTAINMENT COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.2 Three emergency containment cooling units shall be OPERABLE.

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

ACTION:

a. With one of the above required emergency containment cooling units inoperable restore the inoperable cooling unit to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With two or more of the above required emergency containment cooling units inoperable, restore at least two cooling units to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore all of the above required cooling units to OPERABLE status within 72 hours of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 Each emergency containment cooling unit shall be demonstrated OPERABLE:

a. At least once per 31 days by starting each cooler unit from the control room and verifying that each unit motor reaches the nominal operating current for the test conditions and operates for at least 15 minutes.

b. At least once per 18 months by:

1) Verifying that two emergency containment cooling units start automatically on a safety injection (SI) test signal, and

2) Verifying a cooling water flow rate of greater than or equal to 2000 gpm to each cooler.

TABLE 3.7-1

MAXIMUM ALLOWABLE POWER LEVEL WITH INOPERABLE STEAM LINE SAFETY VALVES DURING THREE LOOP OPERATION

MAXIMUM NUMBER OF INOPERABLE SAFETY VALVES ON ANY OPERATING STEAM GENERATOR	MAXIMUM ALLOWABLE POWER LEVEL (PERCENT OF RATED THERMAL POWER)
1	53
2	33
3	14

TABLE 3.7-2

STEAM LINE SAFETY VALVES PER LOOP

	VALVE NUMBER			LIFT SETTING (±3%)* **	ORIFICE SIZE SQUARE INCHES
	Loop A	Loop B	Loop C		
1.	RV1400	RV1405	RV1410	1085 psig	16
2.	RV1401	RV1406	RV1411	1100 psig	16
3.	RV1402	RV1407	RV1412	1115 psig	16
4.	RV1403	RV1408	RV1413	1130 psig	16

*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

**All valves tested must have "as left" lift setpoints that are within ±1% of the lift setting value listed in Table 3.7-2.

CONDENSATE STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.7.1.3 The condensate storage tanks (CST) system shall be OPERABLE with:

Opposite Unit in MODES 4, 5 or 6

A minimum indicated water volume of 210,000 gallons in either or both condensate storage tanks.

Opposite Unit in MODES 1, 2 or 3

A minimum indicated water volume of 420,000 gallons.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

Opposite Unit in MODES 4, 5 or 6

With the CST system inoperable, within 4 hours restore the CST system to OPERABLE status or be in at least HOT STANDBY in the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

Opposite Unit in MODES 1, 2 or 3

1) With the CST system inoperable due to indicating less than 420,000 gallons, but greater than or equal to 210,000 gallons indicated, within 4 hours restore the inoperable CST system to OPERABLE status or place one unit in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

2) With the CST system inoperable with less than 210,000 gallons indicated, within 1 hour restore the CST system to OPERABLE status or be in at least HOT STANDBY within the next 12 hours and in HOT SHUTDOWN within the following 6 hours. This ACTION applies to both units simultaneously.

SURVEILLANCE REQUIREMENTS (Continued)

4.7.1.3 The condensate storage tank (CST) system shall be demonstrated OPERABLE at least once per 12 hours by verifying the indicated water volume is within its limit when the tank is the supply source for the auxiliary feedwater pumps.

STANDBY FEEDWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.6 Two Standby Steam Generator Feedwater Pumps shall be OPERABLE* and at least 135,000 gallons of water (indicated volume), shall be in the Demineralized Water Storage Tank.**

APPLICABILITY: MODES 1, 2 and 3

ACTION:

a. With one Standby Steam Generator Feedwater Pump inoperable, restore the inoperable pump to available status within 30 days or submit a SPECIAL REPORT per 3.7.1.6d.

b. With both Standby Steam Generator Feedwater Pumps, restore at least one pump to OPERABLE status within 24 hours, or:

   1. Notify the NRC within the following 4 hours, and provide cause for the inoperability and plans to restore pump(s) to OPERABLE status and,

   2. Submit a SPECIAL REPORT per 3.7.1.6d.

c. With less than 135,000 gallons of water indicated in the Demineralized Water Storage Tank restore the available volume to at least 135,000 gallons indicated within 24 hours or submit a SPECIAL REPORT per 3.7.1.6d.

d. If a SPECIAL REPORT is required per the above specifications submit a report describing the cause of the inoperability, action taken and a schedule for restoration within 30 days in accordance with 6.9.2.

SURVEILLANCE REQUIREMENTS

4.7.1.6.1 The Demineralized Water Storage tank water volume shall be determined to be within limits at least once per 24 hours.

4.7.1.6.2 At least monthly verify the standby feedwater pumps are OPERABLE by testing in recirculation on a STAGGERED TEST BASIS.

4.7.1.6.3 At least once per 18 months, verify operability of the respective standby steam generator feedwater pump by starting each pump and providing feedwater to the steam generators.

*These pumps do not require plant safety related emergency power sources for operability and the flowpath is normally isolated.

**The Demineralized Water Storage Tank is non-safety grade.

SURVEILLANCE REQUIREMENTS (Continued)

1) Verifying that the air cleanup system satisfies the in-place penetration and bypass leakage testing acceptance criteria of greater than or equal to 99% DOP and halogenated hydrocarbon removal at a system flow rate of 1000 cfm ±10%.

2) Verifying, within 31 days after removal, that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, and analyzed per ANSI N510-1975, meets the criteria for methyl iodine removal efficiency of greater than or equal to 99% or the charcoal be replaced with charcoal that meets or exceeds the criteria of position C.6.a. of Regulatory Guide 1.52 (Revision 2), and

3) Verifying by a visual inspection the absence of foreign materials and gasket deterioration.

d. At least once per 12 months by verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 6 inches Water Gauge while operating the system at a flow rate of 1000 cfm ±10%;

e. At least once per 18 months by verifying that on a Containment Phase "A" Isolation test signal the system automatically switches into the recirculation mode of operation.

PEAKING FACTOR LIMIT REPORT

6.9.1.6 The W(Z) function(s) for Base-Load Operation corresponding to a ±2% band about the target flux difference and/or a ±3% band about the target flux difference, the Load-Follow function $F_Z(Z)$ and the augmented surveillance turnon power fraction, P_T, shall be provided to the U.S. Nuclear Regulatory Commission, whenever P_T is <1.0. In the event, the option of Baseload Operation (as defined in Section 4.2.2.3) will not be exercised, the submission of the W(Z) function is not required. Should these values (i.e., W(Z), $F_Z(Z)$ and P_T) change requiring a new submittal or an amended submittal to the Peaking Factor Limit Report, the Peaking Factor Limit Report shall be provided to the NRC Document Control desk with copies to the Regional Administrator and the Resident Inspector within 30 days of their implementation, unless otherwise approved by the Commission.

The analytical methods used to generate the Peaking Factor limits shall be those previously reviewed and approved by the NRC. If changes to these methods are deemed necessary they will be evaluated in accordance with 10 CFR 50.59 and submitted to the NRC for review and approval prior to their use if the change is determined to involve an unreviewed safety question or if such a change would require amendment of previously submitted documentation.

CORE OPERATING LIMITS REPORT

6.9.1.7 Core operating limits shall be established and documented in the CORE OPERATING LIMITS REPORT (COLR) before each reload cycle or any remaining part of a reload cycle for the following:

1. Axial Flux Difference for Specification 3.2.1.
2. Control Rod Insertion Limits for Specification 3.1.3.6.
3. Heat Flux Hot Channel Factor - $F_Q(Z)$ for Specification 3/4.2.2.
4. All Rods Out position for Specification 3.1.3.2.
5. Nuclear Enthalpy Rise Hot Channel Factor for Specification 3/4.2.3

The analytical methods used to determine the AFD limits shall be those previously reviewed and approved by the NRC in:

1. WCAP-10216-P-A, "RELAXATION OF CONSTANT AXIAL OFFSET CONTROL F_Q SURVEILLANCE TECHNICAL SPECIFICATION," June 1983.
2. WCAP-8385, "POWER DISTRIBUTION CONTROL AND LOAD FOLLOWING PROCEDURES - TOPICAL REPORT," September 1974.

The analytical methods used to determine $F_Q(Z)$, $F_{\Delta}H$ and the K(Z) curve shall be those previously reviewed and approved by the NRC in:

1. WCAP-9220-P-A, Rev. 1, "Westinghouse ECCS Evaluation Model - 1981 Version," February 1982.
2. WCAP-9561-P-A, ADD. 3, Rev. 1, "BART A-1: A Computer Code for the Best Estimate Analysis of Reflood Transients - Special Report: Thimble Modeling W ECCS Evaluation Model."
3. WCAP-10054-P-A, (proprietary), "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code", August 1985.

4. WCAP-10054-P, Addendum 2, Revision 1 (proprietary), "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection in the Broken Loop and Improved Condensation Model", October 1995.*

5. WCAP-10266-P-A, Rev 2 (proprietary), and WCAP-11524-NP-A, Rev 2 (non-proprietary), "The 1981 Version of the Westinghouse ECCS Evaluation Model Using the BASH Code," May 1988.

6. NTD-NRC-94-4143, "Change in Methodology for Execution of BASH Evaluation Model," May 23, 1994.

The analytical methods used to determine Rod Bank Insertion Limits and the All Rods Out position shall be those previously reviewed and approved by the NRC in:

1. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

The ability to calculate the COLR nuclear design parameters are demonstrated in:

1. Florida Power & Light Company Topical Report NF-TR-95-01, "Nuclear Physics Methodology for Reload Design of Turkey Point & St. Lucie Nuclear Plants".

Topical Report NF-TR-95-01 was approved by the NRC for use by Florida Power & Light Company in:

1. Safety Evaluation by the Office of Nuclear Reactor Regulations Related to Amendment No. 174 to Facility Operating License DPR-31 and Amendment No. 168 to Facility Operating License DPR-41, Florida Power & Light Company Turkey Point Units 3 and 4, Docket Nos. 50-250 and 50-251.

The AFD, $F_Q(Z)$, $F_{\Delta}H$, K(Z), and Rod Bank Insertion Limits shall be determined such that all applicable limits of the safety analyses are met. The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance, for each reload cycle, to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector, unless otherwise approved by the Commission.

*This reference is only to be used subsequent to NRC approval.

2.1 SAFETY LIMITS

BASES

2.1.1 REACTOR CORE

The restrictions of this Safety Limit prevent overheating of the fuel and possible cladding perforation which would result in the release of fission products to the reactor coolant. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Operation above the upper boundary of the nucleate boiling regime could result in excessive cladding temperatures because of the onset of departure from nucleate boiling (DNB) and the resultant sharp reduction in heat transfer coefficient. DNB is not a directly measurable parameter during operation and therefore THERMAL POWER and reactor coolant temperature and pressure have been related to DNB. This relationship has been developed to predict the DNB flux and the location of DNB for axially uniform and nonuniform heat flux distributions. The local DNB heat flux ratio (DNBR) is defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux and is indicative of the margin to DNB.

The DNB design basis is as follows: there must be at least a 95 percent probability with 95 percent confidence that the minimum DNBR of the limiting rod during Condition I and II events is greater than or equal to the DNBR limit of the DNB correlation being used. The correlation DNBR limit is established based on the entire applicable experimental data set such that there is a 95 percent probability with 95 percent confidence that DNB will not occur when the minimum DNBR is at the DNBR limit.

The curves of Figure 2.1-1 show the loci of points of THERMAL POWER, Reactor Coolant System pressure and average temperature for which the minimum DNBR is no less than the design DNBR value, or the average enthalpy at the vessel exit is equal to the enthalpy of saturated liquid.

These curves are based on an enthalpy hot channel factor, $F^N_{\Delta H}$, and a reference cosine with a peak of 1.55 for axial power shape. An allowance is included for an increase in $F^N_{\Delta H}$ at reduced power based on the expression:

$$F^N_{\Delta H} \leq F^{RTP}_{\Delta H}[1+ PF_{\Delta H}\ (1-P)]$$

Where P is the fraction of RATED THERMAL POWER.

$F^{RTP}_{\Delta H}$ = $F_{\Delta}H$ limit at RATED THERMAL POWER as specified in the CORE OPERATING LIMITS REPORT.

$PF_{\Delta H}$ = Power Factor multiplier for $F_{\Delta H}$ as specified in the CORE OPERATING LIMITS REPORT.

2.1.1 REACTOR CORE (Continued)

These limiting heat flux conditions are higher than those calculated for the range of all control rods fully withdrawn to the maximum allowable control rod insertion limit assuming the axial power imbalance is within the limits of the f (ΔI) function of the Overtemperature trip. When the axial power imbalance is not within the tolerance, the axial power imbalance effect on the Overtemperature ΔT trips will reduce the setpoints to provide protection consistent with core Safety Limits.

Fuel rod bowing reduces the values of DNB ratio (DNBR). The penalties are calculated pursuant to "Fuel Rod Bow Evaluation," WCAP-8691-P-A Revision 1 (Proprietary) and WCAP-8692 Revision 1 (Non-Proprietary). The restrictions of the Core Thermal Hydraulic Safety Limits assure that an amount of DNBR margin greater than or equal to the above penalties is retained to offset the rod bow DNBR penalty.

2.1.2 REACTOR COOLANT SYSTEM PRESSURE

The restriction of this Safety Limit protects the integrity of the Reactor Coolant System (RCS) from overpressurization and thereby prevents the release of radionuclides contained in the reactor coolant from reaching the containment atmosphere.

The reactor vessel and pressurizer are designed to Section III of the ASME Code for Nuclear Power Plants which permits a maximum transient pressure of 110% (2735 psig) of design pressure. The RCS piping, valves and fittings are designed to ANSI B31.1 which permits a maximum transient pressure of 120% of design pressure of 2485 psig. The Safety Limit of 2735 psig is therefore more conservative than the ANSI B31.1 design criteria and consistent with associated ASME Code requirements.

The entire RCS is hydrotested at 125% (3107 psig) of design pressure, to demonstrate integrity prior to initial operation.

Undervoltage and - 4.16 kV Bus A and B Trips (Continued)

power the Undervoltage Bus trips are automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with a turbine first stage pressure at approximately 10% of full power equivalent); and on increasing power, reinstated automatically by P-7.

Turbine Trip

A Turbine trip initiates a Reactor trip. On decreasing power, the Reactor Trip from the Turbine trip is automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with a turbine first stage pressure at approximately 10% of full power equivalent); and on increasing power, reinstated automatically by P-7.

Safety Injection Input from ESF

If a Reactor trip has not already been generated by the Reactor Trip System instrumentation, the ESF automatic actuation logic channels will initiate a Reactor trip upon any signal which initiates a Safety Injection. The ESF instrumentation channels which initiate a Safety Injection signal are shown in Table 3.3-3.

Reactor Coolant Pump Breaker Position Trip

The Reactor Coolant Pump Breaker Position Trips are anticipatory trips which provide reactor core protection against DNB. The open/close position trips assure a reactor trip signal is generated before the low flow trip setpoint is reached. Their functional capability at the open/close position settings is required to enhance the overall reliability of the Reactor Protection System. Above P-7 (a power level of approximately 10% of RATED THERMAL POWER or a turbine first stage pressure at approximately 10% of full power equivalent) an automatic reactor trip will occur if more than one reactor coolant pump breaker is opened. Above P-8 (a power level of approximately 45% of RATED THERMAL POWER) an automatic reactor trip will occur if one reactor coolant pump breaker is opened. On decreasing power between P-8 and P-7, an automatic reactor trip will occur if more than one reactor coolant pump breaker is opened and below P-7 the trip function is automatically blocked.

Underfrequency sensors are also installed on the 4.16 kV busses to detect underfrequency and initiate breaker trip on underfrequency. The underfrequency trip setpoints preserve the coast down energy of the reactor coolant pumps, in case of a grid frequency decrease so DNB does not occur.

3/4.2 POWER DISTRIBUTION LIMITS

BASES

The specifications of this section provide assurance of fuel integrity during Condition I (Normal Operation) and II (Incidents of Moderate Frequency) events by: (1) maintaining the minimum DNBR in the core greater than or equal to the applicable design limit during normal operation and in short-term transients, and (2) limiting the fission gas release, fuel pellet temperature, and cladding mechanical properties to within assumed design criteria. In addition, limiting the peak linear power density during Condition I events provides assurance that the initial conditions assumed for the LOCA analyses are met and the ECCS acceptance criteria limit of 2200°F is not exceeded.

The definitions of certain hot channel and peaking factors as used in these specifications are as follows:

$F_Q(Z)$ Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod at core elevation Z divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods;

$F^N_{\Delta H}$ Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power; and

$F_{XY}(Z)$ Radial Peaking Factor, is defined as the ratio of peak power density to average power density in the horizontal plane at core elevation Z.

3/4.2.1 AXIAL FLUX DIFFERENCE

The limits on AXIAL FLUX DIFFERENCE (AFD) assure that the $F_Q(Z)$ limit defined in the CORE OPERATING LIMITS REPORT times the normalized axial peaking factor is not exceeded during either normal operation or in the event of xenon redistribution following power changes.

Target flux difference is determined at equilibrium xenon conditions. The full-length rods may be positioned within the core in accordance with their respective insertion limits and should be inserted near their normal position for steady-state operation at high power levels. The value of the target flux difference obtained under these conditions divided by the fraction of RATED THERMAL POWER is the target flux difference at RATED THERMAL POWER for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RATED THERMAL POWER value by the appropriate fractional THERMAL POWER level. The periodic updating of the target flux difference value is necessary to reflect core burnup considerations.

3/4.2.2 and 3/4.2.3 HEAT FLUX HOT CHANNEL FACTOR AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR

The limits on heat flux hot channel factor and nuclear enthalpy rise hot channel factor ensure that: (1) the design limits on peak local power density and minimum DNBR are not exceeded and (2) in the event of a LOCA the peak fuel clad temperature will not exceed the 2200°F ECCS acceptance criteria limit. The LOCA peak fuel clad temperature limit may be sensitive to the number of steam generator tubes plugged.

$F_Q(Z)$, Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod at core elevation Z divided by the average fuel rod heat flux.

$F^N_{\Delta H}$ Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.

Each of these is measurable but will normally only be determined periodically as specified in Specifications 4.2.2 and 4.2.3. This periodic surveillance is sufficient to ensure that the limits are maintained provided:

a. Control rods in a single group move together with no individual rod insertion differing by more than ± 12 steps, indicated, from the group demand position;

b. Control rod groups are sequenced with overlapping groups as described in Specification 3.1.3.6;

c. The control rod insertion limits of Specifications 3.1.3.5 and 3.1.3.6 are maintained; and

d. The axial power distribution, expressed in terms of AXIAL FLUX DIFFERENCE, is maintained within the limits.

When an F_Q measurement is taken, both experimental error and manufacturing tolerance must be allowed for. Five percent is the appropriate allowance for a full core map taken with the movable incore detector flux mapping system and three percent is the appropriate allowance for manufacturing tolerance. These uncertainties only apply if the map is taken for purposes other than the determination of P_{BL} and P_RB.

$F^N_{\Delta H}$ will be maintained within its limits provided Conditions a. through d. above are maintained.

In the specified limit of $F^N_{\Delta H}$, there is an 8 percent allowance for uncertainties which means that normal operation of the core is expected to result in $F^N_{\Delta H} \leq F^{RTP}_{\Delta H}/1.08$, where $F^{RTP}_{\Delta H}$ is the $F^N_{\Delta H}$ limit at RATED THERMAL POWER (RTP) specified in the CORE OPERATING LIMITS REPORT. The logic behind the larger uncertainty in this

3/4.2.4 QUADRANT POWER TILT RATIO

The QUADRANT POWER TILT RATIO limit assures that the radial power distribution satisfies the design values used in the power capability analysis. Radial power distribution measurements are made during STARTUP testing and periodically during power operation.

The limit of 1.02, at which corrective action is required, provides DNB and linear heat generation rate protection with x-y plane power tilts. A limit of 1.02 was selected to provide an allowance for the uncertainty associated with the indicated power tilt.

The 2-hour time allowance for operation with a tilt condition greater than 1.02 but less than 1.09 is provided to allow identification and correction of a dropped or misaligned control rod. In the event such action action does not correct the tilt, the margin for uncertainty on $F_Q(Z)$ is reinstated by reducing the maximum allowed power by 3% for each percent of tilt in excess of 1.

For purposes of monitoring QUADRANT POWER TILT RATIO when one excore detector is inoperable, the movable incore detectors or incore thermocouple map are used to confirm that the normalized symmetric power distribution is consistent with the QUADRANT POWER TILT RATIO. The incore detector monitoring is done with a full incore flux map or two sets of four symmetric thimbles. The two sets of four symmetric thimbles is a unique set of eight detector locations. These locations are C-8, E-5, E-11, H-3, H-13, L-5, L-11, N-8.

3/4.2.5 DNB PARAMETERS

The limits on the DNB-related parameters assure that each of the parameters are maintained within the normal steady-state envelope of operation assumed in the transient and accident analyses. The limits are consistent with the initial FSAR assumptions and have been analytically demonstrated adequate to maintain a minimum DNBR above the applicable design limits throughout each analyzed transient. The indicated Tavg value of 581.2°F and the indicated pressurizer pressure value of 2200 psig correspond to analytical limits of 583.2°F and 2175 psig respectively, with allowance for measurement uncertainty.

The measured RCS flow value of 264,000 gpm corresponds to an analytical limit of 255,000 gpm which is assumed to have a 3.5% calorimetric measurement uncertainty.

The 12-hour periodic surveillance of these parameters through instrument readout is sufficient to ensure that the parameters are restored within their limits following load changes and other expected transient operation. The 18-month periodic measurement of the RCS total flow rate is adequate to ensure that the DNB-related flow assumption is met and to ensure correlation of the flow indication channels with measured flow. Six month drift effects have been included for feedwater temperature, feedwater flow, steam pressure, and the pressurizer pressure inputs. The flow measurement is performed within ninety days of completing the cross-calibration of the hot leg and cold leg narrow range RTDs. The indicated percent flow surveillance on a 12-hour basis will provide sufficient verification that flow degradation has not occurred. An indicated percent flow which is greater than the thermal design flow plus instrument channel inaccuracies and parallax errors is acceptable for the 12 hour surveillance on RCS flow. To minimize measurement uncertainties it is assumed that the RCS flow channel outputs are averaged.

3/4.4.2 SAFETY VALVES

The pressurizer Code safety valves operate to prevent the RCS from being pressurized above its Safety Limit of 2735 psig. Each safety valve is designed to relieve 293,330 lbs per hour of saturated steam at the valve Setpoint. The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that no safety valves are OPERABLE, an RCS vent opening of at least 2.50 square inches will provide overpressure relief capability and will prevent RCS overpressurization. In addition, the Overpressure Mitigating System provides a diverse means of protection against RCS overpressurization at low temperatures.

During operation, all pressurizer Code safety valves must be OPERABLE to prevent the RCS from being pressurized above its Safety Limit of 2735 psig. The combined relief capacity of all of these valves is greater than the maximum surge rate resulting from a complete loss-of-load assuming no Reactor trip until the first Reactor Trip System Trip Setpoint is reached (i.e., no credit is taken for a direct Reactor trip on the loss-of-load) and also assuming no operation of the power-operated relief valves or steam dump valves.

In Mode 5 only one pressurizer code safety is required for overpressure protection. In lieu of an actual operable code safety valve, an unisolated and unsealed vent pathway (i.e., a direct, unimpaired opening, a vent pathway with valves locked open and/or power removed and locked on an open valve) of equivalent size can be taken credit for as synonymous with an OPERABLE code safety.

Demonstration of the safety valves' lift settings will occur only during shutdown and will be performed in accordance with the provisions of Section XI of the ASME Boiler and Pressure Code. The pressurizer code safety valves' lift settings allows a +2%, -3% setpoint tolerance for OPERABILITY; however, the valves are reset to within $\pm 1\%$ during the surveillance to allow for drift.

3/4.4.3 PRESSURIZER

The 12-hour periodic surveillance is sufficient to ensure that the maximum water volume parameter is restored to within its limit following expected transient operation. The maximum water volume (1133 cubic feet) ensures that a steam bubble is formed and thus the RCS is not a hydraulically solid system. The requirement that both backup pressurizer heater groups be OPERABLE enhances the capability of the plant to control Reactor Coolant System pressure and establish natural circulation.

PRESSURE/TEMPERATURE LIMITS (Continued)

1. The reactor coolant temperature and pressure and system heatup and cooldown rates (with the exception of the pressurizer) shall be limited in accordance with Figures 3.4-2 to 3.4-4 for the service period specified thereon:

   a. Allowable combinations of pressure and temperature for specific temperature change rates are below and to the right of the limit lines shown. Limit lines for cooldown rates between those presented may be obtained by interpolation; and

   b. Figures 3.4-2 to 3.4-4 define limits to assure prevention of non-ductile failure only. For normal operation, other inherent plant characteristics, e.g., pump heat addition and pressurizer heater capacity, may limit the heatup and cooldown rates that can be achieved over certain pressure-temperature ranges.

2. These limit lines shall be calculated periodically using methods provided below,

3. The secondary side of the steam generator must not be pressurized above 200 psig if the temperature of the steam generator is below 70°F,

4. The pressurizer heatup and cooldown rates shall not exceed 100°F/h and 200°F/h, respectively. The spray shall not be used if the temperature difference between the pressurizer and the spray fluid is greater than 320°F, and

5. System preservice hydrotests and inservice leak and hydrotests shall be performed at pressures in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section XI.

The fracture toughness properties of the ferritic materials in the reactor vessel are determined in accordance with the NRC Standard Review Plan, the version of the ASTM E185 standard required by 10 CFR 50, Appendex H, and in accordance with additional reactor vessel requirements.

The properties are then evaluated in accordance with Appendix G of the 1983 Edition of Section III of the ASME Boiler and Pressure Vessel Code and the additional requirements of 10 CFR 50, Appendix G and the calculation methods described in Westinghouse Report GTSD-A-1.12, "Procedure for Developing Heatup and Cooldown Curves."

Heatup and cooldown limit curves are calculated using the most limiting value of the nil-ductility reference temperature, RT_{NDT}, at the end of 19 effective full power years (EFPY) of service life. The 19 EFPY service life period is chosen such that the limiting RT_{NDT}, at the 1/4T location in

PRESSURE/TEMPERATURE LIMITS (Continued)

the core region is greater than the RT_{NDT}, of the limiting unirradiated material. The selection of such a limiting RT_{NDT} assures that all components in the Reactor Coolant System will be operated conservatively in accordance with applicable Code requirements.

The heatup and cooldown limit curves, Figures 3.4-2, 3.4-3 and 3.4-4 are composite curves prepared by determining the most conservative case with either the inside or outside wall controlling, for any heatup rate up to 100 degrees F per hour and cooldown rates of up to 100 degrees F per hour. The heatup and cooldown curves were prepared based upon the most limiting value of predicted adjusted reference temperature at the end of the applicable service period (19 EFPY).

The reactor vessel materials have been tested to determine their initial RT_{NDT}; the results of these tests are shown in Tables B 3/4.4-1 and B 3/4.4-2. Reactor operation and resultant fast neutron (E greater than 1 MeV) irradiation can cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the fluence and chemistry factors of the material has been predicted using Regulatory Guide 1.99, Revision 2, dated May 1988, "Radiation Embrittlement of Reactor Vessel Materials." The heatup and cooldown limit curves of Figures 3.4-2, 3.4-3, and 3.4-4 include predicted adjustments for this shift in RT_{NDT} at the end of the applicable service period.

The actual shifts in RT_{NDT}, of the vessel materials will be established periodically during operation by removing and evaluating, in accordance with the version of the ASTM E185 standard required by 10 CFR Appendix H, reactor vessel material irradiation surveillance specimens installed near the inside wall of the reactor vessel in the core area. Since the neutron spectra at the irradiation samples and vessel inside radius are essentially identical, the measured transition shift for a sample can be applied with confidence to the adjacent section of the reactor vessel.

Since the limiting beltline materials (Intermediate to Lower Shell Circumferential Weld) in Units 3 and 4 are identical, the RV surveillance program was integrated and the results from capsule testing is applied to both Units. The surveillance capsule "T" results from Unit 3 (WCAP 8631) and Unit 4 (SWRI 02-4221) and the capsule "V" results from Unit 3 (SWRI 06-8576 were used with the methodology in Regulatory Guide 1.99, Revision 2, to provide

CONTAINMENT VENTILATION SYSTEM (Continued)

resilient material seal degradation and will allow opportunity for repair before gross leakage failures could develop. The 0.60 L_a leakage limit of Specification 3.6.1.2b. shall not be exceeded when the leakage rates determined by the leakage integrity tests of these valves are added to the previously determined total for all valves and penetrations subject to Type B and C tests.

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

3/4.6.2.1 CONTAINMENT SPRAY SYSTEM

The OPERABILITY of the Containment Spray System ensures that containment depressurization capability will be available in the event of a LOCA. The pressure reduction and resultant lower containment leakage rate are consistent with the assumptions used in the safety analyses.

The allowable out-of-service time requirements for the Containment Spray System have been maintained consistent with that assigned other inoperable ESF equipment and do not reflect the additional redundancy in cooling capability provided by the Emergency Containment Cooling System. Pump performance requirements are obtained from the accidents analysis assumptions.

3/4.6.2.2 EMERGENCY CONTAINMENT COOLING SYSTEM

The OPERABILITY of the Emergency Containment Cooling (ECC) System ensures that the heat removal capacity is maintained with acceptable ranges following postulated design basis accidents. To support both containment integrity safety analyses and component cooling water thermal analysis, a maximum of two ECCs can receive an automatic start signal following generation of a safety injection (SI) signal (one ECC receives an "A" train SI signal and another ECC receives an "B" train SI signal). To support post-LOCA long-term containment pressure/temperature analyses, a maximum of two ECCs are required to operate. The third (swing) ECC is required to be OPERABLE to support manual starting following a postulated LOCA event for containment pressure/temperature suppression.

The allowable out-of-service time requirements for the Containment Cooling System have been maintained consistent with that assigned other inoperable ESF equipment and do not reflect the additional redundancy in cooling capability provided by the Containment Spray System.

The surveillance requirement for ECC flow is verified by correlating the test configuration value with the design basis assumptions for system configuration and flow. An 18-month surveilance interval is acceptable based on the use of water from the CCW system, which results in a low risk of heat exchanger tube fouling.

3/4.6.3 EMERGENCY CONTAINMENT FILTERING SYSTEM

The OPERABILITY of the Emergency Containment Filtering System ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting SITE BOUNDARY radiation doses associated with containment leakage. The operation of this system and resultant iodine removal capacity are consistent with the assumptions used in the LOCA analyses. System components are not subject to rapid deterioration. Visual inspection and operating/performance tests after maintenance, prolonged operation, and at the required frequencies provide assurances of system reliability and will prevent system failure. Filter performance tests are conducted in accordance with the methodology and intent of ANSI N510- 1975.

3/4.6.4 CONTAINMENT ISOLATION VALVES

The OPERABILITY of the containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment. Containment isolation within the time limits specified in the In-Service Testing Program is consistent with the assumed isolation times of those valves with specific isolation times in the LOCA analysis.

3/4.6.5 HYDROGEN MONITORS

The OPERABILITY of the Hydrogen Monitors ensures the detection of hydrogen buildup within containment following a LOCA to allow operator action to reduce the hydrogen concentration below its flammable limit.

3/4.6.6 POST ACCIDENT CONTAINMENT VENT SYSTEM

The OPERABILITY of the Post Accident Containment Vent System ensures the capability for emergency venting of containment following a LOCA to reduce the hydrogen concentration to below its flammable limit.

PACVS systems components are not subject to rapid deterioration, having lifetimes of many years, even under continuous flow conditions. Visual inspection and operating tests provide assurance of system reliability and will ensure early detection of conditions which could cause the system to fail or operate improperly. The performance tests prove that filters have been properly installed, that no deterioration or damage has occurred, and that all components and subsystems operate properly. The tests are performed in accordance with the methodology and intent of ANSI N510-1975 and provide assurance that filter performance has not deteriorated below required specification values due to aging, contamination or other effects.

3/4.7.1.1 SAFETY VALVES (Continued)

Operation with less than all four MSSVs OPERABLE for each steam generator is permissible, if THERMAL POWER is proportionally limited to the relief capacity of the remaining MSSVs. This is accomplished by restricting THERMAL POWER so that the energy transfer to the most limiting steam generator is not greater than the available relief capacity in that steam generator. Table 3.7-2 allows a ± 3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM

The OPERABILITY of the Auxiliary Feedwater System ensures that the Reactor Coolant System can be cooled down to less than 350°F from normal operating conditions in the event of a total loss-of-offsite power. Steam can be supplied to the pump turbines from either or both units through redundant steam headers. Two D.C. motor operated valves and one A.C. motor operated valve on each unit isolate the three main steam lines from these headers. Both the D.C. and A.C. motor operated valves are powered from safety-related sources. Auxiliary feedwater can be supplied through redundant lines to the safety-related portions of the main feedwater lines to each of the steam generators. Air operated fail closed flow control valves are provided to modulate the flow to each steam generator. Each steam driven auxiliary feedwater pump has sufficient capacity for single and two unit operation to ensure that adequate feedwater flow is available to remove decay heat and reduce the Reactor Coolant System temperature to less than 350°F when the Residual Heat Removal System may be placed into operation.

ACTION statement 2 describes the actions to be taken when both auxiliary feedwater trains are inoperable. The requirement to verify the availability of both standby feedwater pumps is to be accomplished by verifying that both pumps have successfully passed their monthly surveillance tests within the last surveillance interval. The requirement to complete this action before beginning a unit shutdown is to ensure that an alternate feedwater train is available before putting the affected unit through a transient. If no alternate feedwater trains are available, the affected unit is to stay at the same condition until an auxiliary feedwater train is returned to service, and then invoke ACTION statement 1 for the other train. If both standby feedwater pumps are made available before one auxiliary feedwater train is returned to an OPERABLE status, then the affected unit(s) shall be placed in at least HOT STANDBY within 6 hours and HOT SHUTDOWN within the following 6 hours.

ACTION statement 3 describes the actions to be taken when a single auxiliary feedwater pump is inoperable. The requirement to verify that two independent auxiliary feedwater trains are OPERABLE is to be accomplished by verifying that the requirements for Table 3.7-3 have been successfully met for each train within the last surveillance interval. The provisions of Specification 3.0.4 are not applicable to the third auxiliary feedwater pump provided it has not been inoperable for longer than 30 days. This means that a unit(s) can change OPERATIONAL MODES during a unit(s) heatup with a single auxiliary feedwater pump inoperable as long as the requirements of ACTION statement 3 are satisfied.

AUXILIARY FEEDWATER SYSTEM (Continued)

The monthly testing of the auxiliary feedwater pumps will verify their operability. Proper functioning of the turbine admission valve and the operation of the pumps will demonstrate the integrity of the system. Verification of correct operation will be made both from instrumentation within the control room and direct visual observation of the pumps.

3/4.7.1.3 CONDENSATE STORAGE TANK

There are two (2) seismically designed 250,000 gallons condensate storage tanks. A minimum indicated volume of 210,000 gallons is maintained for each unit in MODES 1, 2 or 3. The OPERABILITY of the condensate storage tank with the minimum indicated volume ensures that sufficient water is available to maintain the Reactor Coolant System at HOT STANDBY conditions for approximately 23 hours or maintain the Reactor Coolant System at HOT STANDBY conditions for 15 hours and then cool down the Reactor Coolant System to below 350°F at which point the Residual Heat Removal System may be placed in operation.

The minimum indicated volume includes an allowance for instrument indication uncertainties and for water deemed unusable because of vortex formation and the configuration of the discharge line.

3/4.7.1.4 SPECIFIC ACTIVITY

The limit on secondary coolant specific activity is based on a postulated release of secondary coolant equivalent to the contents of three steam generators to the atmosphere due to a net load rejection. The limiting dose for this case would result from radioactive iodine in the secondary coolant. One tenth of the iodine in the secondary coolant is assumed to reach the site boundary making allowance for plate-out and retention in water droplets. The inhalation thyroid dose at the site boundary is then;

$$\text{Dose (Rem)} = C * V * B * DCF * X/Q * 0.1$$

Where:

C	=	secondary coolant dose equivalent I-131 specific activity
	=	0.2 curies/ m^3 (µCi/cc) or 0.1 Ci/m3 , each unit
V	=	equivalent secondary coolant volume released = 214 m^3
B	=	breathing rate = 3.47×10^{-4} m3/sec.
X/Q	=	atmospheric dispersion parameter = 1.54×10^{-4} sec/m3
0.1	=	equivalent fraction of activity released
DCF	=	dose conversion factor, Rem/Ci

The resultant thyroid dose is less than 1.5 Rem.

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVES

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blow down in the event of a steam line rupture. This restriction is required to: (1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and (2) limit the pressure rise within containment in the event the steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves within the closure times of the Surveillance Requirements are consistent with the assumptions used in the safety analyses. The 24-hour action time provides a reasonable amount of time to troubleshoot and repair the backup air and/or nitrogen system.

3/4.7.1.6 STANDBY STEAM GENERATOR FEEDWATER SYSTEM

The purpose of this specification and the supporting surveillance requirements is to assure operability of the non-safety grade Standby Steam Generator Feedwater System. The Standby Steam Generator Feedwater System consists of commercial grade components designed and constructed to industry and FPL standards of this class of equipment located in the outdoor plant environment typical of FPL facilities system wide. The system is expected to perform with high reliability, i.e., comparable to that typically achieved with this class of equipment. FPL intends to maintain the system in good operating condition with regard to appearance, structures, supports, component maintenance, calibrations, etc.

The function of the Standby Steam Generator Feedwater System for OPERABILITY determinations is that it can be used as a backup to the Auxiliary Feedwater (AFW) System in the event the AFW System does not function properly. The system would be manually started, aligned and controlled by the operator when needed.

The A pump is electric-driven and is powered from the non-safety related C bus. In the event of a coincident loss of offsite power, the B pump is diesel driven and can be started and operated independent of the availability of on-site or off-site power.

A supply of 65,000 gallons from the Demineralized Water Storage Tank for the Standby Steam Generator Feedwater Pumps is sufficient water to remove decay heat from the reactor for six (6) hours for a single unit or two (2) hours for two units. This was the basis used for requiring 65,000 gallons of water in the non-safety grade Demineralized Water Storage Tank and is judged to provide sufficient time for restoring the AFW System or establishing make-up to the Demineralized Water Storage Tank.

The minimum indicated volume (135,000 gallons) consists of an allowance for level indication instrument uncertainties (approximately 15,000 gallons); for water deemed unusable because of tank discharge line location and vortex formation (approximately 50,300 gallons); and the minimum usable volume (65,000 gallons). The minimum indicated volume corresponds to a water level of 8.5 feet in the Demineralized Water Storage Tank.

The Standby Steam Generator Feedwater Pumps are not designed to NRC requirements applicable to Auxiliary Feedwater Systems and are not required to satisfy design basis events requirements. These pumps may be out of service for up to 24 hours before initiating formal notification because of the extremely low probability of a demand for their operation.

STANDBY STEAM GENERATOR FEEDWATER SYSTEM (Continued)

The guidelines for NRC notification in case of both pumps being out of service for longer than 24 hours are provided in applicable plant procedures, as a voluntary 4-hour notification.

Adequate demineralized water for the Standby Steam Generator Feedwater system will be verified once per 24 hours. The Demineralized Water Storage Tank provides a source of water to several systems and therefore, requires daily verification.

The Standby Steam Generator Feedwater Pumps will be verified OPERABLE monthly on a STAGGERED TEST BASIS by starting and operating them in the recirculation mode. Also, during each unit's refueling outage, each Standby Steam Generator Feedwater Pump will be started and aligned to provide flow to the nuclear unit's steam generators.

This surveillance regimen will thus demonstrate operability of the entire flow path, backup non-safety grade power supply and pump associated with a unit at least each refueling outage. The pump, motor driver, and normal power supply availability would typically be demonstrated by operation of the pumps in the recirculation mode monthly on a staggered test basis.

The diesel engine driver for the B Standby Steam Generator Feedwater Pump will be verified operable once every 31 days on a staggered test basis performed on the B Standby Steam Generator Feedwater Pump. In addition, an inspection will be performed on the diesel at least once every 18 months in accordance with procedures prepared in conjunction with its manufacture's recommendations for the diesel's class of service. This inspection will ensure that the diesel driver is maintained in good operating condition consistent with FPL's overall objectives for system reliability.

3/4.7.2 COMPONENT COOLING WATER SYSTEM

The OPERABILITY of the Component Cooling Water System ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single active failure, is consistent with the assumptions used in the safety analyses. One pump and two heat exchangers provide the heat removal capability for accidents that have been analyzed.

3/4.7.3 INTAKE COOLING WATER SYSTEM

The OPERABILITY of the Intake Cooling Water System ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The design and operation of this system, assuming a single active failure, ensures cooling capacity consistent with the assumptions used in the safety analyses.

3/4.7.4 ULTIMATE HEAT SINK

The limit on ultimate heat sink temperature in conjunction with the SURVEILANCE REQUIREMENTS of Technical Specification 3/4.7.2 will ensure that sufficient cooling capacity is available either: (1) to provide normal cooldown of the facility, or (2) to mitigate the effects of accident conditions within acceptable limits.

With the implementation of the CCW heat exchanger performance monitoring program, the limiting UHS temperature can be treated as a variable with an absolute upper limit of 100°F without compromising any margin of safety. Demonstration of actual heat exchanger performance capability supports system operation with postulated canal temperatures greater than 100°F. Therefore, an upper Technical Specification limit of 100°F is conservative.

3/4.7.5 CONTROL ROOM EMERGENCY VENTILATION SYSTEM

The OPERABILITY of the Control Room Emergency Ventilation System ensures that: (1) the ambient air temperature does not exceed the allowable temperature for continuous-duty rating for the equipment and instrumentation cooled by this system, and (2) the control room will remain habitable for operations personnel during and following all credible accident conditions. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rems or less whole body, or its equivalent. This limitation is consistent with the requirements of General Design Criterion 19 of Appendix A, 10 CFR Part 50.

System components are not subject to rapid deterioration, having lifetimes of many years, even under continuous flow conditions. Visual inspection and operating tests provide assurance of system reliability and will ensure early detection of conditions which could cause the system to fail or operate improperly. The filters performance tests prove that filters have been properly installed, that no deterioration or damage has occurred, and that all components and subsystems operate properly. The tests are performed in accordance with the methodology and intent of ANSI N510 (1975) and provide assurance that filter performance has not deteriorated below returned specification values due to aging, contamination, or other effects.

3/4.7.6 SNUBBERS

All snubbers are required OPERABLE to ensure that the structural integrity of the Reactor Coolant System and all other safety-related systems is maintained during and following a seismic or other event initiating dynamic loads.

The visual inspection frequency is based upon maintaining a constant level of snubber protection to each safety-related system during an earthquake or severe transient. Therefore, the required inspection interval varies inversely with the observed snubber failures and is determined by the number of inoperable snubbers found during an inspection. Inspections performed before that interval has elapsed may be used as a new reference point to determine the next inspection. However, the results of such early inspections performed before the original required time interval has elapsed (nominal time less 25%) may not be used to lengthen the required inspection interval. Any inspection whose results require a shorter inspection interval will override the previous schedule.

When the cause of the rejection of a snubber is visual inspection is clearly established and remedied for the snubber and for any other snubbers that may be generically susceptible, and verified operable by inservice functional testing, that snubber may be exempted from being counted as inoperable for the purposes of establishing the next visual inspection interval. Generically susceptible snubbers are those which are of a specific make or model and have the same design features directly related to rejection of the snubber by visual inspection, or are similarly located or exposed to the same environmental conditions such as temperature, radiation, and vibration.

When a snubber is found inoperable, an evaluation is performed, in addition to the determination of the snubber mode of failure, in order to determine if any Safety Related System or component has been adversely affected by the inoperability of the snubber. The evaluation shall determine whether or not the snubber mode of failure has imparted a significant effect or degradation on the supported component or system.

To provide assurance of snubber functional reliability, a representative sample of the installed snubbers will be functionally tested during plant refueling SHUTDOWNS. Observed failure of these sample snubbers shall require functional testing of additional units.

In cases where the cause of the functional failure has been identified additional testing shall be based on manufacturer's or engineering recommendations. As applicable, this additional testing increases the probability of locating possible inoperable snubbers without testing 100% of the safety-related snubbers.

The service life of a snubber is established via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (newly installed snubbers, seal replaced, spring replaced, in high radiation area, in high temperature area, etc.). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life. The requirements for the maintenance of records and the snubber service life review are not intended to affect plant operation

3/4.7.7 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(a)(3) limits for plutonium. This limitation will ensure that leakage from Byproduct, Source, and Special Nuclear Material sources will not exceed allowable intake values.

Sealed sources are classified into three groups according to their use, with Surveillance Requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism (i.e., sealed sources within radiation monitoring or boron measuring devices) are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

3/4.7.8 EXPLOSIVE GAS MIXTURE

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the GAS DECAY TANK SYSTEM (as measured in the inservice gas decay tank) is maintained below the flammability limits of hydrogen and oxygen. Maintaining the concentration of hydrogen and oxygen below their flammability limits provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50.

3/4 7.9 GAS DECAY TANKS

The tanks included in this specification are those tanks for which the quantity of radioactivity contained is not limited directly or indirectly by another Technical Specification. Restricting the quantity of radioactivity contained in each Gas Decay Tank provides assurance that in the event of an uncontrolled release of the tank's contents, the resulting whole body exposure to a MEMBER OF THE PUBLIC at the nearest SITE BOUNDARY will not exceed 0.5 rem.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 191 TO FACILITY OPERATING LICENSE NO. DPR-31

AND AMENDMENT NO. 185 TO FACILITY OPERATING LICENSE NO. DPR-41

FLORIDA POWER AND LIGHT COMPANY

TURKEY POINT UNIT NOS. 3 AND 4

DOCKET NOS. 50-250 AND 50-251

1.0 INTRODUCTION

By letter dated December 18, 1995, as supplemented on May 3, June 11, July 1, July 3, and August 22, 1996 (hereafter, collectively referred to as power uprate submittal) Florida Power and Light Company (FPL or the licensee) requested changes to the Facility Operating License (FOL) and Technical Specifications (TS) to increase rated thermal power from 2200 Megawatt thermal (MWt) to 2300 Mwt (approximately 4.5 percent) for Turkey Point units 3 and 4. The results of the uprate evaluations and analyses were documented in Westinghouse WCAP-14276, Revision 1, "Florida Power & Light Company Turkey Point Units 3 and 4 Uprating Licensing Report," (WCAP-14276) dated December 1995 and submitted by the licensee with the December 18, 1995 request.

The original Federal Register notice included information from the licensee's December 18, 1995, May 3 and June 11, 1996 letters. The July 1, July 3, and August 22, 1996 letters provided clarification and amplification of the analysis in the previously noticed letters and were not outside the scope of the original Federal Register notice.

2.0 BACKGROUND

Detailed evaluation of the Nuclear Steam Supply System (NSSS) (including Loss of Coolant Accident (LOCA), non-LOCA, Containment Responses and Dose Consequences), engineered safety features, power conversion, emergency power, support systems and environmental issues were performed by the licensee and Westinghouse. The licensee stated that the results of these evaluations and analyses confirmed that Turkey Point Units 3 and 4 can safely operate at the increased power level.

The capability of Turkey Point Units 3 and 4 to operate at uprated conditions was verified by the licensee in accordance with guidelines contained in Westinghouse topical report WCAP-10263, "A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Power Plant". This WCAP methodology, although not formally approved by the NRC, was followed by North Anna, Salem, Indian Point Unit 2, Callaway and Vogtle for their core power upratings.

The licensee stated that Turkey Point Units 3 and 4 have as-designed equipment and system capability to accommodate steam flow rates of at least 5 percent above the original rating and the increase to higher power is obtained by effective utilization of existing systems and equipment.

3.0 ACCIDENT ANALYSES EVALUATION

The accident analyses were reanalyzed or evaluated to support operation at the uprated NSSS power level as discussed in the following sections.

3.1. Evaluation of Non-LOCA Events and Standby Safety Features Analysis

The licensee has reviewed all of the Updated Final Safety Analysis Report (UFSAR) Chapter 14 non-LOCA analyses for Turkey Point Units 3 and 4 to determine their continued acceptability based on plant operation at the uprated power level. The following non-LOCA events were either evaluated or reanalyzed for plant conditions at uprated power level. The licensee's reanalyses were performed using NRC-approved methods and computer codes. The analyses incorporated a Revised Thermal Design Procedure (RTDP), which is a part of the current licensing basis for Turkey Point Units 3 and 4.

3.1.1 Uncontrolled Rod Cluster Control Assembly (RCCA) Bank Withdrawal from a Subcritical Condition

The uncontrolled RCCA bank withdrawal from a subcritical condition is analyzed to ensure that the core and the reactor coolant system (RCS) are not adversely affected. This has been demonstrated since the results of the analysis show that the minimum departure from nucleate boiling ratio (DNBR) remains greater than the safety analysis limit and that the maximum fuel temperatures predicted to occur are much less than those required for clad damage (2700°F) or fuel melting (4800°F) to occur. The staff considers that the effect of the power uprate on this event is, therefore, acceptable.

3.1.2 Uncontrolled RCCA Bank Withdrawal at Power

The uncontrolled RCCA bank withdrawal at power is analyzed to ensure that the core and the RCS are not adversely affected. This has been demonstrated since the results of the analysis at the uprated conditions show that the high neutron flux and overtemperature ΔT reactor trip functions provide adequate protection to ensure that the minimum DNBR remains greater than the safety analysis limit and that the RCS and main steam systems are maintained below 110 percent of the design pressures. The staff considers that the effect of the power uprate on this event is, therefore, acceptable.

3.1.3 RCCA Drop

Dropping of a full length RCCA into the core is analyzed to ensure that any resulting adverse power distribution does not violate the DNB design basis. The analysis shows that following a dropped RCCA event, without automatic rod withdrawal, the plant will return to a stabilized condition at less than or equal to the initial power. The staff considers that, since the DNBR remains above the limit value, the event does not adversely affect the core and the results due to the power uprate are acceptable.

3.1.4 Chemical and Volume Control System (CVCS) Malfunction

Unborated water can be inadvertently added to the RCS via the CVCS and cause a reactivity increase. The event is analyzed to ensure that there is sufficient time for mitigation of an inadvertent boron dilution event prior to the complete loss of shutdown margin (criticality). The results show that the maximum reactivity addition due to the dilution is slow enough to allow the operator sufficient time to determine the cause of the addition and take corrective action before shutdown margin is completely lost. For Mode 1, at least 15 minutes are available for operator action from the time of alarm to preclude a complete loss of shutdown margin. For Modes 2 and 6, at least 15 minutes and 30 minutes, respectively, are available for operator action from the time of initiation of the dilution. This meets the Turkey Point licensing basis for the inadvertent dilution event and is, therefore, acceptable to the staff.

3.1.5 Startup of an Inactive Reactor Coolant Loop

This event is precluded by the current Turkey Point TS, which do not allow operation with an inactive loop.

3.1.6 Excessive Heat Removal Due to Feedwater System Malfunctions

An example of this type of event is one of the feedwater control valves is inadvertently fully opened while the reactor is operated at full power. The reactor protection systems, including power range high neutron flux, overpower ΔT, and turbine trip on high-high steam generator water level, are available for mitigating this event. The reanalysis results indicate a transient minimum DNBR of 2.0, which is above the minimum DNBR limit, and a transient peak RCS pressure of 2300 psia, which is less than the maximum allowable limit. Therefore, the results of this transient analysis are acceptable.

3.1.7 Excessive Load Increase Incident

This event assumes a rapid increase of steam demand that causes a power mismatch between the reactor power and steam load. If the load increase exceeds the capability of the RCS, the transient would be terminated by the reactor protection system to keep the transient DNBR above the minimum DNBR. The reactor protection systems reactor trip setpoints, including overtemperature ΔT, overpower ΔT, power range high neutron flux, and low pressurizer pressure, are available for mitigating this event. The results of the reanalysis show a transient minimum DNBR of 2.1, which is above the minimum DNBR limit, and a transient peak RCS pressure of 2260 psia which is less than the maximum allowable limit. Therefore, the results of the transient are acceptable.

3.1.8 Loss of Reactor Coolant Flow

The licensee has performed reanalysis of both a partial and complete loss of forced reactor coolant flow and compared the results to the American Nuclear Society (ANS) condition II criteria. These incidents may result from a mechanical or electrical failure in one or more of the reactor coolant pumps (RCPs). The transient would be terminated by the reactor protection systems to keep the transient DNBR above the minimum DNBR. The reactor protection systems reactor trip setpoints, including undervoltage or underfrequency on RCP power supplies, underfrequency RCP breaker trips, low reactor coolant loop flow, and pump circuit breaker opening, are available for mitigating this event. The results of the reanalysis for the limiting case (complete loss of flow) show a transient minimum DNBR of 1.55, which is above the minimum DNBR limit and a transient peak RCS pressure of 2370 psia, which is less than the maximum allowable limit.

The RCP locked rotor/shaft break events were reanalyzed as ANS condition IV events. In this analysis, the off-site power is assumed available, which is consistent with the original licensing basis of the plant. While the consequences of a locked rotor are very similar to those of a pump shaft break, the analysis considers a scenario which represents the most limiting condition for the locked rotor and pump shaft break event. Following this event, a reactor trip will be actuated on a low RCS flow signal. For this event, DNB is assumed to occur in the core. The number of rods in DNB are conservatively calculated for use in dose consequences evaluations. The results of the reanalysis show that the number of rods in DNB is less than 10 percent and the radiological consequences are within a small fraction of the 10 CFR 100 guideline values. The peak transient RCS pressure is 2700 psia, which is less than the maximum allowable limit. The results of the analysis meet the acceptance criteria for the condition IV event and are, therefore, acceptable to the staff.

3.1.9 Loss of External Electrical Load and/or Turbine Trip

The licensee has performed a reanalysis of this event for the cases with and without pressure control and with maximum and minimum reactivity feedback. For this event, the reactor protection systems reactor trip setpoints, including overtemperature ΔT, high pressurizer pressure, and low-low steam generator water level, are available for mitigating this event. The results of the reanalysis for the most limiting case (without pressure control) show that the peak transient RCS pressure is 2700 psia, which is less than the maximum allowable limit. Since this is a heatup event, transient DNBR generally remains above the initial point for all cases analyzed. Therefore, the results of this transient are acceptable to the staff.

3.1.10 Loss of Normal Feedwater and Loss of Non-emergency Power to the Plant Auxiliaries

In these events, plant protection is provided by either the reactor trip setpoints for the low-low steam generator water level or the steam flow and feed flow mismatch coincident with low steam generator water level in any loop. The results of the reanalysis show that the consequences of these events are bounded by the loss of external electrical load and/or turbine trip event, which were found acceptable to the staff as indicated above.

3.1.11 Main Steam Line Break (MSLB) Core Response

An MSLB could cause excess cooldown of the RCS. With a negative moderator temperature coefficient, the RCS cooldown results in a reduction of core shut down margin. Assuming the most reactive control rod is stuck in its fully withdrawn position, it is possible that the core will return to critical. However, the core will be ultimately shut down by the injection of borated water from the refueling storage tank via the safety injection pumps. The licensee states that the most limiting MSLB event is performed at hot zero power (HZP) conditions, which did not change for the power uprating. In a letter dated June 11, 1996, the licensee provided its results of an analysis which reflected the uprated power conditions. The transient minimum DNBR for a typical cell is 1.48 which is above the minimum allowable DNBR limit of 1.45. Therefore, the results of the MSLB analysis meet the acceptance criteria for this event and are acceptable to the staff.

3.1.12 Rupture of a Control Rod Drive Mechanism (CRDM) - RCCA Ejection

The mechanical failure of a CRDM pressure housing could cause the ejection of the RCCA and drive shaft, resulting in a rapid reactivity insertion and possible localized fuel damage. The results indicate that the radially averaged enthalpy remains well below 280 cal/gm at any axial fuel location and, therefore, there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the Service Limit C, as described in the American Society of Mechanical Engineers (ASME) Code, Section III, there is no danger of further consequential damage to the RCS. Therefore, the effect of the power uprate on the results of the RCCA ejection accident are acceptable to the staff. The radiological consequences are evaluated in section 3.6 of this SE.

3.2 Evaluation of LOCA and LOCA Related Events

3.2.1 Large Break Loss-of-Coolant Accident (LBLOCA) Analysis

The licensee has performed a reanalysis of LBLOCA to demonstrate conformance with the 10 CFR 50.46 requirements for the conditions associated with the uprating. Peak cladding temperature (PCT) of 2103°F and 2082°F were calculated for the RCS low (562.7°F) and high (585.7°F) Tavg conditions respectively. After assessing the PCT effect for top skewed power shapes and containment purge on the most limiting case, the resulting maximum PCT for a LBLOCA is 2144°F. The results of the reanalysis of a LBLOCA show that all requirements of 10 CFR 50.46 are met and are, therefore, acceptable to the staff.

3.2.2 Small Break LOCA

The small break LOCA analysis utilizes the NOTRUMP computer code to calculate the transient depressurization of the RCS as well as to describe the mass and energy release of the fluid flow through the break. The 3-inch equivalent diameter cold leg break, high nominal vessel average temperature, was found to be the limiting case with a PCT of 1688°F. The small break LOCA analysis for the uprate condition was previously approved by the NRC by Amendment numbers 184 and 190 on August 13, 1996, for implementation pending approval of WCAP-10054-P, Addendum 2, Revision 1 (proprietary), "Addendum to the Westinghouse Small Break LOCA ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection in the Broken Loop and Improved Condensation Model," October 1995.

3.2.3 Hot leg Switchover (HLSO)

The licensee has performed a calculation to determine the new HLSO time and minimum hot leg recirculation flow based on an uprated core power of 2300 MWt. The new HLSO time is 12 hours. The new hot leg recirculation minimum flow is 33 lbm/sec. This hot leg recirculation minimum flow has been shown to be available. The licensee has concluded that with the above HLSO time and flow rate, the core geometry will remain acceptable. The staff finds these results acceptable.

3.2.4 Post-LOCA Long Term Cooling

The licensee has performed an evaluation to determine the effects of power uprating to post-LOCA long term cooling. It is concluded that the Tavg range has a negligible effect on the post-LOCA sump boron concentration. Therefore, the core will remain subcritical post-LOCA and that decay heat can be removed for the extended period of time required by the long-lived radioactivity remaining. The revised post-LOCA long term core cooling boron limit curve is used to qualify the fuel on a cycle-by-cycle basis during the fuel reload process. The staff finds the results acceptable.

3.3 Evaluation of Steam Generator Tube Rupture (SGTR) Event

The licensee has performed a reevaluation of the SGTR event using the methodology consistent with that used in the UFSAR. This method does not include a computer analysis to determine the plant transient behavior following an SGTR. Rather, simplified calculations were performed, based on the expected SGTR transient response, to determine the primary to secondary break flow and the steam release to the atmosphere for use in calculating the offsite doses during the event. Also, a single failure was not assumed in this analysis. Although no single failure is explicitly modeled, the licensee considered the analysis provides a conservative estimate of the offsite doses following an SGTR. The analysis assumes that the primary to secondary break flow is terminated at 30 minutes after the event initiation. The residual heat removal (RHR) system is operating at 24 hours after the SGTR and steam release is terminated at this time. The radiological consequences are evaluated in section 3.6 of this SE.

3.4 Containment Integrity Analysis

The licensee has performed containment integrity analyses at uprated power to ensure that the maximum pressure inside the containment will remain below the containment building design pressure of 55 psig if a design basis LOCA or MSLB inside containment should occur during plant operation. The analyses also established the pressure and temperature conditions for environmental qualification and operation of safety related equipment located inside the containment. The peak pressure is also used as a basis for the containment leak rate test pressure to ensure that dose limits will be met in the event of a release of radioactive material to containment. The licensee indicated that although the current licensed power is 2200 MWt, safety related systems (with the exception of the emergency core cooling system) were originally evaluated for core power level of 2300 MWt. The emergency core cooling system was analyzed at the higher power as part of the uprate request.

The licensee indicated that the containment functional analyses included the assumption of the most limiting single active failure and the availability or unavailability of offsite power, depending on which resulted in the highest containment temperature and pressure. Bounding initial temperatures and pressures for analyses were selected to envelop the limiting conditions for operation. Previously, all three emergency containment cooling (ECC) units were automatically started on a safety injection (SI) signal. The licensee indicated that to support post-LOCA long-term containment pressure/temperature analyses, a minimum of one ECC is required to start immediately with a second ECC unit starting within 24 hours following the event. The revised design and TS would require only two ECCs units to automatically start on SI signal and that the third (swing) ECC unit be maintained in an operational condition and available for manual starting. This change is required to limit the component cooling water system (CCWS) operating temperature during injection and/or recirculation phase of the LOCA at uprated conditions.

3.4.1 Main Steamline Break Containment Integrity Analysis:

The licensee has performed analyses to determine the containment pressure and temperature response during postulated MSLBs inside containment for limiting conditions for operation at uprated power. As in the current licensing basis FSAR, the uprated analyses were evaluated for initial power levels of 102 percent, 70 percent, 30 percent, and zero percent and spectrum of break sizes similar to that in the current FSAR. The MSLB mass and energy release and the pressure and temperature analyses have included the effects of various single failures. The MSLB mass and energy releases were calculated using the LOFTRAN computer code and Containment temperature and pressure using the COCO computer code. The LOFTRAN and COCO computer codes were used in the current design bases analyses and the staff has found the use of these codes acceptable.

As in the current analysis, the licensee indicated that the most limiting case with respect to peak containment pressure was determined to be a full double-ended rupture (DER) downstream of the flow restrictor in main steamline at hot zero power (1.4 ft^2 DER at HZP). The most limiting single failure was found to be a failure of the main steam check valve (MSCV) on the faulted loop with offsite power available. Initial containment pressure and temperature conditions for this limiting case were assumed to be +3.0 psig and 130°F. For the MSLB, the uprating analyses calculated a peak containment pressure of 48.1 psig and a peak temperature of 269.4°F for the limiting case. The current FSAR had calculated a peak containment pressure of 42.8 psig for MSLB case. The peak containment pressure and temperature at uprated conditions remains below the containment design pressure of 55 psig and temperature of

283°F. It also remains below the FSAR transient analysis which calculated a peak accident pressure of 49.9 psig and a peak accident temperature of 276°F.

Based on its review, the staff finds the proposed change due to uprate in peak containment pressure and temperature as a result of postulated MSLB is acceptable since the containment design and original peak accident pressures and temperatures are not exceeded.

3.4.2 LOCA Containment Integrity Analyses

The licensee has performed analyses to determine the containment pressure and temperature response during postulated LOCAs using mass and energy releases which incorporate revised design parameters corresponding to 2300 MWt with updated computer modeling. As in the current licensing basis FSAR, the postulated LOCA analyses were performed for the double ended hot leg (DEHL) guillotine break of reactor coolant pipe and the double ended pump suction (DEPS) break. The cold leg break (between pump and vessel) has been found in previous studies to be much less limiting in terms of overall containment energy releases. The analyses were performed for a diesel failure, a containment spray pump failure, no failure with minimum and maximum initial containment pressures. These cases are shown to result in maximum pressure and temperature response.

The licensee indicated that the mass and energy releases in the containment are calculated using methods described in Westinghouse Topical Report WCAP-10325-A and the containment pressure and temperature response is calculated using the COCO computer codes. Westinghouse Topical Report WCAP-8312A and COCO code were used for the current design bases analyses. The updated Westinghouse WCAP-10325 computer code with same methodology and assumptions (except the Turkey Point specific data) have been used for Catawba, McGuire, Sequoyah, Watts Bar, Surry, Millstone Unit 3, and Beaver Valley Unit 2 and Indian Point Unit 2.

For the DEHL break, the Turkey Point uprating analyses calculated a containment peak pressure of 48.1 psig and peak temperature of 273.9°F. For the DEPS breaks, the uprating analyses calculated a containment peak pressure of 46.2 psig and a peak temperature of 271.1°F with loss of offsite power and initial containment pressure of 0.3 psig. The uprated calculated LOCA peak pressure and temperature of 48.1 psig and 273.9°F remains below the FSAR transient analysis peak accident pressure and temperature of 49.9 psig and 276°F and containment design pressure and temperature of 55 psig and 283°F. In addition, all long-term cases were well below 50 percent of the peak value within 24 hours.

The licensee indicated that the reductions in the calculated peak pressure and temperature for the uprate power analyses were due to the use of revised methods for calculating the mass and energy releases to the containment and updated plant parameters. The updated calculated pressure and temperature curves for LOCA and MSLB cases will remain bounded by the curves used for equipment qualifications and for containment leak rate test pressure. The licensee indicated that a CCW thermal performance analysis was performed for the thermal uprate program. This analysis also considered the LOCA and MSLB transients. When only one or two ECCs are assumed to start in a postulated accident, CCWS acceptance criteria are met.

Based on the above discussion, the staff finds the licensee analyses for determining the containment peak pressure and temperature for design basis LOCA acceptable as the methodology and assumptions used for calculating mass and energy release and for calculating pressure and temperature transients have been used previously for plants of similar design to meet the requirements of Standard Review Plan (SRP) Section 6.2.1.3 for mass and energy analyses and Section 6.2.1.1.A for dry pressurized water reactor (PWR) containment integrity peak pressure analyses. The proposed change for power uprate will not affect the containment integrity as the calculated peak containment pressure of 48.1 psig remains below the containment design pressure of 55.0 psig and containment leak rate test pressure of 49.9 psig.

3.4.3 Short-Term Subcompartment Analysis

The licensee has indicated that the original design basis short-term LOCA mass and energy releases resulting from DERs of the primary loop piping for the subcompartment analyses will remain bounding for uprated power. This is due to the application of the Leak-Before-Break (LBB) Technology to the short-term LOCA mass and energy releases. Under LBB, the most-limiting break would be a DER of one of the largest RCS loop branch lines (pressurizer surge line, accumulator/SI line, or RHR suction line). Based on the above review, the staff concludes that the uprating is acceptable as the subcompartment pressure loading analysis from high-energy-line ruptures remain bounded by the current FSAR analysis. The staff notes that use of LBB methodology has been prevously approved by the NRC for use at Turkey Point.

3.5 Additional Design Basis and Programmatic Evaluations

3.5.1 Hydrogen Generation Rates

The licensee indicated that an analysis of containment post-LOCA hydrogen generation rate was performed for the uprated core thermal power of 2336 MWt (102 percent of 2300 MWt). The analysis showed that with no recombiner in service, the hydrogen concentration will not exceed four percent by volume for 17 days following a LOCA. Placing a hydrogen recombiner in service prior to the 18th day following a LOCA will maintain containment hydrogen levels below the lower flammability limit of 4 percent. Based on the above review, the staff finds that the power uprate will not impact the post-LOCA hydrogen control system.

3.5.2 Plant Programs

The licensee performed evaluations to determine the impact of plant operations at the proposed power level on the following generic issues/programs:

3.5.2.1 Compliance with 10 CFR 50, Appendix R

The licensee evaluated the analyses which were performed in support of the Appendix R evaluation for potential impact resulting from plant operations at the proposed power level. The licensee stated that the evaluation did not identify changes to design or operating conditions that will adversely impact the ability to provide post-fire safe shutdown in accordance with Appendix R.

Since there are no physical plant configuration or combustible load changes resulting from the uprated power level operations, the staff concurs with the licensee that plant operations at the proposed power level will have no impact on the Appendix R evaluation previously performed.

3.5.2.2 Station Blackout (SBO)

The licensee performed evaluations of the impact resulting from plant operations at the proposed uprated power level on system response and coping capabilities for SBO events. The licensee stated that with the exception of the minimum inventory of condensate required to be stored in the condensate storage tank (CST) to provide safe shutdown following an SBO event, no other changes to system design or operating conditions were identified. The licensee stated that the CST minimum required volume would be higher. The minimum usable volume which is required to support the design basis that the plant be maintained at hot standby for 15 hours followed by a 4-hour cooldown to RHR cut-in temperature (350°F) was determined to be 199,000 gallons for plant operations at the proposed power level. Consequently, the licensee proposed to revise the TS to increase the CST minimum required volume from 185,000 gallons to 210,000 gallons.

Based on our review and the experience gained from our review of power uprate applications for similar PWR plants, the staff finds that the impact on system response and coping capabilities for an SBO event resulting from plant operations at the proposed uprated power level will be insignificant, and that the licensee's proposal to increase the TS CST minimum required volume from 185,000 gallons to 210,000 gallons is acceptable.

3.5.2.3 Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment"

The licensee performed evaluations of the effects of plant operations at the proposed power level on component cooling water (CCW) system. In the CCW heat exchanger thermal analysis, revised heat exchanger parameters (e.g., fouling factor, CCW and intake cooling water flow rates, etc.) were used. These revised heat exchanger parameters are to be included in the licensee's Generic Letter 89-13 program for monitoring the system and heat exchanger performance.

Based on our review, the staff finds that the above licensee's commitment meets the intent of Generic Letter 89-13 and, therefore, is acceptable.

3.6 Radiological Consequences

The licensee reevaluated the effect of the power uprate on design basis accident (DBA) radiological consequences. The original licensing DBA source terms for Turkey Point were considered. The licensee also reevaluated the control room habitability under DBA conditions.

The licensee stated that the original radiological consequence analyses could not be exactly reconstituted. Therefore, the licensee reconstituted analyses performed using methodology described in the UFSAR with the original licensing basis assumption at 2346 MWt (102 percent of requested power level). The analyses also considered changes that had occurred since the original analyses were performed, including burnups, enrichments, fuel masses, and operating times. The licensee's reconstituted analyses indicate that, for all DBAs, the calculated offsite radiological consequences doses are within the dose acceptance criteria stated in the SRP and 10 CFR Part 100 and also comply with the dose acceptance criteria for control room operators given in General Design Criterion (GDC) 19 of Appendix A to 10 CFR Part 50.

The staff independently performed confirmatory evaluations at the uprated power level of 2400 MWt by increasing the previously calculated doses in the original safety evaluation report[1] by 4.3% (from 2300 to 2400 MWt, 104 percent of requested power level). The events reevaluated by the staff for the uprated power were the LOCA, MSLB, SGTR, and the fuel handling accident (FHA). The whole body and thyroid dose were calculated for the exclusion area boundary (EAB), the low population zone (LPZ), and the control room. The following table contains the results of the staff calculations compared to the licensees results.

Accident at Exclusion Area Boundary	FPL @ 2346 MWt (102%)	NRC @ 2400 MWt (104%)
Fuel Handling Accident	33 rem thyroid 0.1 rem whole body	44 rem thyroid <1 rem whole body
Steam Generator Tube Rupture	0.068 rem thyroid 0.4 rem whole body	1.5 rem thyroid <1 rem whole body
Steam Line Break	0.042 rem thyroid 0.5 rem whole body	1.5 rem thyroid <1 rem whole body
LOCA	24 rem thyroid 1.4 rem whole body	66 rem thyroid 2 rem whole body

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1 Safety Evaluation by the Division of Reactor Licensing U.S. Atomic Energy Commission in the matter of Florida Power and Light Company, Turkey Point Units 3 and 4, Dade County, Florida, Docket Nos. 50-250 and 50-251. March 15, 1972.

Accident at Low Population Zone		
Fuel Handling accident	3.2 rem thyroid 0.24 rem whole body	4.3 rem thyroid <1 rem whole body
Steam Generator Tube Rupture	0.01 rem thyroid 0.002 rem whole body	<1 rem thyroid <1 rem whole body
Steam Line Break	0.01 rem thyroid 0.00005 rem whole body	<1 rem thyroid <1 rem whole body
LOCA	2.7 rem thyroid 0.02 rem whole body	14 rem thyroid 1 rem whole body
Control Room	15 rem thyroid 0.5 rem whole body	14 rem thyroid <.2 rem whole body

The staff finds that the offsite radiological consequences and control room operator doses at the uprated power level of 2300 MWt will continue to remain within the acceptance criteria stated in the SRP and within the 10 CFR Part 100 and the GDC 19 dose reference values for all DBAs. Therefore, the staff concludes that the licensee's request to uprate the authorized maximum reactor core power level by 4.5 percent to 2300 MWt from its current limit of 2200 MWt is acceptable.

4.0 SYSTEMS, STRUCTURES, AND COMPONENTS EVALUATION

4.1 Reactor Vessel Integrity

4.1.1 Pressurized Thermal Shock (PTS) (10 CFR 50.61) Assessment

The staff reviewed FPL's PTS assessments of the Turkey Point reactor pressure vessels (RPVs) under the current and uprated power conditions for the plants. The current PTS calculations for Intermediate Shell-to Lower Shell Circumferential Weld SA-1101 (the limiting material in the Turkey Point RPVs) are based on a chemistry factor (CF) value of 180°F and a margin term ("M") of 56.00, as determined in accordance with Regulatory Position 1.1 and Table 1 of Regulatory Guide (RG) 1.99, Revision 2, for a ferritic weld containing 0.26 percent copper and 0.60 percent nickel. Tables 2.1-1 and 2.1-2 provide a comparison of the calculated end-of-life (EOL) RT_{PTS} values for Weld No. SA-1101 before and after the uprated power levels are licensed for the plants. The data in Row 2 of the Tables correspond to the values for the current power levels (2200 MWt); the data in Row 3 of the Tables correspond to the values for the uprated power conditions (2300 MWt). The RT_{PTS} values in Tables 2.2-1 and 2.2-2 are based on a CF of 180°F, as determined from Table 1 of RG 1.99, Revision 2, for a ferritic weld material containing 0.26 percent copper and 0.60 percent nickel.

10 CFR 50.61 requires that the RT_{PTS} values for ferritic circumferential weld materials in RPVs be less than 300°F at EOL. Tables 2.2-1 and 2.2-2 indicate

that the RT_{PTS} values at EOL for limiting material SA-1101 in the Turkey Point RPVs have increased by 2-3°F. However, the new RT_{PTS} values for the limiting materials in the Turkey Point RPVs will still be within the PTS screening criteria even under the uprated conditions for the plants. Therefore, the staff concludes that, in regard to the integrity of the Turkey Point RPVs, FPL will continue to comply with the requirements of 10 CFR 50.61 under the uprated conditions for the plants.

4.1.2 Basis for Evaluating P-T Limit Curves

The staff evaluates the P-T Limit Curves used for heatup, cooldown, and normal operation of PWRs based on the following NRC regulations and guidance: 10 CFR Part 50, Appendix G; GL 88-11; GL 92-01, Revision 1; GL 92-01, Revision 1, Supplement 1; RG 1.99, Revision 2; and Standard Review Plan (SRP) Section 5.3.2. In GL 92-01, Revision 1, the staff requested that licensees submit the RPV data for their plants to the staff for review. This data is used by the staff as the basis for the staff's review of P-T Limit submittals, and as the basis for the staff's review of PTS assessments (10 CFR 50.61 assessments). Appendix G to 10 CFR Part 50 requires that P-T Limits for the reactor pressure vessel (RPV) be at least as conservative as those obtained by applying the methodology of Appendix G to Section XI of the ASME Boiler and Pressure Vessel Code.

SRP 5.3.2 provides an acceptable method of calculating the P-T Limits for ferritic materials in the beltline of the RPV based on the linear elastic fracture mechanics (LEFM) methodology of Appendix G to Section XI of the ASME Code (Appendix G). The basic parameter of this methodology is the stress intensity factor K_I, which is a function of the stress state and flaw configuration of the material in question. The methods of Appendix G postulate the existence of a sharp surface flaw in the RPV that is normal to the direction of the maximum stress. The flaw in the RPV is postulated to have a depth that is equal to one-fourth of the RPV beltline thickness and a length equal to 1.5 times the RPV beltline thickness. The critical locations in the RPV beltline region for this methodology are the 1/4 thickness (1/4t) and 3/4 thickness (3/4t) locations, which correspond to the depth of the maximum postulated flaw, if initiated and grown from the inside and outside surfaces of the RPV, respectively.

4.1.3 Summary of the Previous Basis for Approving the Current Set of P-T Limit Curves TS

FPL's current set of P-T Limit Curves were approved by the staff in the License Amendments Nos. 134 and 128 to the respective Facility Operating Licenses DPR-31 and DPR-41, and the staff's Safety Evaluation (SE) to FPL, dated January 10, 1989. In the staff's SE of January 10, 1989, the staff concluded that the current P-T Limit Curves for Heatup and Cooldown would be acceptable until 20 effective full power years (EFPY). The staff based its assessment of the P-T Limit Curves on the methods of SRP 5.3.2, and on the plant-specific RPV data.

It should be noted that FPL's current set of P-T Limit Curves for the Turkey Point units are based on the adjusted reference temperature (ART) values for the 1/4t and 3/4t RPV locations (252.5°F and 200.4°F, respectively), and on a chemistry factor (CF) of 200.2°F. The CF of 200.2°F was determined in accordance with the criteria of Position 2.1 of RG 1.99, Revision 2, as determined from data obtained from Turkey Point Surveillance Capsules "T" and "V" from Unit 3, and Capsule "T" from Unit 4. The surveillance capsules were removed in accordance with FPL's Integrated Surveillance Program for the Turkey Point units, which was previously determined by the staff to meet the requirements of 10 CFR Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements." The staff approved the Turkey Point Integrated Surveillance Program by letter dated April 22, 1985. Table 2.3-1. provides a summary of the Turkey Point surveillance capsule data used to establish the CF (200.2°F) for the limiting RPV beltline material.

It should be noted that the staff's SE of January 10, 1989, did not address the credibility of the Turkey Point surveillance capsule data. For this review, the staff performed a review of the Turkey Point surveillance capsule data. The staff determined that, for the Turkey Point Unit 4 Surveillance Capsule T, the measured value of ΔRT_{NDT} differed from the calculated value of ΔRT_{NDT} by 74°F. This value exceeds the scatter of ΔRT_{NDT} data for ferritic weld materials by 46°F. With the existing surveillance information, the staff considers that the data from Turkey Point Unit 4 Surveillance Capsule T would not be used. However, the use of the surveillance data is within the Turkey Point licensing basis and, as discussed below, use of the surveillance data does not have a significant impact on the results.

Use of surveillance capsule data for establishing the adjusted reference temperatures listed in the Turkey Point P–T Limit Curves (TS Figures 3-4.2, 3-4.3, and 3.4-4) differs from the methodology used for FPL's latest PTS assessment (use of Position 1.1 and Table 1 of RG 1.99, Revision 2). The staff performed an independent calculation to determine what the adjusted reference temperatures would be at the 1/4t and 3/4t vessel locations if methodology of Position 1.1 and Table 1 of RG 1.99, Revision 2, were used for the calculation. Tables 2.4-1 and 2.4-2 compare the adjusted reference temperatures, at the 1/4t and 3/4t locations, respectively, if the methodology of Regulatory Position 2.1 of RG 1.99, Revision 2 and surveillance data are used, and if the methodology of Regulatory Position 1.1 and chemical composition data are used. Tables 2.4-1 and 2.4-2 indicate that, for Weld Heat No. 71249 (the limiting material in the Turkey Point RPVs), the use of chemical composition data and the Table 1 in RG 1.99, Revision 2, yields more conservative ART values than does surveillance capsule data. However, since the P–T Limit curves incorporate the margins of Appendix G to Section XI of the ASME Code, the small differences in the ART values (as summarized in Tables 2.4-1 and 2.4-2, respectively) are not considered to be significant and the staff finds the results acceptable.

4.1.4 Staff Evaluation of FPL's Proposed Changes to the P–T Limit Heatup and Cooldown Curves

FPL's proposed changes to the current P–T Limit Heatup and Cooldown Curves for the Turkey Point units do not involve changes to the actual curves. Instead, to account for the slight increase in the vessel neutron fluence levels, FPL proposed that the P–T Limit Curves be scaled back from 20 EFPY to 19 EFPY.

FPL justified the new expiration date based on the results of a plant specific calculation. The licensee determined the length of time to amass a neutron fluence of 2.022E19 n/cm^2 at the inner surface of the RPVs, based on the new uprated conditions for the units. This calculation was based on a limiting neutron fluence of 1.80E19 n/cm^2 at the RPV inner surface after 16 EFPY, and an uprated neutron flux rate of 2.31E10 n/cm^2-sec. FPL's calculations indicated that the current P–T Limit Heatup and Cooldown Curves would be applicable until 19 EFPY for Turkey Point Unit 3 and until 19.7 EFPY for Turkey Point Unit 4. FPL has conservatively set the amended expiration date for the Turkey Point P–T Limit Curves to the more conservative value from the calculation (i.e., 19 EFPY). This is acceptable to the staff.

4.1.5 Effect on FPL Compliance with 10 CFR Part 50, Appendix G: Upper Shelf Energy (USE) Considerations

In its letter to FPL dated July 24, 1995, the staff requested that FPL assess the effect of the proposed thermal power uprate on EOL USEs and FPL's equivalent margin analyses (EMAs) for the limiting USE materials in the Turkey Point RPVs. On May 3, 1996, FPL responded that the EMA for the Turkey Point RPVs was performed using an inner wall EOL fluence of 2.7E19 n/cm^2, as provided in B&W Proprietary Report BAW-2118P (November 1991, Ref. 17). The staff approved the EMA analysis for the Turkey Point units on October 19, 1993, as supplemented on March 29, 1994.

FPL's estimates for the uprated EOL fluences for the limiting USE materials in the Turkey Point RPVs have been estimated to increase to 2.74E19 n/cm^2 for Unit 3 and 2.68E19 n/cm^2 for Unit 4, respectively. Therefore, since the EOL neutron fluences for Welds SA–1101 will not change significantly as a result of the proposed power uprate, the staff concludes that the proposed power uprate will not affect FPL's EMA for the Turkey Point RPVs, nor any of the conclusions stated in the staff's SEs of October 19, 1993 and March 29, 1994 and is, therefore, acceptable to the staff.

4.1.6 Conclusions - Vessel Integrity Considerations

The EMCB staff has reviewed the FPL submittals and determined that FPL will still comply with the requirements of 10 CFR 50.61 and the requirements of 10 CFR Part 50, Appendix G under the uprated power conditions for the plants. The staff has also determined that FPL's proposed scaling back of the current set of P–T Limit Curves to 19 EFPY is acceptable. The staff, therefore, concludes that, with respect to the structural integrity of the Turkey Point reactor pressure vessels, the proposed thermal power uprate is acceptable.

The staff notes that, by letter dated July 1, 1996, FPL committed to provide a new P-T limit curve analysis for NRC review a minimum of 6 months prior to the expiration of the Turkey Point P-T Limit Curves. FPL also committed, by the same letter, to include in the limiting material property evaluation, (1) the data from the three surveillance capsules previously removed from Turkey Point Units 3 and 4, and (2) supplemental surveillance data from capsules being irradiated in the Davis Besse Reactor Vessel. The licensee stated that an evaluation of the temperature and fluence environment between the host plant (Davis Besse) and Turkey Point will be provided demonstrating the applicability of the surveillance data to the Turkey Point limiting materials. FPL indicated that it plans to utilize the Linde 80 generic initial RT_{NDT} lower bound value of -27°F.

4.2 Reactor Vessel

The licensee reported that the power increase will result in changing the design parameters given in Table 2.1-1 of WCAP-14276. Table 2.1-1 provides various cases that were developed for use in the power uprate analysis. There are no significant changes in thermal transients and LOCA blowdown forces as a result of the power uprating. The licensee evaluated the design and operation of the regions of the reactor vessel affected by the temperature change and fluence, based on the proposed uprated core power. The evaluation included a review of the reactor vessel design specifications, stress report and fracture mechanics analyses.

The regions of the reactor vessel affected by the temperature change include the RPV (main closure head flange, studs, and vessel shell), CRDM nozzles, core support pads, vent nozzles and the instrumentation tubes. The licensee evaluated the maximum ranges of stresses and cumulative fatigue usage factors for the critical components at the core power uprated conditions. The evaluation was performed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition, with addenda through the Summer 1966 to assure compliance with the code of record. The licensee indicated that the core power uprate does not affect the maximum stress ranges in the existing reactor vessel stress reports for Turkey Point Units 3 and 4, and the maximum cumulative fatigue usage factors remain significantly below the allowable ASME Code limit of 1.0. On the basis of its review, the staff concurs with the licensee's conclusion that the reactor vessel is acceptable for the proposed core power uprate.

4.3 Reactor Core Support Structure and Vessel Internals

By letters dated June 11, 1996, the licensee provided the additional information requested, by the staff, with regard to the evaluation of the reactor vessel core support and internal structures. The limiting reactor internal components evaluated include lower core plate, core barrel, baffle plates and baffle/barrel region bolts.

The licensee evaluated the upper and lower internals considering the worst case set of operating parameters provided in Table 2.1-1 of WCAP-14276. Stresses and cumulative fatigue factors for the limiting internal components at the power uprate conditions are below the allowable limits of the original design basis which had been previously reviewed by the staff.

Further, the licensee performed the flow-induced vibration analysis on the guide tubes and the upper support column at the uprated power level. The evaluation indicated that the existing analysis provides sufficient margins to accommodate the increase in the flow-induced vibration loads due to the power uprate.

On the basis of the above evaluation, the staff concluded that the reactor internal components at Turkey Point Units 3 and 4 will remain within the allowable limits of stress and fatigue usage factor for operation at the proposed uprated power conditions.

4.4 Reactor Coolant Pumps (RCPs)

The licensee evaluated the RCPs by reviewing the design specifications in comparison with the proposed uprated conditions. At the core power uprate, the reactor coolant system pressure remains unchanged. There are no significant changes to the design thermal transients. The small fluctuation (6°F) in the RCP inlet temperature has an insignificant effect on the pressure boundary stresses. On the basis of its review, the staff concurs with the licensee's conclusion that the current Model 93 RCPs, when operating at the proposed power uprated conditions, will remain in compliance with the requirements of the codes and standards under which the Turkey Point Units 3 and 4 were originally licensed.

4.5 Control Rod Drive Mechanisms

The licensee evaluated the adequacy of the CRDMs by reviewing the Turkey Point current Model L106B CRDM design specifications and stress report to compare the design basis input parameters against the operating conditions at the uprated core power. Based on this evaluation, the licensee concluded that the original design basis thermal and structural analyses are bounding for the core power uprate. On the basis of its review, the staff concurs with the licensee's conclusion that the current design of CRDMs continues to be in compliance with codes and standards under which the plant was licensed, for the power uprated conditions.

4.6 NSSS Piping and Pipe Supports

The proposed power uprate of Turkey Point Units 3 and 4 involves the increase of temperature difference across the Reactor Coolant System (RCS). The design input parameters that define the various temperature conditions associated with the full power operating conditions of the plant were given in Table 2.1-1 for both the current and the power uprated conditions. The licensee does not project a change in the RCS loop pressure as a result of the proposed core power uprate.

At Turkey Point, the existing design basis thermal analyses of the NSSS piping and supports were reviewed by the licensee, in comparison with the uprated power conditions, with respect to the design system parameters and transients. The licensee concluded that the existing design basis stress analyses for the RCS system piping and supports and systems connecting to the RCS system, remain valid for the power uprated conditions. The evaluation was performed in accordance with the American Standards Association (ASA) B31.1 Power Piping Code to assure compliance with the code of record at Turkey Point Units 3 and 4.

The staff finds that the increase in temperature difference across the RCS system, will have an insignificant effect on the NSSS piping, and will minimally impact the design basis analysis of the piping and pipe support. Therefore, the existing NSSS piping and supports, the primary equipment nozzles, the primary equipment supports, and the branch lines connecting to the primary loop piping will remain in compliance with the requirements of the design bases criteria as defined in the FSAR, and are acceptable for the power uprate.

4.7 Pressurizer

The licensee evaluated the adequacy of the pressurizer and components including the pressurizer spray nozzle, safety and relief nozzle, upper head/upper shell, manway and instrument nozzle, the pressurizer surge nozzle, lower head/heater well, and support skirt for operation at the uprated conditions. The evaluation was done by modifying the existing Turkey Point pressurizer stress report and design basis analyses of the pertinent pressurizer components. The licensee found that the uprate conditions are bounded by those used in the original pressurizer stress analyses. However, the original fatigue analyses were updated to account for the uprated power conditions. The licensee concluded that stresses and cumulative fatigue usage factors remain in compliance with the requirements of the ASME Code, Section III, 1965 Edition through Summer 1965 Addendum. On the basis of its review, the staff concurs with the licensee's conclusion that the existing pressurizer and components remain adequate for the plant operation at the proposed uprated core power.

4.8 Steam Generators (SGs)

The licensee evaluated the SGs by comparing the power uprate conditions with the design parameters of the Westinghouse Model 44F SGs at Turkey Point. The comparison shown in Table 2.1-1 of WCAP-14276 indicates that critical design system parameters such as the primary and secondary side pressures, as well as the vessel outlet and secondary side temperatures, are not significantly affected by the uprated power conditions. The variation in the primary-to-secondary pressure differential is within about 3 percent. The licensee indicated that there are no significant changes to the design transients as a result of the core power uprate. The stress level and cumulative fatigue usage factors of the critical SG components continue to remain in compliance with the requirements of the 1965 Edition of the ASME Code, Section III through the Summer 1965 Addenda. On the basis of its review, the staff concurs with the licensee's conclusion that the current Turkey Point Units 3 and 4 SGs are acceptable for the proposed core power uprate.

4.8.1 SG Tube Integrity Review

4.8.1.1 Effect of the Power Uprate on SG Tube Integrity

FPL contracted with the Westinghouse Corporation to evaluate the structural integrity of SG tubes under the uprated power conditions. The effects of the power uprate on the SG tube integrity are summarized in Westinghouse Topical Report, WCAP-14276, Revision 1. Westinghouse evaluated the effects of the uprated power conditions on structural integrity of the SG tubesheets, tubesheet junctions, tube to tubesheet welds, tubes secondary shell, minor shell penetrations, and feedwater nozzles. Westinghouse evaluated the SG tubes for two different plugging cases: (1) no tube plugging occurs in the SG; and (2) 20 percent of the tubes in the SGs are plugged. Each case used three different multiplying factors as input parameters to account for variations under increased power conditions. Westinghouse estimated that variations in the primary system pressure under uprating conditions were within 1 percent of the reference conditions. Variations in the secondary side pressure were about 6 percent. Variations in the primary-to-secondary pressure differential were about 3 percent. From these variations, a factor of 1.01 was used for the primary side pressure, 1.06 for the secondary side pressure, and 1.03 for the primary to secondary pressure differential. These factors were incorporated in the evaluation to adjust pressure stresses under steady-state conditions to the corresponding pressure stresses under the uprating conditions.

4.8.1.2 Minimum Wall Thickness Considerations

FPL stated that the current plugging limit of 40 percent through wall in the TS would still satisfy the minimum Code wall thickness requirements, even under the uprated power conditions. Using conservative allowances for eddy current measurement uncertainty and continued crack growth, FPL established that an unflawed wall thickness of 0.020 inches would satisfy the minimum wall thickness requirements of the ASME Code for the SG tubes. The average tube wall thickness in the Turkey Point SGs is 0.050 inches. Therefore, FPL concluded that the 40 percent through wall SG plugging limit in the Turkey Point technical specifications would continue to provide adequate margin to the minimum required wall thickness. The staff finds FPL's assessment on this issue acceptable.

4.8.1.3 Tube Wear Considerations

FPL evaluated the U-bend region of the tubes in order to determine whether the uprated conditions would induce additional tube wear from anti-vibration bars. FPL stated that the increase in steam flow and concurrent increase in void fraction could increase vibration in the U-bend region. FPL stated that the additional vibration in the small radius U-bends would not lead to significant increases in fatigue-type degradation or tube wear. FPL also evaluated the larger radius U-bends for increased wear from the anti-vibration bars. FPL stated that the number of U-bends that are subject to wear at the anti-vibration bar intersections as a result of the uprated power conditions would constitute less than 0.3 percent of the total tube count over the life of the SGs. This number is insignificant in contrast to the total number of tubes in the SGs. The staff concludes that the number of plugged tubes from additional wear by the anti-vibration bars is insignificant under the uprated power conditions.

4.8.1.4 Corrosion and Fouling Considerations

FPL stated that the increase in average heat flux resulting from the power uprating could increase the potential for corrosion and long-term fouling. However, FPL also stated that Turkey Point SGs have not experienced significant corrosion or fouling. The staff reviewed FPL's inservice inspection reports for the Turkey Point Units 3 and 4 SG tubes, dated January 17, 1996 and October 6, 1995, respectively. The inspection reports did not indicate any evidence of significant degradation in the Units 3 and 4 SG tubes. Even if additional corrosion were to occur in any of the Turkey Point SG tubes, the inservice inspection requirements and plugging limit in the TS would provide adequate assurance of the structural integrity of the SG tubes.

4.8.1.5 Regulatory Guide 1.121 Analysis Considerations

RG 1.121 is a staff guidance for the assessment of the structural integrity of degraded SG tubes. Because no active corrosion or other degradation phenomena are occurring within the Turkey Point SGs, a plant specific RG 1.121 analysis is not necessary. The staff concurs that the SG tubes in Turkey Point Unit 3 and 4 have not shown significant degradation to date; therefore, no RG 1.121 analysis is required at this time.

4.8.1.6 SG Tube Surveillance Considerations

FPL stated that the scope of its SG inspections has exceeded TS requirements in each of the past three refueling outages. These inspections included bobbin coil inspection for 100 percent of full length tubes and motorized rotating pancake coil inspection of tube manufacturing anomalies on a sampling basis. FPL has determined that manufacturing anomalies affect a limited number of tubes in each SG. The anomalies include minor denting at support intersections and minor over-expansion of the tube expansion transition at the top of the tubesheet. The tubes with these anomalies may be more susceptible to inter-granular attack or stress corrosion cracking than tubes without the anomalies. However, FPL added that corrosion has not been experienced in any of Turkey Point SG tubes and no significant amounts of degradation or wear is expected in the future. In addition, FPL has stated that it will follow the protocol in the report, "PWR Steam Generator Tube Examination Guidelines," for future SG tube inspections. The scope of this report covers inspection methods, equipment, personnel training and qualifications. Based on this information and the current status of corrosion in the SGs (i.e., no corrosion mechanisms to date), the staff concludes that the scope of the inspection is sufficient to provide assurance to the structural integrity of the tubes.

4.8.1.7 Conclusions Regarding SG Tube Integrity

The staff has reviewed FPL proposed license amendment in regard to the effect of the uprated power on the SG tube integrity. The staff has determined that the proposed uprated power will not affect the 40 percent through wall plugging limit required by the TS, nor significantly increase the wear of tubes by the anti-vibration bars. The staff has also determined that the uprated power is not expected to cause a significant increase in the corrosion of the SG tubes. Because the corrosion of the Turkey Point SG tubes is insignificant, the staff has determined that a RG 1.121 analysis is not needed at this time, and that the current scope for the inspection of the SG tubes is sufficient to monitor for degradation of the tubes at this time. Therefore, the staff concludes that FPL has provided reasonable assurance that the structural integrity of Turkey Point SG tubes will be maintained under the uprated power conditions.

4.9 NSSS/Balance-of-Plant (BOP) Interface Systems

4.9.1 Auxiliary Feedwater System/Condensate Storage Tank

The licensee performed evaluations of the effects of plant operations at the proposed uprated power level on auxiliary feedwater (AFW) system/condensate storage tank. It was determined that the AFW system components have sufficient margin to provide the required flow and pressure. The minimum usable CST volume required during an SBO event to maintain the plant at hot standby for 15 hours followed by a 4-hour cooldown to RHR cut-in temperature (350°F) would be higher and was determined to be 199,000 gallons for plant operations at the proposed power level. Consequently, the licensee proposed to revise the TS to increase the CST minimum required volume from 185,000 gallons to 210,000 gallons.

Based on our review and the experience gained from our review of power uprate applications for similar PWR plants, the staff concludes that the AFW system and the proposed TS CST minimum required volume of 210,000 gallons are acceptable for plant operations at the proposed power level.

4.9.2 Component Cooling Water

The CCW system provides cooling water to various safety systems including three emergency containment coolers (ECCs) and non-safety systems during all phases of plant operations. The CCW system is a closed loop system which serves as an intermediate barrier between the plant ultimate heat sink and systems which contain radioactive or potentially radioactive fluids in order to eliminate the possibility of an uncontrolled release of radioactivity. Ultimate heat sink cooling flow is provided by the intake cooling water (ICW) system. The licensee stated that the CCW system heat loads resulting from plant operations at the proposed uprated power level will increase slightly. The increases in heat loads are from the spent fuel pool (SFP) cooling system during both power and refueling operations, and RHR system during plant shutdown. The licensee performed evaluations of the effects of plant operations at the proposed power level on CCW system. Results of the evaluations indicate that when all three ECCs are allowed to operate following a loss-of-coolant accident (LOCA), CCW system operating temperature can exceed its maximum allowable limits. When only one (following a LOCA, only one ECC is required to keep the containment temperature and pressure from exceeding design limits) or two ECCs are assumed to start, CCW system acceptance criteria are met. Therefore, the licensee concluded that the CCW system has adequate capacity to perform its intended cooling function providing that no more than two ECCs are allowed to start automatically following a LOCA. The licensee stated that as part of power uprate program, design changes will be made to assure that no more than two ECCs will automatically start in response to an accident.

Based on our review, the licensee's commitment to the CCW design changes above, and the experience gained from our review of power uprate applications for similar PWR plants, the staff concludes that the CCW system is acceptable for plant operations at the proposed uprated power level.

4.9.3 Spent Fuel Pool Cooling System

The spent fuel pool cooling system (SFPCS) was designed to remove the decay heat released from the spent fuel assemblies stored in the SFP; to maintain the SFP water temperature at or below the design temperature of 150°F during plant operations and refueling; to maintain its cooling function during and after a seismic event; and to structurally withstand a design temperature of 212°F. The decay heat released from irradiated fuel will increase slightly following plant operations at the proposed power level.

Turkey Point routinely offloads the full core during refueling outages. The licensee analyzed this condition for the uprate condition and concluded that adherence to the current administrative limit of 140°F (i.e., stopping the offload if the SFP temperature reaches 140°F) will maintain the peak pool temperature below 150°F. The analysis assumed that eight fuel assemblies are transferred to the spent fuel pool each hour. The licensee stated that this offload rate exceeds the capacity of the fuel transfer equipment and maximizes heat input into the spent fuel pool. The staff concludes that operation in the uprated condition is acceptable since the SFP temperature will remain below 150°F for normal refueling.

The licensee also performed an analysis for the case of full core offload following a forced shutdown with a 1/2 core recently offloaded (36 days after shutdown) and a complete loss of SFP cooling. The analysis indicated that with a complete loss of SFP cooling, the SFP water temperature will rise and eventually reach boiling. The calculated minimum time from the loss-of-pool cooling until the pool boils is 4.5 hours and the maximum boil-off rate is 76.3 gpm. Makeup water in excess of the boil-off rate can be provided to the pool from the refueling water storage tank or via temporary connections from the fire water system or the primary water storage tank. The minimum time to boil allows ample time to restore the SFP cooling function or align makeup water supplies. Therefore, the minor increase in decay heat resulting from the power uprate does not impair the ability of operators to recover from a loss of cooling and the staff concludes that operation in the uprated condition is acceptable.

Overall, based on our review, evaluations described above, and the experience gained from our review of power uprate applications for similar PWR plants, we conclude that plant operations at the proposed power level will have an insignificant impact on the SFPCS.

Also, an issue associated with spent fuel pool cooling adequacy was identified in NRC Information Notice 93-83 and its Supplement 1, "Potential Loss of Spent Fuel Pool Cooling Following a Loss of Coolant Accident (LOCA)," dated October 7, 1993 and August 24, 1995, respectively, and in a 10 CFR Part 21 notification, dated November 27, 1992. The staff is evaluating this issue, as well as broader issues associated with spent fuel storage safety, as part of the NRC generic issue evaluation process. If the generic review concludes that additional requirements in the area of spent fuel pool safety are warranted, the staff will address those requirements to the licensee under separate cover.

4.10 Turbine Generator Systems

The licensee performed evaluations on turbine operations with respect to design acceptance criteria to verify the mechanical integrity under the conditions imposed by plant operations at the proposed uprated power level. Results of the evaluations showed that there would be no increase in the probability of turbine overspeed nor associated turbine missile production due to plant operations at the proposed uprated power level. Therefore, the licensee concluded that the turbine could continue to be operated safely at the proposed uprated power levels.

Based on our review and the experience gained from our review of power uprate applications for similar PWR plants, the staff agrees with the licensee that operation of the turbine at the proposed uprated power level is acceptable.

4.11 Equipment Qualification (EQ) Inside and Outside Containment

The licensee evaluated the effects of plant operations at the proposed power level on qualified equipment including safety-related electrical equipment and mechanical components.

With regard to the radiological dose used for EQ, the licensee stated that the existing dose used for EQ was calculated based on a reactor power level of 2300 MWt. The licensee reperformed the dose analyses for EQ evaluation based on a reactor power level of 2346 MWt (2300 MWt plus 2 percent) and concluded that the existing EQ is still valid for plant operations at the proposed power level.

With regard to the temperatures and pressures used for qualifying equipment inside containment, the licensee stated that results of the revised containment analysis indicate that containment temperatures and pressures are within the existing EQ profiles, except for the long-term temperature at 31 days. The revised analysis indicates an increase of 2.4°F at 31 days. However, this is within the normal range for containment temperature (104°F - 130°F). Therefore, the temperature profile for the accident duration of 31 days is still acceptable and plant operations at the proposed power level will not have an adverse impact on the EQ program.

With regard to high energy line break analyses which support equipment environmental qualification outside containment, the licensee stated that the existing calculations remain bounding for plant operations at the proposed power level.

Since the EQ parameters affected by the proposed changes remain bounded by the values used in the existing EQ program, and based on the experience gained from our review of power uprate applications for similar PWR plants, the staff concludes that plant operation at the proposed uprated power level will have an insignificant or no impact on the EQ of electrical equipment and mechanical components inside and outside containment and, therefore, is acceptable.

5.0 BALANCE-OF-PLANT EVALUATION

5.1 Main Steam System

The licensee performed an evaluation of the effects resulting from plant operations at the proposed uprated power level on the main steam system including the main steam isolation valve (MSIV), main steam check valve (MSCV), main steam bypass valve (MSBV) and main steam safety valve (MSSV). The licensee stated that the steam flow resulting from plant operations at the proposed uprated power level will be 10,061,000 lb/hr which is approximately 5 percent above the design flow of 9,6000,000 lb/hr. The main steam design conditions of 1085 psig and 600°F remain unchanged and bound all predicted operating conditions for the system and components. The licensee concluded that, with the exception of MSSV discharge piping, plant operations at the proposed uprated power level will have an insignificant or no impact on the main steam system and its associated components.

The licensee stated that MSSV discharge pipe backpressure will be higher at the uprated conditions and a modification to the MSSV discharge piping will be required to ensure adequate margin for plant operations at the proposed uprated power level.

Based on our review and the experience gained from our review of power uprate applications for similar PWR plants, the staff considers that plant operations at the proposed uprated power level will have an insignificant or no impact on the main steam system.

5.2 Steam Dump System

The licensee evaluated the steam dump system for the plant operations at 2300 MWt reactor power level and stated that all of the system operating conditions are bounded by the existing design conditions. Based on the experience gained from our review of power uprate applications for similar PWR plants, we find that plant operations at the proposed uprated power level do not change the design aspects and operations of the steam dump system. Therefore, the staff concludes that operation of the steam dump system at the proposed uprated power level is acceptable.

5.3 Condensate and Feedwater System

The licensee evaluated the condensate and feedwater systems for the plant operations at 2300 MWt reactor power level and stated that all of the system operating conditions are bounded by the existing design conditions. Since these systems do not perform any safety related function, the staff has not reviewed the impact of plant operations at the proposed uprated power level on the design and performance of these systems.

5.4 Extraction Steam System

The extraction steam system is designed to provide steam at various pressures and temperatures to preheat condensate and feedwater as it flows from the main condensers to the SGs. Since the extraction steam system does not perform any safety related function, the staff has not reviewed the impact of plant operations at the proposed uprated power level on the extraction steam system.

5.5 Circulating Water System

The circulating water system is designed to remove the heat rejected to the condenser by turbine exhaust and other exhausts over the full range of operating loads, thereby maintaining adequately low condenser pressure. The licensee stated that performance of this system was evaluated for power uprate and determined that the system is adequate for uprated power level operation.

Since the circulating water system does not perform any safety function, the staff has not reviewed the impact of plant operations at the prooosed uprated power level on the designs and performances of this system.

5.6 Turbine Plant Cooling Water System (TPCW)

The TPCW system is a closed-loop cooling water system and provides cooling water during normal operation to various non-safety related equipment coolers. The licensee stated that performance of this system was evaluated for power uprate and determined that the system is adequate for uprated power level operation.

Since the circulating water system does not perform any safety function, the staff has not reviewed the impact of plant operations at the proposed uprated power level on the designs and performances of this system.

5.7 Intake Cooling Water (ICW) System

The ICW system is designed to supply cooling water to safety-related CCW system equipment during a station blackout event and a LOCA or main steam line break accident, and non-safety related TPCW system during normal plant operation. The licensee performed evaluations of the effects of plant operations at the proposed uprated power level on the ICW system and concluded that the ICW system as designed will supply sufficient water to remove the additional heat loads resulting from plant operations at the proposed uprated power level.

Based on our review and the experience gained from our review of power uprate applications for similar PWR plants, the staff finds that plant operations at the proposed uprated power level do not change the design aspects and operations of the ICW system. Therefore, the staff concludes that plant operations at the proposed uprated power level have an insignificant or no impact on the ICW system.

5.8 Heating, Ventilation, and Air Conditioning

The following heating, ventilating, and air conditioning (HVAC) systems were evaluated to ensure that they are capable of supporting the plant uprate conditions:

- control room
- DC equipment/invertor rooms
- Cable spreading & computer equipment rooms
- Radwaste building
- Fuel handling building
- 480 V load centers & 4.16 kV switchgear rooms
- Auxiliary building
- Unit 4 emergency diesel generator building
- Electrical equipment room
- Containment penetrations

During normal plant operation, these HVAC systems cool, heat, and ventilate plant areas to maintain a suitable environment for plant personnel and equipment, as appropriate. The licensee stated that these HVAC systems will continue to maintain normal operating temperatures at or below their maximum normal operating temperatures.

In addition, regarding the control room emergency ventilation system, the existing TS requires a methyl iodide removal efficiency of 90 percent. The licensee stated that the required methyl iodide removal efficiency is being increased to 99 percent to assure consistency between testing efficiency and analysis assumptions for post accident control room doses. This increase is consistent with the recommendations of RG 1.52, "Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Absorption Units of Light-Water-Cooled Nuclear Power Plants," and is more conservative. The staff considers it acceptable. The TS change associated with this area is described in section 6.13 of this SE.

Based on our review and the experience gained from our review of power uprate applications for similar PWR plants, we find that plant operations at the proposed uprated power level do not change the design aspects and operations of the HVAC systems (except as previously discussed). Therefore, we concur with the licensee that plant operations at the proposed uprated power level will have an insignificant or no impact on these HVAC systems.

5.9 <u>Miscellaneous Systems</u>

The licensee stated that various systems were evaluated and found not affected by the power uprate. The following are major plant systems that were not affected by power uprate:

- Instrument air system
- Auxiliary steam and condensate recovery system
- Feedwater heaters
- Condensate polishing system
- Heater, moisture separator and reheater drain system
- Main condenser

Since plant operations at the proposed uprated power level do not change the design aspects and operations of these systems, and these systems do not perform any safety function, the staff did not review the impact of the uprated power level operation on the designs and performances of these systems.

5.10 Radwaste Systems (Liquid and Gaseous)

The liquid and gaseous radwaste activity is influenced by the reactor coolant activity which is a function of the reactor core power. The licensee stated that the existing design of the radwaste systems is based on the core power level of 2300 MWt. Therefore, plant operations at the proposed uprated power level will have an insignificant or no impact on the radwaste systems.

Based on our review, the staff agrees with the licensee that plant operations at the proposed uprated power level will have an insignificant or no impact on the radwaste systems.

5.11 Additional Balance of Plant (BOP) Reviews

The impact of plant operations at the proposed uprated power level on High Energy Line Break (HELB) Outside Containment and Equipment Environmental Qualification is addressed in section 4.11.

5.12 BOP Piping

The licensee evaluated the adequacy of the BOP piping systems based on comparing the existing design bases parameters with the core power uprate conditions. The code of record for BOP piping at Turkey Point is ASA B31.1-1955. In its letter dated June 11, 1996, the licensee indicated that the American National Standards Institute (ANSI) B31.1 Power Piping Code, 1973 Edition with addenda through Summer 1976 (the code) was used for the power uprate at Turkey Point. The staff finds the methodology to be acceptable considering that the stress limits in the code are generally conservative in comparison with the stress limits specified in the Turkey Point UFSAR. On the basis of its analysis, the licensee concluded that the BOP piping, pipe supports and equipment nozzles remain acceptable and continue to satisfy design basis requirements for the power uprate.

In addition, the design bases pipe break analyses were also reviewed by the licensee to evaluate the effects of the uprate conditions on the pipe break locations, jet thrust and jet impingement forces which were used in the plant hazard analyses and the design of pipe whip restraints. The review verified that the existing postulated pipe break locations are not affected by the power uprate since the design bases piping analyses will not change due to the power uprate. The current design bases for jet thrust and jet impingement forces due to postulated pipe breaks for these systems are not affected by the uprate, since the systems do not experience pressure increase as a result of the core power uprate. Based on its review, the staff concurs with the licensee's conclusion that the original design analyses for the pipe break locations, jet thrust, jet impingement and pipe whip restraints are unaffected by the power uprate.

On the basis of the above evaluation, for all the secondary-side systems reviewed, the staff concurs with the licensee's conclusion that the power uprate will have no significant impact on the BOP design bases.

6.0 EVALUATION OF CHANGES TO TS AND FACILITY OPERATING LICENSE (FOL)

The FOL and TS changes requested by the licensee in their power uprate submittal are:

6.1 FOL License Condition 3.A

The licensee proposes to change License Condition 3.A for Operating License DPR-31 and DPR-41 "Maximum Power Level" from 2200 MWt to 2300 MWt. As documented in WCAP-14276, the licensee has provided the results of its reanalyses or evaluation including LOCA and Non-LOCA transients and accidents, containment response, radiological consequences, NSSS and BOP systems and components to support the operation of Turkey Point Units 3 and 4 at an uprated power level. The staff has reviewed the licensee's submittal and concluded that, for the reasons stated in this SE, both Turkey Point Units can safely operate at a core power of 2300 MWt.

6.2 TS 1.24 Definition of "RATED THERMAL POWER"

The license proposed changing 2200 MWt to 2300 MWt to reflect the new uprated power level. The staff finds this change acceptable as specified previously.

6.3 TS Figure 2.1-1 and Table 2.2-1

For TS Figure 2.1-1, "Reactor Core Safety Limits - Three Loops in Operation," the licensee proposed revising Figure 2.1-1 to reflect changes associated with the new operating conditions at the uprated power level.

For TS Table 2.2-1, "Reactor Trip System Instrumentation Trip Setpoints," Functional Unit 5, Overtemperature ΔT and Functional Unit 6 - Overpower ΔT, the revised core safety limits required changes to the overtemperature ΔT and Overpower ΔT setpoints. Use of the Revised Thermal Design Procedure (RTDP) methodology and the inclusion of site specific instrument uncertainties resulted in changes to the other values associated with overtemperature ΔT and Overpower ΔT.

For TS Table 2.2-1, "Reactor Trip System Instrumentation Trip Setpoints" Functional Unit 10 - Reactor Coolant Flow-Low, FPL proposed changing the loop design flowrate from "89,500 gpm" to "85,000 gpm" for analyzed increase in the percentage of plugged steam generator tubes.

For TS Table 2.2-1, "Reactor Trip System Instrumentation Trip Setpoints" Functional Unit 11 - Steam Generator Water Level - Low-Low and Functional Unit 12 - Steam Generator Water Level - Low, the licensee proposed changing the allowable value to incorporate plant specific uncertainties.

Core safety limits for three loops in operation (TS Figure 2.1-1) have been revised to account for the proposed power uprating using the Revised Thermal

Design Procedure (RTDP) methodology. The RTDP methodology has been previously approved by the NRC and implemented at Turkey Point by FPL. The increased power level as well as increased peaking factors and a loop design flow reduction of 4500 gpm were included in the revised safety limits. In addition, new overtemperature ΔT (OTΔT) and overpower ΔT (OPΔT) trip setpoints were generated based on the new core safety limits. Each transient that is sensitive to the changes in these setpoints (i.e., rod withdrawal at power, boron dilution, and loss of load) has been analyzed by the licensee and in all cases, the applicable acceptance criteria, as stated in NUREG-0800 (Standard Review Plan), were met. The revised trip setpoints provided adequate protection to maintain the minimum value of departure from nucleate boiling ratio (DNBR) larger than the safety analysis limit and to maintain the reactor coolant system (RCS) pressure below 110 percent of the design pressure. Therefore, we find the revised core safety limits acceptable.

RTDP Instrument Uncertainties - Use of the RTDP methodology requires that variances in the plant operating parameters, pressurizer pressure, primary coolant temperature, reactor power, and reactor coolant system flow, be justified. Therefore, in support of the power uprate, FPL submitted Revision 2 to the RTDP methodology (WCAP-13719) which addressed the changes to the instrument uncertainties for the primary system operating parameters as a result of the increase in power level. These uncertainty values are acceptable and they, or more conservative values, have been used in the RTDP analysis.

The revised core safety limits of TS Figure 2.1-1 required changes to the OTΔT and OPΔT setpoints. The use of the RTDP methodology and the inclusion of Turkey Point specific instrument uncertainties have resulted in revisions to the values associated with these trip function. These revised setpoints in the proposed TS were used in the accident analysis with acceptable results which are documented in WCAP-14276. The reduced RCS loop flow accounts for an analyzed increase in the percentage of steam generator tubes plugged (20 percent). The effects of the reduced RCS flow have been factored in the revised core safety limits. The reduced RCS flow has been assumed in the accident analysis with acceptable results which are documented in WCAP-14276.

The steam generator level setpoints are revised using the Turkey Point specific instrument uncertainties in accordance with the NRC approved setpoint methodology of WCAP-12745. The revised setpoints have been used in the loss of normal feedwater transient with acceptable results which are documented in WCAP-14276.

The licensee indicated that the new setpoints were established using the instrument setpoint methodology identified in WCAP-12745 Revision 1, "Westinghouse Setpoint Methodology for Protection System -- Turkey Point Units 3 & 4," dated December 1995. In August 1991, the staff, had previously reviewed and approved the setpoint methodology in Revision 0 of WCAP-12745 for use at Turkey Point Units 3 & 4. Therefore, the staff asked the licensee to identify the changes in WCAP-12745 between Revision 0 and Revision 1. In response, by letter dated June 11, 1996, the licensee stated that the instrument setpoint methodology is defined in Revision 0 and that Revision 1 documents the calculations conducted based on use of the methodology.

Similarly, for determining the OPΔT and OTΔT setpoints, the licensee used the methodology documented in WCAP-13719 Revision 1, "Westinghouse Revised Design Procedure Instrument Uncertainty Methodology -- Florida Power & Light Company, Turkey Point Units 3 & 4," dated January 1995, and the associated calculations are documented in Revision 2 of WCAP-13719, dated September 1995. The staff has previously reviewed and approved the setpoint methodology documented in Revision 1 of WCAP-13719.

The licensee stated that the proposed setpoint changes are intended to maintain the existing margins between operating conditions and the reactor trip setpoints. Thus, these new setpoints do not significantly increase the likelihood of a false trip nor failure to trip (actuate the protection system) upon demand. Therefore, the existing licensing basis is not affected by the TS setpoint changes. Based on this the staff finds the proposed setpoint changes acceptable.

6.4 TS Table 3.3-3

Plant specific calculations resulted in changes to various engineered safety features values of TS Table 3.3-3, "Engineered Safety Features Actuation System Instrumentation Trip Setpoints" Functional Unit 1, Safety Injection, Functional Unit 4, Steamline Isolation, and Functional Unit 6, Auxiliary Feedwater.

The licensee has modified the setpoints associated with safety injection, steamline isolation, and auxiliary feedwater actuation using the methodology of WCAP-12745. The revised setpoints are used in the transient and accident analysis with acceptable results which are documented in WCAP-14276.

As stated in section 6.3, the existing licensing basis is not affected by the TS setpoint changes. Based on this the staff finds the proposed setpoint changes acceptable.

6.5 TS 3.2.5 "DNB Parameters" and Associated BASES

The departure from nucleate boiling (DNB) parameters were modified to reflect the plant specific instrument uncertainties associated with the uprate. The revised values of T_{avg} (581.2°F) and pressurizer pressure (2200 psig) correspond to analytical limits of 583.2°F and 2175 psig with allowance for measurement uncertainty. The measured RCS flow value of 264,000 gpm corresponds to an analytical limit of 255,000 gpm (85,000 gpm per loop), which assumes a steam generator tube plugging level of 20 percent and includes a 3.5 percent calorimetric measurement uncertainty. These values are consistent with the values used in the safety analyses, which gave acceptable results, and their effects have been included in the revised core thermal limits of TS Figure 2.1-1. The changes are, therefore, acceptable.

6.6 TS BASES Page B 2-7, Reactor Coolant Pump Breaker Position Trip

This section was changed to indicate that no credit was taken in the accident analyses for operation of these trips. The underfrequency signal does not directly result in a reactor trip, but rather it trips the RCP breakers which in turn trip the reactor. The staff agrees with the licensee proposed change which makes its TS more accurate.

6.7 TS 3.7.1.3 and TS 3.7.1.6

The licensee proposed changes to TS 3.7.1.3, "Condensate Storage Tank" and Associated BASES, and TS 3.7.1.6, "Standby Steam Generator Feedwater System" and Associated BASES, to reflect the required water volumes for the uprated condition. These changes are acceptable to the staff as discussed in section 4.9.

6.8 TS 4.5.2 - "Emergency Core Cooling System," and Associated BASES

The licensee proposed a reduction in the safety injection pump discharge head in surveillance tests. The changes are from 1126 psid to 1083 psid for normal alignment for Unit 4 SI pumps aligned to Unit 3 RWST, and from 1156 psid to 1113 psid for Unit 3 SI pumps aligned to Unit 4 RWST. The reduced pump discharge heads have been incorporated in the safety analyses with acceptable results which are documented in WCAP-14276. The staff finds the proposed changes acceptable since the safety analyses meet the acceptance criteria.

6.9 Safety Valve TS

FPL proposed changes to TS 3.4.2.1 - "Safety Valves," TS 3.4.2.2 - "Safety Valves", TS Table 3.7-2 - "Steam Line Safety Valves Per Loop," and Associated BASES for TS 3/4.4.2 and 3/4.7.1.1.

The licensee proposed changes to increase the pressurizer safety valve tolerances from +/-1 percent to +2 percent,-3 percent and increase the main steam safety valve tolerances from +/-1 percent to +/-3 percent and add the footnote "All valves tested must have 'as-left' lift setpoints that are within 1 percent of the lift setting value." The proposed safety valve tolerances are assumed in the transient and accident analyses with acceptable results which are documented in WCAP-14276. The requirement of making "as-left" lift setpoints within 1 percent of the lift setting value following testing would ensure that the results of any transient and accident would be bounded by safety analyses. The licensee indicated that peak pressure remains below the ASME allowable of 110 percent of design pressure and that valve operability is not affected by the proposed change. The staff finds the proposed changes acceptable since the indicated tolerances have been assumed in the analyses with acceptable results and peak pressure remains below the allowable pressure.

6.10 TS Table 3.7-1 - "Steam Line Safety Valves Per Loop"

The licensee proposed changing the maximum allowable power level with inoperable main steam line safety valves (MSSV) to reflect the revised power level. Since the maximum allowable power range neutron flux high setpoint is based on the nominal Nuclear Steam Supply System (NSSS) power rating of the plant, the licensee has performed a reanalysis to establish the revised values consistent with uprated power level. The licensee used the method consistent with the current licensing bases to develop the revised values. The staff finds the proposed changes acceptable.

6.11 Heatup and Cooldown Curves

FPL proposed changes to TS Figure 3.4-2 - "RCS Heatup Limitations (60 °F/Hr)", TS Figure 3.4-3 - "RCS Heatup Limitations (100°F/Hr)", and TS Figure 3.4-4 - "RCS Cooldown Limitations (100°F/Hr)."

The licensee proposed changing the applicability of the curves from up to 20 effective full power years (EFPY) to 19 EFPY due to increased fluence projections on the vessel for the uprated power level. The staff found this acceptable, as discussed in section 4.1 of this SE.

6.12 TS 4.6.2.2 - "Emergency Containment Cooling System" and Associated BASES

The licensee proposed revising TS to require that two emergency containment cooling units start automatically on a safety injection (SI) signal since analysis has shown that auto-start of all three units on an SI signal is not required. The staff finds this acceptable, as discussed in Section 3.4.

6.13 TS 4.7.5c.2) - "Control Room Emergency Ventilation System"

The licensee proposed revising the methyl iodide removal efficiency from "90 percent" to "99 percent" to provide consistency between testing efficiency and analysis assumptions for post-accident control room doses. This is acceptable, as discussed in section 5.8 of this SE.

6.14 TS 3.2.2 - "Heat Flux Hot Channel Factor"

FPL proposed relocating the heat flux hot channel factor, F_Q, and the nuclear enthalpy rise hot channel factor, $F^N_{\Delta H}$, to the Turkey Point Core Operating Limits Report (COLR). The TS will continue to require operation within the COLR parameters and appropriate actions are incorporated if the F_Q or $F^N_{\Delta H}$ limits are exceeded. The determination of the F_Q and $F^N_{\Delta H}$ limits will be performed using NRC-approved methodology as defined in TS 6.9.1.7. Therefore, the staff finds the proposed relocation to the COLR acceptable.

6.15 TS 6.9.1.7 - "Core Operating Limits Report" (COLR)

The licensee proposed revising TS to (1) add the appropriate wording to reflect the inclusion of $F_Q(Z)$ and $F_{\Delta H}$ in the COLR, (2) add the following statement - "4. Nuclear Enthalpy Rise Hot Channel Factor for Specification 3/4.2.3" and (3) update references to be consistent with the current analyses.

In addition to the relocation of F_Q and $F^N_{\Delta H}$ to the COLR, updated references to the Westinghouse ECCS evaluation model using the BASH code have been included in the COLR list of analytical methods used to determine F_Q and $F^N_{\Delta H}$. This is acceptable since these references have been approved by the NRC.

6.16 TS BASES 3/4.7.1.4

The licensee proposed a change to correct the abbreviation for "Dose Conversion Factor" to read "DCF" to ensure consistency within the TS. This change is editorial, has no effect on the technical content, and is therefore acceptable to the staff.

6.17 TS BASES Page B 3/4 2-4

The licensee proposed deleting the reference to steam generator plugging limit of 5 percent to support anticipated future requests for higher plugging limits. The current limit remains at 5 percent. The licensee stated that the analysis in WCAP-14276 assumed up to 20 percent steam generator tube plugging level for the Small Break LOCA and non-LOCA analyses, while the LBLOCA is currently analyzed assuming a 5 percent steam generator tube plugging level. After the NRC approval of the Westinghouse Best Estimate LBLOCA methodology (BELOCA), the licensee intends to reanalyze the LBLOCA event using BELOCA methodology and assuming a 20 percent tube plugging level. The proposed change would avoid future inconsistency in the TS bases. Since TS bases are used as a matter of reference and the 5 percent value will soon be invalidated and because the TS bases are not enforceable, the staff finds the licensee proposed change acceptable.

7.0 STATE CONSULTATION

In accordance with its stated policy, on September 12, 1996 the NRC staff consulted with the Florida State official, Mr. Harland Keaton of the State Office of Radiation Control, regarding the environmental impact of the proposed action. The State official had no comments.

8.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32, and 51.35, an environmental assessment and finding of no significant impact was published in the Federal Register on September 18, 1996 (61 FR 49176). In this finding, the Commission determined that issuance of these amendments would not have a significant effect on the quality of the human environment.

9.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that (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 public health and safety.

Principal Contributors: C. Liang, L. Kopp, J. Minns, R. Goel, D. Shum, C. Wu, J. Medoff, H. Garg

Attachment: Tables 2.1-1 through 2.4-2

Date: September 26, 1996

Table 2.1-1 Change in RT_{PTS} Values of Limiting Weld Material SA-1101 in the Turkey Point Unit 3 Reactor Pressure Vessel at End-of-License

$RT_{NDT(U)}$ (Unirrad.) (°F)	ID Neut. Fluence (E19 n/cm^2)	Fluence Factor	Chemistry Factor (°F)	ΔRT_{NDT} (°F)	Margin (°F)	RT_{PTS} (°F)
10	2.64	1.260[1]	180	226.8[1]	56	293[1]
10	2.74	1.268[2]	180	228.2[2]	56	295[2,3]

Footnotes:
1. Values Under Current Maximum Licensed Power Levels
2. Values Under Proposed Uprated Power Levels
3. Value was conservatively rounded up from 294.2°F

Table 2.1-2 Change in RT_{PTS} Values of Limiting Weld Material SA-1101 in the Turkey Point Unit 4 Reactor Pressure Vessel at End-of-License

$RT_{NDT(U)}$ (Unirrad.) (°F)	ID Neut. Fluence (E19 n/cm^2)	Fluence Factor	Chemistry Factor (°F)	ΔRT_{NDT} (°F)	Margin (°F)	RT_{PTS} (°F)
10	2.53	1.249[1]	180	224.8[1]	56	291[1]
10	2.68	1.263[2]	180	227.3[2]	56	294[2,3]

Footnotes:
1. Values Under Current Maximum Licensed Power Levels
2. Values Under Proposed Uprated Power Levels
3. Value was conservatively rounded up from 293.3°F

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6-7D16

August 5, 1997

SOUTHERN COMPANY
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Docket Nos. 50-348
50-364

10 CFR 50.90

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

Joseph M. Farley Nuclear Plant
Response to Request for Additional Information
Related to Power Uprate Facility Operating Licenses
<u>and Technical Specifications Change Request</u>

Ladies and Gentlemen:

By letter dated February 14, 1997, Southern Nuclear Operating Company (SNC) submitted a request to amend the Facility Operating Licenses and Technical Specifications for Farley Nuclear Plant Units 1 and 2 to allow an increase in the licensed thermal power from 2652 MWt to 2775 MWt. On July 7, 1997, SNC received a request for additional information (RAI), dated July 1, 1997, related to the Farley power uprate submittal from the NRC staff. On July 28, 1997, SNC received a supplement, dated July 24, 1997, to the July 1, 1997 RAI. The SNC response to the RAI is provided in Attachment I. The additional information requested in the supplemental request is provided in Attachment II.

If you have any questions, please advise.

Respectfully submitted,

Dave Morey

Sworn to and subscribed before me this 5th day of Aug. 1997

Notary Public

My Commission Expires: November 1, 1997

MGE/maf pwrup17.doc

Attachments

cc: Mr. L. A. Reyes, Region II Administrator
Mr. J. I. Zimmerman, NRR Project Manager
Mr. T. M. Ross, Plant Sr. Resident Inspector

I/23

ATTACHMENT I

SNC Response To NRC Request For Additional Information

Related To Power Uprate Submittal - Joseph M. Farley Nuclear Plant, Units 1 & 2

SNC Response to NRC "Request for Additional Information Related to Power Uprate Submittal - Joseph M. Farley Nuclear Plant, Units 1 and 2"

GENERAL QUESTIONS REGARDING WCAP-14723

NRC Question No. 1

Please provide a discussion of the adequacy of the primary and secondary overpressure protection given the relative relieving capacity has gone down (relative to rated power). Include a Standard Review Plan Section 5.2.2 analysis.

SNC Response No. 1

The adequacy of the primary and secondary overpressure protection at uprated conditions was assessed as part of the power uprate analyses. The assessment was performed by analyzing the FSAR limiting transients (primarily the Loss of Load/Turbine Trip event) and showing that the primary and secondary pressure limits continue to be met at uprated power. The results of the FSAR limiting transient analyses are provided in Section 6.0 of the Power Uprate NSSS Licensing Report, with the results of the Loss of Load/Turbine Trip event provided in Section 6.2.7. Based on the analyses for the Loss of Load/Turbine Trip event, Section 6.2.7.6 concludes that the peak primary and secondary pressures remain below 110% of design at all times.

Standard Review Plan Section 5.2.2 addresses reactor coolant system overpressure protection. As discussed in Farley FSAR Section 5.2.2.3 (Report on Overpressure Protection), analysis was performed during the initial licensing process to show the continued integrity of the reactor coolant system during the maximum transient pressure. The conclusions of this section are confirmed as part of the power uprate project by analyzing the FSAR limiting transients (primarily the Loss of Load/Turbine Trip event) and showing that the primary and secondary pressure limits continue to be met.

RCS overpressure protection under low temperature conditions is provided at Farley by the RHR relief valves. These valves have been analyzed and their capability to mitigate the cold overpressure transients has been confirmed. For power uprate, none of the overpressure pump start transients (worst case mass input event) have been affected since the pumps of concern have not been changed by power uprate. The inadvertent start of an RCP at low temperature conditions with the plant cooling down on RHR (worst case heat input event) produces a transient in which the stored energy in the steam generator water is transferred to the RCS. Current Farley Technical Specifications and plant procedures limit the steam generator temperature to no more than 50°F above RCS temperature. Since this limit is not changed by power uprate, the transient is not affected by the uprating.

W/rgm - 7/22/97 & SCS/dwm - 7/31/97

NRC Question No. 2

The submittal indicates that the large break loss-of-coolant accident evaluation model is being changed and that selected other new/improved methods will be used. Please give a description of all the other new or improved methods used to support this license amendment and indicate whether they have received staff approval.

SNC Response No. 2

The power uprate project was structured consistent with the methodology established in WCAP-10263, "A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Power Plant." Inherent in this methodology are key points that include the use of currently approved analytical techniques (e.g., methodologies and computer codes) and the use of currently applicable licensing criteria and standards. Consistent with this methodology, the overall approach established for power uprate analyses was to use the current analysis methods except in select areas where new/improved methods are appropriate. Using the FSAR as a reference for comparison, new or improved methods were used in the following analysis areas.

- As described in Section 6.1.1.2 of the Power Uprate NSSS Licensing Report, the large break Loss of Coolant Accident (LOCA) analysis used the Best Estimate LOCA (BELOCA) methodology and the WCOBRA/TRAC computer code. This methodology was recently approved on a generic basis by the NRC and has been used on several plants which have made submittals to the NRC for approval. References are provided in Section 6.1.1.5 of the licensing report. Subsequent to submittal of the licensing report for power uprate, the NRC approved the first time application of the BELOCA methodology to Indian Point Nuclear Generating Unit 2.

- As described in Section 6.4.1.2 of the Power Uprate NSSS Licensing Report, the LOCA mass and energy (M&E) long term releases analysis used the 1979 version of the LOCA mass and energy release model (including the 1979 ANS-5.1 standard decay heat model) for containment design. This methodology was approved by the NRC in 1983 and has been used by Westinghouse and approved by the NRC on many plant specific dockets. References are provided in Section 6.4.3 of the licensing report.

- As described in Section 6.5.2.2 of the Power Uprate NSSS Licensing Report, Main Steamline Break (MSLB) M&E releases analysis for outside containment used the 1979 ANS-5.1 standard decay heat model. This decay heat model has been previously used by Westinghouse in other analyses for Farley including the MSLB M&E releases inside containment and has been approved by the NRC. References are provided in Section 6.5.4 of the licensing report.

- As described in Section 6.6.3 of the Power Uprate NSSS Licensing Report, the analysis for LOCA hydraulic forces used the NRC approved MULTIFLEX computer code which is the current Westinghouse analytical tool for use in analyzing LOCA hydraulic forces. This code was previously used for LOCA hydraulic forces analysis as part of the Farley Unit 1 Upflow Conversion Project. The use of MULTIFLEX as part of the Power Uprate Project constitutes its first application for Farley Unit 2

LOCA hydraulic forces. References are provided in Section 6.6.6 of the licensing report.

- The neutron fluence analysis at power uprate conditions was performed in accordance with the NRC-approved methodology described in Section 2.2 of WCAP-14040-NP-A, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves." By letter dated July 23, 1997, SNC submitted a Technical Specifications amendment request to relocate the pressure temperature limit curves to the Pressure Temperature Limits Report (PTLR). Table 5.4 of the proposed PTLRs for Unit 1 and Unit 2 provides the reactor vessel end-of-life fluence (EOL) projections at 36 effective full power years (EFPY) based on the methods of WCAP-14040-NP-A and the fluence associated with uprated power. These fluence values were used to determine the projected EOL properties for the reactor vessel beltline materials. Additionally, the surveillance capsule withdrawal schedule provided in Table 3-1 of the proposed PTLR reflects the use of the methods described in WCAP-14040-NP-A at the fluence associated with uprated power.

- As described in Section 7.6.2.2 of the Power Uprate NSSS Licensing Report, the ORIGEN2 code with current code libraries derived from ENDF/B-V was used in the source terms analysis for the uprated thermal power level. This version of the code with current libraries is an updated version of the code and libraries used in the original development of source terms for Farley. Updated versions of the code with libraries have been used by Westinghouse to calculate source terms for other uprating projects (most recently Turkey Point Units 3 and 4) which have been approved by the NRC. References are provided in Section 7.6.5 of the licensing report.

- As described in the Power Uprate NSSS Licensing Report, analyses for LOCA hydraulic forces (for use in structural analyses of the reactor internals, reactor vessel, steam generator, reactor coolant loop piping and fuel assemblies) and LOCA mass and energy short term releases (for use in subcompartment structural evaluations) took credit for the leak-before-break (LBB) exemption which has been previously approved by the NRC for Farley but not previously applied to most of these structural analysis areas. References, including the NRC approval letter for the LBB exemption, are provided in Section 5.5.1 of the licensing report.

- The structural piping analysis for the reactor coolant loops, as described in Section 5.5 of the Power Uprate NSSS Licensing Report, used the PS+CAEPIPE computer code which is the current Westinghouse analytical tool for use in analyzing reactor coolant loop piping (i.e., this code is used in lieu of WESTDYNE). Although this was the first Westinghouse application of this code to the Farley reactor coolant loop piping, it has previously been used on Farley by Southern Company Services (SCS), and its use is documented in the Farley FSAR Appendix 3F, "Computer Programs Used In Structural Analyses." SCS and Westinghouse verified the code against benchmark problems as required by the NRC.

- The containment pressure and temperature analyses for the LOCA and MSLB events, as described in Section 2.13 of the Power Uprate BOP Licensing Report, were performed using the GOTHIC code. GOTHIC has not been submitted for NRC approval. GOTHIC was developed by EPRI from the older NRC code, FATHOMS, under a fully qualified quality assurance program and has undergone extensive peer review. GOTHIC has been validated for safety-related applications at Southern Company Services.

- Offsite dose calculations for accident release were prepared using the multi-node TACT5 computer code as described in Section 2.16 of the Power Uprate BOP Licensing Report. The TACT5 code was developed by the NRC (reference NUREG/CR-5106).

- To evaluate the impact of load changes due to power uprate on the Station Auxiliary Electrical Distribution System, computer simulations were run using the Station Auxiliary (STAUX) Program. The STAUX program provides the capability to perform comprehensive station auxiliary reviews including load flow, short circuit, and motor starting calculations at all buses, load centers, and MCCs. The program was designed to conform with all applicable industry standards, practices, and design criteria. The accuracy of the STAUX computer model was validated by performing a test case and comparing the analytical results of the STAUX computer model with field measurements. While the STAUX program has not been submitted for NRC approval, the program was reviewed by the NRC as part of the EDSFIs at the SNC nuclear plant sites.

Following implementation of power uprate, where applicable, the FSAR will be revised to incorporate descriptions of these new or improved methodologies.

W/rgm - 7/31/97 & SCS/dwm - 8/04/97 & SNC/tws - 7/31/97

NRC Question No. 3

The submittal mentions the boron injection tank (BIT) in a few different locations. Please indicate the current function of the BIT and/or if there are plans to remove the tank.

SNC Response No. 3

As discussed in Section 6.0 of the Power Uprate NSSS Licensing Report, the power uprate analyses were performed to support deletion and removal of the BIT. In this context, deletion signifies deletion of concentrated boric acid solution from the BIT (i.e., the BIT remains in the piping system, but the contents of the BIT are assumed to be at the same boric acid concentration as the piping system in which it is located). Removal of the BIT signifies removal of the tank from the piping system.

At the onset of the uprate analyses, the BIT was scheduled for removal. As a contingency, the power uprate analyses were conservatively performed to support either configuration. The BIT was physically bypassed (i.e., removed from the ECCS piping system) during the 1997 Unit 1 and 1996 Unit 2 refueling outages.

W/rgm - 7/22/97 & SNC/mge - 7/24/97

NRC Question No. 4

The specification for the charging pump discharge pressure is being reduced. Are there any circumstances where injection flow would be necessary or beneficial for make-up or boration (i.e., perhaps an ATWS event) at the pressurizer code safety valve relief pressure that would no longer be available with the new specification?

SNC Response No. 4

As part of power uprate analyses, ECCS flow analysis was redone. The ECCS flow analysis incorporated an increase in the allowable head degradation input assumption for the charging pumps from 8% to 10% of design head. All of the FSAR safety analyses which use ECCS flows as an input assumption were then analyzed or evaluated to show that the associated acceptance criteria were satisfied with the revised ECCS flows at power uprate conditions. The results of the FSAR safety analyses confirmed that associated acceptance criteria were satisfied.

The increase in the allowable pump head degradation assumed in the power uprate analyses does not actually alter any pump specification but would permit a pump to remain in service with a slightly reduced pump head. Should a charging pump degrade to the new 10% degradation limit, slightly less flow would be available at a given RCS pressure than for the previous 8% degradation limit. However, this slight reduction in ECCS flow has been analyzed and can be accommodated within the current analysis acceptance limits.

W/rgm - 7/22/97

NRC Question No. 5

Please provide a description of the transition from fuel with zircaloy cladding to Zirlo cladding. The submittal references both the topical reports for the Vantage 5 and the Vantage+ fuel designs. What fuel design will be used and referenced and describe how any transition core effects will be evaluated. Please provide references for any NRC approvals related to the use of Zirlo cladding at Farley.

SNC Response No. 5

The primary effect of transitioning from fuel with zircaloy cladding to ZIRLO cladding is the impact of the ZIRLO properties on the LOCA analysis. As described in Reference 1, the VANTAGE-5 and VANTAGE+ designs are mechanically and hydraulically equivalent, so there are no additional transition core effects. The Farley Units are currently operating with zircaloy clad fuel and ZIRLO clad fuel (VANTAGE+). LOCA analyses have been performed to support the use of both cladding materials. The Farley Units will initially operate at uprated power with zircaloy clad fuel and ZIRLO clad fuel until the transition to ZIRLO is completed. The LOCA analyses which were performed to support the uprated conditions address the use of both cladding materials. The non-LOCA analyses for power uprate also addressed the effects of zircaloy cladding and ZIRLO cladding as appropriate. NRC approval for the use of ZIRLO cladding in the Farley Units was obtained in Reference 2, below.

Response No. 5 References

1. Davidson, S. L., Nuhfer, D. L., "VANTAGE+ Fuel Assembly Reference Core Report," WCAP-12610-P-A, April 1995.
2. Farley Unit 1 License Amendment 110 and Farley Unit 2 License Amendment 101, letter from NRC to SNC, dated September 8, 1994.

W/rgm - 7/22/97

NRC Question No. 6

Please describe and justify the flow streaming effects that would permit a −1 °F bias to the temperature measurements (page 7-10 of topical).

SNC Response No. 6

In 1991, Westinghouse identified to plants that cold leg temperature measurements with two cold leg RTDs in different circumferential locations demonstrated a temperature gradient. The cold leg temperature gradient is primarily due to different lengths of steam generator tubing and resulting differences in heat transfer rates. The magnitude of the temperature gradient was plant-specific and was affected by: 1) the reactor coolant system (RCS) loop configuration; 2) the reactor coolant pump (RCP) model; and 3) the location of the cold leg RTD(s). Thus, with a temperature gradient in the cold leg and depending on the circumferential placement of the RTD, the cold leg RTD measurement will be either higher or lower than the bulk T-cold temperature.

The narrow range T-cold measurement is electronically combined with the T-hot measurement to form Tavg. Farley uses a Median Signal Selector to select the median Tavg value of the three RCS loops. The median Tavg is used as an input to the Reactor (i.e., Rod) Control System to position the control rods. Therefore, a temperature gradient in the cold leg results in an increased uncertainty in the indicated Tavg of the Reactor Control System. This additional uncertainty is conservatively treated in the calculation of the Reactor Control System uncertainty and in the Farley safety analysis.

Between June 1992 and June 1993 T-cold data was collected on a monthly basis from Farley Units 1 and 2. In all three loops of both units, readings were obtained from both the narrow range and wide range RTDs. A subsequent evaluation was performed by Westinghouse to determine if the cold leg streaming penalty used in the Farley uncertainty analysis was sufficient. The evaluation concluded that the cold leg streaming allowance used in the uncertainty analysis was conservative for Farley operation at 2652 Mwt - core power. The cold leg streaming penalty will remain bounding for the Farley Uprate to 2775 Mwt - core power.

W/wm - 7/31/97

NRC Question No. 7

The analysis Tave window used is 567.2 - 577.2°F; however, the allowable window in the technical specifications is larger. Describe why the analysis window is not used in the technical specifications.

SNC Response No. 7

Prior to the performance of NSSS analyses for power uprate, the NSSS analyses for Farley Nuclear Plant were based on a full power design Tavg value of 577.2°F and applicable uncertainties. The Farley units have been operated at full power at Tavg values less than but close to this maximum design Tavg value. The current Farley Technical Specifications encompassed the design Tavg value as the maximum steady-state Tavg value for full power operation in DNB Parameters Table 3.2-1 (i.e., indicated Reactor Coolant System Tavg ≤ 580.7°F). The Technical Specifications DNB Parameter Tavg limit includes an uncertainty allowance that is based on both the uncertainties assumed in the NSSS analyses and the uncertainties associated with the instrumentation used to perform the periodic Tavg surveillance.

Operation at the uprated power level will potentially result in slightly lower values of full power Tavg than operation at the current power level. To accommodate this potential reduction in full power Tavg, power uprate analyses have been performed for a range of full power Tavg values (i.e., 567.2°F to 577.2°F), which will bound the full power Tavg value(s) for operation at the uprated power level. Applicable Tavg uncertainties were also included in the uprate analyses. The information provided in the Power Uprate NSSS Licensing Report describes the analyses performed for the range of full power Tavg values and the assumed uncertainties. The proposed Technical Specifications for uprate will continue to specify a single value for indicated Reactor Coolant System Tavg (i.e., ≤ 580.3°F), which is based on the maximum design Tavg assumed in the power uprate analyses and applicable uncertainties.

W/rgm - 7/22/97 & SNC/mge - 7/31/97

NRC Question No. 8

The submittal indicates that using the lowest reactor coolant system (RCS) flow is always used in the analysis. In some analysis, like the main steamline break, higher flow can be more limiting. Please describe how RCS flow is modeled when higher flow is limiting.

SNC Response No. 8

The analysis of the FSAR Chapter 15 steamline break transient in support of the Farley Nuclear Plant power uprate models minimum RCS flow (Thermal Design Flow) as noted above. Reactor coolant flow can affect the results of the steamline break, both directly through the DNB ratio calculations and indirectly through the system transient. The impact of increasing the reactor coolant flow by 10%, in both the system transient and in the DNB evaluation, was discussed generically in WCAP-9226, Revision 1, "Reactor Core Response To Excessive Secondary Steam Releases," January 1, 1978 (Proprietary). The results of the case assuming more reactor coolant flow were slightly better than the reference case, with the additional reactor coolant flow being a slight penalty for the system transient but a large benefit with respect to DNB. All of the non-LOCA Chapter 15 analyses performed for the Farley plant uprate model either the Minimum Measured Flow or Thermal Design Flow. The LOCA analyses model Thermal Design Flow. As such, no non-LOCA or LOCA analyses model a maximum RCS flow, which is consistent with the current Farley plant licensing basis analyses.

Power uprate evaluations for NSSS systems or components used higher RCS flow (e.g., best estimate flow or mechanical design flow) if appropriate.

W/gs - 7/22/97 & W/rs - 7/24/97

NRC Question No. 9

Please provide an evaluation of your ability to shut the plant down considering all the changes to the main steam pressure, steam flow, RCS flow, residual heat removal flow, and component cooling water temperatures. On page 4-14 of the topical report, a 50°F/hr cooldown rate is assumed. Please evaluate the ability to achieve this cooldown rate for affected scenarios in the Farley Licensing Basis (i.e., single train cooldown, natural circulation cooldown, etc.).

SNC Response No. 9

Section 4.2.1.2 (page 4-14) of the Power Uprate NSSS Licensing Report describes the evaluation performed to assess the ability of the steam generator Atmospheric Relief Valves (ARVs) to cooldown the plant from no load (hot standby) conditions to hot shutdown conditions. This evaluation addressed the increase in NSSS thermal power and concluded that the ARVs are adequate based on the range of operating conditions for power uprate. Consequently, the steam generator ARVs are adequate to achieve a 50°F/hour cooldown rate from hot standby to hot shutdown as assumed in the Farley licensing basis in support of two train and single train cooldowns. Under natural circulation conditions, cooldown from hot standby to hot shutdown is limited by operating procedures to a normal cooldown rate less than 50°F/hour; consequently, natural circulation cooldown is not limiting relative to the adequacy of the steam generator ARVs for power uprate conditions. Note that power uprate related changes to full power main steam pressure and main steam flow do not impact the ability of the ARVs to cooldown the plant from hot standby to hot shutdown conditions.

Section 4.1.4 of the Power Uprate NSSS Licensing Report describes the evaluation performed to assess the ability of the Residual Heat Removal System (RHRS) to cooldown the plant from hot shutdown to cold shutdown and/or refueling conditions. In addition to addressing the increase in NSSS thermal power, the evaluation incorporated conservative assumptions regarding the performance of the Component Cooling Water (CCW) System and the Service Water (SW) System. The evaluation included analyses for the two train (design basis) cooldown and the single train cooldown scenarios as described in the Farley FSAR. For both two train and single train cooldowns, the evaluation showed that the time required to cooldown from hot shutdown (350°F) to cold shutdown (200°F) and/or refueling (140°F) is lengthened under power uprate conditions. However, the evaluation showed that for both the two train and single train cooldown scenarios, the plant possessed the ability to cooldown from 350°F to 200°F within the Technical Specifications time requirement of 30-hours. The extension in cooldown times associated with power uprate conditions was identified as an economic consideration and not a safety-related consideration. Furthermore, the extension in cooldown times calculated for power uprate conditions was shown to be primarily dependent on the conservative input assumptions for CCW and SW performance and not on the increase in NSSS thermal power.

Since the radiological dose analysis for several of the FSAR transients (e.g., steam generator tube rupture) include the assumption that RHRS operation can be initiated within 8 hours after event initiation, an evaluation was also performed to show that this assumption is valid for power uprate conditions.

W/rgm - 7/31/97

NRC Question No. 10

Page 4-20 indicates that the analysis of a partial load rejection caused an oscillating plant response. Please provide greater detail regarding the calculated results and any associated effects. Include details regarding the magnitude and length of time that the oscillations occurred.

SNC Response No. 10

This question pertains to the 50% load rejection transient which was analyzed as a part of the Condition I analyses for the Farley power uprate. This transient was analyzed at full power for both high and low Tavg conditions and assumed automatic rod control and steam dump control systems. The conservative core conditions for this transient is beginning of core life (BOL), and therefore, a BOL moderator temperature coefficient (MTC) was assumed.

The results of the 50% load rejection at high Tavg was acceptable, but at low Tavg (full power Tavg of 567.2°F), the results showed slightly oscillatory plant responses. The plant responses were acceptable at BOL with a full power Tavg of 570°F. The oscillatory plant response at low Tavg and BOL conditions is due to the combined effect of the less negative MTC and smaller proportional band of the steam dump loss of load controller (6.1°F). With a smaller steam dump proportional band and rods in automatic control, the steam dump valves were demanded open/close for a relatively small change in the RCS temperature. The small changes in the RCS temperature are caused by the automatic action of the rod control system (rods move in or out) coupled with the MTC effect. The oscillatory plant responses at these conditions were observed up to 400 seconds. After 400 seconds, the plant responses were stable.

As stated in the report, an oscillatory plant response during and following a 50% load rejection transient is not due to the power uprate, rather it is due to a combined effect of MTC, smaller steam dump proportional band, and automatic rod control system actions. The plant became stable after 400 seconds. Therefore, these oscillations would not lead to an unsafe plant condition following a 50% load rejection transient.

W/sa - 7/22/97

NRC Question No. 11

No methodologies are presented for many evaluations performed in the topical report Chapter 5. Please reference the methodologies used in Chapter 5 of the topical report calculations (i.e., rod drop times, core bypass flows, and flow induced vibration).

SNC Response No. 11

Using the Farley FSAR for comparison purposes, the SNC response to general question No. 2 above describes the areas where the NSSS analyses for power uprate used different (i.e., new or improved) methodologies. In the other NSSS analyses areas, the power uprate analyses used the same basic methodologies as the analyses currently described in the Farley FSAR.

The SNC response to additional question No. 10 on page 59 provides information describing the methodologies used in the structural evaluations performed for the reactor vessel and reactor internals.

The following provides additional information regarding the methodologies used for the analysis areas (i.e., rod drop time, core bypass flows, and flow induced vibration) cited in the example to this question.

Rod Drop Times

The RCCA scram performance assessment for power uprate involved the following general steps.

1. Adjust the current analytical model (consisting of values for parameters that describe geometry of driveline components, component mechanical interaction relationships, hydraulic resistances of flow paths, RCCA/drive rod assembly weight, and system operating conditions) to account for the new system operating conditions being considered due to power uprating.

2. Assess the impact of such changes in primary system operating conditions on the limiting RCCA scram characteristics used in the plant accident analyses.

Core Bypass Flow

For power uprate, the THRIVE computer code was used to determine the hydraulic behavior of coolant flow within the reactor internals system (i.e., vessel pressure drops, core bypass flows, RPV fluid temperatures and hydraulic lift forces) by solving the mass and energy balances for the Farley Nuclear Plant reactor internals fluid system.

Bypass flow is the total amount of reactor coolant flow bypassing the core region and is not considered effective in the core heat transfer process.

The principal core bypass flow paths are:

1. Baffle/Barrel Region;
2. Vessel Head Cooling Spray Nozzles;
3. Core Barrel - Reactor Vessel Outlet Nozzle Gap;
4. Fuel Assembly - Baffle Plate Cavity Gap; and
5. Fuel Assembly Thimble Tubes.

Fuel assembly hydraulic characteristics and system parameters, such as inlet temperature, reactor coolant pressure and flow, were used in conjunction with the THRIVE code to determine the impact of the new uprated conditions on the total core bypass flow.

Flow Induced Vibration

Flow-induced vibrations (FIV) of pressurized water reactor internals have included in-plant tests, scale model tests, as well as tests in fabricators' shop and bench tests of components, along with various analytical investigations. For power uprate, the vibration response of the Farley reactor internals were obtained using the principle of dimensional analysis and scaling laws. The test results of a 3 loop plant, similar in design to the Farley units, were scaled to the Farley uprated operating parameters.

W/rgm - 7/31/97

NRC Question No. 12

Please provide a reference for the NRC approval of the use of the Westinghouse revised thermal design procedure at Farley and discuss how the transition core effects will be addressed with this thermal design approach.

SNC Response No. 12

The use of the Westinghouse revised thermal design procedure was approved for use at Farley as part of the approval for implementation of VANTAGE-5 fuel (Reference 1). The transition core effects for the VANTAGE-5 fuel were addressed by the NRC-approved methodology specified in References 2 through 6. These references are applicable for the uprating.

Response No. 12 References

1. Letter from S. T. Hoffman (NRC) to W. G. Hairston III dated March 11, 1992, regarding Farley Unit 1 License Amendment 92 and Farley Unit 2 License Amendment 85.
2. Davidson, S. L., and Iorii, J. A., "Reference Core Report - 17x17 Optimized Fuel Assembly," WCAP-9500-A, May 1982.
3. Letter from E. P. Rahe (Westinghouse) to Miller (NRC), dated March 19, 1982, NS-EPR-2573, WCAP-9500 and WCAPs-9401/9402, "NRC SER Mixed Core Compatibility Items."
4. Letter from C. O. Thomas (NRC) to E. P. Rahe (Westinghouse), "Supplemental Acceptance No. 2 for Referencing Topical Report WCAP-9500," January 1983.
5. Schueren, P. and McAtee, K. R., "Extension of Methodology for Calculating Transition Core DNBR Penalties," WCAP-11837-P-A, January 1990.
6. Letter from S. R. Tritch (Westinghouse) to R. C. Jones (NRC) "VANTAGE 5 DNB Transition Core Effects." ET-NRC-91-3618, September 1991.

W/rgm - 7/22/97

NRC Question No. 13

Is Southern Nuclear requesting staff approval of the moderator temperature coefficient limit curve presented in Chapter 7 of the submittal (Figure 7.2-1) or merely showing the currently approved limit curve?

SNC Response No. 13

The moderator temperature coefficient limit curve presented in Figure 7.2-1 is the currently approved limit for the Farley Units. This limit was approved as part of the approval for VANTAGE-5 fuel (Reference 1).

Response No. 13 References

1. Letter from S. T. Hoffman (NRC) to W. G. Hairston III (SNC) dated March 11, 1992, regarding Farley Unit 1 License Amendment 92 and Farley Unit 2 License Amendment 85.

W/rgm - 7/22/97

NRC Question No. 14

Chapter 7.3 presents a number of fuel rod design acceptance limits. For each, please describe where the limit is derived or referenced and if the limit has been accepted by the NRC generically or for Farley specifically.

SNC Response No. 14

The acceptance limits for the key fuel rod design criteria presented in Chapter 7.3 were established in the following references.

Rod Internal Pressure - The NRC-approved rod internal pressure acceptance limit was generically defined in WCAP-8963-P-A, Reference 1. This acceptance limit has been applied and approved for subsequent generic topicals addressing extended burnup with zircaloy cladding (WCAP-10125-P-A, Reference 2) and VANTAGE+ (WCAP-12610-P-A, Reference 3).

Clad Corrosion - The NRC-approved acceptance limits for clad temperature (metal oxide interface temperature) and hydrogen pickup were generically defined for zircaloy in WCAP-10125-P-A, Reference 2. The NRC-approved acceptance limits for clad temperature (metal oxide interface temperature) and hydrogen pickup were generically defined for ZIRLO in WCAP-12610-P-A, Reference 3.

Clad Stress and Strain - The NRC-approved acceptance limits for fuel rod clad stress and strain were generically defined for zircaloy in WCAP-10125-P-A, Reference 2 and for ZIRLO in WCAP-12610-P-A, Reference 3.

Response No. 14 References

1. Risher, D. H. (Editor), "Safety Analysis for the Revised Fuel Rod Internal Pressure Design Basis,"WCAP-8963-P-A, August 1978.
2. Davidson, S. L. (Ed.), et al., "Extended Burnup Evaluation of Westinghouse Fuel," WCAP-10125-P-A, December 1985.

3. Davidson, S. L., Nuhfer, D. L., "VANTAGE+ Fuel Assembly Reference Core Report," WCAP-12610-P-A, April 1995.

W/rgm - 7/22/97

NRC Question No. 15

Please verify that the fluence value used to support the technical specification pressure/temperature limit curves (effective through 16 and 14 effective full power years for Units 1 and 2, respectively) will not be exceeded at the higher full power limit.

SNC Response No. 15

The results of the analyses performed to assess the impact of power uprate on reactor vessel integrity are summarized in Section 5.1.2 of the Power Uprate NSSS Licensing Report. As stated in this section, new heatup and cooldown curves were calculated for 36 EFPY at the new uprated power conditions. These calculations included consideration of the increased neutron fluence due to power uprate. The revised heatup and cooldown curves are included in the proposed Unit 1 and Unit 2 Pressure Temperature Limits Reports (PTLRs) submitted to the NRC by letter dated July 23, 1997. NRC approval of the PTLRs is required prior to startup to support implementation of power uprate.

SNC/tws - 7/24/97

QUESTIONS REGARDING COMPLIANCE WITH 10 CFR PART 50, APPENDIX G, AND 10 CFR PART 50, APPENDIX H

NRC Question No. 1

Provide the projected maximum end-of-life (EOL) fluences at the inner diameter of the Joseph M. Farley Nuclear Plant (Farley) reactor pressure vessels (RPVs) based on the new uprated power conditions and the revised adjusted reference temperature values for the Farley Units 1 and 2 RPV beltline materials.

SNC Response No. 1

Consistent with Paragraph 5.1.2 of the Power Uprate NSSS Licensing Report, revised heatup and cooldown curves have been calculated for 36 EFPY at power uprate conditions. The revised heatup and cooldown limits and related information are included in the Technical Specifications amendment request associated with the PTLR which was provided to the NRC by letter dated July 23, 1997. The maximum end-of-life fluences at the inner diameter of the Farley RPVs, based on the new uprated power, were provided in Table 5-4 of the proposed Unit 1 and Unit 2 PTLRs. The corresponding adjusted reference temperatures associated with the new uprated power are provided in Table 5-5 of the proposed Unit 1 and Unit 2 PTLRs.

SNC/tws - 7/24/97

NRC Question No. 2

Provide an assessment of how the proposed power uprate will affect the current pressure-temperature (P-T) limit curves in the Farley Unit 1 and Unit 2 Technical Specifications. If the uprated power conditions will change (increase) the adjusted reference temperatures for the most limiting beltline materials in the Farley RPVs, new P-T limit curves should be submitted based on the new uprated conditions and fluences.

SNC Response No. 2

Revised pressure-temperature limit curves valid to 36 EFPY, based on the new uprated power, were provided in Figures 2-1 and 2-2 of the proposed Unit 1 and Unit 2 PTLRs.

SNC/tws - 7/24/97

NRC Question No. 3

Provide an assessment of how the proposed thermal uprate will affect the EOL upper-shelf energies for the Farley Units 1 and 2 RPV beltline materials. Include appropriate calculations and figures based on the guidelines of Regulatory Guide 1.99, Rev. 2, "Radiation Embrittlement of Reactor Vessel Material," dated May 1988.

SNC Response No. 3

The EOL Upper Shelf Energies (USE) for Farley Units 1 and 2 beltline materials, based on the fluence associated with the new uprated power, were determined using the methods described in

Regulatory Guide 1.99, Rev. 2. As shown in Tables A and B, which follow this section, the USE projected at EOL (36 EFPY) are greater than 50 ft-lb and continue to meet the requirements of 10 CFR 50, Appendix G.

SNC/tws - 7/24/97

NRC Question No. 4

Will the revised neutron fluences as a result of the uprated conditions affect the surveillance capsule withdrawal schedule for the Farley Units 1 and 2 RPVs?

SNC Response No. 4

The surveillance capsule withdrawal schedules have been revised to reflect the increased fluence associated with the new uprated power using the NRC-approved methods described in WCAP-14040-NP-A. The revised surveillance capsule withdrawal schedules were provided in Table 3-1 of the proposed Unit 1 and Unit 2 PTLRs.

SNC/tws - 7/24/97

NRC Question No. 5

The staff is providing copies of the Pressurized Thermal Shock (PTS) Summary Files and the Upper Shelf Energy (USE) Summary Files for the Farley Units 1 and 2 RPV beltline materials, as obtained from the NRC Reactor Vessel Integrity Database (RVID), Version 2 .0.2 Update the Summary Files to the extent possible based on the most current data for the Farley RPVs, and using the uprated fluence values for the plants. The updated Summary Files may be used to assist you in your responses to Items 1. - 3. listed above.

SNC Response No. 5

SNC has reviewed the RVID PTS and USE Summary Files provided by NRC letter dated July 24, 1997. Attachment II provides the requested information based on the most current data for the Farley RPVs using the uprated fluence values.

TABLE A

Predicted End of License (36 EFPY) Upper Shelf Energy Values for the Farley Unit 1 Reactor Vessel Beltline Materials

Beltline Material	Wt. % Cu	1/4T Fluence (n/cm^2)	Unirradiated USE	Decrease in USE[a]	Projected EOL USE
Inter. Shell Plate B6903-2	0.13	2.48×10^{19}	99 ft-lb	27 ft-lb	72 ft-lb
Inter. Shell Plate B6903-3	0.12	2.48×10^{19}	87 ft-lb	23 ft-lb	64 ft-lb
Lower Shell Plate B6919-1	0.14	2.48×10^{19}	86 ft-lb	24 ft-lb	62 ft-lb
using S/C data	- -	2.48×10^{19}	86 ft-lb	20 ft-lb	66 ft-lb
Lower Shell Plate B6919-2	0.14	2.48×10^{19}	86 ft-lb	24 ft-lb	62 ft-lb
Inter. Shell Longitudinal Weld Seams 19-894 A & B (Heat # 33A277)	0.24	7.67×10^{18}	149 ft-lb	54 ft-lb	95 ft-lb
using S/C data	- -	7.67×10^{18}	149 ft-lb	34 ft-lb	115 ft-lb
Circumferential Weld 11-894 (Heat # 6329637)	0.21	2.48×10^{19}	104 ft-lb	46 ft-lb	58 ft-lb
Lower Shell Longitudinal Weld Seams 20-894 A & B (Heat # 90099)	0.20	7.67×10^{18}	82.5 ft-lb	27 ft-lb	55 ft-lb

NOTES:

a) Per Regulatory Guide 1.99, Revision 2.

SNC/tws - 7/24/97

TABLE B

Predicted End of License (36 EFPY) Upper Shelf Energy Values for the Farley Unit 2 Reactor Vessel Beltline Materials

Beltline Material	Wt. % Cu	1/4T Fluence (n/cm^2)	Unirradiated USE	Decrease in USE[a]	Projected EOL USE
Inter. Shell Plate B7203-1	0.14	2.34×10^{19}	100 ft-lb	28 ft-lb	72 ft-lb
Inter. Shell Plate B7212-1	0.20	2.34×10^{19}	100 ft-lb	35 ft-lb	65 ft-lb
using S/C data	- -	2.34×10^{19}	100 ft-lb	39 ft-lb	61 ft-lb
Lower Shell Plate B7210-1	0.13	2.34×10^{19}	103 ft-lb	28 ft-lb	75 ft-lb
Lower Shell Plate B7210-2	0.14	2.34×10^{19}	99 ft-lb	28 ft-lb	71 ft-lb
Inter. Shell Longitudinal Weld Seam 19-923 A (Heat # HODA)	0.02	7.48×10^{18}	131 ft-lb	23 ft-lb	108 ft-lb
Inter. Shell Longitudinal Weld Seam 19-923 B (Heat # BOLA)	0.03	7.48×10^{18}	148 ft-lb	26 ft-lb	122 ft-lb
using S/C data	- -	7.48×10^{18}	148 ft-lb	13 ft-lb	135 ft-lb
Circumferential Weld 11-923 (Heat # 5P5622)	0.14	2.34×10^{19}	102 ft-lb	35 ft-lb	67 ft-lb
Lower Shell Longitudinal Weld Seams 20-923 A & B (Heat # 83640)	0.05	7.48×10^{18}	126 ft-lb	23 ft-lb	103 ft-lb

NOTES:

a) Per Regulatory Guide 1.99, Revision 2.

SNC/tws - 7/24/97

QUESTIONS REGARDING STEAM GENERATOR INTEGRITY

NRC Question No. 1

Summarize the results of the assessment that evaluates the effect of the power uprate on (1) the minimum wall thickness of steam generator tubes, (2) the number of steam generator tubes susceptible to anti-vibration bar wear, and (3) susceptibility of the steam generator tubing to various forms of degradation mechanisms.

SNC Response No. 1

The results of the assessments of the impact of power uprate on these areas are summarized below.

1. The minimum required wall thickness, following the guidance of Regulatory Guide 1.121, was determined to be 0.022 inches (44% of wall thickness) based on maintaining a safety margin of 3 against burst during normal operations. This minimum wall thickness is acceptable for meeting the loading criteria of Regulatory Guide 1.121, including a postulated accident concurrent with an SSE.

2. The anti-vibration bars (AVB) have been replaced on Farley Units 1 and 2. Since the AVB replacement, AVB wear has not been observed as an active degradation mechanism at Farley. Power uprate is not expected to introduce AVB wear.

3. The susceptibility of steam generator tubing to various forms of degradation is described in Section 5.7.4 of the Power Uprate NSSS Licensing Report with additional information provided in response to questions regarding steam generator integrity Nos. 5 and 6 which follow. The conclusions of the tube degradation evaluation is that power uprate will not have a significant impact on the susceptibility of steam generator tubes to various forms of degradation (ODSCC and PWSCC). As described in Section 5.7.4, power uprate will not have a significant impact on T-hot, the most important parameter with respect to steam generator tube degradation. Consequently, a significant increase in steam generator tube degradation due to power uprate is not expected.

W/gw & rs - 7/31/97 & SNC/rem - 7/31/97

NRC Question No. 2

It is not clear to the staff whether the Southern Nuclear Operating Company, Inc. (SNC), has assessed the structural integrity of the Farley steam generator tubing under uprated power conditions in accordance with Regulatory Guide 1.121 methodology. Clarify and provide the basis for your conclusions.

SNC Response No. 2

The structural integrity of the SG tubes was evaluated and determined to be acceptable using Regulatory Guide 1.121 methodology. Evaluations were performed for minimum wall thickness (as discussed in the response to part (1) of question No. 1 above) under the loading conditions prescribed by Regulatory Guide 1.121.

W/gw & rs - 7/31/97 & SNC/rem - 7/31/97

NRC Question No. 3

Clarify whether SNC has considered performing any additional surveillance methods to monitor for changes in steam generator degradation as a result of the uprated power conditions. Provide the basis for your conclusions.

SNC Response No. 3

Prior to each steam generator inspection, an assessment is made as to what degradation mechanisms are active in the Farley steam generators and in similar steam generators throughout the industry. Inspection plans are developed which will ensure adequate detection ability for the degradation mechanism in the affected location in the steam generator. Consequently, any new degradation mechanisms and any significant increase in degradation rate should be detectable by the planned steam generator inspections.

The repair criteria contained in the Technical Specifications will continue to apply to power uprate conditions with the exception of the Unit 2 criteria for F*. The F* distance will be revised from 1.54 inches to 1.6 inches as a result of the increased normal differential pressure between the primary and secondary (as described in the response to question No. 8 below regarding steam generator integrity). Although a 40% repair criteria does exist in the Farley Technical Specifications, Farley does not use the 40% repair criteria unless a qualified sizing technique exists for the mechanism of concern. The voltage-based alternate repair criteria will continue to be used at Farley in accordance with current Technical Specifications and Generic Letter 95-55.

W/gw & rs - 7/31/97 & SNC/rem - 7/31/97 95-05

NRC Question No. 4

Section 5.7.1 discussed the structural evaluation of steam generator internals. Provide a list of components that were evaluated and results of the evaluation.

SNC Response No. 4

The steam generator components which were evaluated for their structural adequacy at the power uprate conditions were: the tube/tubesheet weld; tubes; channel head/tubesheet junction; tubesheet/shell junction; divider plate; feedwater nozzle; secondary manway opening and bolts; and steam nozzle. With the exception of the secondary manway bolts, the structural analysis showed that all of the components experienced maximum stresses and fatigue usage factors less than the allowable limits. In terms of maximum stresses, the tube/tubesheet weld yielded the greatest stress compared to the allowable limit, with the ratio of calculated/limit being 0.976. With regard to the fatigue usage, the secondary manway bolts had a calculated fatigue usage of 1.18 at 40 years. It was determined that, in order to obtain an acceptable fatigue usage value, the bolts would need to be replaced before the 34th year of operation. SNC plans on replacing the bolts which have not already been replaced to comply with this requirement. The divider plate had the second highest fatigue usage, with a value of 0.944 under normal and upset conditions. Additional information regarding the structural evaluation performed for the steam generator internals is provided in the SNC response to additional question No. 7 below.

W/rs - 7/22/97

NRC Question No. 5

Section 5.7.3 discussed the fatigue evaluation of U-bends from a fluid vibration viewpoint. It is not clear to the staff whether SNC has evaluated the small radius (rows 1 and 2) U-bends for degradation from stress corrosion cracking. Clarify and provide the basis for your conclusions.

SNC Response No. 5

The evaluations performed to assess the impact of power uprate on stress corrosion cracking are described in Section 5.7.4 and included an assessment of the impact of PWSCC, including the effects of power uprate on the kinetics of PWSCC for the steam generator heat transfer tubing. At both Farley Unit 1 and Unit 2, the small radius U-bends were given a thermal stress relief to reduce the residual manufacturing stresses. As described in Section 5.7.4, the only stress that is effected by the power uprate conditions is the throughwall pressure stress which increases moderately due to the increase in normal primary-to-secondary ΔP from approximately 1435 psi to 1463 psi. In combination with the reduction in residual stress, the modest increase in throughwall pressure stress due to power uprate is negligible in terms of enhancing the initiation and propagation of PWSCC in the small radius U-bends.

In order to ensure stress corrosion cracking has not increased in the row 1 and 2 U-bends, all row 1 and 2 U-bends will be inspected at the refueling outage following implementation of power uprate.

W/gw & rs - 7/31/97 & SNC/rem - 7/31/97

NRC Question No. 6

Section 5.7.4.2 stated that the power uprate will not significantly affect outside diameter stress corrosion cracking (ODSCC). Clarify which regions of the steam generator tubes were assessed with respect to ODSCC, including whether the power uprate would affect ODSCC at tube support plates. Provide the basis for your conclusions.

SNC Response No. 6

The impact of changes to primary and secondary side pressures and temperatures due to power uprate was evaluated with respect to corrosion in the tube support plate (TSP) crevices, corrosion within the sludge pile (SP) at the top of the tubesheet, and corrosion on the tubing free span (FS).

The beneficial effect of lowering secondary temperature tends to be stronger than the deleterious effect of increasing the applied stress in the tube support plate (TSP) crevices and on tubing free spans (FS). No credit is taken for the lower secondary temperatures within the sludge pile (SP); hence, a small increase in the expected ODSCC rate in the SP is predicted. However, the SP region in all Farley steam generators is routinely inspected during each refueling outage. Any significant increase in the magnitude or rate of degradation should be readily detectable. There is little difference in the predictions for the two units.

W/gw & rs - 7/31/97 & SNC/rem - 7/31/97

NRC Question No. 7

SNC has implemented voltage-based alternate tube repair criteria in the Technical Specifications for Farley Units 1 and 2. Discuss whether the uprated power conditions would affect the structural and leakage analyses that are recommended in Generic Letter 95-05. Provide the basis for your conclusions.

SNC Response No. 7

As discussed in Section 5.7.5, the impact of power uprate on the repair criteria contained in the Technical Specifications, including the voltage-based alternate repair criteria (ARC) for the tube support plate intersections, was evaluated. The evaluation showed that the 2 volt alternate repair criteria value in the Technical Specifications is not sensitive to the increase in normal primary-to-secondary ΔP associated with power uprate since it is a limit set by Generic Letter 95-05 based on steam generator tube size. Furthermore, the upper voltage repair limit, determined specifically for each operating cycle, is based on a safety margin of 1.4 X steamline break differential pressure. The steamline break differential pressure is based on "an assumed differential pressure across the tube walls equal to the pressurizer safety valve steeping plus 3 percent for the valve accumulation, less atmospheric pressure in faulted steam generators," per Generic Letter 95-05. Since the steamline break differential pressure is not being changed due to power uprate, the upper voltage repair limit is not directly affected by power uprate. However, a change to the upper voltage repair limit may be required due to possible changes in the structural limit or flaw growth rate. The structural limit may change due to changes in the NRC database for establishing the voltage corresponding to the tube structural limit. As stated earlier, the upper voltage repair limit is determined for each individual operating cycle.

W/gw & rs - 7/31/97 & SNC/rem - 7/31/97

NRC Question No. 8

Section 5.7.5 stated that an analysis was performed to revise the F* criteria in the Farley Unit 2 Technical Specifications to bound the best estimate steam generator outlet pressure at 2785 MWt. It is not clear to the staff whether SNC will submit for staff review a license amendment to revise the F* criteria specified in the Farley Unit 2 Technical Specifications. Please clarify.

SNC Response No. 8

The change to the Farley Unit 2 Technical Specification F* criteria is included in the proposed Technical Specifications changes for power uprate. Specifically, Technical Specification 3/4.4.6 value for "F* Distance" has been revised from 1.54 inches to 1.6 inches.
W/rs - 7/22/97

QUESTIONS REGARDING ATTACHMENT 6, SECTION 2.15 - SAFETY-RELATED ELECTRICAL EQUIPMENT QUALIFICATION

NRC Question No. 1

Provide the list of required and qualified radiological doses of the individual safety-related electrical equipment before and after power uprate. In your submittal, it is stated that "for safety-related electrical equipment with uprate doses not bounded by the original design basis, radiological doses at uprate conditions were compared against the dose threshold limits used for the individual components or equipment." We believe that the doses should be bounded by the test report values, not by the dose threshold limits. Explain the differences and why your method is acceptable.

SNC Response No. 1

In the context of the EQ evaluation prepared for power uprate, the terminology of dose threshold limits and test report values means the same. The limiting qualification radiation dose for each room was determined from the System Component Evaluation Worksheet for each Environmental Qualification Package which documents the qualification or tested radiation dose.

B/sk - 7/16/97

NRC Question No. 2

Furnish composite loss-of-coolant accident/main steamline break containment temperature profiles before and after power uprate case on the same plot that extends to 30 days. Identify where the composite temperature power uprate profiles are not enveloped by the design basis profile.

SNC Response No. 2

The power uprate composite temperature profile was superimposed on the existing composite temperature profile. This plot, "FNP Composite LOCA/MSLB Containment Temperature Profile," is attached to the end of this section. Differences between the power uprate composite profile and the existing composite profile are discussed in detail in response to question 3 below.

B/sk - 7/31/97

NRC Question No. 3

Explain why the (power) uprated temperature that exceeds the existing design basis profile by a few degrees (i.e., 5°F) toward the end of the composite temperature profiles (greater than 30,000 seconds) is acceptable by having enough margin between 70 seconds and 10,000 seconds. Should the end of the composite temperature profiles be longer or shorter than 30,000 seconds (8.3 hours)?

SNC Response No. 3

The power uprate composite temperature profile was compared to the existing composite temperature profile and to the applicable equipment qualification test profiles. The review concluded that the power uprate composite temperature profile will not have any significant impact to the environmental qualification of the EQ components at FNP.

As is customary, the 30-day composite temperature profiles (power uprate and existing) were plotted on a semi-log graph. The plot, "FNP Composite LOCA/MSLB Containment Temperature Profile," is attached. For discussion purposes, the composite temperature profile has been divided into three sections. Section 1 is the initial 150 seconds of the postulated accident; Section 2 is from 150 seconds to 7000 seconds; and, Section 3 is from 7000 seconds to 30 days. However, to aid in viewing, Sections 1 and 2 were also plotted on a linear scale from 0 to 7000 seconds; this plot, "FNP Composite LOCA/MSLB Containment Temperature Profile (0 - 7000 seconds)," is also attached. Each plot section is discussed below.

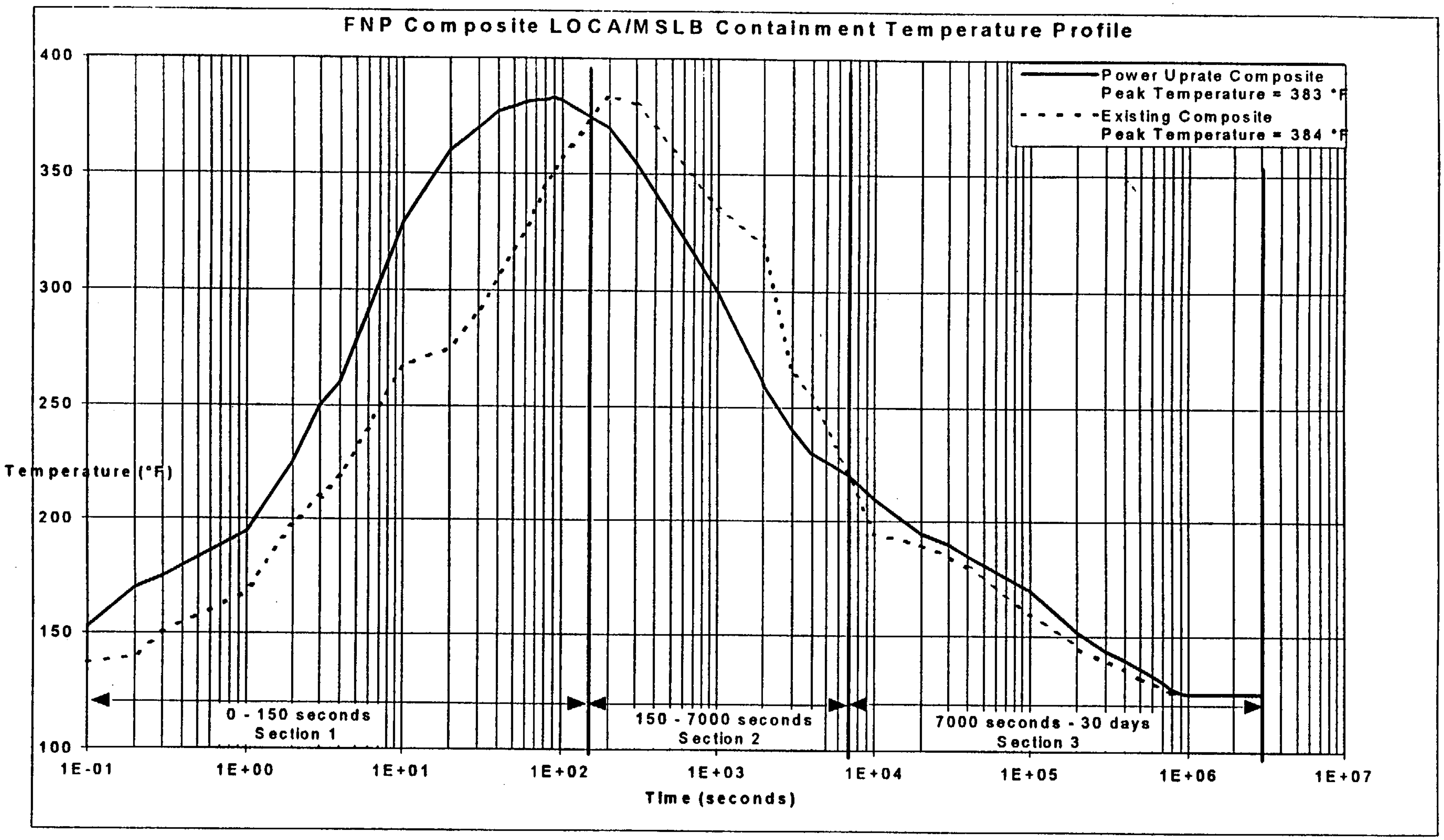
Section 1 is the temperature ramp-up portion of the profile. This ramp-up is due to the postulated main steam line breaks and is for a short duration (150 sec.). Inspection of the ramp-up section of plot with linear scale suggests that the existing ramp-up and the power uprate ramp-up would lead to similar heat transfer to the equipment within the containment. The ramp-up results in exposing the equipment to a high-temperature for a short duration. Since the equipment mass does not heat up instantaneously due to thermal transfer from the environment to the equipment surface, the equipment does not reach thermal equilibrium for short-duration events. Based on engineering experience with transient thermal heat transfer analysis (thermal lag analysis), the short-duration ambient temperature excursion is covered by the existing test data. Therefore, the initial power uprate temperature ramp-up is enveloped by the applicable equipment qualification test data.

For Section 2, the power uprate composite temperature profile is enveloped by the existing composite temperature profile.

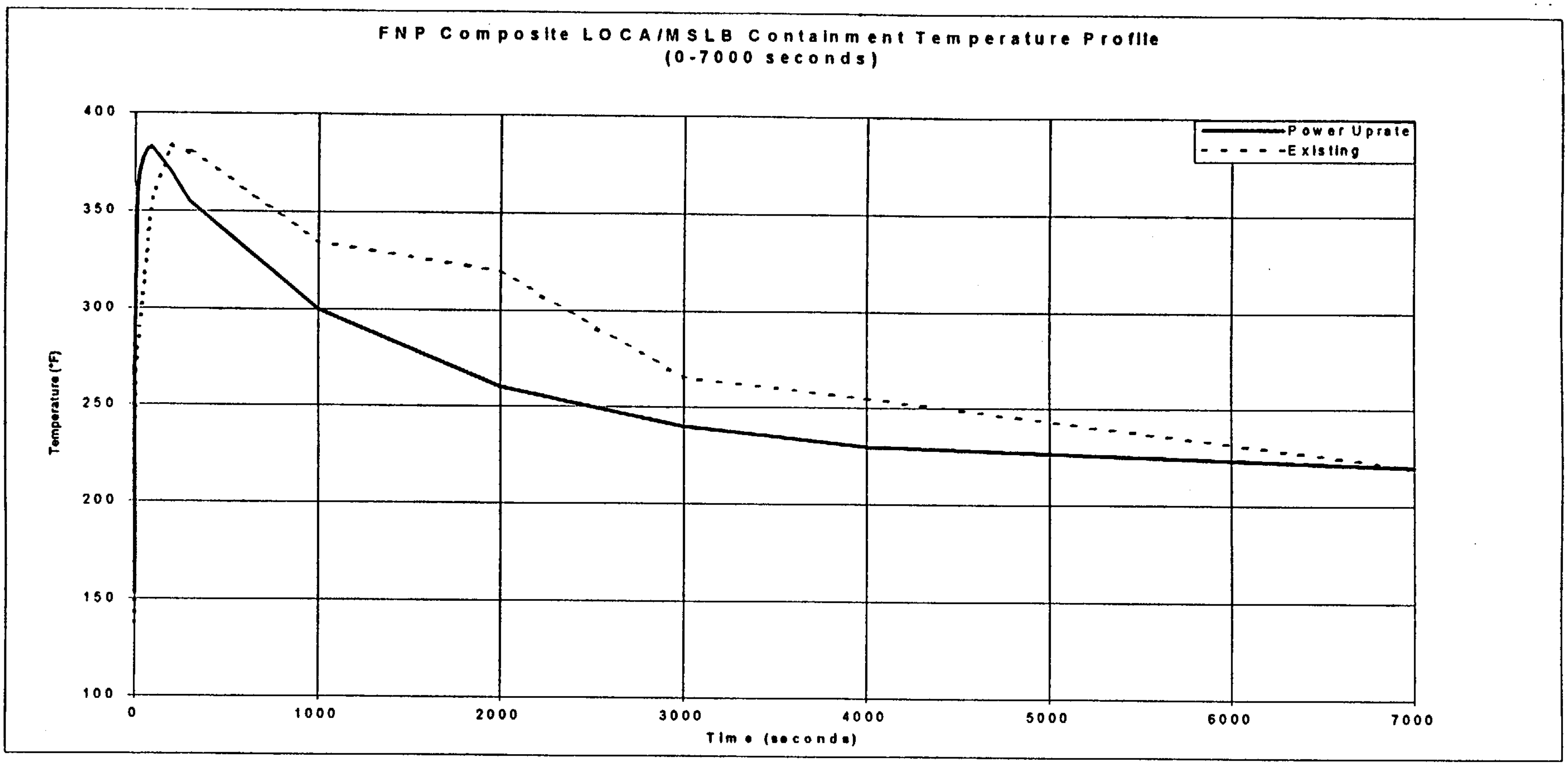
Although the power uprate composite temperature profile in Section 3 exceeds the existing composite temperature profile by approximately 5°F, a review of the test profiles for EQ equipment inside containment indicates that there is sufficient margin in the test profiles to envelop the power uprate composite temperature profile. In addition, the EQ equipment has been qualified for the peak temperature of 384°F which exceeds the power uprate peak temperature of 383°F. Further, the duration at the higher temperatures (i.e., >250°F) is longer for the existing profile than for the power uprate profile.

Based on the above discussion, the FNP designers concluded that the existing equipment qualification was not impacted by the power uprate composite profile.

B/sk & jl- 7/31/97



FNP Composite LOCA/MSLB Containment Temperature Profile
400
350
300
250
200
150
100
Temperature (°F)
Power Uprate Composite
Peak Temperature = 383 °F
Existing Composite
Peak Temperature = 384 °F
0 - 150 seconds
Section 1
150 - 7000 seconds
Section 2
7000 seconds - 30 days
Section 3
1E-01
1E+00
1E+01
1E+02
1E+03
1E+04
1E+05
1E+06
1E+07
Time (seconds)



FNP Composite LOCA/MSLB Containment Temperature Profile
(0-7000 seconds)
Temperature (°F)
400
350
300
250
200
150
100
0
1000
2000
3000
4000
5000
6000
7000
Time (seconds)
Power Uprate
Existing

QUESTIONS REGARDING ATTACHMENT 6, SECTION 2.20 - MISCELLANEOUS ELECTRICAL REVIEWS

NRC Question No. 1

Provide the impact of the load, voltage, and short circuit values for power uprate conditions at all levels of the station auxiliary electrical distribution system (i.e., the onsite power system, the main generator, and its step-up transformer).

SNC Response No. 1

As briefly discussed in BOP Licensing Report, Section 20.0, "Miscellaneous Electrical Reviews," the plant electrical distribution system was evaluated for potential impact associated with the Farley power uprating. Additional information pertaining to this engineering evaluation is presented herein.

In order to support power uprate, the Reactor Coolant Pump (RCP) motors and Condensate Pump motors will be required to deliver slightly higher horsepower (HP) over their current operating values. The additional HP for the RCP motors is required to support the uprate RCS Tavg temperature range and the reduced RCS loop flow rates assumed for full power operation. The additional HP requirement for the Condensate motors is due to the increased feedwater flow rate. There are no other electrical load changes on the plant electrical distribution system as a result of power uprate.

To evaluate the impact of the RCP and Condensate Pump HP increases on the Farley Electrical Distribution System, computer simulations were performed using the Southern Company Services (SCS) Station Auxiliary (STAUX) Program. The STAUX program provides load flow, voltage, and short circuit values at all buses, load centers, and MCCs.

Impact to 4160V System

Impact to Loading - The increase in loading on the non-1E 4160V buses as a result of power uprate represents only 2% or less of the total loading on each 4160V bus. There is no impact on the Class 1E 4160V buses. The total loading after power uprate does not exceed the continuous current ratings of the breakers and transformers.

Voltage Impact - Steady state and starting voltages did not decrease more than 0.4% as a result of power uprate.

Impact to Short Circuit Values - No change in short circuit values occurred on the 4160V bus as a result of power uprate.

Impact to 600V System

Impact to Loading - No change in loading on the 600V buses is required as a result of power uprate.

Voltage Impact - Steady state and starting voltages did not decrease more than 0.4% as a result of power uprate.

Impact to Short Circuit Values - No change in short circuit values occurred on the 600V bus as a result of power uprate.

Impact to 208/120V System

Impact to Loading - No change in loading on the 208/120V buses are required as a result of power uprate.

Voltage Impact - Steady state and starting voltages did not decrease more than 0.4% as a result of power uprate.

Impact to Short Circuit Values - No change in short circuit values occurred on the 208/120V bus as a result of power uprate.

Impact to Main Generator

Load Impact - The generator capability was reviewed to evaluate the impact of increased generator load for power uprate. A detailed discussion of this review is provided in the BOP Licensing Report, Section 2.6, "Main Generator and Auxiliaries." This review confirmed that the generator is capable of operation at the specified uprated MW value.

Voltage Impact - Generator bus voltage range is maintained within a range of 95% - 105% of generator rated voltage (22kV) by design. The actual bus voltage is dictated by system conditions and will not be significantly impacted by power uprate. Calculations performed in support of power uprate show that, for the generator minimum voltage of 95%, the Reactor Coolant Pump buses A, B, and C (which are normally powered from the unit auxiliary transformers) have sufficient voltage. In addition, the bus loads on buses A, B, and C will not be subjected to unacceptably high voltages when the generator voltage is at 105%.

Short Circuit Impact - Calculated short circuit values on the generator bus do not change as a result of power uprate.

Impact to Generator Step-Up Transformer

Load Impact - The increase in MW loading is within the design temperature and load ratings of the transformer, although operating temperature may increase.

Voltage Impact - The additional MW output from the generator will increase the voltage drop through the main power transformer. The actual high (transmission) side winding voltage is set by the system voltage schedule. The low (generator) side winding voltage is adjusted to maintain the high side voltage schedule and kept within operating and equipment limits and therefore is not significantly impacted as a result of power uprate.

Short Circuit Impact - Calculated short circuit values on the generator bus and the 230kV and 500kV buses do not change as a result of power uprate.

SCS/wb & tlc & jms- 7/31/97

NRC Question No. 2

Provide the result of an analysis which was used to conclude that: (1) the bounding steady-state voltages and motor starting voltages remain within acceptable limits, (2) emergency diesel generator loadings are within the design ratings, and (3) there are no impacts on relay trip set points for loss of voltage or degraded grid voltage protective scheme due to power uprate.

SNC Response No. 2

To evaluate the impact on the Farley Electrical Distribution System, computer simulations were performed using the SCS STAUX Program. The STAUX program provides load flow, steady state voltage, and short circuit values for all buses, load centers, MCCs and selected equipment. It also provides motor starting voltage dip for selected motors.

(1) The steady-state and motor starting voltages did not decrease more than 0.4%. These voltages are within the minimum required voltages for plant equipment important to safety. Important non-Class 1E equipment voltages were also verified to remain within acceptable limits.

(2) The Farley Diesel Generator (DG) load calculation was reviewed to determine the potential impact of power uprate on the ability of the DGs to perform their safety-related function; in addition, the impact of power uprate on the ability of the DGs to perform their safety-related function under Station Blackout (SBO) scenarios was also evaluated. No requirements to add or change out safety-related plant equipment or to increase loading of existing safety-related plant equipment beyond the equipment ratings already analyzed in the DG load calculation were identified. The engineering reviews determined that the DGs are not impacted by power uprate and that the DGs will continue to perform their intended safety-related function.

(3) The increased electrical load (i.e., for the RCP and Condensate Pump motors) associated with the Farley power uprate occurs only on non-1E 4160V buses. The corresponding load increase to each startup transformer represents a very small percentage of the transformer total load rating. As a result, the additional voltage drop through the transformer is very small (< 0.4%), and therefore, Class 1E bus voltages are not significantly impacted. This small change is not sufficient to impact the voltage setpoints of the Farley LOSP and degraded grid protection scheme.

SCS/wb & tlc & jms- 7/31/97

NRC Question No. 3

State what would be the negative impact on the stability of the units by increasing Farley generation to 920 MWe per unit.

SNC Response No. 3

The increase in power does not impact the stable operation of the Farley Units for expected design basis conditions. Under normal expected operating conditions, the Farley Units are stable and safety-related buses will continue to be supplied by the off-site preferred power source for single contingency events and faults.

In general, as the megawatt loading of a generating Unit increases for a given system load level, the margin of stability for that Unit will decrease. Thus, for abnormal system alignments such as an outage of a critical transmission line, increasing the MW output of the Units results in a slight decrease in the margin of stability at a given system load level. Load limitations with a transmission line out of service are currently addressed by plant operating procedures with consideration given to how long the line will be out of service, system load requirements, and operational status of the Units.

SCS/wb & tlc & jms- 7/31/97

NRC Question No. 4

Clarify the statement, "There is a slight decrease in the margin of stability for limited faults during valley load conditions. Normal system growth offsets the slight decrease in margin of stability within 3 to 5 years." Please elaborate on how the generation increase due to its power uprate will decrease the stability margin, but the stability will improve later on when the system load grows.

SNC Response No. 4

As discussed in the response to miscellaneous electrical question No. 3 above, in general, as the megawatt loading of a generating Unit increases for a given system load level, the margin of stability for that Unit will decrease. This is because, as the unit load increases, the Unit will tend to become less stable with respect to the system. Increasing the Farley generation to 920MW results in a slight decrease in the margin of stability for any given system load level when compared to the existing generation at Farley. On this same basis, as the system load increases (for a given Unit output), the Unit will tend to become more stable with respect to the system. Thus, normal system load growth will have a favorable impact on the stability margin for the Farley Units resulting in an increase in the stability margin.

SCS/wb & tlc & jms- 7/31/97

QUESTIONS REGARDING ATTACHMENT 6, SECTION 2 - BALANCE OF PLANT PROGRAM DESCRIPTION

NRC Question No. 1

The increase in the probability of turbine overspeed and associated turbine missile production due to plant operations at the proposed uprated power level have not been addressed. Please demonstrate that plant operations at the proposed uprated power level will not increase the probability of turbine overspeed and associated turbine missile production.

SNC Response No. 1

The degree of overspeed protection for the turbine is a function of the entrapped energy at the time of trip, the system design and the turbine speed at the time when the trip is initiated. If the final speed of the turbine following an overspeed trip does not exceed the design overspeed, there is no increased probability of missile production.

Governor and interceptor valves throttle closed when turbine speed is ≥ 103% of rated speed and may reopen to maintain rated speed. At 111% of rated speed the mechanical overspeed mechanism functions to trip the turbine.

The design overspeed trip points were set such that the unit should not achieve a final overspeed greater than the design overspeed of 120%. The energy available to the turbine immediately after a trip will carry the turbine speed beyond that of the trip device setting. For the Farley units, it has been calculated that a mechanical overspeed trip at 111% will not allow the unit to achieve a final overspeed greater than 120%. This calculation was based upon the maximum calculated (Max Calc) design points for the unit. Although the new Max Calc throttle flow will exceed the old Max Calc throttle flow, the level of change in the parameters critical to overspeed (entrapped energy) was within the tolerance of the original overspeed trip setting calculation. The increase in throttle flow was within 0.8%, and the new throttle pressure and LP inlet pressures were less than the original Max Calc point. The enthalpy was virtually the same. Therefore, the 111% calculated trip point for the mechanical trip device is still valid at the uprated conditions and will not result in a final speed greater than the design speed of 120% and therefore will not increase the probability of turbine overspeed and associated turbine missile production. In addition, secondary backup overspeed protection from the DEH control system is provided by a turbine trip at 111.5% of rated speed.

SCS/mp - 7/22/97 & jms 8/1/97

NRC Question No. 2

With regard to spent fuel pool (SFP) decay heat loads and cooling, provide the following information:

a. The heat load and corresponding peak calculated SFP temperature for each case analyzed.

b. Is full core offload a general practice for routine refueling? If it is, how many trains of the SFP cooling system will be available/operable prior to refueling operation?

SNC Response No. 2

a. The following table provides the requested information. Note that temperatures were only calculated for cases 1-3 to demonstrate compliance with the Standard Review Plan. Temperatures were not calculated for the Best Estimate Full Core Offload or post-refueling cases. The total heat load for the Best Estimate Full Core Offload case is bounded by the BOC and EOC Full Core Offload cases. The post-refueling cases were analyzed only for heat loads used in evaluating component cooling water system performance and the ultimate heat sink maximum post-accident temperature.

Case #	1	2	3	4	5A	5B	5C
Case Description	Partial Core Offload (1 / 2 trains)	Full Core Offload (BOC) (1 / 2 trains)	Full Core Offload (EOC) (1 / 2 trains)	Full Core Offload (Best Estimate)	Post Refueling (25 days)	Post Refueling (40 days)	Post Refueling (65 days)
Heat Load (MBTU/hr)	22.1 / 11.05	37.0 / 18.5	36.5 / 18.25	30.3	15.4	13.6	12.0
Max. SFP Temperature (°F)	147 / 126	175 / 140	174 / 140	—	—	—	—

b. Full core offload is a general plant practice. Plant procedures require a minimum of one operable cooling train. Plant procedures further require that fuel handling operations be suspended and actions taken to restore cooling upon receipt of the high temperature alarm.

SCS/jvi - 7/24/97

QUESTIONS REGARDING ATTACHMENT 5, SECTION 6 - NSSS ACCIDENT ANALYSES

NRC Question No. 1

In order to evaluate the impact of future plant changes, equipment problems, or other issues for the power uprate, please provide the doses for the control room operator, EAB, and LPZ for the five accidents listed in Attachment 6. Please demonstrate that the doses for the control room operators comply with the regulatory criteria for control room doses given in 10 CFR Part 50, Appendix A, General Design Criterion 19.

SNC Response No. 1

EAB and LPZ doses were reported in Attachment 6, Section 2.16, of the license amendment request. Control room doses have historically been provided in FSAR Table 15.4-17 for the limiting LOCA in accordance with NUREG-75/087; revised control room doses for the limiting LOCA at power uprate conditions were provided in Attachment 6, Section 2.16, of the license amendment request. These results meet 10 CFR 50, Appendix A, General Design Criterion 19. Note that control room dose calculations were not performed for the five accidents referenced above because the NRC SRP does not require such dose calculations.

SCS/jaw - 7/9/97 & SNC/mge - 7/31/97

NRC Question No. 2

For all of the accidents listed in Attachment 6, provide the assumptions along with the calculational methodology to support the dose analysis results, i.e., the modeling, assumptions, input data, and results of the dose analysis for each postulated accident should be provided. What power level was used for the accidents listed in Attachment 6. What is the core radionuclide inventory based on. What meteorological data are the X/Q calculations based on.

SNC Response No. 2

Input parameters for LOCA were provided in Tables 2.16-1 through 2.16-3 of Attachment 6 of the license amendment request, and the results were provided in Tables 2.16-4 and 2.16-5. Input parameters for the remaining accidents are provided in the following tables (A - I). The results for the remaining accidents were provided in Attachment 6, Section 2.16, of the license amendment request.

The power level considered for radiological consequence calculations was 2831 MWt. The core inventory calculations were based on the methods and parameters discussed in Attachment 5, Section 7.6 (and the associated tables) of the license amendment request.

EAB and LPZ atmospheric dispersion factors are based on the data in FSAR Section 2.3 and are shown in FSAR Table 2.3-12. Revised control room atmospheric dispersion factors (X/Qs) were developed based on the meteorological data listed in the FSAR for the period of April 1972 through March 1973. The joint frequency distribution tables for the data set were obtained from FSAR Table 2.3-8A, and the results were shown in Table 2.16-3 of Attachment 6 of the license amendment request.

TABLE A

PARAMETERS USED IN RCP LOCKED ROTOR ANALYSES

Core thermal power (MWt)	2831
Offsite power	Lost
Fuel defects (%)	NA[a]
Steam generator tube leak rate prior to and during accident (gpd/generator)	150
Activity released to RCS	20% of gap inventory
Secondary side iodine activity	0.1 μCi/gm DEI_{131}
Iodine partition factor in steam generators	0.01
Duration of plant cooldown by secondary system after accident (h)	8
Steam release from three steam generators (lbs)	427,000 (0-2 h) 820,000 (2-8 h)
Feedwater flow to three steam generators (lbs)	574,000 (0-2 h) 908,000 (2-8 h)

a. RCS activity (including iodine spike) is negligible compared to 20% gap release.

SCS/jaw-7/9/97

TABLE B

PARAMETERS USED IN LOSS OF ac POWER ANALYSES

Core thermal power	2831 MWt
Steam generator tube leak rate prior to and during accident	150 gpd per generator
Offsite power	Lost
Fuel defects	1%[a]
Iodine partition factor in steam generators prior to and during accident	0.1
Secondary side iodine activity	0.1 μCi/gm dose equivalent I_{131}
Duration of plant cooldown by secondary system after accident	8 h
Steam release from three steam generators	448,000 lb (0-2 h) 861,000 lb (2-8 h)
Feedwater flow to three steam generators	603,000 lb (0-2 h) 953,000 lb (2-8 h)
Meteorology	Accident (see FSAR Appendix 15B)

a. A pre-existing iodine spike of 30 μCi/gm dose equivalent I_{131} is assumed.

SCS/jaw-7/11/97

TABLE C

PARAMETERS USED IN WASTE GAS DECAY TANK RUPTURE ANALYSES

Core thermal power	2831 MWt
Plant load factor	1.00
Activity released from GWPS	Contents of one tank
Tank contents	See attached table
Number of tanks (normal operation)	6.00
Iodine partition factor in volume control tank	0.01
Time of accident	Immediately after isolation of tank from GWPS
Meteorology	Accident (see FSAR Appendix 15B)

SCS/jaw -7/11/97

TABLE D

WASTE GAS DECAY TANK INVENTORY
(Technical Specification Limit for Conservative Analysis)

Isotope	Activity (Ci)
Xe-133	6.77×10^4
Xe-133m	1.02×10^3
Xe-135	6.77×10^2
Xe-135m	2.88×10^0
Xe-138	2.63×10^{-1}
Kr-85	(a)
Kr-85m	8.03×10^1
Kr-87	9.15×10^0
Kr-88	8.53×10^1

a. The dose conversion factor for Kr_{85} is much less than the other isotopes, and it accumulates much slower than the other isotopes, thus it is conservatively ignored.

SCS/jaw -7/11/97

TABLE E
PARAMETERS USED IN STEAM LINE BREAK ANALYSES

Core thermal power (MWt)	2831
Steam generator tube leak rate prior to accident and initial 8 h following accident (gpd/per generator)	150
Offsite power	Lost
Fuel defects (%)	1[a]
Iodine partition factor for initial steam release from defective steam generator	1.0
Iodine partition factor in non-defective steam generators prior to and during accident	0.1
Time to isolate defective steam generator (h)	8
Initial steam release from defective steam generator (lb) (min)	473,000 (0-30)
Steam release from two non-defective steam generators (lb)(h)	339,000 (0-2) 730,000 (2-8)
Feedwater flow to two non-defective steam generators (lb)(h)	442,000 (0-2) 791,000 (2-8)
Meteorology	Accident (see FSAR Appendix 15b)

a. A pre-existing iodine spike of 30 μCi/gm or an accident initiated iodine spike 500 times the normal appearance rate is assumed.
SCS/jaw - 7/11/97

TABLE F

PARAMETERS USED IN STEAM GENERATOR TUBE RUPTURE ANALYSES

Core thermal power (MWt)	2831
Steam generator tube leak rate prior to and during accident (gpd/generator)	150
Offsite power	Lost
Fuel defects (%)	1[a]
Iodine partition factors in non-defective steam generators prior to and during accident	0.1
Iodine partition factor in defective steam generator prior to and during accident	0.1
Time to isolate defective steam generator (min)	30
Duration of plant cooldown by secondary system after accident (h)	8
Steam release from defective steam generator (lb)(min)	73,300 (0-30)
Steam release from two non-defective steam generators (lb)(h)	400,000 (0-2) 889,000 (2-8)
Feedwater flow to two non-defective steam generators (lb)(h)	320,000 (0-2) 936,000 (2-8)
Reactor coolant released to the defective steam generator (lb)	150,000
Meteorology	Accident (see FSAR Appendix 15B)

a. Pre-accident iodine spike of 30 μCi/gm or accident initiated iodine spike 500 times the normal appearance rate.

SCS/jaw- 7/11/97

TABLE G

ACTIVITIES IN HIGHEST RATED ASSEMBLY AT TIME OF FUEL HANDLING ACCIDENT

Isotope	Fuel Cladding Gap (100 hr. after Reactor Shutdown) (Ci)[a]
I-131	6.99×10^4
I-132	----
I-133	6.22×10^3
I-134	----
I-135	5.34×10^0
Kr-85m	----
Kr-85	2.39×10^3
Kr-87	----
Kr-88	----
Xe-131m	7.31×10^2
Xe-133	9.57×10^4
Xe-133m	1.52×10^3
Xe-135	2.06×10^1
Xe-135m	----
Xe-138	----

a. Total core Ci x gap fraction x radial peaking factor/157 assemblies.

SCS/jaw - 7/11/97

TABLE H
PARAMETERS USED IN FUEL HANDLING ACCIDENT ANALYSIS

Parameter	Accident in Spent-Fuel Pool (Auxiliary Building)	Accident in Refueling Canal (Containment)
Core thermal power	2831 MWt	2831 MWt
Time between plant shutdown and accident	100 h	100 h
Minimum water depth between tops of damaged fuel rods and water surface	23 ft	23 ft
Damage to fuel assembly	All rods ruptured	All rods ruptured
Fuel assembly activity	Highest powered fuel assembly in core region discharged	Highest powered fuel assembly in core region discharged
Activity release from assembly	Gap activity in ruptured rods	Gap activity ruptured rods
Radial peaking factor	1.7 (maximum)	1.7
Decontamination factor in water		
Elemental iodine (99.75%)	133	133
Organic Iodine (0.25%)	1	1
Noble gases	1	1
Amount of mixing in building	1.0×10^5 ft^3	6.6×10^5 ft^3
Iodine filtration system	Penetration room filtration system	Containment purge system
Filter efficiencies		
Elementary iodine	90%	90%
Organic iodine	70%	30%
Atmospheric dilution factors	Accident (see FSAR Table 15B-2)	Accident (see FSAR Table 15B-2)

TABLE I
PARAMETERS USED IN ROD EJECTION ACCIDENT ANALYSES

Core thermal power (MWt)	2831
Containment free volume (ft^3)	2.03×10^6
Fuel defects (%)	1[(a)]
Steam generator tube leak rate prior to and during accident (gpd per generator)	150
Failed fuel (%)	10 of fuel rods in core
Activity released to reactor coolant from failed fuel and available for release	
Noble gases (%)	10.0 of gap inventory
Iodines (%)	10.0 of gap inventory
Melted fuel (%)	0.25 of core inventory
Activity released to reactor coolant from melted fuel and available for release	
Noble gases (%)	0.25 of core inventory
Iodines (%)	0.25 of core inventory
Iodine partition factor in steam generators prior to and during accident	0.1
Plateout of iodine activity released to containment (%)	50
Form of iodine activity in containment available for release	
Elemental iodine (%)	91
Methyl iodine (%)	4
Particulate iodine (%)	5
Containment leak rate (%/day)	0.15 (0-24 h) 0.075 (1-30 days)
Offsite power	Lost
Steam dump from relief valves (lb)	426,000
Duration of dump from relief valve (s)	98
Time between accident and equalization of primary and secondary system pressures (s)	2500
Steam dump to condenser (lb)	0.0
Meteorology	Accident (FSAR App. 15B

a. Iodine activity at 0.5 and 0.1 μCi/gm DEI_{131} in the RCS and secondary systems respectively.
SCS/jaw- 7/11/97

NRC Question No. 3

For the Control Rod Ejection Accident, explain why releases from the secondary side were not included in your evaluation.

SNC Response No. 3

Attachment 5, Section 6 of the license amendment request addressed only the core and NSSS response to a Control Rod Ejection Accident and provided core releases to the RCS. Attachment 6 of the license amendment request addressed the radiological consequences of the accident and included both RCS leakage through the steam generators and activity contained in the secondary side water. Also see SNC response to NSSS accident analyses question No. 2 above.

SCS/jaw - 7/11/97

ADDITIONAL QUESTIONS

NRC Question No. 1

In regard to Sections 5.1.1 and 5.2.3 of Reference 2, provide the maximum calculated stress and cumulative fatigue usage factor (CUF) at the critical locations of the reactor pressure vessel (RPV) and internal components (such as RPV nozzles, core plates, core barrel, baffle/barrel, and fuel assembly, etc.). Also, provide the allowable Code limits, and the Code and Code edition used in the evaluation for the power uprate. If different from the Code of record, provide the necessary justification.

SNC Response No. 1

Regarding Section 5.1.1. and the reactor vessel, the maximum CUF at all of the limiting locations, except those in the CRDM housings, the bottom head instrumentation nozzles, the closure head flange and the closure studs, increase from the previously calculated values. However, the increases are generally minimal, and all of the CUFs remain under the 1.0 limit with margin. The greatest increase in CUF is 0.157 at the core support pads. The Code edition used was the Code of record, which is the ASME B&PV Code, Section III, 1968 Edition through Summer 1970 Addenda.

The stress intensities and CUFs for the reactor vessel critical locations are provided in Table A, which follows.

TABLE A STRESS INTENSITIES AND FATIGUE USAGE FACTORS FOR THE REACTOR VESSEL		
Location	**$P_L + P_b + Q$ Range**	**U_c**
Outlet Nozzles	Nozzle: 54.7 ksi < 3 S_m = 80.1 ksi Safe End: 40.5 ksi < 3 S_m = 49.2 ksi	Nozzle: 0.1299 < 1.0 Support: 0.2871 < 1.0
Inlet Nozzles	Nozzle: 47.83 ksi < 3 S_m = 80.1 ksi Safe End: 45.16 ksi (Unit 1) < 3 S_m = 49.8 ksi 43.77 ksi (Unit 2) < 3 S_m = 49.8 ksi	Nozzle: 0.0276 < 1.0 Support: 0.1693 < 1.0
Main Closure Flange Region		
1. Closure Head Flange	62.08 ksi < 3 S_m = 80.1 ksi	0.2259 < 1.0
2. Vessel Flange	77.98 ksi < 3 S_m = 80.1 ksi	—
3. Closure Studs	104.4 ksi < 3 S_m = 110.3 ksi	0.9211 < 1.0
CRDM Housings	45.95 ksi < 3 S_m = 69.9 ksi	0.5688 < 1.0
Vessel Wall Transition	31.72 ksi < 3 S_m = 80.1 ksi	0.0603 < 1.0
Bottom Head to Shell Juncture	36.53 ksi < 3 S_m = 80.1 ksi	0.0052 < 1.0
Bottom Head Instrumentation Tubes	57.28 ksi < 3 S_m = 69.9 ksi	0.2201 < 1.0
Core Support Pads	42.79 ksi < 3 S_m = 80.1 ksi	0.2224 < 1.0

Regarding Section 5.2.3 and the reactor internals, since the Farley reactor internals were designed prior to the introduction of Subsection NG of the ASME B&PV Code Section III, a plant specific stress report on the reactor internals was not required. However, the criteria described in Subsection NG of the ASME Code were utilized. Component qualifications were based on the use and extension of existing analyses which had been performed for similar plants which were designed and built strictly in accordance with ASME Subsection NG requirements. In addition, a new analysis of the lower core plate was performed in order to remove conservatism.

Maximum Calculated Stress, Allowable, and CUF at Critical Locations of Reactor Internal Components

REACTOR INTERNAL COMPONENT (3)	MAX STRESS Pm	CODE LIMIT Sm	MAX STRESS Pm+Pb	CODE LIMIT 1.5Sm	MAX STRESS Pm+Pb+Q	CODE LIMIT 3Sm	CUF
Lower Core Plate (5.2.3.2)	3.2 ksi	16.2 ksi	5.85 ksi	24.3 ksi	31.6 ksi	48.6 ksi	.046
Baffle-Barrel Bolt (5.2.3.3.3)	NA (1)	NA (1)	NA (1)	NA (1)	NA (1)	NA (1)	.917
Upper Core Plate (5.2.3.3.4)	6.5 ksi	16.4 ksi	13.2 ksi	24.6 ksi	70.2 ksi (2)	49.2 ksi (2)	.08 (2)

Notes:

(1) The baffle-barrel bolts were qualified by test.

(2) The combined primary and secondary stresses exceed the limit. An elastic-plastic fatigue analysis in accordance with NG-3228.3 was performed to demonstrate that the cumulative fatigue usage attributed to the combination of the low cycle events plus all other cyclic events did not exceed the value of 1.0.

(3) The review of other components, such as the Core Barrel (5.2.3.3.1) and Baffle Plate (5.2.3.3.2), showed very high margins and the uprated conditions did not significantly effect the structural integrity of the component.

W/rs - 7/31/97

NRC Question No. 2

In regard to Section 5.2.2.2 of Reference 2, provide an assessment of flow-induced vibration of the reactor internal components due to power uprate.

SNC Response No. 2

For uprated conditions, it was determined that the flow-induced vibration (FIV) loads on the guide tubes and the upper support columns increase by approximately 1.9%. Previous FIV analyses on the guide tubes and the upper support columns show that there exist sufficient margins to

accommodate this small increase in the FIV loads. Consequently, the structural integrity of the Farley reactor internals remains acceptable with regard to flow-induced vibrations.
W/rs - 7/22/97

NRC Question No. 3

In reference to Section 5.4 of Reference 2, provide an evaluation of the control rod drive mechanism with regard to the stress and fatigue usage as a result of the power uprate. Also, provide the allowable Code limits for the critical components evaluated, and the Code and Code edition used for the evaluation. If different from the Code of record, justify and reconcile the differences.

SNC Response No. 3

The evaluation performed for the control rod drive mechanisms (CRDMs) addressed the ASME Code structural considerations for the pressure boundary components of both the part-length CRDMs, which are not in use but the pressure boundary components remain present, and the full-length CRDMs. The code and code edition applicable to the Farley CRDMs is the 1970 Summer Addenda of the ASME Section III-NB Code.

The evaluation performed for the CRDMs used as input the NSSS PCWG Parameters for power uprate as shown in Table 2.1-2 of the Power Uprate NSSS Licensing Report and the NSSS design transients for power uprate as discussed in Section 3.0 of the Power Uprate NSSS Licensing Report. During normal operation, the CRDMs experience the RCS pressure and RCS "vessel outlet" temperature as shown in Table 2.1-2 of the Power Uprate NSSS Licensing Report. The PCWG parameters for power uprate show that RCS pressure does not change but that "vessel outlet" temperature increases slightly (i.e., to a maximum of 613.3 °F). Despite the slight increase in temperature, the normal operating conditions for power uprate remain bounded by the original generic analysis (as documented in the generic code reports) which used the maximum design temperature of 650°F.

With respect to part-length CRDM stress and fatigue, the current lowest margin of safety on the primary plus secondary stress intensity as shown in the generic analysis is 32.6% for the analyzed case of 2500 psi and 650°F. Review of the design transients for power uprate showed that the maximum transient pressure could be approximately 6% above the 2500 psi used in the generic analysis. Since the generic analysis showed a margin of 32.6%, it was concluded that adequate margin existed at power uprate conditions relative to the code stress intensity limit of 3Sm. Furthermore, it was concluded that all ΔPs due to power uprate design transients were less than the Code definition of "significant fluctuation" value and that no fatigue consideration is required since the generic waiver remains unchanged.

With respect to full-length CRDM stress and fatigue, the slight increase in "vessel outlet" temperature will not change thermal stress results and has a negligible effect on CRDM material properties. To assess the impact of power uprate on the full-length CRDMs, the location of maximum stress and fatigue (i.e., canopy of the upper joint) was chosen for conservative numerical evaluation. The results of this conservative evaluation showed that the generic evaluations of primary plus secondary stress ranges including the simplified elastic-plastic analyses performed in the generic report remain applicable. The power uprate evaluation regarding fatigue also used the upper canopy since it has the largest fatigue usage factor. The conservative power uprate evaluation showed a total usage factor of 0.672 which was less than the conservative fatigue usage factor of 0.858 calculated in the generic report and which is less than the Code fatigue usage limit of 1.0. Based on the numerical comparison at the location of maximum fatigue, it was concluded that the results of the generic analysis are valid for power uprate conditions.

In summary, the power uprate evaluations for the part-length and full-length CRDM pressure boundary components showed that the Code criteria are satisfied at power uprate conditions.

W/rs - 7/22/97

NRC Question No. 4

In reference to Section 5.5 of Reference 2, provide the methodology and assumptions used for evaluating the reactor coolant piping systems for the power uprate. Also, provide the calculated maximum stress, critical locations, allowable stress limits, and the Code and Code edition used in the evaluation for the power uprate. If different from the Code of record, justify and reconcile the differences.

SNC Response No. 4

The methodologies and assumptions used in evaluating the impact of power uprate on the Reactor Coolant Loop (RCL) piping and supports are consistent with the original analyses. As discussed in the response to general question No. 2, the PS+CAEPIPE computer code was used in the power uprate evaluation. The evaluation addressed changes to the PCWG parameters (as shown in Table 2.1-2 of the Power Uprate NSSS Licensing Report), NSSS design transients, and LOCA interface loads.

In all cases, except for the RCL crossover leg usage factor, the existing evaluations as documented in the original analyses remained unchanged. The crossover leg usage factor experienced a minor increase from 0.0511 to 0.1319 due to the design transients for power uprate; however, the usage factor remained below the specified acceptance limit of 0.2 for break postulation. This assessment was done in compliance with the ASME B&PV Code Section III, 1971 Edition and all addenda thru Summer 1971. This is the same Code version and addenda used in previous evaluations. In summary, the results of the power uprate evaluation for RCL piping and supports (including primary equipment nozzles, primary equipment supports, pressurizer safety and relief and piping and pressurizer surge line) showed only one variation from previously calculated values and satisfy the requirements of the identified ASME code.

W/rs - 7/24/97

NRC Question No. 5

Discuss the analytical methodology and assumptions used in evaluating pipe supports, nozzles, penetrations, guides, valves, pumps, heat exchangers, and anchors at the power uprate conditions. Were the analytical computer codes used in the evaluation different from those used in the original design-basis analysis? If so, identify the new codes and provide justification for using the new codes and state how the codes were qualified for such applications.

SNC Response No. 5

The response to general question No. 2 regarding WCAP-14723 describes the areas where the NSSS analyses for power uprate used different (i.e., new or improved) methodologies. In the other NSSS analyses areas, the power uprate analyses used the same basic methodologies as the analyses currently described in the FSAR.

The SNC responses to general question No. 11 and additional question No. 10 provide additional information describing the methodologies used in evaluations performed for the reactor vessel and reactor internals.

W/rs - 7/22/97

NRC Question No. 6

In regard to Section 5.6 of Reference 2, provide a comparison of the design parameters and transients for the reactor coolant pump (RCP) against the power uprate condition. Also, provide the maximum-calculated stress and CUF for the RCP, the allowable Code limits, and the Code and Code edition used in the evaluation for the power uprate. If different from the Code of record, provide a justification.

SNC Response No. 6

The evaluation performed for the RCPs used as input the NSSS PCWG Parameters for power uprate as shown in Table 2.1-2 of the Power Uprate NSSS Licensing Report and the NSSS design transients for power uprate as discussed in Section 3.0 of the Power Uprate NSSS Licensing Report. This table provides a comparison of the design parameters. A comparison of the design transients (i.e., type and number of occurrences during the 40 year license period) for Farley power uprate to the original design transients for Farley is provided in Table A, which follows.

With respect to RCP stress and fatigue, the ΔPs and ΔTs associated with the power uprate design transients were reviewed to determine if there were any changes that would qualify as a "significant fluctuation" per the Code definition and thus require consideration relative to fatigue. It was concluded that all ΔPs due to the power uprate design transients were less than the Code definition of "significant fluctuation" value and that no fatigue consideration is required. The design transients were then reviewed to identify the maximum pressure to which the RCP could be exposed. For Farley, this maximum pressure was determined to be approximately 2650 psia for the loss of load transient. A review of RCP analyses performed for other plants showed that increases to 2725 psia have been analyzed in detail and shown to be acceptable. It was concluded that the pressure transients are acceptable.

The effect of power uprate on the various RCP generic reports was then assessed. The ΔP and ΔT values were used in these assessments. For the most part, the assessments of ΔP and ΔT values were sufficient to show continued applicability of the generic reports to power uprate conditions. The increase in ΔT was sufficient to merit analysis for the casing weir plate. Evaluations showed a stress intensity range of 47,325 psi for the power uprate conditions. Comparison of this value to the Code primary plus secondary stress limit of 3Sm = 50,700 psi showed that the Code limit is satisfied. CUF requirements for the weir plate were satisfied by the fatigue waiver evaluation.

The evaluation performed for the RCPs addressed the ASME Code structural considerations for the RCP casing, main flange, main flange bolts, thermal barrier, casing foot, casing discharge and suction nozzles, casing weir plate, seal housing and auxiliary nozzles. The code and code edition applicable to the Farley RCPs is the ASME Section III-NB Code and Appendices, 1971 Edition with Addendum (Unit 1) and through 1972 Summer Addendum (Unit 2).

In summary, the results of the power uprate assessments showed that the Code criteria are satisfied at power uprate conditions.

W/rs - 8/5/97 & SNC/mja 8/4/97

TABLE A

APPLICABLE DESIGN TRANSIENTS CYCLE COUNT COMPARISON FOR REACTOR COOLANT PUMP

Plant Condition	Power Uprate [1] Number of Occurrences in 40 Year Operating License Period	RCP Generic Analysis Number of Occurrences In 40 Year Operating License Period
Normal Condition		
1. Plant Heatup	200	200
2. Plant Cooldown	200	200
3. Unit Loading at 5%/min	18,300	18,300
4. Unit Unloading at 5%/min	18,300	18,300
5. Small Step Load Increase	2,000	2,000
6. Small Step Load Decrease	2,000	2,000
7. Large Step Load Decrease	200	200
8. Steady State Fluctuations	Infinite	Infinite
9. Feedwater Cycling/Hot Standby Operation	2,000[2]	NA
10. Turbine Roll Test	10	10 (Test Condition)
Upset Condition		
1. Loss of Load	80	80
2. Loss of Power	40	40
3. Loss of Flow	80	80
4. Reactor Trip from Full Power	400	400
5. Inadvertent RCS Depressurization	10	10
Faulted Condition		
1. Reactor Coolant Pipe Break	1	1
2. Design Basis Earthquake (DBE)	1	1
3. Steam Line Break	1	1
4. Steam Generator Tube Rupture	(Included above in reactor trip from full power)	1
Test Conditions		
1. Primary Side Hydrostatic Test	5	5
2. Secondary Side Hydrostatic Test	10[3]	5
3. Primary Side Leak Test	50	50

Notes:

(1) The transient descriptions contained in the appropriate component E-specs remained applicable for the power uprate unless it has been modified for power uprate conditions.

(2) Feedwater Cycling/Hot Standby Operation transient included in power uprate for consistency with Steam Generator E-Spec. It need not be addressed for power uprate if it was not in the original design basis.

(3) The number of occurrences for the secondary side hydrostatic test transient increased to 10 from the original design requirement of 5.

NRC Question No. 7

In regard to Section 5.7.1 of Reference 2, provide a comparison of the design parameters and transients for the Farley steam generators (SGs) Model 51 against the power uprate condition. Also, provide the maximum calculated stress and CUF for the SGs vessel shell and nozzles, the allowable Code limits, and the Code and Code edition used in the evaluation for the power uprate. If different from the Code of record, provide a justification.

SNC Response No. 7

A comparison of the design parameters for power uprate to the original design parameters for Farley is provided in Table 2.1-2 of the Power Uprate NSSS Licensing Report. A summary of the design transients (i.e., type and number of occurrences during the 40 year license period) for Farley power uprate is provided in Table A, which follows.

The power uprate evaluations performed for the SGs addressed the ASME Code structural considerations for the critical SG primary side components (including tube to tubesheet weld, tubes, channel head, tubesheet, stubbarrel, tubesheet/shell junction and divider plate) and the critical SG secondary side components (including feedwater nozzle, secondary manway opening, secondary manway bolts, and steam nozzle). The code and code edition applicable to the Farley SGs is the ASME Section III Code, 1971 Edition.

Summaries of the maximum stress/allowable ratios for steam generator components, fatigue usage in steam generator primary side components, and fatigue usage in steam generator secondary side components are provided in Tables B, C and D, respectively, which follow.

TABLE A

APPLICABLE DESIGN TRANSIENTS CYCLE COUNT FOR STEAM GENERATORS

Plant Condition	Number of Occurrences in 40 Year Operating License Period
Normal Condition	
Plant heatup	200
Plant cooldown	200
Unit loading @ 5%/minute	18,300
Unit unloading @ 5%/minute	18,300
Small step load increase	2000
Small step load decrease	2000
Large step load decrease	200
Feedwater cycling/Hot standby operation	2000*
Turbine roll test	10
Upset Condition	
Loss of load	80
Loss of power	40
Loss of flow	80
Reactor trip from full power	400
Faulted Condition	
Reactor coolant pipe break	1
Design basis earthquake	1
Steam line break	1
Test Condition	
Primary side hydrostatic test	5
Secondary side hydrostatic test	10**

*The number of occurrences has been reduced to 2000 from the original design requirement of 18,300.
**The number of occurrences has been increased to 10 from the original design requirement of 5.

TABLE B SUMMARY OF MAXIMUM STRESS/ALLOWABLE RATIOS IN STEAM GENERATOR COMPONENTS			
Load Condition	**Component**	**Ratio Current 100% Power**	**Ratio Low-temp Uprate**
Normal Design	Tubesheet/shell	0.725	0.820
	Tubes	0.79	0.79
	Divider plate	>3Sm	>3Sm
Normal & Upset	Tubesheet	0.733	0.733
	Tube/tubesheet weld	0.872	0.976

TABLE C SUMMARY OF FATIGUE USAGE FOR STEAM GENERATOR COMPONENTS			
Load Condition	**Component**	**Current 100% Power**	**Low-Temp Uprate**
Normal and Upset	Tubesheet (cold leg)	0.186	0.282
	Tube/tubesheet weld	0.063	0.099
	Divider plate	0.791	0.944

TABLE D SUMMARY OF FATIGUE USAGE OF SECONDARY SIDE COMPONENTS	
Components	**Fatigue Usage (Uprated-Low Temperature)**
Feedwater nozzle	0.779
Secondary manway opening	0.051
Secondary manway bolts	1.1803
Steam nozzle	0.590

Note: The bolts are to be replaced prior to 34 years of operation.

NRC Question No. 8

In reference to Section 5.7.3 of Reference 2, provide a detailed evaluation of the flow-induced vibration of the steam generator U-bend tubes due to power uprate regarding the analysis methodology, vibration level, computer codes used in the analysis and the calculated cross flow velocity. Explain why the tube repair would not be required for at least 13.7 years at the proposed power uprate.

SNC Response No. 8

A complete evaluation of potential U-bend vibration and fatigue was performed for Farley in 1988. The results of that evaluation were reported in WCAP-11876 (Reference 1) and concluded that no tubes in either unit required preventive action. The evaluation was updated in 1990 to support a license amendment request to increase the steam generator tube plugging level and reduce the RCS Thermal Design Flow. The update evaluated potential U-bend flow conditions, vibration potential and fatigue usage based on changes in steam pressure and steam flow which resulted from the increased steam generator tube plugging and reduced RCS flow. The results of the updated evaluation were reported in WCAP-12694 (Reference 2) and concluded that fatigue usages for each susceptible tube remained within acceptable ranges, and therefore, no tubes required preventive action. In support of power uprate, the U-bend fatigue evaluation was updated using the same evaluation methodology established in Reference 1 and used in Reference 2 in order to establish whether power uprate conditions (i.e., changes in steam pressure and steam flow) cause any of the inner row U-bend tubes to become susceptible to fatigue. Changes to vibration levels and cross flow velocity due to power uprate were addressed in the evaluation.

A detailed description of the U-bend fatigue evaluation methodology and computer codes is provided in Reference 1. Information and equations include presentation of the one dimensional methodology used to account for changes in operating conditions such as for power uprating. This information is used to calculate the level of stress resulting from the increased flow induced vibration response of the limiting tube(s). The total fatigue usage (including the fatigue usage at the previous operating conditions and also the fatigue usage at the future operating conditions) is then determined. This information is then used to determine how many years of operation would be required to obtain a fatigue usage of 1.0. The number of years of operation required to obtain a fatigue usage of 1.0 for the limiting tube(s) is then documented.

As described in Section 5.7.3 of the Power Uprate NSSS Licensing Report, the U-bend fatigue evaluation for power uprate showed that no preventive tube repair is required to support full power operation of the Farley units at the anticipated steam generator outlet pressure (i.e., 787 psia) for power uprate. This is because at this steam generator outlet pressure, no steam generator tube in either unit is shown to accumulate a total fatigue usage of 1.0 prior to the end of the operating license period. Also as described in Section 5.7.3, analysis performed for lower steam generator outlet pressures and considering the potential for asymmetric steam flow from the different steam generators showed that under these conservative conditions no tube would accumulate a total fatigue usage that would exceed the acceptance limit of 1.0 for at least 13.7 years of operation after implementation of power uprate on Unit 1 and Unit 2 in the 1998 outages. Consequently, no tube would require preventive repair prior to that time. As noted in Section 5.7.3 of the Power Uprate NSSS Licensing Report, following the implementation of power uprate, the steam generator operating conditions (i.e., steam flow and pressure) can be documented on a cycle-specific basis for use in any future update to the U-bend fatigue evaluation.

Response No. 8 References

1. WCAP-11876, "Joseph Farley Unit 1 & 2 Evaluation for Tube Vibration Induced Fatigue," July, 1988.
2. WCAP-12694, "Alabama Power, Joseph M. Farley Unit 1 Increased Steam Generator Tube Plugging and Reduced Thermal Design Flow Licensing Report," August, 1990.

W/rs - 7/24/97

NRC Question No. 9

In regard to Section 5.8 of Reference 2, provide a comparison of the design parameters and transients for the pressurizer against the power uprate condition. Also, provide the maximum calculated stress and CUF at the critical locations (such as surge nozzle, skirt support, spray nozzle, safety and relief nozzle, upper head/upper shell and instrument nozzle) of the pressurizer, the allowable Code limits, and the Code and Code edition used in the evaluation for the power uprate. If different from the Code of record, provide a justification.

SNC Response No. 9

A comparison of the design parameters for power uprate to the original design parameters for Farley is provided in Table 2.1-2 of the Power Uprate NSSS Licensing Report. A comparison of the design transients (i.e., type and number of occurrences during the 40 year license period) for Farley power uprate to the original design transients for Farley is provided in Table A, which follows.

The limiting operating conditions of the pressurizer occur when the RCS pressure is high and the RCS hot leg and cold leg temperatures are low. This maximizes the ΔT that is experienced by the pressurizer. The RCS pressure is unchanged for the uprate, but the minimum cold leg temperature decreases by 13 degrees, with respect to the original design conditions. The CUFs at the critical locations are potentially affected by the uprate conditions, and the new values are provided in Table B, which follows. The maximum calculated stress at the critical locations is unchanged, except for the surge nozzle. For the surge nozzle, PL+Pb+Q stress intensity range is 49,972 psi, and the allowable stress limit of 3Sm is 80,100 psi.

The evaluation was performed by modifying the original Farley Units 1 and 2 pressurizer stress reports, which were performed to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1968 Edition, Summer of 1970 Addendum, for Farley Unit 1 and 1968 Edition, Winter of 1970 Addendum, for Farley Unit 2. No new Code versions were used for the uprate evaluations.

TABLE A APPLICABLE DESIGN TRANSIENTS AND CYCLE COUNT COMPARISON FOR PRESSURIZER		
Plant Condition	**Power Uprate (1) Number of Occurrences in 40 Year Operating License Period**	**Original Design Number of Occurrences in 40 Year Operating License Period**
Normal Condition		
1. Plant Heatup	200	200
2. Plant Cooldown	200	200
3. Unit Loading at 5%/min	18,300	18,300
4. Unit Unloading at 5%/min	18,300	18,300
5. Small Step Load Increase	2,000	2,000
6. Small Step Load Decrease	2,000	2,000
7. Large Step Load Decrease	200	200
8. Steady State Fluctuations	Infinite	Infinite
9. Feedwater Cycling/Hot Standby Operation	2,000 (2)	NA
10. Turbine Roll Test	10	10 (Test Condition)
Upset Condition		
1. Loss of Load	80	80
2. Loss of Power	40	40
3. Loss of Flow	80	80
4. Reactor Trip from Full Power	400	400
5. Inadvertent Auxiliary Spray	10	10
Faulted Condition		
1. Reactor Coolant Pipe Break	1	1
2. Steam Line Break	1	1
Test Conditions		
1. Primary Side Hydrostatic Test	5	5
2. Primary Side Leak Test	50	50

Notes:

(1) The transient descriptions contained in the appropriate component E-specs remained applicable for the power uprate unless it has been modified for power uprate conditions.

(2) Feedwater Cycling/Hot Standby Operation transient included in Power Uprate for consistency with the Steam Generator E-Spec. It need not be addressed for power uprate if it was not in the original design basis.

TABLE B

FARLEY UNITS 1 AND 2 PRESSURIZER FATIGUE USAGES

Component	Calculated Fatigue Usage
Surge Nozzle	<0.17
Spray Nozzle	<0.94
Safety and Relief Nozzle	<0.15
Lower Head, Heater Well Lower Head, Perforation	<0.01 <0.07
Upper Head and Shell	<0.78
Support Skirt/Flange	<0.01
Manway Pad Manway Cover Manway Bolts	0.0 0.0 0.0
Support Lug	<0.05
Instrument Nozzle	<0.11
Immersion Heater	<0.01
Valve Support Bracket	0.01

NRC Question No. 10

In reference to Sections 5.1 and 5.2 of Reference 2, provide the methodology, assumptions, and loading combinations used for evaluating the reactor vessel and internal components with regard to the stress and CUF for the power uprate. Were the analytical computer codes used in the evaluation different from those used in the original design-basis analysis? If so, identify the new codes used and provide justification for using the new codes and state how the codes were qualified for such applications.

SNC Response No. 10

Reactor Vessel

With respect to the methodology used in the uprate evaluation for the reactor vessel, the NSSS Design Transients for the uprate were reviewed to determine the most severe transient temperature variations and magnitudes of pressure variations. The original stress report was modified to reflect the changes to the NSSS Design Transients incurred by the uprate.

For regions of the vessel operating at temperatures near T-hot (outlet nozzles, main closure, CRDM housings), the most severe transients were identified to be:

- Unit loading at 5% of full power;
- Unit unloading at 5% of full power;
- Step load increase of 10% of full power;
- Large step load decrease;
- Loss of load;
- Loss of power; and
- Feedwater cycling at hot shutdown.

For the remaining regions of the vessel, which operate at temperatures near T-cold, the most severe transients were identified to be the same ones as listed above for T-hot, except that Step Load Increase is not included and Loss of Flow in One Loop is added.

Calculations were performed to account for the changes in stress due to the modified temperature and pressure variations. There were no analytical codes used in this evaluation, new or otherwise. The methodology used to evaluate the vessel thermal stresses is provided in Document PB-151987, "Tentative Structural Design Basis for Reactor Pressure Vessels and Directly Associated Components (Pressurized, Water Cooled Systems)," U.S. Dept. of Commerce, 1 December 1958 Revision with Addendum No. 1 dated 27 February 1959. Pressure stresses were scaled from previous results.

Input assumptions that were modified for the Uprate (in addition to the revised transients) were new LOCA reactor vessel/internals interface loads, which were compared to the loads previously considered and found to be enveloped by the previous loads.

Reactor Internals

Methodology

Structural integrity evaluations were performed to demonstrate that the structural integrity of the reactor components is not adversely affected by the change in RCS conditions and transients and/or by secondary effects of the change on reactor thermal hydraulic or structural performance. The presence of heat generated in reactor internal components, along with the various fluid temperatures, results in thermal gradients within and between components. These thermal gradients result in thermal stresses and thermal growth which must be accounted for in the design and analysis of the various components. The approaches (i.e., methodologies) used to evaluate the thermal stresses included:

- determination of temperature distributions in the component;
- determination of stresses in the component; and
- determination of margin of safety and fatigue usage factor for the most severely stressed location of the component.

In addition to the thermal loads, the mechanical loads due to the following conditions were considered: pressure differentials due to coolant flow; weight of the structure; superimposed loads from other components; earthquake (or seismic) loads; loss-of coolant accident (LOCA) loads; vibratory loads; and preloads.

Load Combinations and Loads

Normal operation (Service Level A) conditions include any condition in the course of system startup, operation in the design power range, hot standby and system shutdown, other than Upset, Emergency, Faulted or Testing conditions.

Upset (Service Level B) occurrences include any deviations from Normal conditions anticipated to occur often enough that the design should include a capability to withstand the conditions without operational impairment.

Emergency (Service Level C) conditions include those deviations from normal conditions which require shutdown for correction of the condition or repair.

Faulted (Service Level D) conditions include those combinations of conditions associated with extremely low probability postulated events whose consequences are such that the integrity and operability of the system may be impaired to the extent that consideration of the public health and safety are involved. Under faulted conditions, LOCA (loss of coolant accident) and SSE (safe shutdown earthquake) loads were considered without secondary loadings.

Analytical Computer Codes Different From Original Design Basis

The structural analysis for the reactor internals lower core plate (as described in Section 5.2.3.2 of the Power Uprate NSSS Licensing Report) used the ANSYS finite element computer code which is the current Westinghouse analytical tool for use in thermal and stress analyses of lower core plates. Although this was the first Westinghouse application of this code to the Farley lower core plate, it has previously been used by Westinghouse on Farley, and its use is documented in the Farley FSAR Section 5.2.1.11, "Analysis Method for Faulted Condition."

W/rs - 7/22/97

NRC Question No. 11

Discuss how the calculated CUFs for the reactor vessel and piping components compared to the CUFs resulting from the actual loading cycles based on the data recorded during plant operation.

SNC Response No. 11

The power uprate project was structured consistent with the methodology established in WCAP-10263, A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Power Plant. Inherent in this methodology are key points that include the use of currently approved analytical techniques (e.g., methodologies and computer codes) and the use of currently applicable licensing criteria and standards. Consistent with this methodology, the approach used to assess the impact of power uprate on NSSS components and to show the acceptability of the NSSS components for operation at power uprate conditions was to (1) revise the NSSS design transients (i.e., temperature/pressure profiles) to be applicable to power uprate conditions and (2) using the revised NSSS design transient profiles, evaluate the NSSS components to determine the fatigue usage factors for power uprate conditions. The fatigue usage factors were then compared relative to the code acceptance limits to show that the NSSS components comply with ASME Code acceptance criteria and can operate acceptably at power uprate conditions.

CUFs resulting from actual loading cycles based on the data recorded during plant operation were not calculated as part of power uprate analyses and were not compared to the CUFs based on the NSSS design transients for power uprate. This comparison is not required for compliance with the methodology in WCAP-10263.

W/rs - 7/24/97

NRC Question No. 12

Discuss the operability of safety-related mechanical components (i.e., valves and pumps) affected by the power uprate to ensure that the performance specifications and technical specification requirements (e.g., flow rate, close and open times) will be met for the proposed power uprate. Confirm that safety-related motor-operated valves (MOVs) will be capable of performing their intended functions following the power uprate including such affected parameters as fluid flow, temperature, pressure and differential pressure, and ambient temperature conditions. Identify mechanical components for which operability at the uprated power level could not be confirmed.

SNC Response No. 12

The only physical pump modifications required for uprate were for the condensate pumps (i.e., there were no safety-related pump mods). All other BOP system evaluations were performed with pump flows based on current operation and/or established pump design ranges. Assumed RHR pump and charging pump performance was degraded to provide operational margin and was explicitly modeled in the ECCS flow analyses. Acceptable pump performance was therefore demonstrated by the various analyses (e.g., LOCA and non-LOCA analyses) which met applicable acceptance criteria and technical specification requirements.

The methodology used for the FNP MOV Program to determine the design basis differential pressure (ΔP's) and line pressure included the most restricted conditions for elevation head, maximum pump shut-off head, upstream and downstream pressures (where applicable). The elevation heads were determined by assuming that the elevation head of the tank or sump were at their maximum/minimum operating levels to provide the greatest head differential. In most cases the downstream pressure was assumed to be zero to yield the greatest differential pressure across a valve. In some cases, where system conditions dictated, the downstream or back pressure was used.

The maximum pump shut-off head was used in most cases except for the RHR pump and charging pump mini-flow, service water, and component cooling water MOVs. For the minimum flow valves, the pump head was based on flow data for normal and accident conditions. The pump head for the Service Water and CCW MOVs was based on data obtained from flow models developed specifically for those two systems. The existing flow conditions are not affected by uprate, and therefore, the existing design basis assumptions used in FNP motor-operated valve program are still valid.

In addition to the above parameters the following assumptions were included.

- Pressure drop due to piping loss were neglected, except in cases where the flow models (primarily SW and CCW system) were employed.
- The value used for the density of water was 62.4 lbs/ft^3 at 60°F. This value provided the most conservative value (highest pressure) and any fluid temperature above 60°F was considered negligible.
- Relief valve setpoints were conservatively assumed to be 103% of lift setting.
- In cases where the elevation of sister valves varied from train to train or from one unit to the other, the most conservative elevation value for the group was used to produce the highest differential pressure or line pressure.
- The uprate design basis containment pressures and temperatures for normal and accident conditions are bounded by the current P/T analysis.

SCS/gld & jva - 7/24/97

NRC Question No. 13

In reference to Reference 3, list the balance-of-plant (BOP) piping systems that were evaluated for the power uprate. Discuss the methodology and assumptions used for evaluating BOP piping, components, and pipe supports, nozzles, penetrations, guides, valves, pumps, heat exchangers, and anchorage for pipe supports. Were the analytical computer codes used in the evaluation different from those used in the original design-basis analysis? If so, identify the new codes and provide justification for using the new codes and state how the codes were qualified for such applications.

SNC Response No. 13

The following BOP piping systems were evaluated for power uprate conditions: main steam; extraction steam; condensate and feedwater. The evaluation involved the review of the effect of new temperature, pressure and flow rates on those piping systems. This includes the evaluation of thermal expansion due to new temperature, increase of hoop and longitudinal stress due to pressure, and steam and water hammer effects (if any) due to new flow rates.

In addition to the secondary system piping evaluations discussed below, the piping most susceptible to flow-accelerated corrosion (FAC) has been replaced with FAC resistant piping. The remaining sections of FAC-susceptible piping are being monitored in accordance with the FAC program. The FAC program uses CHECWORKS as a predictive model for selecting inspection locations.

Main Steam

For the main steam piping system, the effect of the uprate temperature is not significant. The uprate operating temperatures are less than those used in the current base calculation; therefore, the thermal expansion effect of the main steam is less for the uprate condition. The uprate pressure is also less than the pressure used in the piping analysis; however, the uprate flow rate is approximately 5% greater than the current flow rate. The uprate flow rate is bounded by the flow rate utilized in the current piping analysis . Another component which requires evaluation in this system are the relief valves. The dynamic thrust load resulting from the opening of a valve is dependent on the flow area and the relief set pressure. As neither one of them changed due to the power uprate, the thrust load remains the same and therefore there is no change in the dynamic response of the piping. Based upon these comparisons, the current calculations for main steam piping bound the uprate condition. Table A shows the parameters of the main steam and reheat steam.

TABLE A

COMPARISON OF ORIGINAL DESIGN AND UPRATED STEAM PARAMETERS

	UNIT 1, 13A4261 DESIGN	UNIT 1, 13A4261 UPRATED	UNIT 2, 13A5031 DESIGN	UNIT 2, 13A5031 UPRATED
Main Steam				
Pressure (psia)	750	740.4	750	746.2
Temperature (°F)	510.9	509.4	510.9	510.3
Enthalpy (Btu/lb)	1197.9	1199.1	1197.9	1199.5
Sp. Vol. (ft^3/lb)	0.60714	0.61632	0.60714	0.6117
Mass Flow Rate (lb/hr)	11,710,478	11,864,730	11,710,478	11,818,870
Vol. Flow Rate (ft^3/hr)	7,109,900	7,312,470	7,109,900	7,229,603

Extraction Steam

For extraction steam piping systems, the uprate temperature is less than the current operating temperature except for the extraction steam to No. 6 Heater which has a 5°F increase in temperature. Therefore, the thermal expansion effect of the new temperature on the extraction piping system is negligible. The pressures of the extraction steam lines are low; therefore, the change from the current operating pressures to the uprate operating pressures are judged to be insignificant in the piping analysis. Since the extraction steam piping systems are traditionally not analyzed for steam hammer load, the change in the flow rate of the extraction steam due to the uprate condition does not have any effect in the current analysis. Based upon these reviews, the current calculations for extraction steam piping bounds the uprate condition.

Condensate and Feedwater Systems

Similar to the extraction steam, the uprate operating temperature is less than the current operating temperature except the feedwater from No. 6 Heater to the steam generator, where the temperature increases less than 5°F. Since this temperature change is small, the current piping analysis is judged to be acceptable for the new operating temperature. Deadhead pressure of the current condensate pump and the modified condensate pump is 595 psi and 628 psi, respectively. The increase in pressure is approximately 5%, and judged to be insignificant in the piping stress analysis. There is no increase of pressure in the feedwater system, similar to that of main steam. The increase in flow rate of the condensate and feedwater is listed in Table B. In the design basis calculations, there is no dynamic analysis (waterhammer analysis) for the condensate and feedwater system.

TABLE B

Feedwater Flow - Uprate Condition vs. Design and Current (Unit 1 and Unit 2)

Heater #	Design (lb/hr)	Current (lb/hr)	Uprate (lb/hr)	% Difference (design-uprate) / (current-uprate)
1	8,246,610	8,411,077	8,907,340	8.0 / 5.9
2	8,246,610	8,411,077	8,907,340	8.0 / 5.9
3	8,246,610	8,411,077	8,907,340	8.0 / 5.9
4	8,246,610	8,411,077	8,907,340	8.0 / 5.9
5	8,246,610	8,411,077	8,907,340	8.0 / 5.9
6	11,650,000	11,691,080	12,303,180	5.5 / 5.2

Based upon these reviews, the piping stress analyses for the condensate and feedwater systems are judged to be acceptable for the uprate condition. No new computer codes were used for the stress analysis of the piping systems for the purpose of evaluating the power uprate conditions.

SCS/an - 7/24/97

NRC Question No. 14

Provide the calculated maximum stresses for the critical BOP piping systems, the allowable limits, the Code of record and Code edition used for the power uprate conditions. If different form the Code of record, justify and reconcile the differences.

SNC Response No. 14

As stated in the SNC response to additional question No. 13, there was no new piping stress analysis performed specially for power uprate. The current piping stress analyses are based on parameters such as pressure, temperature, and flow rate, which have been either reduced or changed insignificantly; therefore, the current analysis results are also acceptable for the uprate conditions.

The code of record for the applicable sections of the main steam and feedwater piping is ASME Section III, 1974 Edition with Summer '75 Addenda. The analyses were performed to the same code.

SCS/an - 7/24/97

NRC Question No. 15

Discuss the potential for flow-induced vibration in the balance of plant heat exchangers following the power uprate.

SNC Response No. 15

Vibration in feedwater heaters can be predicted by comparing the cross flow velocity to the critical flow velocity of the drain cooling zone. The cross flow velocity is determined based on the original design flows by the feedwater heater manufacturer. The critical velocity is determined by the heater manufacturer based on drain cooling zone design. For this evaluation the uprate cross flow velocities of the drain cooling zones were calculated using the ratio of the original drain flow to the uprate flow which was multiplied by the original design cross flow. SCS feedwater heater standard specifications dictate that the critical flow of the drain cooling zone must be at least 1.35 times the actual cross flow of the drain cooling zone. Each of the six feedwater heaters met this criteria at power uprate conditions. Vibration of the drain cooling zone is not a concern based on drain cooling velocity requirements being met with significant margin.

Main condenser tube vibration is a function of steam velocity. For a fixed exhaust area, such as the condenser, steam velocity is a function of steam volumetric flow. Therefore, the higher the volumetric flow, the more susceptible the tubes are to steam vibration. Volumetric flow rate was calculated for uprate and evaluated against the original condenser design. The evaluation concluded that the steam volumetric flow rate under uprate conditions (992×10^6 cf/hr) would only be slightly greater (0.6%) than current operation (986×10^6 cf/hr) and significantly less than the original design conditions (1349×10^6 cf/hr), therefore condenser tube vibration should not be a problem.

The moisture separator reheaters cycle steam inlet volumetric flows increased by approximately 0.5 percent (1 ft^3/sec) over the current steam flows. Cycle steam flow is below the maximum allowable chevron separator flow of 2.57×10^6 lb/hr. Low pressure heating steam volumetric flows increased by a range of 1.4 to 1.9 percent (~1 ft^3/sec) over the current steam flows. Due to the slight cycle steam flow increase, there should be no calculable loss in margin for tube vibration and no observable increase in tube wear due to the increased heating steam flow.

No physical changes are required by power uprate to the Service Water (SW) System or its components such as the system supplied heat exchangers. Therefore, no changes to the current design SW flowrates are expected with no increase in the potential for flow-induced vibration in any SW supplied heat exchanger.

No physical changes are required by power uprate to the Component Cooling Water (CCW) System or its components. Therefore, no changes to the current CCW flowrates are expected with no increase in the potential for flow-induced vibration in any CCW supplied heat exchanger.

To summarize, no significant increase in flowrates to any BOP heat exchanger is expected due to power uprate. Therefore, the potential of flow-induced vibration in these heat exchangers following power uprate is minimal.

SCS/dm - 7/18/97

REFERENCES FOR THE NRC ADDITIONAL QUESTIONS

1. Letter, Southern Company to the NRC, "Joseph M. Farley Nuclear Plant Units 1 and 2, License Nos. DPR-58 and DPR-74, Proposed Facility Operating Licenses and Technical Specification Change Request for Power Uprating," dated February 14, 1997, with attachments.

2. Westinghouse Electric Corporation, WCAP-147239 "Joseph M. Farley Nuclear Plant Units 1 and 2 Power Uprate Project NSSS Licensing Report," dated January 1997 (Attachment V to Reference 2).

3. "Farley Nuclear Plant Units I and 2, Power Uprate Project BOP Licensing Report" (Attachment 6 to Reference 1).

ATTACHMENT II

SNC Response To NRC Supplement Request For Additional Information

Related To Power Uprate Submittal - Joseph M. Farley Nuclear Plant, Units 1 & 2

Upper Shelf Energy Summary Report

FARLEY 1

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Page 1

Docket No: 50-348
EOL Date: 06/25/2017

Beltline Identification	Type	Heat ID	Material Type	USE @ EOL @ 1/4T	1/4 T Neutron Fluence @ EOL	Unirradiated USE	Unirradiated USE Method	%Drop USE @ EOL @ 1/4T	USE % Drop Method	Cu %
INTERMEDIATE SHELL B6903-2	PLATE	C6294-1	A 533B	~~72.89~~ 72	~~2.337~~ 2.48	99.00	65%	~~26.58~~ 27	POSITION 1.2 (NO S DATA)	0.130
INTERMEDIATE SHELL B6903-3	PLATE	C6308-2	A 533B	~~64.01~~ 64	~~2.337~~ 2.48	87.00	65%	~~25.30~~ 26	POSITION 1.2 (NO S DATA)	0.120
LOWER SHELL B6919-2	PLATE	C6897-2	A 533B	~~62.07~~ 62	~~2.337~~ 2.48	86.00	65%	~~27.82~~ 28	POSITION 1.2 (NO S DATA)	0.140
LOWER SHELL B6919-1	PLATE	C6940-1	A 533B	~~66.05~~ 66	~~2.337~~ 2.48	86.00	65%	~~23.20~~ 23	POSITION 2.2 (S DATA)	0.140
INTERMEDIATE SHELL AXIAL WELDS	WELD	33A277	LINDE 1092	~~114.57~~ 115	~~0.773~~ 0.767	149.00	SURV WELD	~~23.11~~ 23	POSITION 2.2 (S DATA)	~~0.250~~ 0.24.
CIRC. WELD	WELD	6329637	LINDE 0091	~~57.93~~ 58	~~2.337~~ 2.48	104.00	10 F DATA	~~44.30~~ 44	POSITION 1.2 (NO S DATA)	~~0.225~~ 0.21
LOWER SHELL AXIAL WELDS	WELD	90099	LINDE 0091	~~58.43~~ 55	~~0.773~~ 0.767	82.50	STAT ANALYSIS	~~20.16~~ 33	POSITION 1.2 (NO S DATA)	~~0.170~~ 0.20

References

~~Fluence,~~ Heat number, IRTndt, ~~chemical compositions,~~ and UUSE (except circ. weld, int. shell oxial weld 19-923A, and lower shell axial welds) values from November 23, 1993, letter from D. Morey (SNOC) to USNRC Document Control Desk, subject: Responses to Requests for Additional Information Regarding GL 92-01.

UUSE for circ weld, int. shell axial weld 19-923A, and lower shell axial welds from June 21, 1994 letter, subject: Responses to open issues regarding GL 92-01.

Ni content of ~~welds from mean value of WOG data.~~ LOWER SHELL AXIAL WELDS REPRESENTS A BEST-ESTIMATE VALUE BASED ON ENGINEERING JUDGMENT. REVISED FLUENCE AND CHEMICAL COMPOSITION FROM JULY 23, 1997, LETTER FROM D. MOREY, TECHNICAL SPECIFICATIONS CHANGE REQUEST - PRESSURE TEMPERATURE LIMITS REPORT.

8/4/97 · TWS

PTS Summary Report

FARLEY 1

Printed 5/14/97 8:04:48 AM
Page 1

Docket No: 50-348
EOL Date: 06/25/2017

Beltline Identification Type	Heat ID	RTpts @ EOL	Neutron Fluence @ EOL	RTndt(u)	RTndt(u) METHOD	ΔRTndt(u) @ EOL	Fluence Factor @ EOL	Chem Factor	Chemistry Factor Method	Margin	Margin Method	Cu %	Ni %	P %	S %
INTERMEDIATE SHELL PLATE	B6903-2 C6294-1	~~156.1~~ 157	~~3.750~~ 3.97	0.0	MTEB 5-2	~~122.1~~ 123.3	~~1.342~~ 1.35	91.00	TABLE	34.0	~~OVERRIDE~~ NOTE 1	0.130	0.600	0.011	0.013
INTERMEDIATE SHELL PLATE	B6903-3 C6308-2	~~154.3~~ 155	~~3.750~~ 3.97	10.0	MTEB 5-2	~~110.3~~ 111.3	~~1.342~~ 1.35	82.20	TABLE	34.0	~~OVERRIDE~~ NOTE 1	0.120	0.560	0.014	0.015
LOWER SHELL PLATE	B6919-2 C6897-2	~~170.8~~ 172	~~3.750~~ 3.97	5.0	MTEB 5-2	~~131.8~~ 133.0	~~1.342~~ 1.35	98.20	TABLE	34.0	~~OVERRIDE~~ NOTE 1	0.140	0.560	0.015	0.018
LOWER SHELL PLATE	B6919-1 C6940-1	~~159.3~~ 162	~~3.750~~ 3.97	15.0	MTEB 5-2	~~121.3~~ 129.9	~~1.342~~ 1.35	~~90.40~~ 95.9	SURVEILLANCE NON-RATIO	17.0	~~OVERRIDE~~ NOTE 2	0.140	0.550	0.015	0.015
INTERMEDIATE SHELL AXIAL WELDS WELD	33A277	~~71.5~~ 68	~~1.240~~ 1.23	-56.0	GENERIC	~~83.4~~ 80.1	1.060	~~78.80~~ 75.7	SURVEILLANCE NON-RATIO	44.0	~~OVERRIDE~~ NOTE 2	~~0.250~~ 0.24	~~0.210~~ 0.17	0.015	0.010
CIRC. WELD WELD	8329637	~~183.2~~ 147	~~3.750~~ 3.97	-56.0	GENERIC	~~153.7~~ 136.5	~~1.342~~ 1.35	~~114.50~~ 100.8	TABLE	~~65.5~~ 66	~~OVERRIDE~~ NOTE 1	~~0.225~~ 0.21	~~0.200~~ 0.11	0.011	0.014
LOWER SHELL AXIAL WELDS WELD	90099	~~107.0~~ 120	~~1.240~~ 1.23	-56.0	GENERIC	~~97.6~~ 110.0	1.060	~~92.00~~ 104.0	TABLE	~~65.5~~ 66	~~OVERRIDE~~ NOTE 1	~~0.170~~ 0.20	0.200	0.022	0.012

References

~~Fluence~~, Heat number, IRTndt, ~~chemical compositions~~, and UUSE (except circ. weld, int. shell oxial weld 19-923A, and lower shell axial welds) values from November 23, 1993, letter from D. Morey (SNOC) to USNRC Document Control Desk, subject: Responses to Requests for Additional Information Regarding GL 92-01.

UUSE for circ weld, int. shell axial weld 19-923A, and lower shell axial welds from June 21, 1994 letter, subject: Responses to open issues regarding GL 92-01.

Ni content of ~~welds from mean value of WOG data.~~ LOWER SHELL AXIAL WELDS REPRESENTS A BEST-ESTIMATE VALUE BASED ON ENGINEERING JUDGMENT. REVISED FLUENCE AND CHEMICAL COMPOSITION FROM JULY 23, 1997, LETTER FROM D. MOREY, TECHNICAL SPECIFICATIONS CHANGE REQUEST - PRESSURE TEMPERATURE LIMITS REPORT.

NOTES:

1. 10CFR50.61(c)(1)(iii)(A) AND (B)
2. 10CFR50.61(c)(1)(iii)(A) AND 10CFR50.61(c)(2)(iii)

8/4/97 TWS

PTS Summary Report

FARLEY 2

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Docket No: 50-364
EOL Date: 03/31/2021

Beltline Identification Type	Heat ID	RTpts @ EOL	Neutron Fluence @ EOL	RTndt(u)	RTndt(u) METHOD	ΔRTndt(u) @ EOL	Fluence Factor @ EOL	Chem Factor	Chemistry Factor Method	Margin	Margin Method	Cu %	Ni %	P %	S %
LOWER SHELL B7210-2 PLATE	C6293-1	~~176.7~~ 176	~~3.800~~ 3.75	10.0	PLANT SPECIFIC	~~132.7~~ 132.5	~~1.345~~ 1.34	~~98.66~~ 98.7	TABLE	34.0	~~OVERRIDE~~ NOTE 1	0.140	0.570	0.015	0.015
INTERMEDIATE SHELL B7203-1 PLATE	C6309-2	~~183.6~~ 183	~~3.800~~ 3.75	15.0	PLANT SPECIFIC	~~134.6~~ 134.2	~~1.345~~ 1.34	100.00	TABLE	34.0	~~OVERRIDE~~ NOTE 1	0.140	0.600	0.010	0.013
LOWER SHELL B7210-1 PLATE	C6888-2	~~172.6~~ 173	~~3.800~~ 3.75	18.0	PLANT SPECIFIC	~~120.6~~ 120.5	~~1.345~~ 1.34	89.80	TABLE	34.0	~~OVERRIDE~~ NOTE 1	0.130	0.560	0.010	0.014
INTERMEDIATE SHELL B7212-1 PLATE	C7466-1	~~219.0~~ 202	~~3.800~~ 3.75	-10.0	PLANT SPECIFIC	~~195.0~~ 195.3	~~1.345~~ 1.34	~~145.00~~ 145.5	~~OVERRIDE~~ SURVEILLANCE NON-RATIO	~~34.0~~ 17	~~OVERRIDE~~ NOTE 2	0.200	0.600	0.018	0.016
CIRC. WELD 11-923 WELD	6P5622	~~118.2~~ 106	~~3.800~~ 3.75	-40.0	PLANT SPECIFIC	~~102.2~~ 90.3	~~1.345~~ 1.34	~~78.00~~ 67.3	TABLE	56.0	~~OVERRIDE~~ NOTE 1	~~0.130~~ 0.14	~~0.200~~ 0.07	0.016	~~0.018~~ 0.008
LOWER SHELL AXIAL WELDS 20-923A/B WELD	83640	~~33.7~~ 2	~~1.230~~ 1.20	-70.0	PLANT SPECIFIC	~~51.8~~ 35.8	~~1.058~~ 1.05	~~40.00~~ 34.1	TABLE	~~51.8~~ 35.8	~~OVERRIDE~~ NOTE 1	0.050	~~0.200~~ 0.07	0.006	0.011
INT. SHELL AXIAL WELD 19-923B WELD	BOLA SMAW	~~-41.1~~ -41	~~1.230~~ 1.20	-60.0	PLANT SPECIFIC	~~9.5~~ 9.6	~~1.058~~ 1.05	~~8.94~~ 9.1	SURVEILLANCE NON-RATIO	~~9.5~~ 9.6	~~OVERRIDE~~ NOTE 2	~~0.020~~ 0.03	~~0.030~~ 0.91	~~0.000~~ 0.004	~~0.000~~ 0.014
INTER. SHELL AXIAL WELD 19-923A WELD	HODA SMAW	~~-11.2~~ 17	~~1.230~~ 1.20	-56.0	GENERIC	~~9.5~~ 28.4	~~1.058~~ 1.05	~~8.94~~ 27.0	~~SURVEILLANCE NON-RATIO~~ TABLE	~~35.3~~ 44.3	~~OVERRIDE~~ NOTE 1	0.020	0.960	0.009	0.010

References

~~Fluence~~, IRTndt, ~~chemical composition~~, heat number and UUSE (except circ. weld, lower shell axial welds, and int. shell axial welds 19-923A) values from November 23, 1993, letter from D. Morey (SNOC) to USNRC Document Control Desk, subject: REsponses to Requests for Additional Information Regarding GL 92-01.

UUSE values for circ weld, lower shell axial welds, and int. shell axial weld 19-923A from June 21, 1994 letter, subject: Reponses to Open Issues Regarding GL 92-01.

Ni content for welds 11-923 and 20-923A/B from mean value of WOG data.

REVISED FLUENCE AND CHEMICAL COMPOSITION FROM JULY 23, 1997, LETTER FROM D. MOREY; TECHNICAL SPECIFICATIONS CHANGE REQUEST - PRESSURE TEMPERATURE LIMITS REPORT.

NOTES:

1. 10CFR50.61(c)(1)(iii)(A) AND (B)
2. 10CFR50.61(c)(1)(iii)(A) AND 10CFR50.61(c)(2)(iii)

NRC - Reactor Vessel Integrity Database

Upper Shelf Energy Summary Report

FARLEY 2

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Docket No: 50-364
EOL Date: 03/31/2021

Beltline Identification: Type	Heat ID	Material Type	USE @ EOL @ 1/4T	1/4 T Neutron Fluence @ EOL	Unirradiated USE	Unirradiated USE Method	%Drop USE @ EOL @ 1/4T	USE % Drop Method	Cu %
LOWER SHELL PLATE	B7210-2 C6293-1	A 533B	~~71.37~~ 71	~~2.368~~ 2.34	99.00	DIRECT	~~27.91~~ 28	POSITION 1.2 (NO S DATA)	0.140
INTERMEDIATE SHELL PLATE	B7203-1 C6309-2	A 533B	~~72.09~~ 72	~~2.368~~ 2.34	100.00	DIRECT	~~27.91~~ 28	POSITION 1.2 (NO S DATA)	0.140
LOWER SHELL PLATE	B7210-1 C6888-2	A 533B	~~75.54~~ 75	~~2.368~~ 2.34	103.00	DIRECT	~~26.66~~ 27	POSITION 1.2 (NO S DATA)	0.130
INTERMEDIATE SHELL PLATE	B7212-1 C7466-1	A 533B	~~61.33~~ 61	~~2.368~~ 2.34	100.00	DIRECT	~~38.67~~ 39	POSITION 2.2 (S DATA)	0.200
CIRC. WELD WELD	11-923 5P5622	LINDE 0091	~~66.55~~ 67	~~2.368~~ 2.34	102.00	10 F DATA	~~32.79~~ 34	POSITION 1.2 (NO S DATA)	~~0.130~~ 0.14
LOWER SHELL AXIAL WELDS WELD	20-923A/B 83640	LINDE 0091	~~103.58~~ 103	~~0.767~~ 0.748	126.00	10 F DATA	~~17.81~~ 18	POSITION 1.2 (NO S DATA)	0.050
INT. SHELL AXIAL WELD WELD	19-923B BOLA SMAW	SMAW	~~121.64~~ 135	~~0.767~~ 0.748	148.00	SURV WELD	~~17.81~~ 9	POSITION ~~1.2~~ 2.2 (~~NO~~ S DATA) 9	~~0.020~~ 0.03
INTER. SHELL AXIAL WELD WELD	19-923A HODA SMAW	SMAW	~~107.67~~ 108	~~0.767~~ 0.748	131.00	10 F DATA	~~17.81~~ 18	POSITION 1.2 (NO S DATA)	0.020

References

~~Fluence~~, IRTndt, ~~chemical composition~~, heat number and UUSE (except circ. weld, lower shell axial welds, and int. shell axial welds 19-923A) values from November 23, 1993, letter from D. Morey (SNOC) to USNRC Document Control Desk, subject: REsponses to Requests for Additional Information Regarding GL 92-01.

UUSE values for circ weld, lower shell axial welds, and int. shell axial weld 19-923A from June 21, 1994 letter, subject: Reponses to Open Issues Regarding GL 92-01.

Ni content for welds 11-923 and 20-923A/B from mean value of WOG data.

REVISED FLUENCE AND CHEMICAL COMPOSITION FROM JULY 23, 1997, LETTER FROM D. MOREY, TECHNICAL SPECIFICATIONS CHANGE REQUEST - PRESSURE TEMPERATURE LIMITS REPORT.

8/4/97-TWS

WCAP-15142
Revision 1

Comanche Peak Steam Electric Station Units 1 and 2 Power Uprate Project NSSS Engineering Report

June 1999

Westinghouse Electric Company LLC
P.O. Box 355
Pittsburgh, PA 15230-0355

I/24

5.6 STEAM GENERATORS

5.6.1 Introduction

The following sections describe the steam generator analyses and evaluations performed for the revised operating conditions. The steam generators models are D4 and D5, respectively, for Units 1 and 2.

5.6.2 Structural Integrity

The bases for the existing structural and fatigue analyses of the steam generators are contained in the Model D4 and Model D5 Steam Generator Stress Reports, and the analyses demonstrate the steam generator components meet allowable ASME Code limits. An evaluation was performed to demonstrate that the ASME limits are still maintained at the revised design conditions. This evaluation considered the most critical components with regard to stress and fatigue usage. The primary inputs for the evaluation are the revised design conditions in Table 2.3-1 and the revised design transients discussed in Section 3.1. Table 2.3-1 indicates that the reactor coolant side pressure remained unchanged at 2250 psia, while steam pressure decreased from 1000 psia to a minimum value of 913 psia causing an increase in the primary to secondary side ΔP. The upper bound steam pressure increased to 1046 resulting in a higher shell side ΔP. Also, the steam temperature decreased from a current design value of 544.6°F to a value of 533.6°F and the feedwater temperature changed from a design value of 440°F to a design range of 390° and 444.6°F. Section 3.1 indicates that the steam temperature and/or steam pressure transient curves were modified for several design basis events.

The evaluation considered these inputs by developing a scale factor needed to calculate the increased stress and fatigue usage. For primary side components affected by the increased differential pressure between RCS and the secondary side, an enveloping scale factor was calculated based on the revised design conditions and the affected design transients. This scale factor was applied on stress and fatigue usage, calculated in the stress reports for 0% plugging, to evaluate for the revised conditions. For secondary side components, a scale factor based on the steam pressure was used to determine the corresponding increase in stress and fatigue. With regards to the reduction in feedwater temperature from 444.6° to 390°F, the feedwater nozzle is the only component that needs to be evaluated since the other steam generator components are not significantly affected by the feedwater temperature.

Table 5.6-1 summarizes the evaluation results. Table 5.6-1 compares the current value for the most limiting fatigue usage for each critical component with the value for the revised design conditions. The results indicate that all applicable fatigue usage values are still less than the allowable limit of 1.0.

Thus, the evaluation demonstrates that the critical components of the steam generators meet the requirements of ASME Code, Section III, Sub-Section NB at the revised design conditions.

5.6.3 Thermal-Hydraulic Performance

Secondary side steam generator performance characteristics such as circulation ratio, moisture carryover, hydrodynamic stability, heat flux and others are affected by increases in thermal power, and steam pressure. Steam pressure is, in turn, determined by the power as well as the primary temperature, tube plugging level and feedwater temperature. This section assesses the magnitude and importance of changes in the secondary side thermal hydraulic performance characteristics at the uprated power, increased plugging, reduced primary side temperatures and feedwater temperature range.

5.6.3.1 SG Fouling Factor

An evaluation was performed to calculate the current level of fouling in the steam generator and compare it to the design basis value. This comparison will help to determine the relationship between the design basis and the expected operating steam pressure.

Field performance data are used to calculate an apparent fouling factor which must be assumed to make the steam generator steam pressure performance consistent with the actual primary side operating conditions. For Unit 1, apparent fouling factors have been in the range 20-60x10^{6} hr-ft^{2}-°F/Btu for the most recent cycles. Most of this variation is the normal variation during any given fuel cycle. However, there is considerable uncertainty in this measurement, especially as a result of steam pressure, primary temperature and primary flow measurement uncertainties. The design value used for the calculations in this evaluation was 50x10^{6} hr-ft^{2}-°F/Btu. The fact that the design value is in the range of the measured values suggests there is no significant steam pressure margin with respect to the fouling factor. Each change of 10x10^{6} hr-ft^{2}-°F/Btu in the fouling factor represents about a 5 psi change in steam pressures for the Models D4 and D5 generators. Some additional steam pressure margin relative to the design value is available as a result of the actual primary flow being greater than the thermal design flow used to calculate the design steam pressure in Table 2.3-1. This margin is only 6-7 psi for a 5% flow difference between actual and thermal design flow. It is expected, therefore, that the Unit 1 actual steam pressures will be near the design values calculated for this report.

Unit 2 apparent fouling factors for recent cycles have been in the range 60-90x10^{6} hr-ft^{2}-°F/Btu and, again, the design value used for the calculations was 50x10^{6} hr-ft^{2}-°F/Btu. For this unit, actual steam pressures could be expected to be 0-15 psi below the design values since each change of 10x10^{6} hr-ft^{2}-°F/Btu in fouling factor represents about a 5 psi change in steam pressure.

5.6.3.2 Thermal Hydraulic Operating Characteristics

Tables 5.6-2 (Unit 1) and 5.6-3 (Unit 2) summarize the results of the evaluations performed for selected thermal hydraulic operating characteristics. These evaluations are discussed as follows.

Circulation Ratio/Bundle Liquid Flow

Tables 5.6-2 (Unit 1) and 5.6-3 (Unit 2) compare the current steam generator circulation ratio to the ratio for the revised design conditions. The circulation ratio is a measure of tube bundle liquid flow in relation to steam flow and is primarily a function of steam flow. The bundle liquid flow minimizes the accumulation of contaminants on the tube sheet and in the bundle. For Unit 1, the bundle flow changes by less than 6% which has a minimal affect on its ability to minimize the accumulation of containments. For Unit 2, there is a slight decrease in the bundle flow which also has a minimal affect on its function. Thus, the bundle flows are still adequate.

Hydrodynamic Stability - Damping Factor

The hydrodynamic stability of a steam generator is characterized by a damping factor. A negative value of this factor indicates a stable unit such that small perturbations of steam pressure or circulation ratio will diminish rather than grow in amplitude. The damping factor is not related to any safety issues but related to operational concerns only such as level control.

Table 5.6-2 indicates that for Unit 1 at the high feed temperature cases (444.6°F), damping factors remain negative at about the same level. The steam generators, therefore, continue to be hydro-dynamically stable at these feed temperatures. For the low feed temperature cases (390°F), however, the damping factors are substantially less negative, dropping from the current value of -149 to -35 hr^{-1}. This large decrease in damping factor is an indicator that the generators may be subject to an instability (e.g., variations in circulation ratio and water level control) if operated at the lower feed water temperature. **While the damping factor is not a precise indicator of possible instability, the significant shift towards instability should be monitored if the plant operates at the lower feed temperatures (e.g., 390°F). A symptom of instability would be observed oscillation in the control of the steam generator water level. The instability can be mitigated by operating at the higher feedwater temperatures and/or increasing the downcomer resistance in the steam generator. Additional destabilizing factors such as corrosion products in the upper tube support plates can also affect steam generator stability.**

Unlike the Model D4 generators in Unit 1, Table 5.6-3 indicates that the Unit 2 damping factors remain highly negative, at a level comparable to the current design, for all cases. Thus, the steam generators remain hydro-dynamically stable for all uprated cases.

Heat Flux - Nucleate Boiling Limits

Table 5.6-2 indicates that the Unit 1 peak heat flux will increase with power and tube plugging. For uprating, increased total heat load is passed through the same bundle heat transfer area, increasing the heat flux. For increased tube plugging (10%), the same heat load is passed through a smaller heat transfer area, also increasing the heat flux. In Table 5.6-2, for most cases, the peak heat flux increases slightly. For the case with no plugging and low feed temperature (390°F), the steam pressure is sufficiently high, as a result of the preheater performance, such that peak heat flux actually drops slightly. In all cases, the maximum calculated heat flux is well within nucleate boiling limits and is comparable to values for steam generators currently operating in the field.

Table 5.6-3 identifies variations in the heat flux that are similar to those for Unit 1. Thus, for Unit 2, the heat flux is also well within nucleate boiling limits.

Secondary Side Pressure Drop

Table 5.6-2 indicates that for Unit 1, the total secondary side pressure drop for the steam generator increased by about 3 psi, which is considered very small in relation to the total feed system pressure drop. Also, Table 5.6-3 indicates that for Unit 2, the steam pressure drops are seen to be equal to or less than the current design pressure drop since the reduced water level and circulation ratio offset the increase in steam flow. For the low feed temperature cases (390°F), the lower steam flow causes the total pressure drop to be less than the design condition value. Thus, the revised pressure drops will have a negligible effect on feedwater system operation.

5.6.3.3 Moisture Carryover

For Unit 1, the moisture separators have 12 primary separator risers and, in the as built condition, are essentially the same as all other Model D4 steam generators. The separators were modified after startup. The modifications included dryer perforated plates and dryer upper tier drains, mid deck relief, perforated primary separator risers and increased primary separator orifice diameter.

Moisture carryover field data are available from other plants with the same separator package as Unit 1. These plants operate at, and above, the separator loadings under consideration for Unit 1. The data are correlated using a separator loading parameter denoted as the modified separator parameter, MSP, defined as follows:

$$MSP = (\text{Steam Flow } (10^6 \text{ lbm/hr}))^2 \times [\text{Steam Specific Volume } (\text{ft}^3/\text{lbm})]^{0.4}$$

The MSP correlates the effects of steam pressure and flow (power). Water level, the third parameter which affects moisture carryover, is usually at its normal elevation. The available Model D moisture carryover measurements are plotted in Figure 5.6-1. The darkened vertical lines on the figure show the value of MSP for the revised design conditions with high feedwater temperature (444.6°F), covering a steam pressure range of 916-1014 psia. The expected MCO, given by the regression line, remains below 0.25% for the full pressure range. Although there is considerable uncertainty, as suggested by the line for the 95% confidence prediction upper bound, it is likely that moisture carryover will remain near or below 0.25% at all these conditions. **If the plant is to be operated in the lower part of this steam pressure range (<950 psia) e.g., higher feedwater temperatures and lower end of T_{AVG} window, consideration should be given to performing a moisture carryover test to determine the actual moisture carryover.** Additional margin, if required, is available through reduced steam generator water level. At the reduced feedwater temperature (390°F), MSP values are ≤10, as a result of the reduced steam flow and increased steam pressure for these conditions. Moisture carryover values well below 0.1% can be expected at the low feed temperature.

The Unit 2 separator package is somewhat different than the Unit 1 package. The as built Model D5 separator package, currently installed in Unit 2, has a number of improvements over the Model D4, as built package. These improvements include an increase in the number of primary separators from 12 to 16, 0.7[5] primary separator orifices, and an improved dryer system with perforated plates and central upper tier drains. Some of the field installed improvements for the Model D4 packages, however, are not in place for the D5 as built package. These include mid deck plate relief and a further increase of primary separator orifice size to 0.8 with a perforated primary riser.

In the absence of field data for the as built Model D5 separators, it would be difficult to project the performance of these separators as a function of increased power. Indeed, field performance data is available for the Model D5 packages at the current rating for CPSES but not at the increased powers corresponding to the revised design conditions in Table 2.3-1. The Model F separator packages are essentially the same as the Model D5 separators, and it is helpful to use data from these separators to assess the performance of the Model D5 separators at the revised design conditions.

Figure 5.6-2 presents the available field data for the as built Model D5 generators, the Model F generators with Phase 1 Modifications (mid-deck relief) and Model F with both Phase 1 and Phase 2 Modifications (0.8 primary separator orifice and perforated primary separator riser). The regression line for the Model D4 data from Figure 5.6-1 is also plotted for reference. Again, the vertical lines on the figure show the value of MSP for the uprated cases with high feedwater temperature (445°F), covering a steam pressure range of 916-1014 psia.

At the current rating, all configurations produce a very low carryover (0.01-0.03). It is not clear that the differences in carryover among the various configurations are significant at this low level of carryover. The slopes of the regression lines, for the Model F separators with either Phase 1 or both Phase 1 and 2 modifications, are shallower than for the Model D4, resulting in a lower projected carryover at the conditions. The increased number of primary separators is felt to be a contributor to this shallower slope. To the extent that this supposition holds for the as built Model D5, the carryover is expected to be near or below that for the Model D4, and remain below 0.25%. In a worst case scenario, the carryover for the D5 could be a factor of two above that of the Model D4, resulting in a carryover of 0.2%-0.4% at the revised design conditions (e.g., higher feedwater temperature 444.6°F and lower T_{AVG} range). **If the plant is to be operated in the lower part of the steam pressure range (e.g., higher feedwater temperature and lower T_{AVG} range), consideration should be given to performing a moisture carryover test to determine the actual moisture carryover.**

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5. Ratio of orifice diameter to primary separator diameter.

5.6.4 U-Bend Fatigue Evaluation

Fluid elastic vibration and fatigue of unsupported, small radius U-bends can occur under some circumstances. A necessary condition for significant fatigue usage is tube denting at the top tube support plate. This denting can occur only for carbon steel tube support plates such as those in the model D4 generators of Unit 1. The Unit 2, Model D5 generators have stainless steel tube support plates. Small radius u-bend vibration and fatigue, therefore, is only of concern for the Unit 1 steam generators.

An evaluation was performed to determine the impact that the revised design conditions had on the U-bend fatigue evaluation performed for the Unit 1 steam generators (Reference 10)[6]. The evaluation for the current conditions recommended that two tubes (S/G3:R10C109 and R11C109) be removed from service. In addition, it identified four other tubes that would be susceptible to U-bend fatigue and which may require preventive action under more severe operating conditions. The relative stability ratios (RSRs) for these tubes are provided as follows:

Limiting RSRs for Susceptible Tubes

Susceptible Tube	Limiting RSR
S/G4:R11C108	0.980
S/G2:R10C92	1.008
S/G2:R11C16	1.055
S/G3:R9C23	1.129

Relative stability ratio for a U-bend tube is the stability ratio at a given operation condition relative to the stability ratio at a reference condition. For a given steam generator geometry, the primary operating characteristics which affect the stability ratio are the steam flow, steam pressure and circulation ratio. RSRs were calculated for a range of steam pressures at three power ratings: 100%, 102%, and 104%. The results are presented in Figure 5.6-3 which gives the RSR as a function of steam pressure with steam flow as a parameter.

Figure 5.6-3 shows the steam pressures and flow rates at which each tube exceeds its maximum allowable RSR and needs to be considered for preventive action. For example, in the available data, both loop 2 and 4 operate at thermal powers 2%-4% above the plant average power. Following an uprate to 4.5%, these loops could be expected to have a steam flow between 4.06 and 4.14x10^6 lbm/hr. The two most susceptible tubes, S/G4:R11C108 and S/G2:R10C92 would require preventive action unless the steam pressure were maintained well above 1000 psia. The third tube, S/G2:R11C16, would require preventive action in the steam pressure range 950-980 psia. The fourth susceptible tube, S/G3:R9C23, has a limiting RSR of 1.129 which is

6. The Unit 2 generators (D5S) are manufactured with stainless steel support plates that help deter tube vibration (leading to U-bend fatigue), and are thus not susceptible to U-bend fatigue.

higher than the highest ordinate value on Figure 5.6-3. This tube should not require preventive action unless the operating steam pressure drops below 900 psia.

It should be noted that in the application of Figure 5.6-3, measurement uncertainties should be added to steam flow and subtracted from steam pressure to assure a conservative limit for preventive action.

5.6.5 F* Criteria

The F* Criteria obviates the need to repair a hardrolled (a.k.a., roll expanded) tube by sleeving or to remove a hardrolled tube from service (by plugging) due to detection of indications, e.g., by eddy current testing (ECT), in a region extending over most of the length of tubing within the tubesheet. This evaluation applies to the roll expanded tubes in the Comanche Peak Unit 1, Westinghouse Model D4 steam generators and assesses the integrity of the tube bundle for ECT indications occurring on the length of tubing within the tubesheet. It should be noted that the F* plugging criteria developed herein are applicable only to hardrolled tubes, and not to the tubes in these steam generators which have WEXTEX expansion joints.

For Comanche Peak Unit 1, the F* criteria are documented in Reference 11. Based on the revised design conditions provided in Table 2.3-1, there is a slight increase in the "3 ΔP" endcap load on the tubes at normal operating conditions. This increase in load results from an increase in primary-to-secondary side pressure difference. The original analysis determined the "3 Δp" endcap load using a Δp across the tubes of 1250 psid (2250 - 1000). Based on the revised design conditions, the Δp across the tubes will increase to 1337 psid (2250 - 913) due to the decrease in steam pressure. The F* criteria is evaluated for both normal operation and FLB conditions. Calculations show that the F* results for the FLB condition are more limiting than the results for normal operation. The F* length for the FLB conditions was 1.13 inches whereas the normal operating condition resulted in a F* length of 1.09 inches. Additional calculations were performed using the revised design conditions defined in Table 2.3-1 and yielded results similar to the previous normal operating conditions (1.09 inches). For the limiting accident condition, FLB, the F* length is not affected by changes in normal operation steam pressure. Therefore, the F* value for FLB contained in Reference 11 remains bounding and Reference 11 has been revised to reflect the fact that the revised design conditions have been considered for F* criteria.

5.6.6 Laser Weld Sleeving (LWS)

The Comanche Peak Unit 1 and 2 LWS repair evaluations were provided in Reference 12. Similar to the F* criteria, the tubesheet sleeve in this WCAP is affected by the revised design conditions due to a slight increase in the "3 ΔP" endcap load on the tube at normal operation. The primary to secondary side ΔP increased from 1250 to 1337 psid as a result of the revised design parameters listed in Table 2.3-1. With the primary side pressure remaining at 2250 psia, the higher ΔP increases the sleeve upward pullout force by a small amount.

Of the two types of tubesheet sleeves, the limiting design in this case, is the elevated tubesheet sleeve (ETS). This is primarily due to the ETS lower joint being located above the tubesheet neutral axis. Tubesheet upward bending during normal operation dilates the tube holes and, in turn, the tube IDs reduce the interference fit contact pressure (CP) between the sleeve and tube during sleeve installation. In the uprate case, the components of the CP which increase resistance to pullout outweigh the component which decreases CP and the result is that the resultant CP is limiting for the original design conditions. Although the pullout-resisting forces are greater for the revised design conditions, the pullout forces due to the greater normal operation ΔP also increase. The result is that the margin of required resistance for the axially shortest rolled joint, divided by that for the available resistance is slightly lower for the revised design conditions than for the original design conditions and therefore, Reference 12 will be revised. The factor, required resistance divided by available resistance, decreases several percentage points from approximately 3.00.

For the limiting accident condition, FLB, the sleeve roll expansion joint length is not affected by changes in normal operation steam pressure.

The change in required tubesheet sleeve joint roll expansion length has been determined in a short evaluation for the roll expanded tubes of Unit 1 and documented in a revision to Reference 12. The joint roll length for the explosive expanded tubes of Unit 1 and for the hydraulic expanded tubes of Unit 2 will be determined in a minor confirmatory test and related evaluation and documented during the sleeving outage preparation.

5.6.7 Conclusions

As a result of performing the evaluations and analysis, it has been determined that:

- The structural components for the Units 1 and 2 steam generators will still meet the allowable ASME Code limits.
- The actual steam pressure for Unit 1 will be near those reported in Table 2.3-1. The actual steam pressure for Unit 2 is expected to be about 0-15 psi lower than those reported in Table 2.3-1.
- The circulation ratio, heat flux and secondary side pressure drop will still be within applicable limits. For Unit 2, the hydrodynamic stability of the steam generator is acceptable. For Unit 1, the hydrodynamic stability of the steam generator may need to be monitored with operation at the low feedwater temperatures.
- The moisture carryover should be less than the current design value of 0.25%.
- For Unit 1, three additional tubes may need to be plugged to accommodate the anticipated reduction in steam pressure to mitigate U-bend fatigue concerns.
- References 11 and 12 have been revised to reflect the revised design conditions.

5.6.8 References

1. WNET-153, Volume 6, "Tube/Tubesheet Weld Analysis," December 1981.

2. WNET 153, Volume 4, "Tubesheet/Shell Junction Analysis," March 1982.

3. WNET 153, Volume 3, "Primary Chamber Components Analysis," October 1981.

4. WNET-153, Volume 5, "Tube Analysis," March 1982.

5. "Reactor Coolant System - Model D5 Steam Generator," Design Specification G-953431, Revision 1, Westinghouse Electric Corporation, Pittsburgh, PA, October 1973.

6. Boiler and Pressure Vessel Code Section III, "Rules for Construction of Nuclear Power Plant Components," 1980 Edition, New York, New York.

7. WNET-153, Volume 10, "Model D5 Steam Generator Stress Report Steam Secondary Manway."

8. WNET-153, Volume 9, "Model D5 Steam Generator Stress Report Steam Outlet Nozzle and Upper Head Complex."

9. WNET-153, Volume 8, "Model D5 Steam Generator Stress Report Steam Outlet Nozzle and Upper Head Complex."

10. WCAP-15009, Comanche Peak Unit 1 Evaluation for Tube Vibration Induced Fatigue, December 1997.

11. WCAP-15004, Rev. 0, 12/97, "F* Tube Plugging Criterion for Tubes with Degradation in the Tubesheet Region of the Comnnche Peak Unit 1 Steam Generators."

12. WCAP-15090, Rev. 0, 7/98, "Specific Application of Laser Welded Sleeves for the Comanche Peak Units 1 and 2 Steam Generators."

Table 5.6-1(a) Unit 1 Comparison of Steam Generator Fatigue Usage for Most Limiting Location

Component	Fatigue Usage	
	Current	Revised Operating Conditions
Tubes	0.0019	0.0210
Tubesheet/Shell Junction	0.6477	0.827
Tube to Tubesheet Weld	0.3563	0.4000
Divider Plate	0.982	1.000
Secondary Manway		
Shell Penetration Bolts[1]	0.390	0.531
Steam Nozzle	0.112	0.163
Feedwater Nozzle	0.856	0.642

(1) The current and revised fatigue usage consider a 40 year qualification life.

Table 5.6-1(b) Unit 2 Comparison of Steam Generator Fatigue Usage for Most Limiting Location

Component	Fatigue Usage	
	Current	**Revised Operating Conditions**
Tubes	0.276	0.331
Tubesheet/Shell Junction	0.241	0.317
Tube to Tubesheet Weld	0.32	0.422
Divider Plate	0.906	0.986
Secondary Manway		
Shell Penetration Bolts[1]	0.88	0.974
Steam Nozzle	0.628	0.642
Feedwater Nozzle	0.220	0.265

(1) The current and revised fatigue usage consider a 20 year qualification life.

Table 5.6-2 Unit 1 Steam Generator Uprated Operating Conditions and Secondary Side Characteristics

Parameter	Current Design	Case 1a[1]	Case 1b	Case 2a	Case 2b	Case 3a	Case 3b
Operating Conditions							
T_{avg} (°F)	589.1	585.6	585.6	592.6	592.6	592.6	582.9
Feed Temp - °F	440	444.6	390	444.6	390	444.6	390
Steam Generator Water Level - % NR	68.2	66.5	66.5	66.5	66.5	66.5	66.5
Plugging - %	0	10	10	10	10	0	0
Operating Characteristics							
Circulation Ratio	2.40	2.19	2.45	2.25	2.49	2.25	2.49
Bundle Liquid Flow - 10^6 lbm/hr	5.30	4.73	5.35	4.98	5.52	4.99	5.53
Peak Heat Flux - Btu/hr-ft^2	124252	140034	133220	137736	131218	128141	110990
Total Secondary DP - psi	23.2	25.9	22.2	25.3	21.8	25.1	21.6
SG Mass - lbm	105191	100900	104162	102256	105500	102630	105840
Damping Factor - hr^{-1}	-149	-140	-35	-146	-54	-148	-61

1. These cases correspond to those presented for the revised design conditions in Table 2.3-1

Table 5.6-3 Unit 2 Steam Generator Uprated Operating Conditions and Secondary Side Characteristics (See Table 2.3-1 for Operating Parameters)

Parameter	Current Design	Case 1a[1]	Case 1b	Case 2a	Case 2b	Case 3a	Case 3b
Operating Conditions							
T_{AVG} (°F)	589.1	585.6	585.6	592.6	592.6	592.6	582.9
Feed Temp. - °F	440	444.6	390	444.6	390	444.6	390
Water Level - % NR	72.5	64.0	64.0	64.0	64.0	64.0	64.0
Plugging - %	0	10	10	10	10	0	0
Operating Characteristics							
Circulation Ratio	3.30	2.98	3.28	3.02	3.30	5.01	3.29
Bundle Liquid Flow - 10^6 lbm/hr	8.71	7.86	8.42	8.05	8.51	8.02	8.49
Peak Heat Flux - Btu/hr-ft^2	124252	140886	134923	138937	132933	129648	113758
Total Secondary DP - psi	21.4	21.4	18.3	20.9	17.8	21.4	18.3
SG Mass - lbm	101900	89794	93428	91422	95087	91840	95458
Damping Factor - hr^{-1}	-321	-311	-275	-318	-288	-318	-291

1. These cases correspond to those presented for the revised design conditions in Table 2.3-1

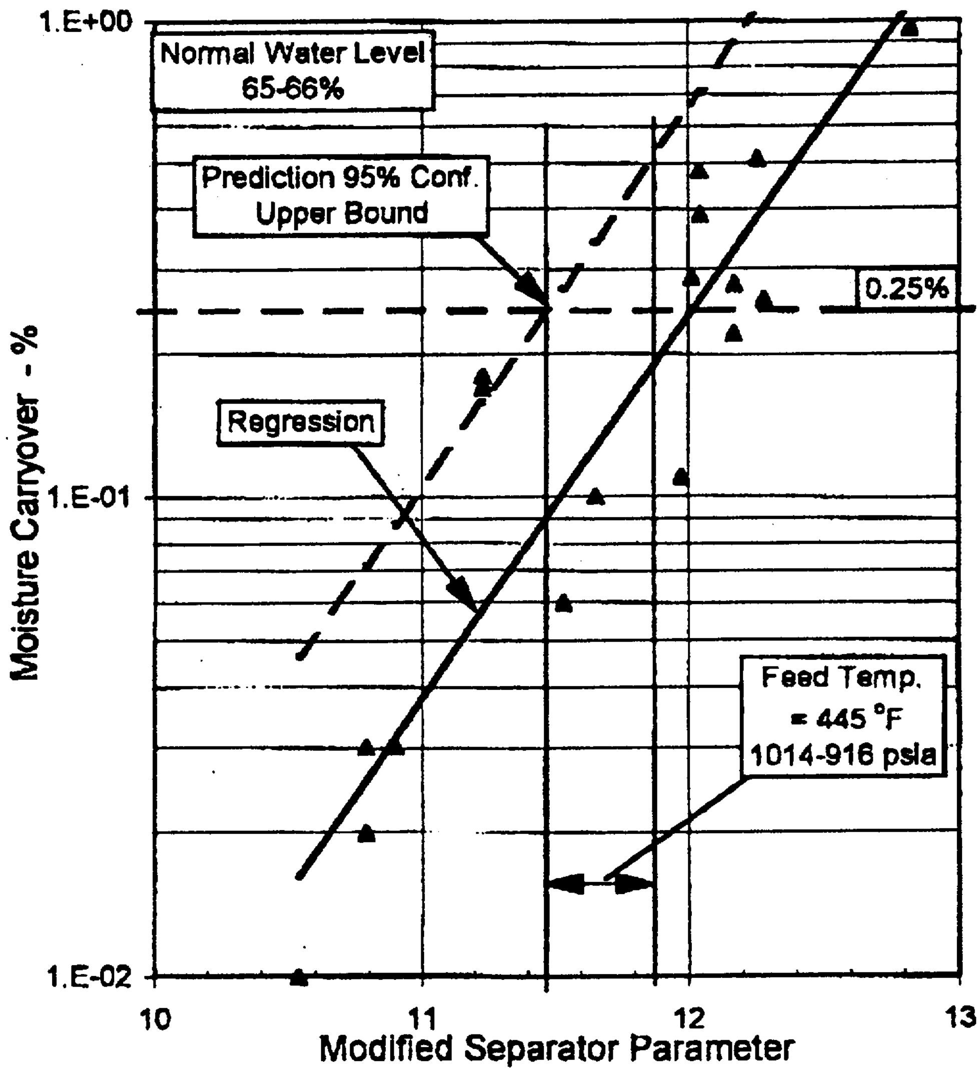

Figure 5.6-1 Moisture Carryover Projection for Comanche Peak Unit 1, Model D4 Steam Generators

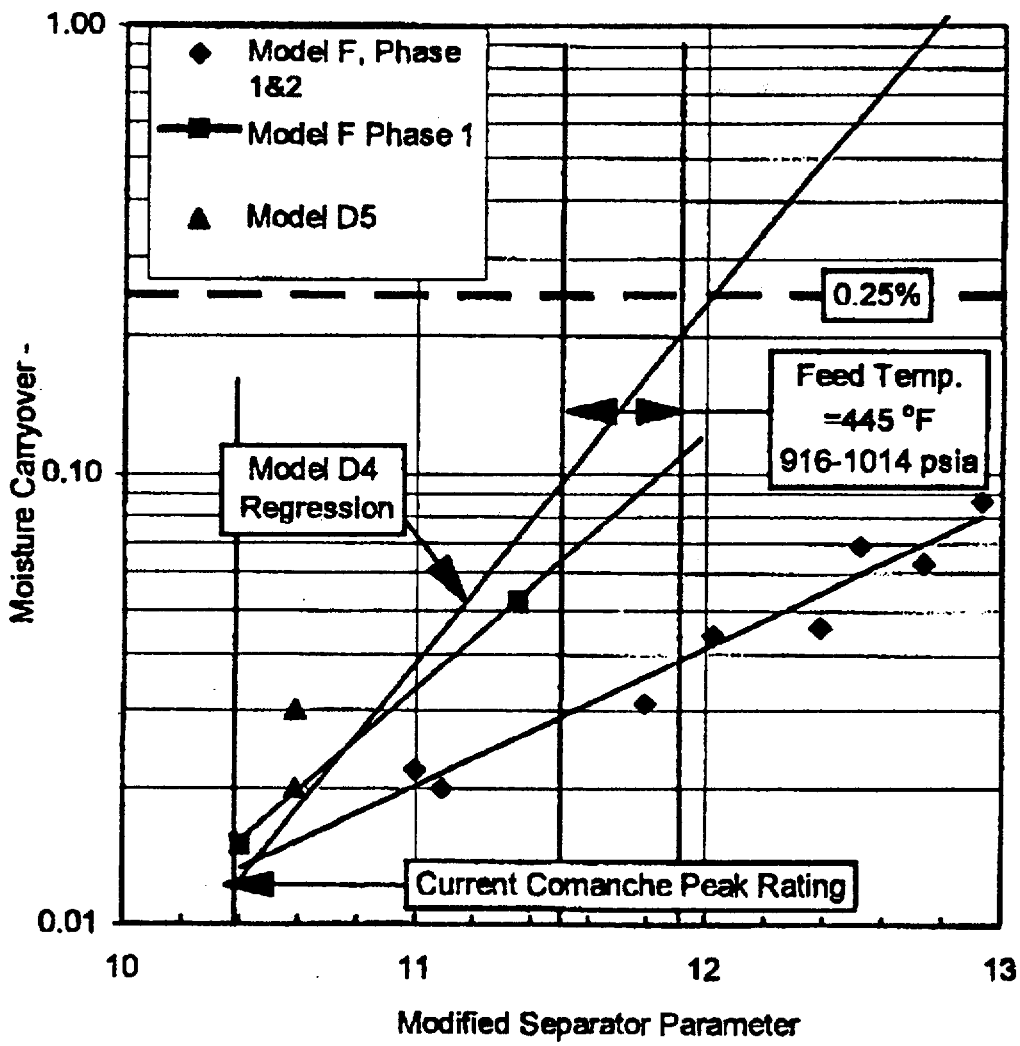

Figure 5.6-2 Moisture Carryover Projection for Comanche Peak Unit 2, Model D5 Steam Generators

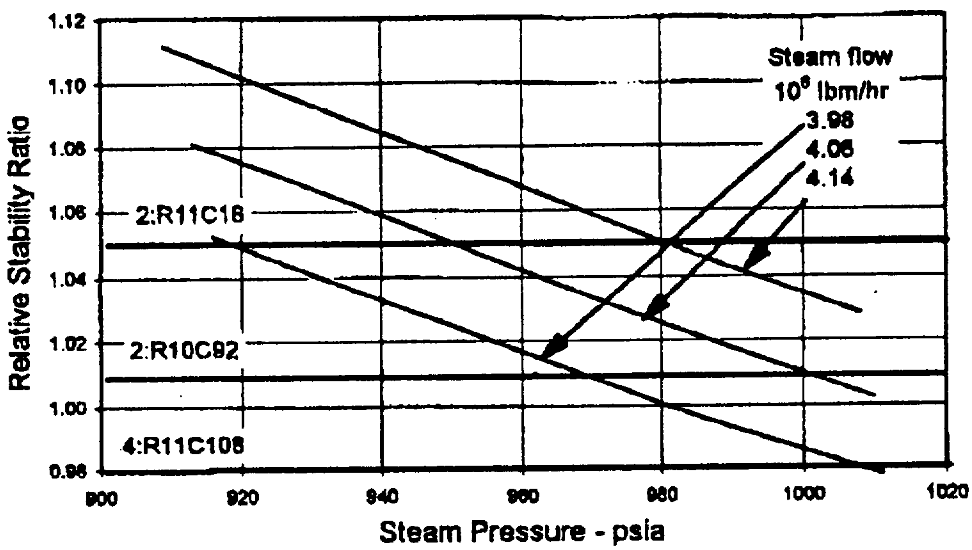

Figure 5.6-3 Comanche Peak Unit 1 U-bend Fatigue: Limiting Operating Conditions for Susceptible Tubes

Mr. D. N. Morey
Vice President - Farley Project
Southern Nuclear Operating
Company, Inc.
Post Office Box 1295
Birmingham, Alabama 35201-1295

December 29, 1999

SUBJECT: JOSEPH M. FARLEY NUCLEAR PLANT, UNITS 1 AND 2 — ISSUANCE OF AMENDMENTS RE: STEAM GENERATOR REPLACEMENTS (TAC NOS. MA4393 and MA4394)

Dear Mr. Morey:

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 147 to Facility Operating License No. NPF-2 and Amendment No. 138 to Facility Operating License No. NPF-8 for the Joseph M. Farley Nuclear Plant, Units 1 and 2. The amendments change the Unit 1 and Unit 2 Improved Technical Specifications (ITS) in response to your application of December 1, 1998, as supplemented by your letters of April 21, July 19, October 18, and November 11, 1999. The amendments revise the ITS to address changes associated with replacing the current Westinghouse Model 51 steam generators with Westinghouse Model 54F steam generators. The Unit 1 ITS set applies after you replace the Unit 1 steam generators in spring 2000 until you replace the Unit 2 steam generators in spring 2001. The Unit 2 ITS set applies after you replace both the Unit 1 and the Unit 2 steam generators.

We are also enclosing a copy of our related safety evaluation. We will include a Notice of Issuance in the Commission's biweekly *Federal Register* Notice.

Sincerely,

L. Mark Padovan, Project Manager, Section 1
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-348 and 50-364

Enclosures: 1. Amendment No. 147 to NPF-2
2. Amendment No. 138 to NPF-8
3. Safety Evaluation

cc w/ encls: See next page

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NOS. 147 AND 138 TO FACILITY

OPERATING LICENSES NPF-2 AND NPF-8

JOSEPH M. FARLEY NUCLEAR PLANT, UNIT 1 AND UNIT 2

SOUTHERN NUCLEAR OPERATING COMPANY

DOCKET NUMBERS: 50-348 AND 50-364

Enclosure 3

Table of Contents

I. INTRODUCTION

By letter of December 1, 1998, as supplemented by letters of April 21, July 19, October 18, and November 11, 1999, the Southern Nuclear Operating Company, Inc. (SNC), et al., submitted a request for changes to the Joseph M. Farley Nuclear Plant, Units 1 and 2, Improved Technical Specifications (ITS). The requested changes would revise the ITS to address changes associated with replacing the current Westinghouse Model 51 steam generators (SGs) with Westinghouse Model 54F SGs. The April 21, July 19, October 18, and November 11, 1999, letters provided clarifying information that did not change the December 1, 1998, application and the initial proposed no significant hazards consideration determination.

II. BACKGROUND

The existing SGs in both Farley units are Westinghouse Model 51. The tubes are made of Alloy 600 and the tube support plates are made of carbon steel. Using these materials contributed, in part, to the existing SG tube degradation. As degradation occurred, SNC requested amendments to the plant technical specifications for various alternate tube repair criteria which the Nuclear Regulatory Commission (NRC) subsequently reviewed and approved. The various repair criteria are voltage-based alternate repair criteria, F* criteria, and sleeving repair criteria.

The new, replacement SGs will be Westinghouse Model 54F using thermally treated Alloy 690 tube material and stainless steel tube support plates. The Alloy 690 tubing material is more resistant to stress corrosion cracking than Alloy 600 tubing material. The Model 54F stainless steel tube support plates will be more resistant to magnetite formation than carbon steel support plates and minimize tube denting. Licensees that have used these materials in their replacement SGs have reported minimal tube degradation. SNC determined that the alternate tube repair criteria in the current ITS are unnecessary for the replacement SGs and requested removing this criteria from the Farley Units 1 and 2 ITS.

SNC plans to replace the Unit 1 SGs in spring 2000 and the Unit 2 SGs in spring 2001. The amendment request contains a proposed Unit 1 ITS changes set and a Unit 2 ITS changes set. The Unit 1 ITS changes set contains changed Unit 1 ITS and unchanged Unit 2 ITS. The approved Unit 1 ITS set will apply after SNC replaces the Unit 1 steam generators in spring 2000 until SNC replaces the Unit 2 steam generators in spring 2001. The Unit 2 ITS changes set contains the previously changed Unit 1 ITS and newly changed Unit 2 ITS. The approved Unit 2 ITS set will apply after SNC replaces both the Unit 1 and the Unit 2 steam generators.

III. EVALUATION

SNC performed analyses and evaluations in accordance with the Farley Nuclear Plant current licensing basis to support replacing the Westinghouse Model 51 SGs. Our evaluation of their associated ITS amendment request follows:

A. Mechanical and Structural Design

1.0 Structural Analysis

The basic design of the Model 54F SG is consistent with that of prior Westinghouse SGs. The Model 54F SG is considered a close replica of the current Model 51 SG. The structural design of the SG is based on the American Society of Mechanical Engineers Boiler & Pressure Vessel Code, Section III (ASME Section III), Subsections NB and NC, 1989 Edition. This edition is currently endorsed in Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.55a and is, therefore, acceptable.

Westinghouse's WCAP-12825 (Ref. 1) technically justified applying leak-before-break (LBB) considerations to eliminate postulated loss-of coolant accident (LOCA) pipe ruptures from the Farley Nuclear Plant reactor coolant loop (RCL) design basis, in accordance with General Design Criterion (GDC) 4 of 10 CFR Part 50, Appendix A. In WCAP-12835 (Ref. 2) and its Supplement 1 (Ref. 3), Westinghouse similarly justified eliminating postulated pressurizer surge line pipe rupture. Our letters of August 12, 1991 (Ref. 4), and January 15, 1992 (Ref. 5), approved applying LBB considerations for eliminating breaks in the Farley Units 1 and 2 primary loop piping based on the Model 51 SGs.

Westinghouse excluded the thermo-hydraulic loads associated with RCL and pressurizer surge line LOCA ruptures from the structural design basis of the RCL piping and the SGs based on our Ref. 4 and Ref. 5 letters. In addition, Westinghouse did not postulate arbitrary, intermediate breaks in the main steamlines in accordance with revised Standard Review Plan (SRP), Section 3.6.2, Mechanical Engineering Branch Position 3-1 provisions.

Each of the current Model 51 SGs is restrained by 5 snubbers, for a total of 15 snubbers per unit. Westinghouse decided to install the Model 54F SGs without using snubbers since Westinghouse analyses eliminated the thermo-hydraulic loads resulting from the postulated RCL LOCAs. Westinghouse re-analyzed the reactor coolant system (RCS) with the existing RCL supports but excluded the five snubbers to verify that the RCS design meets current licensing basis (CLB) design criteria.

Westinghouse's analysis consisted of geometrically non-linear time-history dynamic structural analyses of the RCS subjected to various loading conditions with the Model 54F SG mass distribution and with the snubbers removed. Westinghouse performed these non-linear analyses to account for impact effects due to gapped bumper restraints in the RCS. The dynamic loading conditions consisted of time histories of the operating-basis earthquake (OBE), safe-shutdown earthquake (SSE), and thermo-hydraulic loads due to postulated pipe ruptures in either the main steamlines or the feedwater lines.

Westinghouse performed the time-history analyses using structural computer codes WECAN and WESTDYN. WCAP-8252 (Ref. 6) documents versions of these programs and the Farley Final Safety Analysis Report (FSAR) lists WCAP-8252 as a structural analyses reference. Westinghouse's analysis method is based on the pseudo-force approach which requires calculating the RCL system normal modes and frequencies for its implementation. Modal amplitudes and system response depend on the damping specified for the system. Westinghouse stated in their response of July 19, 1999 (Ref. 7), to our July 2, 1999, request for additional information (RAI) that their analysis used the CLB damping factors shown in Table 3.7-1 of the Farley Units 1 and 2 FSARs. The staff finds this acceptable.

Westinghouse performed a 10 CFR 50.59 LBB reevaluation of the RCL piping and the pressurizer surge line using the piping forces and moments resulting from the non-linear, seismic, structural analysis of the RCS. Westinghouse stated that the reevaluation showed that the recommended LBB margins in Draft Section 3.6.3 of the SRP (Ref. 8) were satisfied at the critical locations. This demonstrates the acceptability of applying LBB for the RCL piping with the Model 54F SGs. Westinghouse also found that the impact on the pressurizer surge line due to the Model 54F SG and a snubber elimination program was negligible. Therefore, the existing LBB analysis, based on the current RCS configuration with the Model 51 SG, remains valid.

2.0 RCS Stresses

The largest combined RCL piping stress resulting from the design loading combination of OBE, deadweight, and pressure was determined to be 21.1 ksi compared to the ASME Section III Code-allowable stress of 26.7 ksi. The largest combined stress under faulted conditions, consisting of SSE and either a main steamline break (MSLB) or a feedwater line break, was determined to be 39.5 ksi compared to the Code-allowable stress value of 53.4 ksi. The highest-stressed RCS equipment nozzle was found to be on the reactor pressure vessel (RPV). The largest nozzle stress intensity was found to be 92 percent of the allowable value under OBE conditions. The same nozzle under combined SSE and the highest loading from LOCA or MSLB or feedwater line break was found to be 69 percent of the allowable faulted condition allowable. The staff finds these results reasonable and acceptable.

3.0 RCL Supports

For the Model 54F SG, the highest stress in a column support was found to be 92 percent of the faulted allowable stress. For the reactor coolant pumps (RCPs), the stress was found to be 42 percent of the faulted allowable stress. The stress in the highest loaded bumper was determined as 31 percent of the upset allowable stress. The staff finds these results reasonable and acceptable.

In SNC's letter of July 19, 1999, Westinghouse also provided the design basis criteria for the support columns. These criteria are based on the structural code of record (Ref. 9) for Farley Units 1 and 2, modified to reflect faulted conditions. The staff has reviewed the Westinghouse response and finds it acceptable.

The reactions of the reactor vessel support structures to applied forces resulting from all load conditions were determined from a finite element analysis of these structures. The dynamic forces applied to these structures consist of a combination of forces obtained from the RCL analysis, reactor pressure cavity, and the reactor vessel internals analysis. The maximum stress intensity under normal or upset conditions was found to be 47 percent of the allowable stress intensity. The maximum stress intensity under faulted conditions was determined to be 38 percent of the faulted condition allowable stress intensity. The staff finds these results reasonable and acceptable.

4.0 Balance of Plant

SNC assessed the effects of installing the Model 54F SGs on balance of plant (BOP) safety-related structures and components not covered in WCAP-15098 (Ref. 10). The Farley Steam Generator Replacement Program BOP Licensing Report (Ref. 11) contains Farley Nuclear Plant BOP analyses and evaluations. Both SNC and Westinghouse provided input to these analyses and evaluations. SNC stated that CLB design criteria and analyses or previous power uprate submittals bound these structures and components. SG replacement impact on

BOP structure and component function and operation has been analyzed or evaluated and was found to have no significant adverse effect. The staff finds this reasonable and acceptable.

5.0 Conclusion

The staff finds that SNC has provided justification to support replacing the current Model 51 SGs with the Model 54F SGs based on the acceptability of applying LBB considerations to the RCL piping. The staff also finds that replacing the SG Model 51 with SG Model 54F will not significantly affect RCS structural integrity, and that the structural design of the RCLs and their supports meet Farley Nuclear Plant, Units 1 and 2, FSAR CLB design criteria.

B. Design Basis Accidents and Transients

SNC re-analyzed or evaluated design basis accidents and transients in support of the SG replacement as described below.

1.0 Re-analyzed Design Basis Accidents and Transients

SNC re-analyzed the following design basis accidents and transients to demonstrate that the applicable licensing criteria and requirements are satisfied considering the effects of the SG replacement. The analyses impacted by the SG replacement either support ITS changes or are not considered bounded by submittals previously reviewed by the NRC.

a. Loss of Normal Feedwater

Westinghouse re-analyzed the loss of normal feedwater transient using the RETRAN-02 computer code. Westinghouse's letter of June 6, 1997 (Ref. 12), submitted WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," to the NRC for review. Our letter of February 11, 1999 (Ref. 13), indicated our acceptance of WCAP-14882 for referencing in licensing applications to the extent specified and under the limitations delineated in the report and in the associated NRC safety evaluation. SNC satisfactorily addressed each of these limitations as they relate to the Farley SG replacement.

The acceptance criteria for the loss of normal feedwater transient are as follows:

- The critical heat flux shall not be exceeded. Preventing departure from nucleate boiling (DNB) demonstrates this.
- Pressure in the reactor coolant and main steam systems shall be maintained below 110 percent of the design pressures.
- There shall be no propagation to a more serious event.

With respect to DNB, the loss of external electrical load event bounds the loss of normal feedwater transient. The loss of external electrical load event demonstrates that the minimum departure from nucleate boiling ratio (DNBR) is greater than the DNB acceptance criterion. With respect to RCS overpressurization, the loss of external load event also bounds the loss of normal feedwater transient. The loss of external load event demonstrates that the peak primary and secondary system pressures remain below 110 percent of design. Analysis results show that the pressurizer does not become water solid.

b. Loss of All AC Power to the Station Auxiliaries

The loss of all AC power event was re-analyzed using the RETRAN-02 computer code. The acceptance criteria for this event are as follows:

- The critical heat flux shall not be exceeded. Preventing DNB demonstrates this.
- Pressure in the reactor coolant and main steam systems shall be maintained below 110 percent of the design pressures.
- There shall be no propagation to a more serious event.

With respect to DNB, the complete loss of flow event bounds the loss of all ac power event. The complete loss of flow event demonstrates that the DNBR is greater than the DNB acceptance criterion. With respect to RCS overpressurization, the loss of external load event bounds the loss of all ac power to station auxiliaries event. The loss of external load event demonstrates that peak primary and secondary system pressures remain below 110 percent of design. Analysis results show that the pressurizer does not become water solid.

c. Main Steamline Rupture at Zero Power

The main steamline rupture was re-analyzed using the RETRAN-02 computer code. The event was conservatively analyzed at zero power with no decay heat. The acceptance criterion for this event is that the critical heat flux shall not be exceeded, which preventing DNB demonstrates. The results of the re-analysis demonstrated that the minimum DNBR for the steamline break event initiated at zero power remains above the limit value.

d. Major Main Feedwater Pipe Rupture

The major feedwater line rupture event was re-analyzed using the RETRAN-02 computer code. The acceptance criteria for this event are as follows:

- Pressure in the reactor coolant and main steam systems shall be maintained below 110 percent of the design pressures.
- Any fuel damage that may occur during the transient should be of sufficiently limited extent so that the core will remain in place and geometrically intact with no loss of core cooling capability.
- Any activity release must result in calculated doses at the site boundary being within a small fraction of 10 CFR Part 100 guidelines.

To ensure that these criteria are met, Westinghouse established an internal criterion that no bulk boiling occurs in the RCS following a feedwater line rupture before SG heat removal capability (being fed by the auxiliary feedwater system) exceeds nuclear steam supply system

(NSSS) residual heat generation. The analysis demonstrated that the auxiliary feedwater system capacity is adequate to remove core decay heat, prevent overpressurizing the RCS, and prevent uncovering the reactor core.

e. Steam Generator Tube Rupture

The steam generator tube rupture (SGTR) event was re-analyzed using the hand calculation method which reflects the current plant licensing basis. This is the same method described in Farley FSAR Section 15.4, and is consistent with the analyses performed to support the Farley power uprate which was approved the NRC's letter of April 29, 1998 (Ref. 14). The SGTR analysis was performed to determine the quantity of primary-to-secondary leakage from the SGs and the quantity of steam released to the environment. The results were used in the radiological consequences analysis to verify that the postulated offsite dose consequences are acceptable.

f. Best Estimate Large-Break LOCA

Section 4.1.1 of Farley's Replacement SG Program NSSS Licensing Report (Ref. 10) discusses large-break LOCA (LBLOCA) re-analyses for replacing SGs, adapting the Farley Best Estimate (BE) LOCA model used to perform the re-analyses, the process implemented to determine the adaptation, and LBLOCA results. We reviewed this information as discussed below.

(i) Replacement SG Adaptation Assessment Process and Farley BE LBLOCA Model

Section 4.1.1.2 of Farley's Licensing Analysis Report described the process SNC used to adapt the existing approved Farley licensing Best Estimate LOCA (BELOCA) methodology to reflect installing the replacement SGs. The process included all elements of the BE methodology and considered input values, reference transient assumptions, various uncertainty response surfaces and distribution functions, effect of the changed containment conditions, and superposition correction. The adaptation process as used in this evaluation report does not necessarily include any specific finding resultant from its application. Based on sensitivity studies and comparative assessments, SNC concluded that the uncertainty elements of the methodology retained the basic characteristics of the current BELOCA licensing methodology. SNC had to re-perform only the reference peak cladding temperature (PCT) calculation and the superposition calculation in establishing the Monte Carlo structure for the replacement SG final PCT calculations.

Based on our review, we conclude that the process used to adapt the existing BELOCA methodology to reflect installing the replacement SGs is acceptable because it is comprehensive and effective in identifying the necessary changes. We also conclude that the same overall process described in Farley Licensing Report Section 4.1.1.2 is acceptable for future SG change/LBLOCA analysis methodology assessments and adaptations, such as steam generator plugging levels outside those already considered in the present analyses. Based on this conclusion we find the adaptation process (Farley Licensing Report Section 4.1.1.2) is acceptable for reference in the Farley Core Operating Limits Report (COLR), Technical Specifications, or other licensing documentation and may be used in future analyses in which SNC changes similar SG parameter values.

(ii) Replacement SG LBLOCA Methodology

The Farley BE LBLOCA methodology is based on the Westinghouse BE LBLOCA methodology described in WCAP-12945-P-A, which acceptably considers within its uncertainty processes input parameter values over ranges that bound their as-operated plant values. In SNC's letter of November 22, 1999, SNC confirmed that SNC and Westinghouse have processes which ensure that the PCT-sensitive parameters (values) used as input to the BE LBLOCA analyses bound the as-operated plant values for Farley. From our review of the Farley BE LBLOCA methodology adaptation process, we noted quantitative effects due to the input of parameter values reflecting the replacement SGs. However, the approved Farley BE LBLOCA methodology itself has not changed because none of its elemental processes have changed. Therefore, based on the continued acceptability of the LBLOCA methodology and SNC's use of processes to ensure that PCT-sensitive input parameter values bound their as-operated plant values, we conclude the Farley replacement SG BE LBLOCA methodology is acceptable and applicable to Farley. We find that SNC's LBLOCA methodology is suitable for reference in the Farley TS and COLRs as long as the processes for specifying analysis inputs continue to assure that PCT-specific input values bound the corresponding as-operated plant values.

(iii) LBLOCA Analyses

SNC performed licensing basis replacement SG LBLOCA analyses using the acceptable BE LBLOCA methodology discussed in Section f. (ii) of this safety evaluation. The licensing basis case is a cold-leg split break with a break discharge coefficient of 1.0 and 20 percent SG tube plugging. SNC identified that Farley Unit 2 continued to be bounding based on sensitivity studies performed as part of the previous power uprate analyses and on qualitative assessments of applying those analyses findings to the replacement SG analyses.

SNC determined that ZIRLO fuel in the hot assembly bounded the other fuel types. The calculated licensing basis PCT is 2065 ^{o}F; the maximum total (pre-transient plus transient) cladding oxidation is 12 percent; and the maximum core-wide hydrogen generation is 0.6 percent. These values fall below the criteria specified in 10 CFR Part 50.46 (b). Compliance with the 10 CFR Part 50.46 (b) criteria that the core remains amenable to cooling and for long-term cooling is qualitatively the same as the acceptable results from the previous Farley (power uprate) BE LBLOCA analyses.

SNC used these bounding analyses for both units. Using the Farley Unit 2 analyses as a basis for both plants is acceptable because SNC has determined that the Farley 2 analysis is bounding for both plants. This is based on extensive sensitivity studies preformed for the power uprating of both Farley units with the approved licensing basis BE LBLOCA methodology and based on qualitative assessments adapting the sensitivity analyses results. However, significant differences in the two Farley unit designs could affect the validity of mutual portions of the uncertainty analyses in the BE LBLOCA model. Therefore, for future re-analyses, SNC must justify the applicability of the analytical results either by determining the bounding analysis from comparative sensitivity analyses of re-analysis scenarios for both units or by performing a plant-specific bounding licensing basis analysis for each unit.

We conclude that the Farley replacement SG BE LBLOCA analyses are acceptable because of the following:

- SNC used an applicable, acceptable LBLOCA model.
- Parameter input values and ranges bound the as-operated plant values and ranges.
- Calculated results comply with 10 CFR Part 50.46 (b) criteria.

We find that SNC's LBLOCA methodology is suitable for reference in the Farley TS and COLRs as long as the processes for specifying analysis inputs continue to assure that PCT-specific input values bound the corresponding as-operated plant values.

g. Small-Break LOCA Analyses

Section 4.1.2 of Farley's Licensing Analysis Report discusses small-break LOCA (SBLOCA) re-analyses to reflect replacing the SGs, identifies the SBLOCA methodology used to perform the re-analyses, indicated that sensitivity studies were used to determine the limiting SBLOCA case, and gave SBLOCA analyses results.

(i) SBLOCA Methodology

The SBLOCA methodology used to analyze both Farley units for the replacement SG configuration is the Westinghouse NOTRUMP model discussed in WCAP-10054-P-A, as adapted to include the COSI Safety Injection/Steam condensation model discussed in WCAP-10054-P-A/WCAP-11767-P, Addendum 2, Revision1, July 1997. This methodology has been approved for application to Westinghouse power reactor designs, including the Farley units. Therefore, the NOTRUMP with COSI SBLOCA analysis methodology applies to both Farley plants.

SNC's November 22, 1999, letter indicated that, for SBLOCA analyses, Westinghouse and SNC have processes to ensure that the values of PCT-sensitive parameters input into SBLOCA analyses bound their as-operated plant values for Farley. This assures that the input values for Farley SBLOCA analyses parameters will be appropriate, and therefore, the SBLOCA analysis methodology applies to Farley.

(ii) Sensitivity Studies and Results

SNC described sensitivity analyses, including break size, operating temperature, time-in-life and fuel type studies, that they performed to identify the worst-case SBLOCA scenario. The results for the bounding 3-inch SBLOCA analysis identify that the fuel with ZIRLO cladding is limiting. The calculated PCT is 2030 ^{o}F, and the calculated maximum local oxidation is 11.88%.

(iii) SBLOCA Conclusions

We conclude that the Farley Replacement SG SBLOCA analyses are acceptable because they were performed with an applicable acceptable SBLOCA model, with parameter input values and ranges that bound the as-operated plant values and ranges, and because the calculated results show compliance with the criteria of 10 CFR Part 50.46(b). We find that SNC's SBLOCA methodology is suitable for reference in the Farley TS and COLRs as long as the processes for specifying analysis inputs continue to assure that PCT-specific input values bound the corresponding as-operated plant values.

h. Future LOCA Re-analyses

In order to more effectively implement 10 CFR Part 50.46 reporting requirements and to validate the uncertainty analyses in the BE LBLOCA methodology, for future LOCA re-analyses it is necessary for SNC either to determine the bounding analysis from comparative sensitivity analyses of re-analysis scenarios for both units or to perform a plant specific bounding licensing basis analysis for each unit.

2.0 Design Basis Accidents and Transients not Re-analyzed

SNC indicated that the following design basis accidents and transients did not require re-analysis since either (a) they were bounded by the previously approved power uprate analyses, or (b) the analyses were not adversely impacted by the SG replacement (i.e., replacing the SGs requires only a minimal change to the current analysis of record, and the analysis still meets applicable acceptance criteria):

- hot leg switchover
- post-LOCA long-term core cooling
- rod ejection accident
- uncontrolled rod cluster control assembly (RCCA) withdrawal from a subcritical position
- RCCA misalignment
- uncontrolled boron dilution
- partial loss of forced reactor coolant flow
- startup of an inactive LBB
- loss of external electrical load and/or turbine trip
- excessive heat removal due to feedwater system malfunctions
- excessive load increase accident
- accidental depressurization of the RCS
- accidental depressurization of the main steam system
- inadvertent operation of the emergency core cooling system during power operation
- minor secondary system pipe breaks
- inadvertent loading of a fuel assembly into an improper position
- complete loss of forced reactor coolant flow
- single rod cluster control assembly withdrawal at full power
- single RCP locked rotor
- rupture of a control rod drive mechanism housing
- steam system piping failure at full power
- anticipated transient without scram

3.0 Technical Specification Changes and Evaluation

SNC has proposed to change the SG water level low-low setpoint from 25 percent to 28 percent and the allowable value from 24.6 percent to 27.6 percent in TS table 3.3.1-1, "Reactor Trip System Instrumentation," and in ITS Table 3.3.2-1, "Engineered Safety Feature Actuation System Instrumentation." SNC also proposes to change the SG water level high-high setpoint from 78.5 percent to 82 percent; and the allowable value from 78.9 percent to 82.4 percent in ITS Table 3.3.2-1, "Engineered Safety Feature Actuation System Instrumentation."

TS LCO 3.4.7, "RCS Loops Mode 5, Loops Filled," currently specifies that the secondary side water level of at least two SGs shall be > 74 percent wide range (WR). SNC has proposed to change the minimum SG water level to > 75 percent WR. In addition, ITS surveillance requirements 3.4.5.2, "RCS Loops Mode 3," 3.4.6.2, "RCS Loops Mode 4," and 3.4.7.2, "RCS Loops, Loops Filled," require that SG secondary side water levels be verified every 12 hours for required RCS loops. SNC has proposed to change the required water level in the surveillance requirements from > 74 percent WR to > 75 percent WR consistent with the proposed limiting condition for operation.

These above proposed changes resulted from analytical values associated with replacement SG design differences and new analyses. These changes provide acceptable results for all effected transients and accidents. We find these changes to be acceptable.

4.0 Conclusion

The staff has reviewed SNC's proposed TS changes associated with replacing the SGs and SNC's supporting re-analysis and evaluation of design basis accidents and transients. Based on the review, the staff concludes that the proposed TS changes are acceptable.

C. Containment Integrity

SNC has performed containment integrity analyses for replacing the SGs at current uprated power to ensure that the maximum pressure inside the containment will remain below the containment building design pressure of 54 psig if a design bases LOCA or MSLB inside containment should occur during plant operation. The analyses also established the pressure and temperature conditions for environmental qualification and operation of safety-related equipment located inside the containment and the containment leak rate test pressure.

SNC indicated that the containment functional analyses included assuming the most limiting single active failure and the availability or unavailability of offsite power, depending on which resulted in the highest containment temperature and pressure. Bounding initial temperatures and pressures for analyses were selected to envelope the limiting conditions for operation.

1.0 LOCA Containment Integrity Analyses

SNC has performed analyses to determine the containment pressure and temperature response during postulated LOCAs using mass and energy releases which incorporate revised Model 54F SG design parameters at the current uprated power level of 2775 MWt. As in the current analyses, the postulated LOCA analyses were performed for the double-ended hot leg (DEHL) guillotine break of reactor coolant pipe and the double-ended pump suction (DEPS) break. SNC determined that the DEHL break results in the most limiting pressure during the blowdown phase and that the DEPS break yields the highest energy flow rates during the post-blowdown period.

SNC indicated that Westinghouse calculated the mass and energy releases in the containment for the Model 54F SG using Topical Report WCAP-10325-P-A. In this analyses, the 1979 ANS 5.1 decay heat model with 2 sigma uncertainty factor was used. The same Westinghouse Topical Report and decay heat model were used in the current licensing basis analyses. The mass and energy release analyses were presented in WCAP-15098 (Ref. 10).

The containment pressure and temperature response analyses for Model 54F SG were performed using the GOTHIC computer code. The use of GOTHIC computer code and input assumptions for Farley was determined acceptable in the current power uprate analyses. The primary change to the Model 54F SG containment analysis model from the power uprate model were the blowdown mass and energy releases because of replacement SG design. No other changes were made to the analyses which would significantly affect the calculated peaks. Only small changes to the residual heat removal heat transfer area and flow were modeled to represent plant design data with a margin for tube plugging.

Farley Model 54F SG analyses calculated a containment peak pressure of 43.8 psig and a peak temperature of 264°F for the LOCA (DEHL and DEPS breaks). The current uprate LOCA peak pressure and temperature were 43.0 psig and 263°F. SNC indicated that the change in the LOCA peak pressure from present 43.0 psig to 43.8 psig is mainly due to the increased blowdown mass and energy releases associated with the Model 54F SG design (more tubes in Model 54F than Model 51). The calculated peak LOCA pressure of 43.8 psig and temperature of 264°F remains below the containment design pressure of 54 psig and design temperature of 280°F. SNC has proposed to revise the ITS to change the containment leak rate test pressure from 43.0 psig to 43.8 psig in accordance with Appendix J requirements.

2.0 Main Steamline Break Containment Integrity Analysis

SNC has performed the Model 54F SG analyses to determine the containment pressure and temperature response during postulated MSLBs inside containment for limiting conditions of operation at current uprated power. As in the current uprated analyses, the Model 54F SG analyses were evaluated for initial power levels of 102 percent, 70 percent, 30 percent, and 0 percent and a spectrum of break sizes. SNC indicated that the Model 54F SG MSLB mass and energy releases were calculated using the RETRAN computer code as described in WCAP-14882-P under the limitations delineated in the report and the associated NRC safety evaluation. Earlier analyses used the LOFTRAN computer code. SNC presented the MSLB mass and energy release analyses in WCAP-15098. The staff has found the use of Non-LOCA RETRAN analyses performed in accordance with the methodologies as described in WCAP-14882 and the associated NRC safety evaluation acceptable.

Containment temperature and pressure were calculated using the GOTHIC computer code. The same code is used in the current uprate analyses. SNC indicated that the primary change to the Model 54F SG containment analysis model from the power uprate model was the blowdown mass and energy releases input due to Model 54F SG design. Another key input change was specifying 8 percent condensate revaporization, as allowed by NUREG-0588, Appendix B for the time in which the atmosphere is superheated. No other changes were made to the model which would significantly affect the calculated peaks. Bounding limiting initial containment conditions were assumed for maximum pressure and temperature results.

The Model 54F SG analyses calculated a peak containment pressure of 52.0 psig and a peak temperature of 367°F for the MSLB. The current uprate MSLB peak pressure and temperature were 52.4 psig and 383°F. SNC indicated that the small changes in peak pressure and temperature are mainly due to difference in MSLB mass and energy releases and 8 percent revaporization as allowed by NUREG 0588, Appendix B. The Model 54F SG MSLB peak calculated containment pressure of 52.0 psig remains below the containment design pressure of 54 psig. The MSLB peak air temperature of 367°F will last for < 6 minutes above 280°F and the containment structure temperature will remain below the containment design temperature of 280°F. Also, updated calculated pressure and temperature curves for LOCA and MSLB cases will remain bounded by the curves used for equipment qualifications.

Based on the above discussion, the staff finds the proposed ITS changes for replacement SGs will not affect the containment integrity as the calculated peak containment pressure and temperature remain below the containment design pressure and temperature and; therefore, are acceptable.

3.0 Short-Term Subcompartment Analysis

SNC indicated that they reviewed the short-term LOCA-related mass and energy releases to assess the effects associated with SG replacement. Although LBB approval for Farley included the pressurizer surge line, pressurizer surge line blowdown was used as bounding input for the RCL subcompartment analyses using GOTHIC computer code. Changes to reflect the Model 54F SG and new grating platforms were included in the model. The result demonstrated that the RCS loop subcompartment pressure remains bounded by previous design basis analysis. The pressurizer compartment was not re-analyzed since the pressurizer spray and surge line conditions do not change for SG replacement.

Based on the above review, the staff concludes that the SG replacement is acceptable as the subcompartment pressure loading analysis remains bounded by the current design basis subcompartment analysis.

D. Post-LOCA Hydrogen Generation

Hydrogen is generated following a LOCA inside containment from the zirconium-water reaction, corrosion of materials inside containment, radiolytic decomposition of core and sump solution, and hydrogen present in the reactor coolant and pressurizer vapor space. SNC indicated that the effect of SG replacement was reviewed for the above modes of post-LOCA hydrogen production and for combustible gas control system capability to maintain acceptable hydrogen concentration inside containment.

SNC stated that two 100 percent capacity hydrogen recombiners, post accident containment venting, post-accident containment mixing, and post-accident combustible gas sampling systems are provided to maintain hydrogen concentration below four volume percent within the containment. Farley Nuclear Plant procedures specify placing the recombiners in service within 1 hour after the LOCA, but SNC takes credit for their operation 1 day after the LOCA start.

SNC used the hydrogen generation model based on NRC Regulatory Guide 1.7 to evaluate the changes from SG replacement. SNC used the LOCA temperature profile from the containment temperature accident analysis as an input for evaluating the corrosion rate of containment materials which generate hydrogen. The analysis results indicate that the post-accident hydrogen concentration inside containment will not exceed the lower flammability limit of 4 volume percent with the operation of one hydrogen recombiner 24 hours after the start of the accident. Plant operators would initiate containment purging at day 7 following an accident in the unlikely event both recombiners fail to start. The dose due to containment purging added to the doses from other post-accident consequences would remain within the limits of 10 CFR Part 100. SNC determined the increase in hydrogen generation rate due to Model 54F SGs has a negligible effect on the hydrogen recombiners, post-accident venting, post-accident hydrogen mixing or sampling systems.

Based on the above review, the staff finds that the SG replacement is acceptable as it will not impact the post-LOCA hydrogen control system.

E. Radiological Dose Consequences

SNC proposes to increase both the instantaneous and the 48-hour ITS values for dose equivalent I-131 (DEI-131) in the reactor coolant to 0.5 mCi/gm. SNC performed analyses and evaluations to demonstrate that all acceptance criteria, including the dose criteria continue to be met for the proposed SG design change and DEI-131 increase.

SNC identified the following design basis accident analyses as being impacted by the change in SG design:

- SGTR
- MSLB
- Loss of Offsite Power
- Turbine Trip/Loss of Load
- RCP Locked Rotor

SNC indicated that the SG design change would not affect any other accident analyses. SNC calculated the doses associated with these accidents for individuals located offsite at the exclusion area boundary (EAB) and at the Low Population Zone (LPZ). SNC used assumptions consistent with the NUREG-0800 SRP, and also used the following major assumptions:

- Dose conversion factors are taken from International Committee on Radiation Protection Publication 30 in lieu of the Regulatory Guides or TID-14844.

- Iodine spike models as described in the appropriate sections of the SRP are used. Although not specifically required by the SRP, a pre-existing iodine spike is also modeled for the loss of offsite power analysis.

- RCS specific activity is assumed to be 1.0 μCi/gm DEI-131, and the RCS operational leakage is assumed to be 1 gpm to the SGs, therefore bounding the proposed ITS limits.

The staff reviewed SNC's calculation assumptions and performed confirmatory calculations. The following sections provide the results of the staff's assessment of SNC's re-analysis of the

FSAR Chapter 15 accidents affected by the SG design change and the change in primary coolant TS levels for dose equivalent I-131.

1.0 Steam Generator Tube Rupture

SNC evaluated SGTR radiological consequences using the guidance of SRP Section 15.6.3. Two cases were analyzed as described in the SRP:

Case 1 - An SGTR with a pre-accident iodine spike of 60 μCi/gm DEI-131 in the primary coolant.

Case 2 - An SGTR with an accident initiated iodine spike with an appearance rate 500 times the equilibrium RCS activity of 1.0 μCi/gm DEI-131.

Both cases assumed no tube uncovery and immediate flashing of primary-to-secondary leakage in the ruptured SG.

SNC's calculated results meet the SRP acceptance criteria for each case as shown in Table 1 below.

Table 1
SNC-Calculated SGTR Doses

	Dose (rem)		SRP Acceptance Criteria (rem)
	EAB	**LPZ**	
Thyroid ***Case 1**	131	49	300
Thyroid ****Case 2**	18	7.3	30
Whole Body	0.26	0.1	2.5

* Case 1 = pre-accident iodine spike
**Case 2 = accident initiated iodine spike

SNC also evaluated the impact of SG tube uncovery during the event for the new SG design. This evaluation assumed 1.0 μCi/gm DEI-131 and a 1 gpm primary-to-secondary leak rate released directly to the environment for the first 30 minutes. The offsite dose results were within 10 percent of 10 CFR Part 100 limits. The staff reviewed SNC's assumptions and determined them to be acceptable. The staff also performed a confirmatory calculation using SNC's assumptions as submitted and confirmed the results. The staff finds the SGTR evaluation acceptable.

2.0 Main Steamline Break

SNC performed an evaluation of the radiological consequences of the MSLB using SRP Section 15.1.5 guidance, except that partition factors in the intact SGs were assumed to be limited to 10. Two cases were analyzed as described in the SRP:

Case 1 - An SGTR with a pre-accident iodine spike of 60 μCi/gm DEI-131 in the primary coolant.

Case 2 - An SGTR with an accident initiated iodine spike with an appearance rate 500 times the equilibrium RCS activity of 1.0 μCi/gm DEI-131.

Both cases assumed no tube uncovery nor immediate flashing of primary-to-secondary leakage in the affected SG. SNC's calculated results meet the SRP acceptance criteria for each case as shown in Table 2 below.

Table 2
SNC-Calculated MSLB Doses

	Dose (rem) EAB	LPZ	SRP Acceptance Criteria (rem)
Thyroid *Case 1	7.4	3.4	300
Thyroid **Case 2	6.9	3.3	30
Whole Body	$1x10^{-2}$	$4.6x10^{-3}$	2.5

* Case 1 = pre-accident iodine spike
**Case 2 = accident initiated iodine spike

SNC also evaluated the impact of SG tube uncovery during the event for the new SG design. This evaluation assumed 1.0 μCi/gm DEI-131 and a 1 gpm primary-to-secondary leak rate released directly to the environment for the first 30 minutes. The offsite dose results were within 10 percent of 10 CFR Part 100 limits. The staff reviewed SNC's assumptions and determined them to be acceptable. The staff also performed a confirmatory calculation using SNC's assumptions as submitted and confirmed the results. The staff finds the MSLB evaluation acceptable.

3.0 Loss of Offsite Power, Loss of Load, and Turbine Trip

SNC evaluated the radiological consequences of a loss of offsite power, loss of load, and turbine trip bounding steam releases for all three events. SNC followed the guidance given in SRP Sections 15.2.1 - 15.2.6, except the partition factors are assumed to be 10. There is no tube uncovery nor immediate flashing of primary-to-secondary leakage. SNC's calculated results meet the SRP acceptance criteria for each case as shown in Table 3.

Table 3
SNC-Calculated Loss of AC Power Doses

	Dose (rem) EAB	LPZ	SRP Acceptance Criteria (rem)
Thyroid	1.2	0.89	30
Whole Body	$2x10^{-3}$	$1x10^{-3}$	2.5

SNC also evaluated the impact of SG tube uncovery during the events for the new SG design. This evaluation assumed a pre-accident spike of 60 μCi/gm DEI-131 and a 1 gpm primary-to-secondary leak rate released directly to the environment for the first 30 minutes. The results were within 10 percent of 10 CFR Part 100 limits. The staff reviewed SNC's assumptions and determined them to be acceptable. The staff also performed a confirmatory calculation using SNC's assumptions as submitted and confirmed the results. The staff finds the evaluation acceptable.

4.0 Reactor Coolant Pump Locked Rotor

SNC performed an evaluation of the radiological consequences of a single RCP locked rotor assuming 20 percent of the fuel clad/pellet gap gas is released to the primary coolant with subsequent leakage to the SGs and secondary coolant. SNC followed the guidance given in SRP Section 15.3.3. SNC's calculated results meet the SRP acceptance criteria for each case as shown in Table 4 below. The staff reviewed SNC's assumptions and determined them to be acceptable. The staff also performed a confirmatory calculation using SNC's assumptions as submitted and confirmed the results. The staff finds the RCP locked rotor accident evaluation acceptable.

Table 4
SNC-Calculated RCP Locked Rotor Doses

	Dose (rem) EAB	LPZ	SRP Acceptance Criteria (rem)
Thyroid	6.0	8.7	30
Whole Body	0.65	0.34	2.5

5.0 Control Room Operator Doses

SNC stated that control room doses for accidents other than the large break LOCA are less than those for the LOCA and were not explicitly calculated for SG replacement. SNC previously calculated LOCA control room doses for power uprate. In the NRC's Farley power uprate safety evaluation of April 29, 1998, the staff performed confirmatory control room dose calculations for several design basis accidents (including the LOCA and all accidents SNC analyzed for the current SG replacement) to confirm that LOCA control room doses were bounding. The staff finds that since the control room atmospheric dispersion factors are the same for all postulated accidents and since the offsite dose results for the SG replacement indicate that the previous LOCA offsite doses bound the re-analyzed accidents, then the previously calculated LOCA control room doses are still bounding for the SG replacement.

6.0 Conclusion

The staff has assessed SNC's evaluations of those accidents where the change from Westinghouse Model 51 to Westinghouse Model 54F SGs would impact offsite dose consequences. The staff has concluded that for those accidents impacted, the resultant doses would not exceed the acceptance criteria given in the SRP for each accident. Therefore, the staff finds the proposed replacement of the Model 51 SGs with the Model 54F acceptable from an offsite radiological dose standpoint. The staff also finds the change to the reactor coolant activity level of dose equivalent I-131 in TS 3.4.16 and Figure 3.4.16-1 to be acceptable.

F. Operational Leakage and Steam Generator Tube Surveillance Program

For the Unit 1 SG replacement, SNC proposed to delete the requirements and references regarding sleeving repair criteria, F* criteria, and voltage-based alternate repair criteria in ITS 5.5.9. These alternate repair criteria will still apply to the Unit 2 SGs until their replacement in 2002. SNC also proposed to change the RCS operational leakage limit in ITS 3.4.13 for Unit 1 from 140 gallons per day to 150 gallons per day. This is acceptable because the limit of 150 gallons per day is consistent with the limit for Unit 2 and with the limit the staff recommended for other pressurized-water reactors.

For the Unit 2 SG replacement, SNC proposed to delete all requirements and references regarding sleeving repair criteria, F* criteria, and voltage-based alternate repair criteria in ITS 5.5.9 in Farley Units 1 and 2.

The sleeving repair criteria, F* criteria, and voltage-based alternate repair criteria are less restrictive than the traditional tube plugging limit which requires that any tube having a crack that is 40 percent through wall (tube wall thickness) or greater be removed from service. The staff finds that removing these alternate repair criteria is acceptable because the 40 percent through wall plugging limit in ITS 5.5.9 will remain the applicable plugging limit for defective tubes.

SNC also proposed to delete preservice tube inspection in ITS 5.5.9.4 which requires SNC to perform a preservice inspection after the field hydrostatic test and prior to initial power operation. SNC stated that all tubes in the replacement SGs will undergo a shop-performed baseline eddy current examination after an ASME Section III hydrostatic pressure test. The Section III hydrotest will be conducted at a test pressure of 1.25 times the design pressure. Under the current ITS requirement, a field hydrotest is performed in accordance with ASME Code Section XI with a lower test pressure than that of the Section III hydrotest. SNC stated that the field hydrotest will not affect the results of the shop-performed baseline tube inspection results. SNC concluded that the current ITS requirement for preservice tube inspection is unnecessary considering that all tubes will have undergone an ASME Section III hydrotest followed by a baseline eddy current examination before installation. The staff approved a similar technical specification change regarding preservice inspection for the North Anna Units 1 and 2 replacement SGs in a letter to Virginia Power Corporation on December 4, 1991. The staff agrees with SNC and finds that SNC proposed changes to preservice inspection in ITS 5.5.9.4 acceptable.

The staff finds that removing sleeving, F* criteria, and voltage-based alternate repair criteria to repair defective tubes from ITS 5.5.9 is acceptable because the more restrictive tube plugging limit of 40 percent through wall will remain as the applicable requirement in the ITS. The staff finds that revising the RCS operational leakage limit for Unit 1 is acceptable because the proposed new limit is consistent with past staff recommendation. The staff also finds that eliminating the preservice inspection requirements in ITS 5.5.9.4 acceptable because the replacement SGs will have undergone a hydrotest and a baseline eddy current inspection before installation. Thus, the staff finds the proposed amendment of the Farley Units 1 and 2 ITS to be acceptable.

IV. STATE CONSULTATION

In accordance with the Commission's regulations, on December 27, 1999, the NRC notified the Alabama State official, Mr. Jim McNees of the Office of Radiation Control, Alabama Department of Public Health, of the proposed issuance of the amendment. Mr. McNees had no comments.

V. ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and change the surveillance requirements. The NRC staff has determined that the amendments involve no significant increase in the amounts and no significant change in the types of any effluents that may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding (64 FR 56533, dated October 20, 1999). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

VI. CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

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REFERENCES

1. WCAP-12825, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as a Structural Design Basis for the Joseph M. Farley Units 1 and 2 Nuclear Power Plants," January 1991 (Proprietary).

2. WCAP-12835, "Technical Justification for Eliminating Pressurizer Surge Line Rupture from the Structural Design Basis for Farley Units 1 and 2," April 1991 (Proprietary).

3. WCAP-12835, Supplement 1, September 1991 (proprietary).

4. NRC letter of August 12, 1991, "Safety Evaluation of Elimination of Dynamic Effects of Postulated Primary Loop Pipe Ruptures from Design Basis for Joseph M. Farley Units 1 and 2."

5. NRC letter of January 15, 1992, "Safety Evaluation of Elimination of Dynamic Effects of Postulated Pipe Ruptures in the Pressurizer Surge Line from Structural Design Basis for Joseph M. Farley Nuclear Plant, Units 1 and 2."

6. WCAP-8252 "Documentation of Selected Westinghouse Structural Analysis Computer Codes," Revision 1, May 1977.

7. Letter of July 19, 1999, from D. Morey, Southern Nuclear Operating Company, to the NRC Document Control Desk.

8. NUREG-800, Standard Review Plan for the Review of Safety Analysis Reports of Nuclear Plants, LWR Edition.

9. AISC Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, 1969.

10. WCAP-15098, "Farley Nuclear Plant Units 1 and 2 Replacement Steam Generator Program NSSS Licensing Report," November 1998 (Proprietary).

11. Southern Company Services, "Farley Nuclear Plants Units 1 and 2 Steam Generator Replacement Program BOP Licensing Report," November 1998.

12. Letter from Liparulo, N.J., Westinghouse Electric Corporation, to NRC, forwarding WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," dated June 6, 1997.

13. Letter from Frank Akstulewicz, NRC, to Hank Sepp, Westinghouse Electric Corporation, "Acceptance for Referencing of Licensing Topical Report WCAP-14882, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," dated February 11, 1999.

14. Letter from Jacob I. Zimmerman, NRC, to Southern Nuclear Company, "Issuance of Amendments - Joseph M. Farley Nuclear Plant, Units 1 and 2 (TAC Nos: M98120 and M98121)," dated April 29, 1998.