This letter forwards proprietary information in accordance with 10 CFR 2.390. The balance of this letter may be considered non-proprietary upon removal of Attachment 4.

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CENG[SM]
a joint venture of
Constellation Energy
eDF

NINE MILE POINT
NUCLEAR STATION

May 9, 2011

U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

ATTENTION: Document Control Desk

SUBJECT: Nine Mile Point Nuclear Station
Unit No. 2; Docket No. 50-410

Response to Request for Additional Information Regarding Nine Mile Point Nuclear Station, Unit No. 2 – Re: The License Amendment Request for Extended Power Uprate Operation (TAC No. ME1476) – Containment Accident Pressure, Combustible Gas Control, Pipe Stress Analysis, and Boral Monitoring Program

REFERENCES:

(a) Letter from K. J. Polson (NMPNS) to Document Control Desk (NRC), dated May 27, 2009, License Amendment Request (LAR) Pursuant to 10 CFR 50.90: Extended Power Uprate

(b) E-mail from R. Guzman (NRC) to T. H. Darling (NMPNS), dated March 29, 2011, "NMP2 EPU Draft RAIs – Containment Review"

(c) E-mail from R. Guzman (NRC) to T. H. Darling (NMPNS), dated April 5, 2011, "Request for Conference Call - Mechanical & Civil Engineering Review"

(d) E-mail from R. Guzman (NRC) to T. H. Darling (NMPNS), dated April 8, 2011, "NMP2 EPU EMCB Supplemental Request for Additional Information (TAC No. ME1476)"

(e) E-mail from R. Guzman (NRC) to T. H. Darling (NMPNS), dated April 14, 2011, "NMP2 EPU – Supplemental RAIs RE: March 23, 2011 RAI Response"

Nine Mile Point Nuclear Station, LLC (NMPNS) hereby transmits revised and supplemental information in support of a previously submitted request for amendment to Nine Mile Point Unit 2 (NMP2) Renewed Operating License (OL) NPF-69. The request, dated May 27, 2009 (Reference a), proposed an

A001
NRR

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amendment to increase the power level authorized by OL Section 2.C.(1), Maximum Power Level, from 3467 megawatts-thermal (MWt) to 3988 MWt.

By e-mails dated March 29, April 5, April 8, and April 14, 2011 (References b through e), the NRC staff requested additional information (RAI) regarding containment accident pressure, combustible gas control, pipe stress analysis, and the Boral Monitoring Program. Attachment 1 (non-proprietary) and Attachment 4 (proprietary) provide the NMPNS response to the RAIs. Attachment 2 provides a technical paper that supports the response to RAI #1 from Reference (d).

Attachment 4 is considered to contain proprietary information exempt from disclosure pursuant to 10 CFR 2.390. Therefore, on behalf of GE-Hitachi Nuclear Energy Americas LLC (GEH), NMPNS hereby makes application to withhold this attachment from public disclosure in accordance with 10 CFR 2.390(b)(1). The affidavit from GEH detailing the reason for the request to withhold the proprietary information is provided in Attachment 3.

There are no regulatory commitments in this submittal.

Should you have any questions regarding the information in this submittal, please contact John J. Dosa, Director Licensing, at (315) 349-5219.

Very truly yours,

STATE OF NEW YORK :
: **TO WIT:**
COUNTY OF OSWEGO :

I, Sam Belcher, being duly sworn, state that I am Vice President – Nine Mile Point, and that I am duly authorized to execute and file this response on behalf of Nine Mile Point Nuclear Station, LLC. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other Nine Mile Point employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

Subscribed and sworn before me, a Notary Public in and for the State of New York and County of Oswego, this 9 day of May, 2011.

WITNESS my Hand and Notarial Seal:

Lisa M. Doran
Notary Public

My Commission Expires:

9/12/2013
Date

Lisa M. Doran
Notary Public in the State of New York
Oswego County Reg. No. 01DO6029220
My Commission Expires 9/12/2013

SB/STD

Attachments:

1. Response to Request for Additional Information Regarding License Amendment Request for Extended Power Uprate Operation (Non-Proprietary)

2. A Margin – Consistent Procedure for Calculating the B2 Stress Index and a Proposed New Design Equation, Ying Tan, Vernon C. Matzen, and Xi Yuan, *Transactions*, SMiRT 16, Washington DC, August 2001 (www.iasmirt.org/SMiRT16/F1984.pdf)

3. Affidavit from GE-Hitachi Nuclear Energy Americas LLC (GEH) Justifying Withholding Proprietary Information

4. Response to Request for Additional Information Regarding License Amendment Request for Extended Power Uprate Operation (Proprietary)

cc: NRC Regional Administrator, Region I
NRC Resident Inspector
NRC Project Manager
A. L. Peterson, NYSERDA (w/o Attachment 4)

ATTACHMENT 1

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING LICENSE AMENDMENT REQUEST FOR EXTENDED POWER UPRATE OPERATION (NON-PROPRIETARY)

Nine Mile Point Nuclear Station, LLC
May 9, 2011

ATTACHMENT 1
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING LICENSE AMENDMENT REQUEST FOR EXTENDED POWER UPRATE OPERATION (NON-PROPRIETARY)

By letter dated May 27, 2009, as supplemented on August 28, 2009, December 23, 2009, February 19, 2010, April 16, 2010, May 7, 2010, June 3, 2010, June 30, 2010, July 9, 2010, July 30, 2010, October 8, 2010, October 28, 2010, November 5, 2010, December 10, 2010, December 13, 2010, January 19, 2011, January 31, 2011, February 4, 2011, and March 23, 2011, Nine Mile Point Nuclear Station, LLC (NMPNS) submitted for Nuclear Regulatory Commission (NRC) review and approval, a proposed license amendment requesting an increase in the maximum steady-state power level from 3467 megawatts thermal (MWt) to 3988 MWt for Nine Mile Point Unit 2 (NMP2).

By e-mails dated March 29, April 5, April 8, and April 14, 2011, the NRC staff requested additional information (RAI) regarding containment accident pressure, combustible gas control, pipe stress analysis, and the Boral Monitoring Program. This attachment provides the response to the RAIs.

The NRC request is repeated (in italics), followed by the NMPNS response.

RAI#1 from NRC E-mail dated March 29, 2011

Containment Accident Pressure (CAP)

In the EPU application, it was stated that NMP2 does not need to credit containment accident pressure (CAP) to assure adequate NPSH to the ECCS pumps. However, based on Commission direction in SRM SECY 11-0014, the staff will be applying new guidance on NPSH margin to EPU reviews, including NMP2, to determine whether use of CAP would be necessary if uncertainties are included in the calculations. Also, the maximum erosion zone (defined in the guidance document) should be addressed. The following are some pertinent documents for the licensee.

Letter from NRC to BWROG (3/1/10) transmitting staff guidance ML100550903
Attachment to letter to BWROG containing guidance. ML100550869

Commission paper on the subject of using containment accident pressure ML102590196
Enclosure 1 to Commission paper: ML102110167
Enclosure 2 to Commission paper: ML102780592

Staff Requirements Memorandum (SRM) on Commission paper: ML110740604

Please consider the 3/1/10 guidance document as draft, as the document is being revised as a result of the SRM. The document, however, provides sufficient information to begin addressing the uncertainties and the maximum erosion zone on NPSH margin.

After due consideration of the requirements in the above referenced documents, provide a summary of the NPSH analyses at the EPU conditions, including NPSH required (NPSHR), CAP used, method of calculating NPSH available (NPSHA). Provide the basis for the required NPSH of the ECCS pumps at NMP2, including flow rates assumed, and a comparison with the flow rate for the LOCA peak cladding temperature (PCT) analyses. Also, provide the pump head drop value used in the NPSH analyses (3% or other).

NMPNS Response

<u>Current Licensing Basis and Extended Power Uprate Impact</u>

Section 6.3.2.2 of the NMP2 Updated Safety Analysis Report (USAR) provides the current licensing basis regarding the available Net Positive Suction Head (NPSH) for the High Pressure Core Spray (HPCS), Low Pressure Core Spray (LPCS), and Low Pressure Coolant Injection (LPCI) pumps. For NMP2, these are the Emergency Core Cooling System (ECCS) pumps. Section 6.3.2.2 states the following regarding the methodology utilized to determine the available NPSH:

Note: The NMP2 USAR often refers to the LPCI system as the Residual Heat Removal System (RHR).

> "RG [Regulatory Guide] 1.1 prohibits design reliance on pressure and/or temperature transients expected during a LOCA [Loss of Coolant Accident] for assuring adequate NPSH. The requirements of this regulatory guide are met for the Unit 2 HPCS, LPCS, and LPCI pumps. The ECCS design conservatively assumes 0 psig containment pressure and maximum expected

temperatures of the pumped fluids. Thus no reliance is placed on pressure and/or temperature transients to assure adequate NPSH. Requirements for NPSH for each pump are given on pump characteristic curves..."

"The limiting condition for NPSH available occurs for all of the ECCS pumps when suction is taken from the suppression pool. In addition to the requirements of RG 1.1, the following design features/criteria were applied to calculations of NPSH available for ECCS suction piping from the suppression pool:

1. Suppression pool level is assumed to be at its minimum drawdown level of 197 ft [feet] and 8 in [inches].

2. Suppression pool suction strainers are assumed clogged with a plant-specific debris mix meeting the requirements of RG 1.82 Revision 2; the pressure drop across the RHS [Residual Heat Removal System], CSH [High Pressure Core Spray System], and CSL [Low Pressure Core Spray System] strainers is ≤ 5 ft.

3. Pumps are assumed to be operating at maximum runout flow with the suppression pool temperature at 212°F.

4. Listed below is the NPSH required to be available at a point 2 ft above the pump mounting flange:

HPCS:	5.3 ft @ 7,175 gpm
LPCS:	7.5 ft @ 7,800 gpm
LPCI:	11.5 ft @ 8,200 gpm

5. Liquid continuity is ensured throughout the entire length of the suction piping.

6. Friction loss in suction pipe is calculated at maximum runout flow, including valve and fittings."

The calculated values for NPSH available established in Section 6.3.2.2 of the NMP2 USAR are:

HPCS NPSHA = 5.18 ft

LPCS NPSHA = 0.19 ft

LPCI NPSHA = 0.37 ft

The NMP2 EPU conditions did not impact the current licensing basis regarding the available NPSH for the ECCS pumps. Section 6.2.5 of Attachment 11 to the NMP2 EPU License Amendment Request dated May 27, 2009, states:

"Following a LOCA, the RHR [LPCI], LPCS and HPCS pumps operate to provide the required core and containment cooling. Adequate NPSH margin (NPSH available minus NPSH required) is required during this period to assure the essential pump operation. The NPSH margins for the ECCS pumps were evaluated for the limiting conditions following a DB LOCA [Design Basis Loss of Coolant Accident] using design inputs from current calculations. The limiting NPSH conditions depend on the pump flow rates, debris loading on the suction strainers, pipe frictional losses, suppression pool level and suppression pool temperature. No changes to any of these parameters result from the implementation of EPU."

Supplemental Evaluation

Introduction

The current licensing basis regarding the available NPSH for ECCS pumps presented in Section 6.3.2.2 of the NMP2 USAR was not developed in a manner that would address the areas of interest raised by the NRC in this RAI, namely uncertainties and maximum zone of erosion. Thus, in order to address the impacts of various uncertainties and the maximum zone of erosion, NMPNS provides the following supplemental evaluation of the available NPSH for the ECCS pumps. The goals of this evaluation were to:

1) Determine if the available NPSH (NPSHA) is greater than the required NPSH ($NPSHR_{3\%}$), including 21% margin ($NPSHR_{eff}$) for all cases. In the RAI, the NRC directed NMPNS to consider the guidance transmitted in the letter from the NRC to the Boiling Water Reactor Owner's Group (BWROG) dated March 1, 2010 regarding uncertainties and the maximum erosion zone as draft. Thus, NMPNS requested additional guidance in a telecom conducted on April 5, 2011, with the NRC staff. In this telecom, the NRC recommended that NMPNS utilize a value of 21% to address uncertainties.

2) Determine if the margin ratio defined by $NPSHA/NPSHR_{3\%}$ is greater than 1.6 for all cases. If not, establish that the amount of time operating at a margin ratio less than 1.6 is less than 100 hours.

3) Determine if the margin ratio defined by $NPSHA/NPSHR_{3\%}$ plus 21% margin (i.e., $NPSH_{eff}$) is greater than 1.6 for all cases. If not, establish that the amount of time operating at a margin ratio less than 1.6 is less than 100 hours.

4) Establish that 1) through 3) above could be achieved without crediting containment accident pressure.

Methodology

The evaluation utilized the following considerations:

1) These scenarios were considered:

   a. Design Basis Accident – Loss of Coolant Accident (DBA-LOCA)
   b. Alternate Shutdown Cooling (ASDC)

c. Appendix R Fire
d. Anticipated Transient without Scram (ATWS)
e. Station Blackout (SBO)

2) The $NPSHR_{3\%}$ values at runout conditions were extracted from the calculations of record for the types of pumps involved. The values used were those that represent the NPSH read directly from the vendor pump curves at the appropriate flow value. The current licensing basis calculation includes a 2 foot margin. This margin was removed in the evaluation.

3) The current licensing basis calculation includes a 10% margin for the calculated pipe pressure drops. For this evaluation, these were re-computed to exclude the 10% margin.

4) The differential pressure (DP) for the strainers was taken to be 5 feet for a debris loaded strainer. This value was applied only to the DBA-LOCA NPSH evaluation. Other non-DBA events used the calculated clean DP.

5) The current licensing basis NPSH calculations are performed for a maximum liquid temperature of 212°F. This evaluation is performed at the maximum temperature reached in the particular analysis that is being evaluated: for example, the DBA-LOCA analysis in the EPU License Amendment Request dated May 27, 2009, indicates the maximum suppression pool temperature is only 207°F.

6) All cases are evaluated based on a 14.696 psia pressure at the suppression pool surface. No credit is taken for containment accident pressure.

Evaluation

An evaluation was performed to determine if the NPSHA for each ECCS pump was greater than the vendor supplied $NPSHR_{3\%}$ curves plus 21% margin (i.e., $NPSHR_{eff}$). Table 1 shows the values for $NPSHR_{3\%}$ and $NPSHR_{eff}$ for each of the ECCS pumps.

Pump	$NPSHR_{3\%}$ (ft)	NPSHR+21% (ft) = $NPSHR_{eff}$
HPCS	3.30	3.99
LPCS	5.50	6.66
LPCI	9.50	11.50

Table 1 – Computation of $NPSHR_{eff}$ Values

Table 2 provides the various components of NPSHA (elevation head, piping loss, strainer loss in both dirty and clean debris loaded configurations), with the exception of the atmospheric pressure minus the liquid vapor pressure term.

			Strainer Loss (ft)		= Elev – Piping - Strainer	
Pump	Elev (ft)	Piping (ft)	Dirty (ft)	Clean (ft)	Result – Dirty (ft)	Result – Clean (ft)
HPCS	20.340	4.419	5	1.06	10.92	14.86
LPCS	20.340	7.650	5	1.26	7.69	11.43
LPCI	20.375	3.250	5	1.36	12.13	15.77

Table 2 – Computation of Head for Elevation, Piping and Strainer (dirty/clean)

The maximum suppression pool temperatures for the DBA-LOCA, ASDC, ATWS, and Appendix R fire scenarios are provided in Table 3. For the SBO scenario, during the coping period, the Reactor Core Isolation Cooling pump takes suction from the Condensate Storage Tank, so there is no further discussion of that scenario in this response.

Case	Suppression Pool Temperature (°F)	Pressure (Pa (ft))	Vapor Pressure (Pv (ft))	= Pa – Pv (ft)
DBA-LOCA	207.0	35.31	31.95	3.36
ASDC	210.0	35.35	33.97	1.38
Appendix R Fire	198.1	35.18	26.53	8.65
ATWS	162.8	34.73	11.97	22.75

Table 3 – Computation of Pa-Pv

In order to determine the minimum NPSHA for the various cases, the maximum temperature for each case is used to determine the pressure minus the vapor pressure term. In the current licensing basis where the maximum temperature was assumed to be 212°F, these two terms are the same, so the resultant term (Pa-Pv) is zero. However, for this evaluation, this term is not zero and will be evaluated for each case.

A standard thermal property table for water is used to determine the vapor pressure versus temperature and the specific volume versus temperature. In the formulation for NPSH, vessel overpressure, always assumed to be 14.696 psia in this evaluation (no credit for containment accident pressure), is converted to feet of liquid at the flowing fluid temperature, which requires the specific volume at that temperature. Table 3 provides the values for atmospheric pressure and vapor pressure converted to feet of liquid for the maximum temperatures reported for the various scenarios.

Using the inputs described above, the minimum NPSHA can be established. Using the minimum NPSHA, the margin ratios to the $NPSHR_{3\%}$ can be determined.

In addition, the NPSH margin ratios developed using the $NPSHR_{eff}$ (plus 21%) value are provided. This is conservative, since a 21% uncertainty margin is applied to the $NPSHR_{3\%}$ value.

The results are provided in Tables 4 – 7 below.

NPSHA = Elevation – Piping – Strainer + Pa - Pv			
Max temperature = 207.0 °F			
Pump	**NPSHA (ft)**	**$NPSHA/NPSHR_{3\%}$**	**$NPSHA/NPSHR_{eff}$**
HPCS	14.28	4.33	3.58
LPCS	11.05	2.01	1.66
LPCI	15.49	1.63	1.35

Note: The shaded value indicates that the NPSH margin ratio is below 1.6.

Table 4 – DBA-LOCA

NPSHA = Elevation – Piping – Strainer + Pa - Pv			
Max temperature = 210.0 °F			
Pump	**NPSHA (ft)**	**$NPSHA/NPSHR_{3\%}$**	**$NPSHA/NPSHR_{eff}$**
HPCS	16.24	4.92	4.07
LPCS	12.81	2.33	1.92
LPCI	17.14	1.80	1.49

Note: The shaded value indicates that the NPSH margin ratio is below 1.6.

Table 5 – ASDC

NPSHA = Elevation – Piping – Strainer + Pa - Pv			
Max temperature = 198.1 °F			
Pump	**NPSHA (ft)**	**NPSHA/NPSHR$_{3\%}$**	**NPSHA/NPSHR$_{eff}$**
HPCS	23.52	7.13	5.89
LPCS	20.08	3.65	3.02
LPCI	24.42	2.57	2.12

Table 6 – Appendix R

NPSHA = Elevation – Piping – Strainer + Pa - Pv			
Max temperature = 162.8 °F			
Pump	**NPSHA (ft)**	**NPSHA/NPSHR$_{3\%}$**	**NPSHA/NPSHR$_{eff}$**
HPCS	37.62	11.40	9.42
LPCS	34.18	6.22	5.14
LPCI	38.52	4.05	3.35

Table 7 - ATWS

These results indicate that for all cases, the minimum NPSHA is always above the NPSHR$_{eff}$ values. Also, the NPSH margin ratios using the NPSHR$_{3\%}$ values all remain above 1.6, or not in the cavitation region. The more conservative NPSH margin ratio using NPSHR$_{eff}$ results in 2 cases where the LPCI pumps NPSH ratios are below 1.6.

It can be shown that for these 2 cases, the NPSH margin ratios are above 1.6 for liquid temperatures below 202°F for the DBA-LOCA case and 208°F for the ASDC case. (Note: The difference in maximum temperatures is the result of assuming a 5 ft debris loading on the strainer for the DBA-LOCA case and no debris loading for the ASDC case.)

Using the tabular values for suppression pool temperature versus time developed to generate the graphs in the NMP2 EPU License Amendment Request dated May 27, 2009, it was determined that the LPCI pumps operate at a margin ratio less than 1.6 for approximately 839 minutes (~14 hours) for DBA-LOCA and 376 minutes (~6.3 hours) for ASDC. Both of these operational times are well below the NRC maximum recommended value of 100 hours of operation in this region.

Conclusions

The NPSHA values for the ECCS pumps were evaluated for the maximum calculated temperature for several different scenarios including DBA-LOCA and ASDC. In accordance with the NRC's recommendation for NPSHR uncertainty, the $NPSHR_{3\%}$ value provided by the pump vendors was increased by 21% ($NPSHR_{eff}$). No credit for containment accident pressure was taken. Also, two NPSH margin ratios were established ($NPSHA/NPSHR_{3\%}$ and $NPSHA/NPSHR_{eff}$).

The following acceptance criteria were applied:

1. $NPSHA > NPSHR_{eff}$ for all cases.

2. $NPSHA/NPSHR_{3\%} > 1.6$ for all cases
   a. For cases less than 1.6, operating time is limited to < 100 hours

3. $NPSHA/NPSHR_{eff} > 1.6$ for all cases
   a. For cases less than 1.6, operating time is limited to < 100 hours

The results of the evaluation show that acceptance criteria 1 and 2 were met for all cases. Acceptance criterion 3a was met for all cases. Therefore, the NMP2 ECCS pumps meet all of the RAI requested NPSH tests without requiring credit for containment accident pressure.

RAI#2 from NRC E-mail dated March 29, 2011

Please provide a brief description of the strategies and guidelines in place at NMP2 for Severe Accident Management in relation to the combustible gas control in containment.

NMPNS Response

NMPNS has developed Severe Accident Mitigation procedures for combustible gas control in the containment. NMP2 combustible gas control strategies and guidelines are consistent with the BWROG generic guidance. These procedures contain actions based on the concentrations of hydrogen and oxygen present in the drywell and suppression chamber and are ordered in terms of increasing combustible gas concentrations. The various actions are listed below in order of least to greatest concentration.

Low concentration (<5% oxygen, detectable hydrogen)

If containment parameters are within the capability of the hydrogen recombiners, then the hydrogen recombiners are used to reduce the hydrogen concentration to less than 5%. Containment purge with nitrogen may also be performed if the offsite release rate is expected to stay below the Offsite Dose Calculation Manual (ODCM) limit.

Medium concentration (>5% oxygen and <6% hydrogen)

Hydrogen recombiners may continue to be operated up to a maximum of < 5% hydrogen concentration. If reactor pressure vessel (RPV) water level cannot be maintained above the top of active fuel (TAF) or the offsite release rate is expected to stay below the General Emergency level, then the containment is purged with nitrogen. The purge is stopped when: 1) the hydrogen and oxygen concentration returns to within limits; or 2) the offsite release rates reach the General Emergency level and the reactor water level can be maintained above TAF.

High concentration (>5% oxygen and >6% hydrogen)

When the containment concentration exceeds 6% or is unknown, then containment sprays are initiated and the containment is purged with air or nitrogen irrespective of offsite release rates until hydrogen concentration is reduced to within limits.

RAI #1 from NRC E-mail dated April 8, 2011

The licensee's response to EMCB-RAI-14 states that the current licensed thermal power (CLTP) analysis applied a stress index different than the one described in the code of record (1974 ASME Section III) in two instances where higher than allowable stresses occurred, and that the revised stress index was taken from the 1989 ASME code edition. Please provide a discussion of the acceptability of the use of a revised stress index based on a later code edition (1989) instead of the use of the 1974 ASME code of record to produce extended power uprate (EPU) stresses lower than allowable. Quantitatively show the equation where the revised index is used and how does it differ from the original stress index.

NMPNS Response

The 1989 ASME code to calculate the B2 stress is applied in the current design basis calculation AX-139BY (Table 8 provides information from this calculation).

Per NB-3681(c) of ASME III 1974, "Values of stress indices are tabulated for commonly used piping components and joints. Unless specific data exist that would warrant lower stress indices than those tabulated or higher flexibility factors than those calculated by the methods of NB-3687 (which data shall be referenced in the Stress Report, NA-3352), the stress indices given shall be used as minima and the flexibility factors shall be used as maxima."

Tan, et. al., documents the history of the application of the B2 stress index used in ASME III in "A Margin-Consistent Procedure for Calculating the B2 Stress Index and a Proposed New Design Equation" (Attachment 2). Tan states, "The relationship between C2 and B2 given above, which remained in the Code from 1969 until 1981, results in the following B2: B2 = (3/4)*C2...". The calculation of B2 was evaluated in more detail as the extent of experimental data was more available, and it was shown "that the relationship between B2 and C2 would be: B2 = (2/3)*C2...". This definition subsequently was adopted in the ASME Code, as seen in the 1989 Code year. Although less conservative than the B2 given in the 1974 Code, it is noted in the reference that the B2 calculated using the new method remains "conservative for 90° or shorter elbows." Note that C2, and all other parameters in the equation, were calculated using the definitions provided in the 1974 code.

Therefore, as allowed by the 1974 Code, sufficient data exists to justify use of a lower B2 stress index as defined in the 1989 Code, and its application results in acceptable Equation 9 stress. Table 8 summarizes the use of the stress indices and the resulting acceptable Equation 9 stress.

Information from AX-139BY, Pages 65-72		
Pdes	1250	Design pressure, psia
D	2.0	Nominal diameter, inches
Do	2.375	Outside diameter, inches
t	0.343	Wall thickness, inches
B1	1.0	
Di	1.689	Inside diameter, inches
I	1.163	Moment of inertia, inches^4
R	3.000	Elbow bend radius, inches
Rm	1.016	Mean pipe radius, inches
b2	0.997	
B2	1.303	Using 1989 Code Definition
C2	1.954	
B2	1.466	Using Original Code year

Local Moments (AX-139BY, pg 72)				
Load Case	Mx	My	Mz	SRSS M1
DWT	1	71	-64	
OBEI, OCCU	117	830	784	
M1	118	901	848	14915

Equation 9 Stress Intensity terms	Original Code Year	Using 1989 Code Year
Pressure Term	4,328	4,328
Moment Term	22,328	19,847
Equation 9 Stress	26,655	24,174
First Uprate (1.0120)	26,975	24,464
EPU (1.051)	28,351	**25,712**
Allowable	27,102	27,102
Stress less than Allow?	NOT OK	OK

Table 8 – Stress Indices Data

RAI #2 from NRC E-mail dated April 8, 2011

Provide an example(s) to quantitatively demonstrate how the scaling factor of 5.1 in PUSAR tables 2.2-2a and 2.2-2b are derived.

NMPNS Response

Evaluation methodologies, including the scaling factor approach for the piping and associated structures such as nozzles, penetrations, supports, etc., are described in Section 5.5.2 and Appendix K of NEDC-32424P-A, Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate (Reference 1), and in Supplement 1, Volume 1, Section 4.8 of NEDC-32523P-A, Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate (Reference 2). Figure K-1 from Reference 1 (attached), Extended Power Uprate (EPU) Piping Evaluation, depicts the process used to evaluate piping for power uprate increases in pressure, temperature and flow.

Using the power uprate heat balance, the piping system parameter values (pressure, temperature and flow) were compared with the corresponding pre-power uprate values to determine the increases in temperature, pressure, and flow due to power uprate conditions. Scaling factors determined from GEH EPU parametric studies were then used to determine the percentage increases in applicable ASME Code stresses, displacements, cumulative usage factors (CUF), and pipe interface component loads (including supports) as a function of the percentage increase in pressure, temperature, and flow. The percentage increases were applied to the highest calculated stresses, displacements, and the CUF at applicable piping system node points to conservatively determine the maximum extended power uprate calculated stresses, displacements and usage factors.

<u>EPU Parametric Studies</u>

GEH performed parametric studies by applying a range of percentage increases to system pressures, temperatures and flow to evaluate the effects on piping stress and fatigue based on the increases due to power uprate in order to simplify the process of determining piping system response to changes in operating parameters. The goal was to develop a simplified yet conservative methodology for evaluating piping systems. In the situations where there is not sufficient design margin to accommodate this simplified scaling methodology, then the EPU impacts would need to be determined through use of the appropriate ASME equations.

For the NMP2 EPU, the value of 5.1 in PUSAR Table 2.2-2a and b was determined by identifying the percentage change in steam flow and applying it to an enveloping curve (Figure 1) generated as a result of the parametric studies. This renders a stress increase of 5.1% for ASME equation 9B. In this case, the change in steam flow was calculated by using the following equation:

> Steam Flow at 102% EPU / Steam Flow at 100% CLTP = 18.066 Mlb/hr / 15.002 Mlb/hr = 1.204 or a percentage change in steam flow of 20.4%

Note: this value is conservative and results in a higher stress factor than the actual EPU change in steam flow derived by the following equation:

Steam Flow at 100% EPU / Steam Flow at 100% CLTP = 17.636 Mlb/hr / 15.002 Mlb/hr = 1.176 or a percentage change in steam flow of 17.6%

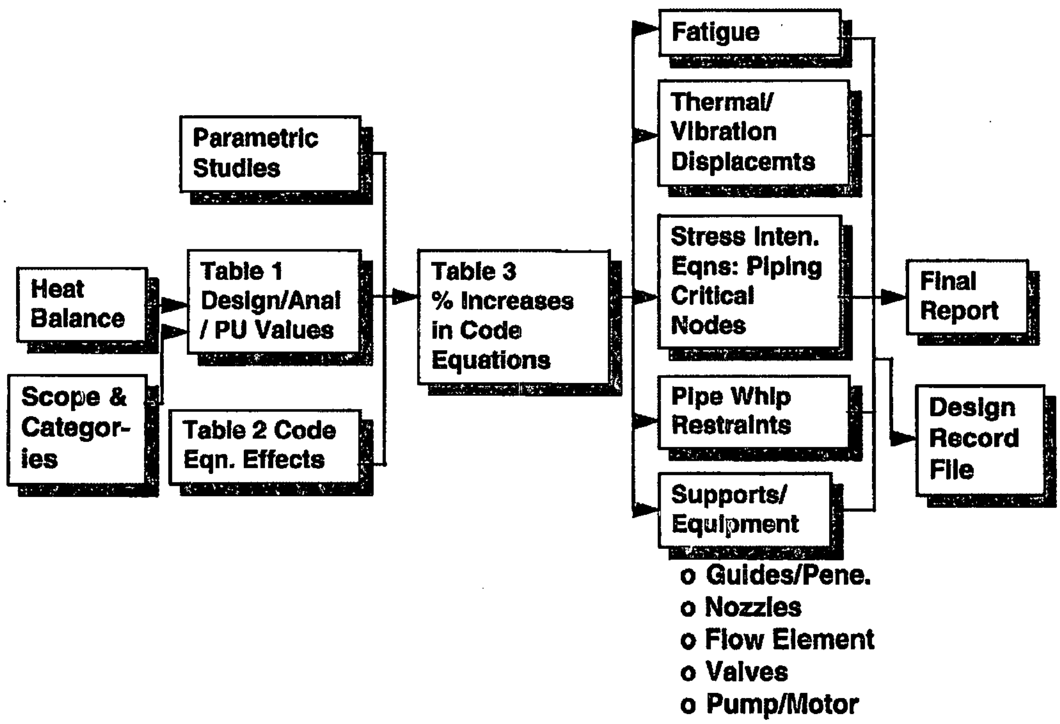

Figure K-1. Extended Power Uprate Piping Evaluation

[[

{3}]]

Figure 1

References:

1. NEDC-32424P-A, Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate
2. NEDC-32523P-A, Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate

RAI #3 from NRC E-mail dated April 8, 2011

Provide an explanation for terms K, H, Mt and M used in PUSAR Tables 2.2-3d, 2.2-3e, 2.2-4c.

NMPNS Response

This nomenclature is developed and used in the calculations of record for the components. "K" is a resultant moment (ft-lbs) for a nozzle calculated as the square root sum of the squares (SRSS) of My and Mz. The coordinate system is defined as follows: X – axis is parallel to nozzle axis, Y – axis is vertical, and Z – axis according to right hand rule. Therefore, "K" is the resultant moment of bending loads on the nozzle in units of ft-lbs and doesn't include a torsion moment component (Mx).

"H" is a resultant load (lbs) for a nozzle calculated as the SRSS of Fy and Fz in accordance with the coordinate system discussed above. Therefore, "H" is the resultant load of non-parallel loadings in units of lbs.

"Mt" is a resultant moment (ft-lbs), i.e., total moment, for a penetration. Mt is calculated as the SRSS of Mx, My, and Mz in accordance with the coordinate system discussed above.

"M" is the total moment calculated for a nozzle in ft-lbs. "M" is calculated as follows:

$$M = 0.5*(K + Fx*Z/(12*A) + SQRT((K + Fx*Z/(12*A))^2 + Mx^2))$$

RAI #4 from NRC E-mail dated April 8, 2011

Please revise response to EMCB-RAI-21, as appropriate, to show whether any piping modifications are required due to the EPU and provide a list of the modifications along with its schedule of completion.

NMPNS Response

Originally, NMPNS determined that a modification to piping support 2CNM-PSR085A4 was required. Subsequently, NMPNS has performed a more detailed analysis of this piping support and determined that the modification to piping support 2CNM-PSR085A4 is not required. Thus, no piping modifications are required to directly address the temperature, pressure, and flow rate changes resulting from EPU.

RAI #5 from NRC E-mail dated April 8, 2011

The licensee's response to EMCB-RAI-22 indicates that EPU comparisons are made to original licensed thermal power (OLTP) temperatures and pressure, and also refers to OLTP stresses. Please clarify whether the response meant to make reference to CLTP and not OLTP. In addition, the licensee's response to RAI-22 (page 21 of 34) states that for feedwater (FW) supports, "total OLTP loads calculated are higher than EPU and are bounding." Table 2.2-4d though, clearly shows that current support total loads are less than the EPU loads, and therefore, are not bounding. Please clarify whether the response meant to say that EPU pipe support total loads are within the pipe support capacity loads, and, are therefore acceptable.

NMPNS Response

The allowable support structural capability was derived using information from the current calculation of record for each support. The current calculation of record derived the structural capability of the supports using the current piping loads (i.e., CLTP piping loads), but also contained the original OLTP piping loads.

A snubber reduction modification was implemented approximately coincidental with the earlier 5% stretch power uprate. A result of this effort was that, in general, the feedwater piping loads for current conditions were determined to be <u>less than</u> the original qualified loads (i.e., OLTP piping loads).

Given the above, the EPU piping loads, although greater than the current piping loads (i.e., CLTP piping loads), were in most cases less than the piping load that the support was originally qualified to (i.e., before the snubber reduction). This meant that for the EPU analysis, even though the EPU support loads are greater than the current support loads, they were <u>less than the original qualified loads</u> for most of the supports analyzed. Therefore, it is possible for the EPU piping loads to be bounded by the original piping loads (based on OLTP conditions) used to qualify the supports.

The EPU stress evaluations for the feedwater system were performed using EPU conditions (flowrate, temperature, and pressure) which are higher than the CLTP conditions. The corresponding EPU support load evaluation resulted in EPU support loads that are greater than the CLTP support loads.

After all of the evaluations were complete, the support loads due to EPU conditions for all of the feedwater supports were verified to be less than the allowable support structural capability, (i.e., with a structure ratio less than one), and are therefore acceptable. That means that all feedwater supports are qualified for the EPU conditions.

Clarifying Question from NRC E-mail dated April 5, 2011

Are the EPU affected piping systems inside containment designed for 102% EPU power conditions and the piping systems outside containment designed for 100% EPU power conditions? The staff asked for OLTP and EPU flow, temperature and pressure data in RAI 15 so that it can use the RAI 15 response in conjunction with RAI-16 response data. RAI-16 deals with scaling factors due to increases in flow, temperature and pressure.

NMPNS Response

Yes, the EPU affected piping systems inside containment are analyzed for 102% EPU power conditions, and the piping systems outside containment are analyzed for 100% EPU power conditions. This methodology is consistent with the current licensing basis.

RAI#1 from NRC E-mail dated April 14, 2011

Supplemental CSGB-RAI-3.a

On page 6 of Attachment 1 of its letter dated March 23, 2011, the licensee states that, "NMPNS does not intend to utilize these coupons [for the initial 10 Boral spent fuel racks] since the coupon tree was not installed at the same time as the associated racks." The NRC staff is uncertain whether the Boral material installed in 2001 has an effective surveillance monitoring program. Please provide the surveillance approach and testing for these 10 Boral spent fuel racks.

NMPNS Response

As stated in the letter dated March 23, 2011, a coupon tree representative of the spent fuel racks installed in 2001 was installed in the NMP2 spent fuel pool in 2007. Following a telecom with the NRC on April 19, 2011, that clarified this RAI, NMPNS revised the NMP2 Boral Monitoring Program to include a plan to test and inspect coupons from the coupon tree representative of the spent fuel racks installed in 2001.

The NMP2 Boral Monitoring Program now requires a coupon from the coupon tree representative of the spent fuel racks installed in 2001 and a coupon from one of the coupon trees representative of the spent fuel racks installed in 2007 to be removed in 2012. Following this, a coupon from the coupon tree representative of the spent fuel racks installed in 2001 and a coupon from one of the coupon trees representative of the spent fuel racks installed in 2007 will be removed on a ten-year frequency.

The coupons from the coupon trees will be tested and inspected in accordance with the methodology and acceptance criteria defined in the letter dated March 23, 2011.

RAI#2 from NRC E-mail dated April 14, 2011

Supplemental CSGB-RAI-3.b

On page 6 and 7 of Attachment 1 of its letter dated March 23, 2011, the licensee states that coupons will be evaluated for visual appearance and lists deterioration of coupon as one of the parameters being evaluated. Please discuss what is meant by deterioration and how it is evaluated.

NMPNS Response

In the letter dated March 23, 2011, NMPNS stated:

> "The coupons will be evaluated as follows: (1) visual appearance (deterioration, corrosion, cracks, and dents); (2) dimensional measurements; (3) specific gravity and density measurements; and (4) Boron-10 (B-10) areal density measurements (via neutron attenuation testing)."

The term "deterioration" was meant to address changes in the physical appearance of the coupon, in addition to corrosion, cracks, and dents. Possible examples of deterioration include blistering, pitting, or bulging.

Deterioration would be evaluated to determine if it was an indication of the potential onset of Boral degradation. This could lead to additional monitoring or an increased frequency for removing and examining coupons.

ATTACHMENT 2

A MARGIN – CONSISTENT PROCEDURE FOR CALCULATING THE B2 STRESS INDEX AND A PROPOSED NEW DESIGN EQUATION

YING TAN, VERNON C. MATZEN, AND XI YUAN

TRANSACTIONS, SMIRT 16, WASHINGTON DC, AUGUST 2001

(WWW.IASMIRT.ORG/SMIRT16/F1984.PDF)

A MARGIN – CONSISTENT PROCEDURE FOR CALCULATING THE B_2 STRESS INDEX AND A PROPOSED NEW DESIGN EQUATION

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2) Engineous Software, Cary, NC

ABSTRACT

In Section III of the ASME Boiler and Pressure Vessel Code, the design equation for primary stresses in piping contains stress equations for straight pipes that are modified by stress indices so that the equations can be applied to other piping components. In this paper we review the history of this equation in the context of elbows and then suggest a new procedure for calculating the B_2 stress index that applies to stresses for bending. The resulting stress index equation, which is the ratio of the collapse moment of a straight pipe to the collapse moment for any component, gives a B_2 value of 1.00 when applied to a straight pipe and a safety margin for the component that is always the same as for the straight pipe. This procedure is based on the Code-defined collapse moment, which we determine using nonlinear finite element analysis (FEA), supported by experimental data. We present B_2 values for elbows with a wide range of pipe bend parameters. The values of B_2 obtained using this equation are 14 to 48% lower than the values obtained using the current Code procedure when applied to stainless steel 90° butt-welding elbows.

INTRODUCTION

Most piping in nuclear power plants is designed by rules given in Section III of the ASME Boiler and Pressure Vessel Code (the Code)[1]. In the Code, stresses are divided into three categories: Primary which "is any normal stress or a shear stress developed by an imposed loading which is necessary to satisfy the laws of equilibrium..."[2]; Secondary which is "a normal stress or a shear stress developed by the constraint of adjacent material or by self-constraint of the structure. The basic characteristic of a secondary stress is that it is self-limiting."[3]; and Peak stress.

In piping design, Code Equation (9), which governs the primary stress intensity for design loads, has the following form:

$$B_1 \frac{PD_o}{2t} + B_2 \frac{D_o}{2I} M_i \leq 1.5 S_m \tag{1}$$

where B_1 and B_2 are stress indices for internal pressure and bending. The equation has been described as assuring "against catastrophic membrane failure..."[4] or placing "bounds on loading such that necessary conditions for a collapse load will not exist anywhere in the piping system"[5].

The stress indices are used to modify nominal stress equations for straight pipes so that the behavior of piping components such as elbows can be controlled using the same basic stress limits as for straight pipe. Moore and Rodabaugh[6] state that "The B_1 and B_2 stress indices reflect the capacities of various piping products to carry load without gross plastic deformation."

Paragraph NB-3682 of the Code provides the following general definition of stress indices:

$$B, C, K, \text{or } i = \frac{\sigma}{S} \tag{2}$$

where, for the B indices, σ represents the stress magnitude corresponding to a limit load and S is a nominal stress associated with the limit load. Values for the B, C and K stress indices are given in Table NB-3681(a)-1 for a variety of piping components. For elbows the user is referred to equations in subparagraph NB-3683.7 where B_2 is defined as

$$B_2 = \frac{1.30}{h^{2/3}} \geq 1.0 \tag{3}$$

where h is the characteristic bend parameter, which is defined as

$$h = \frac{tR}{r_m^2} \tag{4}$$

and where the remaining parameters are defined in the Nomenclature Section.

"For piping products not covered by NB-3680, stress indices ... shall be established by experimental analysis (Appendix II) or theoretical analysis[7]." Appendix II, however, has the following section, titled Experimental Determination of Stress Indices for Piping: "In course of preparation. Pending publication, stress indices for piping shall be determined in accordance with the rules of NB-3680[8]." The appendix does contain a procedure for obtaining experimentally a value for the collapse load[9] although there is no guidance on how to use this information to obtain the stress indices.

In this paper we review the history of the B_2 index and suggest a generic procedure for obtaining values for the index for any type of component. The suggested procedure, which is consistent with the derivation for Eq. (3), relates the collapse moment of any piping product to the collapse moment of a straight pipe and hence will result in a B_2 value of 1.0 when applied to a straight pipe or in the limiting case of an elbow as the subtended bend angle approaches zero degrees. The procedure also guarantees that the margin of the component will always be the same as for a straight pipe with the same material and geometric properties. The suggested new procedure for obtaining the B_2 index relies on an accurate calculation of the collapse load – which we determine using nonlinear FEA methodology and our FEA procedures are verified by experiments.

HISTORY

The history of piping elbows and pipe bends, from von Karman[10] and Bantlin[11] in the early part of the 1900s to the present, has been documented in various papers (See for example Markl[12], Rodabaugh and George[13], Dodge and Moore[14], and Yu[15]). In this paper, we will discuss only those references related directly to the B_2 index; this includes not only B_2, but also C_2 and the stress intensification factor i.

The Foreword to the USA Standard B31.7 for Nuclear Power Piping, published in 1969, gives the following background for the use of stress indices: "Stress indices ... have been used in B31.1 since 1955 where they were called stress intensification factors. These factors are based for the most part on tests by Markl and George[16], and by Markl[17]. Another precedent use is in the ASME Boiler and Pressure Vessel Code, Section III, where the term 'stress index' is used. In the Boiler Code, the stress indices are for internal pressure loading and the stress indices given are based on test data. "Now, if a stress intensification factor is equal to 4, the user immediately visualizes that he has a component where a significant stress is four times as high as in a piece of straight pipe with the same applied moment.[18]" "In B31.1 the use of stress intensification factors is restricted to moment loadings."[19]

The stress intensification factor for elbows, used in the B31.1 Code, was first given by Markl [20] in 1952 as

$$i = \frac{0.9}{h^{2/3}} \geq 1 \tag{5}$$

and was based on his bending-fatigue data.

In 1969 the B31.7 Standard introduced the concept of stress indices as follows: "In B31.7 they [the stress intensification factors] have a wider scope; stress indices are used for three purposes. First, B-indices are based on limit load type of analysis. C-indices represent the Primary-plus-Secondary stresses and K-indices represent peak stresses which are involved in a fatigue evaluation. All three types of indices are used for internal pressure loads, moment loads and thermal gradient loads." The relationship between the B and C indices is described as follows: "From some limited test data [21],[22] probably a very conservative estimate is that the collapse moment is 4/3 of the moment to produce a local bending stress equal to the yield strength of the elbow material. This leads to a B_2 factor for elbows or curved pipes of 0.75 times the C_2 factor. This is an example of engineering judgment based on a few tests and some limited theory."[23] The Foreword also states that the stress indices of B31.7 are "quite close to double the stress intensification factors in B31.1."

Because the B_2 index was related to the C_2 index (and remains so today), it is worth while reviewing the origin of this index. The C_2 equation for elbows in the 1969 B31.7 Code,

$$C_2 = \frac{1.95}{h^{2/3}} \geq 1.5 \tag{6}$$

has not been changed and remains in the Code today. The relationship between C_2 and B_2 given above, which remained in the Code from 1969 until 1981, results in the following B_2:

$$B_2 = \frac{3}{4} C_2 = \frac{1.4625}{h^{2/3}} \geq 1.125 \tag{7}$$

The basis for Eq. (7) was given by Dodge and Moore[24] in 1972. This equation can be obtained from their more general equation

$$C_2 = \frac{2}{\ddot{e}^{2/3}} \frac{1+1/4\tilde{a}}{1+1/\ddot{e}^{4/3} e^{1/\varphi^{\varphi}}} \tag{8}$$

by setting $\gamma=\infty$, $\varphi=0$ and $\nu=0.3$. To obtain this equation, Dodge and Moore used the theory given in Rodabaugh and George[25] to obtain the maximum stress intensity (which is, of course, related to the Tresca yield condition, which is the basis of the Code equations) in an elbow from three moments – in-plane, out-of-plane and torsion – and internal pressure. They used a computer program to evaluate the stress equations for a range of parameters and then plotted the stress index as a function of the bend parameter. Eq. (8) is "A conservative approximation for stress indices, which slightly over-estimates the tabulated values"[26].

In 1974 Mello and Griffin[27] showed, for perhaps the first time, the relationship between the collapse moment determined by limit analysis and the B_2 index:

$$M_{LL} = \frac{Z(1.2S_y)}{B_2} \tag{9}$$

where B_2 is as defined in the 1971 Code, and Eq. (9) is a conservative prediction of the limit moment. Mello and Griffin did not use this equation to calculate the B_2 index, but rather to calculate a Code-based limit moment. In the 1971 Code, the collapse load was taken as that in which the distortion is 2 times the value at the calculated initial departure from linearity. Mello and Griffin include a discussion of various alternatives to this definition.

In 1978 Greenstreet [28] published a report describing a series of 20 bending experiments on commercially available 6 inch 90 degree elbows. The objective of the tests was "to obtain in-plane and out-of-plane limit moments." He considered three existing methods for determining limit loads. The first, described by Demir and Drucker [29], defines the limit load as the load at which the measured deflection is three times the extrapolated elastic deflection. The second method is to use the point of intersection of a line drawn tangent to the initial (elastic) portion of the force-deflection curve and a line drawn tangent to the straight-line portion of the curve in the plastic region. The third method is to determine the load at the 0.2% offset strain from a load-strain diagram where the strains are measured by gages located in the high-strain region of the component. Greenstreet uses what he calls an equivalent method to compare the limit loads for his test specimens. Using the tangent method to determine the limit load, he calculates a parameter 'a' that is defined as the total deflection minus the extrapolated elastic deflection divided by the extrapolated deflection. These relationships are shown in Fig. 1. In Greenstreet's results, the values of the parameter 'a' ranged from 0.25 to 1.00 with an average of 0.38. It is interesting to note that a=2 for the Demir and Drucker method and a=1 in the current Code definition of collapse load. Two results from the Greenstreet report are relevant to our work. In his Table 6, the last column tabulates the ratio of $\frac{M_{CL}}{S_y Z}$ (after converting to our notation) which is the reciprocal of our Eq. (18) (given later in the paper). Although he does not relate this to the B_2 index, he does say that it "can be interpreted as indicating the margins of safety with respect to the onset of yield in straight runs of pipe." Also, in his Table 8, the last column contains the quantity $\frac{M_{CL,component}}{M_{CL,straightpipe}}$ (in our notation), which is the "ratio of the plastic collapse moment to the theoretical plastic collapse moment for straight pipe." Again, this is the reciprocal to our Eq. (24) (also given later in the paper.)

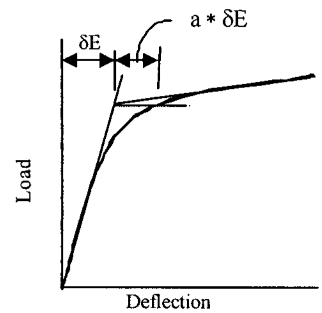

Fig. 1 Definition of 'a'

The relationship between C_2 and B_2 in the current Code was proposed by Rodabaugh and Moore[30] in 1978. In their paper, the authors discuss the design philosophy of the 1969 B31-7 Code, how limit load concepts might be introduced, and the Code definition of collapse as being the load or moment at which the displacement is twice the extrapolated elastic displacement. They begin by examining straight pipes because the "straight pipe serves as a reference geometry for more complex geometries such as elbows and branch connections."[31] This relationship between straight pipes and elbows is significant because it relates directly to the new procedure we describe later for computing the B_2 index. The straight pipe limit load theory was given in a paper by Larson, Stokey and Panarelli[32] in 1974 and is based on the lower bound theorem and the von Mises criterion. For elbows, they begin by summarizing the maximum stress ratios for in-plane bending ($1.8/h^{2/3}$, occurring in the hoop direction), out-of-plane bending ($1.5/h^{2/3}$), and torsion (1.0 for the shearing stress). They then state that "Considering all combinations of M_x, M_y, and M_z as represented by the vector moment $M_t = [M_x^2+ M_y^2+ M_z^2]^{1/2}$, the maximum stress intensity does not exceed $1.95/h^{2/3}$. This is the C_2 index given in the Code Table NB-3682.2-1 (now in subsubparagraph NB-3683.7 (b))." The authors point out that maximum or near-maximum stresses occur at four locations around the circumference, that the most significant stresses are related to through-wall bending, and that "if the moment is increased by 1.5 times the moment causing the maximum elastic stress to reach the yield strength, then four yield lines would form and the elbow could 'collapse'."[33] For in-plane bending, this leads to the following limit load equation

$$M_L = 1.5M_{Yield} = 1.5\left[\frac{h^{2/3}}{1.8}S_y Z\right] = 1.5\left[\frac{h^{2/3}}{1.8}S_y \frac{\pi}{4}D^2 t\right] \tag{10}$$

where the thin-walled pipe approximation has been used for the section modulus. This result is compared to a theoretical limit load analysis for elbows given by Spence and Findlay[34] and shown to be similar. The factor of 1.5 used above would mean that the relationship between B_2 and C_2 would be

$$B_2 = \frac{2}{3}C_2 = \frac{1.30}{h^{2/3}} \geq 1.0 \tag{11}$$

rather than the $3/4C_2$ used in the 1977 Code. The authors suggest that the reasons for this conservatism were related to the allowable stress used at the time and the dearth of test data for limit moments for elbows.

Eq. (11) is based on the assumption that there are no end effects, i.e. the ovalization is uniform along the elbow. The authors state that, because of this assumption, the equation would be conservative for 90° or shorter elbows. The equation is also based on the assumption that pressure effects are negligible, although this is known to be incorrect in the elastic region, where the pressure reduces the stresses. "However, the pressure itself causes stresses, hence, the combination of moments and pressure may increase or decrease the limit moment. In principle, an elastic-plastic, large-deformation theory and computer program based hereon could be used to evaluate such combinations. However, we are not aware of any such analysis being done. We would guess that the cost of such an analysis would be several times the cost of a test."[35] Much has changed in the last 22 years, and the authors would no doubt revise this last conclusion if they were writing today. However, good experimental data are just as valuable today as they were then, although they might be used primarily for verification of finite element codes rather than for parametric studies.

Several revisions to the piping Code appeared in 1978 and 1981 and were discussed by Moore and Rodabaugh.[36] These changes involved modifications to the stress limits and the modification to the B_2-C_2 relationship that Rodabaugh and Moore had suggested in 1978 (i.e. from 0.75 to 0.67). The authors also include the following statement on the relationship between piping components and straight pipes: that Eq. (1) and the corresponding equation for Class II piping, are "highly simplified limit-load formulas expressed in terms *relative to the limit-load behavior of straight pipe*. For piping products with B_1=0.5 and B_2=1.0 ... these equations express the concept that the product is *at least as strong as the attached pipe*. (italics added)" These two aspects of piping design for primary loads are central to our proposed new procedure for calculating the B_2 index.

In 1982, Rodabaugh and Moore[37] summarized the literature on end effects on elbows subjected to moment loadings, and presented their finite element results on elbows with characteristic bend parameters from 0.05 to 1.5. As part of this study, they also investigated the effect of subtended bend angle on the C_2 index, and suggested equations for C_2 for three ranges of α_o (≥ 90°, = 45°, and ≤ 30°). They intuit "that, as α_o approaches zero, the maximum stress index should approach 1.00"[38]. In another part of their work, they suggest directional stress indices for primary and primary plus secondary stresses This work resulted in ASME Code Case N-319[39] giving an alternate procedure for evaluating stresses in butt welding elbows in Class 1 piping, Section III, Div. 1. This case was superseded in 1990 by Case N-319-2[40], which gives the following replacement for the B_2M_i calculation in Eq. (1):

$$\left.\begin{array}{ll} C_{2x} = C_{2y} = 1.71/h^{0.53} \geq 1.0 & \\ C_{2z} = 1.95/h^{2/3} & \text{for } \alpha_o \geq 90^\circ \\ C_{2z} = 1.75/h^{0.56} & \text{for } \alpha_o = 45^\circ \\ C_{2z} = 1.0 & \text{for } \alpha_o = 0^\circ \\ B_2M_i = 0.67\left[(C_{2x}M_x)^2 + (C_{2y}M_y)^2 + (C_{2z}M_z)^2\right]^{\frac{1}{2}} & \end{array}\right\} \tag{12}$$

Even though Eq. (1) is usually thought of in terms of limit load analysis, primary stresses are also related to membrane stresses, and there have been attempts to use elastic analysis to calculate membrane stresses and use them to obtain the B_2 index. This was the approach taken by Rodabaugh and Moore[41] in 1983 for concentric nozzles. They state "Conceptually, [the B indices] are derived on a 'limit-load' basis. However, a tentative assessment of the adequacy of the B indices can be made by considering the calculated membrane stresses." In the second article of this 1983 WRC bulletin on eccentric reducers, Avent et al.[42] define B_2 as follows:

$$B_2 = \frac{\sigma_{mm}}{(M_i/Z)} \tag{13}$$

where σ_{mm} is maximum calculated membrane stress intensity in a model corresponding with M_i. Because this approach is based on linear behavior, any moment below the proportional limit will work. Williams and Lewis[43] have applied this approach to elbows.

In 1988 Touboul et al.[44] used limit load results from Spence and Findlay, Dodge and Moore and ASME Code Case N-317 to create a modified version of the B_2 index to account for internal pressure and subtended bend angle,

$$B_2 = \frac{1.6}{h^{2/3}}\left(\frac{\text{á}}{\text{ð}}\right)^{0.4}\frac{1}{1+\frac{0.7}{\text{ë}}\frac{Pr_m}{tS_y}} \tag{14}$$

where the notation has been modified to make the equation consistent with that used in this paper. Another useful feature of this paper is a discussion of margins, defined as the ratio of the collapse moment to the Code allowed moment, for different loading levels. This is the same approach we will take in assessing our proposed B_2 procedure.

Touboul and Acker[45] in 1991 referred to Eq. (14) as the index that would be used if the moment in Eq. (1) were based on actual component instability, and then present a modified version of this equation with the 0.7 replaced by 0.55 if the moment is to be based on Code-defined collapse. They also address the issue of buckling. They state "...it is usually difficult (and usually impossible) to experimentally distinguish between plastic instability and buckling..." and then propose an equation similar to Eq. (1), but with directional stress indices and modified stress limits.

The first paper to indicate how to use an experimentally determined limit moment to obtain the B_2 index was given in 1995 by Wais[46]. The application was to welded attachments (lugs), but the procedure he presents would seem to be applicable more generally. Using the same approach as Mello and Griffin, Wais states that "The limit load is defined as that load which results in a deflection twice that predicted based on elastic behavior. Once the limit load and hence the limit moment was determined experimentally the expression:

$$M_{CL} = \frac{S_y Z}{B} \tag{15}$$

was used to determine the primary stress B [index]."

In 1999, Liu et al.[47] use a procedure similar to Wais', but with a nonlinear finite element analysis to determine the limit moment instead of an experiment. Their equation takes the form

$$B_2 = \frac{S_{membrane,CL}}{\frac{M_{CL}D_o}{2I}} \tag{16}$$

where $S_{membrane,CL}$ is the maximum membrane stress intensity in a pipe bend corresponding to the collapse moment determined from elastic-plastic finite element analysis due to in-plane closing mode bending, in-plane opening mode bending, out-of-plane bending, or torsion. They also used the linear elastic approach with membrane stresses as a conservative but more economical method to obtain the B_2. For this, they used the following equation:

$$B_2 = \frac{S_{membrane}}{\frac{MD_o}{2I}} \tag{17}$$

where $S_{membrane}$ is the maximum membrane stress intensity as above, but for a moment that is below the collapse value. They conclude "...the B_2 determined from the limit analysis is about 40% lower than that obtained from the corresponding linear elastic analysis..."

Also in 1999, Yu et al.[48] describe their research on the Mello-Griffin-Wais approach for obtaining the B_2 index for elbows. They began by using the equation

$$B_2 = \frac{S_y Z}{M_{CL}} \tag{18}$$

where M_{CL} is obtained from either test data or finite element analysis. Because B_2 should be 1.0 when applied to straight pipes, they first applied this equation to straight pipes but found that B_2 was consistently less than 1.0. They tried various modifications of Eq. (18), including replacing S_y with the equivalent von Mises stress at the point of Code-defined collapse, (this resulted in slightly lower B_2 values) and using the plastic section modulus in place of the elastic modulus Z (this resulted in a B_2 of about 1.0 for the straight pipe.) They suggest that a procedure that will always result in a B_2 of 1.0 for a straight pipe is to normalize Eq. (18) for any component by dividing it by the equation evaluated for a straight pipe with the same material and geometric properties as the component, i.e.

$$B_{2,normalized} = \frac{B_{2,component}}{B_{2,straight\ pipe}} \tag{19}$$

Yu et al. also observed that, when Eq. (18) was substituted into Eq. (19), the result was just the ratio of the limit moments, i.e.

$$B_{2,\text{normalized}} = \frac{\dfrac{S_y \cdot Z}{M_{CL,\text{component}}}}{\dfrac{S_y \cdot Z}{M_{CL,\text{straight pipe}}}} = \frac{M_{CL,\text{straight pipe}}}{M_{CL,\text{component}}} \tag{20}$$

Note that, because the $S_y Z$ terms cancel, the question of whether Z is elastic or plastic is irrelevant. This work by Yu et al. is the basis for the procedure described later in this paper.

In 1995, the Code was modified to accommodate reversing dynamic loading, and fatigue ratcheting as a failure mode. The following design equation for Level D loading was introduced:

$$B_1 \frac{P_D D_o}{2t} + B_2 \frac{D_o}{2I} M_E \leq 4.5 S_m \tag{21}$$

The interesting thing about this equation is that it still contains B indices, which are used elsewhere in the Code only for monotonic loading. Because the failure modes for monotonic loading will in general be quite different from cyclic loading it would seem as though the indices for this equation should have their own definition based on the failure mode associated with the equation. This part of the 1995 Code was not accepted by the NRC, and the ASME Code committees are still working on the appropriate form for design equations for reversing dynamic loading.

SUGGESTED PROCEDURE FOR CALCULATING A MARGIN-CONSISTENT B_2 STRESS INDEX

Eq. (20) was developed by normalizing the B_2 index obtained using Eq. (18), with respect to the B_2 index for a straight pipe [Eq. (19)]. This led to Eq. (20), which is the ratio of the collapse moments. This result can be derived in a more straight forward manner [49] by setting the stress limit for any component equal to the stress limit for a straight pipe, i.e.

$$\acute{o}_{\text{component}} = \acute{o}_{\text{straight pipe}} \tag{22}$$

Then, referring to Eq. (2), the definition of B_2 index, Eq. (22) can be written as follows:

$$B_{2,\text{component}} \cdot S_{\text{component}} = B_{2,\text{straight pipe}} \cdot S_{\text{straight pipe}} \tag{23}$$

Rearranging Eq. (23), letting $B_{2,\text{straight pipe}}=1.0$, and canceling the section modulii Z, we obtain the following:

$$B_{2,\text{component}} = \frac{S_{\text{straight pipe}}}{S_{\text{component}}} = \frac{M_{CL,\text{straight pipe}}/Z}{M_{CL,\text{component}}/Z} = \frac{M_{CL,\text{straight pipe}}}{M_{CL,\text{component}}} \tag{24}$$

From this perspective, Eq. (24) would seem to follow directly from the Code definition. It also has the advantage of guaranteeing that B_2 for a straight pipe will always be 1.0. This attribute was acknowledged in the 1982 paper by Rodabaugh and Moore in their work on C_2 indices for different bend angles. As the subtended bend angle approaches zero, the elbow approaches a straight pipe, and the authors suggested that, in the limit, the index should approach 1.0[38].

Another advantage in using Eq. (24) as the definition for the B_2 index is that the margin for the component always turns out to be the same as the margin for the straight pipe of the same geometric and material properties. This can be seen from the following proof, where the margin is defined, as it was in the paper by Touboul et al.[50], as the ratio of the collapse moment of the component divided by the Code allowed moment of the component.

$$\begin{aligned} \text{Margin}_{\text{component}} &= \frac{M_{CL,\text{component}}}{M_{\text{code,component}}} = \frac{M_{CL,\text{component}}}{\left(1.5S_m \cdot Z/B_{2,\text{normalized}}\right)_{\text{component}}} = \frac{M_{CL,\text{component}}}{1.5S_m \cdot Z} B_{2,\text{component, normalized}} \\ &= \frac{M_{CL,\text{component}}}{1.5S_m \cdot Z} \cdot \frac{M_{CL,\text{straight pipe}}}{M_{CL,\text{component}}} = \frac{M_{CL,\text{straight pipe}}}{1.5S_m \cdot Z} = \text{Margin}_{\text{straight pipe}} \end{aligned} \tag{25}$$

RESULTS

We have applied our definition of B_2 (Eq (24)) to forty different elbow configurations, with values of h ranging from 0.048 to 0.997, subjected to in-plane-closing, in-plane-opening bending moments using the nonlinear FEA code ANSYS. Since the closing mode always controlled, data for the opening mode are not shown. These components are all butt-welding, seamless, 304L stainless steel, long and short radius, 90° elbows at room temperature. Nominal geometric and Code material properties were used. The FEA models utilized ANSYS SHELL 181 elements. See the Appendix at the end of this paper for examples of our FEA verification using experimental data. The details of 4 sets of calculations are tabulated in Table 1. The two rows labeled $B_{2,\text{straight pipe}}$ and $B_{2,\text{elbow}}$ show that using Eq. (18), which would seem to be a literal reading of the Code as given in Eq. (2), can lead to values that are less than one. The next row, $B_{2,\text{elbow, normalized}}$, has values that are all greater than one, as expected. The last row is the ratio of the B_2 value we calculate compared to the Code value. The values for $B_{2,\text{straight pipe, normalized}}$ would, of course, all be 1.00.

Table 1. Examples of New-definition B_2 Values vs. Code B_2 Values for Elbows

Size and Schedule			8" Sch5 SR[1]		2" Sch40 LR[1]		8"Sch160 LR[1]		2" Sch160 LR[1]	
h			0.048		0.375		0.730		0.997	
$B_{2,\text{elbow, code}}$ (Eq. (3))			9.83		2.50		1.60		1.30	
Z	(in^3)	(cm^3)	6.13	100.	0.561	9.19	38.5	631.	0.979	16.0
S_y	(ksi)	(MPa)	25.0	172.	25.0	172.	25.0	172.	25.0	172.
$B_{2,\text{straight pipe}}$ (Eq. (18))[2]			0.93		0.88		0.85		0.83	
$B_{2,\text{elbow}}$ (Eq. (18))[2]			4.72		1.49		1.05		0.93	
$B_{2,\text{elbow, normalized}}$ (Eq. (20))[3]			5.08		1.69		1.24		1.12	
Percent Reduction[4]			48%		32%		23%		14%	

[1] SR = Short Radius, LR=Long Radius

[2] Z is the elastic section modulus

[2 & 3] Collapse moments are obtained from FEA. For elbows, the moments are in-plane closing.

[4] Percent Reduction = $\dfrac{\left|B_{2,\text{elbow, normalized}} - B_{2,\text{elbow, Code}}\right|}{B_{2,\text{elbow, Code}}}$

The complete set of B_2 results for in-plane closing and opening mode bending are shown graphically in Fig. 2, where FEA Data stands for the evaluations of Eq. (24), LR stands for Long Radius elbows and SR stands for Short Radius Elbows. The line for "Minimum B_2" and "Code Equation" are self-explanatory, and the other curves will be explained below. We observe that there is very little difference between Long Radius and Short Radius elbow behavior.

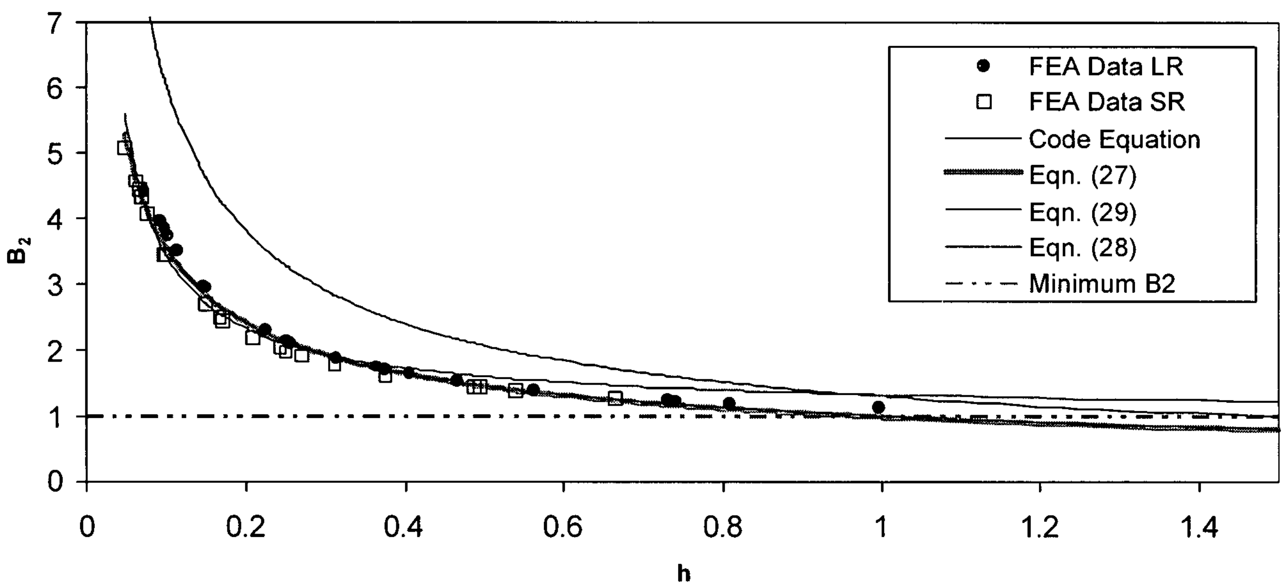

Fig. 2. B_2 Values vs. h for In-Plane Bending, Closing Mode

If we postulate an equation for the FEA data shown in Fig. 2, using an equation of the form

$$B_2 = \alpha + \frac{\beta}{h^\gamma} \tag{26}$$

then we can determine numerical values for the parameters α, β and γ by minimizing the sum of the-squared errors between the FEA data points and the corresponding values from the postulated equation. The minimization uses all of the results, i.e. both LR and SR elbows. If α is set to zero, then the form of the equation is the same as the Code equation, in which $\beta = 1.30$ and $\gamma = 2/3$. If α is set to 1, then the equation guarantees that B_2 will never be less than 1. Alternatively, we could leave α as a free parameter, and let the minimization algorithm establish the optimal value. We show below the results of these different equation possibilities:

Code Equation $$B_2 = \frac{1.30}{h^{2/3}} \tag{3}$$

$\alpha = 0$ $$B_2 = \frac{0.986}{h^{0.554}} \tag{27}$$

$\alpha = 1$ $$B_2 = 1 + \frac{0.323}{h^{0.875}} \tag{28}$$

$\alpha =$ free parameter $$B_2 = 0.047 + \frac{0.950}{h^{0.564}} \tag{29}$$

SUMMARY AND CONCLUSION

In our review of the history of Eq. (1) [Eq. (9) in the Code] and the B_2 index, we conclude that the developers of this equation in the Code were attempting to prevent gross plastic (and nonlinear) behavior of piping by relating the mildly plastic (and nonlinear) behavior of components to straight pipes and then using appropriate allowable stresses. The term 'mildly' is used here because the Code-defined collapse load is, for most elbows, well below the instability load, that is the load for which there is an actual physical collapse. The corollary to our conclusion is that stress index of a component should be related to the collapse behavior of a straight pipe which has the same material and geometric properties as the component. This is the basis of our suggested procedure for calculating the B_2 index as the ratio of collapse moments. We have shown that, using this procedure, (a) the B_2 for a straight pipe will always be 1.00 and (b) the margin for any component will be the same as for a straight pipe with the same material and geometric properties. Also, in the examples presented, the suggested procedure results values of B_2 which are up to 50% less than the values obtained from Eq. (3). Additional work needs to be done before a more definitive statement can be made regarding the B_2 stress index values for elbows, or before it is possible to determine how the results of this procedure would relate to Code equations for other types of components. Three possible equations are suggested to reflect the proposed definition of B_2, with Eq. (28) perhaps being preferred as it guarantees that the index will never be less than one.

FUTURE WORK

Before a definitive statement can be made about the usefulness of the suggested procedure, however, there remain several topics that need to be investigated. These include determining the effects of internal pressure, combined loadings, use of other materials, behavior at elevated temperature (covered in Code Subsection NH) and high strain rates, consideration of other sizes, schedules and bend angles of elbows and a consideration of other components such as tees and branches, and the relationship between Code-defined collapse and actual physical collapse. A study of cyclic loading would also seem to be worthwhile. In this case it would be necessary to redefine what is meant by collapse, and then use this definition in the calculation of a B_2' stress index. If the beneficial attributes of the proposed procedure hold up under continued scrutiny, then it would seem appropriate to propose that it be included in the Code in some appropriate manner.

ACKNOWLEDGEMENT

The authors would like to acknowledge the support of the Center for Nuclear Power Plant Structures, Equipment and Piping at North Carolina State University, the PVRC Subcommittee on Flexibility Models and Stress Intensification Factors (Grant 98-PNV-6) and the North Carolina Supercomputing Center. The assistance of Dr. Tasnim Hassan and graduate student Kevin Wilkins in performing the various experiments is appreciated.

NOMENCLATURE

a = ratio of plastic deformation to extrapolated elastic deformation in Greenstreet's report
B_1 = primary stress index for pressure
B_2 = primary stress index for bending
C_2 = secondary stress index for bending
D = mean pipe diameter
D_o = outside diameter of pipe
E = Young's modulus
h = characteristic bend parameter, tR/r_m^2
i = stress intensification factor (SIF). Also a stress index for detailed analysis in NB-3200, given in tables NB-3685.1-1&2
I = moment of inertia
K = local stress index
M_{CL} = Code defined collapse moment
M_{LL} = limit load moment
M_E = amplitude of the resultant moment due to the inertial loading from the earthquake, other reversing type dynamic events and weight.
M_i = resultant moment due to a combination of Design Mechanical Loads
P = design pressure
P_D = pressure occurring coincident with a reversing dynamic load
R = nominal bend radius of elbow
r_m = mean pipe radius, $(D_o\text{-}t)/2$
S = nominal stress
S_m = allowable design stress intensity value
t = nominal wall thickness
Z = section modulus
α = bend angle of elbow
γ = R/r (unrelated to the circumferential stress-intensification factor given above)
γ_i = in-plane bending maximum circumferential stress-intensification factor
γ_o = out-of-plane bending maximum circumferential stress-intensification factor
λ = $h/\ (1-\nu^2)$
ν = Poisson's ratio
σ = stress magnitude corresponding to a limit load
σ_{mm} = maximum membrane stress intensity
φ = dimensionless pressure parameter, PR^2/Ert

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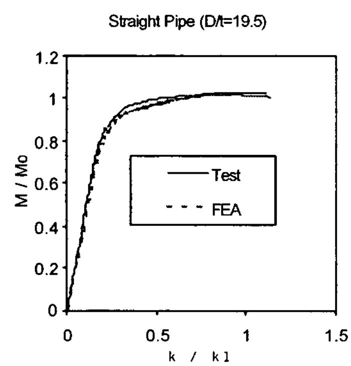
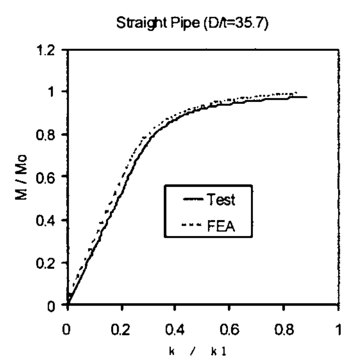
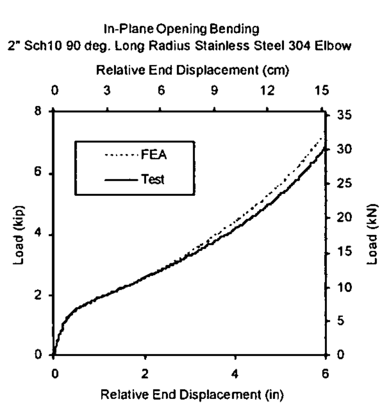
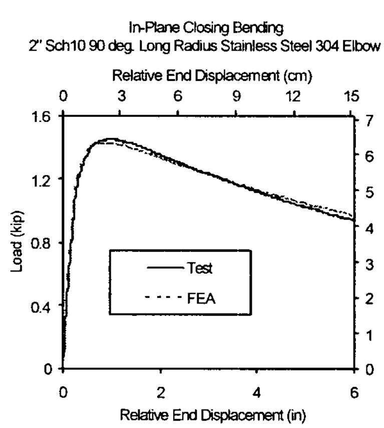
APPENDIX: CORRELATION OF FEA WITH EXPERIMENTAL DATA

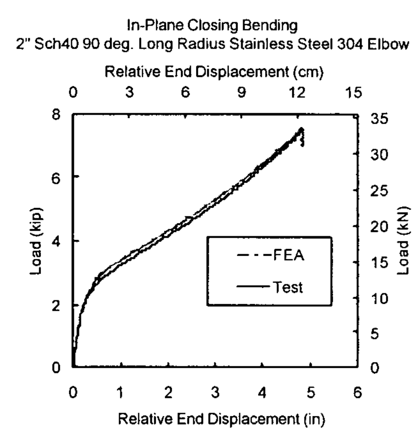
The nonlinear FEA procedures used above to determine the collapse moments of straight pipes and elbows were verified by eight experiments, as demonstrated in Fig. 3 below. They are two four-point-bending tests on straight pipes (presented in Ju [51]) and six elbow tests, two for in-plane closing load, two for in-plane opening load and two subjected to out-of-plane load. All the FEA simulations show close agreement with test responses, which validates the FEA approaches we used to obtain B_2 values shown in Table 1 and in Fig. 2 above. The various issues associated in our finite element analysis such as element type, mesh size, reconciliation with test results and so on were discussed in Tan et al. [52].











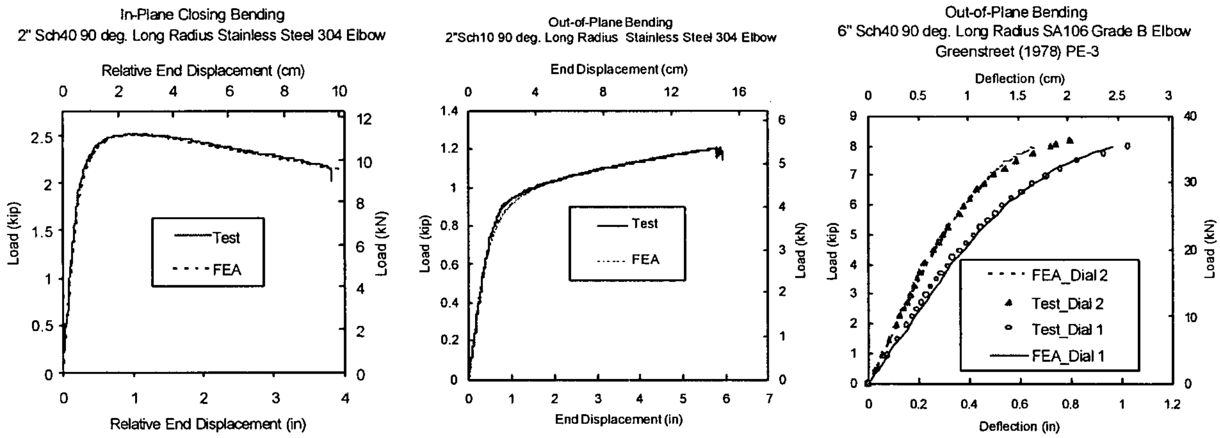


Fig. 3. FEA Results vs. Experimental Results

ATTACHMENT 3

AFFIDAVIT FROM GE-HITACHI NUCLEAR ENERGY AMERICAS LLC (GEH) JUSTIFYING WITHHOLDING PROPRIETARY INFORMATION

GE-Hitachi Nuclear Energy Americas LLC

AFFIDAVIT

I, Edward D. Schrull, PE, state as follows:

(1) I am the Vice President, Regulatory Affairs, Services Licensing, GE-Hitachi Nuclear Energy Americas LLC (GEH). I have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in GEH letter, GE-PPO-1GYEF-KG1-591 R1, Garold Carlisle (GEH) to Theresa Darling (CENG), "NMP2 EPU EMCB Supplemental RAIs," dated May 5, 2011. The proprietary information in Enclosure 1 entitled, "Responses to EMCB Supplemental RAIs (Proprietary)," is identified by a dotted underline inside double square brackets. [[This sentence is an example.{3}]]. Figures containing GEH proprietary information are identified with double square brackets before and after the object. In each case, the superscript notation {3} refers to Paragraph (3) of this affidavit that provides the basis for the proprietary determination

(3) In making this application for withholding of proprietary information of which it is the owner or licensee, GEH relies upon the exemption from disclosure set forth in the Freedom of Information Act (FOIA), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), and 2.390(a)(4) for trade secrets (Exemption 4). The material for which exemption from disclosure is here sought also qualifies under the narrower definition of trade secret, within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975 F2d 871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704 F2d 1280 (DC Cir. 1983).

(4) The information sought to be withheld is considered to be proprietary for the reasons set forth in paragraphs (4)a. and (4)b. Some examples of categories of information that fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by GEH's competitors without license from GEH constitutes a competitive economic advantage over GEH and/or other companies.

b. Information that, if used by a competitor, would reduce their expenditure of resources or improve their competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product.

c. Information that reveals aspects of past, present, or future GEH customer-funded development plans and programs, that may include potential products of GEH.

d. Information that discloses trade secret and/or potentially patentable subject matter for which it may be desirable to obtain patent protection.

(5) To address 10 CFR 2.390(b)(4), the information sought to be withheld is being submitted to the NRC in confidence. The information is of a sort customarily held in confidence by GEH, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GEH, not been disclosed publicly, and not been made available in public sources. All disclosures to third parties, including any required transmittals to the NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary and/or confidentiality agreements that provide for maintaining the information in confidence. The initial designation of this information as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure are as set forth in the following paragraphs (6) and (7).

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, who is the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge, or who is the person most likely to be subject to the terms under which it was licensed to GEH. Access to such documents within GEH is limited to a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist, or other equivalent authority for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GEH are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary and/or confidentiality agreements.

(8) The information identified in paragraph (2) above is classified as proprietary because it contains results of an analysis performed by GEH to support the Nine Mile Point Unit 2 Extended Power Uprate (EPU) license application. This analysis is part of the GEH EPU methodology. Development of the EPU methodology and the supporting analysis techniques and information, and their application to the design, modification, and processes were achieved at a significant cost to GEH.

The development of the evaluation methodology along with the interpretation and application of the analytical results is derived from the extensive experience database that constitutes a major GEH asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GEH's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GEH's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GEH. The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial. GEH's competitive advantage will be lost if its competitors are able to use the results of the GEH experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GEH would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GEH of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing and obtaining these very valuable analytical tools.

I declare under penalty of perjury that the foregoing affidavit and the matters stated therein are true and correct to the best of my knowledge, information, and belief.

Executed on this 5th day of May 2011.

Edward D. Schrull, PE
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