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October 7, 2005
L-05-154

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Subject: Beaver Valley Power Station, Unit Nos. 1 and 2
BV-1 Docket No. 50-334, License No. DPR-66
BV-2 Docket No. 50-412, License No. NPF-73
Supplemental Information for License Amendment Request Nos. 302 and 173

Pursuant to 10 CFR 50.90, FirstEnergy Nuclear Operating Company (FENOC) requested amendments to the above licenses in the form of changes to the Beaver Valley Power Station (BVPS) Operating Licenses and Technical Specifications. License Amendment Requests 302 and 173, transmitted by FENOC letter L-04-125 dated October 4, 2004, proposed Operating License and Technical Specification (TS) changes that support an increase in the licensed power level from the current level of 2689 MWt to 2900 MWt Rated Thermal Power (RTP). This Extended Power Uprate (EPU) License Amendment Request (LAR) also proposed changes reflecting the installation of replacement steam generators in BVPS Unit No. 1.

FENOC License Amendment Request 320, known as the replacement steam generator (RSG) LAR, was transmitted by FENOC letter L-05-069 dated April 13, 2005. The RSG LAR contains those Technical Specification changes proposed in FENOC letter L-04-125, the Extended Power Uprate (EPU) LAR, that are needed to replace the BVPS Unit No. 1 steam generators.

Enclosures 1 through 5 provide supplemental information that pertains to the EPU LAR. The supplemental information is the result of a variety of actions associated with the review of the RSG and EPU submittals. The reason for the supplemental information is provided in each of the enclosures. The content of each enclosure is reflected in the enclosure title. The regulatory commitments contained in this letter are provided in Enclosure 6.

The responses contained in this transmittal have no impact on either the proposed Technical Specification changes or the no significant hazards consideration transmitted by FENOC letter L-04-125.

A001

If you have questions or require additional information, please contact Mr. Gregory A. Dunn, Manager - Licensing, at 330-315-7243.

I declare under penalty of perjury that the foregoing is true and correct. Executed on October 7, 2005.

Sincerely,

James H. Lash

Enclosures:
1. Conformance to WRB-2M Conditions
2. Reactor Vessel Internals Inspection
3. Operator Actions
4. Leading Edge Flow Meter
5. Extended Power Uprate (EPU) Licensing Report Items
6. Commitment List

c: Mr. T. G. Colburn, NRR Senior Project Manager
Mr. P. C. Cataldo, NRC Senior Resident Inspector
Mr. S. J. Collins, NRC Region I Administrator
Mr. D. A. Allard, Director BRP/DEP
Mr. L. E. Ryan (BRP/DEP)

Conformance to WRB-2M Conditions

Reason for the contained supplemental information.

During the development of the RSG LAR (Reference 1-1), which is applicable to only BVPS Unit No.1, it was noted that the EPU LAR (Reference 1-2), which is applicable to BVPS Unit Nos.1 and 2, did not address the specified four conditions associated with the use of the WRB-2M critical heat flux correlation. Therefore, the following supplemental information is provided to demonstrate BVPS Unit No. 2 conformance with the four conditions and to provide consistency between the two License Amendment Requests.

Correlation Background

Nuclear fuel correlations are used to predict the initiation of boiling crisis at the surface of the fuel rods, which might lead to fuel damage. Boiling crisis occurs when the heat flow rate at the cladding surface exceeds a critical heat flux (CHF) so that the mode of heat transfer changes from nucleate boiling to film boiling.

The Vantage 5 fuel design incorporates intermediate flow mixer (IFM) grids. The IFM mixing vanes were the same as the mixing vanes in the standard support grids except the IFM grids had no structural function. Additional CHF tests were performed by Westinghouse for this design and a new CHF correlation was developed called WRB-2. The WRB-2 correlation is similar to the WRB-1 correlation but includes a term that accounts for the change in CHF performance as grid spacing changes. Westinghouse has further modified the fuel design to reduce fuel rod mechanical wear and to further improve thermal/hydraulic performance. In the modified fuel design, the mixing vanes are slightly longer than the previous design. Critical heat flux tests of the modified fuel were conducted with and without control rod guide thimbles, and with and without modified intermediate flow mixer grids. Although the data from these tests could be successfully correlated using WRB-2, a better correlation was obtained when a multiplier "M" was developed using statistical regression techniques. The improved correlation is called WRB-2M. The WRB-2M correlation would be applicable to the Westinghouse RFA and RFA-2 fuel products which are used at both BVPS units.

WRB-2M Correlation Condition Conformance

The NRC Safety Evaluation Report dated December 1, 1998 (Reference 1-3) states that a utility's use of WRB-2M correlation with a Departure from Nucleate Boiling Ratio (DNBR) limit of 1.14 for plant safety analyses, as described in WCAP-15025-P-A (Reference 1-4) may be approved by the NRC staff, and may be used provided the specified four conditions are met. Each of the four conditions, and their fulfillment, is addressed below.

Condition 1. "Since WRB-2M was developed from test assemblies designed to simulate Modified 17x17 Vantage 5H fuel, the correlation may only be used to perform evaluation for fuel of that type without further justification. Modified Vantage 5H fuel with or without modified intermediate flow mixer grids may be evaluated with WRB-2M."

This condition is met. The structural mid-grid design used in the RFA fuel assembly is a minor modification of the Modified Low Pressure Drop mid-grid that was addressed in WCAP-15025-P-A for use with the WRB-2M DNB correlation. The RFA mid-grid design was evaluated by means of the NRC-approved Fuel Criteria Evaluation Process (FCEP) (Reference 1-5). By complying with the requirements of FCEP, it has been demonstrated that the new mid-grid design meets all design criteria of existing tested mid-grids that form the basis of the WRB-2M correlation database and that the WRB-2M correlation with a 95/95 correlation limit of 1.14 applies to the new RFA mid-grid. As required by FCEP, the Westinghouse notification to the NRC of the RFA mid-grid design modifications and the validation of the WRB-2M DNB correlation applicability to the RFA mid-grid was provided in written notification to the NRC (Reference 1-6).

Condition 2. "Since WRB-2M is dependent on calculated local fluid properties, these should be calculated by a computer code that has been reviewed and approved by the NRC staff for that purpose. Currently WRB-2M with a DNBR limit of 1.14 may be used with the THINC-IV computer code. The use of VIPRE-01 by Westinghouse with WRB-2M is currently under separate review."

This condition is met. For the RFA fuel in BVPS Unit 2, the analysis of the RFA fuel was based on the VIPRE computer code (as licensed for Westinghouse in Reference 1-7) and the WRB-2M DNB correlation with a 95/95 correlation limit of 1.14. The use of VIPRE by Westinghouse with WRB-2M was approved by the NRC as part of Reference 1-8. As discussed for Condition 1, the Westinghouse notification to the NRC of the validation of the WRB-2M DNB correlation applicability to the RFA mid-grid was provided in Reference 1-6.

Condition 3. "WRB-2M may be used for PWR plant analyses of steady state and reactor transients other than loss of coolant accidents. Use of WRB-2M for loss of coolant accident analysis will require additional justification that the applicable NRC regulations are met and the computer code used to calculate local fuel element thermal/hydraulic properties has been approved for that purpose."

This condition is met. The WRB-2M correlation is not used for the loss of coolant accident analysis of the RFA fuel in BVPS Unit 2.

Condition 4. "The correlation should not be used outside its range of applicability defined by the range of the test data from which it was developed. The range is listed in Table 1."

This condition is met. Application of the WRB-2M correlation to the RFA fuel upgrade in BVPS Unit 2 was consistent with the range of parameters specified in Table 4-1 of WCAP-15025-P-A.

Conclusions

The supplemental information provided in this enclosure documents that the four specific conditions of the WRB-2M correlation are met for BVPS Unit 2. The addition of this supplemental information does not alter the no significant hazards consideration determination documented in Reference 1-2. Specific references to the WRB-2M correlation in the no significant hazards consideration determination documented in Reference 1-2 are not necessary because the WRB-2M correlation is part of the VIPRE code and the VIPRE code is explicitly referenced in the no significant hazards consideration determination.

Enclosure 1 References

1-1 FENOC Letter L-05-069, License Amendment Request 320, dated April 13, 2005.

1-2 FENOC Letter L-04-125, License Amendment Requests 302 and 173, dated October 4, 2004.

1-3 NRC Safety Evaluation Report, "Acceptance for Referencing of Licensing Topical Report WCAP-15025-P, Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids (TAC NO. MA1074)," December 1, 1998.

1-4 WCAP-15025-P-A, "Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids," April 1999.

1-5 Davidson, S. L. (Ed.), "Westinghouse Fuel Criteria Evaluation Process," WCAP-12488-A, October 1994.

1-6 Letter from H. A. Sepp (Westinghouse) to J. S. Wermiel (NRC), "Fuel Criterion Evaluation Process (FCEP) Notification of the RFA-2 Design, Revision 1 (Proprietary)," LTR-NRC-02-55, November 13, 2002.

1-7 WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999.

1-8 NRC Safety Evaluation Report, "Acceptance for Referencing of Licensing Topical Report WCAP-14565, VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis (TAC NO. M98666)," January 19, 1999.

L-05-154 Enclosure 2

Reactor Vessel Internals Inspection

Reason for the contained supplemental information.

During a phone call on June 20, 2005 with the NRC staff, the reviewer requested the following supplemental information to support the response to Questions J.8 and J.9 of Reference 2-1.

1. Supplemental response for the reactor vessel (RV) surveillance capsule withdrawal schedules to confirm that the NRC had previously approved the withdrawal schedules that were submitted in Table 7-1 of WCAP-15771 for BVPS Unit No. 1 and Table 7-1 of WCAP-15675 for BVPS Unit No. 2.

2. Supplemental response providing a new commitment for the RV internals at BVPS Unit Nos. 1 and 2 to implement the results of the Materials Reliability Program's (MRP's) industry recommended inspection initiatives on pressurizer water reactor (PWR) RV internals. The NRC reviewer referred to the Waterford commitment as an acceptable example.

Supplemental Information

1. The capsule withdrawal schedule submitted in Table 7-1 of WCAP-15771 for BVPS Unit No. 1 was approved by NRC Safety Evaluation Report dated January 13, 2003, "BEAVER VALLEY POWER STATION, UNIT 1 – CHANGES TO THE REACTOR PRESSURE VESSEL SURVEILLANCE CAPSULE WITHDRAWAL SCHEDULE (TAC NO. MB3901)."

   The capsule withdrawal schedule submitted in Table 7-1 of WCAP-15675 for BVPS Unit No. 2 was approved by NRC Safety Evaluation Report dated March 19, 2002, "BEAVER VALLEY POWER STATION, UNIT 2 – CHANGES TO THE REACTOR PRESSURE VESSEL SURVEILLANCE CAPSULE WITHDRAWAL SCHEDULE (TAC NO. MB2974)."

2. FirstEnergy Nuclear Operating Company (FENOC) is currently an active participant in the Electric Power Research Institute (EPRI) MRP research initiatives on aging related degradation of reactor vessel internals components. By way of this submittal, FENOC commits to continue its active participation in the MRP initiative to determine appropriate reactor vessel internals degradation management programs.

Conclusions

The supplemental information provided does not impact the no significant hazards consideration determination documented in Reference 2-2 because the supplemental information has no impact on the three no significant hazards consideration questions.

Enclosure 2 References

2-1 FENOC Letter L-05-078, Responses to a Request for Additional Information in Support of License Amendment Request Nos. 302 and 173, dated May 26, 2005.

2-2 FENOC Letter L-04-125, License Amendment Requests 302 and 173, dated October 4, 2004.

L-05-154 Enclosure 3

Operator Actions

Reason for the contained supplemental information.

During a telephone call held on August 4, 2005 with the NRC reviewers, BVPS personnel were requested to provide information regarding request for additional information (RAI) response L.3 "Operating Procedures" submitted by Reference 3-1 in support of the EPU LAR.

Specifically, the following questions were asked:

1. How does EPU affect the operator's ability to perform the functions required?
2. How exactly do the operator action times change? (amount of change and if the time increases or decreases)?
3. For the operator initiator times, has the licensee done some sort of run through to determine if they can complete the required tasks in an acceptable time?

The NRC reviewer also asked that the following information discussed during the call be included in the response. 1) Are the simulators separate or are they the same for each unit? 2) How many crews would perform the validations? and 3) Describe the Emergency Operating Procedure (EOP) validation process.

Supplemental Information

The following responses are provided to the three questions listed above.

1. The operator's ability to perform the functions required does not change for EPU. The operators are trained on emergency and abnormal operating procedures, and as part of the procedural change process, all of the crews require training on the changes as a result of EPU.

2. See Table 3-1, "Comparison to Operator Action Times in BVPS EPU UFSAR Safety Analysis." These times are the operator action times used in the safety analyses. The EPU and current analysis times are provided to identify the changes. The loss of coolant accident (LOCA), non-LOCA and main steamline break (MSLB) operator action times are not significantly impacted by EPU analysis. The operator action times assumed within the steam generator tube ruptures (SGTR) overfill analysis did shorten in several instances, but a simulator run proved that the overall time to safety injection (SI) termination was not impacted and this total time is the critical time for the overfill analysis.

3. The new operator response times are in the process of being validated as part of the EOP review process. These validations are performed on the simulator for control room actions. Actions outside the control room are being validated via operator walkdowns as part of the procedural change process. The operator action times are monitored and evaluated to ensure the operator can perform the required tasks within an acceptable time to satisfy the event acceptance criteria.

The response to the simulator request and the validation process follows.

Each unit has its own specific plant simulator. One crew at each unit performs the validation of the EOPs for EPU. All of the remaining crews are trained on the changes prior to plant startup.

A summary of the BVPS EOP validation process (1/2OM-53B.1, "Generation, Revision, Review And Approval Of Emergency Operating And Abnormal Operating Procedures") is described below.

The validation process is conducted in three phases; Preparation, Assessment and Resolution.

A. The Preparation Phase consists of the following actions of various members:

1. Operations Manager or designee shall:
   a. Determine which validation method to use (Table-Top, Walk-Through, Simulator, Talk-Through)
   b. Designate an individual knowledgeable in EOP usage as the Review Team Chairman (normally an SRO)
   c. Provide Operations personnel to participate in the validation
   d. Ensure other disciplines are invited to participate as needed in the validation process (Training, QA/QC, Engineering, Human Performance)
   e. Coordinate with Training the use of the Simulator (if applicable)
2. Review Team Chairman shall:
   a. Obtain and become familiar with the EOP changes.
   b. Ensure correct validation method is used.
   c. Recommend what team members are needed for validation.
   d. Determine scenarios for validation if simulator is used.

B. The Assessment Phase may consist of any of the following as determined by the Operations Manager and Review Team Chairman:

- Table-Top — A review of the draft EOP by the Review Team, conducted in a seminar environment
- Walk-Through — A step-by-step walk-through in the plant of the draft EOP being validated
- Simulator — Objective observation of the performance of the draft EOP on the simulator, applying specific evaluation criteria to determine the acceptability of the EOP.
- Talk-Through — The team reads and evaluates the understandability of the steps, notes or cautions in the EOPs. This method can be used for simple changes or as a final validation of proposed corrections or resolutions for discrepancies that have been identified in other validation activities.

C. The Resolution Phase consists of the following:

1. Review discrepancies
2. Research and propose resolutions for discrepancies
3. Discuss discrepancies with Operations Manager or designee
4. Incorporate approved resolutions into procedures

Conclusions

The supplemental information does not impact the no significant hazards consideration determination documented in Reference 3-2 because it consists of additional information pertaining to operating actions assumed in the EPU safety analyses and does not impact the three no significant hazards consideration questions.

Enclosure 3 References

3-1 FENOC Letter L-05-078, Responses to a Request for Additional Information in Support of License Amendment Request Nos. 302 and 173, dated May 26, 2005.

3-2 FENOC Letter L-04-125, License Amendment Requests 302 and 173, dated October 4, 2004.

Table 3-1

Comparison of Operator Action Times in BVPS EPU UFSAR Safety Analysis

UFSAR Safety Analysis	Operator Action	Operator Action Time Used in EPU Analysis	Operator Action Time Used in Current Power Analysis
Loss of Coolant Accident (LOCA)			
LOCA Switchover from Cold Leg Recirculation to Hot Leg Recirculation	Initiate switchover to simultaneous hot leg/cold leg recirculation (BVPS-1) or to hot leg recirculation (BVPS-2)	At the following times after the start of the event: 6.5 hours (BVPS-1) 6.0 hours (BVPS-2)	At the following times after the start of the event: 8.0 hours (BVPS-1) 7.0 hours (BVPS-2)
LOCA Switchover cycling between Hot Leg Recirculation and Cold Leg Recirculation (BVPS-2)	Initiate cycling between hot leg recirculation and cold leg recirculation	At the following times after the start of the previous initiation of a recirculation alignment: 9.5 hours (BVPS-2)	At the following times after the start of the previous initiation of a recirculation alignment: 11.5 hours (BVPS-2)
Non-Loss of Coolant Accident (Non-LOCA)			
Non-LOCA Uncontrolled Boron Dilution (Modes 1, 2 and 3)	Terminate uncontrolled boron dilution flow to the RCS	Within 15 minutes after the start of the event for all Modes	Within 15 minutes after the start of the event for all Modes
Non-LOCA Main Feedline Break	Terminate auxiliary feedwater flow to the faulted steam generator	Within 15 minutes after low-low level is reached in the faulted SG	Within the following times after low-low level is reached in the faulted SG: 10 minutes (BVPS-1) 15 minutes (BVPS-2)
Non-LOCA Spurious SI – Pressurizer Overfill	Terminate high head safety injection flow to the RCS	Within 10 minutes after the start of the event	There is no current power pressurizer overfill analysis for BVPS-1 Within 10 minutes after the start of the event (BVPS-2)
Non-LOCA Loss of Offsite Power – Pressurizer Overfill (due to charging/letdown malfunction)	Mitigate uncontrolled charging flow to the RCS in conjunction with no letdown flow from the RCS	Within 10 minutes after the start of the event	Within 10 minutes after the start of the event

Table 3-1 (Continued)			
Comparison of Operator Action Times in BVPS EPU UFSAR Safety Analysis			
UFSAR Safety Analysis	**Operator Action**	**Operator Action Time Used in EPU Analysis**	**Operator Action Time Used in Current Power Analysis**
Steam Generator Tube Rupture (SGTR)			
SGTR [(1)] Overfill Analysis	1. Isolate auxiliary feedwater flow to the ruptured SG	Within the following times after reactor trip: 6.8 minutes (BVPS-1) 5.5 minutes (BVPS-2)	There is no current power LOFTTR2 SG overfill operational analysis for BVPS-1 Within 9.1 minutes after reactor trip (BVPS-2)
	2. Isolate steam flow (close MSIV) from the ruptured SG	Within the following times after reactor trip: 16.7 minutes (BVPS-1) 15.0 minutes (BVPS-2)	There is no current power LOFTTR2 SG overfill operational analysis for BVPS-1 Within 9.1 minutes after reactor trip (BVPS-2)
	3. Initiate cooldown from the intact SGs via the main steam system after MSIV closure	Within the following times after the MSIV is closed: 1. For actions from inside the main control room: 2.4 minutes (BVPS-1) 2.0 minutes (BVPS-2) 2. For actions from outside the main control room: 10.0 minutes (BVPS-1) 7.0 minutes (BVPS-2)	There is no current power analysis for actions inside the main control room or LOFTTR2 SG overfill operational analysis for BVPS-1 Within 9 minutes after the MSIV is closed for action from outside main control room(BVPS-2)
	4. Initiate RCS depressuriztion (open pressurizer PORV) after completion of the cooldown	Within the following times after reaching the end of cooldown target temperature: 3.0 minutes (BVPS-1) 4.0 minutes (BVPS-2)	There is no current power LOFTTR2 SG overfill operational analysis for BVPS-1 Within 2.5 minutes after reaching the end of cooldown target temperature (BVPS-2)
	5. Terminate SI (isolate the high head safety injection flow path) after completion of RCS depressurization	Within the following times after reaching the end of RCS depressurization target pressure: 4.9 minutes (BVPS-1) 3.0 minutes (BVPS-2)	There is no current power LOFTTR2 SG overfill operational analysis for BVPS-1 Within 1.25 minutes after reaching the end of RCS depressurization target pressure (BVPS-2)

Table 3-1 (Continued)			
Comparison of Operator Action Times in BVPS EPU UFSAR Safety Analysis			
UFSAR Safety Analysis	**Operator Action**	**Operator Action Time Used in EPU Analysis**	**Operator Action Time Used in Current Power Analysis**
Main Steam Line Break (MSLB) Mass and Energy (M&E) Releases			
MSLB M&Es Inside Containment (for containment response)	Isolate auxiliary feedwater flow to faulted SG	Within 30 minutes after the start of the event	Within the following times after the start of the event: 10 minutes (BVPS-1) 30 minutes (BVPS-2)
MSLB M&Es Outside Containment (basis for M&Es that define EQ profile)	Trip the reactor, isolate main feedwater flow to and steam flow from faulted SG and isolate auxiliary feedwater flow (if applicable) to faulted SG	Within 30 minutes after the start of the event	Within the following times after the start of the event: 10 minutes (BVPS-1) 30 minutes (BVPS-2)

Notes:
1. The SGTR analysis for BVPS-2 is a licensing basis safety analysis while the SGTR analysis for BVPS-1 is an operational response analysis for operator training purposes. Operator actions are modeled in conjunction with the performance of the RCS and steam generators in the LOFTTR2 computer code to achieve the desired goal of preventing overfill of the ruptured SG.

Leading Edge Flow Meter

Reason for the contained supplemental information.

During a telephone call held on July 28, 2005 with the NRC reviewers, BVPS personnel were requested to provide supplemental information regarding request for additional information (RAI) response I.1 - I&C Section; Leading Edge Flow Meter (LEFM) submitted by Reference 4-1 in support of the EPU LAR.

Supplemental Information

Reference 4-2 included Attachment C-2, Licensing Requirements Manual, which addresses BVPS Unit No. 2 operation with an inoperable LEFM. As defined in Section 3.8, Reactor Power will be reduced to 98.6% rated thermal power (RTP) should the LEFM be inoperable prior to the next required daily calorimetric heat balance. The asterisk footnote on the BVPS Unit No. 2 LRM markup submitted as part of Reference 4-2 was not corrected for operation at the extended power uprate but identifies the current plant operating conditions. As part of implementation, this footnote is changed based on power ascension testing to properly reflect a BVPS Unit No. 2 power reduction of 1.4% RTP with the LEFM declared inoperable.

The asterisk footnote is applicable to BVPS Unit No. 2 only because of an inaccuracy associated with the BVPS Unit No. 2 venturis. As stated previously, the power levels specified in the asterisk footnote will be changed as the power level is increased. The values will reflect 98.6% of RTP as RTP is raised because power must be limited to 98.6% of RTP when the LEFM is inoperable, regardless of the numerical value of RTP.

Conclusions

The supplemental information being provided does not impact the no significant hazards consideration determination documented in Reference 4-2. There is no change to the LEFM footnote and the supplemental information being provided is immaterial to the no significant hazards consideration.

Enclosure 4 References

4-1 FENOC Letter L-05-078, Responses to a Request for Additional Information in Support of License Amendment Request Nos. 302 and 173, dated May 26, 2005

4-2 FENOC Letter L-04-125, License Amendment Requests 302 and 173, dated October 4, 2004.

L-05-154 Enclosure 5

Extended Power Uprate (EPU) Licensing Report Items

Reason for the contained supplemental information.

During the development of the replacement steam generators (RSG) license amendment request (LAR), items needing correction, clarification or enhancements in the EPU Licensing Report (Enclosure 2 of Reference 5-2) were identified. The items were corrected in the RSG LAR submittal (Reference 5-1). The identification of these items resulted in more rigorous review and validation of the EPU submittal.

Supplemental Information

Markups of the EPU Licensing Report pages are provided in Attachment A to this enclosure. Table 5-1 lists the affected pages contained in Attachment A and provides a discussion pertaining to the items and the changes noted in the attachment.

Table 5-1

EPU Licensing Report Items

Page	Discussion
5-11	Revision provides clarification of the acceptance criteria. There is no effect on the analysis because both criteria do not need to be met.
5-24	The revised values is the sequence event table do not impact the limiting case which is based on maximum PCT. The revised values reflect the calculation values and are the result of transcription errors. Thus, there is no effect on the analysis.
5-80	The revised value is more conservative than the value originally reported. The revised value reflects the impact of Technical Bulletin 04-12. The revised value reflects the calculation value and is the result of a transcription error. Thus, there is no effect on the analysis.
5-89	The change is an enhancement that provides more detail and documents consistency with the Technical Specifications. Thus, there is no effect on the analysis.
5-173	The change is an enhancement that provides more detail and documents consistency with the analysis methodology. Thus, there is no effect on the analysis.
5-177	The change is an enhancement that provides consistency with the analysis. The revised statement is more conservative than the original statement. Thus, there is no effect on the analysis.
5-199	The change is a correction of the positioning of the values. The revised values reflect the calculation values and is the result of a transcription error. Thus, there is no effect on the analysis.
5-236	The revised uncertainty value is more conservative than the value originally reported. The revised value reflects the calculation value and is the result of a transcription error. Thus, there is no effect on the analysis.

Table 5-1 EPU Licensing Report Items	
Page	**Discussion**
5-295	The change is an enhancement that avoids potential confusion with Table 5.3.20-1A which does not report the steam system piping failure at full power case. Thus, there is no effect on the analysis.
5-297	The revised values reflect the calculation values and are the result of transcription errors. Although one of the revised values is more conservative than the value originally reported and the other is less conservative, the magnitude of the change is inconsequential to the analysis and conclusions drawn. Thus, there is no effect on the analysis.
5-307	The revised values reflect the calculation values and are the result of transcription errors. The magnitude of the change to Peak Primary Pressure for the Loss of Load event is inconsequential to the analysis and conclusions drawn. The change to Peak Secondary Pressure for the Complete Loss of Flow event is made to reflect the limiting peak secondary pressure for all of the Complete Loss of Flow event cases run. This is done to achieve consistency with the how limiting pressures are reported for the other events, but does not result in a change to the minimum DNBR for the Unit 1 Condition II events. Acronym typographical error. Thus, there is no effect on the analysis.
5-308	The revised values reflect the calculation values and are the result of transcription errors. The magnitude of the changes to Peak Secondary Pressure for the RCCA Bank Withdrawal at Power and Peak Primary Pressure for the Partial Loss of Flow events are inconsequential to the analysis and conclusions drawn. The change to Peak Secondary Pressure for the Complete Loss of Flow event is made to reflect the limiting peak secondary pressure for all of the Complete Loss of Flow event cases run. This is done to achieve consistency with the how limiting pressures are reported for the other events, but does not result in a change to the minimum DNBR for the Unit 2 Condition II events. The revised value for Minimum DNBR for the Feedwater System Malfunctions, Feedwater Enthalpy Decrease event case is less conservative than the value originally reported. However, this does not change the minimum DNBR for the Unit 2 Condition II events. Acronym typographical error. Thus, there is no effect on the analysis.
5-316	The revised value reflects the calculation value and is the result of transcription errors. The magnitude of the change is inconsequential to the analysis and conclusions drawn. Thus, there is no effect on the analysis.
5-319	The revised value reflects the calculation value and is the result of a transcription error. The magnitude of the change is inconsequential to the analysis and conclusions drawn. Thus, there is no effect on the analysis.
5-383	The revised value reflects the calculation value and is the result of a transcription error. The magnitude of the change is inconsequential to the analysis and conclusions drawn. Thus, there is no effect on the analysis.

A transcription error is defined as an error made in transferring a value from the safety analysis calculation into the EPU Licensing Report. In each case, the corrected value reflects the value used in the calculation. The correction of a transcription error has no effect on the analysis or conclusions drawn because correcting EPU Licensing Report results in the report reflecting the safety analysis calculation value.

Conclusions

All of the identified items have been entered into the BVPS Corrective Action Program and evaluated for impact. None of the identified items impact the results of the EPU safety analysis or the conclusions drawn, or invalidate the no significant hazards consideration. The proposed revisions do not impact the no significant hazards consideration determination documented in Reference 5-2 because they reflect the calculations and analysis upon which the analysis conclusions were drawn and how the three no significant hazards consideration questions were answered.

Enclosure 5 References

5-1 FENOC Letter L-05-069, License Amendment Request 320, dated April 13, 2005.

5-2 FENOC Letter L-04-125, License Amendment Requests 302 and 173, dated October 4, 2004.

Enclosure 5 Attachment A

EPU Licensing Report Items

reactor coolant system blowdown ensues in which the heat from fission product decay, the hot reactor internals, and the reactor vessel continues to be transferred to the RCS fluid. The heat transfer between the RCS and the secondary system may be in either direction and is a function of the relative temperatures of the primary and secondary conditions. In the case of continuous heat addition to the secondary during a period of quasi-equilibrium, an increase in the secondary system pressure results in steam relief via the steam generator safety valves.

When a Small Break LOCA occurs, depressurization of the RCS causes fluid to flow into the loops from the pressurizer resulting in a pressure and level decrease in the pressurizer. The reactor trip signal subsequently occurs when the pressurizer low-pressure reactor trip setpoint, conservatively modeled as 1935 psia, is reached. LOOP is postulated to occur coincident with reactor trip. A safety injection signal is generated when the pressurizer low-pressure safety injection setpoint, conservatively modeled as 1745 psia for BVPS-1 and 1760 psia for BVPS-2, is reached. Safety injection flow is delayed 27 seconds after the occurrence of the low-pressure condition. This delay accounts for signal processing, diesel generator start up and emergency power bus loading consistent with the loss-of-offsite power coincident with reactor trip, as well as the pump acceleration and valve delays.

The following countermeasures limit the consequences of the accident in two ways:

1. Reactor trip and borated water injection supplement void formation in causing a rapid reduction of nuclear power to a residual level corresponding to the delayed fission and fission product decay. No credit is taken in the Small Break LOCA analysis for the boron content of the injection water. In addition, credit is taken in the Small Break LOCA analysis for the insertion of Rod Cluster Control Assemblies (RCCAs) subsequent to the reactor trip signal, considering the most reactive RCCA is stuck in the full out position. A rod drop time of 2.7 seconds was used while also considering an additional 2 seconds for the signal processing delay time. Therefore, a total delay time of 4.7 seconds from the time of reactor trip signal to full rod insertion was used in the Small Break LOCA analysis.

2. Injection of borated water provides sufficient flooding of the core to prevent excessive cladding temperatures.

During the earlier part of the Small Break transient (prior to the postulated loss-of-offsite power coincident with reactor trip), the loss of flow through the break is not sufficient to overcome the positive core flow maintained by the reactor coolant pumps. During this period, upward flow through the core is maintained. However, following the reactor coolant pump trip (due to a LOOP) and subsequent pump coastdown, a period of core uncovery occurs. Ultimately, the Small Break transient analysis is terminated when the top of the core is recovered ~~and~~ ECCS flow provided to the RCS exceeds the break flow rate ~~preventing additional core uncovery and subsequent rod heatup~~.

or the core mixing level is increasing, and

The core heat transfer mechanisms associated with the Small Break transient include the break itself, the injected ECCS water, and the heat transferred from the RCS to the steam generator secondary side. Main Feedwater (MFW) is conservatively isolated in 10 seconds for BVPS-1 (consisting of a 3 second signal delay time and a 7 second main feedwater isolation valve stroke time) and 7 seconds for BVPS-2 (consisting of a 2 second signal delay time and a 5 second main feedwater isolation valve stroke time) following the generation of the pressurizer low-pressure SI signal. Additional makeup water is also provided to the secondary using the auxiliary feedwater (AFW) system. An AFW actuation signal is

Table 5.2.2-4A
BVPS-1 NOTRUMP Results

Event Time (sec)	2-inch	3-inch	4-inch
Break Initiation	0	0	0
Reactor Trip Signal	28.9	12.3	7.3
S-Signal	42.3	20.8	14.4
SI Flow Delivered	69.9	47.8	41.4
Loop Seal Clearing[1]	925	420	~~236~~ 260
Core Uncovery	1020	862	~~632~~ 236
Accumulator Injection	N/A	1355	766
RWST Volume Delivered	3025	3003	2992
PCT Time	3158	1734	~~1724~~ 919
Core Recovery[2]	>TMAX	>TMAX	>TMAX

Notes:

(1) Loop seal clearing is defined as break vapor flow > 1 lb/s.

(2) For the cases where core recovery is > TMAX, basis for transient termination can be concluded based on the following: (1) The RCS system pressure is decreasing which will increase SI flow, (2) Total RCS system mass is increasing due to SI flow exceeding break flow, and (3) Core mixture level has begun to increase and is expected to continue for the remainder of the accident.

Table 5.3.1-4B BVPS-2 Non-LOCA Key Accident Analysis Assumptions	
NSSS Thermal Design Flow (per Loop)	87,200 gpm
Minimum Measured Flow (per Loop)	88,933 gpm
Programmed Full Power Vessel Average Temperature	580.0° to 566.2°F
Maximum Steam Generator Tube Plugging Level	22%
Max $F_{\Delta H}$	1.56 (RTDP) 1.62 (STDP)
DNB Methodology (where applicable)	RTDP
Max EOL MDC	0.43 Δk/g/cc
Max BOL MTC	+5 pcm/°F ≤70% RTP ramping to 0 at 100% RTP
Initial Condition Uncertainties: Power Temperature Pressure Steam Generator Water Level Pressurizer Water Level	 +/- 0.6% RTP +/- 4.0°F(1) +/- 45 psi +/- 7% NRS(2) +/- 7% span

Notes:

(1) The analyses also include ±3.5°F for loop-to-loop asymmetry, -2°F to allow for intentional operation below the design average temperature and a +1°F bias.

(2) The calculated final Steam Generator Water Level uncertainties are +3.5%/-~~10.3~~ 10.1% for BVPS-2. For non-LOCA analyses, a negative bias means that the channel indicates higher than actual and a positive bias means the channel indicates lower than actual. The Feedwater System Pipe Break analysis (see Section 5.3.17) assumed uncertainties of +7%/-10.3% NRS. For all other events, only the positive uncertainty is applicable and a +7% NRS was assumed.

5.3.3.2 Input Parameters and Assumptions

A number of cases were analyzed assuming a range of reactivity insertion rates for both minimum and maximum reactivity feedback conditions at various power levels. The cases presented in Section 5.3.3.4 are representative for this event.

For an uncontrolled RCCA bank withdrawal at power accident, the analysis assumes the following conservative assumptions:

a. This accident is analyzed with the Revised Thermal Design Procedure (Reference 2). Initial reactor power, RCS pressure, and RCS temperature are assumed to be at their nominal values, adjusted to account for any applicable measurement biases, consistent with steady-state full power operation. Minimum Measured Flow is modeled. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 2.

b. For reactivity coefficients, two cases are analyzed.

For BVPS-2, a 0.0

1. Minimum Reactivity Feedback: A +5 pcm/°F moderator temperature coefficient and a least-negative Doppler-only power coefficient form the basis for the beginning-of-life (BOL) minimum reactivity feedback assumption. Zero pcm/°F MTC is assumed for cases initiated at hot full power conditions consistent with the BVPS Technical Specifications

2. Maximum Reactivity Feedback: A conservatively large positive moderator density coefficient of 0.43 $\Delta k/g/cm^3$ (corresponding to a large negative moderator temperature coefficient) and a most-negative Doppler-only power coefficient form the basis for the end-of-life (EOL) maximum reactivity feedback assumption.

c The reactor trip on high neutron flux is assumed to be actuated at a conservative value of 116% of nominal full power. The ΔT trips include all adverse instrumentation and setpoint errors, while the delays for the trip signal actuation are assumed at their maximum values.

d. The RCCA trip insertion characteristic is based on the assumption that the highest-worth rod cluster control assembly is stuck in its fully withdrawn position.

e. A range of reactivity insertion rates are examined. The maximum positive reactivity insertion rate is greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined worth at a conservative speed (48.125 inches/minute, which corresponds to 77 steps/minute).

f. Power levels of 10, 60 and 100% of the NSSS power of 2910 MWt are considered.

5.3.3.3 Description of Analysis

The purpose of this analysis is to demonstrate the manner in which the protection functions described above actuate for various combinations of reactivity insertion rates and initial conditions. Insertion rate and initial conditions determine which trip function actuates first.

5.3.9 Excessive Heat Removal Due To Feedwater System Malfunctions

5.3.9.1 Identification of Causes and Accident Description

Reductions in feedwater temperature or excessive feedwater additions are means of increasing core power above full power. Such transients are attenuated by the thermal capacity of the RCS and the secondary side of the plant. The overpower/overtemperature protection functions (neutron high flux, overtemperature ΔT, and overpower ΔT trips) prevent any power increase that could lead to a DNBR that is less than the limit value.

An example of excessive feedwater flow would be a full opening of one feedwater control valve due to a feedwater control system malfunction or an operator error. At power, this excess flow causes a greater load demand on the RCS due to increased subcooling in the steam generator. With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in RCS temperature and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient of reactivity. Continuous excessive feedwater addition is prevented by the steam generator high-high water level trip.

A second example of excess heat removal is the transient associated with failure of the low-pressure heaters' bypass valve resulting in an immediate reduction in feedwater temperature. At power, this increased subcooling will create a greater load demand on the RCS.

5.3.9.2 Input Parameters and Assumptions

The reactivity insertion rate following a feedwater system malfunction, attributed to the cooldown of the RCS, is calculated with the following assumptions:

a. The full power cases are ~~This accident is~~ analyzed with the Revised Thermal Design Procedure as described in Reference 1. Initial reactor power, RCS pressure, and RCS temperature are assumed to be at their nominal values, adjusted to account for any applicable measurement biases, consistent with steady-state full power operation. Minimum Measured Flow is modeled. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 1. The zero power cases model the Standard Thermal Design Procedure and Thermal Design Flow.

b. The analyses are done at the NSSS power level of 2910 MWt.

c. For the feedwater control valve accident at full-power conditions that result in an increase in feedwater flow to one steam generator, one feedwater control valve is assumed to malfunction resulting in a step increase to 162% for BVPS-1 and 156% for BVPS-2 of nominal full power feedwater flow to one steam generator.

d. The increase in feedwater flow rate results in a decrease in the feedwater temperature due to the reduced efficiency of the feedwater heaters. For the hot full power cases, a 51.4°F for BVPS-1 and 50°F for BVPS-2 decrease in the feedwater temperature is assumed to occur coincident with the feedwater flow increase.

e. For the feedwater control valve accident at zero-load conditions that result in an increase in feedwater flow to one steam generator, one feedwater control valve is assumed to malfunction

Table 5.3.9-1 Time Sequence of Events – Excessive Heat Removal Due to Feedwater System Malfunctions		
Event	BVPS-1 Time (seconds)	BVPS-2 Time (seconds)
One main feedwater control valve fails full open	0	0
Minimum DNBR occurs	111.0	72.5
Hi-Hi steam generator water level trip setpoint is reached	108.9	114.9
Turbine trip occurs due to hi-hi steam generator level	111.4	117.4
Rod motion begins	113.4	119.4
Feedwater isolation valves ~~begin to close~~ are completely closed	118.9	121.9

Table 5.3.12-1A BVPS-1 Time Sequence of Events – Rupture of a Main Steam Pipe		
Case	**Event**	**Time (sec)**
Reactor at hot zero power with offsite power available (Unisolatable steam release paths case)	Double-ended guillotine break occurs	0.0
	Low Steam Pressure SIS actuation setpoint reached	0.7
	MSIVs closed 8 seconds after SIS actuation signal	8.7
	High-head SI pump at rated speed 27 seconds after SIS actuation signal	27.7
	Main Feedwater flow isolated 30 seconds after SIS actuation signal	30.7
	Reactor becomes critical	32.4
	Time of minimum DNBR	~~352.4~~ 359.4
	Power reaches maximum level	~~359.4~~ 352.4
	Reactor returns subcritical	396.0

Both the RCS pressure case and the DNB case assume a zero moderator temperature coefficient (MTC) and a conservatively large (absolute value) Doppler-only power coefficient. The negative reactivity from control rod insertion/scram for both cases is based on 4.0% $\Delta k/k$ trip reactivity from HFP.

Normal reactor control systems and engineered safety systems (e.g., Safety Injection) are not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

The effects of asymmetric RCS flow (maximum loop-to-loop flow asymmetry of 5%) on the Locked Rotor transients were also evaluated.

5.3.15.3 Description of Analysis

The following locked rotor / shaft break cases were analyzed:

1. Peak RCS pressure resulting from a locked rotor / shaft break in one-of-three loops
2. Number of rods-in-DNB resulting from a locked rotor / shaft break in one-of-three loops

The pressure case is analyzed using two digital computer codes. The LOFTRAN code (Reference 2) is used to calculate the resulting loop and core flow transients following the pump seizure, the time of reactor trip based on the loop flow transients, the nuclear power following reactor trip, and the peak RCS pressure. The reactor coolant flow coastdown analysis performed by LOFTRAN is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, the as-built pump characteristics, and is based on conservative system pressure loss estimates. The thermal behavior of the fuel located at the core hot spot is investigated using the FACTRAN code (Reference 3) which uses the core flow and the nuclear power values calculated by LOFTRAN. The FACTRAN code includes a film boiling heat transfer coefficient.

The case analyzed to evaluate core DNB uses LOFTRAN, FACTRAN and the VIPRE code (Reference 4). The LOFTRAN and FACTRAN codes are used in the same manner as in the pressure case. The VIPRE code is used to calculate the DNBR during the transient based on the heat flux from FACTRAN and the flow from LOFTRAN.

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For the peak RCS pressure evaluation, the initial pressure is conservatively estimated to be 40 psi for BVPS-1 and ~~50~~ psi for BVPS-2 above the nominal pressure of 2250 psia to allow for initial condition uncertainties in the pressurizer pressure measurement and control channels. This is done to obtain the highest possible rise in the coolant pressure during the transient. To obtain the maximum pressure in the primary side, conservatively high loop pressure drops are added to the calculated pressurizer pressure. The pressure response reported in Table 5.3.15-1 is at the point in the RCS having the maximum pressure, i.e., at the outlet of the RCP in the faulted loop.

For a conservative analysis of fuel rod behavior, the hot spot evaluation assumes that DNB occurs at the initiation of the transient and continues throughout the event. This assumption reduces heat transfer to the coolant and results in conservatively high hot spot temperatures.

g. Reactivity coefficients – The analysis assumed maximum moderator reactivity feedback and minimum Doppler power feedback to maximize the power increase following the break.

h. Protection system – The protection system features that mitigate the effects of a steamline break are described in Section 5.3.12. This analysis only considers the initial phase of the transient from at-power conditions. Protection in this phase of the transient is provided by reactor trip, if necessary. Section 5.3.12 presents the analysis of the bounding transient following reactor trip, where other protection system features are actuated to mitigate the effects of the steamline break.

i. Control systems – The only control that is assumed to function during a full power steamline rupture – core response event is the main feedwater system. For this event, the feedwater flow is set to match the steam flow.

5.3.19.3 Description of Analysis

The analysis of the steamline break at power for the EPU was performed as follows:

a. The LOFTRAN code (Reference 1) was used to calculate the nuclear power, core heat flux, and reactor coolant system temperature and pressure transients resulting from the cooldown following the steamline break.

b. The core radial and axial peaking factors were determined using the thermal-hydraulic conditions from LOFTRAN as input to the nuclear core models. A detailed thermal-hydraulic code, VIPRE (Reference 2), was used to calculate the DNBR for the limiting time during the transient. The DNBR calculations were performed using the W-3 correlation. Since the initial conditions uncertainties are not statistically included in the W-3 DNBR limit (of 1.30), uncertainties on power, temperature, pressure, etc. were applied to the limiting statepoints and the Thermal Design Flow was assumed in the calculation of the minimum DNBR.

5.3.19.4 Acceptance Criteria and Results

Depending on the size of the break, this event is classified as either a Condition III (infrequent fault) or Condition IV (limiting fault) event, however, the analysis is done to the more conservative Condition II acceptance criteria. The acceptance criteria for this event are consistent with those stated in Subsection 5.3.12.4

A DNB analysis

For BVPS-1, the limiting break size from the spectrum of break sizes analyzed is 0.6 ft^2. ~~, with a minimum DNBR of 1.53 and a peak heat flux of 1.24~~. The sequence of events for the limiting case with a 0.6 ft^2 break is shown in Table 5.3.19-1. Plots for this limiting case are provided in Figures 5.3.19-1A through 5.3.19-4A.

was performed for the limiting point in the transient which determined that the DNB design basis is met

A DNB analysis

For BVPS-2, the limiting break size from the spectrum of break sizes analyzed is 0.8 ft^2 ~~, with a minimum DNBR of 1.44 and a peak heat flux of 1.28.~~ The sequence of events for this limiting case is shown in Table 5.3 19-1. Plots for this limiting case are provided in Figures 5.3.19-1B through 5.3.19-4B.

Table 5.3.19-1 Time Sequence of Events – Steam System Piping Failure at Full Power (Core Response)		
Event	BVPS-1 Time (sec)	BVPS-2 Time (sec)
Steam line ruptures	0.0	0.0
Overpower ΔT reactor trip setpoint reached	30.4	26.5
Rods begin to drop	32.4	28.5
Minimum DNBR occurs	~~32.9~~ 33.0	29.~~1~~0
Peak core heat flux occurs	33.0	29.~~1~~ 0

Table 5.3.20-1A
BVPS-1 Condition II DNB Event Results

Event Name	UFSAR Section	Report Section	Minimum DNBR	Peak Primary Pressure (psia)	Peak Secondary Pressure (psia)
RCCA Bank Withdrawal from Subcritical	14.1.1	5.3.2	Limit met[5,6]	N/A	N/A
RCCA Bank Withdrawal at Power	14.1.2	5.3.3	1.57	N/A[1]	1170.1
RCCA Misalignment	14.1.3	5.3.4	Limit met[5]	N/A	N/A
Loss of Load	14.1.7	5.3.6	2.23	2744.~~5~~.6[4]	1187.7
Feedwater System Malfunctions a. Feedwater Flow Increase b. Feedwater Enthalpy Decrease	 14.1.9 14.1.9	 5.3.9 5.3.9	 1.75[7] 1.67	 2357.0 2300.0	 1124.0 914.0
Excessive Load Increase[2]	14.1.10	5.3.10	Limit met	Limit met	Limit met
RCS Depressurization	14.1.15	5.3.11	1.62	N/A	N/A
Main Steam Pipe Rupture (HZP)[3]	14.2.5.1	5.3.12	Limit met[5,6]	N/A	N/A
Partial Loss of Flow	14.1.5	5.3.13	2.25[8]	2373.8	989.0
Complete Loss of Flow[3]	14.2.9	5.3.14	1.64[8]	2504.1	~~966.5~~ 992.8
Limits	---	---	1.55	2748.5	1208.5

Notes:

(1) A generic Westinghouse evaluation addresses peak pressures for Rod Withdrawal at Power analyses.

(2) Current methodology for evaluating this event involves a comparison of conservative generic statepoints to the plant specific core thermal limits. In all cases, the generic statepoints are bounded by the core thermal limits.

(3) These events are not Condition II events but are analyzed to the more restrictive Condition II acceptance criteria.

(4) The analysis supports a pressurizer safety valve setpoint tolerance of +/-3.0%

(5) DNB statepoints are evaluated and the conclusion is that the limits are met.

(6) The 1.55 DNBR limit listed above is not applicable for these events. See Table 6.1-3 for the applicable DNB correlations and limits.

(7) The results reported are for the HFP case. An additional case was analyzed at HZP conditions. It was concluded that this case is bounded by the HZP ~~SLB~~ steam line break analysis (UFSAR 14.2.5.1).

(8) These values are applicable for the RFA fuel. For the V5H fuel, the Partial Loss of Flow minimum DNBR is 1.90 compared to a limit of 1.32 (thimble cell) and the Complete Loss of Flow minimum DNBR is 1.39 compared to a limit of 1.33 (typical cell).

Table 5.3.20-1B
BVPS-2 Condition II DNB Event Results

Event Name	UFSAR Section	Report Section	Minimum DNBR	Peak Primary Pressure (psia)	Peak Secondary Pressure (psia)
RCCA Bank Withdrawal from Subcritical	15.4.1	5.3.2	Limit met[5,6]	N/A	N/A
RCCA Bank Withdrawal at Power	15.4.2	5.3.3	1.58	N/A[1]	1174.~~1~~8
RCCA Misalignment	15.4.3	5.3.4	Limit met[5]	N/A	N/A
Loss of Load	15.2.2 & 15.2.3	5.3.6	1.83	2746.2[4]	1191.0
Feedwater System Malfunctions					
a. Feedwater Flow Increase	15.1.2	5.3.9	1.96[7]	2353.3	1141.2
b. Feedwater Enthalpy Decrease	15.1.1	5.3.9	~~1.72~~ 1.66	2287.3	928.0
Excessive Load Increase[2]	15.1.3	5.3.10	Limit met	Limit met	Limit met
RCS Depressurization	15.6.1	5.3.11	1.64	N/A	N/A
Main Steam Pipe Rupture (HZP)[3]	15.1.5	5.3.12	Limit met[5,6]	N/A	N/A
Partial Loss of Flow	15.3.1	5.3.13	2.25[8]	~~2361.0~~ 2360.9	995.0
Complete Loss of Flow[3]	15.3.2	5.3.14	1.64[8]	2503.3	~~977.4~~ 1002.7
Limits	---	---	1.55	2748.5	1208.5

Notes:

(1) A generic Westinghouse evaluation addresses peak pressures for Rod Withdrawal at Power analyses.

(2) Current methodology for evaluating this event involves a comparison of conservative generic statepoints to the plant specific core thermal limits. In all cases, the generic statepoints are bounded by the core thermal limits.

(3) These events are not Condition II events but are analyzed to the more restrictive Condition II acceptance criteria.

(4) This analysis supports a pressurizer safety valve setpoint tolerance of +1.6%/-3.0%.

(5) DNB statepoints are evaluated and the conclusion is that the limits are met.

(6) The 1.55 DNBR limit listed above is not applicable for these events. See Table 6.1-3 for the applicable DNB correlations and limits.

(7) The results reported are for the HFP case. An additional case was analyzed at HZP conditions. It was concluded that this case is bounded by the HZP SLB analysis (UFSAR 15.1.5).

(8) These values are applicable for the RFA fuel. For the V5H fuel, the Partial Loss of Flow minimum DNBR is 1.90 compared to a limit of 1.32 (thimble cell) and the Complete Loss of Flow minimum DNBR is 1.38 compared to a limit of 1.33 (typical cell).

steamline break

time-dependent flashing fraction that incorporates the expected changes in primary-side temperatures cannot be calculated. Instead, a conservative calculation of the flashing fraction is performed using the limiting conditions from the break flow calculation cases. Two time intervals are considered, as in the break flow calculations; pre-reactor trip and post-reactor trip (SI initiation occurs concurrently with reactor trip). Since the RCS and steam generator conditions are different before and after the trip, different flashing fractions would be expected.

The flashing fraction is based on the difference between the primary-side fluid enthalpy and the saturation enthalpy on the secondary side. Therefore, the highest flashing will be predicted for the case with the highest primary-side temperatures. For the flashing fraction calculations, it is conservatively assumed that all of the break flow is at the hot leg temperature (the break is assumed to be on the hot leg side of the steam generator). Similarly, a lower secondary-side pressure maximizes the difference in the primary and secondary enthalpies, resulting in more flashing. The highest pre-trip flashing fraction based on the range of operating conditions covered by this analysis is for the case with a hot leg temperature of 603.9°F, an initial RCS pressure of 2250 psia, and an initial secondary pressure of 623 psia. The case with a hot leg temperature of 617°F would have a lower flashing fraction because the corresponding conservatively high secondary pressure is 831 psia and the flashing is more dependent on secondary pressure than hot leg temperature. All cases consider the same post-trip RCS pressure of 188~~4~~8.4 psia and post-trip steam generator pressure of 932.75 psia. The highest post-trip flashing fraction, based on the range of operating temperatures covered by this analysis, is for a case with a hot leg temperature of 617°F. It is conservatively assumed that the hot leg temperature is not reduced for the 30 minutes in which break flow is calculated.

Miscellaneous Parameter Assumptions

- Low pressurizer pressure SI actuation setpoint = 1860 psia
- Lowest steam generator safety valve reseat pressure = 932.75 psia, and includes 11.6% main steam safety valve (MSSV) blowdown and 3% safety valve setpoint tolerance.

5.4.1.3 Description of Analyses Performed

A T_{avg} window of 566.2° up to 580.0°F is considered. Section 2.1.1 documents four Performance Capability Working Group (PCWG) cases that have been used for the BVPS-1 SGTR analysis.

Cases are analyzed at a T_{avg} of 566.2° and 580.0°F, with 0% and 22% SGTP. All the cases support a power of 2910 MWt (NSSS power) and thermal design flow (TDF) of 87200 gpm/loop.

Break Flow, Steam Releases, and Feedwater Flows

In total, four cases were considered in the SGTR thermal-hydraulic analysis to bound the EPU operating conditions. Note that these four cases are individually analyzed in order to determine the limiting steam release and limiting break flow between 0 and 30 minutes for the radiological consequences calculation. A single calculation is performed to determine long-term steam releases from, and feedwater flow to, the intact steam generators for the time interval from the start of the event (0 hours) to 2 hours and from 2 hours to RHR cut-in at 8 hours. The 0 to 2 hour calculations use the 0 to 30 minute intact steam

Table 5.4.1-1 BVPS-1 Limiting SGTR Thermal-Hydraulic Results *	
Tube Rupture Break Flow for 0 to 30 Minutes	
T_{avg} = 566.2°F, 0% SGTP	135,900 lbm
T_{avg} = 566.2°F, 22% SGTP	136,300 lbm
T_{avg} = 580.0°F, 0% SGTP	134,700 lbm
T_{avg} = 580.0°F, 22% SGTP	135,500 lbm
Steam Release from Ruptured SG (Post-Trip) for 0 to 30 Minutes	
T_{avg} = 566.2°F, 0% SGTP	55,~~7~~800 lbm
T_{avg} = 566.2°F, 22% SGTP	53,100 lbm
T_{avg} = 580.0°F, 0% SGTP	62,600 lbm
T_{avg} = 580.0°F, 22% SGTP	58,600 lbm
* Values rounded up to the nearest 100	

5.6.3 Steam Releases for Radiological Dose Analysis

5.6.3.1 Introduction

In support of radiological dose analyses, steam and radioactivity releases to the environment are postulated to occur via the following scenarios.

- An activity level exists in the reactor coolant system (RCS): The activity level in the RCS may be low, resulting from activated corrosion products or from the potential minute release of fission material from defective fuel assemblies. The activity level may also be moderate to high, resulting from potential fuel cladding failures and the subsequent fission product release.

- A primary-to-secondary leak occurs: The most common primary-to-secondary leak would be a leak through the wall of one or more steam generator tubes. A maximum allowable leak rate is specified in the Technical Specifications based on tube integrity requirements. The Technical Specifications leakage limit is used to determine radioactivity releases to the environment.

- Secondary-side activity is released into the atmosphere: Given that a primary-to-secondary leak exists and the condenser is not available for steam dump following an accident that produces a reactor trip, steam and radioactivity will be released through the atmospheric dump valves while the plant is being brought to a cold shutdown condition. The Loss of Non-Emergency AC Power event, and other events that result in a loss-of-offsite power, are situations that result in the unavailability of the condenser.

Vented steam releases have been calculated for the Loss of Non-Emergency AC Power, Locked Rotor, and Steamline Break events to support the EPU Project.

5.6.3.2 Input Parameters and Assumptions

The following general assumptions associated with EPU have been used in the calculation of the steam releases and feedwater flows.

- NSSS power (2910 MWt) plus 0.6% uncertainty

- RCS average temperature (580.0°F)

- Nominal RCS pressure (2250 psia)

- Steam generator tube plugging is chosen to maximize secondary-side mass inventory. The operating conditions used in this analysis reflect the high end of the T_{avg} RCS temperature range, high secondary-side (steam) temperature, the low end of the main feedwater temperature range, and no steam generator tube plugging.

- Nominal steam temperature (522.6°F) for BVPS-1 with the Model 54F replacement steam generators (RSGs) and nominal steam temperature (521.9°F) for BVPS-2 with the original steam generators (OSGs).

L-05-154 Enclosure 6

Commitment List

The following list identifies those actions committed to by FirstEnergy Nuclear Operating Company (FENOC) for Beaver Valley Power Station (BVPS) Unit Nos. 1 and 2 in this document. Any other actions discussed in the submittal represent intended or planned actions by FENOC. They are described only as information and are not regulatory commitments. Please notify Mr. Gregory A. Dunn, Manager - Licensing, at 330-315-7243 of any questions regarding this document or associated regulatory commitments.

Commitment	Due Date
FirstEnergy Nuclear Operating Company (FENOC) commits to continue its active participation in the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) initiative to determine appropriate reactor vessel internals degradation management programs.	Not Applicable