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

December 29, 2008

Mr. Peter P. Sena III
Site Vice President
FirstEnergy Nuclear Operating Company
Beaver Valley Power Station
Mail Stop A-BV-SEB1
P.O. Box 4, Route 168
Shippingport, PA 15077

SUBJECT: BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENTS RE: TECHNICAL SPECIFICATION TASK FORCE 411 AND 418 (TAC NOS. MD7531 AND MD7532)

Dear Mr. Sena:

The Commission has issued the enclosed Amendment No. 282 to Facility Operating License No. DPR-66 for the Beaver Valley Power Station, Unit No. 1 and Amendment No. 166 to Facility Operating License No. NPF-73 for the Beaver Valley Power Station, Unit No. 2. These amendments consist of changes to the Technical Specifications (TSs) in response to your application dated December 21, 2007, as supplemented by letter dated August 1, 2008.

The amendments revise the TSs associated with Reactor Trip System and Engineered Safety Features Actuation System (ESFAS) Instrumentation bypass test times, Completion Times, and Surveillance Frequencies consistent with Revision 1 to TS Task Force (TSTF)-411, "Surveillance Test Interval Extensions for Components of the Reactor Protection System [RPS] (WCAP-15376)" and Revision 2 to TSTF-418, "RPS and ESFAS Test Times and Completion Times (WCAP-14333)."

A copy of the related safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

Nadiyah S. Morgan, Project Manager
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-334 and 50-412

Enclosures:
1. Amendment No. 282 to DPR-66
2. Amendment No. 166 to NPF-73
3. Safety Evaluation

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FIRSTENERGY NUCLEAR OPERATING COMPANY

FIRSTENERGY NUCLEAR GENERATION CORP.

DOCKET NO. 50-334

BEAVER VALLEY POWER STATION, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 282
License No. DPR-66

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by FirstEnergy Nuclear Operating Company, et al. (the licensee), dated December 21, 2007, as supplemented by letter dated August 1, 2008, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. DPR-66 is hereby amended to read as follows:

   (2) <u>Technical Specifications</u>

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 282, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 90 days.

FOR THE NUCLEAR REGULATORY COMMISSION

Mark G. Kowal, Chief
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the License and
Technical Specifications

Date of Issuance: December 29, 2008

ATTACHMENT TO LICENSE AMENDMENT NO. 282

FACILITY OPERATING LICENSE NO. DPR-66

DOCKET NO. 50-334

Replace the following page of the Facility Operating License with the attached revised page. The revised page is identified by amendment number and contains marginal lines indicating the areas of change.

Remove	Insert
3	3

Replace the following pages of Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
3.3.1-2	3.3.1-2
3.3.1-3	3.3.1-3
3.3.1-4	3.3.1-4
3.3.1-5	3.3.1-5
3.3.1-6	3.3.1-6
3.3.1-7	3.3.1-7
3.3.1-8	3.3.1-8
3.3.1-9	3.3.1-9
3.3.1-10	3.3.1-10
3.3.2-1	3.3.2-1
3.3.2-2	3.3.2-2
3.3.2-3	3.3.2-3
3.3.2-4	3.3.2-4
3.3.2-5	3.3.2-5
3.3.5-1	3.3.5-1
3.3.5-2	3.3.5-2

(3) FENOC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) FENOC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use in amounts as required any byproduct, source, or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components;

(5) FENOC, pursuant to the Act and 10 CFR Parts 30, and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This amended license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter 1: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

FENOC is authorized to operate the facility at a steady state reactor core power level of 2900 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 282, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

(3) Auxiliary River Water System

(Deleted by Amendment No. 8)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One Power Range Neutron Flux - High channel inoperable.	-------------------- **- NOTE -** The inoperable channel may be bypassed for up to 12 hours for surveillance testing and setpoint adjustment of other channels. --------------------	
	D.1.1 Place channel in trip.	72 hours
	AND	
	D.1.2 Reduce THERMAL POWER to $\leq$ 75% RTP.	78 hours
	OR	
	D.2.1 Place channel in trip.	72 hours
	AND	
	D.2.2 -------------------- **- NOTE -** Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. --------------------	
	Perform SR 3.2.4.2.	Once per 12 hours
	OR	
	D.3 Be in MODE 3.	78 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. One channel inoperable.	- NOTE - The inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels.		
	E.1	Place channel in trip.	72 hours
	OR		
	E.2	Be in MODE 3.	78 hours
F. One Intermediate Range Neutron Flux channel inoperable.	F.1	Reduce THERMAL POWER to < P-6.	24 hours
	OR		
	F.2	Increase THERMAL POWER to > P -10.	24 hours
G. Two Intermediate Range Neutron Flux channels inoperable.	G.1	- NOTE - Limited plant cooldown or boron dilution is allowed provided the change is accounted for in the calculated SDM.	
		Suspend operations involving positive reactivity additions.	Immediately
	AND		
	G.2	Reduce THERMAL POWER to < P-6.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. One Source Range Neutron Flux channel inoperable.	-- **- NOTE -** Limited plant cooldown or boron dilution is allowed provided the change is accounted for in the calculated SDM. --	
	H.1 Suspend operations involving positive reactivity additions.	Immediately
I. Two Source Range Neutron Flux channels inoperable.	I.1 Open reactor trip breakers (RTBs).	Immediately
J. One Source Range Neutron Flux channel inoperable.	J.1 Restore channel to OPERABLE status.	48 hours
	<u>OR</u>	
	J.2.1 Initiate action to fully insert all rods.	48 hours
	<u>AND</u>	
	J.2.2 Place the Rod Control System in a condition incapable of rod withdrawal.	49 hours
K. One channel inoperable.	-- **- NOTE -** The inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels. --	
	K .1 Place channel in trip.	72 hours
	<u>OR</u>	
	K.2 Reduce THERMAL POWER to < P-7.	78 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
L. One Turbine Trip channel inoperable.	- NOTE - The inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels.	
	L.1 Place channel in trip.	72 hours
	OR	
	L.2 Reduce THERMAL POWER to < P-9.	76 hours
M. One train inoperable.	- NOTE - One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE.	
	M.1 Restore train to OPERABLE status.	24 hours
	OR	
	M.2 Be in MODE 3.	30 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
N. One RTB train inoperable.	- NOTE - One train may be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE.		
	N.1	Restore train to OPERABLE status.	24 hours
	OR		
	N.2	Be in MODE 3.	30 hours
O. One or more channels inoperable.	O.1	Verify interlock is in required state for existing unit conditions.	1 hour
	OR		
	O.2	Be in MODE 3.	7 hours
P. One or more channels inoperable.	P.1	Verify interlock is in required state for existing unit conditions.	1 hour
	OR		
	P.2	Be in MODE 2.	7 hours
Q. One trip mechanism inoperable for one RTB.	Q.1	Restore inoperable trip mechanism to OPERABLE status.	48 hours
	OR		
	Q.2	Be in MODE 3.	54 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
R. One channel inoperable.	- NOTE - The inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels.		
	R.1	Place channel in trip.	72 hours
S. Required Action and associated Completion Time of Condition R not met. OR Two or more channels inoperable.	S.1.1	Initiate action to fully insert all rods.	Immediately
	AND		
	S.1.2	Initiate action to place the Rod Control System in a condition incapable of rod withdrawal.	Immediately
	OR		
	S.2	Initiate action to borate the RCS to > the all rods out (ARO) critical boron concentration.	Immediately

SURVEILLANCE REQUIREMENTS

- NOTE -
Refer to Table 3.3.1-1 to determine which SRs apply for each RTS Function.

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.2	**- NOTE -** Not required to be performed until 24 hours after THERMAL POWER is ≥ 15% RTP. Compare results of calorimetric heat balance calculation to power range channel output. Adjust power range channel output if calorimetric heat balance calculations results exceed power range channel output by more than +2% RTP.	24 hours
SR 3.3.1.3	**- NOTE -** Not required to be performed until 7 days after THERMAL POWER is ≥ 50% RTP. Compare results of the incore detector measurements to Nuclear Instrumentation System (NIS) AFD. Adjust NIS channel if absolute difference is ≥ 3%.	31 effective full power days (EFPD)
SR 3.3.1.4	**- NOTE -** This Surveillance must be performed on the reactor trip bypass breaker prior to placing the bypass breaker in service. Perform TADOT.	62 days on a STAGGERED TEST BASIS
SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	92 days on a STAGGERED TEST BASIS

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.6	-- **- NOTE -** Not required to be performed for source range instrumentation until 12 hours after power has been reduced below P-6. -- Perform COT.	184 days
SR 3.3.1.7	-- **- NOTE -** This Surveillance shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. -- Perform COT.	------------------------ **- NOTE -** Only required when not performed within previous 184 days ------------------------ Prior to reactor startup <u>AND</u> Twelve hours after reducing power below P-10 for power and intermediate range instrumentation <u>AND</u> Every 184 days thereafter

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.8	----- - NOTE - Verification of setpoint is not required. ----- Perform TADOT.	 184 days
SR 3.3.1.9	----- - NOTE - Not required to be performed until 7 days after THERMAL POWER is $\geq$ 50% RTP. ----- Calibrate excore channels to agree with incore detector measurements.	 Once per fuel cycle
SR 3.3.1.10	----- - NOTES - 1. This Surveillance shall include verification that the time constants are adjusted to the prescribed values. 2. Neutron detectors are excluded from CHANNEL CALIBRATION. ----- Perform CHANNEL CALIBRATION.	 18 months
SR 3.3.1.11	Perform COT.	18 months
SR 3.3.1.12	----- - NOTE - Verification of setpoint is not required. ----- Perform TADOT.	 18 months

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1.

ACTIONS

- NOTE -
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or train(s).	Immediately
B. One channel or train inoperable.	B.1 Restore channel or train to OPERABLE status.	48 hours
	OR	
	B.2.1 Be in MODE 3.	54 hours
	AND	
	B.2.2 Be in MODE 5.	84 hours
C. One train inoperable.	**- NOTE -** One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE.	
	C.1 Restore train to OPERABLE status.	24 hours
	OR	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	C.2.1 Be in MODE 3. AND C.2.2 Be in MODE 5.	30 hours 60 hours
D. One channel inoperable.	-- **- NOTE -** The inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels. -- D.1 Place channel in trip. OR D.2.1 Be in MODE 3. AND D.2.2 Be in MODE 4.	 72 hours 78 hours 84 hours
E. One Containment Pressure channel inoperable.	-- **- NOTE -** One channel may be bypassed for up to 12 hours for surveillance testing. -- E.1 Place channel in bypass. OR E.2.1 Be in MODE 3. AND E.2.2 Be in MODE 4.	 72 hours 78 hours 84 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One channel or train inoperable.	F.1 Restore channel or train to OPERABLE status.	48 hours
	OR	
	F.2.1 Be in MODE 3.	54 hours
	AND	
	F.2.2 Be in MODE 4.	60 hours
G. One train inoperable.	- NOTE - One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE.	
	G.1 Restore train to OPERABLE status.	24 hours
	OR	
	G.2.1 Be in MODE 3.	30 hours
	AND	
	G.2.2 Be in MODE 4.	36 hours
H. One channel inoperable.	- NOTE - The inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels.	
	H.1 Place channel in trip.	72 hours
	OR	
	H.2 Be in MODE 3.	78 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. One Main Feedwater Pumps trip channel inoperable.	I.1 Restore channel to OPERABLE status.	48 hours
	<u>OR</u>	
	I.2 Be in MODE 3.	54 hours
J. One channel inoperable.	- NOTE - One channel may be bypassed for up to 12 hours for surveillance testing.	
	J.1 Place channel in bypass.	72 hours
	<u>OR</u>	
	J.2.1 Be in MODE 3.	78 hours
	<u>AND</u>	
	J.2.2 Be in MODE 5.	108 hours
K. One or more channels inoperable.	K.1 Verify interlock is in required state for existing unit condition.	1 hour
	<u>OR</u>	
	K.2.1 Be in MODE 3.	7 hours
	<u>AND</u>	
	K.2.2 Be in MODE 4.	13 hours

SURVEILLANCE REQUIREMENTS

- NOTE -
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	92 days on a STAGGERED TEST BASIS
SR 3.3.2.3	Perform MASTER RELAY TEST.	92 days on a STAGGERED TEST BASIS
SR 3.3.2.4	Perform COT.	184 days
SR 3.3.2.5	**- NOTE -** Verification of relay setpoints not required. Perform TADOT.	184 days

3.3 INSTRUMENTATION

3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start and Bus Separation Instrumentation

LCO 3.3.5 The DG Start and Bus Separation instrumentation specified in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4,
When associated DG is required to be OPERABLE by LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

- NOTE -
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels inoperable.	A.1 Enter the applicable Condition(s) referenced in Table 3.3.5-1 for the affected channel(s).	Immediately
B. One or more Functions with one channel per bus inoperable.	**- NOTE -** The inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels provided the corresponding instrument channels, electrical bus, and DG in the other train are OPERABLE. B.1 Place channel in trip.	72 hours
C. One or more Functions with two channels per bus inoperable.	C.1 Restore one channel per bus to OPERABLE status.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One or more Functions with one channel per bus inoperable.	D.1	Restore inoperable channel to OPERABLE status.	1 hour
E. Required Action and associated Completion Time not met.	E.1	Enter applicable Condition(s) and Required Action(s) for the associated DG made inoperable by LOP DG start or Bus Separation instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	-- **- NOTE -** Verification of setpoint is not required. -- Perform TADOT.	184 days
SR 3.3.5.2	Perform CHANNEL CALIBRATION.	18 months
SR 3.3.5.3	Verify ESF RESPONSE TIMES are within limit.	18 months on a STAGGERED TEST BASIS

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

FIRSTENERGY NUCLEAR OPERATING COMPANY

FIRSTENERGY NUCLEAR GENERATION CORP.

OHIO EDISON COMPANY

THE TOLEDO EDISON COMPANY

DOCKET NO. 50-412

BEAVER VALLEY POWER STATION, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 166
License No. NPF-73

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by FirstEnergy Nuclear Operating Company, et al. (the licensee), dated December 21, 2007, as supplemented by letter dated August 1, 2008, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. NPF-73 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 166, and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto are hereby incorporated in the license. FENOC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 90 days.

FOR THE NUCLEAR REGULATORY COMMISSION

Mark G. Kowal, Chief
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the License
and Technical Specifications

Date of Issuance: December 29, 2008

ATTACHMENT TO LICENSE AMENDMENT NO. 166

FACILITY OPERATING LICENSE NO. NPF-73

DOCKET NO. 50-412

Replace the following page of the Facility Operating License with the attached revised page. The revised page is identified by amendment number and contains marginal lines indicating the areas of change.

Remove	Insert
3a	3a

Replace the following pages of Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
3.3.1-2	3.3.1-2
3.3.1-3	3.3.1-3
3.3.1-4	3.3.1-4
3.3.1-5	3.3.1-5
3.3.1-6	3.3.1-6
3.3.1-7	3.3.1-7
3.3.1-8	3.3.1-8
3.3.1-9	3.3.1-9
3.3.1-10	3.3.1-10
3.3.2-1	3.3.2-1
3.3.2-2	3.3.2-2
3.3.2-3	3.3.2-3
3.3.2-4	3.3.2-4
3.3.2-5	3.3.2-5
3.3.5-1	3.3.5-1
3.3.5-2	3.3.5-2

transactions shall have no effect on the license for the BVPS Unit 2 facility throughout the term of the license.

(b) Further, the licensees are also required to notify the NRC in writing prior to any change in: (i) the term or conditions of any lease agreements executed as part of these transactions; (ii) the BVPS Operating Agreement, (iii) the existing property insurance coverage for BVPS Unit 2, and (iv) any action by a lessor or others that may have adverse effect on the safe operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations set forth in 10 CFR Chapter 1 and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

FENOC is authorized to operate the facility at a steady state reactor core power level of 2900 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 166, and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto are hereby incorporated in the license. FENOC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NOS. 282 AND 166 TO FACILITY OPERATING

LICENSE NOS. DPR-66 AND NPF-73

FIRSTENERGY NUCLEAR OPERATING COMPANY

FIRSTENERGY NUCLEAR GENERATION CORP.

OHIO EDISON COMPANY

THE TOLEDO EDISON COMPANY

BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2

DOCKET NOS. 50-334 AND 50-412

1.0 INTRODUCTION

By application dated December 21, 2007 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML073620062), as supplemented by letter dated August 1, 2008 (ADAMS Accession No. ML082180124), FirstEnergy Nuclear Operating Company (licensee), requested changes to the Technical Specifications (TSs) for Beaver Valley Power Station, Unit Nos. 1 and 2 (BVPS-1 and 2). The supplement dated August 1, 2008, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the Nuclear Regulatory Commission (NRC) staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on June 10, 2008 (73 FR 32745).

The proposed changes would revise various TS sections to allow relaxations of reactor trip system (RTS) and engineered safety feature actuation system (ESFAS) channel logic completion times, bypass test times, allowable outage times, and surveillance testing intervals. The licensee proposed to adopt changes previously approved by the NRC staff in Westinghouse Topical Report WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS [reactor protection system] and ESFAS Test Times and Completion Times," issued October 1998, as approved by NRC in a letter dated July 15, 1998. Implementation of the proposed changes is in accordance with TS Task Force (TSTF) Change Traveler TSTF-418, Revision 2, "RPS and ESFAS Test Times and Completion Times (WCAP-14333)." The NRC-approved TSTF-418, Revision 2, by letter dated April 2, 2003 (ADAMS Accession No. ML030920633).

Enclosure

In addition, the licensee proposed to adopt changes approved by the NRC staff in WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," dated March 2003, as approved by the NRC in a letter dated December 20, 2002. Implementation of the proposed changes is in accordance with TSTF-411, Revision 1, "Surveillance Test Interval Extension for Components of the Reactor Protection System (WCAP-15376)." The NRC-approved TSTF-411, Revision 1, by letter dated August 30, 2002 (ADAMS Accession No. ML022460347).

2.0 BACKGROUND

The Pressurized-Water Reactor Owners Group (PWROG), formerly the Westinghouse Owners Group, Technical Specifications Optimization Program (TOP) evaluated changes to surveillance test intervals (STIs) and completion times (CTs, also called allowed outage times) for the analog channels, logic cabinets, master and slave relays, and reactor trip breakers (RTBs). The methodology evaluated increases in surveillance intervals, test and maintenance out-of-service times, and the bypassing of portions of the RPS during test and maintenance. In 1983, the PWROG submitted Westinghouse Topical Report WCAP-10271-P, "Evaluation of Surveillance Frequencies and Out-of-Service Times for the Reactor Protection Instrumentation System," which provided a methodology for justifying revisions to a plant's TSs for the RPS. The PWROG stated in WCAP-10271 that plant staff devoted significant time and effort to perform, review, document, and track surveillance activities that, in many instances, may not be necessary because of the high reliability of the equipment. Part of the justification for the changes was their anticipated small impact on plant risk.

By letter dated February 21, 1985, the NRC staff accepted WCAP-10271, including its Supplement 1, with certain conditions. In 1989, the NRC staff issued a safety evaluation report (SER) for WCAP-10271, Supplement 2, which approved similar relaxations for the ESFAS. An additional supplemental SER issued in 1990 provided consistency between RTS and ESFAS STIs and CTs. The NRC subsequently adopted the TS changes proposed in WCAP-10271 into NUREG-1431, "Standard Technical Specifications Westinghouse Plants," Revision 0, issued September 1992. In this regard, the licensee implemented WCAP-10271 and its supplements by license amendment Nos. 181 and 267 for BVPS-1 and license amendment Nos. 61 and 149 for BVPS-2.

After the approval of WCAP-10271 and its supplements, the PWROG submitted Westinghouse Topical Report WCAP-14333-P, "Probabilistic Risk Analysis of RPS and ESFAS Test Times and Completion Times," in May 1995. WCAP-14333-P provided justification for the following TS relaxations beyond those approved in WCAP-10271:

- Increase the bypass test times and CTs for both the reactor trip system (RTS) and ESFAS solid-state and relay protection system designs for the analog channels, increase the CT from 6 hours to 72 hours and the bypass test time from 4 hours to 12 hours for the logic cabinets, master relays, and slave relays, increase the CT from 6 hours to 24 hours.

- When the logic cabinet and RTB both cause their train to be inoperable when in test or maintenance, allow bypassing of the RTB for the period of time equivalent to the bypass test time for the logic cabinets, provided that both are tested at the same time and the plant design is such that both the RTB and the logic cabinet cause their associated electrical trains to be inoperable during test or maintenance.

Following the approval of WCAP-14333, PWROG submitted WCAP-15376 for NRC staff review on November 8, 2000. WCAP-15376 evaluated the analog channels, logic cabinets, master relays, and RTBs.

- Increase the RTS and ESFAS instrumentation STI from 2 or 3 months (WCAP-10271) to 6 months.
- Increase the STI (2 to 4 months), CT (1 to 24 hours), and bypass test times (2 to 4 hours) for the RTBs.

3.0 REGULATORY EVALUATION

3.1 Description of System

The proposed TS modifications affect the RTS and ESFAS. The RTS is designed to initiate a reactor trip when the system exceeds limits to permissible operation. The ESFAS is designed to actuate emergency systems for accidents that challenge the normal control and heat removal systems.

The ESFAS instrumentation includes sensors, power supplies, signal processing, and bistable outputs and typically consists of three or four channels. Instrumentation signals (i.e., bistable outputs) feed relays that input into the logic portion of the ESFAS. The logic (i.e., logic cabinets) includes two redundant and independent logic blocks consisting of two trains (A and B) of logic where the input coincidence for various trip functions is determined. Either logic train initiates the ESFAS function through output cards driving master and slave relays. Portions of ESFAS instrumentation are shared with the RTS.

The RTS is comprised of instrumentation including sensors, power supplies, signal processing, comparators (bistables), input relays, logic circuits, and output cards. Portions of the RTS instrumentation are shared with the ESFAS. The RTS includes actuation paths from the Train A and Train B logic to the RTB. Normally, an RTB receives its signal from its associated logic train. The system utilizes bypass breakers for when a breaker is out-of-service. In this configuration, the bypass breaker is associated with the logic train of the operable RTB. The RTS utilizes two normally closed RTBs and two normally open bypass breakers. Train A logic actuates RTB A, and Train B logic actuates RTB B. Opening of either RTB will disconnect power from the control rods, causing a reactor trip.

BVPS-1 and 2 utilizes the solid state protection system (SSPS) for the logic portion of the RTS/ESFAS.

3.2 Proposed TSs Changes

The licensee proposed to revise BVPS-1 and 2 CTs, STIs, and bypass test times for TS 3.3.1, "Reactor Trip System (RTS) Instrumentation," TS 3.3.2, "Engineered Safety Feature Actuation system (ESFAS) Instrumentation," and TS 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start and Bus Separation Instrumentation." Enclosure 1 of the licensee's original application dated December 21, 2007, describes the specific TS changes while Enclosure 1, Attachment A provides TS markups. The licensee also included, for information, revised BVPS-1 and 2 TS Bases in Enclosure 1, Attachment B.

The licensee also proposed STI and CT changes to instrumentation not specifically evaluated by WCAP-14333 or WCAP-15376. The licensee proposed the following three revisions to the TS as listed in Section 2.0 of Enclosure 1 of the December 21, 2007, application:

3.2.1 TS 3.3.1, "RTS Instrumentation"

1. The bypass test time in the Note of the Required Actions for Condition D is increased from 4 hours to12 hours, the CT for Required Actions D.1.1 and D.2.1 is increased from 6 hours to 72 hours, and the CT for Required Actions D.1.2 and D.3 is increased from 12 hours to 78 hours.

2. The bypass test time in the Note of the Required Actions for Condition E is increased from 4 hours to 12 hours, the CT for Required Action E.1 is increased from 6 hours to 72 hours, and the CT for Required Action E.2 is increased from 12 hours to 78 hours.

3. The bypass test time in the Note of the Required Actions for Condition K is increased from 4 hours to 12 hours, the CT for Required Action K.1 is increased from 6 hours to 72 hours, and the CT for Required Action K.2 is increased from 12 hours to 78 hours.

4. The bypass test time in the Note of the Required Actions for Condition L is increased from 4 hours to 12 hours, the CT for Required Action L.1 is increased from 6 hours to 72 hours, and the CT for Required Action L.2 is increased from 10 hours to 76 hours.

5. The CT for Required Action M.1 is increased from 6 hours to 24 hours, and the CT for Required Action M.2 is increased from 12 hours to 30 hours.

6. The bypass test time in Note 1 of the Required Actions for Condition N is increased from 2 hours to 4 hours, Note 2 is deleted, the CT for Required Action N.1 is increased from 1 hour to 24 hours, and the CT for Required Action N.2 is increased from 7 hours to 30 hours.

7. The bypass test time in the Note of the Required Actions for Condition R is increased from 4 hours to 12 hours, and the CT for Required Action R.1 is increased from 6 hours to 72 hours.

8. The frequency of the trip actuation device operational test (TADOT) in Surveillance Requirement (SR) 3.3.1.4 is increased from 31 days on a staggered test basis to 62 days on a staggered test basis.

9. The frequency of the actuation logic test in SR 3.3.1.5 is increased from 31 days on a staggered test basis to 92 days on a staggered test basis.

10. The frequency of the channel operational test (COT) in SR 3.3.1.6 is increased from 92 days to 184 days.

11. The frequency of the Note for SR 3.3.1.7 is increased from 92 days to 184 days, and the frequency of SR 3.3.1.7 is increased from 92 days to 184 days.

12. The frequency of the TADOT in SR 3.3.1.8 is increased from 92 days to 184 days.

3.2.2 TS 3.3.2, "ESFAS Instrumentation"

1. The CT for Required Action C.1 is increased from 6 hours to 24 hours, the CT for Required Action C.2.1 is increased from 12 hours to 30 hours, and the CT for Required Action C.2.2 is increased from 42 hours to 60 hours.

2. The bypass test time in the Note of the Required Actions for Condition D is increased from 4 hours to 12 hours, the CT for Required Action D.1 is increased from 6 hours to 72 hours, the CT for Required Action D.2.1 is increased from 12 hours to 78 hours, and the CT for Required Action D.2.2 is increased from 18 hours to 84 hours.

3. The bypass test time in the Note of the Required Actions for Condition E is increased from 4 hours to 12 hours, the CT for Required Action E.1 is increased from 6 hours to 72 hours, the CT for Required Action E.2.1 is increased from 12 hours to 78 hours, and the CT for Required Action E.2.2 is increased from 18 hours to 84 hours.

4. The CT for Required Action G.1 is increased from 6 hours to 24 hours, the CT for Required Action G.2.1 is increased from 12 hours to 30 hours, and the CT for Required Action G.2.2 is increased from 18 hours to 36 hours.

5. The bypass test time in the Note of the Required Actions for Condition H is increased from 4 hours to 12 hours, the CT for Required Action H.1 is increased from 6 hours to 72 hours, and the CT for Required Action H.2 is increased from 12 hours to 78 hours.

6. The bypass test time in the Note of the Required Actions for Condition J is increased from 4 hours to 12 hours, the CT for Required Action J.1 is increased from 6 hours to 72 hours, the CT for Required Action J.2.1 is increased from 12 hours to 78 hours, and the CT for Required Action J.2.2 is increased from 42 hours to 108 hours.

7. The frequency of the actuation logic test in SR 3.3.2.2 is increased from 31 days on a staggered test basis to 92 days on a staggered test basis.

8. The frequency of the master relay test in SR 3.3.2.3 is increased from 31 days on a staggered test basis to 92 days on a staggered test basis.

9. The frequency of the COT in SR 3.3.2.4 is increased from 92 days to 184 days.

10. The frequency of the TADOT in SR 3.3.2.5 is increased from 92 days to 184 days.

TS 3.3.5, "L-O-P DG Start and Bus Separation Instrumentation"

1. The bypass test time in the Note of the Required Actions for Condition B is increased from 4 hours to 12 hours, and the CT for Required Action B.1 is increased from 6 hours to 72 hours.

2. The frequency of the TADOT in SR 3.3.5.1 is increased from 92 days to184 days.

3.3 Regulatory Requirements and Guidance

Part 50 to Title 10 of the *Code of Federal Regulations* (10 CFR Part 50) establishes the fundamental regulatory requirements with respect to the domestic licensing of nuclear production and utilization facilities.

Section 50.36(c)(3), "Technical specifications," of 10 CFR requires a licensee's TSs to have SRs for testing, calibration, and inspection to assure that the necessary quality of systems and components is maintained, that facility operations remain within safety limits, and that the Limiting Conditions of Operation will be met. Although 10 CFR 50.36 does not specify specific TS requirements, the rule implies that required actions for failure to meet the TS test bypass times, CTs, and STIs must be based on reasonable protection of the public health and safety. Therefore, the NRC staff must have reasonable assurance that the proposed TS changes will not adversely affect the performance of required safety functions in accordance with the design-basis accident analysis in Chapter 15 of the licensee's final safety analysis report (FSAR) with the proposed test bypass times, CTs, and STIs.

In 10 CFR 50.55a(h)(2), the NRC requires that the protection systems be consistent with their licensing basis or with the Institute of Electrical and Electronics Engineers (IEEE) 603-1991 for plants whose construction permits were issued before January 1, 1971, or that the protection systems meet IEEE 279-1971 or IEEE 603-1991 for plants whose construction permits were issued after January 1, 1971, but before May 13, 1999. Section 4.2 of IEEE 279-1971 discusses the general functional requirement for protection systems to ensure that they satisfy the single failure criterion.

Section 50.65, "Requirements for monitoring the rffectiveness of maintenance at nuclear power plants" (Maintenance Rule), of 10 CFR requires licensees to monitor the performance or condition of systems, structures, and components (SSCs) against licensee-established goals in a manner sufficient to provide reasonable assurance that SSCs are capable of fulfilling their intended functions. In addition, 10 CFR 50.65(a)(4), as it relates to the proposed surveillance, bypass test times, and CTs, requires the assessment and management of the increase in risk that may result from the proposed maintenance activity.

Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50 establishes the minimum requirements for the principal design criteria for the design, fabrication, construction, testing, and performance of SSCs important to safety. In this regard, General Design Criterion (GDC) 13, "Instrumentation and Control," states that the licensee shall provide appropriate controls to maintain these variables and systems within prescribed operating ranges. Further, GDC 21, "Protection System Reliability and Testability," states that the design of the protection system shall provide for high functional reliability and inservice testability commensurate with the safety functions to be performed. GDC 22, "Protection System Independence," provides criteria for protection system independence.

Regulatory Guide (RG) 1.174, "An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," issued November 2002 describes a risk-informed approach with associated acceptance guidelines for licensees to assess the nature and impact of proposed permanent licensing basis changes by considering engineering issues and applying risk insights.

RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," issued August 1998 describes an acceptable risk-informed approach and additional acceptance guidance geared toward the assessment of proposed permanent TS CT changes. RG 1.177 identifies a three-tiered approach for the licensee's evaluation of the risk associated with a proposed CT TS change, as discussed below:

- Tier 1 assesses the risk impact of the proposed change in accordance with acceptance guidelines consistent with the Commission's Safety Goal Policy Statement, as documented in RGs 1.174 and 1.177. The first tier assesses the impact on operational plant risk based on the change in core damage frequency (ΔCDF) and change in large early release frequency (ΔLERF). It also evaluates plant risk while equipment covered by the proposed CT is out-of-service, as represented by incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP). Tier 1 also addresses probabilistic risk assessment (PRA) quality, including the technical adequacy of the licensee's plant-specific PRA for the subject application. Tier 1 also considers the cumulative risk of the present TS change in light of past (related) applications or additional applications under review along with uncertainty/sensitivity analysis with respect to the assumptions related to the proposed TS change.

- Tier 2 identifies and evaluates any potential risk-significant plant equipment outage configurations that could result if equipment, in addition to that associated with the proposed LAR, is taken out-of-service simultaneously, or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved. The purpose of this evaluation is to ensure that appropriate restrictions are in place such that risk-significant plant equipment outage configurations will not occur when equipment associated with the proposed CT is implemented.

- Tier 3 addresses the licensee's overall configuration risk management program (CRMP) to ensure that adequate programs and procedures are in place for identifying risk-significant plant configurations resulting from maintenance or other operational activities and that the licensee takes appropriate compensatory measures to avoid risk-significant configurations that may not have been considered during the Tier 2 evaluation. Tier 3 guidance can be satisfied by the Maintenance Rule, 10 CFR 50.65(a)(4), subject to the guidance provided in RG 1.177, Section 2.3.7.1, and the adequacy of the licensee's program and probabilistic risk assessment (PRA) model for this application. RG 1.182, "Assessing and Managing Risk Before maintenance Activities at Nuclear Power Plant," endorses NUMARC 93-01, Section 11 which also provides guidance on the implementation of 10 CFR 50.65(a)(4).

RGs 1.174 and 1.177 also describe acceptable implementation strategies and performance monitoring plans to help ensure that the assumptions and analyses used to support the proposed TS changes will remain valid. The implementation and monitoring program guidance of Section 2.3 of RG 1.174 and Section 3 of RG 1.177 states that monitoring performed in conformance with the Maintenance Rule can be used when it is sufficient for the SSCs affected by the risk-informed application.

Section 19.2, "Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance," of NUREG-0800, "Standard Review Plan for the

Review of Safety Analysis Reports for Nuclear Power Plants" (hereafter referred to as the SRP), provides general guidance for evaluating the technical basis for proposed risk-informed changes. SRP Section 19.2 states that a risk-informed application should be evaluated to ensure that the proposed changes meet the following five key principles:

(1) The proposed change meets the current regulations, unless it explicitly relates to a requested exemption or rule change.

(2) The proposed change is consistent with the defense-in-depth philosophy.

(3) The proposed change maintains sufficient safety margins.

(4) When proposed changes increase CDF or risk, the increase(s) should be small and consistent with the intent of the Commission's Safety Goal Policy Statement (51 FR 30028)

(5) The licensee should monitor the impact of the proposed change using performance measurement strategies.

SRP Section 19.1, "Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," addresses the technical adequacy of a baseline PRA used by a licensee to support license amendments for an operating reactor. SRP Section 16.1, "Risk-Informed Decision Making: Technical Specifications," provides more specific guidance related to risk-informed TS changes, including CT changes as part of risk-informed decisionmaking.

4.0 TECHNICAL EVALUATION

The NRC staff has reviewed the licensee's analyses in support of its proposed application dated December 21, 2007, as supplemented by letter dated August 1, 2008.

4.1 Background of TS Changes as Described in TSTFs

Westinghouse Topical Report WCAP-14333 provided the justification for increasing the completion and the bypass test time for RTS and ESFAS. A summary of the changes that were justified in WCAP-14333 is listed below:

WCAP-14333 RTS and ESFAS CT and Bypass Test Time Changes		
Component	CT	Bypass Test Time
Analog Channels	6+6 hours to 72+6 hours	4 hours to 12 hours
Logic Cabinets	6+6 hours to 24+6 hours	No relaxation beyond the TOP (WCAP-10271-P and its supplements)
Actuation Relays	6+6 hours to 24+6 hours	No relaxation beyond the TOP (WCAP-10271-P and its supplements)

Similarly, WCAP-15376 provided the justification for increasing the completion and bypass time for the RTBs and for increasing the STIs for the RTBs, instrumentation channels, logic cabinets, and master relays of the RPS instrumentation. The changes justified in WCAP-15376 are summarized below:

WCAP-15376 RTS and ESFAS Surveillance Test Interval and Completion Time Changes – SSPS		
Component	STI	Completion Time and Bypass Time
Analog Channels	3 months to 6 months	No change
Logic Cabinets	2 months to 6 months	No change
Master Relays	2 months to 6 months	No change
RTBs	2 months to 4 months	CT: 1 hour to 24 hours. Bypass Time: 2 hours to 4 hours.

4.2 Summary Description of the TS Changes Proposed by Licensee

The following table summarizes the proposed WCAP-14333 changes, as applicable to BVPS-1 and 2.

RTS/ESFAS Components	CT		Bypass Test Time	
	Current (Hour)	Proposed (Hour)	Current (Hour)	Proposed (Hour)
Analog Channels	6+6[1]	72+6[1]	4	12
Logic Cabinets	6+6	24+6	4	No Change
Master Relays	6+6	24+6	4	No Change
Slave Relays	6+6	24+6	4	No Change
RTBs	6	No Change[2]	2	No Change[2]

1. The +6 hours is the time allowed for the specified mode change.

2. WCAP-14333 does not directly revise the RTB CT and bypass test times, and it is assumed that the bypass test times for the RTBs and the logic cabinets are separate and independent. However, WCAP-14333 assumes that with either a logic cabinet or RTB in test or maintenance their associated train is also unavailable. Based on this, the analysis presented in WCAP-14333 includes a provision to accept a bypass test time of the RTBs equivalent to the bypass test time for the logic cabinets provided that: (1) both are tested concurrently, and (2) the plant design is such that both the RTB and the logic cabinet cause their associated electrical trains to be inoperable during test or maintenance. Therefore, the RTB bypass test time is extended to 4 hours for this maintenance configuration. With the implementation of WCAP-15376, the RTB bypass test time is increased to 4 hours, consistent with the logic cabinet bypass test time.

The following table summarizes the proposed WCAP-15376 changes, as applicable to BVPS-1 and 2.

RTS/ESFAS Components	STI		CT		Bypass Test Time	
	Current (Month)	Proposed (Month)	Current (Hour)	Proposed (Hour)	Current (Hour)	Proposed (Hour)
Logic Cabinets	2	6	No Change Requested		No Change Requested	
Master Relays[1]	2	6				
Analog Channels	3	6				
RTBs	2	4	1	24+6[2]	2	4

1. Applicable to SSPS plants only.

2. The +6 hours is the time allowed for the specified mode change.

4.3 Review of Methodology

In accordance with SRP Sections 19.1, 19.2, and 16.1, the NRC staff reviewed the licensee's incorporation of WCAP-14333 and WCAP-15376 using the three-tiered approach and the five key principles of risk-informed decisionmaking presented in RGs 1.174 and 1.177 and the SER conditions and limitations for WCAP-14333 and WCAP-15376.

4.4 Key Information Used in the Review

The key information used in the NRC staff's review comes from Enclosures 1 and 3 of the application dated December 21, 2007, as supplemented by the request for additional information (RAI) response dated August 1, 2008; TSTF-411, Revision 1, and TSTF-418, Revision 2; as approved by SERs dated August 30, 2002, and April 2, 2003, respectively; and the NRC staff's SERs on WCAP-14333 and WCAP-15376. The NRC staff also referred to previous SERs related to WCAP-10271, the licensee's individual plant examination (IPE) and individual plant examination of external events (IPEEE) assessments, and previous BVPS-1 and 2 amendment implementations of WCAP-01271.

4.5 Traditional Engineering Evaluation

The traditional engineering evaluation addresses key principles 1, 2, 3, and 5 of the NRC staff's philosophy of risk-informed decisionmaking, which concern compliance with current regulations, evaluation of defense in depth, evaluation of safety margins, and performance measurement strategies. Key principle 4 is evaluated in Section 4.6.1 of this safety evaluation (SE).

4.5.1 Key Principle 1 and 2: Compliance with Current Regulations and Defense in Depth

The proposed changes do not involve changes to instrument actuation setpoints, setpoint tolerance, testing acceptance criteria, or channel response times. No hardware changes are proposed or required to implement these changes at the plant. This amendment request will allow more time for maintenance and testing activities, provide additional operational flexibility, and reduce the potential for forced outages to comply with the current RTS and ESFAS instrumentation TS. The licensee explained that industry information has shown that a significant number of reactor trips are related to instrumentation test and maintenance activities, which indicates that the TS should provide sufficient time to complete these activities in an orderly and efficient manner.

In 10 CFR 50.55a(h)(2), the NRC staff requires that the protection systems be consistent with the plant licensing basis or IEEE 603-1991 for plants with construction permits issued before January 1, 1971, or that the protection systems meet IEEE 279-1971 or IEEE 603-1991 for plants with construction permits issued after January 1, 1971, but before May 13, 1999. The licensee stated that because the construction permit for Unit 1 was issued on June 20, 1970, the Unit 1 protection systems are consistent with the licensing basis for Unit 1 or IEEE 603-1991. Because the construction permit for Unit 2 was issued on May 3, 1974, the Unit 2 protection systems meet IEEE 279-1971 or IEEE 603-1991.

Furthermore, the licensee stated that no change is required for BVPS-1 and 2 UFSAR description of conformance to GDC 2, 4, 13, 20, and 21 and GDC 22–25 or to the RGs listed in Section 3.3 as a result of the changes proposed in original application dated December 21, 2007. Because there will be no change to the RTS, ESFAS, or LOP instrumentation design, the proposed TS changes meet all the applicable regulatory requirements and guidance documents specified in Section 3.3.

4.5.2 Key Principle 3: Safety Margins

The RAI response to the Westinghouse Owners Group letter OG-01-058, "Transmittal of Response to Request for Additional Information Regarding WCAP-15376-P, Revision 0, 'Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times' (MUHP-3046)," dated September 28, 2001, requires each plant to review its setpoint calculation methodology to determine the impact of extending the COT surveillance frequency from 92 days to 184 days.

The licensee stated that the BVPS-1 and 2 RTS and ESFAS setpoint methodology includes an allowance for instrument drift. As-found instrument setpoint readings are recorded during the performance of the plant procedures for the required surveillances. As part of these procedures, the as-found readings are compared to the required setpoint tolerance, and the instrument channel is adjusted, if needed, in order to maintain the channel setpoint as close to the specified setpoint as practical. If the setpoint is found outside of its allowable tolerance band, then the condition is documented and evaluated using the corrective action program. The channel is required to meet the surveillance procedure requirements, which includes a review by a licensed senior reactor operator, before it is returned to an operable status. Qualified instrument and control technicians perform the surveillance procedures using step-by-step written procedures and industry-endorsed human performance error prevention practices.

To assess the potential drift effects of extending the COT and the TADOT surveillance frequencies from 92 days to 184 days as proposed in the license amendment request, the licensee reviewed the results of the surveillance procedures for the functions affected by the proposed TS changes. This review used the data generated by completed surveillance procedures and compared the as-found setpoint from the previous as-left setpoint to determine the setpoint drift over the surveillance interval. A review of these data determined that the drift magnitudes are well within the process rack operability criteria specified by the surveillance procedures and are consistent with operability criteria for an operable channel as defined by the process rack vendor. No bias or significant adverse trends were noted. No history of frequent process rack recalibration was noted in this review for the current surveillance frequency. No bias or significant adverse trends were noted.

In addition, the licensee performed a search of the industry operating experience database in August 2007 for the RPS and ESFAS at six plants that had license amendments previously approved that extended surveillance intervals based on WCAP-15376-P-A. The search found no problems attributed to drift at these plants since the approval dates of their respective license amendments.

From the review of the above information, the NRC staff finds that, based on existing BVPS-1 and 2 setpoint methodology and plant surveillance procedures, the proposed TS changes to increase COT and TADOT surveillance frequencies from 92 days to 184 days are acceptable.

4.5.3 Key Principle 5: Performance Measurement Strategies-Implementation and Monitoring Program

RGs 1.174 and 1.177 establish the need for an implementation and monitoring program to ensure that extensions to TS CTs, bypass test times, and surveillance intervals do not degrade operational safety over time and that no adverse degradation results from unanticipated degradation or common-cause mechanisms. Section 4.6.5 of this SE provides the NRC staff's evaluation of the licensee's implementation and monitoring program.

4.6 Staff Technical Evaluation (Probabilistic Risk Assessment)

4.6.1 Key Principle 4: Risk Evaluation

The licensee employed a risk-informed approach, based on the methodology of WCAP-14333 and WCAP-15376, to justify changes to RTS and ESFAS CTs, bypass test times, and STIs. The risk metrics, ΔCDF, ΔLERF, ICCDP, and ICLERP, were used by the licensee to evaluate the risk impact of the proposed changes consistent with the acceptance guidance presented in RGs 1.174 and 1.177.

To determine that WCAP-14333 and WCAP-15736 are applicable to BVPS-1 and 2, the licensee addressed the conditions and limitations of the NRC staff SERs and the implementation guidance that compares plant-specific data to the generic analysis assumptions. The evaluation compared the baseline assumptions, including surveillance, maintenance, calibration, actuation signals, procedures, and operator actions, to confirm that the generic evaluation assumptions used in the topical reports are also applicable to BVPS-1 and 2.

The following paragraphs discuss the licensee's evaluation of the SER conditions and limitations of WCAP-14333 and WCAP-15376.

(1) A licensee should confirm the applicability of the WCAP-14333 and WCAP-15376 analyses for its plant.

In Enclosure 3 of the licensee's original application dated December 21, 2007, Tables 1 through 5 provide the evaluation for WCAP-14333 and WCAP-15376. The evaluation included a comparison of parameters and assumptions with BVPS plant-specific data.

Data included plant-specific signals, actuation and failure experience, component test and maintenance intervals, procedures, and anticipated transient without scram (ATWS) information. As stated in the staff SE for WCAP-15376, the estimates for LERF were based on the reference plant having a large dry containment and the assumption that the only contributions to LERF would be from containment bypass or core damage events with the containment not isolated. Containment failure events were not specifically considered in WCAP-15376. Therefore, the NRC staff SE for WCAP-15376 requested that a plant-specific assessment should be performed for plants referencing WCAP-15376 to assess any impacts to the proposed TS changes. BVPS-1 and 2 are both utilizing large dry containments and, therefore, the WCAP-15376 analysis and results are applicable to BVPS.

In the NRC staff SER for WCAP-15376, the NRC staff recognized the similarity between RTS and ESFAS systems, design, function, and initiating event frequency, but noted the unavailability of the RTS showed a wide range of estimates. One example was the apparent variability in the contribution to core damage from ATWS events. The licensee demonstrated that the WCAP-14333 and WCAP-15376 ATWS analysis and assumptions including ATWS contribution to CDF are applicable to BVPS-1 and 2.

Based on the evaluation presented in Section 4.6.2, Tier 1, of this SE, the NRC staff considers the condition satisfied for BVPS-1 and 2.

(2) Under WCAP-14333, the licensee should address the Tier 2 and Tier 3 analyses, including CRMP insights, by confirming that these insights are incorporated into its decisionmaking process before taking equipment out-of-service.

Based on the evaluation presented in Section 4.6.3 (Tier 2) and Section 4.6.4 (Tier 3) of this SE, the licensee addressed both Tier 2 and Tier 3 risk significant configurations and confirmed these insights are incorporated into the BVPS-1 and 2 CRMP. Therefore, the NRC staff considers this condition satisfied for BVPS-1 and 2.

(3) The licensee should evaluate the risk impact of concurrent testing of one logic cabinet and associated RTB on a plant-specific basis to ensure conformance with the WCAP-15376 evaluation, including the guidance of RGs 1.174 and 1.177.

Concurrent testing of one logic cabinet and associated RTB was not originally evaluated or precluded by WCAP-15376. In response to an NRC staff RAI, the PWROG provided a generic ICCDP estimate of 3.2E-7 for the more limiting configuration of a logic cabinet and RTB out-of-service for 30 hours. The resulting generic estimate is within the RG 1.177 ICCDP acceptance guidance of 5.0E-7. In addition, the licensee has established the conformance of BVPS-1 and 2 to the generic WCAP-15376 analysis (i.e., Condition and Limitation 1) as documented in Enclosure 3 of the licensee's original application dated December 21, 2007. Based on the information above, the generic WCAP-15376 ICCDP estimates are expected to be applicable to the BVPS-1 and 2 plant-specific case and, therefore, the NRC staff finds it acceptable.

(4) To ensure consistency with the reference plant, the licensee should confirm that the model assumptions for human reliability in WCAP-15376 are applicable to the plant-specific configuration.

Enclosure 4, table 5 of the licensee's original application dated December 21, 2007, confirmed that the assumptions regarding human reliability used in WCAP-15376 are applicable to BVPS-1 and 2. This review concluded that for the operator actions identified in WCAP-15376, plant procedures, training and sufficient time are available consistent with the assumptions in WCAP-15376. Based on the information above, the NRC staff considers condition 4 to be satisfied.

(5) For future digital upgrades with increased scope, integration, and architectural differences beyond those of Eagle 21, the NRC staff finds that the generic applicability of WCAP-15376 to a future digital system is not clear and should be considered on a plant-specific basis. BVPS-1 and 2 design is based on analog instrument racks and an SSPS, therefore, this condition is not applicable to the implementation of WCAP-15376 at BVPS.

(6) WCAP-15376 included an additional condition based on the PWROG response to an NRC staff RAI that committed each plant to review its plant-specific setpoint calculation methodology to ensure that the extended STIs do not adversely impact the plant-specific setpoint calculations and assumptions for instrumentation associated with the extended STIs. (See section 4.5.2 of this SE)

4.6.2 Tier 1: Probabilistic Risk Assessment Capability and Insights

The first tier evaluates the impact of the proposed changes on plant operational risk based on the BVPS-1 and 2 implementation of WCAP-14333 and WCAP-15376. The Tier 1 NRC staff review involves (1) evaluation of the technical adequacy of the PRA and its application to the proposed changes, and (2) evaluation of the PRA results and insights based on the licensee's proposed application.

PRA Technical Adequacy

WCAP-14333 and WCAP-15376 utilized a representative PRA model for the evaluation of the CT, test bypass time and STI extensions. Although the WCAP-14333 and WCAP-15376 SERs accepted the use of a representative model as generally reasonable, the application of the representative model and the associated PRA results to a specific plant introduces a degree of uncertainty because of modeling, design, and operational differences. Therefore, each licensee adopting WCAP-14333 and WCAP-15376 needs to confirm that the topical report analyses and results are applicable to their plant.

The NRC staff reviewed the information provided in the proposed application and the findings and conditions of the NRC staff SERs for WCAP-14333 and WCAP-15376 for applicability to BVPS-1 and 2. WCAP-14333 and WCAP-15376 do not require specific use of the BVPS PRA or plant-specific estimates of ΔCDF, ΔLERF, ICCDP, or ICLERP in the implementation of either topical report. However, in its SER for WCAP-14333 and WCAP-15376, the NRC staff found that the applicability of the generic PRA analysis for the proposed CT, bypass test time, and STI changes to other Westinghouse plants may not be representative based on design variations in actuated systems and the contribution to plant risk from accident classes impacted by the proposed change.

The licensee reviewed the scope and detail of the BVPS-1 and 2 PRA using the topical report analysis parameters as listed in Enclosure 3 of the licensee's original application dated December 21, 2007, to demonstrate the plant-specific applicability of the proposed CT, bypass test times, and STI changes. The licensee confirmed the topical report actuation logic; component test, maintenance, and CTs, STI intervals; at-power maintenance; ATWS; total internal events CDF; transient events; operator actions; trip actuation signals; and ESFAS actuation signals were applicable to BVPS-1 and 2 plant-specific values. Based on comparisons to the topical report analysis parameters and the NRC staff SE conditions and limitations for WCAP-14333 and WCAP-15376, the licensee concluded that WCAP-14333 and WCAP-15376 are applicable to BVPS-1 and 2.

The licensee also proposed changes to functional units not generically evaluated and approved by WCAP-10271. TS changes not included in the WCAP-10271 generic analysis, but addressed on a plant-specific basis by BVPS-1 and 2, are listed in Section 3.2 of this SE.

Both WCAP-14333 and WCAP-15376 state that the CTs, STIs, and bypass test time evaluation performed under these topical reports are applicable to the signals previously evaluated under WCAP-10271 and its supplements. Therefore, signals not specifically addressed under WCAP-10271 but found to be applicable through plant-specific WCAP-10271 evaluations, are also applicable to WCAP-14333 and WCAP-15376. The functional units identified in Section 3.2 of this SE are applicable to WCAP-14333 and WCAP-15376 based on previously approved BVPS-1 and 2 license amendment Nos. 267, 149, 309, and 181 implementations of WCAP-10271 and its related supplements.

Previous plant-specific functional units approved under WCAP-10271 are acceptable because the analysis performed under WCAP-14333 and WCAP-15376 is based on analysis methods used in WCAP-10271. Therefore, previously approved BVPS-1 and 2 plant-specific changes to functional units under WCAP-10271 are also considered applicable to the analysis approach and guidance of WCAP-14333 and WCAP-15376 and are acceptable to the NRC staff.

BVPS-1 and 2 also identified an application that includes a new TS 3.3.2 ESFAS instrumentation Functional Unit 2b (2); Refueling Water Storage Tank (RWST) Level Low Coincident with Containment Pressure High High for the initiation of the recirculation spray system (RSS). As stated by the licensee, this change is due to modifications to the containment sump screens that necessitated a corresponding change to the RSS ESFAS start signal. The licensee performed a plant-specific signal unavailability evaluation for the recirculation spray signal consistent with the analysis done for WCAP-10271. The licensee then compared the unavailability result to similar signal configurations (auxiliary feedwater (AFW) pump start) in WCAP-10271. Based on this comparison, the change in unavailability for the RSS Functional Unit was comparable with the signal configurations in WCAP-10271 and is, therefore, also acceptable to the NRC staff.

Based on the information above, the NRC staff concludes that the licensee has demonstrated the applicability of WCAP-14333 and WCAP-15376 to BVPS-1 and 2 for the proposed changes in STIs, bypass test times and CTs.

Peer Review

Based on the licensee's original application dated December 21, 2007, RG 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessments Results for Risk Informed Activities," is not applicable and was used for information only by the NRC staff.

The Westinghouse Owners Group (WOG) peer reviewed the BVPS-1 and 2 PRA in July 2002 with certification dated December 2002. The licensee indicated that facts and observations (F&Os) written to BVPS-2 were applicable to BVPS-1 as well. The peer review team was provided with the modeling differences during their review. The peer review identified 5 Category A and 19 Category B F&Os with a potential to impact the BVPS-1 and 2 PRA models. All A and B F&Os were entered into the licensee's corrective action program and subsequently dispostioned and incorporated into the BVPS-1 and 2 PRA models. The BVPS-1 PRA was updated in September 2003 (BVPS-1REV3) and BVPS-2 was updated in May of 2003 (BVPS-2REV3B). The latest revisions of the BVPS-1 and 2 models are BVPS-1, Rev. 4 and BVPS-2, Rev. 4 and these are the models used for this application. Therefore, no outstanding F&Os were applicable to this application. The licensee confirmed that there is no outstanding license amendment requests (LARs), modifications, or revised procedures that are not incorporated into the licensee's PRA models used for this application.

The BVPS-1 and 2 PRA is controlled and updated through BVPS-1 and 2 administrative and business practice procedures. These procedures are designed to keep the PRA models current and provide for configuration control. PRA software configuration management, verification and software quality assurance are also controlled by plant procedures. The BVPS-1 and 2 PRA model was compared to the representative PRA model used in WCAP-14333 and WCAP-15376 to confirm applicability to WCAP-14333 and WCAP-15376.

As discussed above, no plant-specific design or operability issues were identified that would invalidate the topical report generic results, and the NRC staff concludes that the generic results are applicable. Therefore, the NRC staff concludes that the PRA is technically adequate for this application.

External Events

The proposed changes will increase the unavailability of the affected SSC by increasing the CT for the analog cabinets, logic cabinets, master relays, slave relays, and RTBs. To be important for an external event, the external event must occur while the SSC is in the extended completion time.

The analysis for both WCAP-14333 and WCAP-15376 did not include external events. The NRC staff SER for WCAP-14333 qualitatively considered external events including fire and seismic using risk insights from a reference plant PRA different from that used by the PWROG. The NRC staff SER for WCAP-14333 concluded that the proposed changes will have only a very small impact on external event risk. Seismic and fire external events are quantitatively evaluated in the BVPS Unit 1 and 2 PRA models. The licensee specifically evaluated ESFAS actuation signals with regard to seismic and fire sequence CDF. The licensee stated that the external event assessment indicated that ESFAS actuation signals contributed 1 percent or less to external event CDF. Based on the small contribution of ESFAS actuation signals on CDF and the small increase in signal unavailability attributable to the proposed CT and bypass test times, the impact of the LAR on external event risk is expected to be very small for both WCAP-14333 and WCAP-15376 at BVPS-1 and 2. Therefore, the NRC staff finds it acceptable.

High winds, floods and other (HFO) external events were evaluated in the Individual Plant Examination of External Events (IPEEE) using the screening approach described in NUREG-1407, "Procedure and Submittal Guidance for the IPEEE for Severe Accident Vulnerabilities," issued June 1991, and GL 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities," Supplement 4, dated November 23, 1988, to demonstrate that each plant meets the criteria in the 1975 SRP. In accordance with NUREG-1407, if a plant meets the 1975 SRP criteria, licensees can screen out HFO external events as a significant contributor to total CDF. Based on the IPEEE HFO evaluation results and conclusions for BVPS-1 and 2, the external CDF contribution from HFO events met the 1975 SRP screening guidelines (i.e., if the plant is in conformance with the 1975 SRP for an external event, then it is concluded that the contribution to core damage from that external event is less than 1.0E-6/year – assuming that the conditional probability of core damage is less than 0.1). The licensee confirmed in their RAI response that the IPEEE HFO event conclusions are still applicable to BVPS-1 and 2. Therefore, the impact of the proposed CT, bypass test time and STI changes due to HFO risk is expected to be very small and a negligible contribution to RTS and ESFAS instrumentation STI, CT and bypass test time Δ risk.

Total Risk Contribution

The NRC staff considered whether the estimated external event risk, in conjunction with the WCAP-14333 and WCAP-15376 internal event risk for BVPS-1 and 2 could exceed the RG 1.174 base CDF of 1E-4/year with the implementation of WCAP-14333 and WCAP-15376. The estimated combined total internal and external (fire and seismic) CDF is about 1.95E-5/year and 2.40E-5/year for BVPS-1 and 2, respectively. Based on the estimated WCAP-14333 and WCAP-15376 internal event risk for BVPS-1 and 2 and the very small estimated increase in external event risk, the NRC staff finds that the total CDF is not expected to be higher than 1E-4/year when implementing WCAP-14333 and WCAP-15376. Therefore, the NRC staff concludes the change in risk should remain small and not cause the RG 1.174 and RG 1.177 acceptance guidance to be exceeded.

Cumulative Risk

The licensee stated that the current PRA models have incorporated the extended power uprate and risk-informed revisions implemented prior to April 20, 2006, for BVPS-1 and November 13, 2006, for BVPS-2. The licensee stated there are no risk-informed changes pending or approved and implemented that require incorporation into the BVPS-1 and 2 PRA models.

WCAP-15376 generically evaluated the cumulative CDF risk from pre-TOP WCAP-10271 to WCAP-15376 (WCAP-14333 inclusive). The cumulative impact on internal events CDF for the 2/3 logic representative of BVPS-1 and 2 was slightly above the RG 1.174 acceptance guideline of less that 1E-6/year for a very small change, but within the acceptance guidelines for a small change. The cumulative impact on internal events LERF for BVPS-1 and 2 was within the RG acceptance guidance of less than 1E-7/year for a very small change. BVPS-1 and 2 previously implemented WCAP-10271 and its related supplements. The WCAP-10271 CTs and STIs have been incorporated into the BVPS-1 and 2 PRA models used to evaluate this application. Since the proposed change for BVPS-1 and 2 is limited from WCAP-10271 to WCAP-15376, the change in cumulative risk is expected to be within the WCAP-15376 estimates.

PRA Results and Insights

The CDF for internal and external events is 1.95E-05/yr for BVPS-1 and 2.40E-5 for BVPS-2. The LERF for internal and external events is 7.54E-8/yr for BVPS-1 and 4.09E-7yr for BVPS-2 respectively. The ΔCDF when implementing WCAP-14333 is estimated to be 6.1E-7/year for plants having previously implemented WCAP-10271. The ΔCDF for WCAP-15376 is estimated at 8.5E-7/year based on plants previously implementing WCAP-14333. Both ΔCDF estimates are within RG 1.174 acceptance guidance of 1E-6/yr. The ΔLERF for both WCAP-14333 and WCAP-15376 are within the RG 1.174 LERF acceptance guidelines of 1.0E-7/year. The estimated ICCDP for WCAP-14333 is dependent on the CT selected but remains within the RG 1.177 acceptance guideline of less than 5.0E-7 for a single CT change. The estimated ICCDP for WCAP-15376 for an RTB and/or an RTB and logic cabinet out-of-service is also within the RG 1.177 ICCDP acceptance guideline of 5.0E-7. The estimated ICLERP for WCAP-14333 and WCAP-15376 (logic Cabinet and/or RTB) is also dependent on the CT selected but remains within the RG 1.177 ICLERP acceptance guideline of 5.0E-8. The above risk estimates are applicable to plants that are primarily 2/3 logic such as BVPS-1 and 2 that previously implemented WCAP-10271 (i.e., a TOP). Based on the information above, the implementation of WCAP-14333 and WCAP-15376 at BVPS-1 and 2 is within the RG 1.174 and RG 1.177 acceptance guidance for ΔCDF, ΔLERF, ICCDP, and ICLERP.

4.6.3 Tier 2: Avoidance of Risk-Significant Plant Configurations

A licensee should provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when specific plant equipment is taken out-of-service in accordance with the proposed TS change.

Based on WCAP-14333, WCAP-15376, and licensee evaluations, including the functional units not evaluated generically by WCAP-14333, the licensee identified the following Tier 2 restrictions:

For WCAP-14333:

- To preserve ATWS mitigation capability, activities that degrade the ability of the AFW system, reactor coolant system (RCS) pressure relief systems (pressurizer power operated relief valves (PORVS) and safety valves), ATWS mitigating systems actuation circuitry (AMSAC), or turbine trip should not be scheduled when a logic train is inoperable.

- To preserve loss-of-coolant accident (LOCA) mitigation capability, one complete emergency core cooling system (ECCS) train that can be actuated automatically must be maintained when a logic train is inoperable.

- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable.

- Activities in electrical systems (e.g., AC and DC power) and cooling systems (e.g., service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable. That is, one complete train of a function that supports a complete train of a function noted above must be available.

For WCAP-15376

- The probability of failing to trip the reactor on demand will increase when an RTB train is removed from service; therefore, systems designed for mitigating an ATWS event should be maintained and available. RCS pressure relief power operated relief valves (PORVS) and safety valves, AFW flow (for RCS heat removal), AMSAC, and turbine trip are important to ATWS mitigation. Therefore, activities that degrade the availability of the AFW, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when an RTB is inoperable.

- Due to the increased dependence on the available reactor trip train when one logic train unavailable, activities that degrade other components of the RTS, including master relays or slave relays, and activities that cause analog channels to be unavailable, should not be scheduled when a logic train is inoperable.

- Activities in electrical systems (e.g., AC and DC power) that support the systems or functions listed in the first two bullets should not be scheduled when an RTB is inoperable.

The licensee evaluated the concurrent component outage configurations and confirmed the applicability of the Tier 2 restrictions for BVPS-1 and 2. Based on the above, the NRC staff finds the licensee's Tier 2 analysis supports the implementation of WCAP-14333 and WCAP-15376 at BVPS-1 and 2 and satisfies the condition of the NRC staff SERs for WCAP-14333 and WCAP-15376 regarding Tier 2.

4.6.4 Tier 3: Risk-Informed Configuration Risk Management Program

Tier 3 addresses the licensee's overall configuration risk management program (CRMP) to ensure risk-significant plant configurations that result from maintenance or other operational activities are evaluated and that the licensee takes appropriate compensatory measures to avoid risk-significant configurations that may not have been identified during the Tier 2 evaluation.

The management of risk assessment of online configurations and scheduling for BVPS-1 and 2 is monitored using BVPS-1 and 2 PRA models and Safety Monitor Program software to determine plant CDF for plant conditions in conformance with the Maintenance Rule, 10 CFR 50.65(a)(4) as implemented through NUMARC 93-01, Section 11 as endorsed by RG 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." The licensee identified applicable procedures covering the on-line risk management program that cover the identification and evaluation of risk impact prior to removing equipment for maintenance and the development of weekly maintenance schedules to control on-line risk.

Configuration risk results are assigned risk thresholds by color code which are designed to maintain risk within an acceptable color band. The color codes are representative of increasing risk and use green, yellow, orange and red. Green represents up to two times the zero maintenance baseline risk with yellow, orange and red indicating increasing risk levels. Risk found within the yellow band result in efforts to minimize the duration of activities and increase supervisory oversight. Maintenance configurations resulting in orange or red color codes require management approval. The BVPS-1 and 2 CRMP accounts for Solid State Protection Train and ATWS systems unavailability. Tier 2 modeled components associated with WCAP-14333 and WCAP-15376 are also accommodated by the Safety Monitor PRA models. Emergent conditions including grid and weather events are evaluated and plant configurations risk is reassessed as required.

A review of recent inspection reports that evaluated the licensee's maintenance risk and emergent work risk assessments, scheduling, and configuration control for selected planned and emergent work activities found them acceptable and monitored in accordance with the requirements of Maintenance Rule, 10 CFR 50.65(a)(4) and plant procedures.

The NRC staff finds that the licensee's CRMP program to control risk is capable of adequately assessing the activities being performed to ensure that high-risk plant configurations do not occur and/or compensatory actions are implemented if a high-risk plant configuration or condition should occur. As such, the licensee's program provides for the assessment and management of increased risk during maintenance activities as required by the Maintenance Rule, 10 CFR 50.65(a)(4) and satisfies the RG 1.177 guidelines for a CRMP for the proposed change.

4.6.5 Implementation and Monitoring Program

RGs 1.174 and 1.177 also establish the need for an implementation and monitoring program to ensure that extensions to TS STI, CT, or bypass test times do not degrade operational safety over time and that no adverse effects occur from unanticipated degradation or common-cause mechanisms. The purpose of an implementation and monitoring program is to ensure that the impact of the proposed TS change continues to reflect the reliability and availability of SSCs impacted by the change. In addition, the application of the three-tiered approach in evaluating the proposed CT and bypass test times provides additional assurance that the changes will not significantly impact the key principle of defense in depth.

The licensee stated that condition monitoring is provided under the licensee's 10 CFR 50.65 Maintenance Rule program. RG 1.174 states that monitoring that is performed in conformance with the Maintenance Rule can be used when the monitoring performed is sufficient for the SSCs affected by the risk-informed application. The licensee provided a regulatory commitment that applicable BVPS programs will be reviewed and revised as required to ensure that the RTS and ESFAS modeling assumptions (i.e., equipment unavailability and component failure) for WCAP-14333 and WCAP-15376 will continue to be met at BVPS. Therefore, BVPS-1 and 2 satisfies the RG 1.174 and RG 1.177 guidelines for an implementation and monitoring program for the proposed change and is acceptable to the NRC staff.

4.7 Comparison with Regulatory Guidance

The proposed changes conform to TSTF-411, Revision 1, and also conform to TSTF-418, Revision 2, and the analysis performed in WCAP-14333 and WCAP-15376 as approved by the NRC staff, including limitations and conditions identified in the NRC staff's SERs. Additional TS changes not specifically evaluated by WCAP-14333 and WCAP-15376 are justified based on previously approved BVPS-1 and 2 implementation of WCAP-10271, including plant-specific evaluation at BVPS. As such, the implementation of WCAP-14333 and WCAP-15376 at BVPS-1 and 2 is within the RG 1.174 and RG 1.177 acceptance guidance for ΔCDF, ΔLERF, ICCDP, and ICLERP.

4.8 Staff Findings and Conditions

The NRC staff finds that the licensee has demonstrated the applicability of WCAP-14333 and WCAP-15376 to BVPS and has met the limitations and conditions as outlined in the NRC staff's SERs. The NRC staff found the risk impacts for ΔCDF, ΔLERF, ICCDP, and ICLERP as estimated by WCAP-14333 and WCAP-15376 to be applicable to BVPS-1 and 2 and within the acceptance guidelines for RG 1.174 and RG 1.177. The licensee's Tier 2 analysis evaluated concurrent outage configurations and confirmed the applicability of the risk-significant configurations identified by the NRC staff SER limitations and conditions and topical report analysis to ensure control of these configurations. The licensee's Tier 3 CRMP is consistent with the RG 1.177 CRMP guidelines and the Maintenance Rule, 10 CFR 50.65(a)(4) for the implementation of WCAP-14333 and WCAP-15376. The licensee monitors the reliability and availability of the RTS and ESFAS components under the Maintenance Rule 10 CFR 50.65(a)(1). Therefore, the NRC staff finds the TS revisions proposed by the licensee are consistent with the CTs, bypass test times, and STIs approved for WCAP-14333 and WCAP-15376 and meet the NRC staff's SE conditions and limitations for WCAP-14333 and WCAP-15376.

5.0 REGULATORY COMMITMENT

Prior to, or concurrent with amendment implementation, the licensee will review applicable BVPS-1 and 2 programs and revise them as necessary to ensure that the intent of the RTS and ESFAS equipment unavailability and component failure modeling assumptions in WCAP-14333 and WCAP-15376 are met at BVPS-1 and 2.

Also, concurrent with implementation of the amendments, the licensee will revise the applicable portions of the BVPS-1 and 2 TS Bases to incorporate the subject conditions and limitations of WCAP-14333 and WCAP-15376.

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Pennsylvania State official was notified of the proposed issuance of the amendments. The State official had no comments.

7.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and change surveillance requirements. The NRC staff has determined that the amendments involve no significant increase in the amounts and no significant change in the types of any effluents that may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding 73 FR 32745). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

6.0 CONCLUSION

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

Principal Contributors: Clifford Doutt
Subinoy Mazumdar

Date: December 29, 2008

DATED: December 29, 2008

AMENDMENT NO. 282 TO FACILITY OPERATING LICENSE NO. DPR-66 BEAVER VALLEY POWER STATION, UNIT NO. 1 AND AMENDMENT NO. 166 TO FACILITY OPERATING LICENSE NO. NPF-73 BEAVER VALLEY POWER STATION, UNIT NO. 2

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December 29, 2008

Mr. Peter P. Sena III
Site Vice President
FirstEnergy Nuclear Operating Company
Beaver Valley Power Station
Mail Stop A-BV-SEB1
P.O. Box 4, Route 168
Shippingport, PA 15077

SUBJECT: BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENTS RE: TECHNICAL SPECIFICATION TASK FORCE 411 AND 418 (TAC NOS. MD7531 AND MD7532)

Dear Mr. Sena:

The Commission has issued the enclosed Amendment No. 282 to Facility Operating License No. DPR-66 for the Beaver Valley Power Station, Unit No. 1 and Amendment No. 166 to Facility Operating License No. NPF-73 for the Beaver Valley Power Station, Unit No. 2. These amendments consist of changes to the Technical Specifications (TSs) in response to your application dated December 21, 2007, as supplemented by letter dated August 1, 2008.

The amendments revise the TSs associated with Reactor Trip System and Engineered Safety Features Actuation System (ESFAS) Instrumentation bypass test times, Completion Times, and Surveillance Frequencies consistent with Revision 1 to TS Task Force (TSTF)-411, "Surveillance Test Interval Extensions for Components of the Reactor Protection System [RPS] (WCAP-15376)" and Revision 2 to TSTF-418, "RPS and ESFAS Test Times and Completion Times (WCAP-14333)."

A copy of the related safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/RA/

Nadiyah S. Morgan, Project Manager
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-334 and 50-412

Enclosures:
1. Amendment No. 282 to DPR-66
2. Amendment No. 166 to NPF-73
3. Safety Evaluation

cc w/encls: Distribution via Listserv

Amendment No.: ML083380061 *Input received. No substantive changes made.

OFFICE	LPLI-1/PM	LPLI-1/LA	ECIB/BC	APLA/BC	ITSB/BC	OGC	LPLI-1/BC
NAME	NMorgan	SLittle	WKemper*	MRubin*	RElliot	LSubin	MKowal
DATE	12/09/08	12/09/08	11/14/2008	11/21/2008	12/10/08	12/11/08	12/29/08

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