August 9,2004

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10 CFR 50.90

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

DUANE ARNOLD ENERGY CENTER
DOCKET 50-331
LICENSE No. DPR-49

Response to Request for Additional Information Regarding License Amendment Request (TSCR – 056): "Elimination of License Condition 2.C.(2)(b) for Performance of Large Transient Tests for Extended Power Uprate

Reference: M. Peifer (NMC) to USNRC, "License Amendment Request (TSCR – 056): "Elimination of License Condition 2.C.(2)(b) for Performance of Large Transient Tests for Extended Power Uprate," NG-04-0111, dated February 27, 2004.

In the referenced letter, the Nuclear Management Company, LLC (NMC) submitted a license amendment request to change the Operating License for the Duane Arnold Energy Center (DAEC). The proposed amendment would remove license condition 2.C.(2)(b) to perform large transient testing as part of the Extended Power Uprate (EPU) power ascension testing program at the DAEC.

Subsequent to this application, the Staff contacted NMC on April 22, 2004 to discuss the proposed amendment. During that conference call, the Staff requested that NMC supplement the referenced request with additional information to conform to the draft Standard Review Plan (SRP) on EPU Testing (SRP Chapter 14.2.1). The Enclosure to this letter provides that requested information.

NMC would like to reiterate its belief that performing the large transient tests required by this license condition will not add significantly to the current state of knowledge about plant behavior under EPU conditions, will not likely reveal unforeseen equipment issues related to EPU operation, and that, given this low benefit, the challenges to plant equipment resulting from these tests are not in the best interest of overall safe and economical plant operation.

NMC repeats its original request that this application be approved by March 1, 2005 to support startup from the next scheduled refueling outage at the DAEC. Modifications are planned during that outage that will allow reactor power to be increased above the threshold requiring performance of the Main Steam Line Isolation Valve (MSIV) Closure test (1823.8 MWt), per the license condition. Therefore, we are requesting approval of our application to allow reactor power to be increased above 1823.8 MWt during startup from that outage without requiring the performance of the large transient tests.

There are no new regulatory commitments being made in this letter.

Please contact Tony Browning of my Staff at (319) 851-7750, if you have any questions regarding this application.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on August 9,2004.

Mark Peifer
Site Vice President, Duane Arnold Energy Center

cc: Regional Administrator - Region III, USNRC
Project Manager - DAEC, Office of Nuclear Reactor Regulation
Resident Inspector Office - DAEC, USNRC
State of Iowa

Enclosure

ENCLOSURE

Supplemental Information

Regarding

Duane Arnold Energy Center

License Amendment Request (TSCR-056)

The following information is formatted to correspond to the associated section of SRP Chapter 14.2.1, Section III – Review Procedures.

A. Comparison of EPU Test Program to the Initial Plant Test Program

The following Tables contain: 1) the comparison of the EPU Test Program for the DAEC compared with the original plant startup test program as described in DAEC Updated Final Safety Analysis Report (UFSAR) Chapter 14.2; and, 2) a matrix of these tests versus the thermal power levels at which they were/are performed. This matrix contains both the tests conducted as part of EPU Phase 1 implementation, as well as the planned testing for future Phases (i.e., Phase 2 and 3), based upon the current plans for modifications to be installed.

Table 1

Test No.	Test Title	Required for EPU	EPU Phase 1 1790 MWt	EPU Phase 2 1840 MWt	EPU Phase 3 1912 MWt
1	Chemical and Radiochemical Monitoring	Yes	X	X	X
2	Radiation Monitoring	Yes	X	X	X
3	Fuel Loading	Note 1			
4	Full Core Shutdown Margin	Note 2	X	X	X
5	Control Rod Drive (CRD) System	Note 2	X	X	X
6	Source Range Monitor (SRM) Response and Control Rod Sequence	Note 2	X	X	X
9	Water Level Measurement	Note 3			
10	Intermediate Range Monitor (IRM) Performance	Note 2	X	X	X
11	Local Power Range Monitor (LPRM) Calibration	Note 2	X	X	X
12	Average Power Range Monitor (APRM) Calibration	Note 2	X	X	X
13	Process Computer	Note 4			
14	Reactor Core Isolation Cooling (RCIC) System	Note 2	X	X	X
15	High Pressure Coolant Injection (HPCI) System	Note 2	X	X	X
16	Selected Process Temperatures	Note 2	X	X	X
17	System Expansion	Note 5			
18	Core Power Distribution	Note 6			
19	Core Performance	Yes	X	X	X
20	Steam Production	Note 7			
21	Flux Response to Rods	Note 8			
22	Pressure Regulator	Yes			
	a) Data Collection		X	X	X
	b) Backup Controller		X	X	X
	c) Step Changes in Pressure		X	X	X
23	Feedwater System	Yes			
	a) Loss of FW Heating		Note 9	Note 10	Note 10
	b) Single FW Pump Trip		Note 11	Note 11	Note 12
	c) Step Changes in Level		X	X	X
	d) FW Flow Element Calibration		X	X	X
24	Bypass Valves	Yes	X	Note 13	Note 13
25	Main Steam Isolation Valves	Yes			
	a) Functional Check	Note 2	X	X	X
	b) Full MSIV Closure Test	Note 14			
	c) MSIV Closure Time	Note 2	X	X	X
	d) Single MSIV Closure Test		X	Note 15	Note 15
	e) Flow Element Calibration		X	X	X
26	Relief Valves	Note 2	X	X	X
27	Turbine Stop and Control Valve Trips	Note 16			
28	Shutdown from Outside the Control Room	Note 17			

Test No.	Test Title	Required for EPU	EPU Phase 1 1790 MWt	EPU Phase 2 1840 MWt	EPU Phase 3 1912 MWt
29	Flow Control	Note 18			
30	Recirculation System	Note 2	X	X	X
31	Loss of Turbine-Generator and Offsite Power	Note 19			
32	Recirculation MG Set Speed Control	Note 20			
33	Main Turbine Stop Valve Surveillance Test	Yes	Note 13	Note 13	Note 13
34	Recirculation and Jet Pump Instrumentation Calibration	Note 21			
70	Reactor Water Cleanup System	Note 22			
71	Residual Heat Removal System	Note 23			
72	Drywell Atmosphere Cooling System	Note 24			
73	Cooling Water Systems	Note 25			
74	Offgas System	Note 26			
90	Vibration Monitoring - Internals	Note 27			
	General Plant Data Collection	Note 28	X	X	X
	Steam and Feedwater Piping Vibration Monitoring	Note 29	X	X	X
	Turbine Combined-Intermediate Valve (CIV) and Turbine Control Valve (TCV) Surveillance Testing	Note 30	X	Note 30	Note 30
	General Service Water (GSW) Heat Exchanger Performance Monitoring	Note 31	X	X	X

Notes to Table:

(1) This test demonstrates the ability to safely and efficiently load fuel to the full core size. Fuel loading is performed during every refueling outage in accordance with site procedures. Extended Power Uprate (EPU) has no impact on this evolution; therefore, no additional testing was required for EPU.

(2) Credit is taken for existing Technical Specification Surveillances. Testing will be performed as required by Technical Specifications in all Phases of EPU testing.

(3) The purpose of this test is to verify the calibration and agreement of the GEMAC (narrow range) and YARWAY (wide range) water level instrumentation under various plant conditions. This instrumentation was not affected by EPU. Thus, this testing is not specifically required. Any anomalous behavior would be observed as part of other testing activities.

(4) This test verifies the performance of the process computer under plant operating conditions. EPU does not affect the functions of the process computer; however, some input variables required modification. This test is not specifically required for EPU.

(5) The purpose of this test is to verify that the reactor drywell piping systems are free and unrestrained with regard to thermal expansion, and that suspension components are functioning in the specified manner. The test also provides data for calculation of stress levels in nozzles and weldments. ***An*** analysis for EPU conditions indicated the piping systems were acceptable for EPU; therefore, further testing is not required.

(6) This test determines core power distribution in three dimensions, confirms reproducibility of Traversing Incore Probe (TIP) System readings, and determines core power symmetry. Existing site procedures verify proper TIP operation and core power symmetry. EPU does not significantly impact these parameters. TIP operation is not affected by EPU. Thus, special testing is not required.

(7) This test demonstrates the ability to operate continuously at rated reactor power, demonstrating that the Nuclear Steam Supply System (NSSS) provides steam at a sufficient rate and quality. This test is the initial warranty run, which is not applicable to EPU.

(8) The purpose of this test is to demonstrate the stability of the core local power-reactivity feedback mechanism with regard to small perturbations in reactivity caused by rod movement. This was an initial

startup test requirement that is no longer applicable, due to the incorporation of thermal-hydraulic instability requirements on the power/flow map.

(9) The Loss-of-Feedwater Heating (LOFH) test performed during initial startup testing demonstrates adequate response to LOFH. The transient event is caused by an equipment failure or operator error that causes isolation of one or more feedwater heaters. Cycle-specific transient analyses as part of the Core Operating Limits Report (COLR) show acceptable response relative to fuel thermal limits; i.e., minimum critical power ratio (MCPR) and fuel overpower. The LOFH transient was reanalyzed for EPU, and fuel thermal limits were acceptable. Therefore, the LOFH test is not required for EPU.

(10) With the introduction of new FW Heaters as part of EPU Phase 2, performance of the new heaters will be monitored to demonstrate that the specific assumptions for the LOFH transient in the COLR (FW delta T and inlet subcooling) remain bounding. It is not necessary to perform a LOFH test to assure the analysis inputs are bounding.

(11) This test verifies the capability of the automatic recirculation pump runback to prevent a low water level scram following a single RFP trip. **As** discussed in PUSAR Section 7.4.2, transient analyses were performed, which concluded that scram avoidance is not assured after EPU. However, this is a similar result as pre-EPU. This information has been included in control room operator training and is modelled on the plant-specific simulator. Thus, the peformance of this test would not provide any further useful information on feedwater system performance.

(12) One of the proposed modifications for Phase 3 is to add **a** third FW pump provide system capability for operation at the licensed power level of 1912 MWt. One of the attributes of adding this third pump is an improvement in reactor water level response to a single FW pump trip transient. If this modification is implemented, testing of the transient response to a single FW pump trip will be considered as part of Phase 3 EPU testing.

(13) The purpose of this test is to determine the highest power level practical for performing routine, on-line stroke testing of the turbine valves without causing a plant trip. The testing conducted in Phase 1 determined this power level to be 1600 MWt. Thus, further testing in EPU Phases 2 and 3 is not required.

(14) This test was not required as part of EPU Phase **1** testing, as the required power level per the license condition is 1823.8 MWt, which was not reached in Phase 1. This test is currently required to be performed as part of Phase 2 testing. However, the purpose of this license amendment request is to not perform this test as part of EPU testing. If this test is required to be perform during Phase 2 testing, it is not required to be repeated in Phase 3.

(15) The purpose of this test is to determine the highest power level practical for performing routine, on-line stroke testing of the MSIVs without causing a plant trip. The testing conducted in Phase 1 determined this power level to be 1460 MWt. Thus, further testing in EPU Phases 2 and **3** is not required.

(16) This test is not required as part of either EPU Phase 1 or 2 testing **,** as the required power level per the license condition is 1906.7 MWt, will not be reached until Phase 3. However, the purpose of this license amendment request is to not perform this test as part of EPU testing.

(17) This test demonstrates the ability to shut down the reactor from normal steady-state operating conditions to the point where cooldown is initiated and under control with reactor pressure and water level controlled from outside the main control room. EPU does not alter the capability of the reactor to be shut down from outside the main control room; therefore, this test is not required for EPU.

(18) The purposes of this test are to determine the plant response to changes in recirculation flow; adjust all flow control elements; and, to demonstrate the plant load following capability in local manual, master manual, and automatic flow control modes. EPU does not significantly affect the recirculation flow control system, as the increase in pump speed and drive flow needed to achieve rated core flow is minor (< 2.7%). The licensed maximum core flow limit is not being changed by EPU. In addition, the DAEC only operates in manual control mode. Thus, this testing is not required for EPU.

(19) The purpose of this test is to determine the reactor transient performance during the loss of the main generator and all offsite power, and to demonstrate acceptable performance of the station electrical supply system. The loss-of-offsite power (LOOP) results in a generator load reject event, which is discussed in Note 16 above (Test No. 27). The performance of the electrical distribution system is confirmed by individual equipment tests; thus, an integrated test of the entire electrical distribution system is not required.

(20) The purposes of this test are to determine the individualized characteristics of the recirculation control system (i.e., Drive Motor, Fluid Coupler, Generator, Drive Pump, and Jet Pumps), to obtain acceptable speed control system performance by the adjustment of the linear and non-linear controller elements, and to determine the maximum allowable pump speed. **As** stated in Note 18 above (Test No. 29), rated core flow is not changed for EPU, thus specific testing of the recirculation system, including individual components in the control system, is not required.

(21) The purpose of this test is to obtain a complete integrated calibration of the installed jet pump and recirculation pump flow instrumentation with the reactor shutdown prior to the jet pump flow calibration (Test No. 30). Similar to Test No. 30, as there is no change in rated core flow due to EPU, the ability to calibrate these instruments over their required ranges is also not affected. Thus, no testing is required.

(22) This test demonstrates the specific aspects of the mechanical operability of the Reactor Water Cleanup (RWCU) System. Detailed evaluations show the impact of the new licensed power is minor changes in RWCU System operating requirements, due to the changes in feedwater flow and temperature. These changes are well within the system's design parameters. No specific RWCU testing is required for EPU.

(23) The purpose of this test is to demonstrate the ability of the Residual Heat Removal (RHR) System to remove residual and decay heat from the nuclear system so that refueling and nuclear servicing can be performed and to condense steam while the reactor is isolated from the main condenser. The capability of the RHR System to remove residual and decay heat has been demonstrated many times over the years. The effect of EPU on system performance is merely an increase in reactor cooldown time, i.e., system mission time. The RHR System will continue to perform acceptably. The steam condensing mode of RHR has been removed and thus, is not a factor. Therefore, the RHR System startup test is not required for EPU.

(24) The purpose of this test is to verify the ability of the Drywell Atmosphere Cooling System to maintain design conditions in the drywell during operating conditions and post scram conditions. The evaluation for EPU determined that the normal operating temperatures inside the Drywell will increase less than 2°F, thus the impact on the cooling system is negligible and no testing is required.

(25) The purpose of this test was to verify the performance of the cooling water systems for the reactor and turbine buildings, and other service water systems was adequate with the reactor at rated temperature. The impact of EPU operation on these systems was evaluated and found to be small. Modifications were made to the General Service Water (GSW) system to provide additional main generator stator cooling to maintain adequate design margins. Selected steady-state temperature data for specific GSW loads (e.g., main generator stator and isophase bus cooling) were obtained during EPU Phase 1 testing (see Note 31 below).

(26) The purposes of this test are to verify the proper operation of the Offgas System over its expected operating parameters, and to determine the performance of the activated carbon adsorbers. The impact of EPU on Offgas operation is well within the original system design specifications, thus no testing is required.

(27) This initial startup test demonstrated the mechanical integrity of the reactor system under conditions of flow-induced vibration by taking vibration measurements and correlating them to analytical models. It should be noted that the steam dryer was not required to be instrumented during this original testing. The impact of EPU on reactor internals vibration was evaluated at the uprated power and maximum core flow, using the results from the original vibration measurements and modeling, as well as evaluations from other BWRs. The maximum licensed core flow was not increased for EPU, and it was determined the reactor vessel internals design continued to comply with existing structural requirements. Thus, no specific vibration testing/monitoring of the vessel internal is required for EPU. See Note 29 below.

(28) Plant parameters, both Nuclear Steam Supply System (NSSS) and Balance of Plant (BOP) were recorded at various Test Conditions and evaluated for anomalous behavior prior to increasing power to the next Test Condition. This was not an original FSAR startup test, but was added to the EPU test program.

(29) The purpose of this test is to gather vibration measurements on the Main Steam and Feedwater system piping to evaluate the vibration stress effect due to the EPU and is similar to that performed during the original pre-startup testing. Testing was performed in Phase 1 and will continue in both Phases 2 and 3.

(30) The purpose of this test is to demonstrate an acceptable procedure for turbine CIV and TCV surveillance testing at a power level as high as possible without producing a reactor scram. While not an original FSAR Startup Test, this testing was added, as it is similar in nature to the Turbine Stop Valve Test (Test No. 33, above). The testing conducted in Phase 1 determined this power level to be 1500 MWt for CIV testing and 1600 MWt for TCV testing. Thus, further testing in EPU Phases **2** and 3 is not required.

(31) Sections of GSW system piping were replaced for EPU with piping of a larger size to increase the cooling to critical components, such as generator stator hydrogen cooling. This testing was to c o n f i i adequate cooling and to provide data for further system balancing (i.e., optimize cooling to critical components.) This was not an original FSAR Startup Test.

Table 2

Test No.	Test Title	EPU Test Conditions (% of OLTP – 1593 MWt)																	
		Phase 1														Phase 2		Phase 3	
		< 80	80	83	88	92	94	96.7	98.6	100.4	102	104.1	108	110.5	112.4	114.3	115.5	118	120
			1275	1320	1400	1460	1500	1540	1570	1600	1630	**1658**	1720	1760	**1790**	1820	**1840**	1880	**1912**
1	Chemical and Radiochemical Monitoring											1	1	1	1,2	2	2,3		
2	Radiation Monitoring											1	1	1	1,2	2	2,3	3	3
19	Core Performance											1	1	1	1,2	2	2,3	3	3
22	Pressure Regulator																		
	a) Data Collection	1[A]	1[(A)]	1[(A)]	1[(A)]	1[(A)]	1[(A)]	1[(A)]	1[(A)]	1[(A)]	1[(A)]	1[(A)]	1[(A)]	1[(A)]					
	b) Backup Controller	1[B]						1											
	c) Step Changes in Pressure	1[C]					1	1				1			1,2	2	2,3	3	3
23	Feedwater System																		
	a) Loss of FW Heating																		
	b) Single FW Pump Trip																		
	c) Step Changes in Level		1				1					1	1	1	1,2	2	2,3	3	3
	d) FW Flow Element Calibration											1	1	1	1	2	2	3	3

[A] Data collection began at –15% of rated reactor steamflow, in –2% increments in turbine steamflow up to –88% of rated turbine steamflow (–1776 MWt).
[B] Backup Controller test was also performed at –575 MWt (36%) and 1150 MWt (72%)
[C] Step Change test was also performed at –575 MWt (36%) and 1150 MWt (72%).

Test No.	Test Title	EPU Test Conditions (% of OLTP – 1593 MWt)																	
		Phase 1														Phase 2		Phase 3	
		< 80	80	83	88	92	94	96.7	98.6	100.4	102	104.1	108	110.5	112.4	114.3	115.5	118	120
			1275	1320	1400	1460	1500	1540	1570	1600	1630	**1658**	1720	1760	**1790**	1820	**1840**	1880	**1912**
24	Bypass Valves	1[D]		1	1	1	1	1	1	1	1								
25	Main Steam Isolation Valves																		
	b) Full MSIV Closure Test																		
	d) Single MSIV Closure Test	1[E]		1	1	1	1												
	e) Flow Element Calibration											1	1	1	1	2	2		
27	Turbine Stop and Control Valve Trips																		
33	Main Turbine Stop Valve Surveillance Test	1[F]		1	1	1	1	1	1	1									
	General Plant Data Collection											1	1	1	1,2	2	2,3	3	3
	Steam and Feedwater Piping Vibration Monitoring	1[G]	1									1	1		1,2	2	2,3	3	3

[D] Bypass Valve test was also performed at 1150MWt (72%) and 1240MWt (78%).
[E] Single MSIV Closure test was also performed at 1150MWt (72%) and 1240MWt (78%).
[F] Turbine Stop Valve test was also performed at 1150MWt (72%) and 1240MWt (78%).
[G] Vibration data was also collected at 829 MWt (50%).

Test No.	Test Title	EPU Test Conditions (% of OLTP – 1593MWt)																	
		Phase I														Phase 2		Phase 3	
		< 80	80	83	88	92	94	96.7	98.6	100.4	102	104.1	108	110.5	112.4	114.3	115.5	118	120
			1275	1320	1400	1460	1500	1540	1570	1600	1630	**1658**	1720	1760	**1790**	1820	**1840**	1880	**1912**
	Turbine Combined-Intermediate Valve (CIV) and Turbine Control Valve (TCV) Surveillance Testing	1[H]		1	1	1	1'	1	1	1	1								
	General Service Water (GSW) Heat Exchanger Performance Monitoring											1	1	1	1	2	2	3	3

[H] CIV and TCV tests were also performed at 1150MWt (72%) and 1240MWt (78%).
[1] Due to limits on the Main Steam Reheater drain capacity, CIV testing was halted at 1500MWt (94%)

B. Post Modification Testing Requirements for Functions Important to Safety Impacted by EPU-Related Plant Modifications

The following is a listing of those modifications, installed or currently planned, and their associated testing, to support the implementation of the Extended Power Uprate (EPU) at the Duane Arnold Energy Center (DAEC). The next phase of implementation (Phase 2) is currently planned for the Spring 2005 refueling outage (RFO-19).

With respect to the planned activities, as stated in our original license amendment application for EPU, these plans do not constitute commitments on our part to install them exactly as described or on the planned schedule. Further engineering evaluations may determine the need for additional modifications, or conversely, obviate the need for a currently-identified modification.

Additionally, this listing constitutes the major planned activities to support EPU implementation, other minor modifications or adjustments of existing equipment, which may be necessary, are not described herein.

Phase 1 (Operation up to 1790 MWt)

Completed during RFO17 (May 2001)

- Main Turbine
  - Replace High Pressure Turbine
  - Convert Turbine Control Valve operation to "partial arc"
  - Electro-Hydraulic Control (EHC) System tuning
- Main Generator
  - New Hydrogen Coolers- increased cooling capacity
    - New General Service Water (GSW) piping of increased capacity to support larger Hydrogen Coolers
- Main Transformer Cooling Upgrade – new, larger coolers
- Isophase Buss temperature monitoring – install new temperature sensors
- Grid Stability Enhancements
  - Install capacitor bank to increase plant volts-ampere reactive (VAR) capability (on-line modification)
- Feedwater (FW) Heaters
  - FW Heater level control settings to new heat balance
  - Trim on FW Heater level control valves to allow higher flow
  - Install bypass around FW Heaters 5A/B to maintain extraction steam flow at pre-EPU values (heater tube vibration concerns)
- Install LP Condenser tube stakes (vibration dampening)
- Instrumentation Upgrades
  - Neutron Monitoring
    - Recalibrate LPRMs/APRMs to new 100% power (Performed after receipt of EPU license amendment)
    - Install trip reference cards for Maximum Extended Load-Line Limit Analysis (MELLLA) operating domain on power/flow map
  - Main Steamline High Flow trip – new instruments and recalibrate to new setpoint (Performed after receipt of EPU license amendment)

- Turbine 1st Stage Pressure (Reactor Protection System & End-of-Cycle Recirculation Pump Trip bypass) – recalibrate to new setpoint, based upon operating characteristics of new High Pressure Turbine
- Standby Liquid Control system – revise alarm setpoint on tank volume
- Control Room Indications – re-span to new ranges
- Process Computer – reprogram to new instrument ranges

- Main Steam and Feedwater Piping Vibration Monitoring System – install sensors and data collection system
- Safety/Relief Valve discharge piping snubber upgrade (one S/RV line)
- Auxiliary Transformer tap setting change (March 2002 shutdown)

Completed during RFO18 (April 2003)

- Main Steam Reheater Cross-Around Relief Valve capacity increase (phased upgrade - one valve planned for each outage over 4 RFOs)
- Install HP Condenser tube stakes (vibration dampening)

All of the above Phase 1 modifications have been installed, tested (performance monitoring, calibrations and Startup Testing) and are currently in operation.

Phase 2 (Operation up to 1840 MWt - target)

To be installed during RFO19 (Spring 2005)

- Feedwater Capacity Increase
  - Condensate Pump and Motor upgrades – allow higher flowrate
    - Electrical Protective Relay setting adjustments
  - FW Heater Upgrades
    - 3A/B Replacement
    - 4A/B Replacement
    - 5A/B Replacements and remove bypass installed in RFO17

Planned Post Modification Testing:

- Condensate Pump and Motor Upgrades
  - Factory Acceptance Testing (full flow performance test with motor)
  - In-plant Testing
    - Pump and motor vibration baseline measurements
    - Performance monitoring
- FW Heater Upgrades
  - Factory Acceptance Testing (Eddy-current testing, weld non-destructive examinations)
  - In-plant Testing (In-service leak testing, thermal performance testing, FW Heater level controller adjustments)

Phase 3 (Operation up to 1912 MWt)

Tentative plans – no scheduled dates for implementation

- Install Supplemental FW pump – increase FW flow to rated conditions at 1912 MWt.
- Electrical System Upgrades
  - Increase rating on Isophase Buss to 20,000 amp rating
  - Rerate the Auxiliary Transformer, Startup Transformer, and Main Generator output breakers to higher electrical output
  - Install new Main Transformer for higher electrical output
  - Grid Stability – conduct studies for potential changes
  - Reset/Replace protective relays/breakers (as needed)
- Implement MELLLA – Plus (MELLLA+)
  - Revise thermal-hydraulic stability solution (convert to DSS-AB)
    - Install new APRM trip reference cards to new flow-biased trips
    - {Other software/hardware changes, as required after final NRC approval of LTR}

Proposed Post-Modification Testing:

- Supplemental FW pump
  - Performance Testing (flow vs discharge pressure, pump vibration baseline)
  - Startup Test #23b – Single FW pump trip (as deemed appropriate)
  - Startup Test #23c – Step Changes in Level
- Electrical System Upgrades
  - Performance Monitoring
- MELLLA+
  - Channel Functional Testing and Calibration of trip reference cards
  - {Other - dependent upon final implementation strategy}

Aggregate Impact of EPU Modifications on Dynamic Plant Response

As noted previously, all of the Phase 1 modifications have been installed and most have been in service for approximately 3 years, while the remainder have been in service for over one year. These modifications were tested as part of either their modification/construction acceptance testing (e.g., instrument calibrations) and/or during the Phase 1 Startup Test Program (e.g., Pressure Control System Step Changes). Because they are in service they are now part of routine plant equipment monitoring. In addition, during the ensuing plant operation since EPU implementation, several plant events have occurred, including manual scrams from intermediate power levels, as well as a dual main recirculation pump runback event. In none of these actual events has the plant's dynamic response been abnormal.

The Phase 2 modifications are primarily to address current Feedwater/Condensate System flow capacity limitations. The modifications will bring system capacity up to that needed to achieve a target power level of 1840 MWt. The final achievable power level will be determined during power ascension testing for Phase 2. Because the

modifications are focused on the Feedwater/Condensate System, testing will target this equipment (i.e., Startup Test #23c and d), in addition to the general testing required during power ascension (e.g., Startup Tests #1 and 2). As noted in Table 1, footnote #10, alternatives to the Loss-of-Feedwater Heating test will be conducted. These modifications will not significantly change the overall plant dynamic response to the anticipated initiating events described in the UFSAR.

The proposed Phase 3 modifications are primarily electrical in nature that will allow the plant to reach its design electrical output capability at the licensed power level. These modifications will be tested by performance monitoring. We do not anticipate that these modifications will result in a change in the plant's dynamic response to any anticipated operational occurrence, as they are intended to ensure adequate margins to equipment ratings and protective trip relay settings. When the Supplemental Feedwater pump is installed to bring the system capacity up to that needed for 1912 MWt, a combination of component testing (pump flow vs discharge pressure) and integrated plant testing (Startup Test #23b) will be considered to assure that the plant dynamic response is not adversely affected. Adoption of the extension of the power/flow map to include the Maximum Extended Load-Line Limit Analysis – Plus (MELLLA+) domain will require revision of the current strategy for detection and suppression of core thermal-hydraulic instabilities. The DAEC currently utilizes the so-called Option I-D solution. Adoption of MELLLA+ will require conversion to the so-called DSS-AB solution, which is currently under NRC review. Vermont Yankee is the lead plant application for Option I-D conversions. Final modifications and testing are dependent upon the NRC review and approval of that application.

C. Use of Evaluation To Justify Elimination of Power-Ascension Tests

This information was previously supplied, in the SRP format, in our original application.

Subsequent to that original application, NMC became aware of a Staff Request for Additional Information (RAI) on the Vermont Yankee EPU submittal, which is germane to our request to eliminate Large Transient Testing. NMC provides the following responses to those questions for the DAEC.

NRC RAI Question:

Discuss why LTT [Large Transient Testing] is not considered necessary in light of recent industry experience relative to steam dryer failures. Include in your response:

(a) how operation at EPU conditions may be likely to cause high-cycle fatigue in safety-related plant components (e.g., due to high steam line flow rates);

(b) how lessons-learned from the April 16, 2003, inadvertent opening of a power operated relief valve at QC2 [Quad Cities Unit 2], and its role in the second steam dryer failure, may be affected by plant operation at EPU conditions;

(c) the possibility that performing LTT may identify undetected latent flaws in plant components and equipment normally subjected to pre-EPU conditions; and,

(d) how information contained in GE Service Information Letter (SIL) No. 644 and NRC Information Notice 2002-26, were considered in the licensee's decision not to perform LTT.

NMC Responses:

a) The potential for higher steam flow rates due to EPU to cause high cycle fatigue in safety-related components was identified in the GE topical reports for evaluating the effects of EPU (i.e., ELTR-1 and 2). Based upon the GE recommendations in the ELTRs, NMC has installed vibration monitoring sensors and data collection equipment at the DAEC on both the main steam piping and feedwater piping, where the potential for increases in flow-induced vibration was deemed to be the highest. We have taken vibration data up to our current power level (112.4% of Originally Licensed Thermal Power (OLTP)) and most monitored locations showed little, if any increase in vibration above that observed at the previous licensed power level. Only one location on the main steam piping has vibration that exceeds the "negligible" threshold and an engineering evaluation concluded that the resulting stress effect will remain well within the acceptance criteria as power is increased up to the full EPU level.

The specific Large Transient Tests (LTTs) under discussion are both steam supply shutoff events that lead to reactor vessel pressurization, which in turn lead to the opening of the S/RVs. However, the transients do not result in increased steam flows that would drive flow-induced vibrations above the levels seen during steady-state operation. In addition, these transients are short in duration (minutes), not nearly long enough to induce the type of high cycle fatigue that has taken months to occur in the industry.

Consequently, NMC does not believe that performing the specific LTTs, per the license condition, would yield any new information about these recent industry events or their causes.

b) The root cause of the inadvertent opening of the relief valve at QC2 was found to be steam cutting on the pilot valve seat, which allowed the pressure above the main disk to become lower than steamline pressure, forcing open the main valve (Reference NRC Special Inspection Report 50-265103-06). The root cause of this failure is not directly attributable to EPU operation. One of the "lessons learned" from the QC2 event was to carefully monitor relief valve tailpipe temperature indications for signs of seat leakage, using the guidelines of GE SIL 196, Supplement 4.

In April of 2004, the DAEC shutdown to repair an S/RV with evidence of seat leakage, as indicated by increased tailpipe temperature. NMC had been trending the intermittent tailpipe temperature increases for several months. The DAEC action plan had included reviews of the QC2 event and the GE SIL. The preliminary root cause of the leakage was S/RV pilot valve leakage, most likely due to debris contamination internal to the valve. NMC has no evidence that this S/RV problem was due to flow-induced vibration. The final root cause is due to be completed later this summer.

A review of the licensee evaluation of the second QC2 dryer failure indicates that the inadvertent opening of the relief valve most likely did not initiate the cracking in the

dryer, but may have exacerbated it with the induced pressure loading and accelerated the cracking to become through wall [ADAMS # ML0323905380].

Based upon NMC's most-recent dryer inspection (see Response to Question d below), NMC does not believe that the DAEC dryer has cracking of the level of significance that has led to dryer failures at the other plants.

c) The LTT under discussion are original plant startup tests that have a well-defined scope and acceptance criteria, per the original General Electric design specification.

Specifically, for the MSIV closure test:

Test No. 25 Main Steam Isolation Valves

The major objectives of this test are to:

- Functionally check the MSIVs for proper operation at selected power levels.
- Determine reactor transient behavior during and following simultaneous full closure of all MSIVs and following closure of one MSIV.
- Determine MSIV closure times.
- Determine the maximum power level at which a single valve closure can be made without scram.
- Confirm the acceptable calibration of the main steam flow elements at EPU conditions (added requirement based on previous plant power uprate experiences).

The above testing is either required by Technical Specifications (TS), (MSIV functional test, closure time verification, and flow element calibration) or is a one-time test (Single and Full MSIV closure tests). The Single MSIV testing to determine the maximum power level for TS on-line surveillance testing was performed during Phase 1 testing and will not be repeated again in Phases 2 or 3. Only the Full MSIV Closure Test has not been performed for EPU.

Test Number 25B - Full MSIV Isolation Test

Purpose - The purpose of this test is to determine reactor transient behavior during and following simultaneous full closure of all MSIVs.

Description - Simultaneously fully close all the MSIVs at approximately 110% (+0%/-5%) of previously tested power level while monitoring reactor transient behavior. Correct performance of Reactor Core Isolation Cooling (RCIC) and Safety/Relief Valves will be demonstrated. Reactor process variables will be monitored to determine transient behavior of the reactor system during and following the MSL isolation.

Acceptance Criteria[J]:

Level 1 - Reactor pressure shall be maintained below 1240 psig, the setpoint of the first Spring Safety Valve (SSV), during the transient following closure of all MSIVs.

Level 2 - The maximum reactor pressure should be less than 1200 psig, 40 psi below the first SSV setpoint, during the transient following closure of all MSIVs. This pressure margin should prevent SSV weeping.

Similarly for the Generator Load Reject Test:

Test No. 27 – Turbine Stop and Control Valve Trips

The purpose of these tests are to demonstrate the response of the reactor and its control systems to protective trips of the turbine (i.e., turbine trips) and main generator (i.e., generator load rejects). Based upon transient analyses for EPU, the plant response to the turbine trip is similar to that of the generator load rejection event. Thus, it is not necessary to perform the turbine trip test for EPU.

Test Number 27B - Generator Load Reiect

Purpose - The purpose of this test is to demonstrate the response of the reactor and turbine control systems to a protective trip of the generator at high power (at approximately 115% (+0%/-5%) of the previously-tested power level).

Description - The main generator breaker will be tripped in such a way that a load imbalance occurs. Several reactor and turbine operating parameters will be monitored to evaluate the response of the turbine bypass, turbine control and stop valves, S/RVs, reactor protection system (RPS), and the effect of recirculation pump overspeed, if any, during the test. Additionally, the peak values and change rates of reactor steam dome pressure and heat flux will be determined. The transient response to a generator load rejection at high power will be demonstrated.

Acceptance Criteria:

Level 1

a) Reactor pressure shall be maintained below 1240 psig, the setpoint of the first SSV, during the transient following the fast closure of the control valves.

[J] Test criteria for each test have up to two levels of importance. The criteria associated with plant safety are classified as Level 1. The criteria associated with design expectations are classified as Level 2.

b) Reactor thermal power, as indicated by the simulated heat flux, must not significantly exceed that analyzed by the EPU Transient Analyses (non-LOCA) for the Generator Load Rejection event.
c) The turbine control valves must begin to close before the stop valves during the control valve trip.
d) Feedwater settings must prevent flooding of the main steam lines following this transient.

Level 2

a) The maximum reactor pressure should be less than 1200 psig, 40 psi below the first SSV setting, during the transient following fast closure of the turbine stop and control valves. This pressure margin should prevent SSV weeping.
b) The measurement of simulated heat flux must not be greater than that analyzed by the EPU Transient Analyses (non-LOCA) for the Generator Load Rejection event.
c) The trip scram function for higher power levels must meet RPS specifications. The pressure regulator and feedwater controls must regain control before a low pressure reactor isolation or high level trip of feedwater pumps occurs.
d) Feedwater control adjustments shall prevent low level initiation of the HPCI system and main steam isolation as long as feedwater flow remains available.

If required to perform the above tests, NMC's test plans will strictly conform to these requirements. While the Control Room Operators will do general observations of overall plant behavior, only those plant variables and equipment performance directly tied to a Level 1 or Level 2 acceptance criteria will be monitored and recorded. Any additional component or variable monitoring would be outside the scope of these specific tests.

The flow-induced vibration failures of components in the main steam and feedwater systems (relief valves, small piping, probes, etc.) seen in the industry were caused by high cycle fatigue during normal operation. The short transient loads associated with these LTTs would not identify undetected latent flaws in components subject to fatigue unless the component was already on the verge of failure. Therefore, these LTTs are not believed to provide any additional significant information with respect to long-term flow-induced vibration and fatigue issues.

Thus, the likelihood that performing these specific LTTs would "identify undetected latent flaws in plant components and equipment normally subjected to pre-EPU conditions" is deemed to be highly unlikely.

d) As stated previously, NMC inspected the DAEC steam dryer during RFO18 (Spring 2003), as recommended by GE SILs 433,474, and 644, subsequent to 16 months of operation above the previous licensed power level. In addition to VT-3 inspection of the steam dryer accessible surfaces, external VT-1 inspections were performed for several areas (e.g., dryer bank end plates and dryer bank tie bars). These VT-1 inspections by NMC were proactive because the original SIL 644 inspection recommendation only applied to BWR/3 steam dryers. These inspections did not find any major problems, only minor cracking, such as in the drain channels, which is

consistent with BWR operating experience prior to EPU operation. The likely cause of the DAEC dryer cracking is Intergranular Stress Corrosion Cracking (IGSCC), which is not power level dependent. A Justification for Continued Operation (JCO) was prepared that concluded plant startup and operation with the existing dryer cracking was acceptable for the upcoming (i.e., current) operating cycle. The DAEC dryer will be inspected during the next refuel outage, currently scheduled for Spring 2005.

NMC has considered a couple of additional points regarding the steam dryer cracking problems seen in the industry in making its decision to not perform the LTTs.

First, the DAEC steam dryer is of the BWR/4 design, i.e., is a slanted hood design versus the square hood design in the BWR/3 that has seen the significant cracking. The design of the BWR/4 dryer is considered to be more robust and less susceptible to cracking and failure than the BWR/3 design (GE SIL-644, Suppl).

Second, it has been acknowledged that the parameter of interest is steam velocity, not steam flowrate per se (IN 2002-26, Supp. 2). Comparing the DAEC with the BWR/3 that has exhibited the steam dryer integrity problems, shows that the steam velocity of the DAEC at full uprated conditions is well below that of the BWR/3 in question. The DAEC has the same size main steam piping (20 inch ID) as the BWR/3. However, the DAEC rated steam flowrate is only 71% of that at the BWR/3 at rated conditions (8.35 Mlbm/hr for DAEC and 11.71 Mlbm/hr for the BWR/3). This lower steam velocity would suggest that the DAEC is much less susceptible to the flow-induced cracking seen at the BWR/3, which is consistent with our operating experience to date.

NMC continues to monitor dryer performance on-line, consistent with the recommendations in GE SIL-644, and has yet to observe any moisture carryover (or other parameter changes) that would suggest the types of problems documented in Information Notice 2002-26. NMC actively participates in the BWR Owners' Group (BWROG) EPU and Steam Dryer Committees and is staying abreast of new information, as it becomes available. NMC will evaluate any new recommendations from NRC, GE or the BWROG for applicability to the DAEC and incorporate them into our existing inspection or monitoring programs, as appropriate.

Again, the LTTs required by the license condition are not intended to identify steam dryer defects or other flow-induced vibration-caused equipment problems that have been observed at other BWRs operating at EPU conditions. They have a specific purpose and acceptance criteria, as described in our Response to Question c) above. Consequently, NMC does not believe that performance of these specific LTTs would validate any of the current theories regarding the possible cause of the steam dryer cracking (e.g., vortex shedding) or other flow-induced high-cycle fatigue equipment problems seen in the industry.