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May 11, 2007

NG-07-0412
10 CFR 50.90

U.S. Nuclear Regulatory Commission
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DUANE ARNOLD ENERGY CENTER
DOCKET NO. 50-331
OPERATING LICENSE NO. DPR-49

Response to Request for Additional Information Regarding License Amendment Request (TSCR – 056A): "Elimination of License Condition 2.C.(2)(b) for Performance of Large Transient Tests for Extended Power Uprate (TAC NO. MD2835)

References: 1) 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.

2) K. Feintuch (USNRC) to G. Van Middlesworth (FPL Energy Duane Arnold), "Duane Arnold Energy Center - Request for Additional Information Related to the Amendment Request to Eliminate Requirement to Perform Generator Load Rejection Large Transient Testing (TAC NO. MD2835)," February 5, 2007.

In the Reference 1 letter, the Nuclear Management Company, LLC (NMC)[1] 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; specifically, the performance of a Generator Load Reject (GLR) test from essentially 100% rated thermal power.

In Reference 2, the Staff requested additional information related to that application. The Enclosure to this letter provides that requested information.

FPL Energy Duane Arnold continues to reiterate its belief that performing the large transient test 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

[1] By License Amendment 260, dated January 27, 2006, the facility operating license and operating authority for the Duane Arnold Energy Center was transferred to FPL Energy Duane Arnold, LLC.

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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.

There are no new or revised 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 May 11, 2007.

Gary Van Middlesworth
Site Vice President, Duane Arnold Energy Center
FPL Energy Duane Arnold, LLC

Enclosure

cc: Administrator, Region III, USNRC
Project Manager, DAEC, USNRC
Resident Inspector, DAEC, USNRC
D. McGhee (State of Iowa)

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION (RAI) RELATED TO THE AMENDMENT REQUEST TO ELIMINATE REQUIREMENT TO PERFORM GENERATOR LOAD REJECTION LARGE TRANSIENT TESTING DUANE ARNOLD ENERGY CENTER DOCKET NO. 50-331

By application dated February 27, 2004, as supplemented by letters dated August 9, 2004 and January 7, 2005, the Nuclear Management Company, LLC (NMC) requested an amendment for the Duane Arnold Energy Center (DAEC) that would remove license condition 2.C.(2)(b) from Facility Operating License No. DPR-49. Due to the nature of plant modifications for the DAEC extended power uprate (EPU) project, the NMC letter dated January 7, 2005, requested that the Nuclear Regulatory Commission (NRC) issue separate license amendments, one for each of the two large transient tests (LTTs) associated with the license condition. On March 17, 2005, the NRC issued Amendment No. 257 for the DAEC that modified license condition 2.C.(2)(b) to remove the requirement to perform the main steam isolation valve closure test.

To address the licensee's request for the removal of the remaining license condition that would require the performance of a generator load rejection test at 15 percent above the pre-EPU power level of 1658 MWt (i.e., 1906 MWt), the NRC staff requests additional information to complete its review.

1. RAI (1) Update Information Relative to Standard Review Plan (SRP) 14.2.1

SRP 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Program," provides general guidelines for reviewing proposed EPU power ascension testing programs. This review provides assurance that the proposed testing programs adequately demonstrate that plant structures, systems, and components important to safety that are affected by the proposed power uprate will perform satisfactorily in service at the proposed uprated power level.

Provide the following supplemental information, as necessary, to fully update the letters dated August 9, 2004, and January 7, 2005:

(a) Update the discussion of the comparison of the proposed EPU test program to the initial plant test program.

(b) Update the discussion of the modifications performed to achieve the EPU and the power ascension test considerations for plant modifications.

(c) Update the discussion on the justification for eliminating EPU power ascension test. The discussion should include:

(1) Relative power uprate operating experience;

(2) Introduction of new thermal-hydraulic phenomena or identified system interactions;
(3) Facility conformance to limitations associated with computer modeling and analytical methods;
(4) Plant operator familiarization with facility operation and trial use of operating and emergency operating procedures;
(5) Reductions in the margin of safety;
(6) Guidance contained in vendor topical reports; and
(7) Risk implications.

(d) Update the discussion related to evaluation of the adequacy of proposed testing plans.

FPL Energy Duane Arnold Response

1. (a) Subsequent to the August 9, 2004 and January 7, 2005 letters noted above, the DAEC EPU now consists of five (5) Phases, not three (3) as originally planned. New Phase III increased power from 1840 MWth to 1880 MWth and was executed in the Fall of 2006. As noted in Reference 1, no modifications were necessary to achieve this intermediate power level. The new Phase IV is targeted to achieve an average steady state power level of 1893 MWth. Although the Phase IV modifications could potentially allow operation above 1893 MWt, without expanding the power/flow operating map, using options such as Increased Core Flow Analysis (ICFA) and/or Maximum Extended Load Line Limit Analysis – Plus (MELLLA+), extended operation at these higher power levels is not practical. Because licensing such a power/flow map extension will take additional time, a new Phase V is added to target steady state operation up to the full licensed power level of 1912 MWth. Consequently, all previous references to Phase III (alternatively Phase 3) in the cited letters should now refer to Phase IV/V (alternatively Phase 4/5).

   In addition, the footnotes to Table 1 in the Enclosure of the August 9, 2004 letter are updated as follows.

   (12) One of the proposed modifications for Phase 4/5 is FW system improvements. Depending upon the scope of changes to the FW system, this testing may be performed as part of the post-modification test.

   (14) This test was exempted by License Amendment #257.

1. (b) The following is an updated listing of those modifications currently planned, and their associated testing, to support the final phases of the Extended Power Uprate implementation at the DAEC. The next phase of implementation (Phase 4) is currently planned for the Spring 2009 refueling outage (RFO-21). Phase V implementation is not currently planned.

   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 4 (Operation at 1893 MWt)

Tentative plans – Spring 2009 Refuel Outage (RFO-21)

- Feedwater (FW) System Improvements
    - Replace existing FW pump(s) (and motor(s), as needed)
- Electrical System Upgrades
    - Increase rating on Isophase Bus to 20,000 amp rating
    - Re-rate the Auxiliary 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)

Proposed Post-Modification Testing:

- FW System Improvements
    - Performance Testing (flow vs discharge pressure, pump vibration baseline, motor vibration baseline)
    - Startup Test #23b – Single FW pump trip (as deemed appropriate, depending upon scope of changes)
    - Startup Test #23c – Step Changes in Level
- Electrical System Upgrades
    - Performance Monitoring

Phase 5 (Operation up to 1912 MWt)

- Implement MELLLA – Plus (MELLLA+)
    - Revise thermal-hydraulic stability solution (convert to Detect and Suppress Solution – Confirmation Density (DSS-CD))
        - Install new APRM trip reference cards to new DSS-CD trips
        - {Other software/hardware changes, as required after final NRC approval of LTR}

Proposed Post-Modification Testing:

- MELLLA+
    - Channel Functional Testing and Calibration of trip reference cards
    - {Other - dependent upon final implementation strategy}

1. (c) the following is an update of the previous information supplied to justify the elimination of the Generator Load Reject (GLR) test at high power.

1. Previous Operating Experience

All of the original Phase I modifications have been installed and have been in service for 6 years, while the remainder (Phase 2) have been in service for 2 years (Note: Phase 3 did not involve any modifications and was based upon operating margins available after the Phase 2 modifications were installed). These modifications were tested as part of either their modification/construction acceptance testing (e.g., instrument calibrations) and/or during the Phase 1, 2, and 3 Startup Test Programs (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 and a turbine trip event from less than full power. In none of these actual events has the plant's dynamic response been abnormal, i.e., significantly different from that experienced at pre-EPU power levels.

The DAEC has experienced the GLR transient at the previous licensed power level (1658 MWt). No abnormalities or deviations from predicted behavior were observed. No modifications have been performed as part of EPU implementation that would cause the DAEC to behave fundamentally different from previous operating experience. While the Turbine Control Valves were modified from "full arc" to "partial arc" admission (i.e., a change in the valve stroke characteristics) as part of EPU, the effect of this modification is to slow down the rate of pressure increase, i.e., the rate of steamflow cutoff is now less severe than prior to the EPU. In addition, early in plant life, the DAEC operated in "partial arc" mode and converted to "full arc" in the mid-80's. Thus, the DAEC has prior operating experience with the turbine valves in partial arc mode, including turbine/generator trip events, as detailed in our response to Question 3 below.

2. Introduction of New Thermal-Hydraulic Phenomena or Identified System Interactions

In the ensuing 6 years of operation since NRC approval of EPU at the DAEC, no new thermal-hydraulic phenomena or systems interactions have been identified. The flow-induced vibration failures of components in the main steam and feedwater systems (relief valves, small piping, probes, etc.) seen in the industry, including DAEC as described in Reference 1, were caused by high cycle fatigue during normal operation. The short transient loads associated with the GLR test would not identify undetected latent flaws in components subject to fatigue unless the component was already on the verge of failure. Therefore, this test would not provide any additional significant information with respect to long-term flow-induced vibration and fatigue issues.

3. Facility Conformance to Limitations Associated with Analytical Analysis Methods

No new limitations on these methods were imposed by the Staff as a result of EPU implementation at the DAEC.

4. Plant Staff Familiarization with Facility Operation and Trial Use of Operating and Emergency Operating Procedures

The plant staff has operated the DAEC for 6 years at uprated conditions, including experiencing operational transients and three Phases of EPU Startup Testing. The licensed operators have been through many cycles of re-qualification training on the plant-specific simulator, including training exercises with the Emergency Operating Procedures. FPL Energy Duane Arnold firmly believes that the DAEC staff is thoroughly familiar with plant operations at EPU conditions.

5. Margin Reduction in Safety Analysis Results for Anticipated Operational Occurrences

One of the benefits of a "no-pressure increase EPU" is that the severity of pressurization transients is not significantly impacted by the increased power level/steamflow. For example, the calculated increase in peak pressure from pre-EPU conditions to EPU from a GLR transient, with failure of the turbine bypass valves (the bounding case), was less than 1%. Thus, there is not a significant reduction in safety margin from these bounding transients due to EPU.

6. Guidance Contained in Vendor Topical Reports

General Electric (GE) has updated their original vendor topical report for EPU (i.e., the ELTR), for constant pressure power uprates (CPPU) (Reference 2). The new topical report no longer specifies the requirement for performing this large transient test as part of power ascension testing. While the DAEC EPU was licensed to the ELTR, it is, in this regard, a CPPU nonetheless. Thus, this specific aspect of the GE CPPU topical report is applicable to the DAEC.

7. Risk Implications

While this application is not "risk-informed," FPL Energy Duane Arnold continues to believe, on a qualitative basis, that the perceived benefits from performing this test are negligible, when assessed against the risks of subjecting the plant to an otherwise unnecessary challenge.

1. (d) Conclusion

As described in detail in Reference 1, FPL Energy Duane Arnold has performed the power ascension testing program for EPU up to the current steady state operating power level of 1880 MWt (an increase in power of 13.4% from the previous licensed power level of 1658 MWt.) As noted in that report, while minor equipment problems were encountered during the testing, the Expert Panel concluded that the plant exhibited acceptable operation at 1880 MWt and recommended steady state operation at this level. No issues have subsequently been encountered that would invalidate our previous operating experience with the GLR large transient or warrant its being performed in the next phase of EPU implementation at DAEC.

Based upon all the above information, FPL Energy Duane Arnold does not believe that the risk of performing this large transient test is warranted in light of the limited value of the information that would be gained from its performance. In addition, granting this application is consistent with current regulatory practice, based upon the guidelines in the SRP chapter, and the precedence of the other licensees that have been granted EPU applications subsequent to the DAEC that did not require these tests as part of their power ascension testing program.

2. RAI (2) Main Generator Load Reject at Hatch Units at EPU Conditions

The Hatch generator load reject events, at EPU conditions, have been referenced several times in your justification for relief from performing the LTT. Provide the event data for these two events including the post-scram event evaluation and the applicable transient analysis for comparison of the actual plant response to the analytical results.

FPL Energy Duane Arnold Response

2. The following information was submitted by Southern Nuclear Operating Company in the cited Licensee Event Reports (LERs) and thus, FPL Energy Duane Arnold makes no claims as to the accuracy or completeness of this information. It should also be noted that this information has been cited numerous times by other

licensees in EPU applications as part of their justification for not performing this large transient test[1].

Excerpted from Hatch Unit 2 (Docket # 50-366) LER 99-005 (ML062640137)

The reactor protection system, an Engineered Safety Feature system, actuated on turbine control valve fast closure when the main turbine tripped following a trip of the main generator from a ground fault. Both reactor recirculation pumps tripped also on turbine control valve fast closure. Nine of eleven safety/relief valves opened on high vessel pressure; four of the valves continued to operate in the low-low set mode until pressure decreased to their respective closure setpoints.

Vessel pressure reached a maximum value of 1124 psig three seconds after receipt of the scram.

In this event, the main generator tripped from a ground fault in the isophase bus duct. The main turbine tripped as designed in response to the generator trip. The turbine trip actuated the reactor protection system and scrammed the reactor. All systems functioned as expected and per their design given the water level and pressure transients caused by the turbine trip and reactor scram. Vessel water level was maintained well above the top of the active fuel throughout the transient and indeed never decreased to the Level 3 actuation setpoint. Because the water level decrease was mild, no safety system, including emergency core cooling system, actuations on low water level were received nor were any required.

Excerpted from Hatch Unit 1 (Docket # 50-321) LER 01-002 (ML011490225)

Specifically, the reactor protection system actuated on turbine control valve fast closure when the main turbine tripped following the detection of a fault in unit auxiliary transformer lB. Group 2 and outboard Group 5 primary containment isolation valves closed and the RCIC and HPCI[2] systems initiated. Five of eleven safety/relief valves opened on high vessel pressure; four of the valves continued to operate in the low-low set mode until pressure decreased to their respective closure setpoints.

Vessel pressure reached a maximum value of 1127 psig after receipt of the scram.

In this event, the main turbine tripped when the unit auxiliary transformer lockout relay actuated on signals from the phase 2 and phase 3 differential current relays. The turbine trip actuated the reactor protection system and scrammed the reactor. All systems functioned as expected and per their design given the water level and pressure transients caused by the turbine trip and reactor scram. Vessel water level was maintained well above the top of the active fuel throughout the transient.

The applicable transient analysis is taken from the Hatch Unit 2 Final Safety Analysis Report (FSAR), Rev. 22.

[1] Examples: Dresden/Quad Cities (ML011450195), Brunswick (ML020020398), Vermont Yankee (ML033100141), Browns Ferry (ML0511702420) and Susquehana (ML0609603380).
[2] RCIC = Reactor Core Isolation Cooling; HPCI = High Pressure Coolant Injection

15.2.3.2 <u>Generator Load Rejection with Bypass (Event 6)</u>

The generator load rejection with bypass (LRBP) event is a nonlimiting AOO[3] and does not require reanalysis for reloads. However, due to a power increase of more than 10% of the original licensed power level, the LRBP event was required to be reanalyzed for power uprate at an RTP[4] of 2763 MWt. The power uprate analysis confirms that the LRBP event bounds the LRNBP[5] event.

The following discussion presents the results of the 2763 MWt power uprate analysis.

15.2.3.2.1 Identification of Causes

The causes of the LRBP event are the same as the causes of the LRNBP event (paragraph 15.2.3.1.1).

15.2.3.2.1.1 Starting Conditions and Assumptions.

The starting conditions and assumptions for the LRBP are the same as the starting conditions and assumptions for the LRNBP (paragraph 15.2.3.1.1.1), with one exception: the turbine bypass system is assumed to be operable.

15.2.3.2.1.2 Event Description.

The event description for the LRBP is the same as the event description for the LRNBP (paragraph 15.2.3.1.1.2), with the following exception: the turbine bypass valves are opened simultaneously with TCV fast closure when the load demand is stepped to zero.

15.2.3.2.2 Analysis of Effects and Consequences

15.2.3.2.2.1 Methods, Assumptions, and Conditions.

For the analysis for power uprate (2763 MWt), the analysis methods described in subsection 15.1.7 were used. The 1-D transient analysis model was used to simulate the event. The key analysis input parameters are identified in table 15.2-3.

15.2.3.2.2.2 Results and Consequences.

For the analysis for power uprate (2763 MWt), the LRBP event was analyzed at rated power and flow. The analysis results for power uprate are provided in table 15.2-1.

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[3] AOO = Abnormal Operating Occurrence
[4] RTP = Rated Thermal Power
[5] LRNBP = Load Reject with No Bypass

Excerpted from the table of power uprate transient results for Hatch:

Transient	Initial Power/Flow	Peak Neutron Flux (%*)	Peak Heat Flux (%*)	Peak Stm line Press (psig)	Peak Vessel Press (psig)	ΔCPR
LRBP	100P/100F	260	111	1249	1219	0.16

* The peak neutron flux and the peak heat flux are referenced to operating conditions at 2558 MWt.

For completeness, the following discussions from the Hatch UFSAR for the LRNBP event referenced above are included.

15.2.3.1 Generator Load Rejection with No Bypass (Event 5)

The LRNBP event was reanalyzed for power uprate at an RTP of 2763 MWt. The following discussion provides the results of the power uprate analysis.

15.2.3.1.1 Identification of Causes

Fast closure of the turbine control valves (TCVs) is initiated whenever electrical grid disturbances that result in significant loss of load on the generator occur. TCV rapid closure is required to prevent overspeed of the turbine-generator rotor. TCV fast closure causes a sudden reduction in steam flow, which results in an RPV pressure increase. TCV fast closure scrams the reactor.

15.2.3.1.1.1 Starting Conditions and Assumptions.

The following plant operating conditions and assumptions form the principal bases for the LRNBP analysis for power uprate:

A. The reactor and the turbine are initially operating at rated power with a dome pressure of 1035 psig when load rejection occurs.

B. The turbine electrohydraulic control (EHC) system power/load imbalance device detects load rejection before a measurable speed change takes place.

C. A scram and an EOC-RPT[6] are automatically initiated upon sensing TCV fast closure.

D. All plant control systems, with the exception of the turbine bypass system, continue normal operation.

[6] EOC-RPT = End-of-Cycle Recirculation Pump Trip

E. Auxiliary power is continuously supplied at rated frequency.

F. The reactor is operating in the manual flow control mode when load rejection occurs.

G. The turbine bypass valve system is failed in the closed position.

H. One SRV[7] is assumed to be out of service.

15.2.3.1.1.2 Event Description.

For the analysis of power uprate conditions, the complete loss of generator load produces the following sequence of events:

A. The power/load imbalance device steps the load reference signal to zero and closes the TCVs and intermediate (intercept) valves at the earliest possible time. The turbine accelerates at a maximum rate until the valves close at a maximum rate by means of fast acting, solenoid-operated, disc-dump valve action. The TCVs close at a full stroke rate of ~ 0.150 s.

B. A reactor scram and an EOC-RPT are initiated upon sensing TCV fast closure.

C. The pressure rises to the SRV setpoints. The SRVs open, discharging steam to the suppression pool, to limit the pressure increase.

3. RAI (3) Comparison Data Between DAEC And Hatch

In several of your documents for justification for removal of the generator load reject test from EPU testing, DAEC has been compared as similar to Hatch in several respects, including MARK I containment. Provide additional plant comparison data of both DAEC and Hatch including at least the following:

(a) Rated thermal power (MWt)
(b) Power density (MWt/assembly),
(c) Number of fuel assemblies,
(d) Steamline length (feet),
(e) SRV capacity (percent of steam flow),
(f) Turbine bypass capacity (percent of steam flow),
(g) Turbine closure time (seconds),
(h) Main steam valve closure time (seconds),
(i) Scram insertion time (seconds), and
(j) Turbine control valve stroke (full or partial).

[7] SRV = Safety/Relief Valve

FPL Energy Duane Arnold Response

3. The following information was submitted by Southern Nuclear Operating Company and thus, FPL Energy Duane Arnold makes no claims as to the accuracy or completeness of this information regarding Plant Hatch.

Item	Parameter	DAEC	Hatch
(a)	Rated thermal power (MWt)	1912	2804 *
(b)	Power density (MWt/assembly),	5.196	5.007
(c)	Number of fuel assemblies,	368	560
(d)	Steamline length (feet),	253.7	306.0 ft
(e)	SRV capacity (percent of steam flow),	59.57	79.38
(f)	Turbine bypass capacity (percent of steam flow),	20.6	21.2
(g)	Turbine closure time (seconds),	0.150	0.150
(h)	Main steam valve closure time (seconds),	3.0 (min) 5.0 (max)	3.0 (min) 5.0 (max)
(i)	Scram insertion time (seconds), and	3.875	3.875
(j)	Turbine control valve stroke (full or partial).	partial	partial

* Subsequent to their EPU, Hatch Unit 2 has also implemented a Thermal Power Optimization (TPO) Uprate of approximately 1.5% rated power. EPU power level – 2763 MWt.

4. RAI (4) Generator Load Reject Initial Startup Test Results And Other Generic License Renewal Events

Provide the generator load reject test results from the initial plant startup test program. Also, provide the event data for each generator load reject event experienced at DAEC during the life of the plant.

FPL Energy Duane Arnold Response

From (Ref. 3), the description of the original startup test is provided.

TEST CRITERIA

The criteria for each Startup Test is listed below. There are two types of criteria refered *(sic)* to as Level 1 and Level 2, which are defined as follows:

Level 1

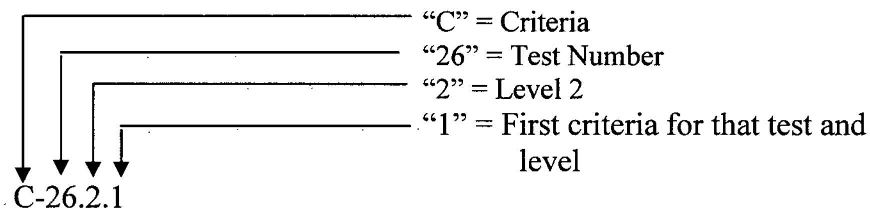
The values of process variables assigned in the design of the plant and equipment are included in this category. If a Level 1 criterion is not satisfied, the plant will be placed in a hold-condition which is satisfactory, until a resolution is made. Tests compatible with this hold-condition may be continued. Following resolution, applicable tests must be repeated to verify that the requirements of the Level 1 criterion are satisfied.

Level 2

The limits considered in this category are associated with expectations in regard to the performance of the system. If a Level 2 criterion is not satisfied, operating and testing plans would not necessarily be altered. Investigations of the measurements and of the analytical technique used for the predictions would be started.

For transient tests which may produce oscillatory response in process variables, the criterion is specified in terms of the decay ratio (defined as the ratio of successive maximum amplitude of the same polarity). The decay ratio must be less than 1.0 to meet the Level 1 criterion and must be less than 0.25 to meet Level 2 criterion.

The following designation is used in identifying each criteria:



TEST NUMBER 27 - TURBINE STOP AND CONTROL VALVE TRIPS

Level 1

C-27.1.1 Reactor pressure shall be maintained below 1240 psig, the setpoint of the first safety valve, during the transient following fast closure of the turbine stop and control valves.

C-27.1.2 Reactor thermal power, as indicated by the simulated heat flux readout, must not exceed the safety limit line.

C-27.1.3 The turbine control valves must begin to close before the stop valves during the control valve trip.

C-27.1.4 Feedwater system settings must prevent flooding of the steam line following these transients.

Level 2

C-27.2.1 The maximum reactor pressure should be less than 1200 psig, 40 psi below the first safety valve setpoint, during the transient following fast closure of the turbine stop and control valves. This pressure margin should prevent safety valve weeping.

C-27.2.2 The measurement of simulated heat flux must not be significantly greater than pre-analysis.

C-27.2.3 The pressure regulator and feedwater controls must regain control before a low pressure reactor isolation or high level trip of feedwater pumps occurs.

C-27.2.4 Feedwater control adjustments shall prevent low level initiation of the HPCI System and main steam isolation as long as feedwater flow remains available.

C-27.2.5 The trip at 25% power must not cause a scram. The trip scram function for higher power levels must meet RPS[8] specifications.

From (Ref. 3), the write-up for the original startup test results is provided. Rated power was 1593 MWt. Also pertinent, at that time a full Group 1 isolation (Closure of MSIVs) occurred at reactor low-low water level, as was experienced during the tests at 54% and 70% power. Today, the Group 1 isolation occurs on reactor low-low-low water level and would not be expected to occur during this event at any power level.

2.4.27 TURBINE STOP VALVE TRIP AND CONTROL VALVE TRIP

b) Turbine Stop Valve Trip

This test, also refered *(sic)* to as a Turbine Trip, was performed at 54, 70, and 95% power. The test was performed at the lower levels to verify correct plant response, prior to proceeding to the higher levels. At 95% power, the transient response was milder than predicted.

(C-27.1.1 and 27.2.1) The peak reactor pressure fell between 1076 and 1090 psig, well below the predicted value of 1138 psig, and far below the criteria of 1240 psig and 1200 psig. Whether or not any relief valves lifted cannot be concluded from the data.

(C-27.1.2 and 27.2.2) Neutron flux, which had been predicted in the worst case to double, actually showed no upward spike at all. The anticipatory scram, initiated by the Stop Valve, combined with control rods with a fast insertion time, are responsible for this.

(C-27.2.5) The RPS System did not initiate the scram, as flux did not reach any scram setpoint. [9]

[8] RPS = Reactor Protection System
[9] This should be a reference to the Neutron Monitoring System (NMS) as it is referring to the core flux levels. All Scrams are initiated within the RPS System.

(C-27.1.4 and 27.2.3 and 4) During both the 54% and 70% power turbine trips, a reactor isolation occured *(sic)*. This meant that proper level and pressure control could not be demonstrated for these tests. At 95% power no isolation occured *(sic)*, and correct pressure and level control was demonstrated.

The feedwater control system maintained water level adequately, and neither a high level FW pump trip nor flooding of the steam lines occured *(sic)*. Nor did a low level HPCI initiation or reactor isolation occur. In addition, the pressure control system maintained reactor pressure and prevented a low pressure isolation.

Since the above startup test, the following unplanned GLR events have occurred at the DAEC.

Event Date	Event Description	Report Number/Date
10/19/74	Generator trip on "neutral over-voltage" while closing auxiliary transformer disconnects after changing taps.	Semi-Annual Operating Report, 3/6/75
9/22/77	Generator lock out occurred during phase fault relay installation.	Monthly Operating Report, 10/7/77
5/9/82	Reactor scram caused by generator loss of field	Monthly Operating Report, 6/14/82
10/24/83	Reactor scram due to turbine control valve fast closure.	Monthly Operating Report, 11/15/83
8/26/89	Turbine Control Valve Fast Closure Trip Results in Reactor Scram While Performing Testing	LER 89-011, Rev. 1, 10/25/89
6/23/00	Turbine Trip and Reactor Scram Due to Main Generator Lockout	LER 00-002, Rev. 1, 5/25/01

Note: Prior to the DAEC implementation of the new Licensee Event Report (LER) rulemaking (10CFR 50.73), via License Amendment #105 in 1984, a reactor trip, in and of itself was not a uniquely reportable event and only mentioned in either annual, semi-annual or monthly operating summary reports, in accordance with DAEC Technical Specifications (TS). Hence, there are little recorded details for those GLR events prior to the 1989 event, without exhaustive searches of plant microfilm records, including in-plant strip chart recorders, which FPL Energy Duane Arnold believes is neither practical nor warranted.

However, by inference we can deduce that the above events were not abnormal in any significant way; else they would have been reported as a Reportable Occurrence, per DAEC TS requirements. The key is the following from the TS list for a Reportable Occurrence:

Performance of structures, systems, or components that require remedial action or corrective measures to prevent operation in a manner less conservative than assumed in the accident analyses in the safety analysis report or technical specification bases;

Because none of the pre-1984 events were reported as Reportable Occurrences, nor do any of the associated reports describe any necessary corrective actions as a result of the events, we can conclude that they did not meet the above criterion.

For the post-1984 events, we have LER summaries that provide more detailed descriptions of those GLR events.

Summary of the 1989 GLR Event

With the reactor at ~100% power (1655 MWth), during weekly "Power/Load Unbalance and Relay Circuits Test," a malfunction occurred in the test circuit causing the turbine control valves (TCV) to close. A full reactor trip occurred in response to the TCV fast closure signal. All control rods fully inserted. Consistent with the reactor trip on TCV fast closure, a dual recirculation pump trip also occurred. Reactor water level began to drop immediately due to void collapse, reaching a low value of approximately 160 inches above top of active fuel (TAF). Primary Containment Isolation System Groups II through V isolations occurred as designed when level reached 170 inches TAF decreasing. Reactor vessel pressure rose to a high of approximately 1120 psig. Three (3) safety/relief valves, two (2) of which are Low-Low Set valves, lifted a single time to reduce reactor pressure. Reactor Feed Pumps continued to operate and reactor water level recovered and began increasing within 30 to 60 seconds. As reactor level approached the 211 inches TAF trip point, the Operators manually tripped the Feed Pumps. Reactor pressure stabilized at approximately 960 psig via automatic operation of the turbine bypass valves.

The Reactor Protection System and all other plant safety systems operated appropriately during the trip event. Long term recovery was hampered by a fault in a non-essential electrical bus, unrelated to the initial event.

Summary of the 2000 GLR Event

With the reactor operating at 100% power (1658 MWth), DAEC experienced a generator lockout due to a trip of a Plant Unit Differential Current relay (378/U-03). This, in turn, caused a turbine trip, reactor scram, and an End-of-Cycle recirculation pump trip (EOC-RPT) of both reactor recirculation pumps. All control rods inserted upon receipt of the scram signal. Four (4) safety-relief valves lifted briefly to limit reactor pressure to a peak of approximately 1115 psig. Reactor vessel level reached a low of 164 inches above TAF during the initial void collapse. Primary containment isolation system valves (PCIS Groups II, III, and IV) also closed. Vessel level reached 211 inches TAF during level recovery, which caused the running 'B' reactor feedwater pump to trip on high level. The feedwater pump was restarted when the high level trip was reset.

Reactor vessel pressure and level were maintained within safe operating limits during the transient. The plant response was consistent with a turbine control valve fast closure event at rated power with turbine bypass capability (reference DAEC Updated Final Safety Analysis Report section 15.2.1.1)[10] including the brief lifting of safety-relief valves.

Conclusion:

DAEC's operating experience with GLR events is consistent with its analysis basis, both at original rated power (1593 MWth) and at "stretch" uprate power (1658 MWth). To date, during the three (3) phases of EPU testing, FPL Energy Duane Arnold has not observed any equipment performance issues that would cause us to expect a different result if a GLR event were to occur in the future at full EPU power (1912 MWth). Consequently, we continue to believe that performance of this test during Phase IV of EPU is not necessary to demonstrate safe continued operation at that power level.

[10] This UFSAR discussion is now found in Section 15.1.2.1.1.

References

1. G. Van Middlesworth (FPL Energy Duane Arnold) to USNRC, "Startup Test Report for Extended Power Uprate – Phase III, NG-06-0822, December 5, 2006.

2. Letter from J. F. Klapproth (GE Nuclear Energy), to U.S. Nuclear Regulatory Commission, "Submittal of Proprietary Licensing Topical Report NEDC-33004P, 'Constant Pressure Power Uprate,' Revision 3," February 6, 2003.

3. G. Hunt (IEL&P) to J. Keppler (USAEC), "D.A.E.C Startup Testing Report," December 24, 1974.