FAQ Log April 2017

FAQ No.	PI	Topic	Status	Plant/Co.	Point of Contact
16-04	MS	Maintenance on HPCI	Introduced Nov. 16 Discussed Jan. 12 Tentatively approved Mar. 23 Finalized April 13	Browns Ferry Unit 2	Eric Bates (TVA) Jamie Paul (TVA) Z. Hollcraft (NRC)
17-01	IE03	2016 Power Change	Introduced Jan. 12 Discussed Mar. 23	Grand Gulf 1	Jim Nadeau (ENT) Matt Young (NRC)
17-02	IE03	PVNGS 3 Power Change	Introduced Mar. 23 Discussed April 13	Palo Verde 3	George Andrews (APS) Charles Peabody (NRC)
17-03	MS	Baseline UA Critical Hours	Introduced April 13	Generic	Ken Heffner (Certrec) Zack Hollcraft (NRC)

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FAQ 16-04, Browns Ferry Safety System Functional Failure (Draft NRC Response)

Plant: Browns Ferry Nuclear Plant Unit 2
Date of Event: March 19, 2016
Submittal Date: November 8, 2016
Licensee Contact: Eric Bates/Jamie Paul Tel/email: 256-614-7180/256-729-2636
NRC Contact: __________________________ Tel/email: __________________

Performance Indicator:
MS05 Safety System Functional Failure (SSFF)

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective: When approved.

Question Section:

1. If a condition on a single train safety system that could have affected operability is created during maintenance while the equipment is out of service (OOS), such that the condition did not exist prior to the equipment being declared inoperable for maintenance, was discovered during post-maintenance testing (PMT) prior to surveillance (SR) testing, and accident conditions or operation cannot produce the observed degradation or equipment failure, should it count as a SSFF against the Reactor Oversight Process (ROP) Performance Indicator (PI)?

NEI 99-02 Guidance needing interpretation (include page and line citation):

1. Section 2.2, Safety System Function Failures: The guidance is silent regarding how to count a condition created while a system, structure, or component (SSC) was OOS for maintenance, which would have affected Operability, and was outside the scope of the planned maintenance. (page 30)

Event or circumstances requiring guidance interpretation:

Browns Ferry (BFN) entered Technical Specification (TS) Limiting Conditions for Operation (LCO) 3.5.1, Emergency Core Cooling Systems (ECCS) – Operating, Condition C on March 17, 2016. Condition C was entered due to High Pressure Coolant Injection (HPCI) inoperability for planned maintenance to repack the steam admission valve. The purpose of the HPCI system is to provide high pressure core cooling in the event of a Loss of Coolant Accident or in the event of a reactor isolation and failure of the Reactor Core Isolation Cooling (RCIC) system. Besides vessel injection, another safety function of the HPCI system is to maintain structural integrity regarding Primary and Secondary Containment pressure boundaries. On March 19, 2016, Operations personnel received a ground alarm during performance of valve diagnostic (MOVATS) testing on the Unit 2 HPCI Steam Admission Valve. The valve motor breaker was opened and the alarm cleared. The thermal overload relay was found tripped, resulted in the alarm, and was reset. Later on March 19, 2016, Operations attempted to stroke the valve from the Control Room for PMT using a hand switch and the valve failed to stroke due to a stuck contactor in the breaker.

Troubleshooting later revealed that the breaker thermal overloads had tripped and that a breaker contactor in the valve closing circuit had become hot enough to fuse its contacts together, which prevented the valve from opening. There was no vendor specific service life for these contacts. The cause of the equipment failure was determined to be due to excessive valve stroking during the earlier PMT on March 19, 2016. The cause was not reviewed by a vendor or an independent party. The corrective actions are to revise procedures to limit the number of strokes per hour for the applicable piece of equipment.

BFN received a NRC-identified Severity Level IV non-cited violation (NCV) of 10 CFR 50.72(b)(3)(v) and 10 CFR 50.73(a)(2)(v) for the licensee's failure to notify the NRC within 8 hours and submit a Licensee Event Report (LER) within 60 days of discovery of a condition that could have prevented the fulfillment of a safety function. Specifically, the licensee failed to notify the NRC that the HPCI system had been rendered inoperable due to an equipment failure. BFN submitted LER 50-260/2016-002-00, High Pressure Coolant Injection System Failure Due to Stuck Contactor, to the NRC in response to this NCV. BFN did not deny the violation but is advocating at the ROP TF that the condition should not count against the SSFF PI.

If licensee and NRC resident/region do not agree on the facts and circumstances explain:
BFN's NRC Senior Resident Inspector's perspective is the valve motor breaker failure was not part of the HPCI planned maintenance; therefore, the failure should count as a SSFF due to it not being part of the planned maintenance.

Potentially relevant existing FAQ numbers: There are no relevant FAQ numbers.

Response Section:
Proposed Resolution of FAQ:

The SSFF PI should only count failures that occur or potentially existed while there was an expectation that the SSC was Operable. Conditions affecting operability created during a maintenance OOS period that did not exist while the SSC was considered Operable and were identified and corrected while still in a maintenance state do not count for purposes of the SSFF PI. This exemption applies even if the condition created required repairs outside of the scope of planned maintenance and those repairs were required in order to return the equipment back to Operable status.

Examples of conditions that would not count as a SSFF under this resolution would include:

- An electrician transposes connecting leads to terminals in the actuation panel for a single train safety system causing a failed PMT. The condition was created during the maintenance activity and corrected while still in a maintenance state within the LCO window.

- During MOVATS testing, while a single train system is OOS for unrelated maintenance, a valve technician overheats the contactors causing them to stick. Replacement of the contactor is not part of the original scope of the planned maintenance activity but is identified and completed prior to SR Operability testing.
- A nearby instrument required to maintain operability of a single train safety system is damaged while breaking a bolt loose for an unrelated maintenance activity on the same system. This condition was not part of the preplanned maintenance. Correcting this condition requires an additional 4 hours of LCO time.

This proposed change applies similar treatment from MSPI failure guidance on page F-29 of NEI 99-02 to SSFF criteria.

> "Failures identified during post maintenance tests (PMT) are not counted unless the cause of the failure was independent of the maintenance performed" … "System or component failures introduced during the scope of work are not indicative of the reliability of the equipment, since they would not have occurred had the maintenance activity not been performed."

This failure was not counted by BFN as a MSPI failure and similarly should not count as a SSFF.

If appropriate, provide proposed rewording of guidance for inclusion in next revision:

Add the following on Page 30, section 2.2, starting after the period on line 7:

> If the following elements are met for a condition affecting Operability of a SSC, then the condition does not count for purposes of the SSFF PI:
> - Created during a maintenance OOS period and it did not exist while the SSC was considered Operable,
> - Not possible and/or reproducible during accident conditions, and
> - Identified and corrected while still in a maintenance state.
>
> This exemption applies even if the condition:
> - Required repairs outside of the scope of planned maintenance, and
> - Repairs were required in order to return the equipment back to Operable status.

PRA update required to implement this FAQ? No
MSPI Basis Document update required to implement this FAQ? No

NRC Response:

The staff reviewed the guidance found in NUREG 1022 Revision 3 to determine if additional exclusions of reported SSFFs should be considered for inclusion in NEI 99-02. The following was found:

> *reports are not required when systems are declared inoperable as part of a planned evolution for maintenance or surveillance testing when done in accordance with an approved procedure and the plant's TS (unless a condition is discovered that would have resulted in the system being declared inoperable).*

Section 3.2.8 of NUREG 1022 contains an example of this that further clarified the staff's intent:

> *For example, if the licensee removes part of a system from service to perform maintenance, and the Technical Specifications permit the resulting configuration, and the system or component is returned to service within the time limit specified in the Technical Specifications, the action need not be reported under this paragraph. However, if, while the train or component is out of service, the licensee identifies a condition that could have prevented the whole system from performing its intended function (e.g., the licensee finds a set of relays that is wired incorrectly), that condition must be reported.*

While this example is for a different reporting criteria, it demonstrates the interpretation of the previous excerpt from section 3.2.7. The intent is to clarify that if the licensee discovers a condition during the maintenance that existed prior to the maintenance, it is reportable. However if the licensee creates a new condition during the maintenance that would have rendered the system inoperable, that is not reportable as long as it is repaired prior to restoration of operability in accordance with Technical Specifications. The licensee proposed change to NEI 99-02 includes the following key attribute:

- Created during a maintenance OOS period and it did not exist while the SSC was considered Operable,

This proposed NEI 99-02 criteria is already covered by NUREG 1022, Rev. 3. As such, it is not required.

The staff does not concur with the recommended change to NEI 99-02. Since a SSFF report was made, barring meeting some separate criteria for excluding the SSFF PI found in the NEI 99-02 guidance, this SSFF should count towards the SSFF PI.

FAQ 17-02
Palo Verde Unit 3 Scram

Plant:	Palo Verde Nuclear Generating Station (PVNGS), Unit 3		
Date of Event:	09/19/2016		
Submittal Date:	03/23/2017		
Licensee Contact:	George Andrews	Tel/email:	623-393-2219
NRC Contact:	Charles Peabody	Tel/email:	623-393-3737

Performance Indicator:

IE03, Unplanned Power Changes per 7000 Critical Hours

Site-Specific FAQ (see Appendix D)? (__) Yes or (X) No

FAQ to become effective (X) when approved or (other date) ___________________

Question Section

Does an unplanned power change caused by a main turbine trip that ends in an elective manual scram and is counted as an unplanned scram also need to be counted as an unplanned power change?

On September 19, 2016, the Palo Verde Nuclear Generating Station (PVNGS) Unit 3 main turbine tripped from 100% power resulting in an automatic reactor power cutback, which reduced power greater than 20%. The reactor power cutback system automatically reduced unit power to approximately 50%, and operators subsequently initiated a power reduction to 12% power in accordance with the load rejection abnormal operating procedure. During the power reduction to 12%, PVNGS management elected to complete a reactor shutdown to troubleshoot and repair the cause of the turbine trip, which was not known. PVNGS counted this event as an unplanned scram because the staff was using an abnormal operating procedure to direct plant actions.

The resident inspector proposed that the main turbine trip event should be counted under both unplanned scram and unplanned power change performance indicators since the cause of the manual scram was discretionary and therefore different than the malfunction that caused the turbine trip-initiated unplanned power change.

PVNGS does not agree that both should be counted and proposes the event be counted solely as an unplanned scram since the reason (the component failure) for the discretionary plant shutdown/manual scram was the same as the turbine trip/unplanned power change.

NEI 99-02 Guidance needing interpretation (include page and line citation):

Section 2.1 of NEI 99-02, Revision 7 (page 11, lines 11-14) provides the following definition:

> "*Unplanned scram* means that the scram was not an intentional part of a planned evolution or test as directed by a normal operating or test procedure. This includes scrams that occurred during the execution of procedures or evolutions in which there was a high chance of a scram occurring but the scram was neither planned nor intended."

Section 2.1 of NEI 99-02, Revision 7 (page 17, lines 1-9) states:

> "Off-normal conditions that begin with one or more power reductions and end with an unplanned reactor trip are counted in the unplanned reactor scram indicator only. However, if the cause of the downpower(s) and the scram are different, an unplanned power change and an unplanned scram must both be counted. For example, an unplanned power reduction is made to take the turbine generator off line while remaining critical to repair a component. However, when the generator is taken off line, vacuum drops rapidly due to a separate problem and a scram occurs. In this case, both an unplanned power change and an unplanned scram would be counted. If an off-normal condition occurs above 20% power, and the plant is shut down by a planned reactor trip using normal operating procedures, only an unplanned power change is counted."

Event or circumstances requiring guidance interpretation:

The PVNGS design includes provisions that permit a 100% secondary load rejection without incurring an automatic reactor trip. A load rejection results in a reactor power cutback which automatically drops selected subgroups of regulating bank control rods into the reactor and initiates a steam bypass control system quick-open demand which opens all eight steam bypass control valves to modulate and reduce power to approximately 50%. The load rejection does not result in an automatic reactor trip as demonstrated by this event.

On September 19, 2016, the PVNGS Unit 3 main turbine tripped at 1434 with the unit operating at 100% power. A reactor power cutback occurred automatically, as designed. The control room staff began a power reduction to 12% using abnormal operating procedure 40AO-9ZZ08, "Load Rejection." Subsequently, based on an assessment of need for troubleshooting and repairs, potential reactivity management challenges at the end of core life, and the uncertainty of cause which might delay the return to full power, the control room staff and plant management made a decision to complete a plant shutdown and place the plant in Mode 3 by tripping the reactor using step 3.24 of 40AO-9ZZ08 from approximately 34% power at 1554 to facilitate repairs. No additional, unexpected plant conditions were occurring that would require a plant shutdown other than the loss of the main turbine. Refer to the Figure 1 for a graphical display of the power changes during the event.

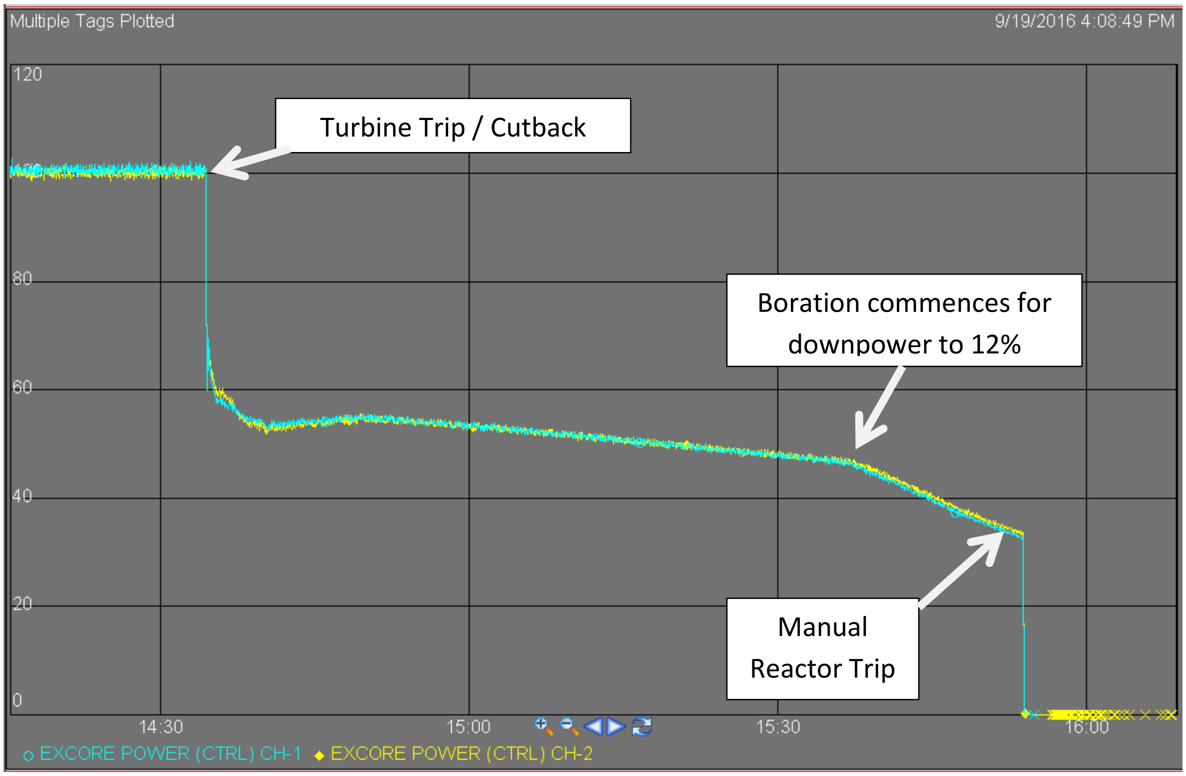

Figure 1: Reactor Power during the Event

Time	**Action**
1434	Main turbine trip from 100% power, reactor power cutback reduced power to approximately 53% - operators began briefing and development of game plan for power reduction in accordance with the procedure
1532	Commenced 1300 gallon boration at 31 gallons per minute to reduce power to 12% from approximately 45% power based on reactor engineering game plan
1554	Manual trip of the reactor at approximately 34% power to facilitate troubleshooting and repair of the cause of the main turbine trip

Tripping the reactor from 34% power was a permissible step of the abnormal operating procedure to establish plant conditions to perform troubleshooting and conduct repairs. The abnormal operating procedure provides the option of either plant shutdown or holding power at 12% while conducting repairs following a load rejection event. Stabilizing at 12% power at the end of core life presents challenges to the operators that are not warranted for an extended period of operation. However, the reactor protection system was not challenged and plant conditions did not require a reactor scram. The plant was not approaching reactor scram setpoints, and conditions were not likely to result in a scram. The control room staff was provided with a reactor engineering game plan that indicated the plant would be capable of reducing reactor power to 12% and stabilizing there. PVNGS management decided to shutdown the reactor and perform repairs in Mode 3 because the cause of the turbine trip was unknown and placing the plant in Mode 3 was preferred to sustaining 12% power operations for an extended period of time at the end of core life. The control room staff demonstrated conservative decision making with this course of action.

The NEI 99-02 example for a condition that would require counting an event both as an unplanned scram that occurred during an unplanned power change is given beginning on line 4 of page 17 of NEI 99-02. The intent of that discussion is to exemplify the disparate causes of the unplanned scram and unplanned power changes that required inclusion under both performance indicators. The unplanned scram was caused by the loss of condenser vacuum during an unplanned power changed to conduct unplanned turbine generator repairs. The scram was due to a separate degrading condition that, by itself, could have resulted in a reactor scram.

The NEI 99-02 example is dissimilar from the September 19th, 2016, Unit 3 main turbine trip. The manual scram to complete the shutdown of the plant in order to troubleshoot and repair the cause of the main turbine trip was directly related to the cause of the main turbine trip itself and not to some other unrelated failure or degrading condition in the plant. No additional, unexpected plant conditions were occurring that would require a plant shutdown. The ultimate causal linkage of the unplanned power change (turbine trip) ending in a manual scram to correct the cause of the initiating turbine trip should count only as an unplanned scram as described in the referenced NEI guidance.

PVNGS proposed resolution: The event would count only as an unplanned scram.

If licensee and NRC resident/region do not agree on the facts and circumstances, explain:

The resident inspectors generally agree with the event synopsis. However, there is an outstanding question of whether the manual trip was required by station procedures. The manual trip is permitted by the abnormal operating procedure, but it was not specifically directed. There is some question as to whether the plant could have been stabilized at 12% to take the turbine off line. Reactor Engineering was advising the operators to continue the down power rather than scram at the time the licensee's management made the decision to manually trip the reactor. If the plant had been stabilized at 12%, then a reactor trip would not have been required and there would be no issue of double counting; it would only register as an unplanned down power. PVNGS chose to manually trip the reactor, which was a conservative decision that was made at the discretion of the licensee, separate from and in no way directly caused by the spurious turbine trip or required by the procedure. Furthermore, had the station been unable to meet a Power Distribution Limit while continuing to down power that would have satisfied direct causation for inclusion as an unplanned scram only. But, as it stands, PVNGS ultimately made a separate decision to manually trip the reactor on less than 72 hours' notice. Therefore, it should be counted as a separate event under the current language of NEI 99-02, Revision 7.

Potentially relevant FAQs:

FAQ 156: An unplanned runback was terminated by a scram. Should it count as both unplanned scram and unplanned power change? The answer is no without any details.

FAQ 296: An unplanned power change was initiated to repair a stator cooling leak and condenser vacuum was lost requiring a reactor scram. Both were required to be counted because the cause of each was different. No discretionary decision making was involved. This is the example in NEI 99-02.

FAQ 319: Unplanned power change resulted from a loss of a station power transformer induced loss of condenser vacuum (loss of 3 of 6 circulating water pumps). When power was restored, high circulating screen DP resulted in a loss of the fourth circulating water pump and a manual trip of the reactor. No discretionary decision making was involved. The NRC appropriately determined that this event should be counted as both an unplanned power and an unplanned scram because two separate plant equipment failures occurred (loss of transformer and high DP).

FAQ 440: The licensee asked a question: Whether a planned shutdown to repair a reactor recirculation pump motor that faulted two days prior and caused an unplanned power change should result in an unplanned power change or an unplanned scram. The licensee manually tripped the reactor to repair the motor using the normal plant shutdown procedure. The licensee counted this as an unplanned power change and asked whether this should be an unplanned scram or unplanned power change. The NRC answered it should be counted as an unplanned scram because the shutdown from single loop condition from 55% is not its normal method of shutting down the reactor. The NRC did not answer the question whether the event should be counted as an unplanned power change as well.

This FAQ is similar to the Palo Verde event in that it contained an element of discretionary decision making (in the licensee's opinion). It is dissimilar in that the licensee argued the event should not have counted as an unplanned scram and PVNGS is asking whether the main turbine trip should be counted as an unplanned power change. The NRC response only addressed the unplanned scram question.

Response Section

Proposed Resolution of FAQs:

The main turbine trip that ended in a manual scram should count only as an unplanned scram.

If appropriate, provide proposed rewording of guidance for inclusion in next revision:

PRA update required to implement this FAQ? No

MSPI Basis Document update required to implement this FAQ? No

FAQ 17-03 Baseline Unavailability Critical Hours

Plant: Generic FAQ Based on ROPTF Whitepaper
Date of Event: Not Applicable
Submittal Date: April 11, 2017
Industry Contact: Ken Heffner Tel/email: 919-434-8337 ken.heffner@certrec.com
NRC Contact: Zack Hollcraft Tel/email: 301-415-3024/zachary.hollcraft@nrc.gov

Performance Indicator:
MS06, MS07, MS08, MS09, MS10

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective: When approved.

Question Section:

NEI 99-02 Guidance needing interpretation (include page and line citation):

Currently, NEI 99-02, page F-9, starting at line 36 says "The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004. (Plant-specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance.) These values may change if the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value should be adjusted to reflect the current maintenance practices, including low frequency maintenance evolutions."

Event or circumstances requiring guidance interpretation:

The guidance is silent on whether, if the planned unavailability baseline hours change, a licensee should retain the 2002 to 2004 critical hours as baseline, or revise the baseline critical hours to some other period of operation. As the intent of updating the baseline unavailability is to have the value be a reflection of the current maintenance philosophy, revising the baseline critical hours to those of the most recent three years of operation would be appropriate. By using the most recent three-year period, inappropriate inflation of the baseline unavailability is avoided If the plant had an extended outage during the 2002-2004 period (the lower denominator would inflate the allowance for planned unavailable during periods without the extended outage).

If licensee and NRC resident/region do not agree on the facts and circumstances explain:
N/A – this FAQ is based on an ROPTF whitepaper.

Potentially relevant existing FAQ numbers: There are no relevant FAQ numbers.

Response Section:
Proposed Resolution of FAQ:

Since the baseline unavailability value can change as maintenance philosophy changes, , it is appropriate to change the baseline critical hours to those from the most recent three years, rather than retain the critical hours from the original baseline period of 2002-2004.

Special Considerations:
If the plant had an extended outage (e.g., greater than six months) during the 2002-2004 time frame or the most recent three-year period, then baseline values could be erroneously inflated

If appropriate, provide proposed rewording of guidance for inclusion in next revision:

The following should be added to the current guidance on page F-9 of Revision 7, starting at line 42: "If the planned unavailability baseline value is adjusted, the critical hours should be changed to those of the most recent three-year period. If the most recent three-year period includes an extended shutdown (> 6 months), the most recent three-year period that does not include the extended shutdown should be used".

PRA update required to implement this FAQ? No
MSPI Basis Document update required to implement this FAQ? No

The Table below illustrates how the Planned UA is calculated. Note that original used unavailable hours from 2002 to 2004.

Baseline Planned UA Calculation EDG A

	1Q02	2Q02	3Q02	4Q02	1Q03	2Q03	3Q03	4Q03	1Q04	2Q04	3Q04	4Q04
Total ROP UA	9.95	0.00	0.00	10.50	0.00	21.88	21.64	7.62	0.00	1.18	35.80	5.27
(fault exposure UA)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(Unplanned UA)	0.00	0.00	0.00	0.00	0.00	0.00	16.97	0.00	0.00	0.00	16.58	0.00
On-line Excluded	0.00	0.00	0.00	0.00	0.00	110.78	0.00	0.00	0.00	0.00	0.00	0.00
Other Function UA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(Rx not critical UA)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(SSC Cascaded UA)	9.80	0.00	0.00	10.50	0.00	21.88	0.00	7.62	0.00	0.00	19.22	1.27
Total	0.15	0.00	0.00	0.00	0.00	110.78	4.67	0.00	0.00	1.18	0.00	4.00
Critical Hours	1942.88	1805.95	2208.00	2209.00	2115.10	2183.00	2208.00	1457.07	2184.00	2183.00	2208.00	2209.00

Total Planned UA (2002 to 2004) 120.78

Total Critical Hours (2002 to 2004) 24913.0

Baseline Planned UA **4.85E-03**

Generic Baseline Unplanned Unavailability **1.70E-03**

Currently, NEI 99-02, page F-9 says “The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004. (Plant-specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance.) These values may change if the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value should be adjusted to reflect the current maintenance practices, including low frequency maintenance evolutions.”

The guidance is silent on whether, if the planned unavailability baseline hours change, should a licensee use the 2002 to 2004 critical hours, or use the critical hours from the most recent three years. As the intent of updating the baseline unavailability is to have the value be a reflection of the current maintenance philosophy, using the most recent 3-year critical hours would be appropriate..

Special Considerations:

IF the plant had an extended outage (>1 year) either during the 2002-2004 time frame or the most recent 3-year period, the baseline values can be artificially inflated. Looking at the data above, if the plant had been in an extended outage for the entirety of 2002, there would have been neither unavailability or critical hours during that period. Though the maintenance philosophy would have been unchanged, justifying using the same baseline unavailability. The chart below shows the impact on the baseline unavailability:

Baseline Planned UA Calculation EDG A (Plant Shutdown during 2002)

	1Q02	2Q02	3Q02	4Q02	1Q03	2Q03	3Q03	4Q03	1Q04	2Q04	3Q04	4Q04
Total ROP UA	9.95	0.00	0.00	10.50	0.00	21.88	21.64	7.62	0.00	1.18	35.80	5.27
(fault exposure UA)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(Unplanned UA)	0.00	0.00	0.00	0.00	0.00	0.00	16.97	0.00	0.00	0.00	16.58	0.00
On-line Excluded	0.00	0.00	0.00	0.00	0.00	110.78	0.00	0.00	0.00	0.00	0.00	0.00
Other Function UA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(Rx not critical UA)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(SSC Cascaded UA)	9.80	0.00	0.00	10.50	0.00	21.88	0.00	7.62	0.00	0.00	19.22	1.27
Total	0.00	0.00	0.00	0.00	0.00	110.78	4.67	0.00	0.00	1.18	0.00	4.00
Critical Hours	0.00	0.00	0.00	2209.00	2115.10	2183.00	2208.00	1457.07	2184.00	2183.00	2208.00	2209.00

Total Planned UA (2002 to 2004)	120.63
Total Critical Hours (2002 to 2004)	18956.1
Baseline Planned UA	**6.36-03**
Generic Baseline Unplanned Unavailability	**1.70E-03**

Conclusion:

It is therefore recommended that the following be added to the current guidance "If the planned unavailability baseline value is adjusted, the critical hours should be changed to the most recent three years. If the most recent 3-year period includes an extended shutdown (>1 year), the most recent 3-year period that does not include the extended shutdown should be used".