Progress Energy

AUG 2 7 2007

SERIAL: HNP-07-114
10 CFR 54

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

Subject: SHEARON HARRIS NUCLEAR POWER PLANT, UNIT NO. 1
DOCKET NO. 50-400 / LICENSE NO. NPF-63

DOCUMENTATION OF CHANGES TO SEVERE ACCIDENT MITIGATION ANALYSIS FOR SHEARON HARRIS NUCLEAR POWER PLANT LICENSE RENEWAL APPLICATION (TAC NO. MD3611)

References:
1. Letter from Thomas J. Natale to the U. S. Nuclear Regulatory Commission (Serial: HNP-07-069), "Response to Request for Additional Information Regarding Severe Accident Mitigation Alternatives for Shearon Harris Nuclear Power Plant (TAC No. MD3611)," dated May 10, 2007
2. Letter from Samuel Hernandez to Robert J. Duncan II, "Requests for Additional Information Regarding Severe Accident Mitigation Alternatives for Shearon Harris Nuclear Power Plant (TAC No. MD3611)," dated March 27, 2007

Ladies and Gentlemen:

On November 14, 2006, Carolina Power & Light Company, now doing business as Progress Energy Carolinas (PEC), requested the renewal of the operating license for the Shearon Harris Nuclear Power Plant, Unit No. 1, also known as the Harris Nuclear Plant (HNP), to extend the term of its operating license an additional 20 years beyond the current expiration date.

The license renewal application contained an analysis of Severe Accident Mitigation Alternatives (SAMAs). Recently, errors have been discovered in the SECPOP computer code which is used in the SAMA analysis. Also, NRC reviewers have had two questions regarding the PEC response, dated May 10, 2007, to an NRC request for additional information (RAI) dated March 27, 2007. These items have been discussed with the NRC by telephone. This letter provides the responses to the questions regarding the response to the RAI, and a formal discussion of the impact of the error in the SECPOP code.

Please refer any questions regarding this submittal to Mr. Roger Stewart, Supervisor - License Renewal, at (843) 857-5375.

Progress Energy Carolinas, Inc.
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New Hill, NC 27562

A126
NRR

I declare, under penalty of perjury, that the foregoing is true and correct (Executed on AUG 2 7 2007).

Sincerely,

Thomas J. Natale
Manager - Support Services
Harris Nuclear Plant

TJN/jsk

Enclosure: Documentation of Additional Information Regarding Severe Accident Mitigation Alternatives for Shearon Harris Nuclear Power Plant

cc:

Mr. P. B. O'Bryan (NRC Senior Resident Inspector, HNP)
Ms. B. O. Hall (Section Chief, N.C. DENR)
Mr. M. L. Heath (NRC License Renewal Project Manager, HNP)
Dr. W. D. Travers (NRC Regional Administrator, Region II)
Ms. M. G. Vaaler (NRC Project Manager, HNP)

Documentation of Additional Information Regarding Severe Accident Mitigation Alternatives for Shearon Harris Nuclear Power Plant

Request No. 1

"Question 6(a)i requested a more detailed description of the modifications for several Phase II SAMAs. For SAMAs 2, 4 and 8 the provided description is not adequate to determine whether the estimated costs are reasonable.

- SAMA 2 changes 1D and 1E buses to be normally aligned to an off-site power source and appears to only be a procedure change. A typical value for a procedure change is $50k. What is the basis for $200k?
- SAMA 4 appears to include procedure changes that direct alignment of the Emergency Boration path to the CSIP suction header so that borated water would be available in conjunction with the non-borated water from the RWST. It also includes actions using fire hoses to add water to the RWST. Again, a typical procedure change is $50K. What is the basis for the $150K?
- SAMA 8, with an estimated cost of $300k, includes two elements: (1) aligning a direct feed from the "b" EDG to 1B3-SB and (2) proceduralizing the use of existing equipment to delay RCP seal damage long enough to align the "C" CSIP for seal injection. It does not appear that these changes include hardware changes or other activities beyond procedure changes. In addition, in response to RAI 6(e), it was stated that the estimated cost to proceduralize the use of existing equipment to delay RCP seal damage was $250k. As such, it appears that $50k is estimated with aligning a direct feed from the "b" EDG to 1B3-SB and that this is a procedure change only. What is the scope of changes that are associated with the $250k cost that supports a cost greater than 50k?"

Response No. 1

- For SAMA 2, the Electrical Load Analysis (calculation) would need to be reviewed and revised. The Distribution System Design documents would also need to be modified. The Startup Transformer (SUT) design would need to be reviewed for this change in its normal loading. This would be a plant modification that would also require transmission review/interface.
- For SAMA 4, the proposed method for providing make-up water to the Refueling Water Storage Tank (RWST) would need to be reviewed for make-up capability from the fire protection system (sizing hoses, and determining the supply and injection points). (Note: Once the certain security strategies are implemented, this portion may already be covered.) Additionally the ability of the Charging Safety Injection Pumps (CSIPs) to take suction from the Emergency Boration path and the RWST would need to be reviewed to determine if there are interlocks or other physical

complications that would need to be resolved and documentation updated, as appropriate.

- For SAMA 8, based on review of the AC Power Distribution Design, it appears that it may be desirable to stage a cable to jumper between the 480V "A" Switchgear and the 480V Switchgear 1B3-SB. This appears to be feasible, and would need to be proceduralized. The use of the Component Cooling Water (CCW) without Emergency Service Water (ESW) cooling for heat removal, would need to be analyzed to ensure the heat removal capability using the spent fuel pools as the heat sink. Additionally, the alignment of power, via temp cable from "A" bus to "B" bus, to "C" CSIP with "A" ESW cooling, from Normal Service Water (NSW), would need to be reviewed to ensure this is feasible, and there are no interlocks that would prevent this alignment.

Request No. 2

"Additional information in response to RAI 6(b) was provided for OPER-66, however the purpose and modification of this action remain unclear.

- It is stated that HNP has the ability to operate the turbine driven AFW pump after 125VDC battery depletion (Section E.6.1). It is also stated that 'Four hours after the last EDG failure, no batteries remain available causing all control room indication to be lost. Therefore, manual control of the TDAFWP is no longer credible four hours after station blackout occurs' (RAI 6b). Please clarify. Does OPER-66 require long-term DC for success? If not, how does the operator control steam generator level in the black?

- It is stated that "OPER-66 is credited in cutsets totaling about 3.5% of total CDF primarily in accident sequences with the loss of the 1B-SB Emergency Bus as the initiating event" and "OPER-66 is credited in Loss of Offsite Power sequences totaling about 0.4% of total CDF with battery power available for indication (RAI 6b). Why is OPER-66 not in more cutsets? What is suppressing it? Why is the RRW of OPER-66 small considering the 30% LOOP contribution?

- OPER-66 appears to have a four hour mission time (until battery depletion). As OPER-66 is an action to locally operate the TDAFWP after power failure, it appears that it is required to be aligned within the four hours and then continues after power failure. Is this correct?

  When OPER-66 is changed to 0.5 from 1.0 and the XOPER-66 value is appended, does the new Human Reliability Analysis (HRA) value change from 1.2E-2 to 6E-03?

What are the available cues, complexity to implement and available time that led to the 0.5 value? The response states that these factors are considered but does not discuss the factors."

Response No. 2

Further review of the OPER-66 definition and the Shearon Harris Nuclear Power Plant's (HNP's) capabilities indicates that portions of the Severe Accident Mitigation Analysis (SAMA) analysis and the SAMA Request for Additional Information (RAI) responses are based on a misinterpretation of the HNP Probabilistic Risk Analysis (PRA) model. Parts of the SAMA analysis were predicated on the belief that OPER-66 represented the probability that the operators would fail to locally operate the turbine driven auxiliary feedwater (TDAFW) pump after depletion of both battery divisions in a Station Black Out (SBO). OPER-66 actually represents the probability that the operators will fail to locally operate the TDAFW pump after failure/depletion of the "B" DC division when the "A" division is still available (non-SBO scenarios). The requirement that the "A" DC division be available for OPER-66 success is due to the fact that DC power is needed to support steam generator (SG) level instrumentation, which was the only means of measuring Steam Generator (SG) level at the time of the analysis. Without a means of measuring SG level, it is assumed that the SGs will either be overfilled or allowed to dry out and that secondary side cooling would fail. While HNP is in the process of implementing certain security related changes that could potentially provide a means of measuring SG level after a total loss of DC power, this change is not yet implemented and is not credited in model of record (MOR05), which was used to support the SAMA analysis.

Based on a review of the SAMA submittal and RAI responses, the following areas could have been impacted by the misinterpretation of OPER-66:

- SAMA identification process
- Quantification of SAMAs 1 and 8
- RAI Response 6c
- RAI Response 7b

Each of these areas have been revisited and corrected, as documented below.

<u>SAMA Identification Process</u>

The primary concern related to the misinterpretation of OPER-66 is that the important risk factors related to OPER-66 would not be addressed by any SAMA and that potentially cost effective means of addressing that risk would not be analyzed. In this case, SAMA 8 was developed to address another primary contributor to scenarios including OPER-66 and the majority of the OPER-66 risk was, coincidentally, addressed in the original SAMA analysis. This contributor is event %T12B (LOSS OF 6.9 KV EMERGENCY BUS 1B-SB), which causes loss of power to 1B3-SB transformer and the eventual loss of the "B" DC division while the "A" DC division remains available. SAMA 8 includes provisions to provide power to the 1B3-SB transformer directly from Emergency Diesel Generator (EDG) "B" when the 1B-SB bus has failed. Success of

SAMA 8 would provide control power for the TDAFW pump and OPER-66 would not be required.

Cutset analysis shows that %T12B accounts for 56 percent of the OPER-66 Core Damage Frequency (CDF) contribution and that the remaining 44 percent is not addressed by the SAMA 8 enhancements. For example, about 30 percent of the CDF contribution for OPER-66 is associated with scenarios in which Common Cause Failure (CCF) of all inverters necessitates local control of the TDAFW pump. The subsequent failure to align backup instrument power from the 120V AC supply results in loss of SG level instrumentation and failure of TDAFW makeup. In these cases, power is available to bus 1B3-SB, so the SAMA 8 enhancement would provide no benefit. If this portion of the CDF (8.85E-8/yr) were eliminated, the total HNP CDF would be reduced by a factor of 1.010, which is below the 1.014 RRW SAMA screening threshold used in the HNP SAMA analysis. This implies that any additional SAMAs to eliminate the portion of OPER-66 risk related to inverter CCF would not be cost effective. Even when the SECPOP code error corrections are accounted for, the Risk Reduction Worth (RRW) review threshold only decreases to 1.0135 and this conclusion is not changed. Note that OPER-66 is not included on the Level 2 importance list and a review of the Level 2 impact is not required.

SAMA 8 was shown to be cost effective, but mostly through benefits related to internal fires. Given that the majority of OPER-66 risk is addressed by a cost beneficial SAMA and that SAMAs developed to address the portion of OPER-66 risk not addressed by SAMA 8 would not be cost effective, the impact of the OPER-66 interpretation error is considered to be small.

Quantification of SAMAs 1 and 8

SAMA 1: Quantitatively, the misinterpretation of OPER-66 led to an optimistic representation of SAMA 1's capabilities. This is due to the fact that the quantification strategy accounted for SAMA 1's ability to reduce the risk of both SBO and loss of DC TDAFW control power scenarios without explicitly including the failure probability of aligning the 480V AC generator to the 1B3-SB bus for SBO cases.

For non-SBO cases in the SAMA submittal, the evaluation of the operator action to align the 480V AC generator to provide control power for the TDAFW pump was performed by plant personnel with the proper perspective of OPER-66's function. The Human Error Probability (HEP) was developed using the original OPER-66 HRA calculation as the template with the timing and execution steps modified to reflect alignment of the portable generator rather than local operation of the TDAFW pump. The result was that implementation of SAMA 1 was credited for allowing the operators to use the portable generator to power the 1B3-SB bus with the 480V AC generator to support continued control room operation of the TDAFW pump in non-SBO cases. Because the evaluation of the 480V AC generator alignment was performed using the correct interpretation of OPER-66, the resulting HEP is appropriate for the application and reflects the impact of implementing SAMA 1 for the non-SBO scenarios. This was manifested through the manipulation of OPER-66, which was intended to address SBO scenarios in the SAMA submittal analysis. One potential issue is that credit is taken for SAMA 1 in the "inverter failure" cases. As described above in the "SAMA Identification Process" discussion, the availability of power to 1B3-SB is not an issue for those cases and crediting SAMA 1 to mitigate inverter failures artificially inflates the averted cost-risk.

For the SBO cases, SAMA 1 success requires the operators to manually start the 480V AC generator and align it to the hydrostatic test pump to preserve Reactor Coolant Pump (RCP) seal cooling. This portion of the action is needed to prevent the development of a seal Loss-of-Coolant Accident (LOCA) that would exceed the makeup capabilities of the hydrostatic test pump and to ensure that there is a means of providing makeup for normal seal leakage. In addition to seal injection alignment, the operators would have to align the temporary feed cables from the 480V AC generator to the 1B3-SB bus to power the "B" battery chargers for successful SBO mitigation. This action is required to ensure that long term control/instrumentation power is available to support TDAFW operation. In the SAMA submittal, the OPER-66 flag, which addressed non-SBO scenarios, was incorrectly manipulated to account for this alignment error when it would have been more appropriate to include it in the lumped event "ALTSEAL". Failure to account for the 480V AC alignment error in "ALTSEAL" also artificially inflated the SAMA 1 averted cost-risk. The potential drawback to including the 480V AC generator alignment error in "ALTSEAL", however, is that a generator alignment failure would also fail SAMA 1 for non-SBO seal LOCA cases. Given that the OPER-66 evaluation HEP developed for aligning the 480V AC generator in the SAMA analysis yielded a failure probability of only 5.4E-03, "ALTSEAL" would increase by only 5 percent (to 1.05E-01 from 1.00E-01) if that HEP were directly used to represent 480V AC generator alignment failures in SBO cases. The actual HEP for 480V AC generator alignment in SBO cases would be similar to the non-SBO evaluation with the exception that the time available for the action would be increased and some performance shaping factors would change. Specifically, for SBO cases, the action's system window would be based on the time battery depletion (about 4 hours) rather than a procedurally driven cue to begin feed and bleed efforts in place of secondary side heat removal recovery, which plant personnel estimated would occur at about 75 minutes for non-SBO cases. While the increased available time would result in a reduction in the failure probability, increased stress (extreme stress is assumed to be applicable for the SBO cases rather than high stress) and more difficult working conditions would increase some components of the failure probability. While the net impact of these changes was estimated to be small, the SBO version of the HEP has been quantified for completeness. The result of the HRA for aligning the 480V AC generator in an SBO is 5.8E-3, which is very similar to the HEP of 5.4E-3 that was obtained for the non-SBO scenarios.

With respect to how the cutsets were manipulated to reflect the ability to align the portable 480V AC generator to bus 1B3-SB for non-SBO scenarios, consider the case in which there is only one HEP in the cutset. In the HNP model, the operator action flag for operating the TDAFW pump locally (event OPER-66) is included in the cutset based on fault tree quantification. The post processor then scans each cutset for HEP flags and applies an additional event that addresses any dependent operator actions so that the final value for all HEP contributions is the appropriate joint HEP (JHEP) value. These events are of the form "XOPER-**". For the example case with only one HEP, the "XOPER-**" event is assigned the value of the independent HEP. For the OPER-66 event, XOPER-66 is 1.20E-02. Given that the operator action to align the 480V AC generator would replace OPER-66 and that the HEP for 480V AC generator alignment was estimated to be about 5.4E-03, modifying the OPER-66 flag's value from 1.0 to 0.5 yields 6.0E-03 when it is combined with the XOPER-66 event. This approximates the impact of replacing OPER-66 with 480V AC generator alignment in the cutsets. OPER-66 could have been assigned the value of 0.45 (5.4E-03/1.2E-02=0.45), but the answer was rounded to 0.5 for simplicity. This approach yields an averted cost risk that is potentially greater than what would result from a re-evaluation of all JHEPs in which OPER-66 is replaced by portable generator alignment.

Since SAMA 1 was classified as "not cost beneficial" even when the 95th percentile PRA results were applied, reducing the credit taken for SAMA 1 to correct the OPER-66 misinterpretation error would have no impact on the SAMA analysis and a full re-quantification is not considered to be required to address this issue.

SAMA 8: The misinterpretation of the OPER-66 role in the loss of 6.9kV AC bus sequences for SAMA 8, coincidentally, had no effect on the quantification. In the SAMA submittal, it was assumed that OPER-66 represented local operation of the TDAFW pump after battery depletion at 4 hours using a local SG level monitoring method or a flow correlation for success. In actuality, OPER-66 represents the local operation of the TDAFW pump after battery depletion at 4 hours (loss of TDAFW control power) in conjunction with the use of SG level instrumentation that is powered from the available AC division. The submittal assumed that SAMA 8 would allow continued Main Control Room (MCR) operation of the TDAFW pump by providing both control and instrumentation power through the direct feed from EDG "B" to bus 1B3-SB. In actuality, SAMA 8 would allow continued MCR operation of the TDAFW pump by providing control power (instrumentation would already be available from the opposite division). For either interpretation of OPER-66, the OPER-66 flag would be modified in the same way to represent the enhancement.

The HEP that was developed for OPER-66 for SAMA 1 was also assumed to be applicable to SAMA 8. While there are differences in the details of how the cables are aligned to support DC power in SAMAs 1 and 8, the applications are similar. The SAMA 1 version of providing alternate power to bus 1B3-SB was based on providing a temporary feed directly from a portable 480V AC generator to bus 1B3-SB. For SAMA 8, a temporary feed was assumed to be installed between EDG "B" and transformer 1B3-SB. Because the differences in the alignments are small, the use of the SAMA 1 HEP in the SAMA 8 quantification is considered to be justified.

The OPER-66 misinterpretation had no impact on the alternate seal cooling portion of the SAMA 8 assessment. The potential impact on the internal fire portion of the quantification is discussed in the RAI 6c discussion below.

In summary, while the assumptions related to how SG level assessment was performed and when it was done were incorrect in the SAMA submittal, the differences between the incorrect assumptions and the way the plant is actually operated did not result in any differences in the way the SAMA should be modeled and no update of the SAMA 8 cost benefit analysis is required.

RAI Response 6c

The response to RAI 6c provided estimates of the averted cost-risks for SAMAs 1 and 8 using the standard method of applying a multiplier on the internal events results to account for the external events contributions rather than the expanded methods used in the SAMA submittal. As discussed above, the misinterpretation of OPER-66 did not have a meaningful impact on the internal events results; therefore, the response to RAI 6c would remain unchanged.

RAI Response 7b

The misinterpretation of OPER-66 had a significant impact on the response to RAI 7b. In that response, the impact of installing a portable generator was estimated by manipulating the OPER-66 flag, which, as described above, was intended to only address local TDAFW operation when instrumentation power is available. As a result, a revised quantification strategy is required to appropriately account for the benefit of installing the portable generator. With regard to the actual portable generator implementation strategy, at least two different approaches could be taken given that it is possible to operate the TDAFW pump without DC control power at HNP. One approach would be to use a smaller 120V AC generator to provide power to the level instrumentation and rely on local operation of the TDAFW pump to maintain SG level. A second approach would be to use a larger 480V AC generator to provide power to a 480V AC bus that would power the battery chargers. The latter approach would provide power for both level instrumentation and TDAFW control such that the TDAFW pump could be operated from the main control room. The assessment performed here assumes that the 480V AC generator is used to preclude the need to rely on potentially difficult local TDAFW operations.

As part of the quantification process, the MOR05 model was reviewed to determine the most appropriate method to quantify the benefit of portable generator enhancement. As part of this review, it was determined that the use of a flag to mark seal LOCA events in MOR05 resulted in the retention of non-minimal SBO cutsets. For each of the failure combinations resulting in a seal LOCA and core damage, there were related cutsets that included secondary side heat removal failures in place of the seal LOCA flag. Given that the seal LOCA condition would result in core damage independent of secondary side heat removal status, retention of the cutsets including secondary side heat removal failures overestimated the SBO contribution. Before an accurate assessment of the portable generator enhancement's benefit could be determined, it was necessary to remove these non-minimal cutsets from the baseline model. In order to do this, the flag events and offsite power recovery terms were set to "True" and the cutsets were minimized. This removed the cutsets that included the superfluous secondary side heat removal failures. After minimization, the flag events and offsite power recovery terms were restored to their original states so that the appropriate values could be calculated for the cutsets.

The process described above addresses the scenarios that are initiated by Loss of Offsite Power (LOOP) events; however, it does not address similar situations that exist for consequential LOOP/SBO cases due to differences in the cutset structures. Effort could be expended to eliminate the non-minimal consequential LOOP/SBO cutsets, but they are low contributors and do not impact the conclusions of the analysis. For this evaluation, the non-minimal consequential LOOP/SBO events have not been addressed.

The following table summarizes the steps of the correction process:

Steps Taken to Correct the Baseline MOR05 Cutsets

Steps	Description of Steps
1. Set the following events to "True": X-CNDSL X-OPR18RSL X-OPR12RSL X-OPR6 X-OPR6RSL X-OPR0 X-OPR0RSL	Setting the events to "True" removes them from consideration in the minimization process. These events include the seal LOCA flag (X-CNDSL) and the AC power recovery terms. The AC power recovery terms are included in the list because their assignment can be influenced by secondary side heat removal status and different AC power recovery terms can interfere with the minimization process.
2. "Subsume" the cutsets.	This is the Computer Aided Fault Tree Analysis (CAFTA) command to perform cutset minimization.
3. Remove the "True" designator from each of the following events: X-CNDSL X-OPR18RSL X-OPR12RSL X-OPR6 X-OPR6RSL X-OPR0 X-OPR0RSL	Removing the "True" designator allows the original and appropriate event values to be used in the CDF calculation for the cutset.

In addition to the changes identified above, the Level 3 results were updated to reflect the corrections of the two SECPOP errors. These corrections and the impact on the Level 3 results are documented separately. The results of the revised base case are presented below:

Revised HNP Baseline Results Summary

	CDF (/yr)	Dose-Risk	OECR
Base Results	8.99E-06	29.11	$51,822

A further breakdown of this information is provided below according to release category.

Revised HNP Baseline Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.91E-07	2.15E-08	8.13E-09	3.54E-08	4.37E-08	4.60E-08	1.62E-07	6.35E-09	1.75E-07	6.39E-07	3.93E-07	9.40E-07	**2.86E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.84	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.50	20.06	0.23	1.86	**29.11**
OECR$_{BASE}$	$8	$0	$2,385	$83	$34	$425	$7	$23	$1,047	$53	$9,100	$33,228	$187	$5,302	**$51,882**

These results were used to regenerate the base Modified Maximum Averted Cost Risk (MMACR):

Internal Events MACR Contribution	External Events MACR Contribution	Modified MACR
$1,886,000	$1,886,000	$3,772,000

From the revised baseline, the impact of providing the portable generator capability was modeled by assuming that the successful alignment and operation of a portable 480V AC generator would allow the operators to maintain the plant in a stable state for the 24 hour mission time for non-seal LOCA SBO cases. The non-seal LOCA cases were assumed to include those in which RCS cooldown was possible before loss of RCP seal cooling (EDG and EDG support system run failures). The cutset changes were performed through the use of an additional recovery file. The following table summarizes the logic that was included in that file:

Recovery File Logic for Crediting 480V AC Portable Generator

Recovery Logic	Description of Logic
`**RECOVERY** X-ALTDG0.1 X-OPR18RSL-F* X-OPR12RSL-F*`	These lines add the event "X-ALTDG" to any SBO cutsets that included the long term recoveries "X-OPR18RSL" or "X-OPR12RSL" given that there were no coincident failures of the Auxiliary Feedwater (AFW) system (which would only be TDAFW in an SBO).
`**RECOVERY** X-LBUSPDG 0.5 %T12B OPER-66`	This logic addresses the non-SBO cases that would benefit from the availability of the 480V generator's ability to provide control power for TDAFW (no local operation required). The event "X-LBUSPDG" is added to any cutset that includes the loss of the "B" emergency bus in conjuncition with the operator action OPER-66. The value of 0.5 is assigned to the event "X-LBUSPDG" in order to alter the total independent HEP for OPER-66 from 1.2E-02 to about 6.0E-03, as described above in the discussion of the quantification of SAMA 1.

The 0.1 failure probability used for "X-ALTDG" is based on estimates of the following contributors to blackout operation of the TDAFW pump:

- Failure to manually operate the SG Power Operated Relief Valves (PORVs) to control pressure (7.5E-02). The HNP HRA includes an evaluation of local SG PORV operation, but it does not appear to address SBO conditions. A multiplier of 5 on the base value of 1.5E-02 was used to obtain the contribution from this action for SBO conditions (5*1.5E-02=7.50E-02).
- Portable Generator alignment failure (5.80E-03) (as described in the SAMA 1 quantification subsection, above).
- Portable generator reliability (generic DG data): Run = 1.33E-02 (9hrs*1.48E-03/hr = 1.33E-02), Start = 6.28E-03. The required run time is assumed to be 9 hours as it is the average remaining mission time after onset of SBO conditions for the X-OPR12SL and X-OPR18SL cases. The more limiting case of 12 hours could be applied in place of the average, but because the actual time required for generator operation would have to account for "coping time" mechanisms such as time to battery depletion, SG boildown, and primary system boildown, 9 hours is considered to be reasonable. A more detailed examination of all the coping time contributions would likely show that a required run time of 9 hours is pessimistic for both cases.
- TDAFW reliability: Run = 7.41E-03 (9hrs*8.23E-04/hr=7.41E-03), start not required).

The total of 0.108 from the above contributors was truncated to 0.1 for this calculation. The following tables summarize the results of these changes.

Installation of a Portable 480V AC Generator Results Summary

	CDF (/yr)	Dose-Risk	OECR
Base Results	8.99E-06	29.11	$51,822
SAMA Results	8.59E-06	28.92	$51,350
Percent Change	4.4%	0.7%	1.0%

A further breakdown of this information is provided below according to release category.

Installation of a Portable 480V AC Generator: Results By Release Category

Release Category	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	3.22E-09	1.07E-10	3.91E-07	2.15E-08	8.13E-09	3.54E-08	4.37E-08	4 60E-08	1.62E-07	6.35E-09	1.75E-07	6.39E-07	3.93E-07	9.40E-07	**2.86E-06**
Freq. (/yr)$_{SAMA}$	3 15E-09	9.98E-11	3.65E-07	2.10E-08	7.90E-09	3.38E-08	3.85E-08	4.45E-08	1.62E-07	6.35E-09	1.75E-07	6.39E-07	3.79E-07	8.79E-07	**2.75E-06**
Dose-Risk$_{BASE}$	0.01	0.00	0.84	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.50	20.06	0.23	1.86	**29.11**
Dose-Risk$_{SAMA}$	0.01	0.00	0.78	0.03	0.02	0.12	0.02	0.04	0.36	0.02	5.50	20.06	0.22	1.74	**28.92**
OECR$_{BASE}$	$8	$0	$2,385	$83	$34	$425	$7	$23	$1,047	$53	$9,100	$33,228	$187	$5,302	**$51,882**
OECR$_{SAMA}$	$8	$0	$2,227	$81	$33	$406	$6	$22	$1,047	$53	$9,100	$33,228	$181	$4,958	**$51,350**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table assuming the lower bound cost of implementation for a plant enhancement that includes a hardware change.

Installation of a Portable 480V AC Generator: Net Value

Revised Base Case MMACR	SAMA MMACR	Averted Cost-Risk	Cost of Implementation	Net Value
$3,772,000	$3,724,112	$47,888	$100,000	-$52,112

The results of the cost benefit analysis show that installation of a portable 480V AC generator would not be cost effective even when the lower bound implementation cost of $100,000 is used.

If the 95th percentile PRA results are used, the averted cost-risk increases by a factor of 1.5 to $71,832, but the net value remains negative at -$28,168 and the enhancement is still not cost beneficial.

Finally, as mentioned in the opening discussion, HNP is in the process of implementing a security related enhancement that will provide SG level indication in long term SBO scenarios. As part of the security work at the site, it was determined that it would be possible to obtain SG level indication by connecting a portable instrument to one of the SG level channels. While the current scope of the enhancement does not necessarily include standard SBO scenarios, the potential to modify the scope of the procedures to include any SBO scenario is being investigated. This strategy for addressing long term operation of the TDAFW pump in an SBO does not benefit from the ability to operate the pump from the MCR, but it does not require the site to maintain an additional on-site AC source, the reliability of the portable level instrument is likely better than a portable AC generator, and the enhancement is already being implemented to address similar accident scenarios.

Discussion of the Impact of SECPOP Code Errors

It was recently learned that a portion of the MACCS2 (NUREG/CR-6613) site file produced by the SECPOP2000 code (NUREG/CR-6525) is not compatible with the input format of the MACCS2 code. The following is a summary of the process leading from discovery of the problem through determining its effects on the HNP SAMA evaluation.

<u>Discovery of Problem</u>

ERIN Engineering MACCS modelers preparing the SAMA analysis for the Beaver Valley License Renewal Environmental Report discovered that the format of the Regional Economic Data portion of the site file produced by SECPOP2000 is not compatible with the MACCS2 input format specification. They found this through a sensitivity study of MACCS's Milk Disposal Costs. The ERIN modelers found that no matter what value was used for the regional MACCS parameters DPF (fraction of farm sales resulting from dairy production), the milk disposal costs were zero. They tracked that problem back to an incompatibility between the SECPOP2000-produced site file format and the MACCS2 input format for the regional economic data. ERIN Engineering informed Scientech (its client) of the format incompatibility; Scientech then notified the NRC.

Problem Confirmation and Solution

The format incompatibility was confirmed by direct inspection of SECPOP2000 site files' Regional Economic Data formats and the MACCS2 input format according to the latter's users' guide. The SECPOP2000 format for this data is (converted to FORTRAN vernacular) "(I4, 1X, A7, I2, 2F10.3, 3F10.1)." That format is confirmed (in SECPOP's Visual Basic coding) on the bottom of page H-50 and the top of page H-51 of NUREG/CR-6525. The MACCS2 input format is given at the bottom of page A-15 and the top of page A-16 of NUREG/CR-6613 as (again converted to FORTRAN vernacular) "(I4, 1X, A10, 5X, 2F5.3, 3F10.1)." The latter format is confirmed by the MACCS2 FORTRAN source code in Subroutine "SDFINP", format 190. The result of this is that the five MACCS2 regional economic data parameters, FRMFRC, DPF, ASFP, VFRM and VNFRM are printed (right-justified) by SECPOP2000 in columns 15-24, 25-34, 35-44, 45-54 and 55-64. MACCS2 reads those same parameters from columns 21-25, 26-30, 31-40, 41-50, and 51-60.

DPF, for example, typically has the form "0.xxx." SECPOP2000 would print this in columns 30-34, with the leading zero in column 30. MACCS2 would then read this parameter (from columns 26-30) as 4 blanks followed by a zero, i.e., "0". The SECPOP2000 Regional Economic Data can be edited so that it is compatible with the MACCS2 input format specification by performing the following steps:

1. Delete four columns 25-28 (or 26-29) so that all columns to the right of the original column 30 are moved 4 places to the left.
2. FRMFRC typically is of the form "0.xxx," appearing in columns 20-24. MACCS2 will read columns 21-25, or ".xxxb," where b signifies a blank. That is the correct value, the leading zero can be ignored, and that parameter need not be edited for those regions.
3. Occasionally SECPOP2000 gives FRMFRC for a region as slightly greater than 1. In that case the value "1.xxxb" appearing in columns 20-25 must be rewritten as "b1.xxx", leaving the parameters edited in step 1 unchanged.

November 2006 HNP SAMA and Revised Calculation

The Regional Economic Data of the site file used for the baseline November 2006 HNP SAMA analysis was inspected and confirmed to be a result of applying the SECPOP2000 output. That site file was edited as described above and the MACCS2 computer calculation of baseline conditional dose and cost for each modeled sequence repeated.

Revised Dose and Cost Risk for Baseline Case

The original and revised conditional doses and costs for each of the modeled sequences are provided in the tables that follow. Although the original and revised conditional dose values are essentially identical, conditional cost values for two sequences, RC-5 and RC-5A, did change substantially. Changes in these two conditional cost values account for more than 99 percent of the increase (from $43,030 to $51,800) in total baseline cost risk.

HNP Conditional Dose

November 2006 Version							
Sequence:	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3
PERSON-SV	1.64E+04	2.08E+01	2.17E+04	1.25E+04	2.17E+04	3.51E+04	5.13E+03
Sequence:	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7
PERSON-SV	9.11E+03	2.23E+04	3.01E+04	3.11E+05	3.11E+05	5.99E+03	2.00E+04
June 2007 Revision (Regional Economic Data Format Revised)							
Sequence:	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3
PERSON-SV	1.64E+04	2.09E+01	2.17E+04	1.25E+04	2.17E+04	3.51E+04	5.13E+03
Sequence:	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7
PERSON-SV	9.12E+03	2.23E+04	3.01E+04	3.11E+05	3.11E+05	6.00E+03	2.00E+04

HNP Conditional Cost

November 2006 Version							
Sequence:	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3
Dollars	2.58E+09	1.40E-01	6.06E+09	3.83E+09	4.17E+09	1.18E+10	1.56E+08
Sequence:	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7
Dollars	5.01E+08	6.41E+09	8.27E+09	4.10E+10	4.10E+10	4.75E+08	5.61E+09
June 2007 Revision (Regional Economic Data Format Revised)							
Sequence:	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3
Dollars	2.59E+09	3.01E+02	6.10E+09	3.84E+09	4.20E+09	1.20E+10	1.57E+08
Sequence:	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7
Dollars	5.03E+08	6.45E+09	8.32E+09	5.17E+10	5.17E+10	4.77E+08	5.63E+09

The total baseline dose and cost risk are obtained by multiplying each of the sequence conditional doses and costs by that sequence's probability and then summing. The baseline frequencies are shown in the following table and are unchanged from the November 2006 version. The total HNP baseline dose risk of 28.97 person-rem (0.2897 person-sv) per reactor year is unchanged for the June 2007 revision. The total November 2006 HNP baseline cost risk of $43,030 per reactor year increases to $51,800 per reactor year for the June 2007 revision.

HNP Baseline Sequence Frequency

Sequence:	RC-1	RC-1A	RC-1B	RC-1BA	RC-2	RC-2B	RC-3
Frequency	3.22E-09	1.07E-10	3.97E-07	2.17E-08	8.13E-09	3.54E-08	4.37E-08
Sequence:	RC-3B	RC-4	RC-4C	RC-5	RC-5C	RC-6	RC-7
Frequency	4.60E-08	1.62E-07	6.36E-09	1.75E-07	6.40E-07	3.93E-07	9.55E-07

Revised SAMA Analysis

As described above, the corrections to the SECPOP2000 input to the MACCS2 analysis impacted the conditional dose-risk and cost-risk associated with the HNP SAMA analysis. The HNP modified Maximum Averted Cost Risk (MACR) (accounts for external events) was recalculated to ascertain the potential impact on the SAMA analysis. The modified MACR based on the mean PRA results increased from $3,510,000 to $3,774,000 (7.5 percent increase). The 95th percentile PRA results sensitivity case was also recalculated and it was determined that the modified MACR increased from $5,265,000 to $5,661,000 (also a 7.5 percent increase). The changes to the modified MACR estimates did not impact the analysis.

In addition to the impact on the modified MACR, the SECPOP error also impacted the averted cost-risks that were calculated for each of the SAMAs. The following table provides a summary of the impact of using the corrected results in conjunction with the mean PRA results in the detailed cost-benefit calculations that were performed.

Results Summary for SECPOP Error Correction (Mean PRA Results)

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (Post SECPOP Correction)	Net Value (Post SECPOP Correction)	Change in Cost Effective-ness?
SAMA 1	$1,000,000	$389,627	-$610,373	$390,266	-609,734	No
SAMA 2	$200,000	$53,062	-$146,938	$56,340	-$143,660	No
SAMA 3	$565,000	$34,204	-$530,796	$34,174	-$530,826	No
SAMA 4	$150,000	$62,238	-$87,762	$62,088	-$87,912	No
SAMA 6	$150,000	$111,240	-$38,760	$111,238	-$38,762	No
SAMA 7	$1,700,000	$81,860	-$1,618,140	$82,220	-$1,617,780	No
SAMA 8	$300,000	$298,979	-$1,021	$299,379	-$621	No
SAMA 9	$70,000	$93,614	$23,614	$93,794	$23,794	No
SAMA 10	$50,000	$11,222	-$38,778	$10,920	-$39,080	No
SAMA 11	$400,000	$8,604	-$391,396	$8,602	-$391,398	No
SAMA 12	$275,000	$60,584	-$214,416	$61,004	-$213,996	No
SAMA 13	$225,000	$111,148	-$113,852	$111,358	-$113,642	No
SAMA 15	$250,000	$93,974	-$156,026	$95,386	-$154,614	No
SAMA 16	$400,000	$6,048	-$393,952	$6,016	-$393,984	No
SAMA 17	$500,000	$52,820	-$447,180	$56,670	-$443,330	No
SAMA 18	$175,000	$35,886	-$139,114	$38,742	-$136,258	No
SAMA 19	$50,000	$9,384	-$40,616	$9,382	-$40,618	No
SAMA 21	$3,350,000	$407,428	-$2,942,572	$408,450	-$2,941,550	No
SAMA 22	$350,000	$65,813	-$284,188	$70,763	-$279,238	No

As demonstrated in the above table, the corrections to the SECPOP input had a minimal impact on the averted cost-risk estimates and did not alter the conclusions for any of the Phase 2 SAMAs that are based on the mean PRA results.

In addition to the review of the mean PRA results estimates, it was necessary to examine how the 95th percentile PRA results quantifications were impacted given that they were also used to identify potentially cost-beneficial SAMAs. The following table provides a summary of the cost-benefit calculations using the corrected SECPOP input in conjunction with the 95th percentile PRA results. As with the mean PRA results, there were no changes to the conclusions for any of the SAMAs.

Results Summary for SECPOP Error Correction (95th Percentile PRA Results)

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (Post SECPOP Correction)	Net Value (Post SECPOP Correction)	Change in Cost Effective-ness?
SAMA 1	$1,000,000	$584,441	-$415,560	$585,399	-$414,601	No
SAMA 2	$200,000	$79,593	-$120,407	$84,510	-$115,490	No
SAMA 3	$565,000	$51,306	-$513,694	$51,261	-$513,739	No
SAMA 4	$150,000	$93,357	-$56,643	$93,132	-$56,868	No
SAMA 6	$150,000	$166,860	$16,860	$166,857	$16,857	No
SAMA 7	$1,700,000	$122,790	-$1,577,210	$123,330	-$1,576,670	No
SAMA 8	$300,000	$448,469	$148,469	$449,069	$149,069	No
SAMA 9	$70,000	$140,421	$70,421	$140,691	$70,691	No
SAMA 10	$50,000	$16,833	-$33,167	$16,380	-$33,620	No
SAMA 11	$400,000	$12,906	-$387,094	$12,903	-$387,097	No
SAMA 12	$275,000	$90,876	-$184,124	$91,506	-$183,494	No
SAMA 13	$225,000	$166,722	-$58,278	$167,037	-$57,963	No
SAMA 15	$250,000	$140,961	-$109,039	$143,079	-$106,921	No
SAMA 16	$400,000	$9,072	-$390,928	$9,024	-$390,976	No
SAMA 17	$500,000	$79,230	-$420,770	$85,005	-$414,995	No
SAMA 18	$175,000	$53,829	-$121,171	$58,113	-$116,887	No
SAMA 19	$50,000	$14,076	-$35,924	$14,073	-$35,927	No
SAMA 21	$3,350,000	$611,142	-$2,738,858	$612,675	-$2,737,325	No
SAMA 22	$350,000	$98,719	-$251,281	$106,144	-$243,856	No